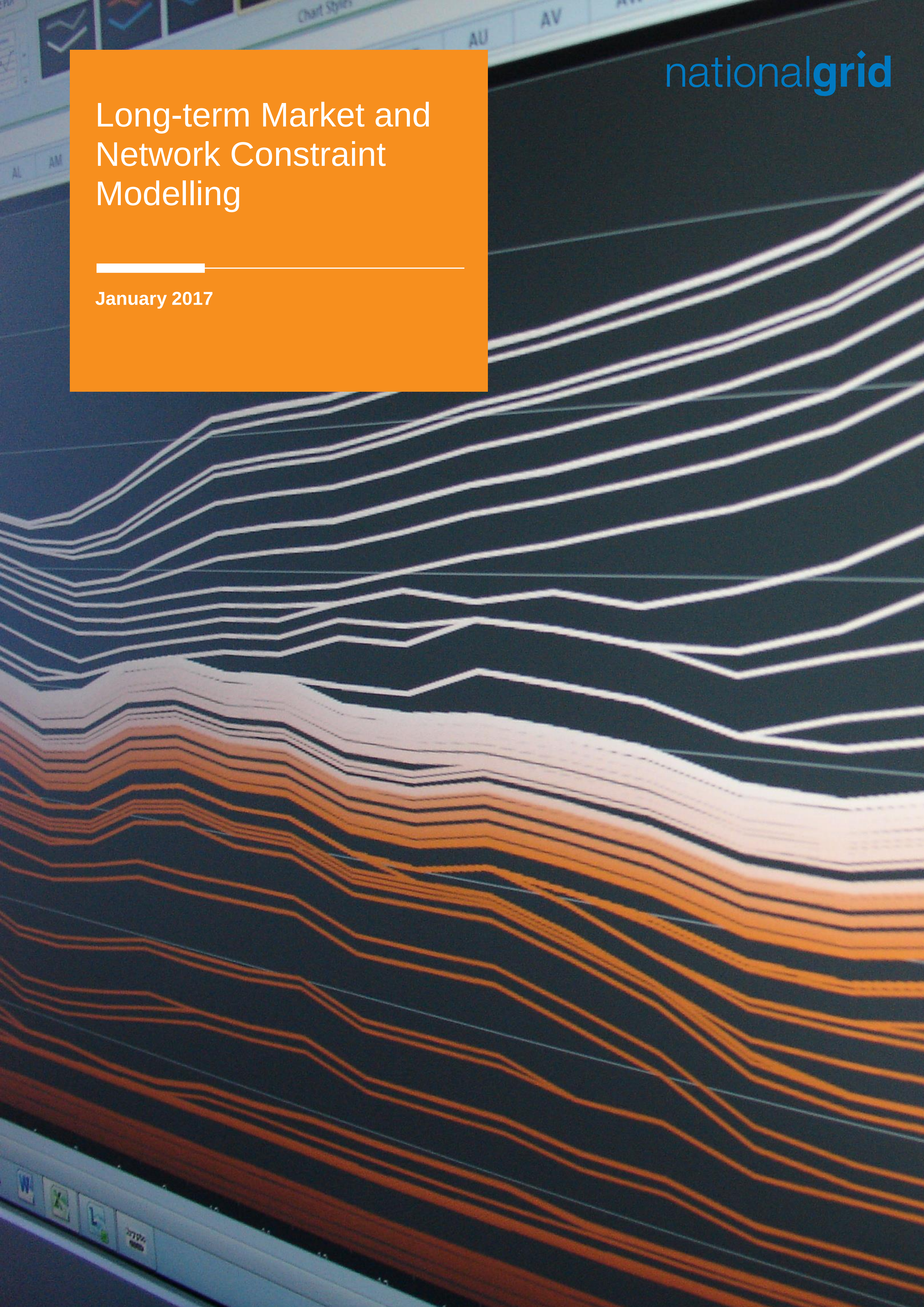

nationalgrid

Long-term Market and Network Constraint Modelling

January 2017

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1 Executive summary

1.1 Scope of this report

This report provides information on how National Grid, in its role as System Operator (SO), undertakes its long-term electricity market and network constraint modelling. In 2016 the SO transitioned from using a tool developed in-house, named ELSI (Electricity Scenario Illustrator), to a model procured externally, for developing long-term constraint forecasts of the network, which informs continuing investment decisions. This new model is called BID3.

This report explains:

- why we chose BID3
- why we needed to move from ELSI to BID3
- what the enhanced capabilities of BID3 over and above ELSI are
- what it will be used for
- how we ensured the model is the most economic and efficient solution for current and future work
- what enhancements were required to the model
- how the model works
- what modelling assumptions we make
- what are the sources of data that are inputs to the model
- what are some of the areas we have already identified for development of our BID3 modelling activities to continue to improve and enrich our modelling and analysis

1.2 Summary

As part of the Integrated Transmission Planning and Regulation Project (ITPR), the SO is required to provide significantly greater in depth economic analysis of the electricity network and capacity developments. In addition we are also obliged to undertake independent cost benefit assessments of network reinforcement options as part of the 'Needs Cases for Strategic Wider Works' submissions to Ofgem led by different transmission owners and on a GB wide basis as part of the new licence obligation regarding production of the Network Options Assessment (NOA). The NOA's purpose is to make recommendations to the Transmission Owners (TOs) across Great Britain as to which projects to proceed with to meet the future network requirements as defined in the Electricity Ten Year Statement (ETYS). Further to ITPR, we have existing obligations under Electricity Market Reform (EMR) to undertake analysis and reporting to HM Government's Department for Business, Energy and Industrial Strategy (BEIS) on de-rating factors of interconnectors and forecast flows of interconnectors at different levels of GB capacity margin.

BID3 is an economic dispatch optimisation model. It can simulate all European power markets simultaneously from the bottom up, i.e. it can model individual power stations, for example. It includes demand, supply and infrastructure, and balances supply and demand on an hourly basis. It models the hourly generation of all power stations on the system, taking into account fuel prices, historical weather patterns and operational constraints.

BID3's more sophisticated modelling capability will enable the SO to continue to meet the needs of its customers and stakeholders. It will enable us to perform our enhanced SO role, model more accurately the dynamic relationship between GB and other markets and improve our modelling of particular plant behaviours that will impact their Short Run Marginal Costs (SRMC).

To ensure we procured a new electricity economic model in the most economic and efficient manner without compromising on quality, we implemented a comprehensive project plan including a competitive procurement exercise, development, training and rollout.

A key feature that we requested Pöyry Management Consulting (BID3's developers) include within the model is the ability to model the balancing markets, post gate closure and therefore the subsequent cost to the SO in having to re-dispatch plant to account for network constraints on the 'actual' flow of power.

Total constraint costs measure the cost of re-dispatching plant from the market equilibrium to a configuration which respects constraints on power flows within the network. BID3 performs this via a cost minimisation algorithm. Total constraint costs can then be compared to measure the effects of reinforcements and of changing generation or demand configurations. BID3 enables the SO to identify where issues are on the grid, and therefore be able to provide a narrative, and the intuition behind results.

Through all the energy scenarios detailed within the FES (Future Energy Scenarios) there is an increase in interconnection between GB and the rest of Europe. How these interconnectors are treated in the re-dispatch, and their respective bid/offer adders/multipliers is therefore very important to the forecasts of future constraint costs. Furthermore, accurately forecasting market prices in each of the European markets and the resulting flows to GB is also critical as this provides us with the starting point for flows to be re-dispatched on (and the marginal price they are re-dispatched at). BID3 has enabled us to enhance our modelling of the impact of interconnectors on the European electricity market. This is just one reason why BID3 was chosen as the SO's new constraint modelling tool.

1.3 We welcome your views

We hope that you find this report useful. If you wish to contact us to provide feedback on any aspect of this report, then please use the most appropriate means for you. A list of potential options is provided in Section 18.

2 Background

One of the key activities within the NOA process is the assessment of constraint costs. Historically, including for the production of NOA 1 in March 2016 (and its predecessor documents, the Electricity Ten Year Statement (ETYS)), we used our Electricity Scenario Illustrator (ELSI) model to develop long term forecast of constraints on the network. This model was developed in-house and had been our preferred model to inform long term investment decisions. The model had been continuously developed and refined over the years to improve our modelling. This year, to deliver NOA 2016/17, we have used a different model, named BID3. BID3 is an electricity market model that we have procured from Pöyry Management Consulting (Pöyry), and we have worked closely with them to develop and enhance BID3's capabilities.

The BID3 model contains many advanced features which enhances the capability of System Operator (SO) market modelling. Some of these features remain to be explored by the SO and so it is recognised that our modelling capability will advance as we seek to optimise our use of the model.

BID3, with its more sophisticated modelling capability will enable the SO to continue to meet the needs of its customers and stakeholders. Some of the benefits of BID3 are it will enable us to:

- Perform our enhanced SO role
- Meet our need to model more accurately the dynamic relationship between GB and other markets
- Improve our modelling of plant to include some of the wider considerations that plant will have in determining their Short Run Marginal Costs (SRMC)
- Develop better approximations of the behaviour of interconnected markets and their markets of influence in turn.

The BID3 model represents a significant step forward in SO's capability to realistically model the pan-European electricity market. Our use, understanding and development of the model will undoubtedly evolve over the coming years, as we explore the many different ways the model can be configured and run.

Stakeholder Engagement

We welcome your views on how we can continue to develop our economic analysis of the electricity market by using BID3.

3 Why BID3?

As part of the Integrated Transmission Planning and Regulation Project (ITPR), the SO is required to provide significantly greater in-depth economic analysis of the electricity network and capacity developments. In addition we are also obliged to undertake independent cost benefit assessments of network reinforcement options as part of the 'Needs Cases for Strategic Wider Works' submissions to Ofgem led by different transmission owners and on a GB wide basis as part of the new licence obligation regarding production of the Network Options Assessment (NOA). The NOA's purpose is to make recommendations to the Transmission Owners (TOs) across Great Britain as to which projects to proceed with to meet the future network requirements as defined in the ETYS. Further to ITPR, we have existing obligations under Electricity Market Reform (EMR) to undertake analysis and reporting to HM Government's Department for Business, Energy and Industrial Strategy (BEIS) on de-rating factors of interconnectors and forecast flows of interconnectors at different levels of GB capacity margin.

BID3

BID3 is an economic dispatch optimisation model. It can simulate all European power markets simultaneously from the bottom up, i.e. it can model individual power stations, for example. It includes demand, supply and infrastructure, and balances supply and demand on an hourly basis. It models the hourly generation of all power stations on the system, taking into account fuel prices, historical weather patterns and operational constraints. Balancing of supply and demand is via a linear (or mixed integer, if chosen) optimisation which minimises total system short-run costs while respecting a variety of system and plant specific constraints. An hourly market dispatch schedule of electricity generators, interconnector flows, storage technologies, and flexible demand is produced. It accurately models renewable sources of generation, such as hydro and intermittent sources of generation, such as wind and solar.

By using BID3, the SO is joining an established user community: it is used daily by utilities, regulators, TSOs and government departments across Europe.

4 What will BID3 be used for?

National Grid through the licence it holds to act as the GB Electricity SO is required to produce a number of electricity market performance outputs relating to the long term planning of the GB electricity transmission system, both internally and in relation to interconnection with adjacent markets on continental Europe.

The BID3 model will be a significant tool in facilitating this requirement. It will be predominantly used for long-term network planning covering time horizons ranging from 20 years in the future to year-ahead. This is principally governed by the time horizon covered in our Future Energy scenarios (FES) annual publication for GB capacity and demand forecasts.

Key licence-driven work that BID3 is used for:

- **Network Options Assessment (NOA)**
  The NOA publication describes the options that the Transmission Owners have provided to meet reinforcement requirements of boundaries on the National Electricity Transmission System (NETS). The publication goes on to identify the SO's recommended option or options based on Cost Benefit Analysis for each boundary. Included within NOA 2016/17 is an interconnection assessment. This evaluates the future optimum interconnection capacity between GB and European markets, and the ideal timing of any capacity increase. NOA currently covers Incremental Wider Works (IWW), Strategic Wider Works (SWW), Offshore Wider Works (OWW), interconnection analysis and evaluation of onshore competition.

- **Strategic Wider Works (SWW)**
  SWW process was introduced as part of the RIIO-T1 for Electricity Transmission Owners in 2012. It provides a funding mechanism allowing transmission owners to bring forward high value projects of strategic importance to meet the future requirements of the GB electricity system on a needs case basis at the most appropriate time rather than fixed upfront in price controls, thereby helping to manage uncertainty and providing an additional case-specific regulatory examination of the works as required. With the introduction of the NOA process in 2015, the SWW process has become a derivative of its outputs, with reinforcements that exceed pre-determined financial thresholds that are identified as 'proceed' from the NOA passed through the SWW process and SWWs which are approved to proceed being included in the base-line network against which further reinforcements are assessed.

- **Connection Infrastructure Option Note (CION)**
  The CION process is the principal way the SO identifies the infrastructure requirements required for project specific load transmission connections. For new offshore wind and interconnector projects, where the nature of long offshore transmission cables facilitates greater choice in the connection of points onshore, the CION process includes a cost-benefit analysis process where the choice of connection substation is optimised relative to the balance of constraints and investment costs for capital infrastructure on the network.

- **Electricity Market Reform (EMR)**
  BID3 will provide two inputs into EMR: interconnector flow distributions and de-rating factor analysis. It is also being considered as an alternative to the SO's capacity

assessment model which is used to model the level of security. The interconnector flow distributions are an input into the Dynamic Dispatch Model (DDM) which is used to calculate the capacity to procure for the capacity market auctions. De-rating factor analysis models the ability of interconnectors to provide imports to GB in different scenarios and sensitivities. This analysis provides a range of values to assist BEIS in deciding the de-rating factors to apply to each interconnector for the capacity market auctions.

- **Future Energy Scenarios (FES)**
  The energy scenarios within FES consider the potential changes to the demand and supply of energy for GB and is unconstrained by the capability of the current gas and electrical networks. As part of this the model will be used to provide key FES outputs for electricity interconnection and feed into the power supply and power demand analysis.

4.1 What BID3 is not

It is important to note that BID3 is not an electrical network or power system model nor does it have the capability to simulate load flow calculations. It is based on the established concept of network boundaries and zones which the SO studies through load flow simulations as part of the ETYS process, in other commercially available software.

5 BID3 quality assurance and validation

To ensure we procured a new electricity economic model in the most economic and efficient manner without compromising on quality, we implemented a comprehensive project plan including a competitive procurement exercise, development, training and rollout. From establishing the need case to recommending the final supplier a rigorous procurement exercise has been undertaken with contributions and guidance from multiple specialist and expert stakeholders. The model has been extensively benchmarked against ELSI and two independent reviewers (Professor Keith Bell, University of Strathclyde and Dr Iain Staffell, Imperial College London) were appointed to review our development work, BID3 configuration and benchmarking. They reviewed our detailed design report, benchmarking reports and challenged our design assumptions and identified short and longer-term improvement points. A copy of their report is available on our website[1].

[1] http://www.nationalgrid.com/noa

BID3 has now been successfully used for the NOA 2016/17 process, we will though continue to test and develop BID3 in the future. Planned activities include further back-casting the model performance for modelling constraints to historical outturn.

6 Developments to BID3 required by National Grid: modelling the GB Balancing Mechanism

A key feature we requested that Pöyry include within the BID3 model is the ability to model the balancing markets, post gate closure and therefore the subsequent cost to the SO in having to re-dispatch plant to account for network constraints on the 'actual' flow of power.

There are numerous approaches which System Operators and Transmission Owners can adopt to model networks: the SO makes use of the concept of system boundaries to model the network in GB and has done so for a number of years. This concept is known to our stakeholders and clients and is how we have gone about representing the network in BID3. The electricity transmission system in BID3 is represented by a series of zones, separated by boundaries. The total level of generation and demand is modelled so that each zone contains a total installed generation capacity by fuel types (like Combined Cycle Gas Turbine (CCGT), coal and nuclear) and a percentage of overall demand.

The system boundary concept helps us to calculate system capabilities and the future transmission requirements of bulk power transfer capability. The transmission system is split by boundaries that cross important power-flow paths where there are limitations to capability or where we expect additional bulk power transfer capability will be needed. Each boundary has a maximum capability that restricts the amount of power that can be securely transferred across it. Boundaries don't exist physically but are instead a conceptual split of the network into two adjacent parts. The boundaries represent the actual transmission circuits that make this connectivity happen. We apply the System Security and Quality of Supply Standards (SQSS) to work out the requirements. We may plan to an N-1, N-D or N-2 security depending on the planning standards that have been applied to the boundary. The level of zonal connectivity is defined in BID3 to allow the system to balance as a whole.

Our goal is to deliver the optimum investment at the correct time. To achieve this, we have to balance between investment cost with operational cost, taking into account any costs that we'd incur if the investment didn't take place. So we start by calculating the volume of constraints.

The rationale behind how we model

Dispatch (unconstrained)

The market first schedules generation so that supply meets demand at each point in time, assuming the transmission network is capable of sending power wherever it is needed i.e. unconstrained. We approximate this through our dispatch where we schedule generation to meet demand, whilst minimising cost (which is equivalent under a competitive market where generators charge their marginal cost). This can also be thought of as merit order dispatch. This provides us with an approximation of the market solution at gate closure.

Re-dispatch (constrained)

If the transmission network were unconstrained then the market would be allowed to dispatch as it saw fit. However, constraints on the transmission network mean that generation sometimes must be restricted in some areas of the country/network to satisfy boundary constraints, and increased elsewhere to balance supply and demand. This duty is performed by the SO at minimum cost, and it is this activity that we seek to approximate through our re-dispatch. BID3 therefore takes the unconstrained dispatch as a starting point and re-dispatches generation such that demand is met in all zones on the network, and all boundary constraints are respected. The solver adjusts the positions such that the cost of doing so is minimised. All of the usual constraints present in a Dispatch run are also present in the Re-dispatch, such as start-up and no-load times on generators.

7 Modelling boundary inputs

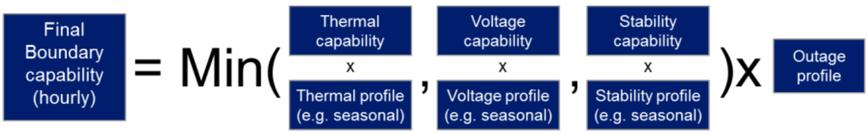
Within BID3 the SO specifies three boundary capability (MW) values for each time period modelled and where applicable in both directions as determined by power system study.

1. Thermal capability
2. Voltage capability
3. Stability capability

This recognises that the capability of a boundary may be limited in different seasons and time periods by different electrical restrictions. Practically BID3 will only accept the minimum of these three numbers as the limiting capability in the optimisation, in a particular direction. For avoidance of doubt the SO models the defined and reverse capability of a boundary, where it exists as two separate boundaries each with their own minimum in the optimisation function.

For each hour of the year, BID3 will use the equation shown in Figure A1 to calculate the actual transfer capability seen by the solver.

Figure A1: Boundary transfer capability



In the context of boundaries a profile is a within 'time period' adjustment to the capability for a boundary and is a number between 0 and 1, reflecting a percentage change. So for example the thermal capability will be seasonally dependent and so we can adjust the thermal capability of a boundary by scaling this down from the 'maximum' (winter peak) capability. Whilst we recognise that stability and voltage limits are not seasonally dependent, we have the capability to include a scaling factor should we desire. The outage profile is a percentage adjustment on the limiting capability for the boundary reflecting adjustment factors we use when accounting for circuit outages.

7.1 Re-dispatch

In a re-dispatch run plant and fixed price interconnectors are re-dispatched from a start position taken from the initial dispatch run.

The System Operator must pay to move a plant or fixed price interconnector up from its dispatch position according to:

- Cost to SO of increasing Position = Increase in Position (MWh) * Offer Price(€/MWh)

A plant or interconnector will pay the SO to move down from its dispatch position according to:

- Saving to SO of decreasing Position = Decrease in Position (MWh) * Bid Price(€/MWh)

The Offer and Bid Prices are calculated differently for plants and fixed price interconnectors.
In BID3 we are able to specify bid / offer values for each unit independently. This is either done as a % multiplier of the SRMC, or as a €/MWh adder. Four new inputs can be added to the plant:

- Offer multiplier (%)
- Bid multiplier (%)
- Offer absolute adder (€/MWh)
- Bid absolute adder (€/MWh)

BID3 only applies one bid and offer per plant and typically we only specify one type per plant (multiplier or adder not both), which is described later in this document.

8 Optimisation

The solver adjusts the positions of plants and fixed price interconnectors such that the cost of doing so (defined by the above equations) is minimised. All of the usual constraints present in a dispatch run are also present in the re-dispatch.

It is important to note that care may need to be taken regarding the exact parameters used in the dispatch and re-dispatch. For example, overly realistic intertemporal constraints may cause a butterfly style effect where a re-dispatch action causes the plant's action to be different for the rest of the optimisation horizon, which would be assumed to be paid for by the SO in the model. In the presence of intertemporal constraints the SO would pay for the changed generation in some of the surrounding periods, but not all. The generator would then re-optimise given its altered generation profile and this would form the new output for future periods (in effect a rolling optimisation). This cannot be captured at the moment, and so a detailed analysis of the effects optimisation parameters and settings make to all the outputs of interest will be performed as National Grid roll out the application of BID3.

9 Bid and offer adders / multipliers

Bids and offers

The total constraint cost used to solve a transmission congestion issue is associated with the bid and offer components within the balancing mechanism. The 'bid' is a volume of energy at a £/MWh to reduce generation in an area; and the 'offer' is the associated £/MWh to replace the energy in another area of the system.

In order to calculate bid/offer multipliers for thermal plants in GB for use in BID3, historic data of actions taken by the SO was studied in order to more accurately reflect the true cost of relieving boundary constraints in BID3. This data included bid/offer volumes and costs for every thermal plant from financial years 2011/12 to 2015/16. Five years of data were chosen in order to ensure enough years were considered to account for yearly variation in fuel prices and plant behaviour, while ensuring that the data is recent enough to be reflective of today's GB energy market. Thermal generation types were split into four categories from which both bid and offer multipliers were calculated; coal, gas (excluding OCGT), OCGT and oil.

The first step in calculating the multipliers is to group every bid/offer action by the thermal types listed above. Once this has been done, a yearly average bid/offer price (£/MWh) can be calculated for each financial year and thermal type. The equations below show how the thermal bid multipliers are calculated, offer multipliers follow the exact same methodology.

$$Bid\ Multiplier = \frac{Yearly\ average\ Bid\ off\ cost}{Yearly\ average\ SRMC}$$

$$SRMC = \frac{Fuel\ price + CO2\ cost}{Plant\ efficiency}$$

Fuel prices, CO2 costs and plant efficiencies were based on historic data in order to calculate an average SRMC for each thermal plant grouping for the previous financial years. Once a multiplier has been calculated for all years and generation types, an average over the five years of data is taken. Using this data and having followed this methodology, the bid/offer multipliers calculated for use within BID3 are shown in Table A1 below. A thermal average multiplier has also been calculated for use with certain plant types, which is simply the average of the coal and gas bid/offer multipliers.

Table A1: Bid and Offer Multipliers

	Bid Multiplier	Offer Multiplier
Gas	0.80	1.63
Coal	0.70	1.56
Oil	0.38	4.16
OCGT	1.37	1.31
Thermal Average	0.75	1.59

The bid prices depend on the type of technology. For synchronous generation, evidence from the SO data confirms that the bid prices represent a proportional saving achieved by generators. For renewable generators and any other generators receiving subsidies through the CfD framework (such as new nuclear), the bid prices represent the opportunity cost associated with constrained generation so are valued at the level of subsidy available by technology type. The renewable subsidy levels for bid values are sourced from Wood Mackenzie

Stakeholder engagement

We would like stakeholder views on how we should model bid prices for renewable plant who don’t receive a subsidy in the future.

Where there is insufficient generation to meet demand in a given time period and the model has exhausted all available options to ensure capacity can become available, then the model can revert to demand reduction measures at a cost set to the Value of Lost Load (VoLL). A single value is attributable for VoLL in the model and this has been pre-set to 6,000 £/MWh. This figure is recommended by Ofgem and BEIS (formerly DECC) in its Reliability Standard Methodology, DECC 2014[2].

One benefit of BID3 over ELSI is that the calculation of Bid/Offer multipliers and adders are priced within the objective function in BID3 and in ELSI they are a post-process calculation.

10 Constraint costs by boundary

Total constraint costs measure the cost of re-dispatching plant from the market equilibrium to a configuration which respects constraints on power flows within the network. BID3 performs this via a cost minimisation algorithm. Total constraint costs can then be compared to measure the effects of reinforcements and of changing generation or demand configurations. To form this metric over the whole of the GB network and examine the problem as a whole is essential since the Main Integrated Transmission System (MITS) is interconnected and relieving constraints in one area of the country may cause problems elsewhere. However, it is important to both National Grid and our stakeholders to be able to identify where issues are on the grid, and therefore be able to provide a narrative, and the intuition behind results.

In order to provide this an additional feature has been added to BID3 where constraint costs can be allocated by boundary. While constraint costs can sometimes never truly be attributed to a single boundary, for example where a zone is interconnected with many other zones in a group as opposed to radially. However, an indication of where constraints are occurring can be provided by allocating constraint costs by boundary.

Constraint costs are allocated to individual boundaries using the following steps:

1. BID3 outputs the hourly shadow price of congestion associated with each boundary (by taking the dual value of the boundary constraint) i.e. how much would constraint costs be reduced by if a boundary constraint were to be marginally relaxed
2. For each boundary the hourly Congestion Rent Delta is then computed: Congestion Shadow Price * (Flow (unconstrained) - Flow (constrained))
3. Constraint costs per boundary will be calculated by allocating the total constraint costs to each boundary pro-rata using the Congestion Rent Delta

This allocation could be done by hour:

[2] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf

$$Constraint\ Cost\ (b,h) = Total\ Constraint\ Cost(h) * \frac{Congestion\ Rent\ Delta(b,h)}{\sum_b Congestion\ Rent\ Delta(b,h)}$$

or for each week:

$$Constraint\ Cost\ (b,h) = \sum_h Total\ Constraint\ Cost(h) * \frac{\sum_h Congestion\ Rent\ Delta(b,h)}{\sum_{b,h} Congestion\ Rent\ Delta(b,h)}$$

The hourly approach is the most mathematically accurate since the sum of a product is computed rather than the product of a sum, which is the case under the weekly approach. However, the hourly approach ignores any dynamic/ intertemporal effects a boundary constraint may have on constraint costs i.e., a constraint and consequent bid/offer action may change the strategy of a generator in the following periods. For example, a generator may be offered on to solve a boundary constraint several hours before it would otherwise have turned on. Under the weekly approach this would be allocated to the boundary. Using the hourly approach the intertemporal effects of a boundary constraint would not be allocated to the boundary since we are only looking at each hour in turn and not looking at the total effect of a boundary constraint in that hour.

11 Accounting for transmission losses

Losses due to flows across boundaries can be calculated after the optimisation by multiplying the flow across the boundary by the loss rate for the boundary. This forms part of our post-processing procedure, and as such does not influence the dispatch or re-dispatch and is therefore information the SO can only view retrospectively.

Losses on the Main Interconnected Transmission System (MITS) do not explicitly affect how much a generator sells, or is paid for. For example, a generator in the South West does not get paid less if their electricity is being transferred to the North East. Losses on interconnectors are an important concept to model as they ensure erroneous transfers of power cannot occur between markets that are geographically far apart. It’s easier to model losses on interconnectors as part of the optimisation compared to boundaries.

The distinction between interconnector losses and transmission losses in the GB therefore comes down to the fact all generators in GB are in the MITS - their power can flow anywhere. For an interconnector they are flowing to a specific location and they will lose power transferring from one location to another. This affects how interconnectors operate, but losses on the MITS do not affect how generators operate.

A considered alternative would be to increase demand to account for them. This though presents us with an additional complication of demand inconsistency between the unconstrained (dispatch) run and the constrained (re-dispatch) run. This inconsistency would mean generation would not be equal to total demand, an important scenario pre-requisite.

An alternative would be to model a Transmission Loss Adjustment Factor (TLAF): these multiply a plant's SRMC by a factor (e.g. 1.02) to reflect the fact that generation is more expensive from that plant due to losses incurred transmitting its generation to demand centres. This higher cost is seen by the optimisation. These factors are input by the user for each user-defined Transmission Zone. The SO does not currently apply TLAF's in the optimisation though this is something that will be considered alongside calculating the post-processed loss rate by boundary.

12 Treatment of interconnectors

Through all the energy scenarios within FES there is an increase in interconnection between GB and the rest of Europe. Even in low prosperity scenarios such as Slow Progression and No Progression there is a marked increase in interconnectivity with at least a threefold increase in capacity. How the SO treats these interconnectors in the re-dispatch, and their respective bid/offer adders/multipliers is therefore very important to the forecasts of future constraint costs. Furthermore, accurately forecasting market prices in each of the European markets and the resulting flows to GB is also critical as this provides us with the starting point for flows to be re-dispatched on (and the marginal price they are re-dispatched at). This is just one reason why BID3 was chosen as the SO's constraint modelling tool.

Interconnectors are unique within our modelling since they do not generate power themselves, and are only able to transfer it between markets. Therefore, when a bid or offer action is taken on an interconnector they need be treated differently to balancing mechanism units/generators.

There are two main components to bid/offer prices for interconnectors. Firstly, like generators, they must be paid to change the quantity of generation. In the case of interconnectors this is in the foreign market rather than GB. However this is generally the same as modelled in the GB market.

The second component of interconnector bid/offer costs is the trader/interconnector being compensated for lost arbitrage revenue/sending additional power along the line. When the interconnector is importing to GB and is asked to bid off, or is exporting and is asked to offer on, then the trader loses arbitrage revenue as a result of reduced flows. In order for the trader to accept the bid/offer they must be compensated for this reduced arbitrage revenue. The SO is therefore assumed to compensate the trader for their lost revenue and must pay them the market spread adjusted for the losses they would have endured on the interconnector.

The example of an interconnector bid action above provides a good intuition behind how interconnector bids and offers should be priced. The full details of how interconnectors are treated are fleshed out below.

In ELSI, the short run marginal cost (SRMC) of a generator, including interconnectors, was used to determine the most cost effective bid and offer actions: in BID3 the bid and offer prices themselves are used to determine which constraint actions to take. This means that if the bid and offer prices can be set correctly then the forecast of the cost of taking constraint actions will be improved. BID3 also has the capability to set the bid and offer price by time period, year and scenario. This means that changes in the generation mix in the overseas market, and therefore the price to constrain on or off these generators, can be taken into account. Furthermore, the changing spread, and so changing opportunity cost to the trader of reducing their flow on the interconnector, can also be incorporated.

To determine the correct pricing for interconnector constraint actions the first stage is to determine the parties involved and the potential for a constraint action to affect these parties. In a conventional constraint action the SO will issue a bid instruction to one generator and an offer instruction to another generator. Where an interconnector is involved the process becomes more complicated. As an example, assume that the SO requires a bid to be taken on an interconnector that was scheduled to import to GB; then this instruction will be given to the interconnector. There will also be an offer instruction given to another generator in GB to balance the system. However the overseas market will now be out of balance and therefore a bid instruction will have to be issued to a generator in the overseas market (or possibly an interconnector to yet another overseas market).

The current method for running GB constraint forecasts in BID3 is to use a ‘fixed interconnector prices’ method. This is the same as is currently used in ELSI where a pre-determined overseas market price is used in each time period for each overseas market. This overseas market price is the marginal price of the overseas market for the relevant time period and becomes the SRMC of the interconnector.

If a constraint action is taken then the following parties will require compensation, or possibly be willing to pay if they can save fuel:

- The trader(s) who had a contract to trade using the affected interconnector
- The interconnector affected
- The plant in GB which will replace lost energy or be constrained off as a result of the constraint action

- The plant in the overseas market which will replace lost energy being constrained off as a result of the constraint action.

The plant in GB already has a known bid or offer price, BID3 will take the best action and price this action accordingly. The action on the GB plant is not considered any further here as BID3 is already capable of taking the correct actions on GB plant.

Since interconnectors may be at three distinct states: import, export or float, there are a number of permutations of how the parties will be affected by a constraint action on an interconnector. If a trader had a contract to import electricity to GB and a constraint action was taken that prevented this then the trader would have lost the profit from the trade. This profit would be the spread multiplied by the volume of electricity traded. Similarly an interconnector makes money by charging traders to transmit electricity, this would also be lost if the transmission was not allowed to take place. However since the interconnector fee is paid for by the trader(s) the interconnector will only lose out if more power will flow after the constraint action than before as the trader would not have paid for this extra capacity which they did not plan to use.

Table A2 outlines the permutations of actions. The effect on the trader(s) and the spread (which affects the profit that they would have made) is shown. Each permutation also has a likelihood assigned to it. This is determined by a logical approach to why the interconnector would be in a certain position, e.g. the likelihood of an interconnector being at import and being required to import more (which implies that the interconnector was at partial import to begin with) is lower as it is less common for interconnectors to be part loaded than fully loaded.

Table A2: Interconnector constraint action permutations

Unconstrained interconnector status	Interconnector constraint action	Trader	Likelihood	Spread
GB Import	Bid to float	Lose spread	High	Significant
GB Import	Bid to export	Lose spread up to float	High – Medium	Significant
GB Import	Offer more import	No loss	Medium – Low	Moderate
Float	Bid to export	No loss	Medium	Negligible
Float	Offer to float	No loss	Medium	Negligible
GB Export	Offer to float	Lose spread	High	Significant
GB Export	Offer to import	Lose spread up to float	High – Medium	Significant
GB Export	Bid more export	No loss	Medium – Low	Moderate

When the SO takes a constraint action on an interconnector they will effectively be taking control of the trade of electricity from the trader(s). Since this action means that the trader(s) will not be able to profit from their trading it seems reasonable to assume that they would be willing to sell the rights to their trade at a price equal to the profit that they would have made from the trade, as they will not therefore lose out financially. This assumes that the trader will not try to take advantage of the situation and exact rent from the situation. The trader is implicitly given a take it or leave it offer equal to the value of the arbitrage revenue they would have earned, and this is accepted. The profit is equal to the spread between the markets multiplied by the volume of electricity traded; the losses over the interconnector must also be taken into account.

There is a question regarding what would happen if the SO required the interconnector to flow a different volume of electricity than before the constraint action. If the volume after the constraint action were greater than before then if a trader had requested this position then the interconnector would charge the trader for the capacity. Therefore it is appropriate to include a cost for the interconnector if the flow volume is increased by the constraint action.

If the interconnector is part loaded importing/exporting, or at float and is asked to offer on/bid off, or either, then the additional capacity on the interconnector is not currently being utilised but must be paid for. Several alternatives exist for pricing this interconnector capacity including the long term price of capacity, and variable cost of additional flow on the interconnector (e.g. additional maintenance). Technically the value of the capacity is 0, since the spread is presumably not wide enough for traders to make a profit from additional arbitrage, accounting for line losses. We have chosen to take the market spread for the value as this represents the shadow value of the interconnector capacity, and as such a fair price for the interconnector capacity. In this we are implicitly assuming a solution whereby whoever holds the rights to the capacity does not try to exact rent from the situation, i.e. we do not participate in a Nash bargaining game over the capacity.

Having defined the background we now outline the proposed implementation in BID3.

The first objective is to find the marginal plant in the overseas markets and the spread between the GB and overseas markets. BID3 can be run for all scenarios for 20 years at 1 hour resolution to determine the overseas market prices and the GB unconstrained price. The spread will be calculated offline for each market and each time period using this data. The overseas market price is determined by the marginal plant in that country and therefore the bid and offer price for that plant can be calculated for each time period (it is assumed that since we are using fixed prices in the overseas market that the marginal plant stays the same no matter how much the interconnector flows are changed in the constrained run). In some cases the marginal plant in one overseas market may be a plant in another market to which the first market is connected (including indirect connections). This makes determining the exact plant difficult and therefore a banding system will be used whereby similar fuel types will be grouped together. The resolution of the banding is dictated by the overlap in SRMC between plants of differing fuel type in different markets.

When changing generation quantities in the balancing market in BID3, for GB we assume that bid/ offer actions are taken to minimise total constraint cost, including bid/ offer multipliers/adders. For interconnectors, however, for simplicity we assume that the marginal generator will be offered on or bid off, and a bid/ offer multiplier/ adder is then applied. This is subtly different to the GB approach where the generator to be bid off/offered on is chosen based on marginal cost and the bid/offer multipliers/adders, rather than purely marginal cost. However, it is worth noting that the SO chooses between interconnectors and generators in GB based on the full cost of repositioning an interconnector in BID3.

The output of the unconstrained run will also give the flow on each of the interconnectors in each time period. This information can be used to determine which factors should be used in calculating each bid and offer for each time period. Since an interconnector can either be instructed to reduce imports/increase exports (bid) or to increase imports/reduce exports (offer) and there are three states that the interconnector could be at in the unconstrained run there are therefore six permutations.

1. Interconnector importing – reduce imports / float / start exporting
2. Interconnector importing – increase imports
3. Interconnector at float – start exporting
4. Interconnector at float – start importing
5. Interconnector exporting – increase exports
6. Interconnector exporting – reduce exports / float / start importing

The formula for calculating the price for 1 MWh of each action is as follows:

1. $Interconnector\ bid = P_{GB} - P_{Foreign} \times (1 + Loss) - \ Plant\ Bid\ \times\ (1 + Loss)$
2. $Interconnector\ offer\ =\ Interconnector\ Fee +\ Plant\ Offer\ \times (1 + Loss)$
3. $Interconnector\ bid = Interconnector\ Fee -\ Plant\ Bid\ \times (1 - Loss)$
4. $Interconnector\ offer = Interconnector\ Fee +\ Plant\ Offer\ \times (1 + Loss)$
5. $Interconnector\ bid\ =\ Interconnector\ Fee -\ Plant\ Bid\ \times (1 - Loss)$
6. $Interconnector\ offer\ =\ P_{Foreign} \times (1 - Loss) - P_{GB} + Plant\ Offer\ \times (1 - Loss)$

Where the interconnector fee is equal to the spread between market prices and the plant offer/bid is a mark-up/down from the marginal price in the overseas market.

In each case the plant bid or offer is the price to take a bid or offer on the marginal plant in the overseas market. The losses are the capacity weighted average of the interconnector losses of the interconnectors connected to the overseas market. The spread is the difference between the market prices in the time period. Note that if the interconnector is at float in the unconstrained schedule then the spread will be very small and will be set to zero. The interconnector fee is a cost that is charged by the interconnector for using capacity which was not scheduled to be used in the unconstrained schedule. For each time period the equations used will depend upon the status of the interconnector in the unconstrained schedule. If the interconnector is importing then equations (1) and (2) are used, for float equations (3) and (4) are used and for exporting equations (5) and (6) are used.

One unavoidable error occurs in equations (1) and (6). This error will occur when the direction of flow on the interconnector reverses in the unconstrained and constrained schedules. The reason that the error occurs is that if the interconnector was scheduled to import and is told to export due to a constraint there should be two bid prices used, equation (1) until the interconnector is at float and then equation (3) until the constrained export value is reached. The process should be similar if the interconnector was scheduled to export and equations (6) and (4) should be used. However since BID3 can only accept one bid and one offer for an interconnector per time period this is not possible. Therefore equation (1) or (6) only will be used to determine the bid and offer prices when the interconnector is importing or exporting in the unconstrained schedule.

It should also be noted that due to losses on the interconnector the actual volume of the bids and offers on the plants in GB and the overseas market are not the same (i.e. if GB is importing 1 GW from France and the interconnector has 5% losses, then 1.05 GW will be being generated in France to facilitate the interconnector flow). Where there are markets connected by more than one interconnector an average loss factor weighted by the capacity of the interconnectors connected in that year will be used.

The value for an interconnector bid and offer for each market in each time period in a given scenario and year will therefore be calculated using the following process:

1. Run BID3 for the whole of all markets with GB unconstrained
2. Calculate the spread by working out the difference between the wholesale prices of GB and the overseas market
3. Calculate which plant band in the overseas market the marginal plant is in using the wholesale price. From this the bid and offer price can be calculated. The same bid and offer multipliers or adders as the GB plant will be used
4. Determine the flow on the interconnector in the time period and use the appropriate pair of equations to calculate the bid and offer

Stakeholder engagement

We welcome your views on our assumptions for modelling interconnectors. Your input will help us continuously improve our analysis.

13 The structure of BID3 data

Figure A2 provides a high level overview of the structure of input data within BID3.

Figure A2: BID3 input data

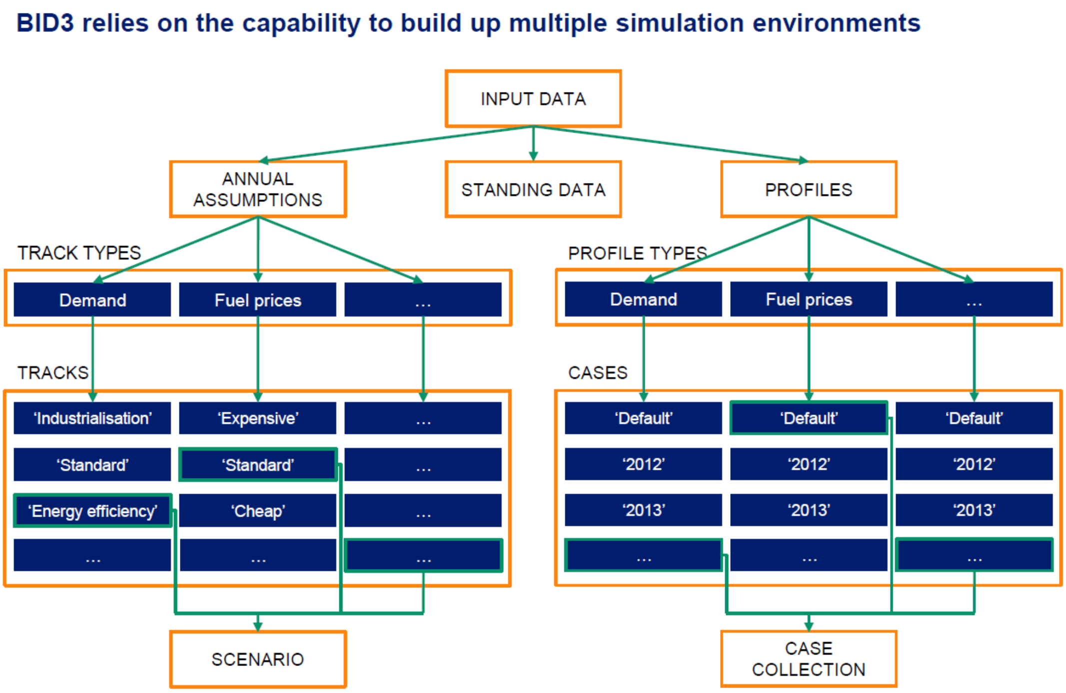


Figure A2 shows that a scenario in BID3 consists of various tracks that are annual levels of fundamental elements that can be set for power plants, demand, interconnectors and fuel. The different tracks can then be combined in to scenarios.

A case collection consists of different profiles and describes how elements change within a year. These can be random changes such as outages and changes influenced by the weather such as inflows and wind, which affect production, and temperature, which affect demand.

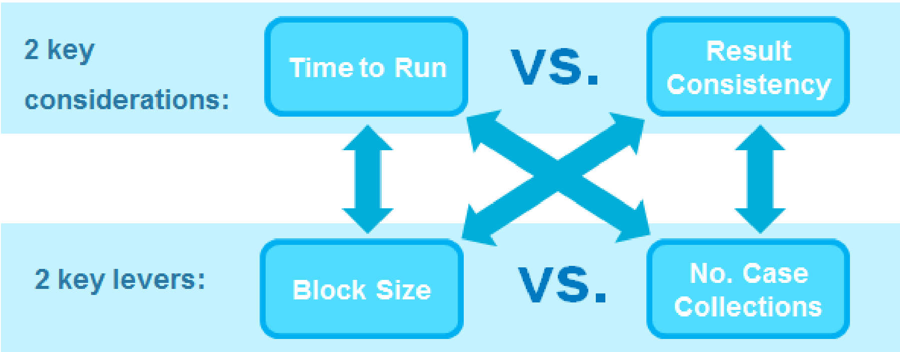
14 BID3 set up: optimising performance

BID3 is a complex and powerful model: a wide range of settings can be adjusted resulting in the creation of very large amounts of data, but at the expense of significantly longer run times. We were keen to ensure an optimum trade-off between consistency of results and run time. The two key levers for achieving this result are:

- Block size – the number of periods each day is broken down into
- Number of case collections – how many historic within-year profiles are included within each run

Figure A3 below highlights the interdependencies between block size, number of case collections, time to run and result consistency.

Figure A3: BID3 set up for NOA – trade-offs



Initial testing showed that block size had negligible impact on annual constraint cost by scenario, with limited loss of result resolution by using higher block sizes. In addition block sizes of 1 and 2 (ie breaking the day down into 24 or 12 periods) resulted in run times that were too large for the timeframe available for NOA 2016/17. However, there was little increase in run time for block size 3 compared to block size 4, so block size 3 was chosen as the optimal balance between runtime and result consistency.

Testing also showed that runs using the single 2013 case collection show little variance to runs using an average of five historic year case collections across all scenarios. Hence it was concluded it was satisfactory to use only the 2013 case collection for NOA 2016/17, in all scenarios.

We will continue our detailed parameter and computing optimisation investigations post-NOA 2016/17, to ensure we maintain our focus on using BID3 in the most efficient manner.

15 Generation modelling assumptions in BID3

15.1 Future Energy Scenarios (FES)

Electricity demand and supply data for Great Britain is sourced from National Grid's FES. The scenarios outline a range of credible pathways for the future of energy out to 2050 for Great Britain. The scenarios outline the possible sources of, and demands for, gas and electricity in the future, and the implications of this for the energy industry. The scenarios are used for a range of activities within the SO, including network planning. The scenarios are made by engaging with hundreds of stakeholders every year, via an annual conference and exhibition, workshops, bilateral meetings and webinars. The information gathered supports and inputs into our detailed modelling.

The FES process is an annual one, which culminates in the publication of the FES report. The report and much of the underlying data are available at http://fes.nationalgrid.com/.

Figure A4 below provides a high level overview of the 2016 FES.

Figure A4: The 2016 scenario matrix

15.2 European data

The European data used within BID3 is all provided by Pöyry and National Grid accepts ownership of the data for its analysis purposes in 2016. There is one common European scenario applied across all FES scenarios, which is the Pöyry 'Central' scenario. The Central scenario presents a best view of future electricity prices based on internally consistent combinations of assumptions and drivers. It provides wholesale electricity price outcomes over the timeframe to 2040.

The Central scenario is based upon a modelled environment in which demand, capacity build, market design and fuel and carbon prices are all in dynamic equilibrium. In addition, there are also a number of assumptions that are not modelled dynamically, but are drivers of the scenario outcome. Some of the most important of these are Gross Domestic Product (GDP) growth, level of decarbonisation, and market behaviour (with the market behaviour driver broadly reflecting the level of competition in commodity and power markets).

The scenario assumes that over the long term, new capacity enters the market to meet the increase in demand and to replace plant that is scheduled to close in that period, ensuring plant capacity margins remain adequate at times of system tightness. Historical weather, demand and plant outage are used to prevent losses within a '1 in 5' peak year. In addition, sufficient back up capacity is assumed to cover the largest possible generation failure in each country without loss of load.

For renewable generation projections, a range of factors are taken into account, including National Renewable Energy Action Plans (NREAPs) submitted by the 28 EU Member States, renewable capacity development to date, individual national targets and the potential for economic build without subsidy. The renewable energy targets for 2020, as agreed in the EU Renewable Energy Directive (RED), are taken as an ambition for most EU member states, although there is still uncertainty regarding the ability of some member states to meet these commitments. The level of renewable electricity attainment varies by country, depending on an analysis of the likelihood that it can meet the national 2020 target. Several parameters are taken into account, including the absolute value of the country's required renewables deployment, its track record of achieving renewables targets, its resource potential and the maturity of its support mechanisms.

The electricity markets in many European countries are currently undergoing significant change. The traditional market structure of paying for energy delivered is not providing sufficient remuneration to ensure the required investment in new capacity. As a result many European governments are implementing or actively considering a substantial change in the structure of their wholesale energy markets by including capacity mechanisms or other capacity support schemes, such as strategic reserve. Market design assumptions within the scenario are based on the current plans for the country, with the scenario reflecting the most likely outcome.

The SO is recruiting a new team to produce European data for each of the FES scenarios. This will be used from FES 2017 onwards.

15.3 Plant availability

The availability factors of all generation types are an important assumption within BID3. Plant availabilities are sourced from Pöyry and from FES. They are generally by month, and are a de-rating factor like those used in ELSI. It reflects outages, both planned and unplanned, and allows the plant a small amount of headroom i.e. it won't often produce at absolute peak output. From this de-rated value there is then an additional 'Ambient factor' applied to the plant to represent the likely operating conditions faced across the year. These are generally monthly but can be made more granular. Again these are from Pöyry. Mostly, generic profiles specific to fuel type are used, however, where Pöyry has more detailed information about a specific plant they have refined their profiles to provide a more accurate representation.

BID3 is able to model each individual plant within a given region. To speed up the model run time without sacrificing results quality, BID3 aggregates plants with similar variable costs. The variable costs are built up of several components: efficiency, fuel cost, transportation cost for fuel, O&M costs etc.

15.4 Thermal power and CHP

Thermal technologies are characterized by technology type, fuel type, efficiency, start-up cost, part load efficiency, operating cost, and availability. BID3 also captures other aspects of thermal systems, such as must-run restrictions (for example, in order to model a take-or-pay gas contract). The model also allows detailed combined heat and power (CHP) modelling and can distinguish between extraction CHP and backpressure CHP. A further distinction between public and industrial CHP can be applied. For each CHP plant, heat related production profiles can be specified.

15.5 Hydro power

One of the key components of BID3 is sophisticated hydro modelling that simulates the way hydro is priced and operated in the market. Hydro in general is split in the model into Reservoir (storage) hydro and Run-Of-River (that is, hydro plant with very small or no effective storage) hydro. Inflows are modelled on multiple levels, with inflow expectation, the ability of generators to forecast inflows ahead of time, and actual inflow levels (and the consequent impact of errors in expectation, forecast ability and (systematic) errors in forecasting), all specified explicitly in the model.

The hydro reservoir structure in each hydro-enabled region is modelled in BID3 as a single, large hydro reservoir that is effectively the sum of all the hydro reservoirs in the region. Each reservoir is modelled as a store of power (rather than directly as water). Thus, all storage (and consequently inflow) data is measured in units of power (e.g. storage in TWh, inflow in GWh per period). Release from each reservoir is in the form of spill and generation. Spill occurs when either: reservoir storage levels exceed the maximum, or generation levels in a given period are less than the minimum release level required for that period, and the shortfall is met by spilled release. Total release in a period is also subject to a specified maximum release level. The inflows to the various hydro power regions are based on actual hydrological years. The market behaviour of hydro power producers as simulated in the model reflects the intrinsic uncertainty about future inflow.

15.6 Wind and solar output

Wind and solar power production is simulated at an hourly resolution. The generation profiles are based on historical generation patterns. The simulation process ensures that the difference between consecutive hours and between different market areas is realistic. It can also be modelled with priority entry to the grid. In effect this implies that the BID3 model sometimes delivers price of zero in areas with a lot of wind, like Denmark, which is very much in line with observations from the markets.

Wind and solar in BID3 are ‘must run’, that is they will be allocated first for each time period based on their case collection load factor and other plant are dispatched thereafter to meet the demand. A curtailment factor can be applied as can limits on the levels on non-synchronous generation on the system. To determine the load factor of a wind farm or solar plant, the following approach is used:

- Pöyry procured 30 years of wind speeds and 10 years of solar irradiance data from Anemos[3] for all North West Europe:
- Wind is based on a 20km x 20km x 10 minute re-analysis of the MERRA[4] data
- Solar data is based on a 4km x 4km grid with hourly time resolution

[3] http://www.anemos.de/en/index.php

[4] MODERN-ERA RETROSPECTIVE ANALYSIS FOR RESEARCH AND APPLICATIONS)- MERRA is a NASA re-analysis for the satellite era using a major new version of the Goddard Earth Observing System Data Assimilation System Version 5 (GEOS-5). The Project focuses on historical analyses of the hydrological cycle on a broad range of weather and climate time scales and places the NASA EOS suite of observations in a climate context

For most zones two profiles are created:

- Existing: To be applied to all existing wind farms
- Future: To be applied to all future wind farms (i.e. named, planned and generic)

The exception being zones where there is little or no existing wind, where we only have one profile. The reason for having two profiles is that (i) wind load factors may differ between grid squares within a zone (ii) existing wind should have selected the squares with the highest wind speeds, with future wind (planned and generic) plant being left with worse ones. At the same time there are improvements in hub heights and turbines – the net result tends to be new wind has higher load factors than existing.

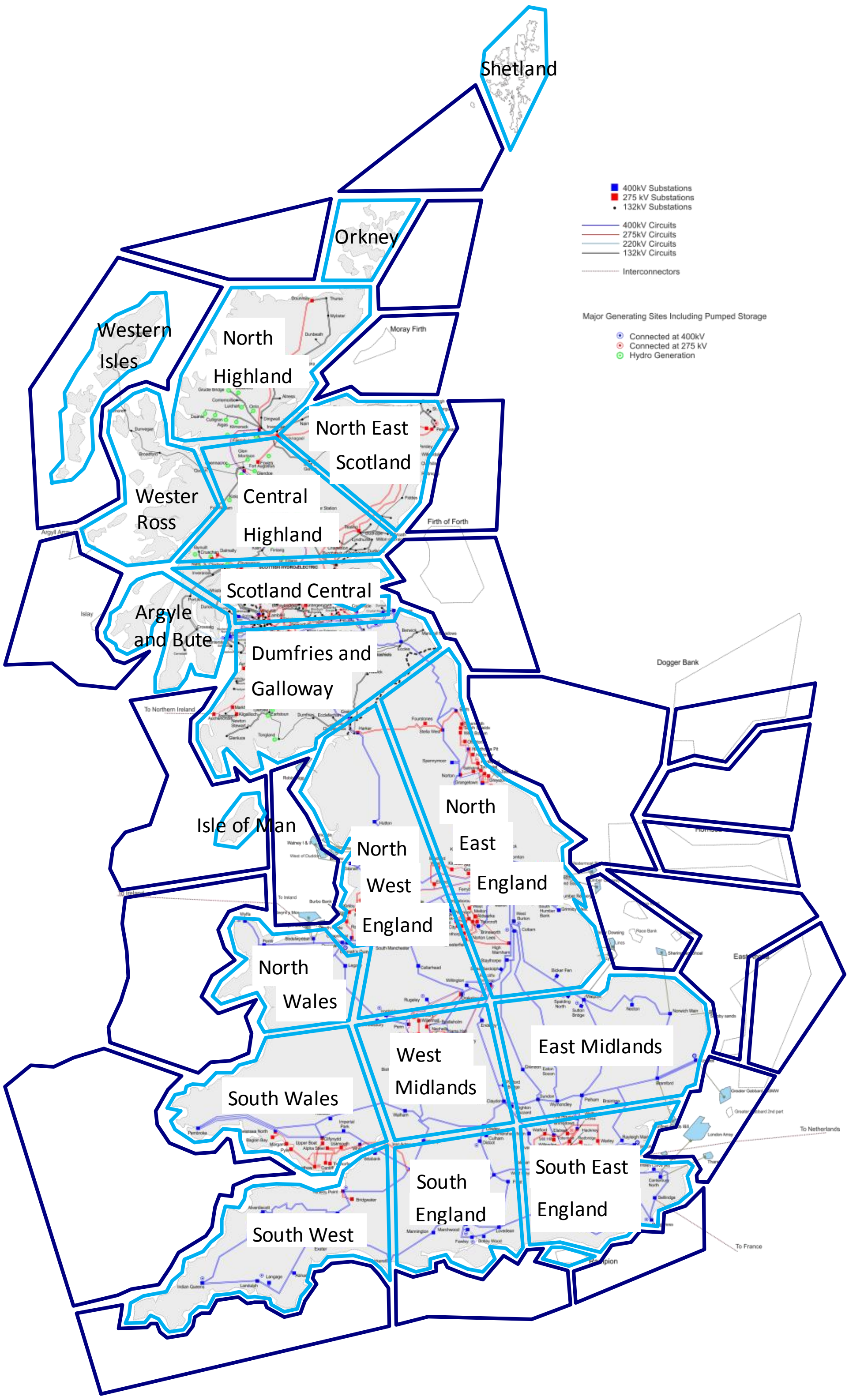
For existing and future the allocation process is:

- Allocate existing wind farms to each zone (the SO defined a number of zones that it wished to model) –see Figure A5
- For each zone work out which 20km grid square each wind farm is in
- Average the wind profiles in these grid squares, weighted by the capacity in them

In summary two wind profiles are created per region (future and existing). These are created from 'profiles' for each grid square. Say there are 100 grid squares in a region. To go from 100 to 1 we need to do some kind of average. This will not be a straight average but a weighted average, weighted by how much capacity is planned to be built in each grid square. All future wind farms in this region will be given that profile. The reason for this is simplicity for the user: not wishing to have profiles for all 100 grid squares.

For each wind farm we assume a turbine type (typically based on swept area per MW) and hub height, with defaults (by zone) for new wind farms and where there is no data available. We then apply a power curve to the wind speeds to get the load factors each hour. A scale factor is applied to the wind speed, partly for wake effects, but also to help match historical load factors. An availability profile is applied to the resulting load factors, covering outages, electrical losses etc. See Figure A5 below for a representation of wind zones across the UK.

Figure A5: Onshore and offshore wind zones



For each solar zone one profile is created. See Figure A6 for a representation of solar zones across the UK. The reason for having only one profile is that we assume solar insolation is the same in all grid squares of a zone and therefore future plant will get the same load factor as existing plant.

There is less variation in solar load factors and profiles over short distances than for wind, so we simply take a straight average over all grid squares in the zone.

- Allocate every grid square in the UK to a solar zone. This allocation will be done based on whether the centre of the square lies within the boundaries of the zone

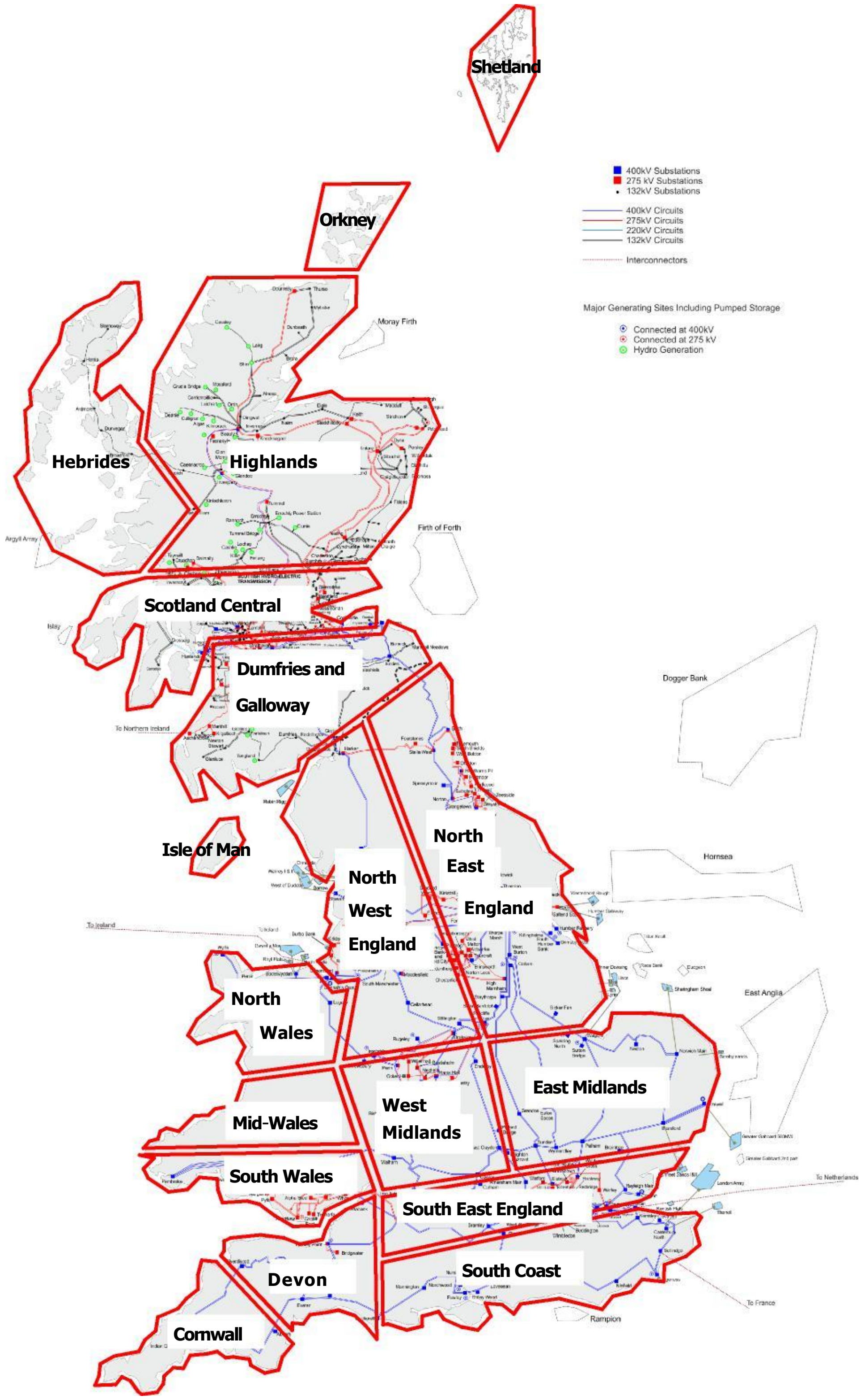
- Average the solar generation profiles in these squares

In summary one profile created for solar by region. A similar process to wind is applied to calculate the load factor. Here we just assume that the load factor is proportional to the irradiation, with the constant of proportionality based both on what is sensible physically (covers temperature and inverter losses etc.) and what gives load factors in line with history. The solar data is sourced for Transvalor[5].

See Figure A6 below for a representation of solar zones across the UK.

[5] https://www.transvalor.com/en/

Figure A6: Solar zones



Stakeholder engagement

We welcome your views on the generation availability assumptions used within our analysis. We'll use your feedback to continue to improve our analysis.

15.7 Exchange rates

For NOA 2016/17 we used the current exchange rate at the time the analysis was undertaken. This ensures consistency with pricing of all other inputs.

16 Summary of data sources within BID3

Tables A3 and A4 summarise the sources of data used within BID3.

Table A3: Data sources

Category	Source	Comment
Fuel prices	Pöyry	Fuel prices from all European countries (including GB) come from a single consistent source. Assumed flat across the forecast period.
Carbon price	National Grid	The carbon floor price was incorrectly applied to two of the four FES scenarios (No Progression and Consumer Power) for NOA 2016/17: initial inspection suggests this has had limited impact. We are currently investigating this matter further.
BSUoS	Pöyry	Fixed fee. (Not in ELSI)
Scarcity rent	Pöyry	Not currently used by National Grid. (Not in ELSI)
Start-up and No load costs	Pöyry	Fixed by technology. (Not in ELSI)
Ramp rates	Pöyry	Not currently used by National Grid. (Not in ELSI)
Temperature dependent start cost	Pöyry	Not currently used by National Grid. (Not in ELSI)
Minimum on- and off-times	Pöyry	Not currently used by National Grid. (Not in ELSI)
Boundaries	ETYS + TO's	Same as ELSI
Interconnector availability	National Grid	95% for all interconnectors. Same as ELSI
Bids / offers	National Grid	See text in bid / offer section

Table A4: Within-year profiles set-up

Category	Source	Comment
Fuel prices	N/A	Within year profiling not currently used. Same as ELSI
BSUoS	Pöyry	Fixed fee
RES generation	Pöyry	See text in wind and solar output section.
Plant availability	Pöyry	ELSI previously modelled plant availability as a constant by season. BID3 models monthly, for most plant
Demand	Pöyry	Based on historic profiles
Boundaries (availability + outage)	National Grid + TO's	Same as ELSI
Interconnector availability	National Grid	Within year profiling currently not applied
Bids/ offers	National Grid	See text in bids/offer section
Regulated inflow Unregulated inflow Snow share of inflow	Pöyry	BID3 has minimum weekly resolution. (Not in ELSI)

17 BID3 continuous improvement

BID3 is a powerful tool and we have started the journey of understanding how it can improve and enrich our modelling and analysis. We are confident that the work done to date represents a significant step change in capability and has enhanced our modelling for NOA 2016/17.

Our development work over the last year and the feedback from the independent review has helped us to identify focus areas for further investigation to see if BID3 and our configuration of parameters and data can yield further and deeper insight to aid decision making. Areas for investigation include:

- More representative boundary outage modelling to reflect year round effects
- Including dynamic constraints like plant ramp rates and minimum stable generation limits in the optimisation (i.e. using a mixed integer rather than a linear optimisation)
- Modelling of plant scarcity rent components
- Building in National Grid's new European FES data
- Examining the impact of Power Transfer Distribution Factors (PTDF's) to allocate interconnector flow, aligned with the changes being introduced by Capacity Allocation and Congestion Management (CACM)[6]
- More detailed wind and solar modelling (i.e. incorporating panel orientation diversity)

18 Stakeholder engagement

We would like to hear your views on this report and our long term market and network constraint modelling. You can engage with us in the following ways:

- Email us at: **transmission.etys@nationalgrid.com**
- Customer seminars
- Operational forums
- Feedback via survey at **hhttps://www.surveymonkey.com/r/2016-17NOA**
- Bilateral stakeholder meetings

[6] https://www.entsoe.eu/major-projects/network-code-development/capacity-allocation-and-congestion-management/Pages/default.aspx