

National Grid Electricity Transmission System Operator (SO) Incentives for 1 April 2010

Development of Constraints
Forecast 2011/12

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Executive Summary

National Grid Electricity Transmission (NGET) is the National Electricity Transmission System Operator (NETSO) for England, Scotland, Wales and Offshore, defined hereon in as National Grid for simplicity.

Under the Transmission Licence, National Grid is obliged to perform Balancing Services Activities (BSA), which are defined as the operation of the transmission system and the procurement and use of Balancing Services required for reliable operation of the transmission system.

National Grid is obligated under the terms of the Transmission Licence to balance the system in a safe, efficient, economic and co-ordinated manner. The application of financial incentives encourages National Grid to invest in systems and resources to ensure BSA costs and risks are economically and efficiently managed and that innovative ideas and procedures are developed to reduce costs in return for a share of any savings delivered.

The Balancing Services Incentive Scheme (BSIS) is designed to deliver financial benefits to the industry and consumers from reductions in the costs or minimising risk associated with operating the electricity transmission network. The current format of the BSIS has been in place since NETA implementation in 2001.

On 13 November 2009, Ofgem formally requested National Grid to provide our best estimate of constraint costs for 2011/12 to help form a view on the appropriateness of a two year incentive scheme.

This document provides a response to this request, outlining the our best view at this time of the forecast constraint costs for 2011/12 with the information currently available to us. In addition, the report outlines the methodology used in developing this forecast and the main risks associated with the assumptions used.

The aim of the document is to present and seek views from Ofgem and the industry on the assumptions made in producing the 2011/12 constraint forecast and how this may impact the development of a two year incentive scheme.

This report forms an addendum to the Initial Proposals consultation. However, due to the responses to the Initial Proposals consultation being requested for Wednesday 16 December 2009, it is not feasible to request responses to this addendum in the same timescales. Therefore we request that responses to this addendum are submitted at the later date of 22 December 2009.

Responses to this consultation will be used by Ofgem to inform the development of their Final Proposals for SO incentives for implementation from April 2010. These should be available in early 2010. Any responses received will be placed on our website (unless explicitly requested not to) and sent in full to Ofgem.

Executive Summary

The main points of the document are:

- We used a revised forecast methodology to determine the constraint costs for 2011/12
- We provide an overview of potential methods of reducing the risk range for constraints and how this may impact on the development of an incentive
- We conclude that with the appropriate designed incentive, a two year, fully bundled scheme could be implemented in April 2010
- This 2011/12 central forecast is £498m with a forecast a risk range of £371m to £674m or -25% to +35%. This risk range is higher than 2010/11 risk range due to the greater forecasting uncertainties in 2011/12
- The constraint forecast summary is:

| Forecast | 2010/11 | 2011/12 |
|--------------------------|---------|---------|
| England and Wales | £187m | £133m |
| Scotland | £290m | £366m |
| Total Constraints | £477m | £498m |

- The industry are requested to respond on the following question:

Does the industry agree with the:

- development of a two year incentive that includes constraint costs?
- the proposed constraint adjusters be developed?
- the development of a fully bundled incentive scheme?

Responses to this consultation should be sent to soincentives@uk.ngrid.com

1 Introduction

In our Initial Proposals, we provided a constraint forecast for 2010/11 of £477m. Due to the uncertainties highlighted within the consultation with developing a longer term constraints forecast, we did not provide a constraint forecast for 2011/12.

On the 13 November 2009, Ofgem¹ formally requested National Grid to provide a best estimate forecast for constraints for 2011/12 to help industry participants to form a view on the appropriateness of a two year electricity incentive.

This report shows the methodology used to develop the constraints forecast for 2011/12 and our best estimates of the forecast constraint costs.

As part of the development of the forecast, we also discuss the implementation of appropriate constraint cost adjustments. These adjustments aim to reduce the impact of changes in constraint cost drivers from the outturn costs, therefore reducing the risk range but not the absolute cost forecast.

With appropriate incentive parameters, and the development of adjustments, we believe that a two year fully bundled incentive scheme can be implemented.

2 2011/12 Constraints Forecasting Methodology

The following section describes how the 2011/12 constraint forecast was derived. The process recently undertaken to derive the 2010/11 constraint forecast is described first so that the differences between the two processes can be understood.

The process for the development the 2010/11 constraint forecast within England and Wales was based upon National Grid's capital investment and outage planning processes. The key milestone in the outage planning process is the commencement of outage placement in engineering week 10 (March 2009 in the case of the 2010/11 plan year). At this stage all of the known outages that are required during the plan year for construction and maintenance should have been identified. These are then placed (with start and end dates) into an overall system wide outage plan. The creation of this plan takes account of factors including external contractual obligations, scheme delivery milestones, maintenance requirements, resources, system security and system cost.

To ensure the initial outage placement can be carried out it is important that the capital schemes have been sanctioned and that detailed design work has commenced to ensure that the specific requirements of the work can be reflected in the outage plan. An example of the specific requirements that need to be considered for an asset replacement scheme would be where additional outages are required on adjacent equipment to ensure safe access to replace the transmission equipment.

¹<http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Information%20Provision%20for%20System%20Operator%20Incentive%20Scheme.pdf>

Following the completion of outage placement and the creation of the year ahead outage plan, detailed network analysis studies are undertaken to optimise system security and costs. These studies in turn are used to identify transmission system constraints and volumes that feed into the BSIS constraint forecast.

The outage planning process in Scotland is defined in the appropriate STC² Procedure and is aligned with the England and Wales process.

The costing process considers a constraint 'resolution' price, which reflects

- Market conditions at the time actions were required to manage the constraint
- The volume of actions required
- The probability that a constraint limit will be require actions to be taken
- What actions are required/available to manage system flows

Separate models have been developed for specific boundaries in England and Wales and in Scotland.

The Scotland model was developed to forecast costs for 2009/10 and further developed for the 2010/11 forecast. The model is based on the most significant boundaries on the Scottish system and the location of generation and demand relative to these boundaries. Constraint limits for these boundaries, from power system analysis, are input to the constraint forecast model. The predicted running of generation is based on the running patterns seen since BETTA go-live up to the end of the 2008/9 BSIS year with a Monte Carlo simulation utilised to produce the variation around this and test the impact of different patterns. This is further combined with OC2³ data submissions and forecast demand to produce an expected flow across each boundary at daily resolution. Where this predicted transfer is in excess of the constraint limit, the model costs the actions required, taking account of intertrip schemes and where a single action may act to resolve multiple constraints.

This type of model is not suitable for forecasting costs of constraints in England and Wales, due to the interaction of and complexity of constraint limits. For most outages in England and Wales, a volume of actions required to manage the constraint is prescribed from power system analysis work and operational experience. A risk factor to capture the probability of needing to take actions to manage a constraint is applied. The risk factor considers generation availability as given in OC2 data, predicted running patterns based on historical running regimes and the direction of flows expected on the IFA⁴.

Where it has been identified that an outage is likely to result in significant constraint costs, additional modelling is carried out (e.g. for the Thames Estuary). Power system analysis provides a constraint limit, calculated against a set generation background. This chosen generation background will not be constant for the duration of the outage and the volume of constraint actions required will vary as the generation background changes. The model uses Monte Carlo simulations (from @Risk) to predict expected generation running at weekly resolution. Changes between this generation pattern and the generation pattern in the power system study are assessed and translated into a change to the prescribed constraint volume,

² System Operator – Transmission Owner Code

³ OC2 refers to the "Operating Code" section of the Grid Code which covers the requirements for generation to provide this information to the System Operator.

⁴ The Anglo-French interconnector

considering the circuit loading, circuit rating schedule and the effect of individual generators on the loading of the critical circuit.

Models of this form, specific to a single system issue and dependent on detailed power system analysis, have been used to forecast costs for Thames Estuary and Grendon – Staythorpe for 2010/11.

The process for the development of the 2011/12 constraint forecast has taken place considerably in advance of our normal process. The main differences associated with the availability of outage requirements at this early stage include:

- Uncertainty about the new capital schemes that will commence in 2011/12, for example due to customer driven connection work where user commitment is left as late as possible or consents which may be delayed
- Those capital schemes due to commence in 2011/12 that have not been developed sufficiently to provide accurate outage programmes
- Uncertainty about the maintenance outage requirements for rectification of defects and other conditioned based maintenance
- Uncertainty on generator availability meaning that outages can not be placed with certainty. This also affects the volume of the constraint forecast for the associated outages

The process adopted to produce an England and Wales 2011/12 BSIS constraint forecast was determined primarily by the uncertainty around the overall construction and maintenance outage requirements and the timescales to complete the work. The core of the process was the use of an 'expert group' who used their judgement in those areas where there was uncertainty and insufficient time to complete detailed technical analysis.

The input to the process was the best information available at that time about the capital schemes that would be in delivery during 2011/12. Outage plans were available for many of these schemes with varying levels of accuracy. Where outage plans were not available, the extent of the work required to deliver the specified outage were estimated by the 'expert group'. The 'expert group' allocated these outages, where appropriate, to the major transmission system boundaries and estimated the resulting constraint limits.

A total of 345 Main Interconnected Transmission System (MITS) circuit outage-weeks were identified through this exercise. This compares with 887 MITS circuit-weeks for construction work identified within the more normal 2010/11 process. The other main differences associated with the outage placement and network analysis compared to our normal processes include:

- The outages were not placed (start and end dates) within an overall outage plan. The assessment of Transmission constraints was therefore made primarily by considering each of the major system boundaries in isolation. It was not possible to assess the wider system interactions beyond these local boundaries.
- No network analysis studies were undertaken to assess the transmission system boundary limits and therefore constraint volumes.

The outage planning process in Scotland is defined in the STCP 11 and there is no obligation for the Scottish TOs to provide detailed outage information beyond the year ahead process. However, the Scottish TOs have provided outage information for major construction schemes with long term investment purposes. In addition National Grid requested whether any further information could be made available and

this was provided by the Scottish TOs where possible. This outage information was used as the basis for forecasting Scottish Transmission constraints using a similar process to the one that has been described for England and Wales above.

The model used for constraint costs in Scotland was adapted for the 2011/12 forecast. The constraint limits determined by the 'expert' group were input to the model, new generators added and the OC2 data updated to reflect submissions for 2011/12. A range was added to each boundary limit to reflect the additional uncertainty in the limit. The model operation was otherwise unchanged from use with the 2010/11 forecast.

Detailed models focusing on specific issues were not produced for England and Wales. Given the level of uncertainty in the outages and constraint volumes, and the time required to set up the assessments, power system analysis has not completed for 2011/12 plan and thus detailed models could not be developed.

The approach of applying a risk factor of actions being required to the volumes estimated by the 'expert' group was extended for use with all outages in England and Wales. As for 2010/11, historic running patterns of generation, OC2 data and predicted flows on the IFA and Britned were used to determine the probability of actions being required.

3 Assumptions used to develop the Constraints forecast for 2011/12

As discussed in the mini consultation on Constraints and the Initial Proposals document, constraint costs are driven by

- The volume of actions required
- The price of those actions

The volume of actions required to manage a constraint is dependant on

- Generation
- Demand
- Direction and volume of flows on interconnectors
- System capacity
- System to Generation intertrip schemes

The price of the actions is dependant on

- The price of the action required to resolve the constraint
- The price of replacement action to rebalance the energy position
- Price of margin actions required to replace margin sterilised behind the constraint

To develop a constraint forecast, we need to develop both volume and price assumptions. In developing the 2011/12 constraint cost forecast, we used the following methodology to develop our assumptions.

3.1 Volume assumptions:

3.1.1 Generation:

Conventional Flexible plant:

To develop the conventional coal and gas fired generation background, the following was used:

- Generation availability as shown in the OC2 data submissions
- Historic running patterns since January 2008 have been used to predict running regimes of generation in England and Wales.
- Data since BETTA Go-live has been used for Scotland⁵
- Commissioning dates for new generation⁶.

3.1.1.1 Nuclear Availability:

As discussed in the initial proposals, improved availability from nuclear generation is expected to continue as seen in recent months following significant refurbishment outages during 2008. When preparing the constraint forecasts, this means that raw OC2 data submissions are used for nuclear generation without application of an availability assumption.

3.1.1.2 Wind Generation:

The Scottish constraints forecast has assumed that 100MW⁷ of wind will connect each month in Scotland. This assumption has been derived from the TEC register and thus includes advanced projects under the Interim Connect and Manage (ICM) regime. The exact dates for the connection of wind farms under ICMR are at present still uncertain and hence have not been used in the described forecasts.

Prices to reduce the output of wind generation are assumed to be -£450MWh, as for the 2010/11 forecast.

3.1.1.3 Demand:

The demand forecast used in the constraints forecast is from the same data set used in the Energy Forecasting model. The assumptions used are as described in the Initial Proposals document.

⁵ 2009/10 data has not been used due to the high volume of contracts that influenced generation output. The volume of contracts in place in 2009/10 has been more significant than in previous years. Thus using outturn data for 09/10 would incorrectly lower the output of generation located in Scotland.

⁶ Where no other information is available, this is based on Connection dates. Where possible, more detailed information is provided from National Grid's customer connection team.

⁷ The Energy forecast for 2011/12 assumes 200MW of wind generation will connect across GB, 100MW of which is in Scotland and the remainder in England and Wales.

3.1.1.4 Direction and Volume of flows on interconnectors:

IFA (England to France):

The forecast for flows on the IFA (England – France) is based on the current forward power price spreads between the French and the UK energy markets.

Price spreads for traded peaks (07:00 to 19:00) between France and the UK indicate that significant volume of power will flow to France from UK on the IFA over the summer. The forecast assumes a 90% chance of at least a 1500MW export to France over the summer. Exports to France of 2000MW are expected over the winter. Power is expected to flow from France to the UK over night.

Britned (England to Holland):

Britned is due to commission in early 2011. Price spreads between Holland and the UK indicate that this interconnector will export over the peaks.

Flows during commissioning may not follow market signals. It is assumed that during 2011 and 2012, Britned flows will follow market dynamics.

Moyle:

Historically the spread in prices between the Single Electricity Market (SEM) and the UK market has not served as an indicator of power flow on the Moyle (Scotland – Northern Ireland) interconnector. Monte Carlo simulations, based on historic flows, are used to predict flows.

Wheeling of Power

It is possible that on commissioning Britned the ‘wheeling’ of power through the UK system from Holland to France could occur e.g. Britned importing power onto the UK system and the French interconnector exporting power to France. Such an event will cause a number of transmission system issues in the southeast of England.

However, recent studies of the interconnector price spreads have indicated that no such wheeling will occur. Hence, for the purposes of the 2011/12 constraints forecasts, it has been assumed that no wheeling will occur.

3.1.1.5 System Capacity:

The 2010/11 forecast is based on an outage programme submitted by Transmission Owners and power system analysis. Detailed models have been developed for boundaries where high costs are associated (e.g. Scotland, Thames Estuary).

A detailed outage programme is not available for 2011/12 at this stage and as such, different assumptions have been used to develop a forecast of constraint limits and actions required to manage system flows.

The 2011/12 forecast is based on:

- Indicative outages on key system boundaries that are required to deliver capital schemes such as new connections and asset replacement
 - For England and Wales, these outages are based on the best information known at the time of the forecast

- For Scotland, SP and SHETL have submitted provisional outage programmes

This outage plan was used to develop the costs associated with constraint incurred due to the indicative outage pattern required to deliver the capital plan.

The outage plan used to develop the forecast for England and Wales does not include any maintenance outage requirements. Maintenance outages are not included in the plan until the capital plan outages are placed. As the capital plan outages have not as yet been formally placed, no maintenance plan has been agreed. Therefore, to accommodate the potential constraint costs incurred by taking maintenance outages, the forecast costs developed using the capital plan outages was increased by 10% to include some provision for these unknown maintenance outages.

For Scotland, Scottish Power Transmission provided indicative volumes of maintenance work to be completed in 2011/12, providing a view of the circuits that required work and an estimation of the duration of outages to complete the work. No dates for these outages are currently available.

SHETL highlighted that they do not have their maintenance plans developed for 2011/12 at this stage. The volume of work required is such that all opportunities to access circuits would be taken to complete the necessary maintenance.

All maintenance outages have been assumed to be taken at times where they nest with outages required for capital works or where a boundary has 'space' to place such outages. Thus, the duration of active boundary limits in Scotland was extended to account for additional outages required on boundaries. Where there was no available slot on a boundary for maintenance constraint limits due to capital schemes tightened. This effectively models optimal placement of maintenance outages.

The expected constraint limits incurred due to this outage pattern and associated volumes of actions required have been identified. This was done without completing any power system analysis. The resource to complete the required power system studies was not available within the timescales. Equally, the system model is not available for the 2011/12 at this time. The constraint limits were determined by a group of experienced outage planners and based on operational experience of transmission system operation.

A more detailed discussion on impact of some key capital schemes is available in Appendix B.

3.1.1.6 Fault Outages:

The forecast costs for constraints in 2011/12 do not include any provision for the impact of fault outages at this time.

3.1.1.7 System to Generator intertrips schemes:

The forecast assumes that a system to generation tripping scheme is used as a post fault action where the required equipment is in place and where it would be economic to use such a scheme.

The forecast assumes that CAP170 is not in place.

Contract terms and prices for arming fees for all intertrip schemes assumed are not in place yet. The forecast used indicative prices, based on contracts in place currently and on discussions ongoing with providers. The forecast does not include any provision for fees paid in the event of a system to generation tripping scheme firing.

3.2 Price Assumptions

As discussed in the initial proposals consultation, the cost of a constraint is made up of the price of actions to resolve the constraint, the price of actions to rebalance the energy position and the cost of replacing margin. The price of actions to resolve a constraint is derived by the same method as for 2010/11.

Generic bid and offer prices are taken from the energy and margin models developed for the Energy Components forecast for 2011/12. The energy forecast model also gives a view of when the market will be long or short so resolution prices reflect if the action to resolve the constraint acts in the direction of the market or against, capturing the impact of bidding off generation when the market is short in the constraint forecast. Historic trends used to scale back the bid price for constraining off plant received from the forecast GBs bids are currently based on the same data set⁸ as used to scale bids for 2010/11.

Reducing the output of conventional generation provides a more economic alternative to reducing the output of wind generation when balancing the transmission system. The price assumed in the constraint forecasting to reduce the output of a wind generator is -£450/MWh. This assumption is unchanged from that used for 2010/11 costs.

⁸ This data set will be updated with additional outturn data as part of the Reforecast of constraint costs for 2010/11

4 Constraints Forecast for 2011/12

4.1 England and Wales:

The cost of resolving constraints in England and Wales in 2010/11 is forecast at £133m, with an expected (mean) value of £150m and 80% probability of being between £97m and £210m. The difference between central view and expected mean reflects the asymmetric nature of the forecast range.

The volume of work to be completed is similar to that planned for 2010/11, which was an increase on the amount planned for 2009/10.

The reinforcement of the North to Midlands boundary⁹ continues from 2009 into 2011/12. Up rating the transfer capacity of this boundary has required outages on Grendon – Staythorpe in 2009/10 and 2010/11. Outages on two equally significant circuits (Cottam – Staythorpe and Grendon – West Burton) on the boundary are required in 2010/11 and 2011/12. Constraints associated with these outages in 2011/12 are forecast to be £47m.

Outages required for Transmission Investment for Renewable Generation (TIRG) works are planned for the North East for England. There is currently no cost forecast for these works as they result in a limitation on imports. Imports are not forecast due to historic running patterns and market conditions.

New generation connections in the North West, East Anglia, Wales and in the Thames Estuary contribute to the outage requirements for 2011/12.

Outages are required for Off Shore wind connections in the North West. Based on availability of generation in the area as shown in OC2 data submissions, £4m is forecast to manage known issues in the area. The impact of increased transfers from Scotland, due to the reinforcement of the Cheviot boundary, on flows in the North West is not yet fully understood. More detailed study work is required to ascertain if there are local issues which will incur constraint costs,

Off shore wind connections has also led to a requirement to increase the rating of a double circuit route in East Anglia. Each of the Norwich – Walpole circuits will be taken out of service in turn and the overhead line replaced. The rating of the new overhead line is expected to be more than double that of the existing conductor. A significant volume of constraint actions are expected for the outage on the first circuit. The rating of the circuit when it returns to service is such that no constraint volumes are expected for the second outage. £24m is forecast to manage this boundary.

The 2011/12 programme for Thames Estuary is very busy with a major circuit out of service across the outage season. The Littlebrook – Tilbury outage work, started in 2010/11, continues for the eight weeks of 2011/12. Work then starts to connect the Quadrature boosters at Kemsley, required as part of the reinforcement strategy for this area of the transmission system. While the outages are as onerous as those in the 2010/11 plan, the time of year when the work is planned and expected imports on the IFA mean that the costs associated are significantly reduced. Also, the most significant outages are planned to take place at the same time as those on the Flow

⁹ North to Midlands boundary upgrade, East Anglia and Thames Estuary are discussed in more detail in Appendix B

South boundary, thus a single action is assumed to alleviate multiple constraints. Approximately £26m is forecast to manage constraint costs in this area.

There is a significant amount of refurbishment of circuit breakers and overhead lines required during 2010/11. Much of the outages required are on the Lower Flow South system boundary. Actions required to manage constraints due to the North to Midlands upgrade are assumed to alleviate constraints on the Lower Flow South boundary. An additional £7m is forecast to manage specific issues.

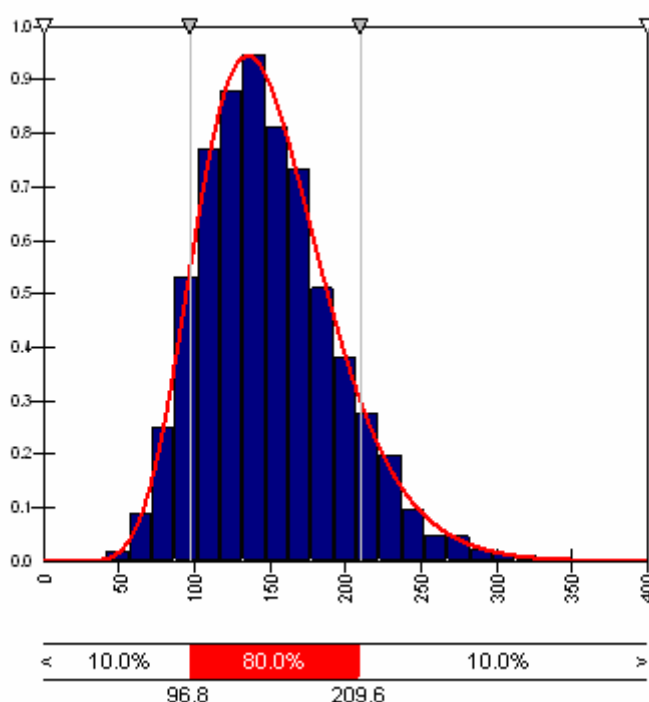


Figure 1: Risk range for 2011/12 constraints forecast for England and Wales

Changes from 2010/11:

1. There is no outage pattern currently planned which has an impact on system flows and constraint costs comparable to the outages in the Thames Estuary in 2010/11. Costs in the Thames Estuary are forecast to reduce by approximately £75m.
2. The work required in the East Anglia area for off shore wind connections incurs a significant volume of constraint actions. Outages of this length have not been taken previously in this area. This is an area where the forecast would benefit from detailed power system analysis and in depth modelling, as was completed for Grendon – Staythorpe costs for 2010/11.
3. The increase in constraint resolution price, due to changes in prices for margin, power and trades on the IFA, results in a change to the forecast of £9m, approximately an increase of 7%.
4. Time of year when outages are planned is key to the reduction in the constraint forecast. As the most significant boundaries are expected to be active at the same time, an action to resolve issues on one boundary will act

to alleviate issues on another. The volume of work required in the Thames Estuary in 2010/11 was such that outages were required over the winter

4.2 Scotland

The costs of constraining units behind the derogated non-compliant Cheviot boundary (between Scotland and England) are currently forecast for 2011/12 at £145m, of which £103m is for intertrip utilisation. The costs of resolving constraint within Scotland are currently forecast for 2011/12 at £221m.

The power flows within the Scottish system are primarily from North to South, flowing into England via two 400kV double circuits, the Cheviot¹⁰ boundary. The constraint limit across this boundary can be due to both thermal and stability issues. Generation to system intertrip schemes and contracts with generation units, in addition to actions in the BM, are used to resolve this constraint boundary. Work to reinforce this boundary has been in progress for a number of years.

During 2010/11, work is planned on the Eccles – Stella West route to increase the rating of the circuit. The new rating has not yet been confirmed and as such, the increase in transfer capability after these works are completed is uncertain. However, as the Cheviot transfer limit increases, boundary transfers internal to Scotland, become the binding limit.

During 2011/12 there are 25 weeks of outages planned on the Cheviot boundary. Towards the end of the outage season, a second 400/275kV interbus transformer is due to be commissioned at Strathaven. Nineteen weeks of outages are required at Strathaven to connect and commission this transformer, which reduce the transfer from Scotland which can be secured. The commissioning of the interbus transformer is anticipated to increase an internal boundary limit and allow more generation across the Cheviot boundary.

The outage programme in the north of Scotland is dominated by construction of the Beaulieu – Denny overhead line and connection works for new wind generation. Beaulieu – Denny works require outages at a number of substations in the North West. A double circuit outage on the SSE N-S boundary is required for the connection of new wind generation.

The outages required to complete work planned in 2011/12 has reduced the transfer limits which can be secured on internal system boundaries. The volume of new wind generator connecting in the North of Scotland has resulted in an increased number of active internal constraint limits. Wind generation must be reduced to manage flows across these boundaries.

The total cost of constraints in Scotland has a central forecast for 2011/12 of £366m, with 80% probability of being between £274m and £464m. This wide range reflects the uncertainty in the forecast.

¹⁰ This is also known as the B6 boundary

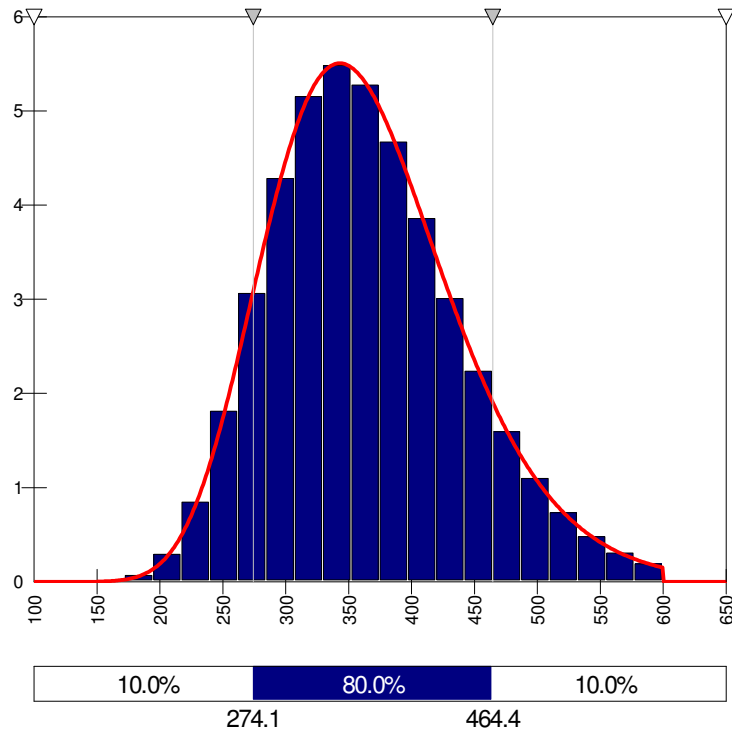


Figure 2: Risk range for 2011/12 constraints forecast for Scotland

The increase in the forecast is predominately driven by an increase in the volume of wind which must be restricted to secure system limits. This is caused by the combination of reduced internal constraint limits, due to the outage programme used in the forecast, and an increased volume of wind generation behind these boundaries. This accounts for an increase of £111m to the forecast from 2010/11 forecast.

The forecast currently assumes a bid price of -£450/MWh to restrict the output of wind generation. This is based on average bid prices for wind generation within the BM. As the volume of wind generation increases, the level of market participant may increase leading to wind generators submitting higher bid prices.

The forecast was updated using a bid price of -£150/MWh for wind generation to assess the potential reduction in costs possible with greater participation from wind generators. This reduced the forecast by £76m, all of which was part of the internal costs rather than Cheviot costs.

5 Drivers of increased range in forecast

The range of the forecast for constraints for 2010/11 is +22% and -20%. This range stretches to -25% and +35% for 2011/12.

5.1 Generation

5.1.1 Generation Availability from OC2:

The impact of the anticipated transmission outage plan for 2011/12 on the system has been assessed against the generation background indicated by OC2 data submissions for 2011/12. Generators are obliged to provide a forecast outage plan as part of the Grid Code obligations (Operating Code 2).

The OC2 data submissions are updated on a weekly basis for outages planned for the following 52 weeks. Submissions for the following year are updated periodically. The generation outage data used in the forecast for 2011/12 is based on data submissions from September for 2011 and June for 2012 while the updated forecast for 2010/11 will be almost entirely based on data submitted the week the re-forecast is finalised. This introduces additional uncertainty into the forecast.

Updating OC2 data submissions beyond 52 weeks ahead is a significant task for the generators. Completing this update would not have allowed the December 11th deadline to be met. Therefore we have used the latest available information that may be less accurate.

5.1.2 New Conventional Generation:

Deciding the date at which new generators connecting to the system will begin commercial operation is an element of constraint forecasting which carries with it a high level of uncertainty at the year-ahead (2010-11) stage. This is because the lead time from construction commencing to the plant being ready to start commissioning is approximately 3 years for a CCGT (for 2011-12 the new conventional connections which we are concerned with are all CCGTs). This means that two thirds of the construction risk has been overcome and there is a reasonable level of certainty of the commissioning date being met.

For the 2 year-ahead (2011-12) forecast, the new connections that are being considered are only likely to be one third of the way through construction. This means that there is much less certainty that commissioning dates will be met.

In general, these dates only move back rather than forward. Developing the assumptions for connection dates at 2 – 3 years ahead with little additional information would mean arbitrarily determining their energisation date. Looking back at historic generation connection dates, there is no clear pattern followed with some generators having major delays through construction whilst others have worked much closer to their planned dates .

Therefore, we have assumed the submitted connection dates for each new generator that plans to connect, where additional information is not available

5.1.3 Wind

An additional 200MW of wind is forecast to connect each month in 2011/12 with this split equally between Scotland and England and Wales. New wind connections in

England and Wales are not anticipated to significantly impact the constraint forecast. This volume may increase or decrease, as more projects are granted connection dates or as projects are delayed and cancelled.

The price of actions to reduce wind output is that used in the 2010/11 forecast and is an approximation of the average bid prices for wind in the BM. Work continues to increase the participation of wind generation in the BM. The level of participation of new generation in the BM is also uncertain. The level of participation and bid prices achieved in 2011/12 introduce a significant risk to the forecast; the impact of differences in bid prices is also anticipated to increase as the volume of wind increases. Achieving a higher bid price than -£450/MWh will reduce constraint costs. As more wind connects behind active constraint boundaries, the effect of bid prices achieved will become more pronounced.

5.1.4 Interim Connect and Manage

Under the Interim Connect and Manage regime, there is potential for significant volumes of generation to connect in addition to the generation assumed in this forecast. Generators on the TEC register are assumed in the development of the forecast. A number of connection offers have been made which are dependent on specific system boundaries being granted derogation from SQSS; these generators are not considered by the forecast.

The assumption of 100MW of wind generation connecting per month in Scotland accounts for some connection offers which have been advanced due to Interim Connect and Manage. No other additional generation has been included in the forecast.

The potential for generation to connect under this regime introduces a significant risk over running patterns.

5.1.5 Risks to Forecast due to Nuclear Generation Availability

As discussed in the assumptions and the initial proposals, improved availability from nuclear generation is expected to continue in 2011/12. to the forecast for 2010/11 and also 2011/12. Given lead times for required equipment and generator build times, there is more certainty in the volumes likely to connect under IC&M in 2010/11 than in 2011/12.

5.1.6 Large Combustion Plant Directive:

The historical output of machines affected by LCPD has been used as an indication of their future running patterns. For England and Wales, during the outage season only, there are notable reductions in output post-LCPD implementation. This reduction is therefore assumed to remain for 2011-12. This has the effect of causing a continued requirement for extra machines to be dispatched in the South. However, for the Estuary issue, reduced running of LCPD plant has lessened the requirement slightly (compared to winter when running of LCPD affected plant is more likely). Also, as the date for opted out plant to have ceased operation approaches, there is less certainty

There are a number of outages expected where constraint volumes are heavily dependant on specific nuclear generation. Thus any uncertainty regarding availability reduces certainty in the forecast. While this risk is present in the 2010/11 forecast, the volume of constraints affected in 2011/12 is greater due to the outage plan.

5.1.7 Risk to Forecast due to Changes in Demand Forecast

The demand forecast used in the constraints forecast is from the same data set used in the Energy Forecasting model. The assumptions used are as described in the Initial Proposals document. The effect of changes in demand forecast on the costs of constraint components is small when compared to changes in generation patterns and thus represents a significantly lower risk than generation availability. .

5.1.8 Direction and volume of flows on interconnectors:

UK – European Spreads:

The volume and direction of flows on the IFA and Britned are forecast based on forward power prices published in Argus. At the year-ahead (2010-11) stage, quoted quarterly prices can be directly compared for each market for the outage season (Q1 2011 is not yet available). For 2011/12, seasonal products are quoted for the UK. However only “Calendar Year” prices are available for France and Holland. A comparable spread is therefore approximated.

The weight within each quarter for 2010/11 is calculated and the ratios used to derive quarterly prices for comparison to UK prices. This makes an assumption that quarterly breakdowns in the French and Dutch markets remain roughly constant each year. This assumption is not required when forecasting at year-ahead.

The further a product is broken down (i.e. into Months and Quarters) the higher the level of certainty that can be applied to its price. Therefore, closer to real time, the Argus price gives a better indication of power flows on the interconnectors. Given the impact that interconnector flows have on system flows and constraint volume and costs, the risk around interconnector flows presents a significant risk of windfall gains and losses.

Britned Commissioning:

Britned is due to commission in early 2011. Price spreads indicate that IFA and BritNed will export together. As such, BritNed is expected to reduce constraints in the Thames Estuary. Should BritNed fail to commission successfully and operate reliably, the volume of constraints in the Thames Estuary would increase.

The dependence on the timely connection of a new facility at this lead time increases the risk of the constraint forecast.

Wheeling of Power

Price spreads between UK and Holland and UK and France indicate that power on both interconnectors will flow in the same direction (to or from the UK), thus no wheeling of power through the GB transmission system has been assumed. It is possible that RTE and TenneT will seek to wheel power through the UK to manage constraints on interconnection between their transmission systems; however the method by which they can achieve this is anticipated to be via SO – SO trades. National Grid has mechanisms available to price such trades so that compensation for the required action is obtained.

Moyle:

Currently the Moyle interconnector (Northern Ireland – Scotland) has TEC of 80MW, although it is technically capable of importing up to 400MW. Prior to the introduction of Interim Connect and Manage TEC could not be increased prior to wider reinforcements being completed, however this is now a possibility. Increased imports from Northern Ireland will have the same effect of another new generator, increasing the volume of constraint actions required.

5.1.9 System Capacity:

System capacity is reduced due to outages required for new connections, system reinforcement asset replacement, maintenance and fault outages. There are also a number of intact system restrictions e.g. boundaries on which constraints can occur with all circuits in service.

The outage plan used in the development of the 2011/12 forecast has been based on the best information on capital scheme requirements provided by TOs. As mentioned previously, some of the TOs were able to provide indicative maintenance plans. Where these were not provided, an assumption of the likely impact of these unknown maintenance outages on constraint costs was made.

Capital works – new connections and asset replacement

The plan for capital schemes due to be delivered in England and Wales in 2011/12 is reasonably well established. However, the details of some schemes are not fully known at this stage and changes are expected as detailed design work is completed. The phase of development of each scheme is key to the level of confidence in the outage programme required.

Where a scheme is in the initial stage of development (internally described as IP1), the scheme has not yet been developed for sanction. As such, no detailed design work has been completed and outage requirements for the scheme will not have been specified. The outage programme developed by the Year Ahead planning team will not include any requirements for that scheme. As a scheme moves through development stages (IP2 through to IP4), requirements become better established. Significant changes are still expected at the IP2 stage. Only at IP3, does the scheme design and thus outage requirements become stable. Of the schemes to be completed in England and Wales in 2011/12, 55% are at stages IP3, IP4 or In Delivery (where work has already started or is due to commence in 2010/11).

For Scotland, SP have indicated they have a similar level of confidence in the capital schemes driving their outage plan submitted for 2011/12. SHETL have less confidence in their capital plan; one of the major uncertainties with the SHETL outage plan is that it is dependant on the planning decision taken on construction of the Beaulieu – Denny overhead line. The decision on whether the Beaulieu – Denny circuit proceeds will drive the SHETL outage programme in 2011/12.

Some of the schemes currently planned for 2011/12 will not be completed; however additional scheme work will replace them. The assumption throughout the process is that in the event of a scheme being replaced by an alternative scheme, the impact of outages required for both schemes on constraint costs is equal. Although this is a reasonable assumption it is possible that the revised scheme will impact constraints differently than the original scheme and therefore impact the constraint costs.

Maintenance:

The outage programme is developed so that system access requirements for new connections are given highest priority. Outages for asset replacement are overlaid on this initial plan. Maintenance requirements are then placed optimally. Optimal placement of maintenance outages does not guarantee that an outage will not incur constraint costs, rather the risk and volume of costs is minimised where possible. However, completion of maintenance works is not optional and although they are generally more flexible, costs may be incurred for such works.

Given the uncertainty around capital outages requirements at this stage, no maintenance outages have been placed for England and Wales. As we have no view of specific maintenance requirements, the forecast costs for the capital works in England and Wales have been scaled up by 10% to take account of maintenance outages. The drivers (maintenance or construction) for outages in the 2010/11 plan have been considered to inform assumptions on the volume of maintenance work required in 2011/12. Outages for maintenance make up 30% of the programme for 2010/11; a similar percentage has been assumed for 2011/12. However, maintenance costs are forecast to account for 10% of costs to reflect optimal placement of maintenance outages.

Therefore the constraint costs are:

Overall constraint costs = (Capital scheme constraints costs) x (maintenance scaling factor)

The approach used in Scotland differs slightly. SP indicated requirements in terms of a number of weeks required on particular circuits; an assumption was made as to the volume of work which SHETL would need to complete. Requirements were placed considering where constraint limits due to capital works would not be made worse by maintenance outages. The binding restriction may not be system access but rather resources or equipment; as such optimal placement with respect to constraint costs may not be possible. This will not be known until detailed assessment of the maintenance requirements and work involved is known. As such, this introduces an increased level of uncertainty into the forecast.

Absence of Power System Analysis:

As described above, no power system analysis has been completed; the forecast is based on operational experience of within year and year ahead planners. This uncertainty over constraint volumes increases the risk beyond that contained within the 2010/11 forecast. Symmetric ranges have been applied to estimated constraint limits to capture the possibility that volumes may be under or over forecast.

A volume of actions required has been estimated for outages in England and Wales. Monte Carlo simulations have been used to vary these volumes and thus describe a range on the forecast.

For Scotland, constraint limits were estimated for significant system boundaries. Monte Carlo simulations have been used vary the limit by an amount proportional to the size of the limit symmetrically.

In addition to the risk on the limits prescribed, the full interaction between some outages may not have been captured and system issues requiring additional actions may become apparent when detailed analysis is carried out.

The timescales during which the forecast was prepared were not sufficient to complete the level of system analysis required to develop a more robust forecast. However, the data sets used in the power system studies are prepared as detailed design work for schemes is completed. As such, data sets required for 2011/12 are currently in the early stages of production.

Significant changes to Transmission System.

Some of the work planned for 2010/11 will dramatically alter the transmission system configuration and capacity (e.g. Thames Estuary, completion of TIRG). As such, there a number of areas of where there no operational experience can be drawn upon to assess the impact of outages planned in that area, after completion of these works. Equally, where the impact of works on the immediate area is relatively well understood, interactions with other system boundaries are not yet fully understood; power system analysis is required to ensure all associated issues are fully understood.

As the impacts are not known, limits assumed in the forecast are potentially over restrictive, resulting in forecast costs being too high. However, there is an equal risk that volumes assumed in the forecast are optimistic and that the forecast costs are lower than required.

5.1.10 Fault Outages:

As discussed in the Initial proposals (section 2.8.1.6) faults resulting in damage to transmission system equipment required significant outages to allow safe return of the equipment to service. The impact of these outages cannot be mitigated in the same manner as planned outage. The forecast does not contain any provision for the impact on fault outages on constraint costs.

In addition to the impact on constraint cost incurred within 2011/12, fault outages may affect the volume of work completed during 2010/12. For example, a type fault on a piece of equipment with a catastrophic failure mechanism may limit access to the transmission system. This can potentially result in maintenance work and asset replacement work planned for 2010/11 being pushed into 2011/12. This work may be required in addition to works planned for 2011/12, increasing constraint costs or the work may replace some other planned work, changing the system limits and affecting the volume of constraint actions needed.

5.1.11 System to Generation Intertrip Scheme:

The assumptions made in the forecast concerning the use of system to generator intertrip schemes are the same as those used in the forecast for 2011/12. Extending the constraints forecast from 2010/11 to 2011/12 does not introduce any additional risk to the forecast, beyond that inherent with a forecast for a single year.

5.2 Prices

The figure below illustrates the change in forward prices over time compared to the outturn. The range has been developed comparing forward power prices and day ahead price. As can be seen from the graph,

- at 4 weeks ahead the ability to use forward power prices as an indication of short-term prices sits within a range of around +30%/-25% of actual prices
- at 16 weeks ahead (approximate time between of the year ahead 'final forecast' and the start of the incentive scheme), the ability to use as forward power prices is only +50% / -30%
- Beyond 40 weeks ahead, the range only increases further to +60% / -40%

Thus, while power price introduces a level of uncertainty to the forecast costs, extending the forecast to a second year does not increase this level of uncertainty significantly beyond that inherent with a forecast for a single year.

Forward price accuracy

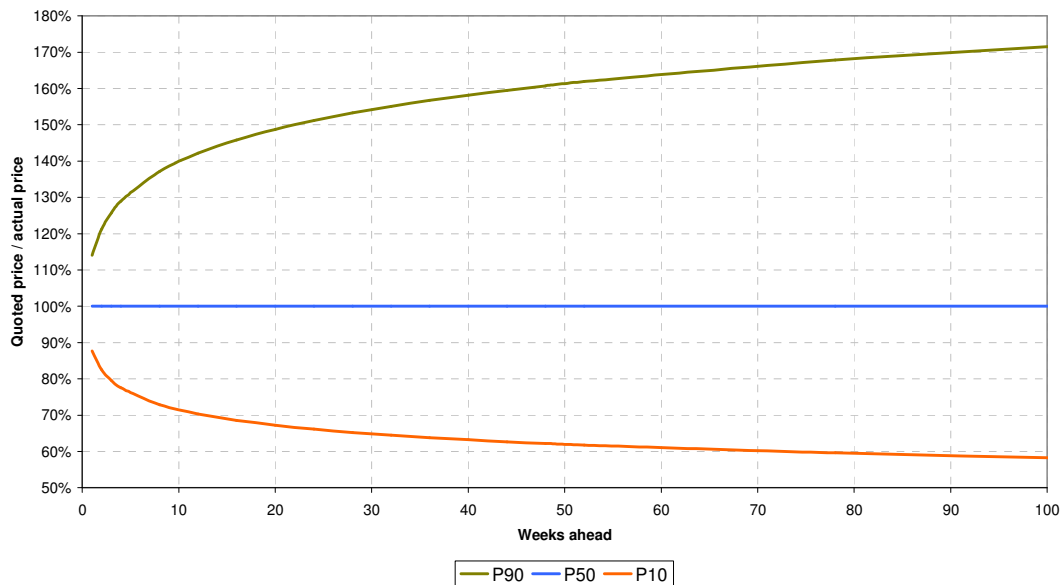


Figure 3: Forward power price relationship with day ahead power prices

5.3 Market Modifications:

There are a number of market developments that will drive constraints costs, the result of which are currently unknown. These are:

- CAP170¹¹ - Category 5 System to Generator Operational Intertripping Scheme
- Locational BSUoS¹²
- P229¹³ – Introduction of a Seasonal Zonal Transmission Losses Scheme

¹¹ More information on CAP170 can be found at <http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentsproposals/>

¹² More information on Locational BSUoS can be found at <http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/>

¹³ Information on the BSC mod P229 can be found at <http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=254>

P229 seeks to allocate transmission loss costs more appropriately across generators and demand customers. An assessment of the impact of P229 indicates a change in generation patterns. This change in generation pattern may be beneficial to constraints.

The impact of these modifications would significantly impact constraint costs post implementation. Due to the uncertain outcome of the implementation these proposals, the potential impact has not been included in this forecast.

6 Incentive Development

This section describes additional electricity scheme options for the treatment of different risk profiles within a fully bundled scheme.

6.1 Overview

In the preparation of the BSIS Initial Proposals¹⁴, National Grid outlined its preferred scheme option for implementation in April 2010. Specifically National Grid highlighted its preference for an unbundled constraints incentive.

The industry and Ofgem have expressed some concern with the implementation of unbundled incentive scheme. These concerns were mainly focused on the allocation of balancing actions to specific cost categories e.g. an action that is taken to resolve a constraint that also results in additional operating reserve.

National Grid recognises this concern and to address this, within section 4.5.1 of the BSIS Initial Proposals, we suggested that a 'Constraint Costing Methodology Statement' could be developed as a licence requirement similar to the requirement to prepare and adhere to the Balancing Principles Statement (a requirement in section C16 licence). To ensure consistency of outturn against target costs, the same methodology would be used to determine the forecast constraint costs and the outturn constraint costs.

One of the major factors in the decision to unbundle constraints from the other cost components was the differential in the risk profile for the two proposed incentives. The table below shows the forecast upper and lower cost ranges for both constraints and the remaining balancing cost components for 2010/11 and 2011/12¹⁵.

¹⁴ This document can be found at the following web address -

<http://www.nationalgrid.com/NR/rdonlyres/519DEB34-5CCE-40D6-9980-9DE23A41E666/38228/ElectricitySOIncentivesInitialProposalsConsultatio.pdf>

¹⁵ National Grid has provided a constraint forecast for 2011/12 in response to Ofgem's open letter of 16th November 2009 -

<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=Information%20Provision%20for%20System%20Operator%20Incentive%20Scheme.pdf&refer=Markets/WhIMkts/EffSystemOps/SystOpIncent>

| | Year | Lower range | Mean | Upper range |
|---------------------------------|---------|----------------|---------|----------------|
| Constraints cost forecast range | 2010/11 | £387.6m 20% | £485.5m | £594.2m 22% |
| | 2011/12 | £371m 25% | £498m | £674m 35% |
| 'Energy' cost forecast range | 2010/11 | £454.6m 8% | £492.6m | £531.5m 8% |
| | 2011/12 | £490.1m 7% | £524.8m | £575.7m 10% |

Figure 4: Risk profiles of constraint and energy components

The unbundling of constraints, with this unbundled scheme having lower sharing factors and caps and collars than the remaining cost components, is one method of addressing the differential in risk profiles. There are a number of other methods that can be used to address the differential in risk profiles. One such method, as detailed in the initial proposals, and one which has been adopted previously, is to reduce the sharing factors and caps and collars for the overall bundled scheme, reducing the impact of any changes in costs on the System Operator. However, this approach can lead to a conservative approach to managing incentive costs.

Another method of addressing the differential in risk profile is the implementation of suitable and appropriate cost adjustments. For example, the implementation of the Net Imbalance Adjustment (NIA) has led to a reduction in the risk range of costs for all components excluding constraints, resulting in a relatively narrow risk range, indicating a more controllable cost base.

Within section 4 of the Constraints mini consultation¹⁶, published on 9th September 2009, we considered a number of adjustments that could be used to reduce the potential for windfall gains and losses that would ensure that National Grid focus attention on deriving value from the management of the drivers of constraints within its control. In section 4.7.3 of the BSIS Initial Proposals we summarised respondents views to the implementation of adjusters, specifically in relation to a two year incentive the main points raised are:

- Adjustments would reduce or remove the incentive to reduce costs
- Although respondents agreed that the adjustments identified were cost drivers, they believed that National Grid had some control over these drivers

Following the industry and Ofgem raising concerns with the implementation of unbundled incentive schemes, we feel it is important to further consider potential constraint related incentive scheme adjustments as an alternative to unbundling.

¹⁶ This document can be found at the following web link - <http://www.nationalgrid.com/NR/rdonlyres/5BCE1A3B-D7BC-4F1B-8DFF-68B6162643DA/36862/NGETSystemOperatorIncentivesfor1April2010Consultat.pdf>

6.2 Potential adjustments

Within the Constraints mini consultation we outlined four potential adjustments that could be considered, which can be categorised into three areas:

- Price adjustment
 - Bid / Offer price spread
- Volume adjustment for generation
 - Volume of new generation connecting
 - Volume of generation behind derogated boundaries
- Volume adjustment for outages
 - Number of outage weeks on circuits across key boundaries

Based upon the feedback to the Constraints mini consultation and further analysing the drivers impacting the 2010/11 and 2011/12 forecasts of constraints we have further developed how adjustments could be implemented.

6.2.1 Prices adjustment

One of the key factors involved in calculating the cost of a constraint is the price of actions taken to resolve the constraint. In simple terms, this is the difference between the Bids and Offers needed to manage the constraint. Whilst we are able to use alternative, more economic, methods to manage constraints such as constraint contracts or intertrips, the assessment of these alternative services are compared against the forecast Bid/Offer spread to determine whether the alternative services are economic. A level of efficiency assumed from using constraint contracts and intertrips is built into our forecast.

Figure 5 below shows how the spread between Bid and Offer prices has varied historically with changes in wholesale price.

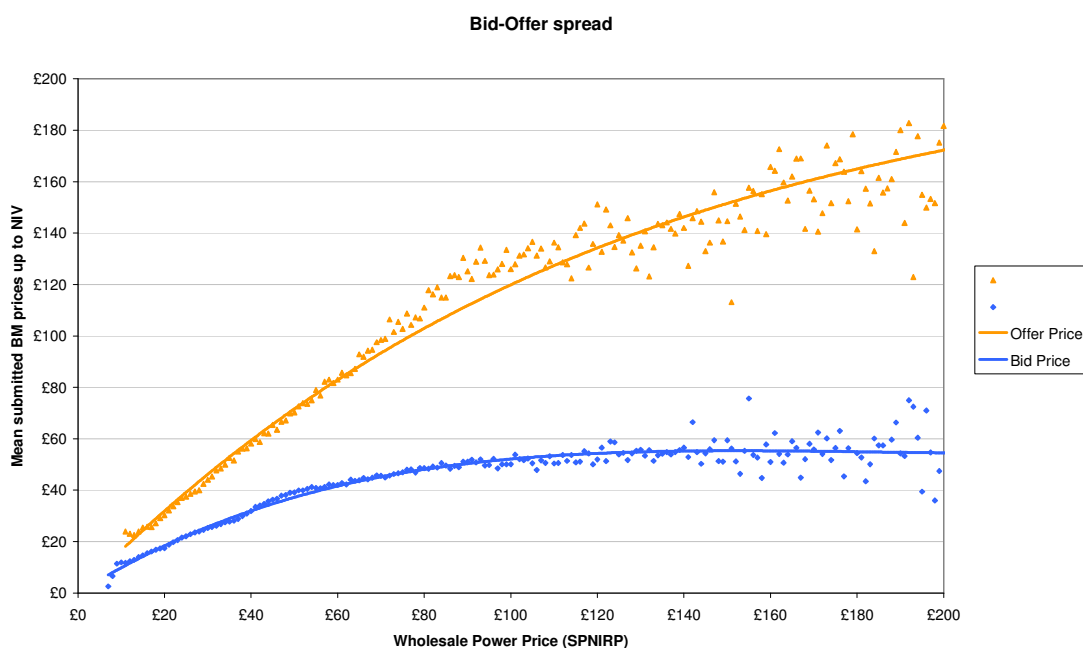


Figure 5: Bid – Offer spread against changes to wholesale prices

As can be seen from the graph above a change in wholesale price will influence the bid/offer spread and hence the cost to resolve a constraints. Adjusting our incentive scheme for changes in the bid/offer spread will therefore remove the potential for windfall gains or losses for changes from those used in the forecast that it outside of National Grid's control.

A key concern on using such an adjustment is that a suitable incentive remains on National Grid to reduce risk or costs. For instance an incentive that is based upon outturn bid/offer spreads may reduce the incentive to contract with generators to manage the price risk or reduce the incentive to work with the Transmission Owner to consider alternative periods to take the outage where prices may be lower.

To overcome this issue the adjustment to prices could be made on a forward looking basis after a set period, say monthly or every six months or have bands of bid/offer spreads where if the price moves within the bands, there is no adjustment and if the price moves outside of the band, there is an adjustment. Such an approach would provide a balance between National Grid's ability to manage price risk with the need to remove the potential for windfall gains or losses for factors outside of National Grid's control. National Grid's typical maximum horizon for contracting with generators is six months ahead. This is due to the uncertainty of the constraint requirement beyond this horizon, i.e. at this horizon, generation and therefore constraint volumes and prices are more uncertain.

A methodology for revising the constraint target as described above could be as follows:

Revised constraint target = Remaining monthly constraint target x adjustment factor

Adjustment factor is calculated using the forecast Bid / Offer spread and the actual Bid / Offer spread

It is evident that a price adjustment would reduce the risk range for constraints. At this time, National Grid has not been able to determine the level of risk reduction. Further work will be required to provide the analysis to determine this.

For the constraining of conventional generation, the above bid/offer spread relationship is generally maintained. However, where the constraint requires a change in non-conventional generation, this relationship would not hold true. For instance, where wind generation needs to be constrained, the cost is not dependant on market prices. Therefore an additional adjustment may need to be implemented for constraints that require wind generation to change their output.

6.2.2 Volume adjustment for generation background

The volume of constraints is heavily dependant on the background generation. As the majority of the generation is self dispatched to meet contractual requirements, National Grid has limited control over the volumes. For example, constraints in the South East are heavily influenced by flows on the IFA, with the flows themselves being influenced by the GB-France wholesale price arbitrage. In the constraint forecast for 2010/11 the assumption is that the IFA will flow to France; however, if the IFA flows fully to England then constraint costs associated with outages in the Thames Estuary will be zero. Such a change would result in a significant windfall

gain to National Grid (e.g. a £100m reduction in targeted costs, assuming a 25% sharing factor would provide a £25m windfall profit).

In addition to the points raised above, with the introduction of ICM the capacity of generation connected at certain parts of the network may increase beyond that anticipated at the time the incentive scheme was agreed. This is particularly the case for incentive schemes that are in excess of one year in duration.

In the Constraints mini consultation, we discussed potential adjustments around new generation connecting or generation output behind a derogated boundary; however, as demonstrated above with the example of IFA flows on the Thames Estuary constraint, these adjustments alone would not remove all potential windfalls and would need to be boundary specific. Any adjustment for generation background would therefore need to be more general, i.e. wider than just derogated boundaries or just new generation connecting.

An adjustment to account for changes in generation background would need to be specific to a constraint rather than generic across all constraints. To illustrate why, a comparison can be made on how generation output impacts different constraints. For the Thames Estuary constraint, a reduction in exports on the IFA to France (or indeed a move to imports to England) would reduce constraint costs whilst reductions to generation on the south coast would increase costs. By comparison, on the Cheviot boundary any reduction in generation north of the boundary would reduce costs. Generation volumes associated with the Cheviot boundary interacts with multiple constraint boundaries within Scotland (e.g. reductions to generation north of Cheviot may reduce costs on multiple boundaries). It is therefore necessary to develop adjustments specific to each constraint.

Developing a methodology to determine the outturn generation volumes in order to compare with those agreed in the forecast would need some form of measuring generation output. There are a number of potential ways in doing this; one such way is to derive the outturn volume using the relevant generators Final Physical Notification¹⁷ (FPN). Any difference in volumes can then be valued based upon an assumed bid-offer spread and the resultant adjustment determined.

However, a key tool National Grid uses to manage constraints is contracts. These contracts typically cap or collar a generators output by reference to maximum or minimum FPN. National Grid is therefore paying a generator to alter their FPN to manage a constraint and this would not be accounted for as part of the adjustment methodology that uses FPNs alone, i.e. National Grid may pay to reduce a generators output and then the adjustment also reduces the incentive target. To ensure National Grid is not penalised for contracting to manage constraints in the most economic way it would therefore be necessary to take account of contracted volume as part of the adjustment.

Such a 'contract volume' adjustment could be calculated by National Grid providing a view of the generation output it is reducing or increasing as part of contract. However, this raises two issues; firstly it would mean that the contracting risk that National Grid is exposed to is reduced (i.e. the target would adjust to the contract assumption) and, secondly, it would require a methodology to ensure the assumption

¹⁷ This is a final notification at gate closure before any balancing action (i.e. bid or offer in the balancing mechanism) that may be used to manage a constraint

is correct (i.e. it may benefit National Grid to overstate the assumption). An alternative method would be to forecast what the generation output would have been had National Grid not contracted. This could be done by making assumptions on a generator's fuel price, efficiency and cost of carbon; and compare this to a market price to assess whether a generator would have run. National Grid has previously used such formulas in constraint contracts¹⁸.

Finally, with respect to an adjustment for generation background, consideration needs to be given for outage period or timing changes. For example, the SO may request the TO to move an outage back a few weeks to better align with a generator outage to reduce constraint costs. An adjustment for background generation would need to take account of such changes to ensure it does not create any perverse incentives.

We therefore believe that an adjustment can be developed that could reduce the risk in changes to generation output from those assumed; however, this adjustment will be relatively complex and will need to be dependant on each system boundary.

6.2.3 Number of outage weeks on planning boundaries

One of the drivers of constraint costs is the number and location of outages, especially outages on critical boundaries. We have recently seen fairly significant changes to the expected connection date of generation in the short-term, a move to a two incentive scheme for constraints increases the chance of windfall gains or losses simply from a generator amending their connection date with the resultant change in outages.

In addition to outages changing for generation connection dates, a number of outages may change throughout the year, e.g. extending or deferring outages due to unforeseen complications.

Whilst generators or the TOs may impact outages, clearly National Grid as System Operator plays a key role in amending outage plans of all TOs to manage constraints costs. A recent example of this was the redesign of the Thames Estuary investment to reduce constraints which led to a reduction in forecast costs of £72m which has been incorporated in to the 2010/11 forecast.

For an adjustment to work for outage weeks it would be necessary to differentiate between outages changes due to a change to a generator outage, a TO overrunning on an outage or where the SO has amended the outage plan to refine it to reduce constraint costs.

There are a number of issues with the implementation of an outage week adjustment methodology. These have been highlighted in previous consultations and responses from the industry. Therefore, we believe it that it is not prudent to further develop this adjustment proposal at this time.

¹⁸ http://www.nationalgrid.com/NR/rdonlyres/3C73E6E5-2278-4BEB-962F-6D8F18A64BB7/28302/CMS_Service_Description_Issue2.pdf

6.3 Scheme Design

Our Initial Proposals set out our preferred scheme which is the unbundling of constraints from the remaining cost components.

In addition we proposed a fully bundled scheme for 2010/11 as outlined below:

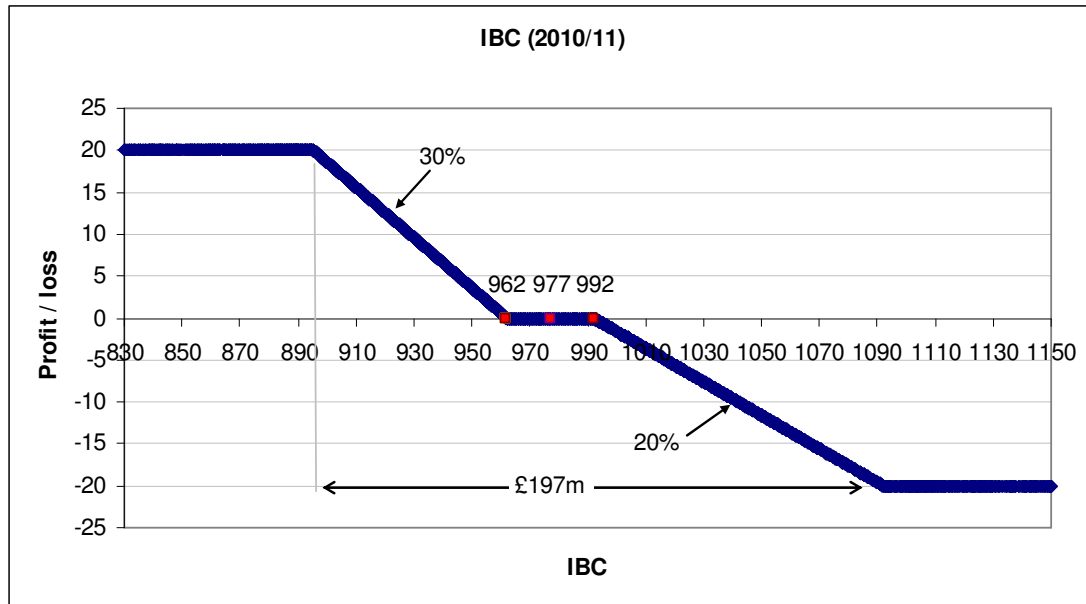


Figure 6: Fully bundled one year incentive for 2010/11 from the Initial Proposals consultation

| Scheme | Target | Upside sharing factor | Cap Collar | & Downside Sharing factor | Deadband |
|---------------------------|--------|-----------------------|------------|---------------------------|----------|
| Fully bundled for 2010/11 | £977m | 30% | £20m | 20% | £30m |

Figure 7: Table for a fully bundled one year incentive for 2010/11 from the Initial Proposals consultation

This incentive scheme design reflects the uncertainty around the constraints forecast for 2010/11. With the inclusion of the adjustment factors outlined above, we believe that this would reduce the overall risk range and therefore allow for appropriate sharing factors to be developed.

At this time the change in risk profile associated with the inclusion of the adjustors has not been calculated and therefore we have not proposed a specific scheme.

For 2011/12, a fully bundled incentive scheme could be developed. The scheme design would depend on the introduction of the proposed constraint adjusters, overall cost target and the resultant risk ranges. The second year of the incentive scheme would have different scheme parameters to reflect the greater uncertainty with the constraints forecast in year 2.

6.4 BSUoS Forecast

The table below shows the BSUoS forecast for 2009/10, 2010/11 and 2011/12. As can be seen, there is an approximately 50% increase in forecast BSUoS costs from 2009/10 to 2010/11 and a 7% increase from 2010/11 to 2011/12.

| Forecast | 2009/10 | 2010/11 | 2011/12 |
|-----------------------------|------------|------------|------------|
| Constraints | £206m | £477m | £498m |
| Remaining components | £364m | £485m | £525m |
| Central Forecast | £566m | £962m | £1023m |
| Total BSUoS costs | ~£900m | ~£1360m | ~£1460m |
| BSUoS costs (£/MWh) | ~£1.39/MWh | ~£2.10/MWh | ~£2.25/MWh |

Figure 8: Table for a fully bundled one year incentive

Question A: Do you agree with the:

- development of a two year incentive that includes constraint costs?
- the proposed constraint adjusters be developed?
- the development of a fully bundled incentive scheme?

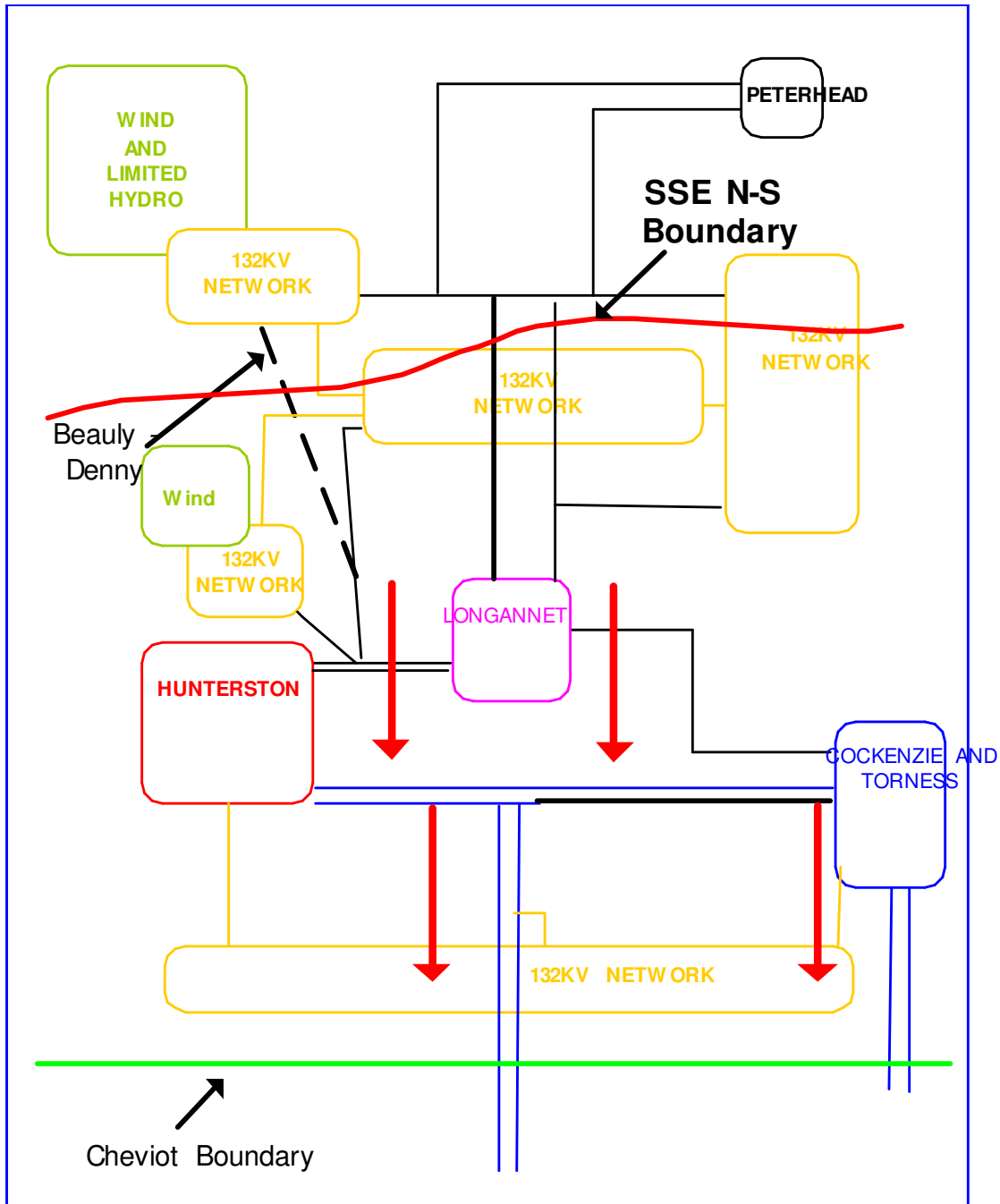


Figure 9: SSE N-S boundary

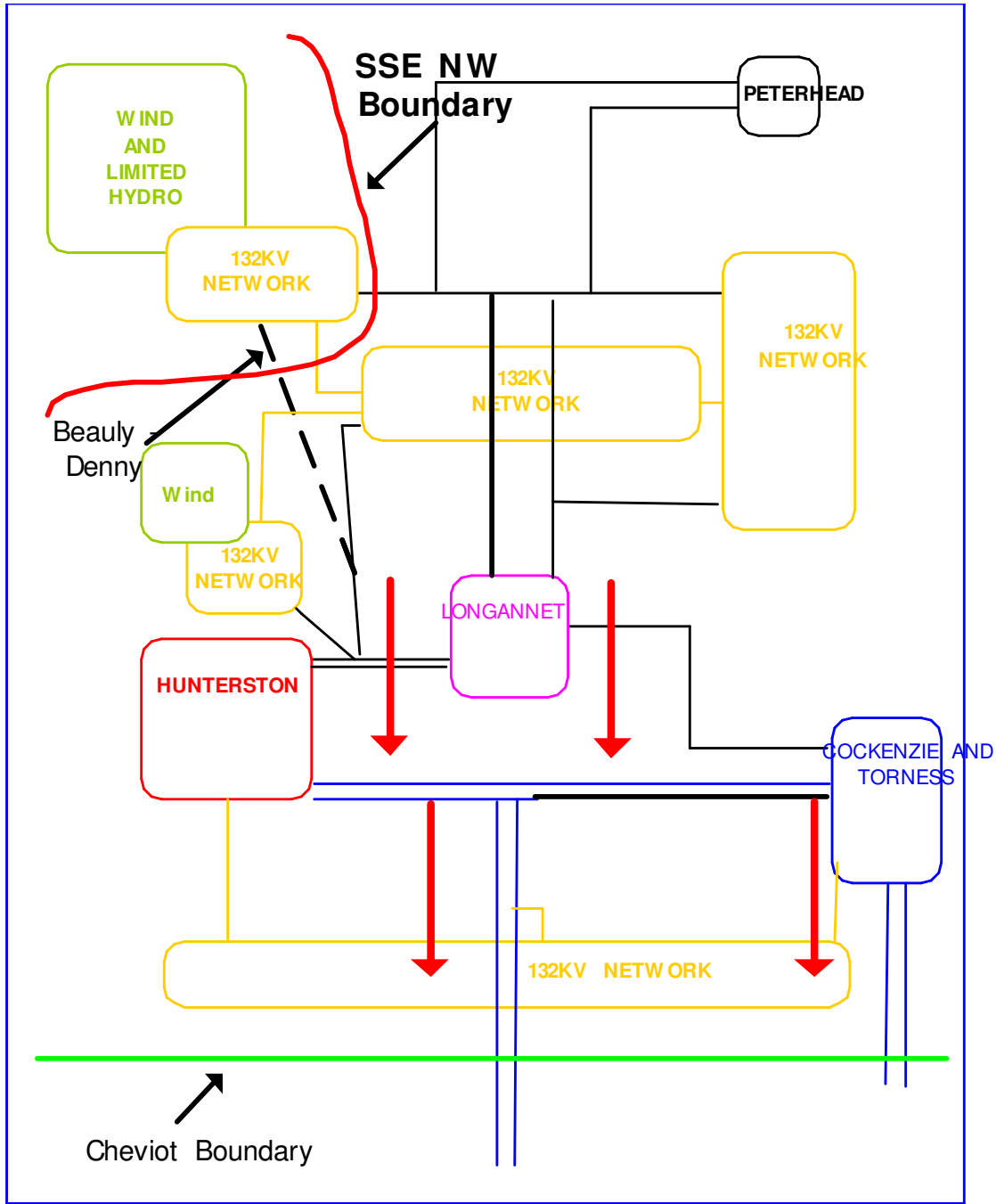


Figure 10: SSE NW boundary

Appendix B – Overview of Impact of significant outages

Overview of impact of most significant outages in England and Wales

FlowSouth

Outage Requirements:

Upper Trent Capability Enhancement works

The volume of new generation connecting north of the Flowsth boundary (such as Staythorpe, West Burton B) with the expectation of increased transfers from Scotland led to the Strategy to develop the North to Midlands boundary (Upper Trent Capability Enhancement). Outages to reconductor and increase the rating on the Grendon – Staythorpe, Cottam – Staythorpe and Grendon – West Burton routes are required as part of this strategy. Due to the length of the circuits, reconductoring the full circuit cannot be completed in a single year. In 2009 work started on the Grendon – Staythorpe circuit. This is due to continue in 2010, followed by the first outage on the Cottam – Staythorpe circuit. A second outage is required on the Cottam – Staythorpe circuit in 2011 which is followed by an outage on the Grendon – West Burton.

Woodhead tunnel works

The Woodhead tunnel was originally constructed in 1838 as part of a cross Pennine rail route. It currently houses two cables, laid in the last 1960s, which are currently parts of the Stalybridge - Thorpe Marsh and Macclesfield - Stocksbridge circuits. These circuits are subject to heavy power flows. Structurally the tunnel is in poor condition and the civil integrity is compromised. Outages are required to remove the cables from the 1838 tunnel.

The Macclesfield – Stocksbridge circuit will be moved in 2010. An outage, expected to be of 20 weeks duration, of the Stalybridge – Thorpe Marsh is required in 2011.

Circuit Breaker Refurbishment Works:

The programme of works to refurbish a number of circuit breakers, thereby extending their asset life and postponing replacement, continues. Outages to refurbish a circuit breaker are typically eight weeks in duration. An outage on the Feckenham – Walham, on the same system boundary, is required in 2011.

System Issues:

Under outage conditions, the loss of a double circuit along the boundary increases the flow on the parallel routes, leading to the potential for thermal or voltage constraints. During the outage season, when demands are lower, the constraint is typically thermal. Detailed study work has not been completed to assess the specific loadings which must be secured.

Constraint Limit:

Detailed power system analysis was carried out to assess the impact of the Grendon – Staythorpe outages in 2009 and 2010 and the Cottam – Staythorpe in 2010. The constraint limit calculated has been used in the forecast for 2011/12. This assumes that the impact of one circuit on the boundary is the same as the impact of another. This is an approximation which is believed to be acceptable against a background of such uncertainty in other areas. The volume of actions required to limit power flows to this level have been increased in the forecast for 2011/12 to capture the impact of new generation connecting above the constraint boundary.

For the period of 2011 when works on the Woodhead tunnel overlap with the reconductoring works, the volume of generation which must be curtailed increases by 500WM.

Due to the volume of generation behind the boundary where actions to resolve the constraint may be taken, the risk of NG taking actions¹⁹ to manage the constraint has been set to 30%.

The forecast cost to manage outages which limit the transfer across this system boundary is £47m, assuming that:

1. One circuit on the boundary on outage for the season with one East – West circuit out of service for periods
2. New generation behind the constraint boundary successfully commission
- 3.
4. The impact of one of circuits West Burton – Staythorpe – Grendon route is the same as another and the volume of constraint calculated for 2010 is representative of the volume required for outages in 2011.
5. Historic plant running since LCPD is representative of plant running in the future

Thames Estuary

Background:

This part of the system is subject to high system flows and is heavily congested. This is due to the volume of generation in the area relative to the local demand, the capacity of transmission circuits, the demand in London and impact of exporting on the IFA on overall system flows. The IFA connects to the GB transmission system at Sellindge. When the IFA is exporting, Estuary generation will flow south to feed this demand, placing a high loading on the cables between Grain and Kemsley. In the event of the fault of this double circuit, the generation will still attempt to feed the demand at Sellindge by alternative routes, resulting in circuits in London being overloaded.

This area of the system is one which is heavily congested and where under intact system conditions and exports on the IFA, constraint limits are close to being active continually. There is a significant amount of generation connecting in the area over the coming years. In order to facilitate these connections, a major programme of

¹⁹ Actions in this context refers only to those with cost implications rather than development of innovative system configurations to manage constraints

construction work is underway and due to continue until 2013 including both local and wider system reinforcement and replacement of aging assets.

Key works planned for 2010/11 include the establishment of a new transmission circuit from Littlebrook to Tilbury and the up-rating of existing 275kV circuits between Barking and Littlebrook for operation at 400kV. The most significant outages in the 2010/11 plan were required to decommission the Littlebrook – Barking circuits and the commissioning of a double circuit route between Tilbury and Littlebrook.

Works Planned

The most significant works planned for 2011/12 are:

1. Final Stages of Littlebrook – Tilbury 400kV circuit commissioning
2. Replacement of the Beddington – Rowdown 2 cable
3. Connection of London Array wind farm
4. Commissioning of the Kemsley Quadrature boosters

Maintenance requirements in the area are not yet understood and thus outage requirements are not known. Due to the significant changes to the system configuration following the commissioning of the new Littlebrook – Tilbury 400kV double circuit, interaction between outages in the greater London area and Thames Estuary is also not fully understood. There is potential for managing outage combinations that historically have been secure to becoming onerous, resulting in increased constraint costs as the full programme of reinforcement works are completed.

Commissioning of second Littlebrook – Tilbury circuit:

The engineering solution devised to reduce constraint volumes during outages required to construct and commission the second Littlebrook – Tilbury circuit will be in place until Week 19. A double circuit outage is then required to remove the engineering solution, followed by two weeks with the circuit remaining out of service without the benefit of the enhanced rating provided by the engineering solution. Both Littlebrook – Tilbury 400kV circuits are then due to be in service, allowing work required for the Kemsley QBs to commence.

Beddington – Rowdown cable replacement:

The Beddington – Rowdown cable is an oil filled cable which has reached the end of its asset life and is due for replacement. A scheme has been in progress for a number of years to build a new cable tunnel between Beddington and Rowdown to house a replacement XPLE cable rated at 400kV. The rating of the new cable is anticipated to be twice that of the existing cable. However this rating will not be confirmed until detailed design work has been completed. This enhanced rating will be required as the wider system reinforcements are complete.

Approximately 9 weeks are required to decommission the existing 275kV cable and commission the replacement 400kV cable.

London Array:

London Array is a proposed 1000MW Wind Farm off the Kent coast. The wind farm will connect into a new 400kV substation at Cleave Hill, which is mid way between Canterbury and Kemsley.

Eleven weeks of outages on the Canterbury North – Kemsley No. 2 circuit are required during 2011/12 to connect the new Cleave Hill substation to the transmission system. The overhead line circuit will be turned into the new substation to create a Canterbury North – Cleave Hill circuit and a Cleave Hill – Kemsley circuit

Kemsley Quadrature Boosters (QB):

A quadrature booster (also known as a phase shifter) is a specialised form of transformer used to control the flow of power on a circuit, providing a means of relieving overloads on heavily laden circuits and re-routing power to other transmission circuits. The Kemsley QBs are to be installed on the Canterbury North circuit and the Cleave Hill circuit. They will also be selectable to the Grain – Kemsley circuits.

A significant volume of work is required to connect and commission these QBs. Upon commissioning of the second Littlebrook – Tilbury circuit, work will commence at Kemsley to connect the QBs. Outages on circuits from Kemsley to Grain, Canterbury North and Littlebrook are required for approximately 10 weeks.

The volume of work required to delivery these schemes is such that there is a significant outage in the Thames Estuary from week 14 until the end of week 44. This leads to a high risk of significant volume of maintenance work required on the boundary after clock change.

System Issues

Power system studies have been completed in preparation of the 2010/11 forecast to quantify the impact of the Littlebrook – Tilbury outages on the system capacity. Power system studies have shown the most onerous circuit fault is that of the Grain – Kemsley double circuit. When exporting on the IFA, this fault pushes Estuary generation down the single Littlebrook – Tilbury circuit, resulting in significant circuit overloads following a fault.

The exact outage requirements of circuits from Kemsley for connection of the new QBs are not yet known and power system analysis has not been carried out yet. The system configuration in the areas will have changed significantly due to the commissioning of the Littlebrook – Tilbury circuits. As such, no system experience can be called upon to determine constraint requirements. Given that the new circuits are due to the low impedance 400kV circuits, they are assumed to present the most attractive path to MW. Thus, any outage on the route from Littlebrook to Sellindge (and the exporting IFA) which leaves only one single circuit of a double circuit route in service is expected to result in a system limit comparable to the limit in place during 2010/11. Connection of the Kemsley QBs will provide a method to manage such overloads in the future.

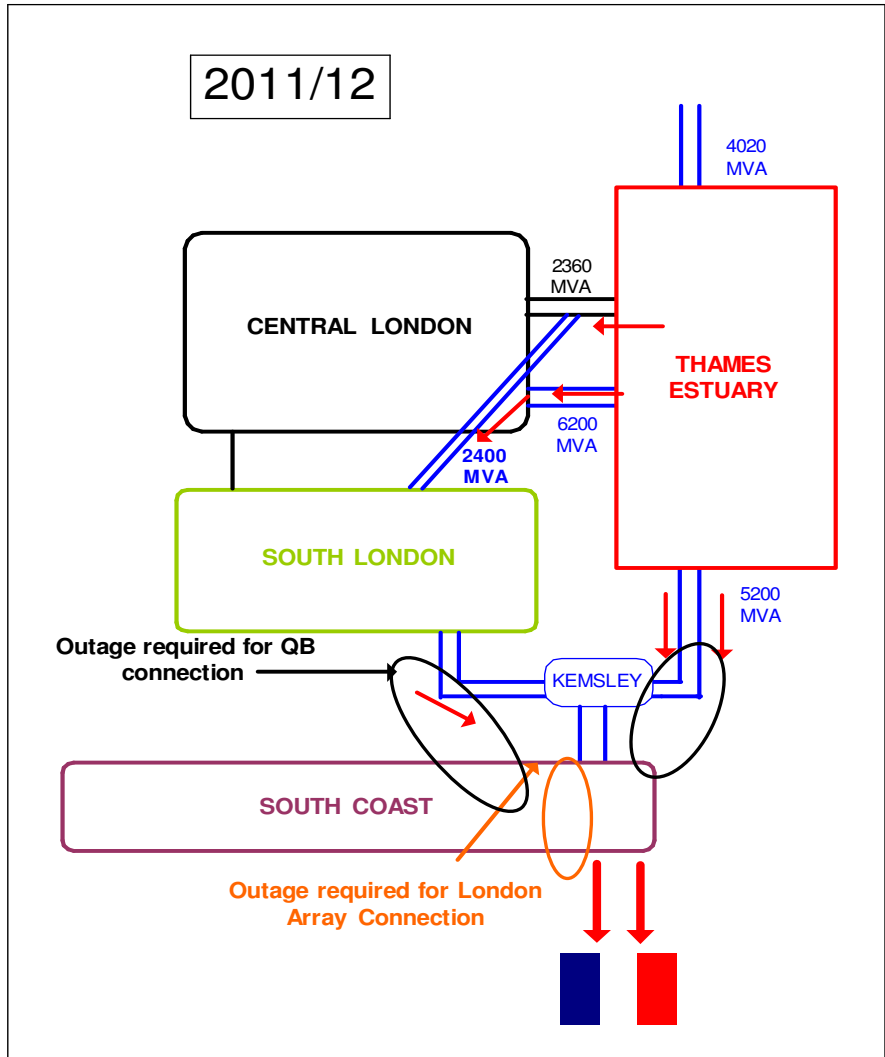


Figure 11: Thames Estuary constraint boundary in 2011/12

Constraint Limit

The constraint limit calculated for the most onerous outages in 2010/11 showed that imports of 500MW on the IFA coupled with arming 1200MW of Estuary generation to intertrip are required to secure the transmission system in the event of the critical fault. As discussed above, the impact on the transmission system of outages anticipated in 2011/12 has been assumed to cause a similar constraint. As for 2010/11, the most cost effective method of resolving the constraint will be trading on the IFA to limit flows to secure levels.

The constraint limit of 500MW import on the IFA was based on a number of assumptions. These have been reviewed and updated to reflect new connections in the area and the time of year when outages in 2011/12 are expected to be required.

These changes and impacts are detailed below.

1. Britned commissioning

BritNed is assumed to commission in early 2011, connecting to the transmission system at Grain. Forward price spreads between UK and Holland indicate that

power will flow from UK to Holland for 2011/12, potentially not the full volume. Effectively BritNed when exporting will provide an additional route out of the group for Grain generation.

This reduces the constraint volume by about 500MW, allowing flows on the IFA to be traded to a float position rather than imports of 500MW.

2. Coal Plant Running

The outages anticipated for 2011/12 are expected to start in April and finish by the end of October. The load factor of opted out LCPD plant is assumed to be lower over the summer than over winter. The constraint limit has been modified to reflect the change in expected generation.

The load factor of the LCPD opted out plant has been assumed to be half that forecast for weeks 33 to 47 in 2010/11. This has the effect of reducing the constraint limit by a further 500MW, allowing exports of up to 500MW to be secured.

3. Natural position on IFA

Forward price spreads between UK and France indicate that exports of 1500MW can be expected for Q2 and Q3. Thus, trades are required from a natural position of 1500MW exports rather than 2000MW as is the case during the 2010/11 outages.

4. Volume of trades on IFA required for concurrent outages

There are a number of outages on the Lower Flow South Boundary and the South Coast boundary which necessitate limiting exports on the IFA to 1000MW. Some of the generation required to replace northern generation output reduced to manage the Flowsth boundary is assumed to be replaced via trades on the IFA. Thus the Thames Estuary issues only limit exports by 500MW in addition to the restriction required to manage overall system power flows. The forecast for Thames Estuary includes the costs of trades for this additional 500WM and the costs of arming intertrips in the area.

Forecast:

The forecast cost to manage constraints associated with outages in the Thames Estuary is £26m, assuming:

1. There is an outage of a significant circuit in the area from week 14.
2. The impact of any such outage on system capacity is similar to the impact of the second Littlebrook – Tilbury outage planned for 2010/11, prior to the engineering solution being in place
3. The forecast assumes good nuclear availability, consistent with the Energy Model.
4. LCPD opted out plant runs at half the load factor assumed for 2010/11
5. Trades on the IFA are possible as a means of managing the constraint by the start of the critical outage at Week 33 2010, similar to trading mechanisms available prior to the introduction of the Capacity Management system on the IFA.
6. The forecast for flows on both the IFA and BritNed is based on current price spreads between France and the UK and Holland and the UK. The spreads

indicate that both interconnectors will export and that no power will be wheeled through the UK transmission system.

7. BritNed will commission in early 2011
8. A system to generation tripping scheme is used as a post fault action to reduce the overload on the critical circuit following the most onerous fault, in addition to the use of the IFA intertrip scheme. The forecast assumes that 1200MW of generation is tripped, in line with the largest loss secured by frequency response held under normal system conditions and allowing for generation selected to intertrip not generating at maximum output.

Contract terms and prices for intertrip schemes assumed in the forecast are not in place yet. Discussions are underway with a number of generators to agree terms from April 2010. The forecast assumes these discussions are successful..

East Anglia

There is a significant pocket of generation, sitting below the Humber group, which results in a heavy push of generation south from the group.

There is a significant volume of new generation due to connect in the East Anglia area, the first of which are Greater Gabbard and Gunfleet Sands. There is an 11-year program to rebuild the East Anglian network, to be able to accommodate up to 8.6GW of new generation already contracted, and potentially another 10GW of Round 3 wind projects on top of that. The first stage starts in 2011 with 30 weeks of outages to re-conductor the Norwich – Walpole circuits. The re-conducting of these overhead lines is expected to increase the rating of each circuit to 2.5 times its current volume (the exact final rating will be confirmed after the detailed design work is completed).

During the outage of the first circuit, the most onerous system fault will leave the group connected to the South of the system by the remaining Norwich – Walpole circuit. To limit the loading of this circuit to that permitted by its rating schedule, a volume of 600MW of generation in the group must be constrained off. Historic running patterns of generation in the group have been examined; generation in the group has a relatively high load factor. A risk factor of 50% has been applied to capture the need to take actions to manage the system. In the increase in rating achieved by the re-conducting is such that no issues are expected for the outage of the second Norwich – Walpole circuit. In the event of a failure of one machine at Sizewell, a volume of constraint would be required to secure the system. As the rating of the new circuit has not been confirmed and no power system study work has been carried out, the volume of constraint required is unknown, but is potentially of the order 500 – 700MW. If during the outage of the first circuit, any span of the OHL can be not restrung successfully (i.e. if one of the 224 transmission towers on the route can not be accessed) the increased rating will not be achieved. The volume of constraint anticipated for the first outage will be required for both. Issues may present themselves during the detailed design stage, limiting the volume of work to be completed during each outage.

The forecast cost to manage outages required to re-conductor the Norwich – Walpole circuits is £24m, assuming:

1. Outages of 15 weeks on each circuit
2. All spans of the Norwich – Walpole 1 circuit can be accessed and successfully restrung during the first outage
3. Historic running patterns are representative of future running patterns of generation in the group