PLEXOS Validation for 2016-17

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Version History

Version	Date	Description	Prepared by	Approved by
1.0	11th May 2016	Final version	Luke Humphry	Andrew Nind

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1 Introduction

1.1 Overview

In July 2015 the Commission for Energy Regulation (CER) and the Northern Ireland Authority for Utility Regulation (NIAUR or Utility Regulator), jointly known as the Irish Regulatory Authorities (RAs), engaged Baringa Partners LLP (Baringa) under the work package titled “Consultancy Assistance to Support PLEXOS Validation and Directed Contracts”.

This support comprises two work streams:

- Work Stream 1. Quarterly update of the formulae used to set Directed Contract (DC) strike prices, Rounds 14 – 19
- Work Stream 2. Validation of the SEM PLEXOS model used to set Directed Contract strike prices and volumes for 2016 – 2017

In this document we describe the work carried out under Work Stream 2, validating the PLEXOS model for 2016 – 2017.

1.2 Scope

1.2.1 In Scope

The scope of the validation exercise is limited to the forward looking PLEXOS model. This model is used by the RAs to calculate the DC strike price formulae and volumes, and it is planned that the validated model will be published and made available to market participants.

We have validated all input data to the model to allow it to be used to provide electricity market projections for 2016 and 2017.

The areas of input data that have been updated include:

- Generator submitted data
  - Marginal Generation Costs
  - No Load Costs
  - Start Costs
  - Technical Offer Data
- Hydro plant daily generation volumes
- Outages
  - Planned maintenance
  - Forced outages
- Demand

- Embedded generation
- Wind generation
- Demand side units
- Interconnectors
- GB bids on interconnectors

In the following report sections we describe each of these areas in turn, outlining the changes made over the previous validated model and the effect on SMP and generator dispatch.

1.2.2 Out of Scope

With agreement from the RAs, a number of model settings and methodologies that were validated in the most recent backcast have not been changed in this update.

The following settings and methodologies were out of scope and have not been changed:

- PLEXOS version (6.207 R03 32bit)
- Solver and mode (Xpress MP, Rounded Relaxation)
- Rounded relaxation self-tuning increment (0.05)
- Modelling of hydro and pumped storage plant without minimum stable levels

Though out of scope for this update, due to the lack of backcast, the following recommendations were made by Baringa for future SEM models:

- Update PLEXOS version to 7.300 R04 64bit
- Investigate including minimum stable levels for hydro
- Reduce rounded relaxation self tuning increment to 0.1

The model has been validated with data extending to the end of 2017, though it should be noted that this does not include the change of market structure that will result from the planned switch to I-SEM in Oct 2017. At this point in time it has not been decided what the precise structure of I-SEM will look like, or indeed if DCs will continue in their current form. The validated model is only valid for the current SEM, up until the point of transition to I-SEM.

1.3 Market Participant Responses

As part of the validation exercise all major market participants were contacted with a request for details of the technical and commercial properties of their plant. The response rate was very high, and market participants are thanked for responding to follow up questions in a timely and thorough manner.

1.4 Comparison with previous models

In the following sections comparisons are made to the modelled SMP as incremental changes are made to the model (each change builds on the previous changes that have been discussed). Though the focus in this report is SMP, other market indicators have been investigated as part of the validation: generation mix, interconnector flows, plant merit order.

The comparison in this report is against the model used for the R15 DC strike price formulae update in October 2015 (though updated with commodity forward prices from 4th March 2016). The last validated model made available to market participants was in March 2015, and some small changes were made between this and the version used in October 2015. Where comparisons are made, the sources of the old and new assumptions are clearly stated.

It should be noted that the model used for the R16 update in March 2016 was a partial update from that used in R15 rather than the fully updated validated model presented here. Generator and interconnector changes were included in R16, but system updates outlined here (demand, wind capacities, DSP capacities, embedded generation, forced outage rates etc) were not.

2 Generator data

2.1 Generators added and removed

In May 2015 the three oil fired units at Great Island were decommissioned, and have been removed from the model. Two plant are scheduled to come online in 2017 and have been added to the model – Mayo Biomass CHP and Dublin waste to energy. Two plant have been renamed – “Meath” becomes “IW1” and “Maydown” becomes “Lisahally”.

2.2 Generator submitted data

2.2.1 Validation methodology

Market participants were requested to submit technical and commercial cost data for the major generation plant in the market. All generator data was validated against recent submissions to the market.

Market submission data was supplied by the Single Electricity Market Operator (SEMO), collated for the period 1st Oct 2014 – 1st Oct 2015. The submission data consisted of:

- Commercial offer data (COD)
  - Price/Quantity pairs
  - Start-up costs
  - No-load costs
- Technical offer data (TOD)
  - Max capacity
  - Min stable level
  - Min on/off times
  - Hot/warm/cold start times
  - Ramp up/down rates between min stable level and max capacity

Using the generator parameters supplied by market participants for this round of the validation, the market submissions were recalculated by Baringa, and compared with the actual submitted values.

Where the calculated submissions did not match the actual submissions there was further investigation to understand the discrepancy. Particular attention was paid to September 2015, being the last month of historic data that was used to validate this forward looking model.

Where there were discrepancies, market participants were contacted and in many cases supplied additional information to understand any differences in assumptions. Only when the differences in the calculated and original submitted values were acceptably small were the generator parameters deemed to be "valid" for use in the forward looking model.

In a small number of cases market participants highlighted that plant properties had changed since the 1st Oct 2015, in which case recent market submission data was collected for the plant in question to validate the new parameter values.

2.2.2 Marginal Generation Costs

Marginal generation costs are defined as those incurred for each additional MWh of output, ie €/MWh or £/MWh. Marginal costs can be calculated from the price/quantity pair Commercial Offer Data (COD). Historic commodity prices, along with the submitted heat rates, load points, VOM, mark-ups and Transmission Loss Adjustment Factors (TLAFs), were used to calculate the daily average generation cost at different load points.

Table 1 Data used to validate marginal generation costs

Market submissions	Calculated using generator parameters
Price	Incremental heat rates
Quantity	Load points
	VOM (€/MWh, £/MWh)
	Mark up
	TLAF
	Historic fuel prices
	Historic carbon prices
	Historic FX rates
	Fuel adder assumptions

For many generators there was good agreement between the market submissions and calculated costs, though initially for some generators the difference was unacceptably high.

The most common reasons for differences were:

- Different fuel adder assumptions
- Double counting of fuel costs in VOM entry of generator parameters
- Mark-ups on incorrect bands

Market participants were in many cases willing to share confidential data detailing the breakdown of their bids on a small number of days, which was extremely useful in pin-pointing where the differences in assumptions were. This data was used only for the validation exercise described here, and will not be used for any other purpose.

There were some changes in generator properties compared with previous years for individual generators, but for the system as a whole there was no significant movement, and no systematic change.

2.2.3 No-Load Costs

No-load costs are defined as those incurred per hour of operation, regardless of output level ie €/h or £/h. No-load costs are submitted by market participants directly to the market. Historic commodity prices, along with the submitted no-load fuel usage, VOM and TLAFs, were used to calculate a daily no-load cost.

Table 2 Data used to validate no-load costs

Market submissions	Calculated using generator parameters
No load cost	No-load fuel usage VOM (€/h, £/h) TLAF Historic fuel prices Historic carbon prices Historic FX rates Fuel adder assumptions

Where there was not good agreement initially, this was again primarily due to:

- Different fuel adder assumptions
- Double counting of fuel costs in VOM entry of generator parameters

2.2.4 Start Costs

Start costs are defined as those incurred per start of a generation plant, ie €/start or £/start. Start costs are submitted by market participants directly to the market, and are given for Hot, Warm and Cold starts. Historic commodity prices, along with the submitted start up energy requirement (on a hot/warm/cold basis), the split of fuels (for multi start fuel plant), VOM and TLAFs, were used to calculate daily start costs.

Table 3 Data used to validate start costs

Market submissions	Calculated using generator parameters
Start costs (Hot/warm/cold)	Start up energy (Hot/warm/cold) Start fuel split %, if multiple start fuels VOM (€/start, £/start) (Hot/warm/cold) TLAF Historic fuel prices Historic carbon prices Historic FX rates Fuel adder assumptions

Again, differences in the market submissions and calculated costs were primarily due to:

- Different fuel adder assumptions
- Double counting of fuel costs in VOM entry of generator parameters

2.2.5 Technical Offer Data

Technical offer data is primarily submitted to the market in the same format that is required for the PLEXOS model. As with COD, historic Technical Offer Data (TOD) from the market was used to validate the generator parameters submitted to the RAs.

Table 4 Data used to validate start costs

Market submissions	Generator parameters
Max capacity	Max capacity
Min stable level	Min stable level
Min on/off times	Min on/off times
Hot/warm/cold start times	Hot/warm/cold start times
Ramp up/down rates Ramping Breakpoints	Ramp up/down rates

In most cases good agreement was found. The only area where significant differences were observed initially was for the ramp up and down rates. There were two main reasons for the initial differences:

- Ramp rates are valid between min stable level and max capacity only in the PLEXOS model, whereas some generators provided rates from off to full load
- Historic ramp rates used for comparison were calculated to maximum available capacity (rather than name plate capacity). Where the ramp rate changes with output this can cause differences

In many cases the generator submission has not been used, in favour of the average (mode) seen in the historic market submissions. In all such cases generators have been informed of the change and have agreed to it.

2.2.6 Effect of changes on output

The effect of updating all generator properties using the valid parameters described above was to increase SMP slightly in Summer and decrease SMP slightly in Winter. Figure 1 and Figure 2 below show the average daily SMP profile for Summer and Winter 2016/17, using forward prices from the 4th March 2016 (as used to set the Directed Contract strike price formulae for R16).

There is no significant change in the mix of generator types that are generating (gas, coal, distillate, etc), though some individual plant have moved in the merit order and so see changes in load factor as a result.

Figure 1 Summer SMP, with and without generator parameter changes

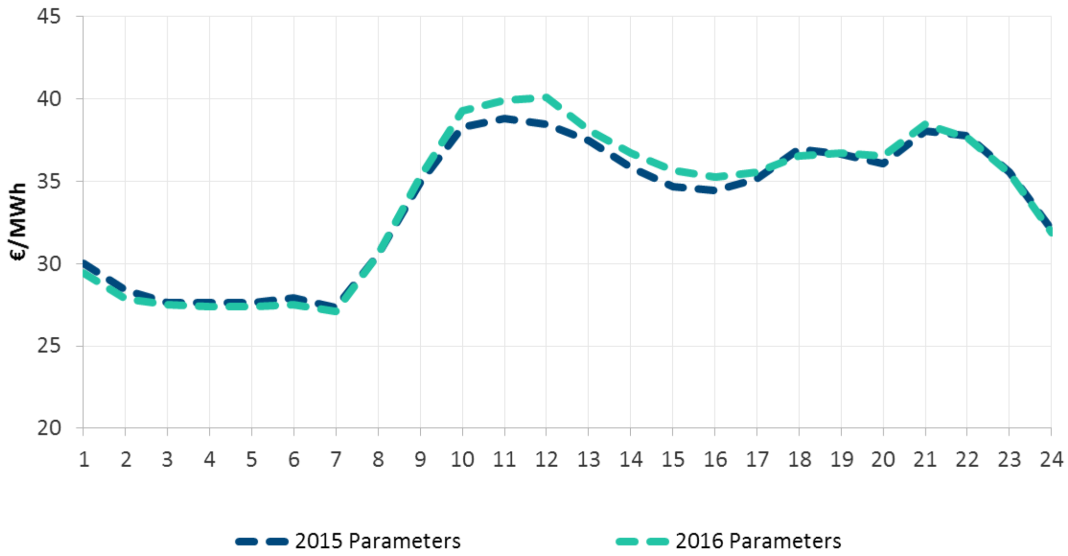
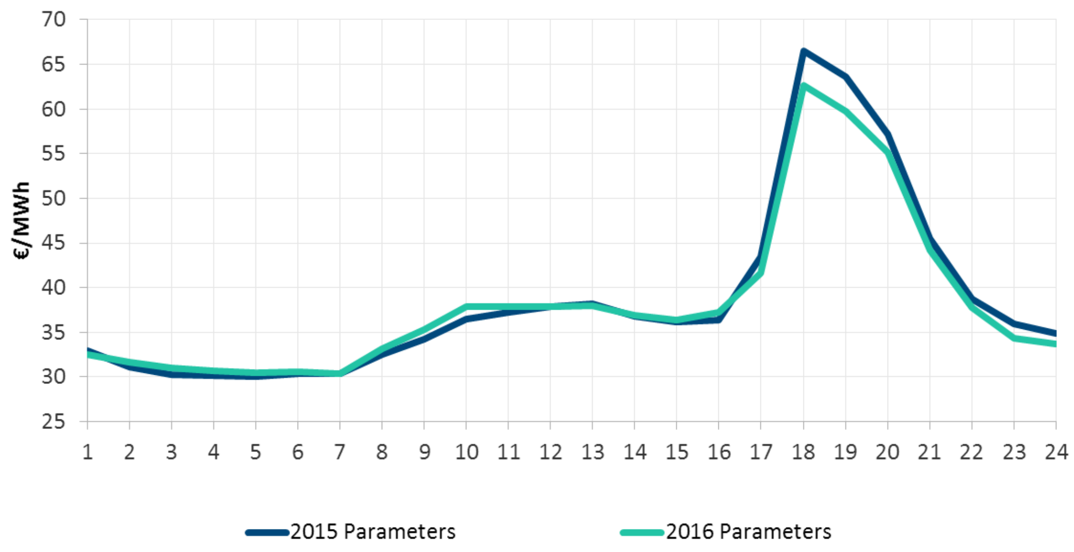


Figure 2 Winter SMP, with and without generator parameter changes



2.3 Hydro and pumped storage

The representation of hydro and pumped storage generators has not changed in this update. Hydro plant are represented as run of river with limited storage, having a daily limit on generation but with the flexibility to choose when in the day to run to meet this limit. Pumped storage is modelled using a head reservoir and tail reservoir with losses incurred when pumping from tail to head.

Both hydro and pumped storage are modelled without min stable levels, consistent with the approach used in the last backcast validation. Pumped storage is assumed to ramp to full capacity within the 30 minute granularity of the model, and so ramp rates are omitted.

The one parameter that has been updated is daily generation limits for hydro, using the Transmission Systems Operators' (TSOs') best current view, consistent with the Generation Capacity Statement (GCS) 2016-2025. The changes are small, and do not have a significant effect on plant dispatch or SMP.

2.4 Outages

2.4.1 Planned maintenance

Outage information for planned maintenance has been updated to the most recent public schedule published by SEMO on their website. For 2016 we use the schedule published in February 2016, for 2017 we use the schedule published in October 2015. Outages and capacity reductions are applied to generation plant in the model as per the SEMO schedule.

The changes in outage schedule are small when looked at market-wide, and do not have a significant effect on SMP.

2.4.2 Forced outages

Market participants were requested to supply forced outage rates for all plant. The numbers received did not change significantly from those supplied in previous validation exercises. However, these were significantly lower than the historic forced outage rates of most generators.

Historic forced outages were supplied by the TSOs for the period 2013-2015 and the average forced outage rate found. For all but a few generators this historic rate was higher than that supplied by market participants. For the SEM as a whole, historic forced outage rates are on average 6.1%, rather than 2.8% predicted by market participants, which implies a decrease in available energy of 2.6 TWh between the two forced outage rate values. It is thought the reason for this difference may be that market participants have not factored in rare, and often lengthy, major forced outages. The TSOs refer to such events as "high-impact low-probability" (HILP), and note that while for any single plant they are rare, it is likely that at any point in time at least one generator will be undergoing such an event.

Given that there is no evidence that forced outage rates are likely to significantly decrease in the future, we have used the historic rates (2013-2015) as collated by the TSOs to ensure the correct plant availability for the system. However, individual plant that incurred a HILP event over this historic period may not incur such an event in the future, and vice versa for plant that did *not* incur such an event historically. To avoid locking in pessimistic or optimistic forced outage rates for individual plant in the forward looking model, forced outages rates have been averaged (on a capacity weighted basis) over plant types. This results in projected system availability matching that seen historically, but avoids locking in historic HILP for individual plant. Gas fired plant were initially separated into peakers and CCGT/CHP, but there was no significant difference in historic forced outage rates, and so a blended rate was used for all gas fired generators. No historic forced outage rate was available for the single biomass fired plant in the model (Mayo CHP), and so the SEM average was applied to this plant.

Table 5 shows the forced outage rates by plant type, both the rates initially submitted by market participants and the average historic rates as used in the model.

Table 5 Forced outage rates by plant type

Generator Type	Market Participant Submitted	Historic (used in validated model)
Gas	2.7%	6.2%
Oil	3.0%	2.0%
Coal	3.5%	9.1%
Peat	4.2%	7.9%
Hydro	1.1%	4.5%
Pumped Storage	1.4%	6.0%
Distillate	2.1%	2.4%
Waste	7.6%	6.7%
Biomass	0.0%	6.1%
SEM wide	2.8%	6.1%

The reduction in plant availability that comes from using historic outage rates has upward pressure on prices, of approximately 0.3 €/MWh on average. Figure 3 and Figure 4 show the average daily SMP profile in Summer and Winter respectively.

Figure 3 Summer SMP, with and without historic forced outage rates

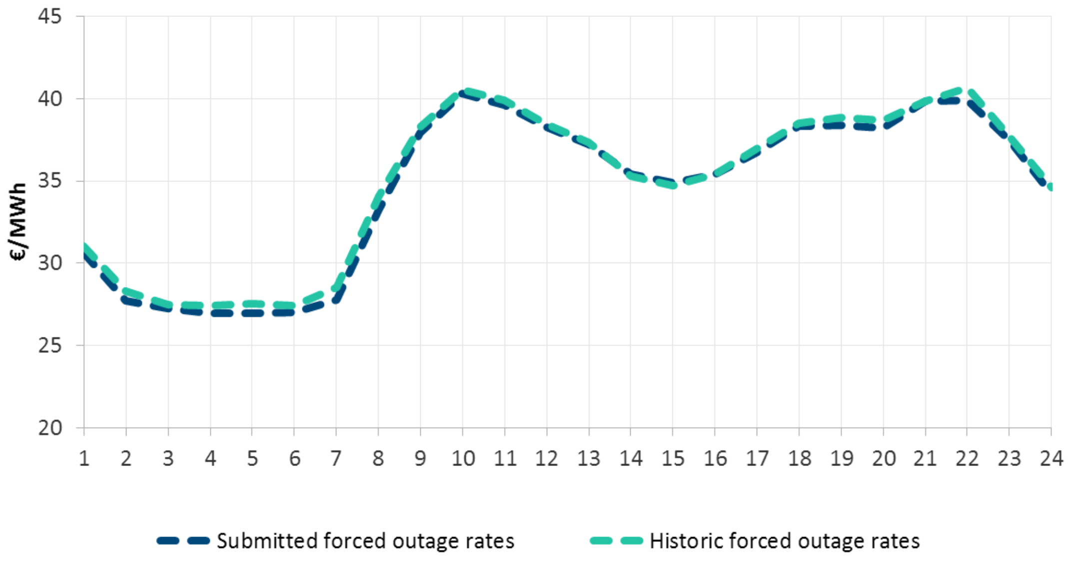
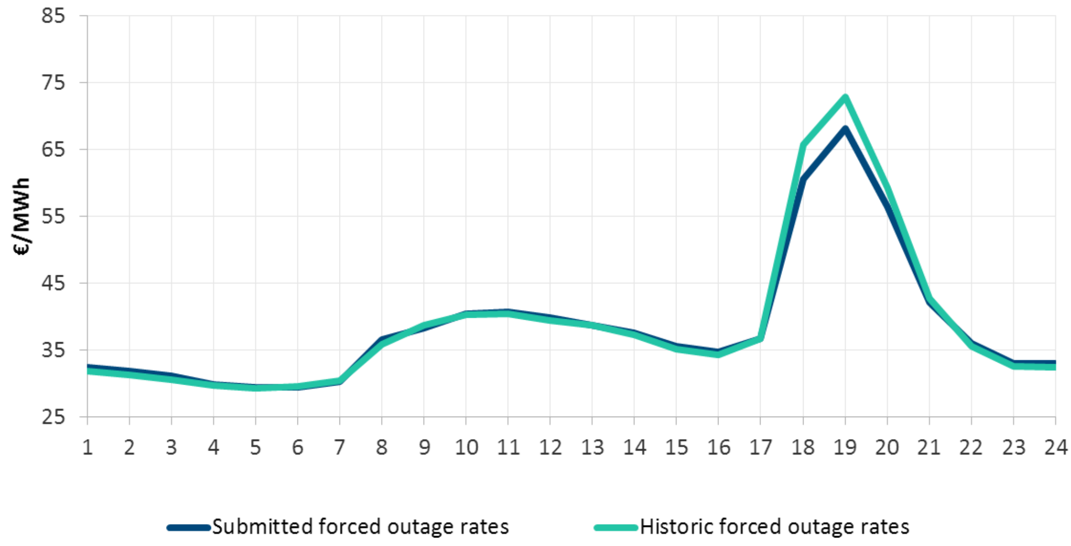


Figure 4 Winter SMP, with and without historic forced outage rates



3 System data

3.1 Demand

Demand has been updated to match the TSOs' latest assumptions, consistent with the Median Total Electricity Requirement (TER) forecast in the GCS 2016-2025. Annual energy and peak demand projections are higher than in the previous GCS, primarily due to an increase in forecast demand from data centres and improved economic growth forecasts. This has resulted in an increase in annual and peak demand of approximately 2% in 2016 and 3% in 2017, as shown in Table 6.

Table 6 Change in GCS electricity demand forecasts

Energy Forecast	*Units*	GCS 2015	GCS 2016	Difference
All Island TER - 2016	*GWh*	36,432	37,086	1.8%
All Island TER Peak - 2016	*MW*	6,671	6,805	2.0%
All Island TER - 2017	*GWh*	36,934	38,038	3.0%
All Island TER Peak - 2017	*MW*	6,702	6,888	2.8%

The base year used to create the half hourly demand profile has been updated to use 2014 data, which has resulted in slight smoothing in the seasonal shape of demand – slightly higher demand in Summer and slightly lower in Winter.

The effect of updating the demand assumptions is to increase SMP by 0.5 €/MWh in both Summer and Winter, as shown below in Figure 5 and Figure 6.

Figure 5 Summer SMP, with and without updated demand

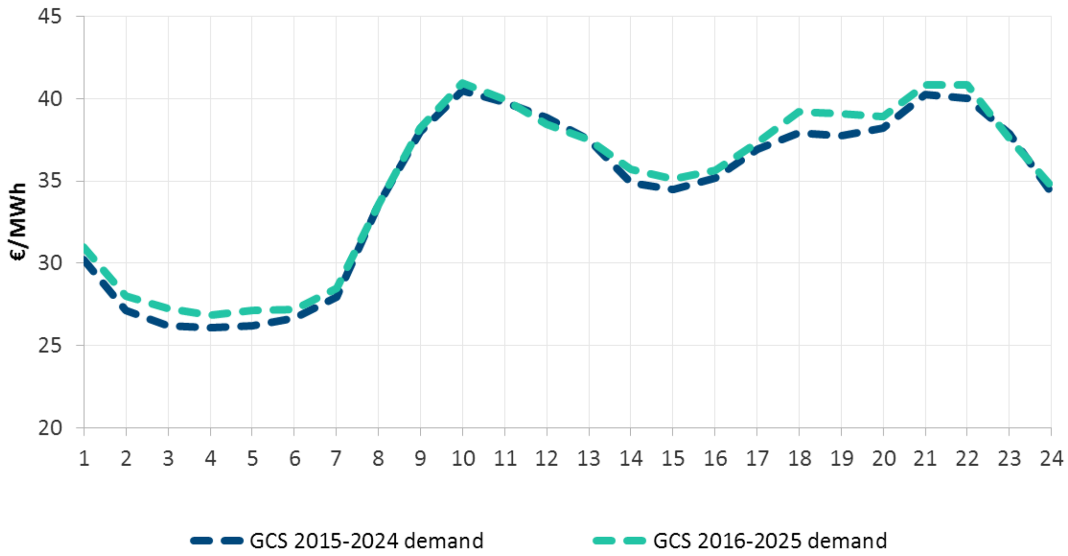
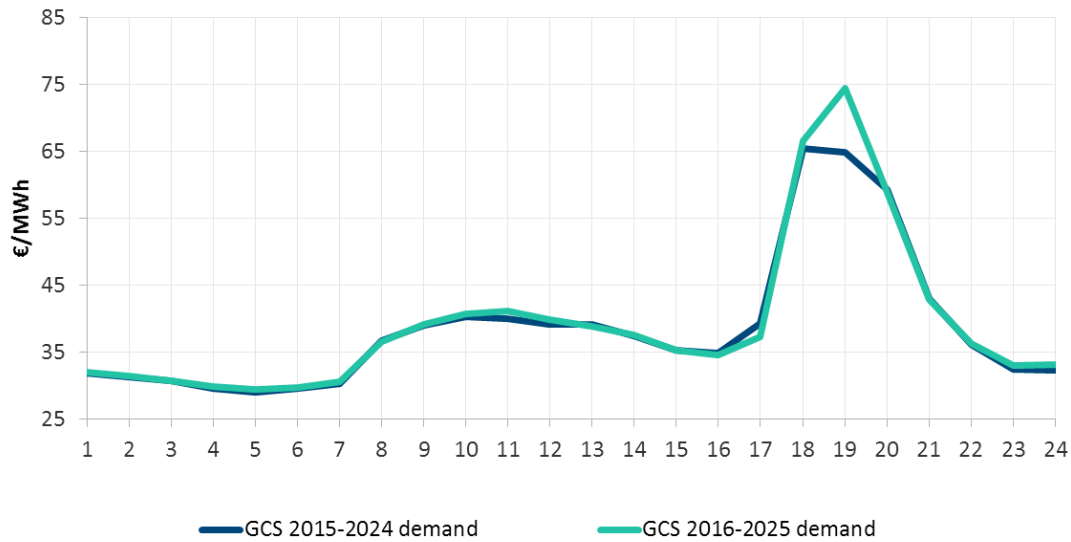


Figure 6 Winter SMP, with and without updated demand



3.2 Embedded generation

Embedded generation is represented using an hourly profile, defined for both weekdays and weekends. This has been updated using the TSOs' latest assumptions and matches the GCS 2016-2025. The change is small, and there is no significant effect on SMP.

3.3 Wind generation

Wind capacity assumptions have been updated to match the forecast in the GCS 2016-25. For 2016 and 2017 this forecast is based on proposed projects, with a de-rating to account for the likelihood that not all will be completed. Updating to the latest GCS assumptions results in an increase in assumed wind generation capacity of approximately 195MW in January 2017.

The half hourly wind profiles have changed very slightly in this update. Previously 2009 was used as the base year for all forward projections. The capacity factor in 2009 (ie Market Scheduled Quantities, before any constraints are applied) was 31%. The long run average for the SEM is 30%, as outlined in the latest GCS. In this update we have normalised the 2009 profiles to match the long run average of 30%, a small decrease in output.

The combined effect of this increase in wind generation capacity and decrease in capacity factor is a net increase in wind generation, and a decrease in SMP by approximately 0.4 €/MWh on average, as shown in Figure 7 and Figure 8.

Figure 7 Summer SMP, with and without updated wind generation

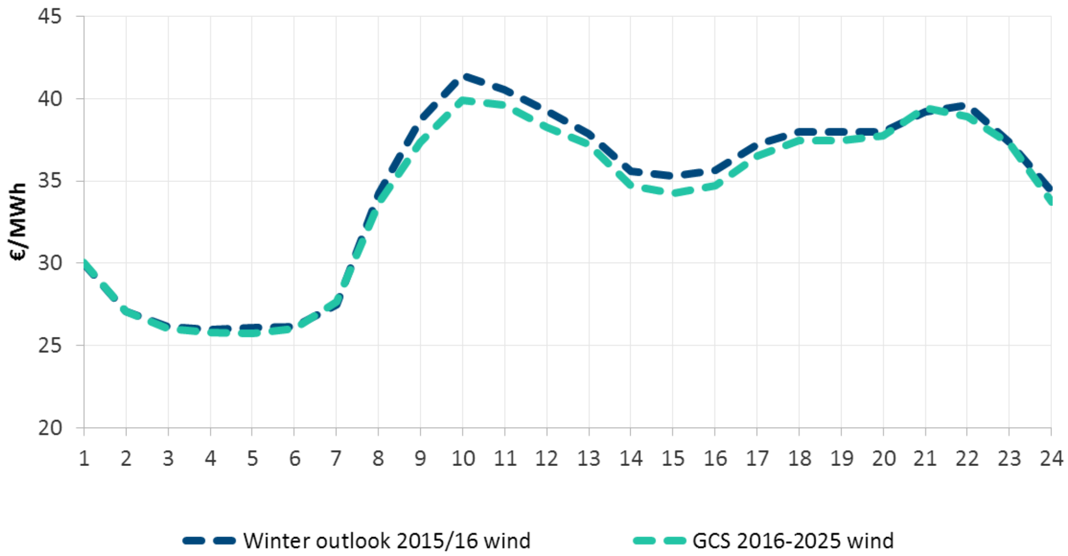
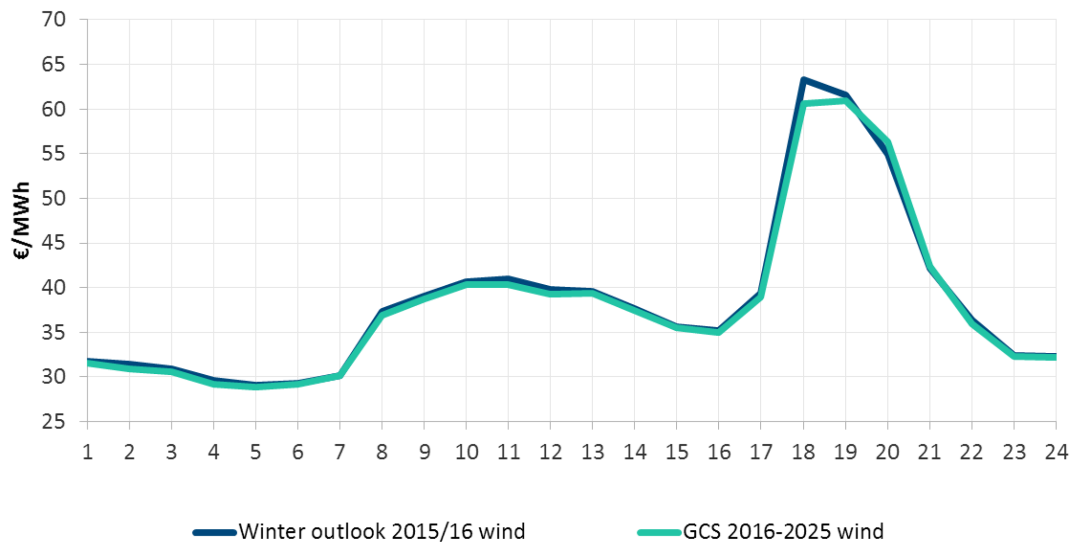


Figure 8 Winter SMP, with and without updated wind generation



3.4 Demand side units

Demand side participation through individual and aggregated demand side units (DSUs) has been updated to include the latest capacity forecasts in the TSO GCS 2016-2025. A single bid price of 330 €/MWh is used. DSU is used very infrequently in the market model, and the increase in capacity has no significant effect on SMP.

3.5 Interconnectors

Interconnector assumptions are unchanged from those used in R15 of DC strike prices.

Moyle is assumed to come back to full import and export capacity (approximately 450MW and 290MW respectively) in Feb 2016, though go on outage during April to September 2016. In October 2017 the export capacity is assumed to drop to 80MW, as per the current agreement on Transmission Export Capacity (TEC) that Moyle have with National Grid.

Losses for both East-West and Moyle are consistent with TSOs' current assumptions.

3.6 TLAFs

Transmission Loss Adjustment Factors (TLAFs) have been updated to match the published TSO values for 2015/16.

4 Modelling methodologies

4.1 CO2 as price

Previously, the cost of CO2 permits to cover emissions from fossil fuel fired generation were included in the PLEXOS model through a “tax” on the relevant fuels. The tax was calculated outside of the PLEXOS model using relevant emissions rates, to give a tax in €/GJ of fuel. In the updated model the cost of carbon has been included directly, as a €/kgCO2 cost. The cost of carbon is included in the calculated generation cost by the inclusion of a “Production Rate” in the PLEXOS model.

There are two reasons for moving to this approach:

- Eliminates the possibility of inconsistent emissions rates being applied in the model (calculating emissions volumes) and the fuel input sheet (calculating costs)
- Allows for simple checks on the output CO2 prices coming from the model, in market units

Model results are unchanged as a result of this update in methodology.

4.2 GB bid representation

GB bids on the interconnectors are represented using a gas fired generator. It should be noted that it is *bids* that are being calculated, rather the wholesale price of electricity in the BETTA market. Bids are typically lower than GB wholesale prices, as interconnector bids that clear in the SEM on shadow price will receive additional revenues through capacity payments and uplift. The uncertainty associated with these revenues results in a risk premium that slightly increases bids when compared to a scenario of perfect foresight.

A regression has been performed comparing historic GB bids on the interconnectors with historic gas and carbon prices, on a daily basis for the period January 2014 to December 2015. Using this regression the implied heat rate for the single gas plant representing GB interconnector bids is calculated.

In previous validated models a single heat rate was used for all periods. In this update an hourly heat rate has been calculated, for Summer and Winter, as shown in Figure 9 and Figure 10. There is a clear diurnal shape that varies with season. The diurnal shape of GB bids does not match GB prices, as may at first be expected, due to bidders removing SEM uplift from bids. SEM uplift is reasonably correlated with GB wholesale prices, and removes the typical shape of GB prices in the GB interconnector bids.

Figure 9 Heat rate used to represent GB interconnector bids, Summer

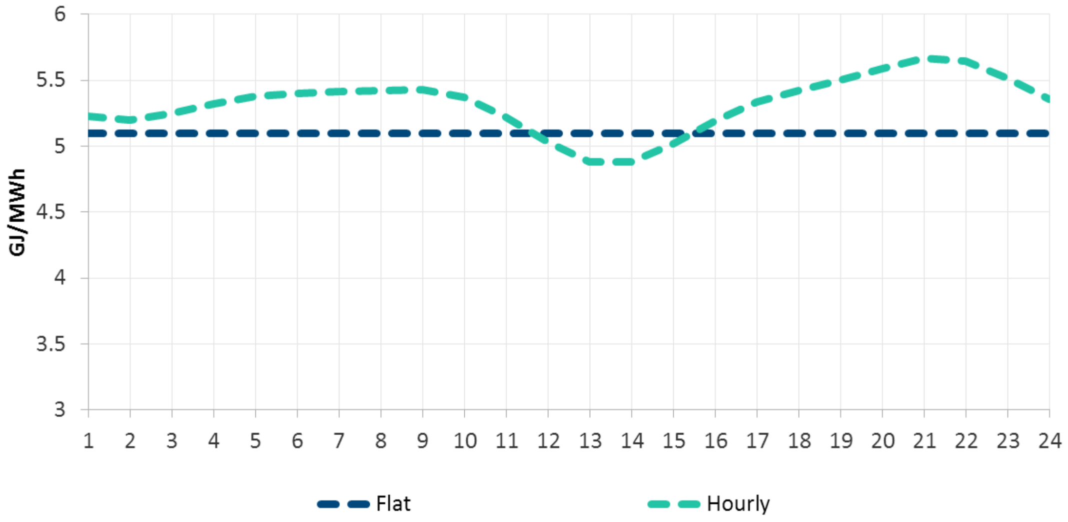
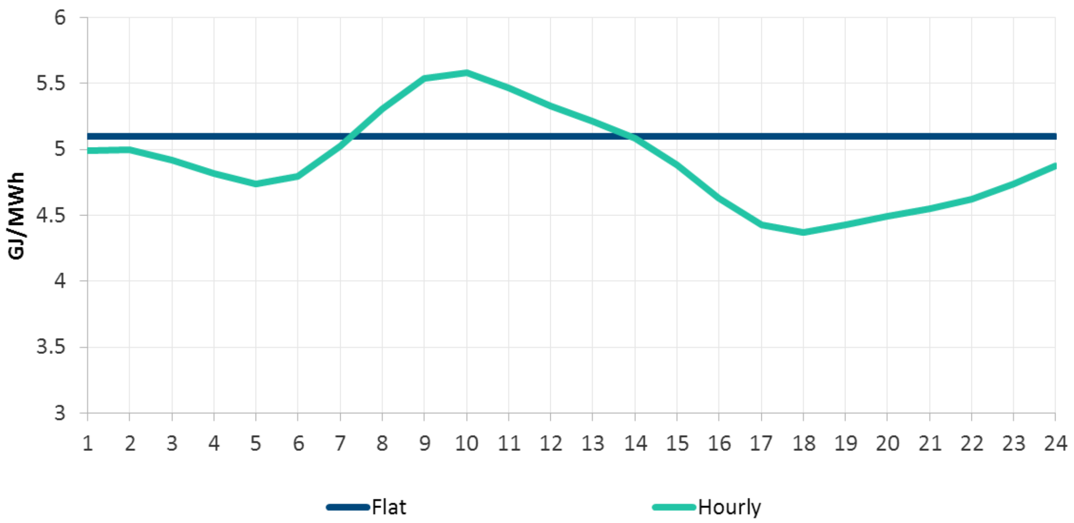


Figure 10 Heat rate used to represent GB interconnector bids, Winter



The effect of including diurnal and seasonal shape into the heat rate used for GB interconnector bids, is to increase the shape in SMP, as shown in Figure 11 and Figure 12, which is more reflective of recent outturn SMP shape. SMP is increased by approximately 0.4 €/MWh as a result. There is little effect on monthly interconnector flows, which show fairly balanced imports and exports in the near term, matching recent historic flows.

Figure 11 Summer SMP, with and without shaped GB interconnector bids

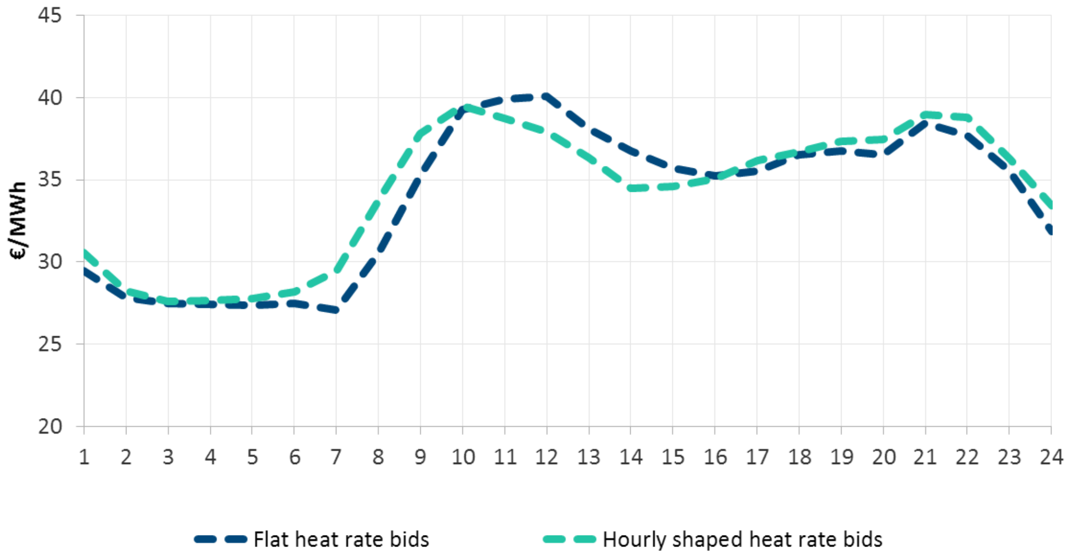
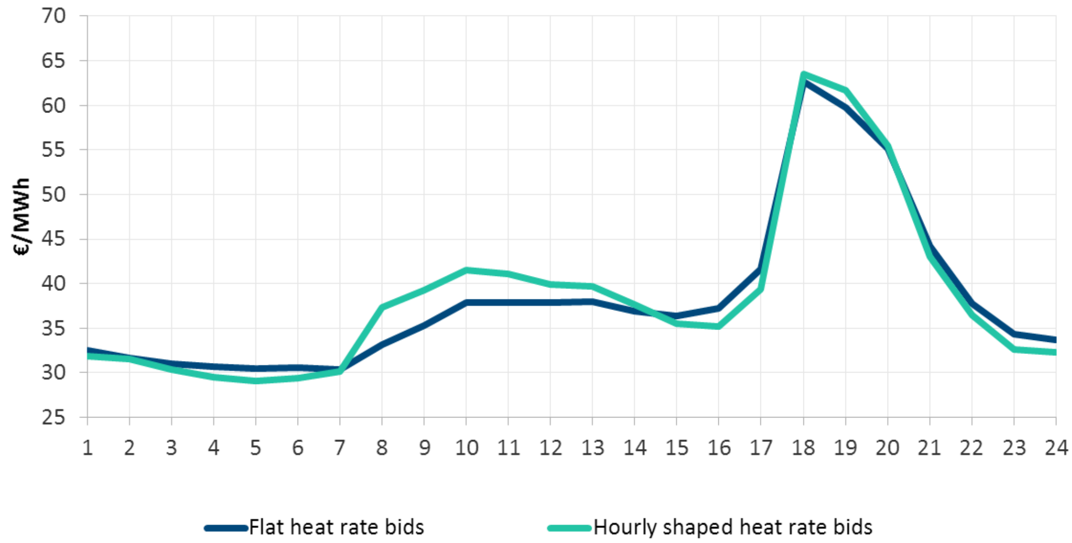


Figure 12 Winter SMP, with and without shaped GB interconnector bids



5 Fuel adders and input sheet

5.1 Fuel Adders

Market participants were requested to submit details of any additional costs that increase the cost of fuel used above the standard market traded prices, so called “fuel adders”.

Using the responses, and publicly available costs (for gas network charges for example), fuel adders have been updated. To ensure the confidentiality of generator costs, the updates to fuel adders are always blended between market participant submissions, and none of the updated values come from any single participant.

The changes are fairly small in most cases. The one fuel adder with a more significant change is the short term gas capacity charge. This has been updated using the latest values for 2015/16 published by Gas Networks Ireland, resulting in a very small increase in cost. However, these values are published in HHV terms, and must be converted to LHV to be on the correct basis for the LHV PLEXOS model. Converting to LHV increases gas capacity costs by approximately 11%.

There no significant effect of these changes on plant dispatch or SMP. Most of the fuel adder changes are minor, and those plant bidding in short term gas capacity charges are rarely dispatched in Winter months when these charges are high, so the conversion to LHV makes little difference to SMP.

5.2 Commodities price input sheet

As in previous updates of the validated model a fuel input sheet is supplied to be used in conjunction with the model. This can be used to convert market fuel prices to the correct format and basis for the PLEXOS model. The fuel inputs sheet has been updated to produce PLEXOS inputs for carbon prices as well as fuel prices, and so is renamed the “Commodities price input” sheet. The structure of the sheet remains the same, and the formatting has been tidied up. The latest fuel adder assumptions are included.

6 Summary

6.1 Final model results

The final validated model includes all of the changes described in the previous sections. The net effect on SMP is an increase in Summer months of approximately 1.4 €/MWh and in Winter months of 0.2 €/MWh, as shown in Figure 13 and Figure 14.

Figure 13 Summer SMP, with and without all changes included

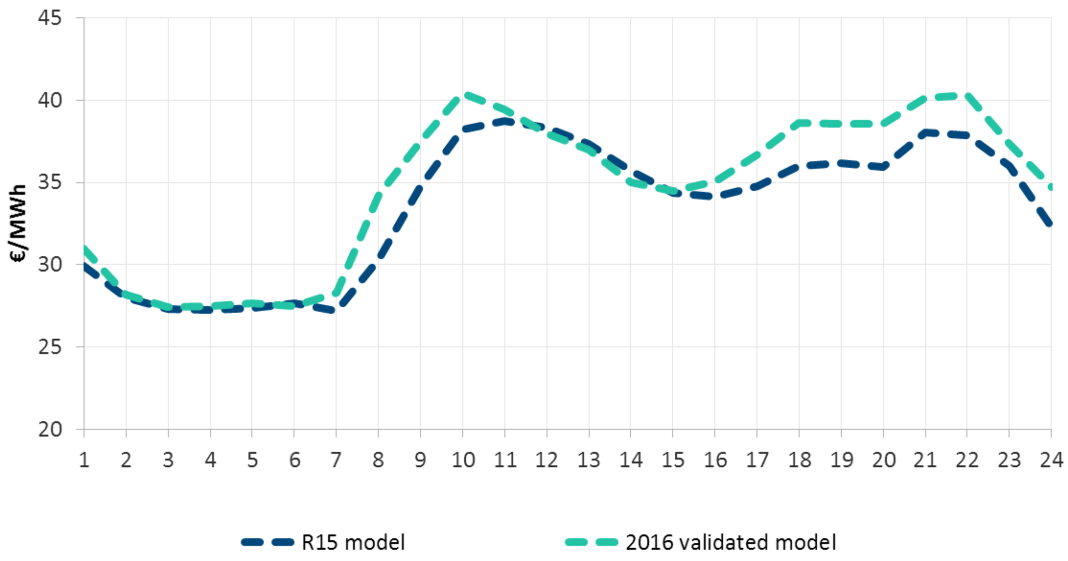
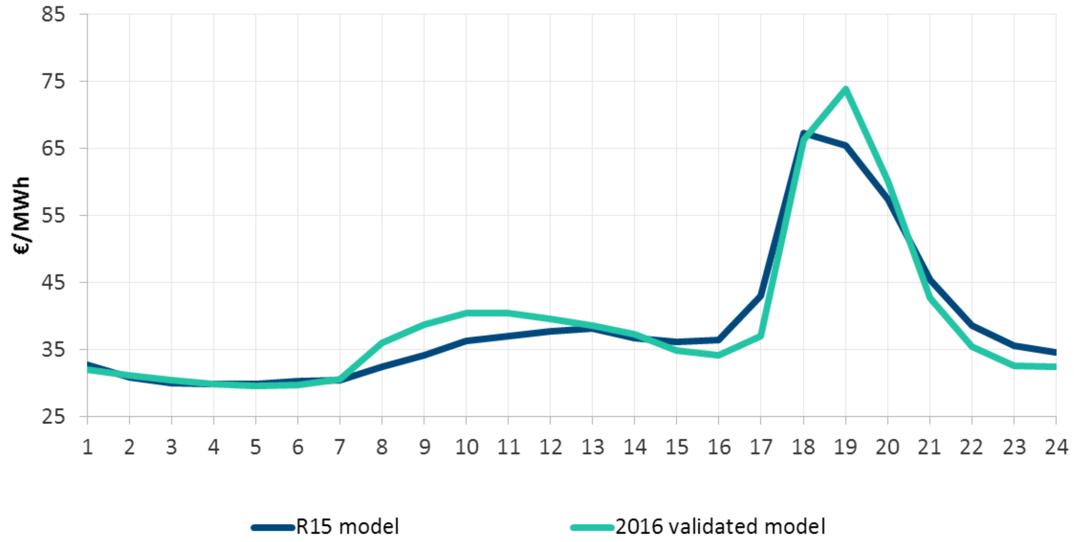


Figure 14 Winter SMP, with and without all changes included



There is no significant change to the type of plant being dispatched, shown for the validated model in Figure 15. Interconnector flows are also little changed, shown for the validated model in Figure 16. The lower flows in Summer 2016 and Spring 2017 are due to scheduled outages on Moyle and EWIC respectively.

Figure 15 Generation by plant type

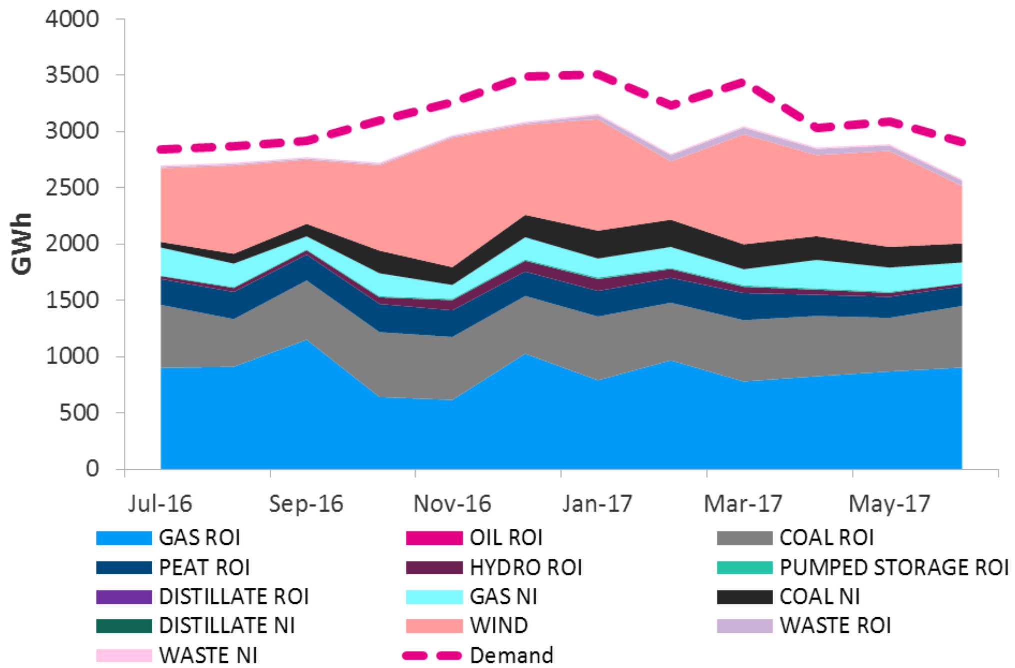
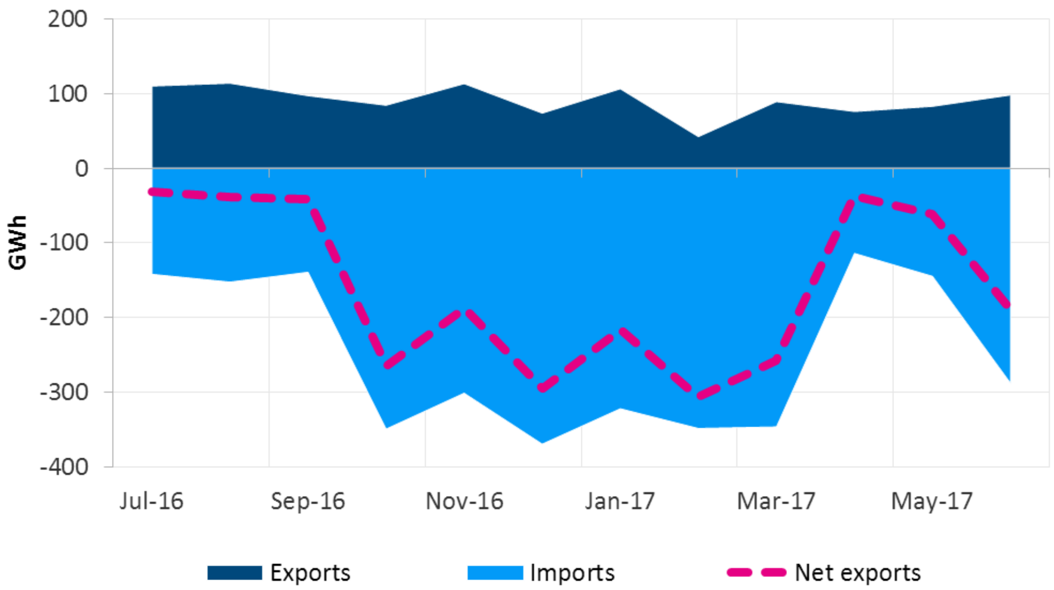


Figure 16 Combined interconnector flows



6.2 Supplied models

This report is supplied to the RAs with two versions of the validated PLEXOS model.

1. RAs' model
   - Includes VOM costs, supplied by market participants on a confidential basis
2. Public model
   - All confidential data removed