Validation of Market Simulation Software in SEM to end 2013

An Information Paper

1st November 2012

SEM/12/099

# Table of Contents

## Contents


1 Introduction & Overview ... 3
1.1 Aim of Project & Paper ... 3
1.2 Applications for Model ... 4
2 Calibration of the Backcast Model ... 5
2.1 Data ... 5
2.2 PLEXOS modelling approaches ... 6
2.2.1 PLEXOS 6.207 ... 6
2.2.2 3 State Start Costs ... 6
2.2.3 Dump Energy ... 6
2.2.4 Xpress-MP Solver ... 6
2.2.5 Peat and Aughinish ... 6
2.2.6 Hydro ... 6
2.2.7 Turlough Hill Pumped Storage ... 7
2.2.8 Units under test ... 7
2.2.9 Uplift Settings ... 7
2.2.10 Rounded Relaxation Self-Tuning ... 7
2.2.11 Medium Term Schedule ... 7
2.3 The Moyle Interconnector ... 8
2.3.1 Great Britain market representation ... 8
2.3.2 Interconnector User Bids / V&OMs ... 9
2.4 Backcast Results ... 10
2.4.1 November 2010 to October 2011 – Moyle Fixed ... 10
2.4.2 November 2010 to October 2011 – Moyle Free ... 15
3 Validation of the Forecast model ... 21
3.1 Forecast model ... 21
3.1.1 Data and assumptions required ... 22
3.2 Generator Data ... 23
3.2.1 Validation process ... 23
3.2.2 Key validation results ... 23
3.2.3 New entrants and retirements ... 24
3.2.4 Confidential data ... 25
3.2.5 Market data & assumptions ... 25
3.2.6 Wind ... 25
3.2.7 Embedded generation ... 26
3.2.8 Transmission Loss Adjustment Factors (TLAFs) ... 26
3.2.9 Outages ... 26
3.2.10 Hydro availability ... 26
3.2.11 Interconnector capacity and scheduled outages ... 27
3.2.12 Delivered fuel prices ... 27
3.2.13 Priority dispatch and non-firm capacity ... 28
3.3 Quarterly DC Auctions – Round 2 changes ... 29
4 Conclusion ... 30
4.1 Main Model Approaches ... 30
4.1.1 PLEXOS Software ... 30
4.1.2 Unit Commitment ... 30
4.1.3 Treatment of Interconnectors ... 30
4.1.4 Start States ... 30
4.1.5 TLAFs ... 30
4.1.6 Confidential data ... 30

# 1 Introduction & Overview

## 1.1 Aim of Project & Paper

The Regulatory Authorities (RAs), consisting of the Commission for Energy Regulation (CER) and the Utility Regulator (UR), have recently validated a PLEXOS model for use in simulating system marginal prices (SMPs) and other market outcomes in the all-island Single Electricity Market (SEM). The SEM is a gross mandatory pool market and the Market Operator, SEMO[1], uses bespoke software to schedule and price the market every day.

The work in validating PLEXOS was carried out by the Market Modelling Group (MMG) in the CER, and this was audited by the Market Monitoring Unit (MMU) in the Utility Regulator. From late 2011 through to June 2012 the RAs' MMG undertook the following, as explained in this information paper:

- Calibrated a backcast PLEXOS model against actual half hourly ex post SEM data on system marginal prices, shadow prices, uplift and market schedule quantities. This is explained in section 2 of this paper.
- Validated the PLEXOS forecast model input data, for Q4 2012 and the whole of the calendar year 2013. This is explained in section 3 of this paper.

This work was presented on at an Information Seminar at the CER's offices on 7th June 2012. The version of PLEXOS being used at this time was 6.205R07. The presentation slides are available here: http://www.allislandproject.org/en/market_decision_documents.aspx?article=0180d6b1-6ee3-4f8f-9a9b-57e66968be07

Subsequent to the Seminar, a bug was identified in the Rounded Relaxation Self-Tune method and version 6.205R07 has been superseded by several new versions since. As a result the backcast was retested in later versions. The results presented here are from PLEXOS version 6.207R03.

As a result the PLEXOS model has been validated for the period from 1st October 2012 to end 2013 using PLEXOS version 6.207R03. Section 4 of this paper presents the conclusions and our recommendations on the approach for running the validated PLEXOS SEM model (the forecast model) for Q4 2012 and 2013, which is published on the All-island Project website[2], excluding confidential data.

[1] SEMO is a joint venture between EirGrid plc and SONI Limited

[2] http://www.allislandproject.org/en/market_decision_documents.aspx?article=261a5576-bd83-4544-b250-7b18b55bd9ba

# 1.2 Applications for Model

The most immediate use of the model is to support the RAs' market power mitigation strategy, specifically through the imposition of Directed Contracts (DCs) on the incumbent market participants, ESB Power Generation and NIE Power Procurement Business as applicable. Before putting in place DCs, the RAs carry out a validation of their market simulation model, PLEXOS. This validated model is then used to determine the quantity and pricing (SMP) of the DCs made available from 1st October 2012.

In previous years the RA's have used the validated PLEXOS model to offer DCs on an annual basis for the contract year. Following the publication of the decision on Directed Contracts Implementation for 2012/'13 and Beyond[3], DC subscription windows are now to be held every quarter with DCs being allocated on a rolling basis up to 5 quarters ahead. The validated PLEXOS model will therefore be used by the RAs to model market outcomes beyond the end of 2013. Before each quarterly round of DCs the model will be updated with new inputs if necessary (e.g. demand, scheduled outages, TLAFs, etc). The RAs will also re-run the concentration model every quarter to set the quantities of DCs. Any updates will be notified to market participants in the RAs' quarterly papers on DC prices and quantities.

In addition, the RAs will use the validated PLEXOS model to support other areas of work such as:

- Forecasting the SMP for the PSO Levy;
- Market Monitoring; and,
- Modelling to inform RA policy on the SEM.

[3] http://www.allislandproject.org/en/market_decision_documents.aspx?article=b3fd5271-d1a7-4ca8-9ebe-16caba305249

# 2 Calibration of the Backcast Model

The aim of the backcast calibration exercise is to replicate reasonably closely, within a PLEXOS model, the actual ex-post SMPs, interconnection flows and market schedule quantities (MSQs) observed in the SEM. The PLEXOS modelling configuration that provides the best replication of the ex-post data across the calibration horizon is then used to inform any recommendations for the validated forecast model (see section 3).

## 2.1 Data

The technical and commercial characteristics of each predictable price maker generator (PPMG) in the SEM are defined by submitted technical and commercial offer data – Technical Offer Data (TOD) and Commercial Offer Data (COD) respectively. For offer price-quantity pairs, no load costs, start costs and start cost times, actual availabilities, min up times, min down times and minimum stable generation, the exact data submitted to the Market Operator was used in the backcast PLEXOS model. The ramp rates were provided in processed form and entered into the PLEXOS model as single ramp up and ramp down rates.

Some of this data was provided by the RAs' Market Monitoring Unit (MMU) and some was taken directly from the SEMO website, before being converted into the appropriate PLEXOS CSV file input format.

Some of the data is in half hourly granularity, and some is in daily granularity, as detailed in Table 1 below.

**Table 1**

| Half Hourly Data | Daily Data |
|---|---|
| Load | Price-Quantity Pairs |
| Availability | No Load Cost |
| Minimum Stable Level | Start Costs |
| | Start Times |
| | Minimum On/Off Times |
| | Ramp Rates Up/Down |

The Peat, Aughinish, Hydro and Wind generators were modelled differently to the other generators in the SEM, in a similar manner to previous year's validation exercise. Sections 2.2.5 and 2.2.6 explain how Peat, Aughinish and Hydro are modelled. The Wind generators were aggregated into a single unit, and the actual aggregate wind output was modelled directly as fixed load on a single wind generator in the PLEXOS model.

For this year's backcast, market data covering the period November 2010 to end October 2011 was processed and entered into PLEXOS.

## 2.2 PLEXOS modelling approaches

This section outlines the PLEXOS modelling approaches used for this calibration exercise. Generally the same approach was applied as last year unless indicated here.

### 2.2.1 PLEXOS 6.207

For this year's validation process we have moved to the latest edition of PLEXOS - Version 6.207. The Revision being used is 6.207R03. This version is XML based and has the advantage of producing relatively small solution files.

### 2.2.2 3 State Start Costs

The SEM market engine accepts 3 start costs – hot, warm and cold, from generators as part of their COD. In previous years only 1 start cost was inputted to PLEXOS for each generator (the warm start cost) as tests using all 3 showed that results and run times were unacceptable. However last year, due to improvements to the PLEXOS Rounded Relaxation algorithm, tests showed that PLEXOS could now handle 3 start costs. As a result 3 start costs were used last year, for the first time, in order to replicate what is provided to the market engine and this approach has been maintained this year.

### 2.2.3 Dump Energy

Dump Energy allows for the possibility of negative prices if generation exceeds demand and energy must be dumped. In the validated model the Price Floor is set to -100 €/MWh to match that used in the market. The cost of Dump Energy is set to -100,000 €/MWh.

### 2.2.4 Xpress-MP Solver

As was the case last year, the Xpress-MP solver was used in conjunction with Rounded Relaxation for the backcast.

### 2.2.5 Peat and Aughinish

The Peat generators and Aughinish CHP are currently registered as "predictable price taker" generation (PPTG) units. Such units are scheduled in the SEM on the basis of submitted nomination profiles rather than offer prices. In order to replicate this treatment in the backcast exercise the maximum availability as submitted to the Market Operator was used, and the Commercial Offer Data for these units was excluded to ensure that they are dispatched fully when available, and that they do not impact the calculation of uplift. The SEM uplift algorithm applies a cost recovery constraint to "price maker" generator units (excluding pumped storage). However, the formulation of the cost recovery constraint in PLEXOS considers all generators, and does not distinguish between price makers and price takers. Any plant with non-zero incremental, no load or start costs may therefore impact the cost recovery constraint in the PLEXOS uplift algorithm. Price takers should therefore be modelled in PLEXOS without incremental, no load or start costs to avoid influencing uplift.

### 2.2.6 Hydro

In last year's backcast calibration there was a move away from using historic half-hourly market schedule quantities to create daily energy limits for each of the four hydro schemes across the backcast horizon, as had been the method in prior years. Instead the "daily limits" that the market engine was given (a combination of 'Hydro Energy Limits' and the units' actual metered generation) were used. This change in approach was made because the market engine (especially when using its Lagrangian Relaxation solver) did not always fully schedule the hydro units up to their energy limits. This approach, using the "daily limits" that the market engine was given, was maintained in this year's backcast.

Start Costs and Min Stable Level values are not included on Hydro units.

### 2.2.7 Turlough Hill Pumped Storage

The Turlough Hill pumped storage units were on outage for the duration of this year's backcast period.

### 2.2.8 Units under test

When units are under test they submit nomination profiles rather than offer prices and receive the SMP. In last year's validation for the first time the load of any units under test was fixed. This approach was maintained this year.

### 2.2.9 Uplift Settings

The Uplift MSL filter prevents units that are at Minimum Stable Level (MSL) over the entire course of a contiguous period of operation from setting uplift in PLEXOS. This means that if PLEXOS schedules a unit to run at its MSL only, then the uplift algorithm will not include the costs of that unit when calculating uplift. The Uplift Ramping filter does the same for units that are "ramping". Tests were done with these filters off and the results were found to be further from the actual market outcomes. So all results presented in this report are from runs where these filters are on, and it is recommended to keep them on.

The Uplift Cost Basis must be set to "bid based" for the backcast. This ensures that the uplift computation in PLEXOS is based on submitted offer data. It must be set to "cost based" for the forecast model. This ensures that the uplift computation is based on heat rates, start fuel off takes and delivered fuel prices.

### 2.2.10 Rounded Relaxation Self-Tuning

Rounded Relaxation Self-Tuning is a new feature. The Self-Tuning algorithm tests all values for the "Rounding Up Threshold" (between the "Rounded Relaxation Start Threshold" and the "Rounded Relaxation End Threshold" in increments of the "Rounded Relaxation Threshold Increment") each day and uses the one which gives the best objective function value.

The following Self-Tuning parameters are used:

- Rounded Relaxation Start Threshold: 0.05
- Rounded Relaxation End Threshold: 0.95
- Rounded Relaxation Threshold Increment: 0.05

### 2.2.11 Medium Term Schedule

A Medium Term Schedule is used with:

- One duration curve in each day
- Four blocks in each duration curve

## 2.3 The Moyle Interconnector

The Moyle interconnector (Moyle) links Northern Ireland to Scotland, meaning that the Great Britain (GB) market can influence the SEM. Flows on Moyle should be largely driven by arbitrage of the relative prices in the two markets, so when prices are higher in SEM than GB there tends to be imports (of cheaper GB electricity) to SEM while when prices are lower in SEM than GB there tends to be exports (of cheaper SEM electricity) from SEM.

Backcast exercises in previous years showed that fixing Moyle flows to their actual historic levels in PLEXOS resulted in SMP being significantly higher on average than historic prices. This was because fixing the flow significantly decreased the overall flexibility available to PLEXOS. However, this year's backcast actually gave better results with Moyle flows fixed (see Section 2.4).

As it is not known exactly what future flows will look like the aim of our modelling of Moyle is to come up with a method which:

1. Accurately replicates flows for the backcast calibration period and the impact those flows have on SMP, so that the model is properly calibrated for use in the forward period; and,
2. Predict flows for the forward model which move as would be expected with different fuel/carbon prices across the SEM and GB.

However, the ability of PLEXOS to now better model the SMP with Moyle flows fixed opens the possibility of using different treatment of interconnection in the future.

### 2.3.1 Great Britain market representation

The regression model of Great Britain (GB) gas (and carbon) to electricity prices was developed using a similar methodology as applied in last year's validation process. A single gas fired generator is used to represent the GB market. This single generator has 12 different heat rates and variable operating costs, created as described below.

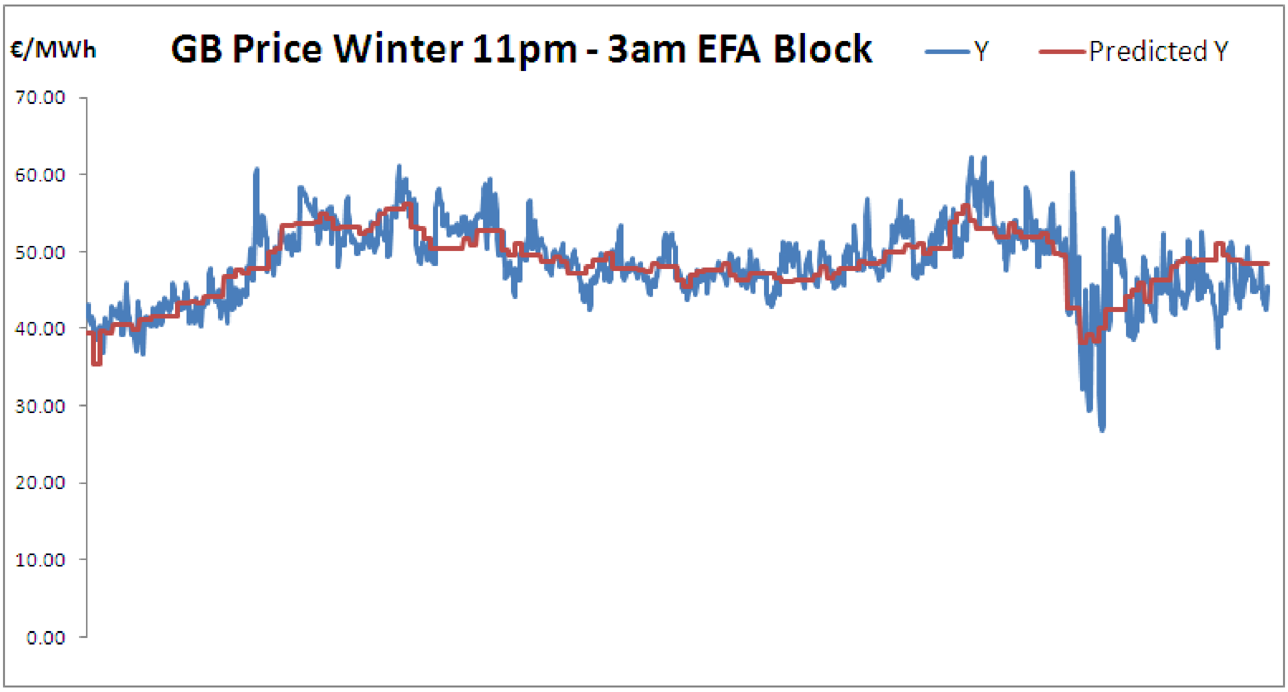
The half hourly APX intraday price was chosen as a representation of the half hourly GB electricity price. 12 separate regressions were then carried out for data from November 2010 to October 2011 for GB electricity prices against daily combined gas and carbon prices - one for each of the six traded Electricity Forward Agreement (EFA)[4] block time periods, for both summer and winter.

One change from last year is that regressions with zero intercepts were used. This was done so that the forecast model would give more consistent outturns for future GB gas price scenarios (high and low). The resulting regression coefficients were then used as the GB generator's heat rates. This captures the correlation between the gas generation cost (including carbon) and the GB electricity price, which has traditionally been strong given that gas generation has predominantly been the marginal plant on the GB system.

For example: the graph in Figure 1 below shows the GB price predicted by the regression formula, for the Winter 11pm to 3am EFA block, compared to the actual APX intraday price for this EFA block over the 12 months from November 2010 to October 2011. It can be seen that the half hourly volatility is removed but that the general price movement is followed.

[4] GB electricity can be traded over-the-counter in four hour blocks known as EFA blocks. The six blocks that make up a trading day begin at 23:00 and follow at four hour intervals.

**Figure 2 Predicted and Actual GB Electricity price**




### 2.3.2 Interconnector User Bids / V&OMs

In reality Moyle flows are not determined purely by the price differential (arbitrage) between GB and SEM. To take account of this, GB prices and average interconnector user bids over the 12 months from November 2010 to October 2011 were analysed. The average difference between the two was calculated for each of the six traded EFA block time periods, for both summer and winter. These differences were then applied as negative V&OM (Variable Operations and Maintenance) charges to the simple GB generator.

## 2.4 Backcast Results

This section presents the results of the backcast modelling exercise for the 12 months from November 2010 to end October 2011. It describes the base case results obtained by running PLEXOS in Rounded Relaxation mode with our recommended model settings and taking on board the issues discussed above.

The results are presented in two separate sections as follows:

- November 2010 to October 2011 - Moyle Fixed:
  - where flows across the Moyle Interconnector are fixed in PLEXOS to their actual historic levels.
- November 2010 to October 2011 - Moyle Free:
  - where the GB price is modelled through a simple proxy in PLEXOS, as discussed in Section 2.3, and flows across the Moyle Interconnector are free to follow price arbitrage between this price and the price in the SEM.

### 2.4.1 November 2010 to October 2011 – Moyle Fixed

**Prices**

With Moyle flows fixed, the average SMP from PLEXOS is 0.9% higher than the historic SEM outturn price. The average Shadow Price and Uplift from PLEXOS are 3.2% lower and 16% higher respectively. The graphs below show the intraday shape of SMP, Shadow Price and Uplift over the 12 months.

**Figure 3**

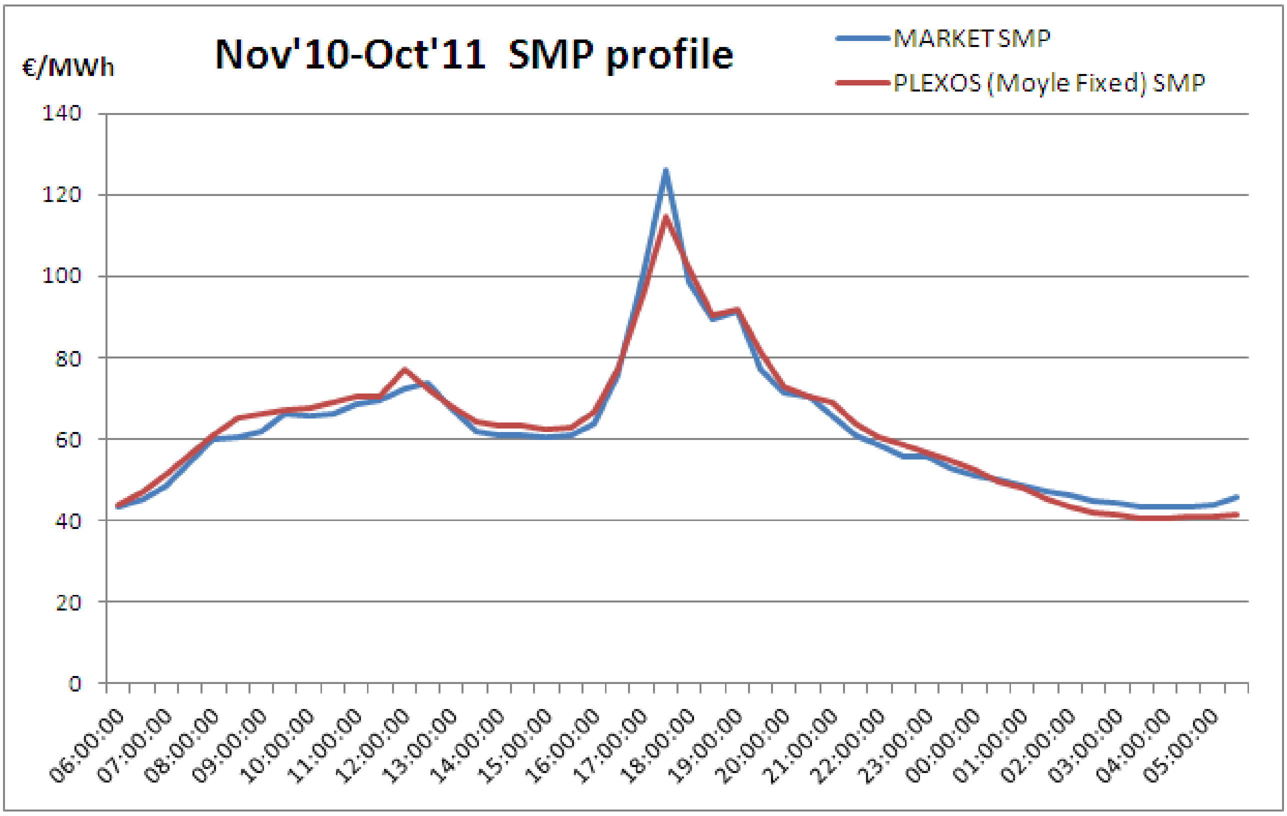


**Figure 4**

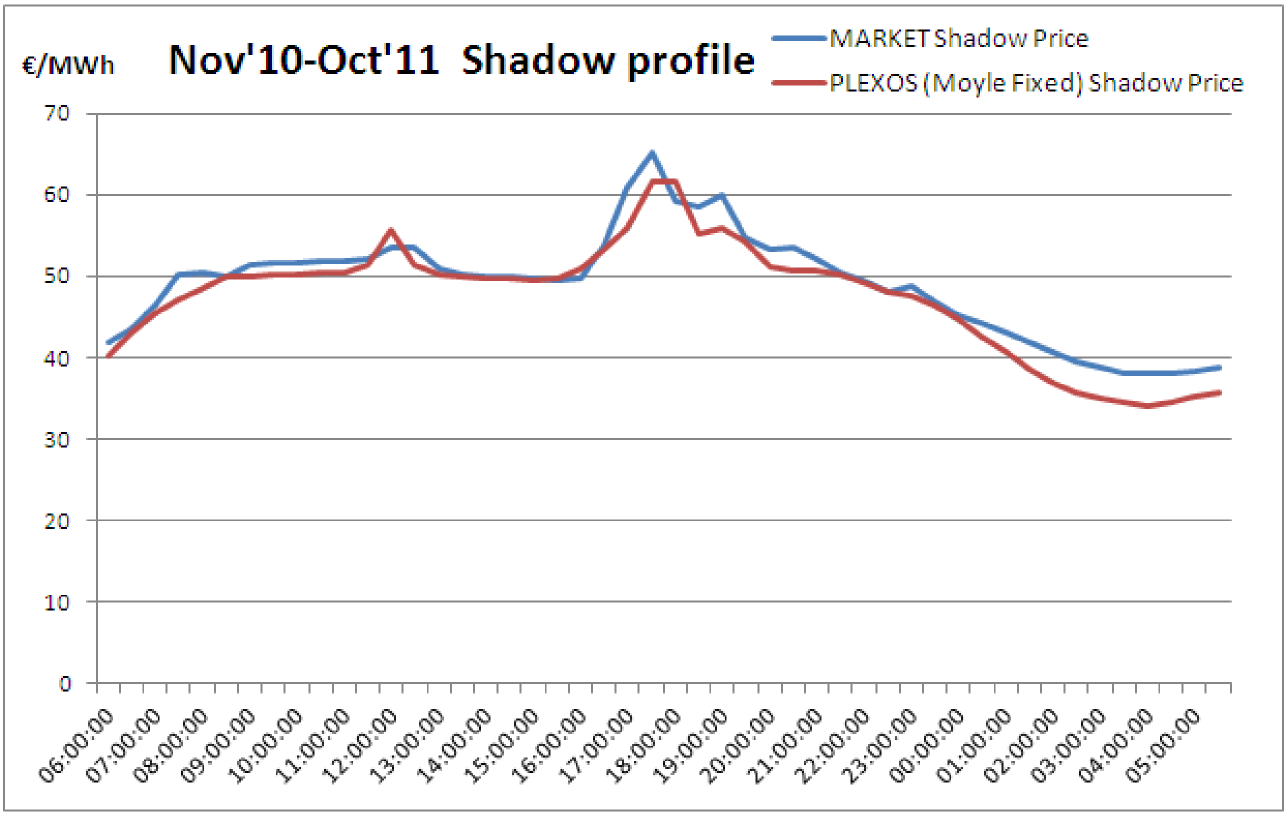



**Figure 5**

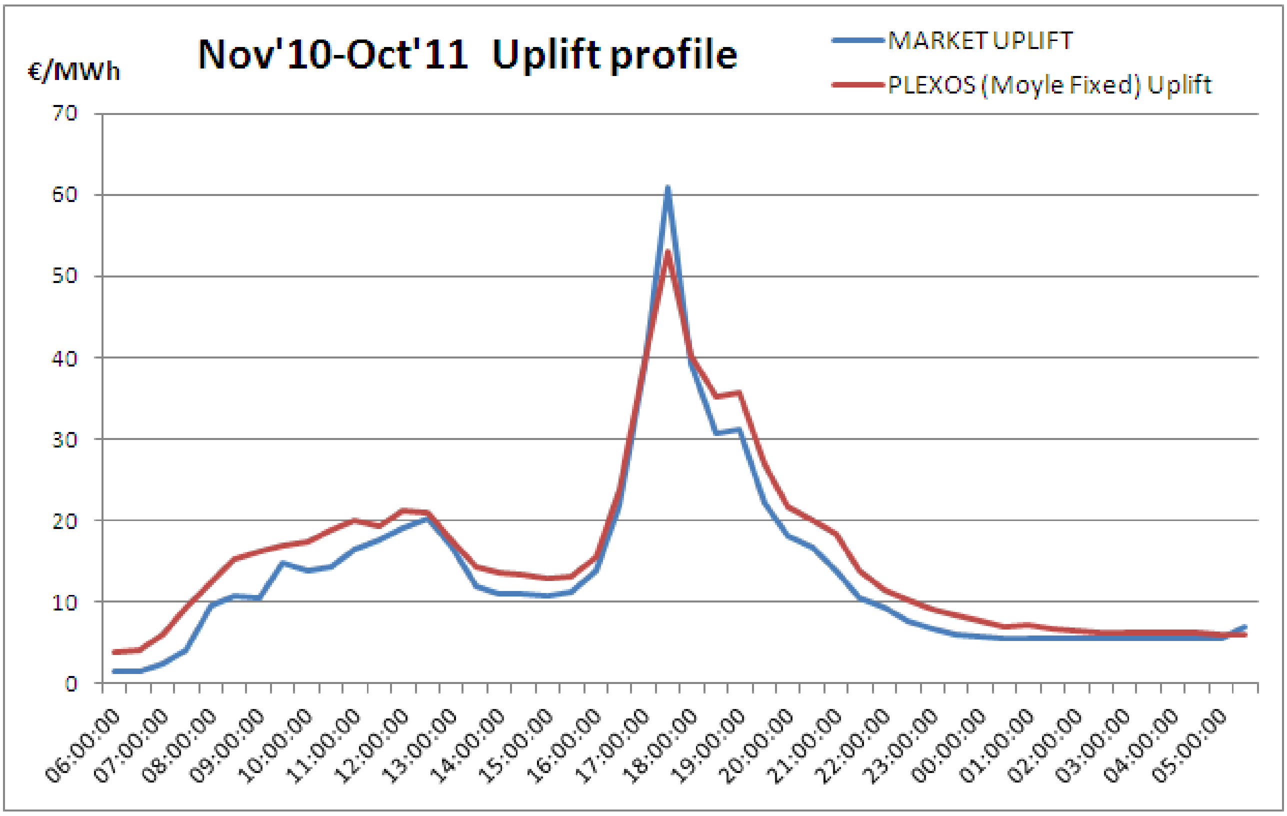
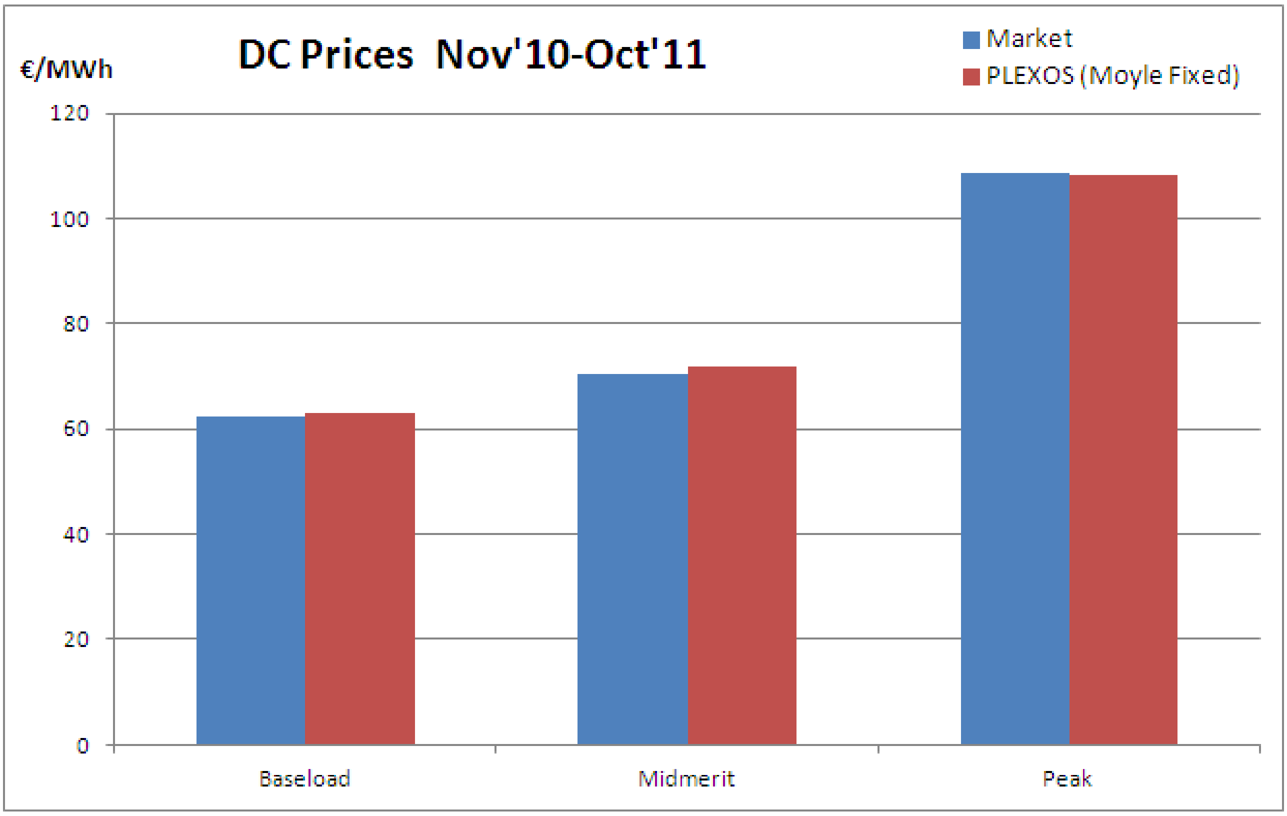


Figure 6 below shows the average levels of SMP across the settlement periods of the three Directed Contract products (Baseload, Midmerit and Peak) over the 12 months. The average Midmerit price from PLEXOS is 2% higher than the market outturn and the average Peak price from PLEXOS is 0.3% lower. As referred to earlier, the baseload SMP (i.e. in all settlement periods) is 0.9% higher in PLEXOS than in the market.

### Figure 6




### Generation

Figure 6 and Figure 7 below compare generation in PLEXOS and actual MSQs in the market for the 12 months by both fuel type and station.

**Figure 7**

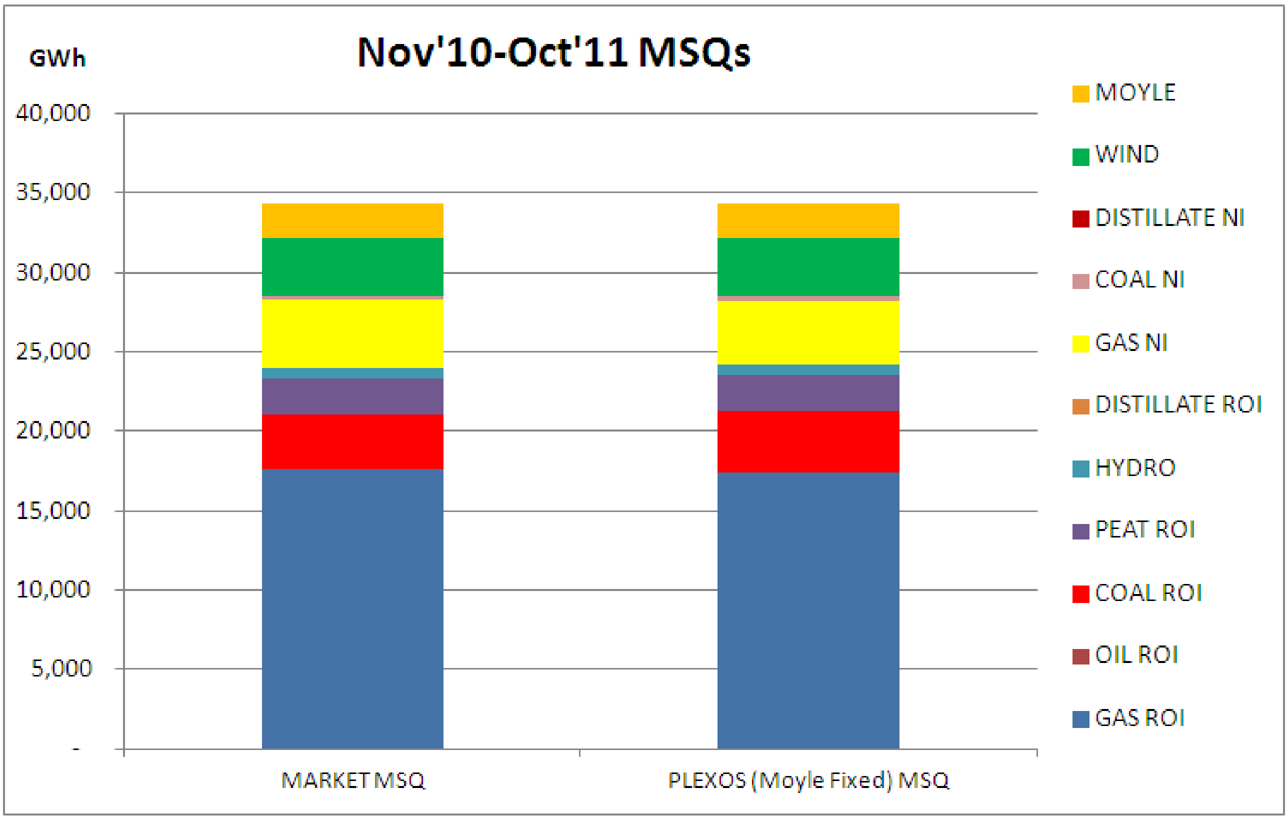
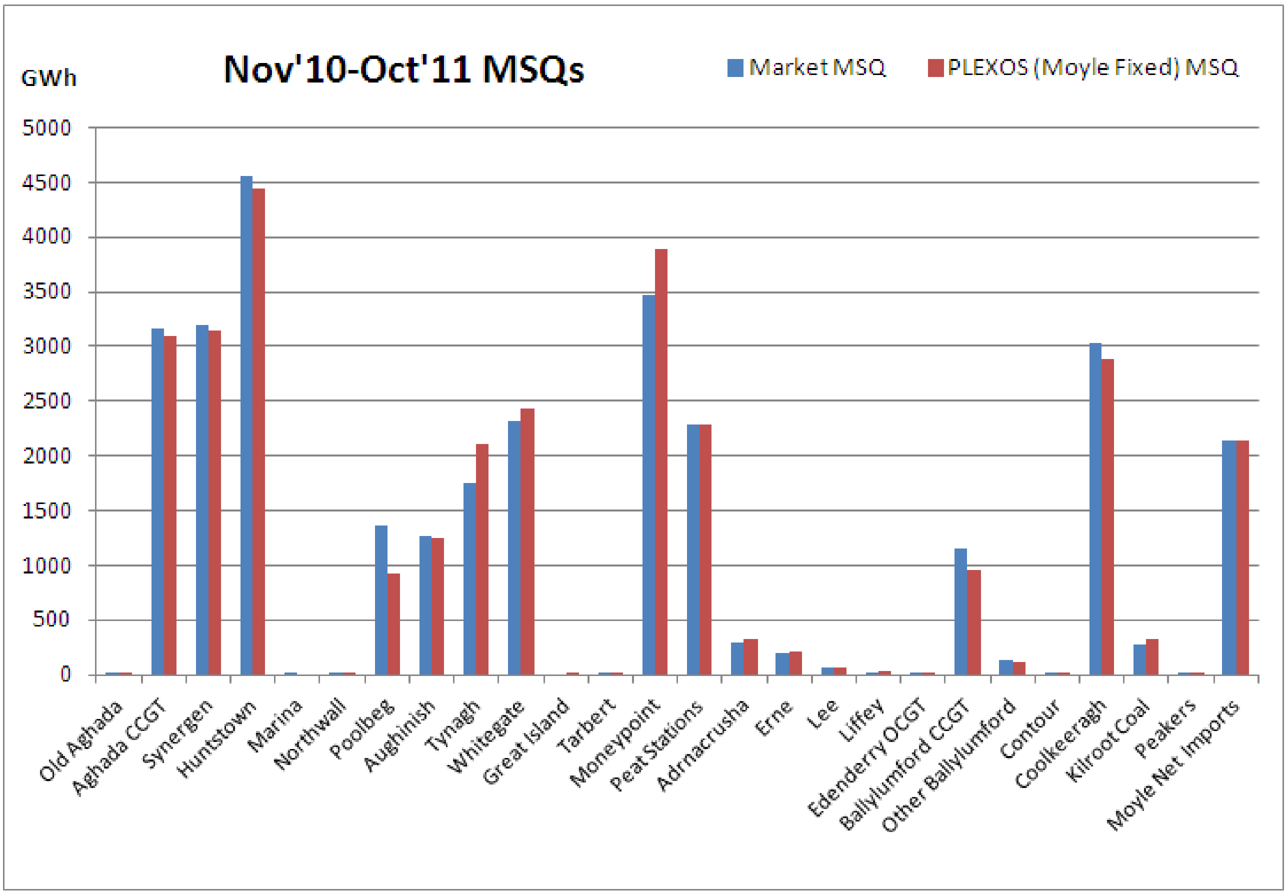


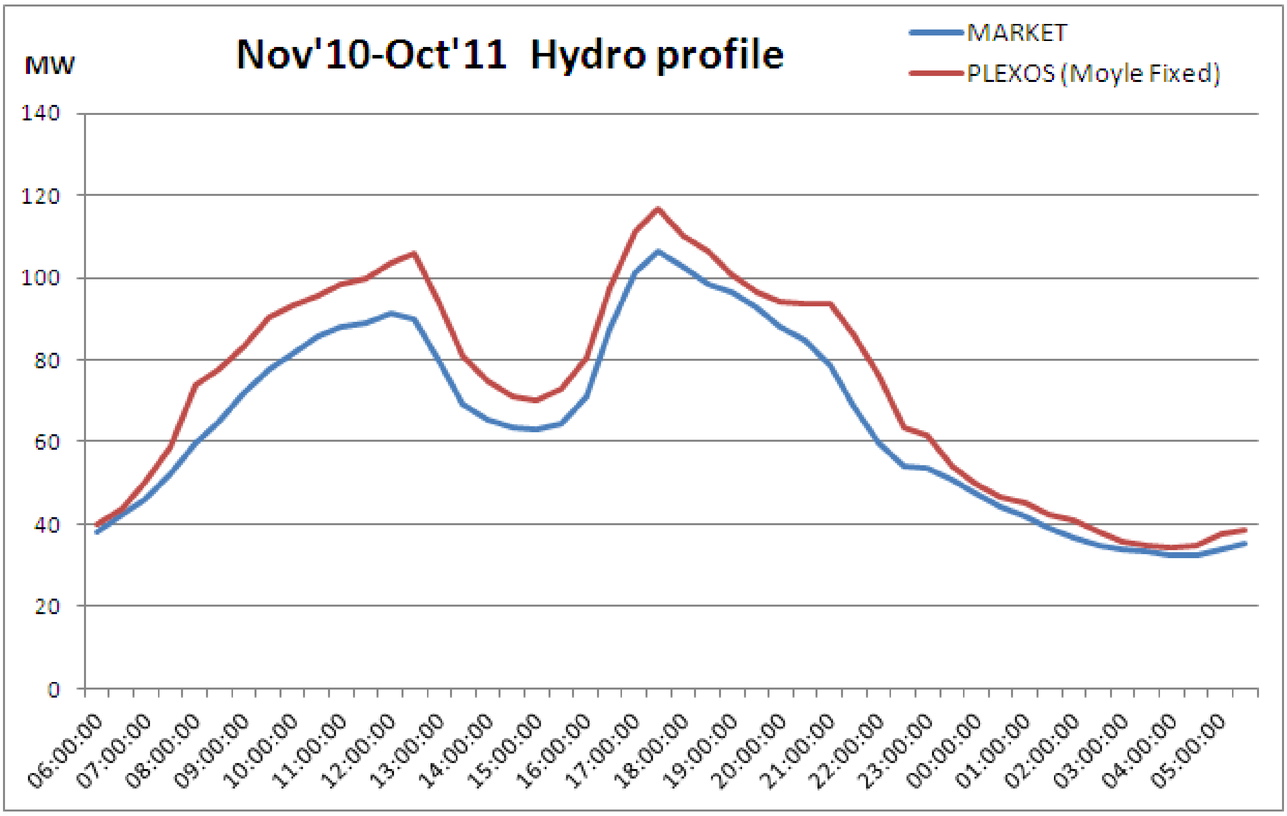

**Figure 8**



**Hydro**

Figure 9 shows the intraday shape of hydro generation in PLEXOS, with Moyle flows fixed, and the market over the 12 months. When given the actual hydro 'daily limits', as explained in section 2.2.6, PLEXOS schedules the hydro units more than the market does (using Lagrangian Relaxation) by approximately 12% but the generation profile has a similar shape.

**Figure 9**



## 2.4.2 November 2010 to October 2011 – Moyle Free

**Prices**

With Moyle flows free, the average SMP from PLEXOS is 1.2% higher than the historic SEM outturn price. The average Shadow Price and Uplift from PLEXOS are 2.3% lower and 14% higher respectively. The graphs below show the intraday shape of SMP, Shadow Price and Uplift over the 12 months.

**Figure 10**

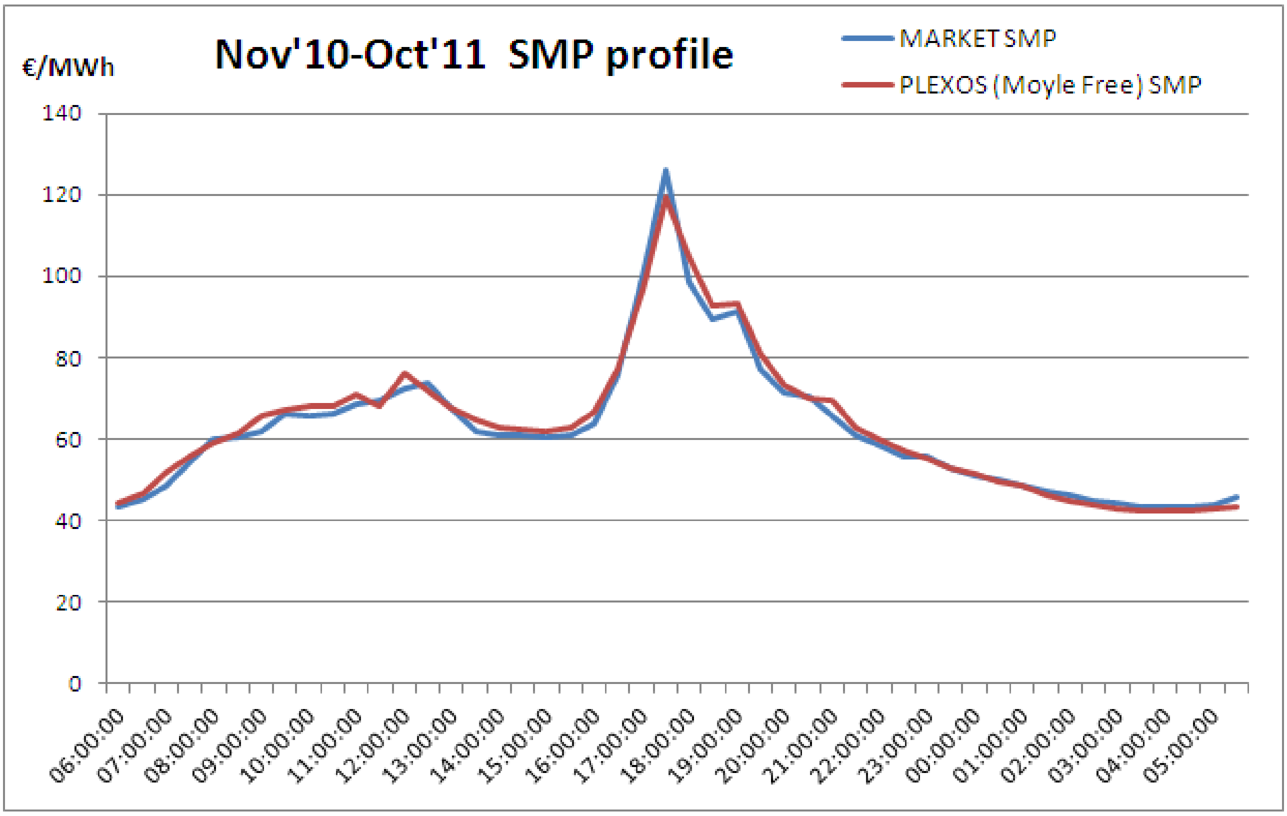


**Figure 11**

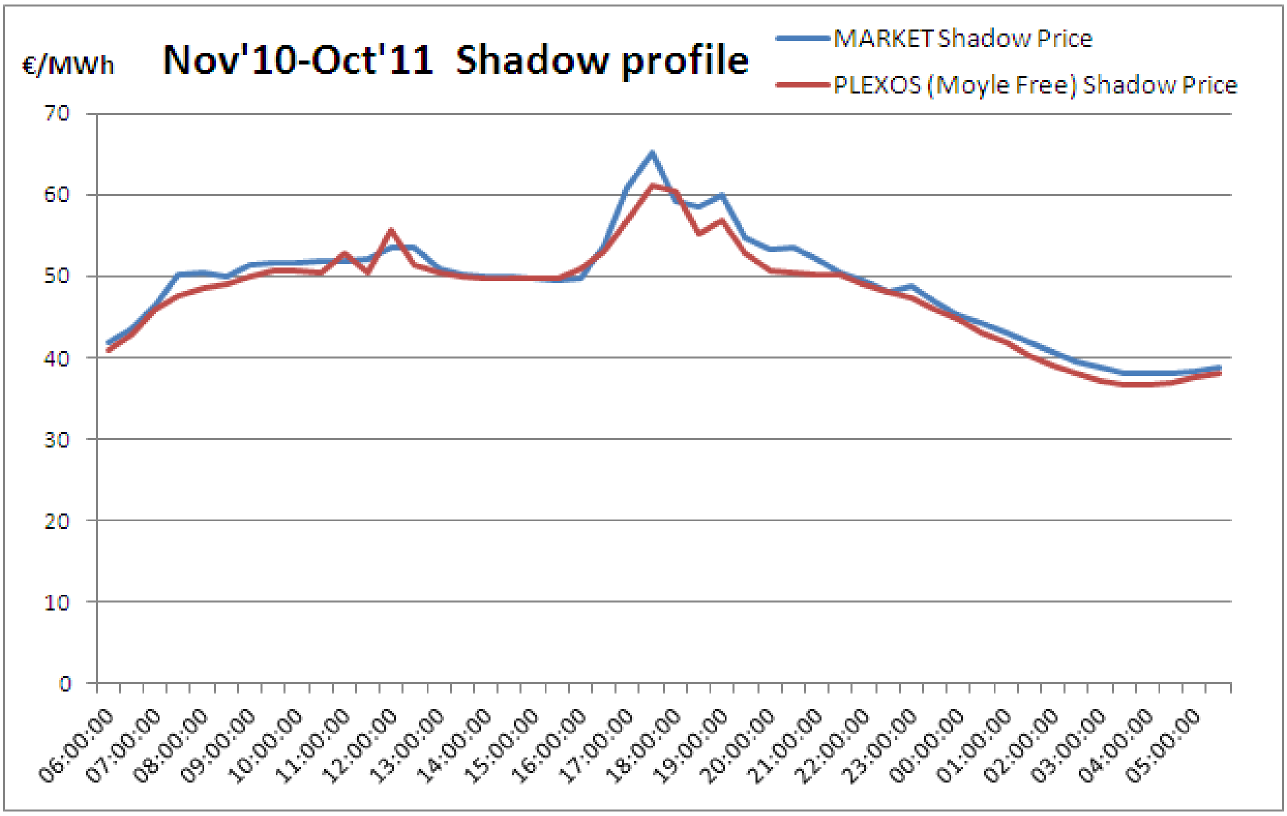



**Figure 12**

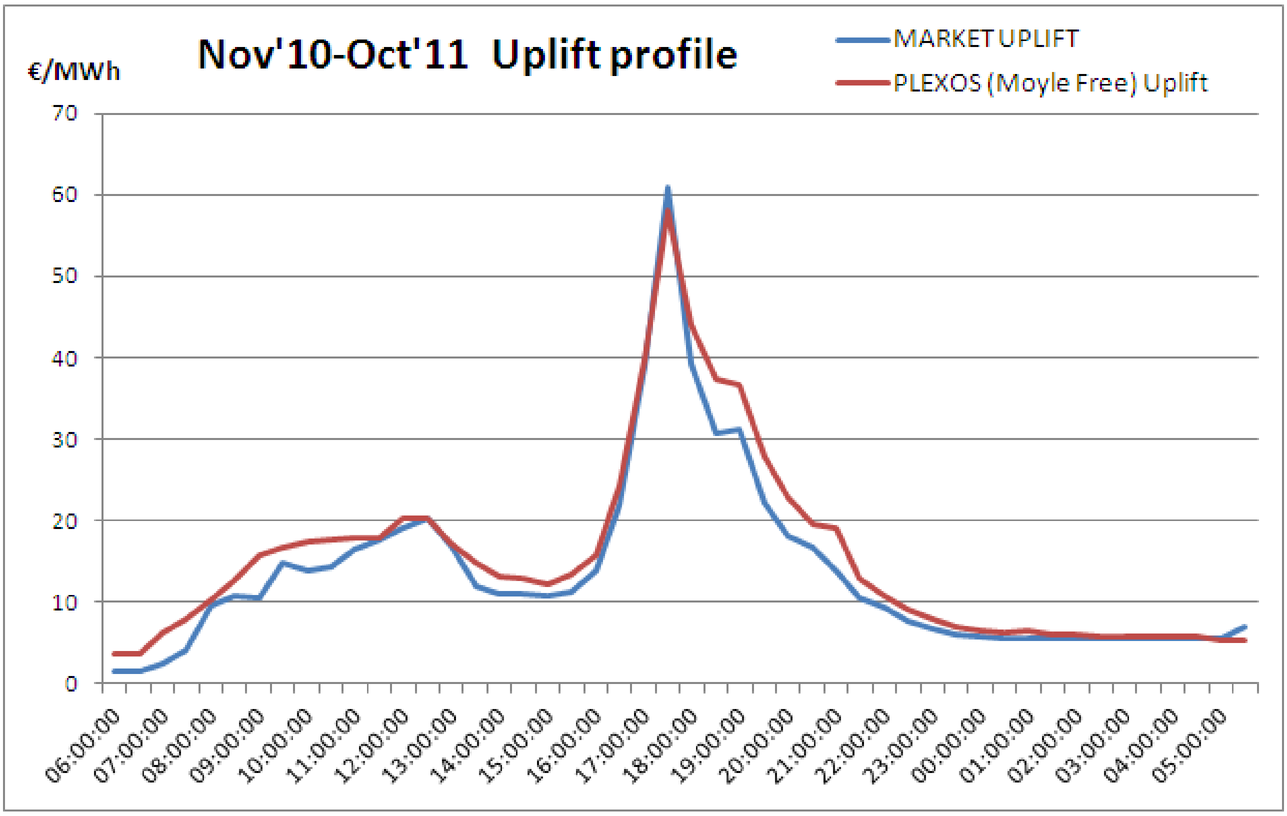
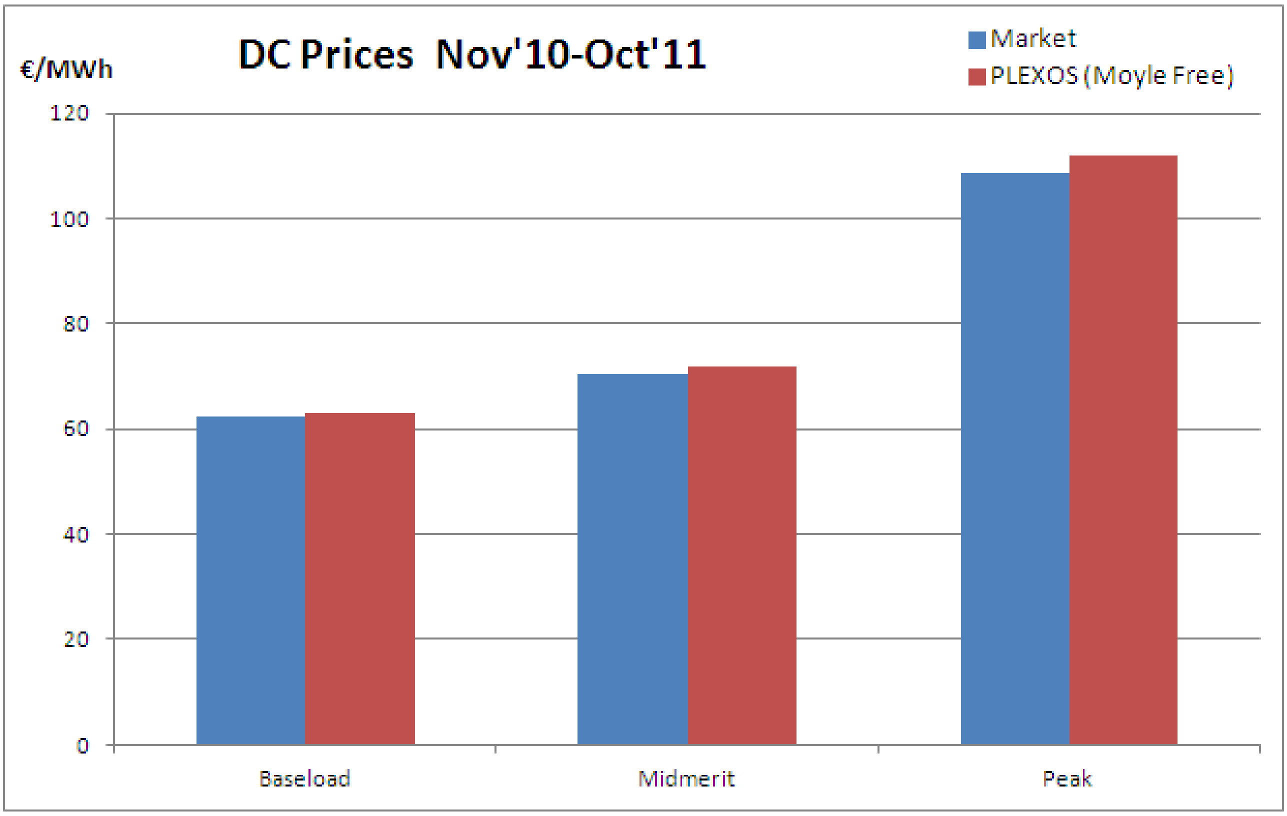


Figure 13 below shows the average levels of SMP across the settlement periods of the three Directed Contract products (Baseload, Midmerit and Peak) over the 12 months. The average Midmerit price from PLEXOS is 1.9% higher than the market outturn and the average Peak price from PLEXOS is 3% higher. As referred to earlier, the baseload SMP (i.e. in all settlement periods) is 1.2% higher in PLEXOS than in the market.

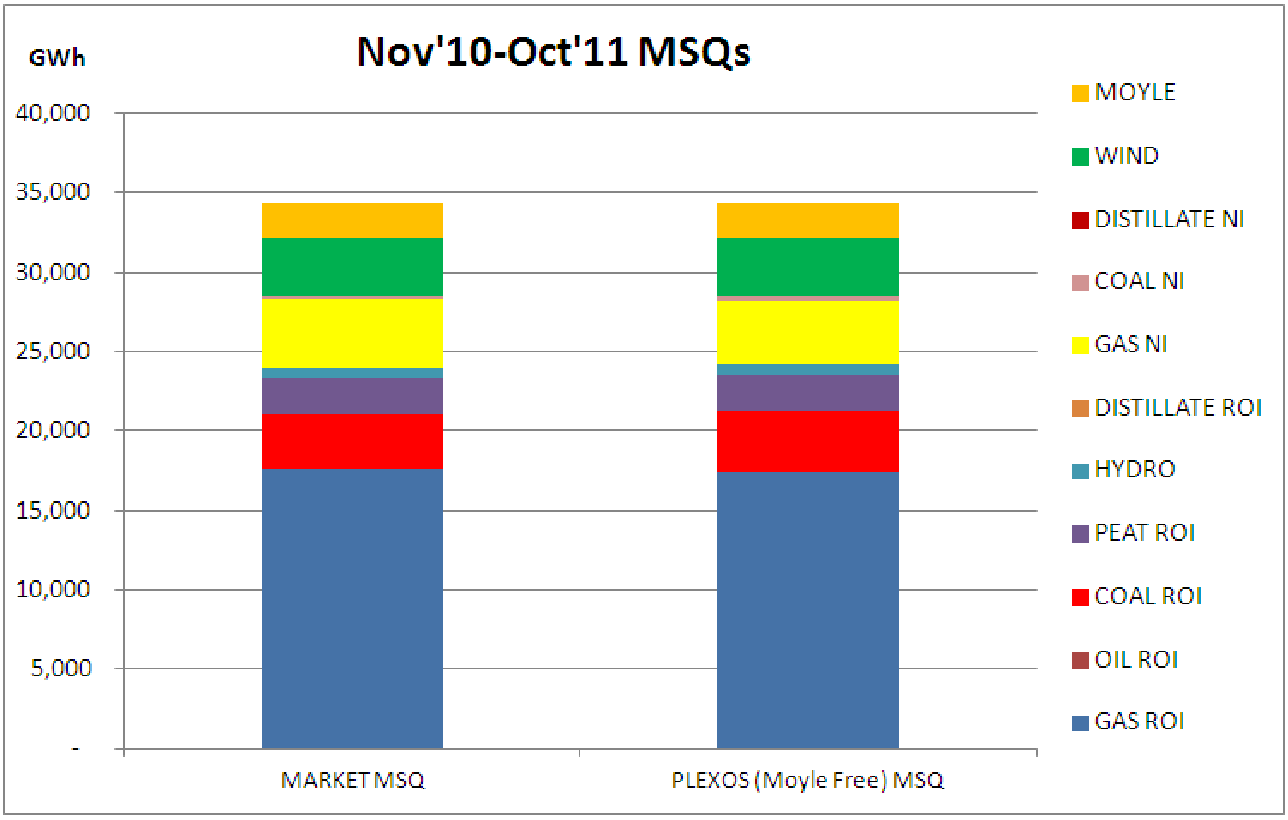
### Figure 13



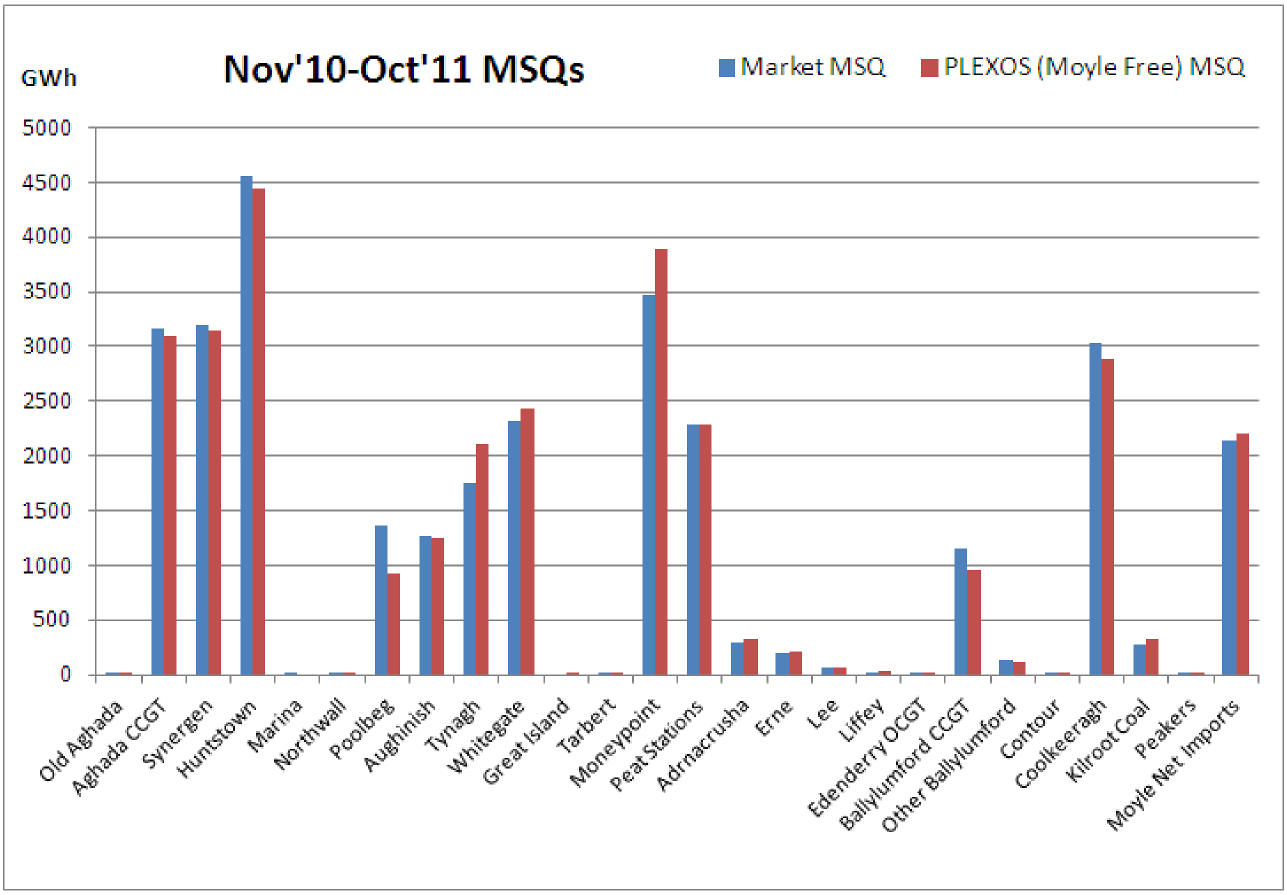

### Generation

The graphs below compare generation in PLEXOS and actual MSQs in the market by both fuel type and station.

## Figure 14



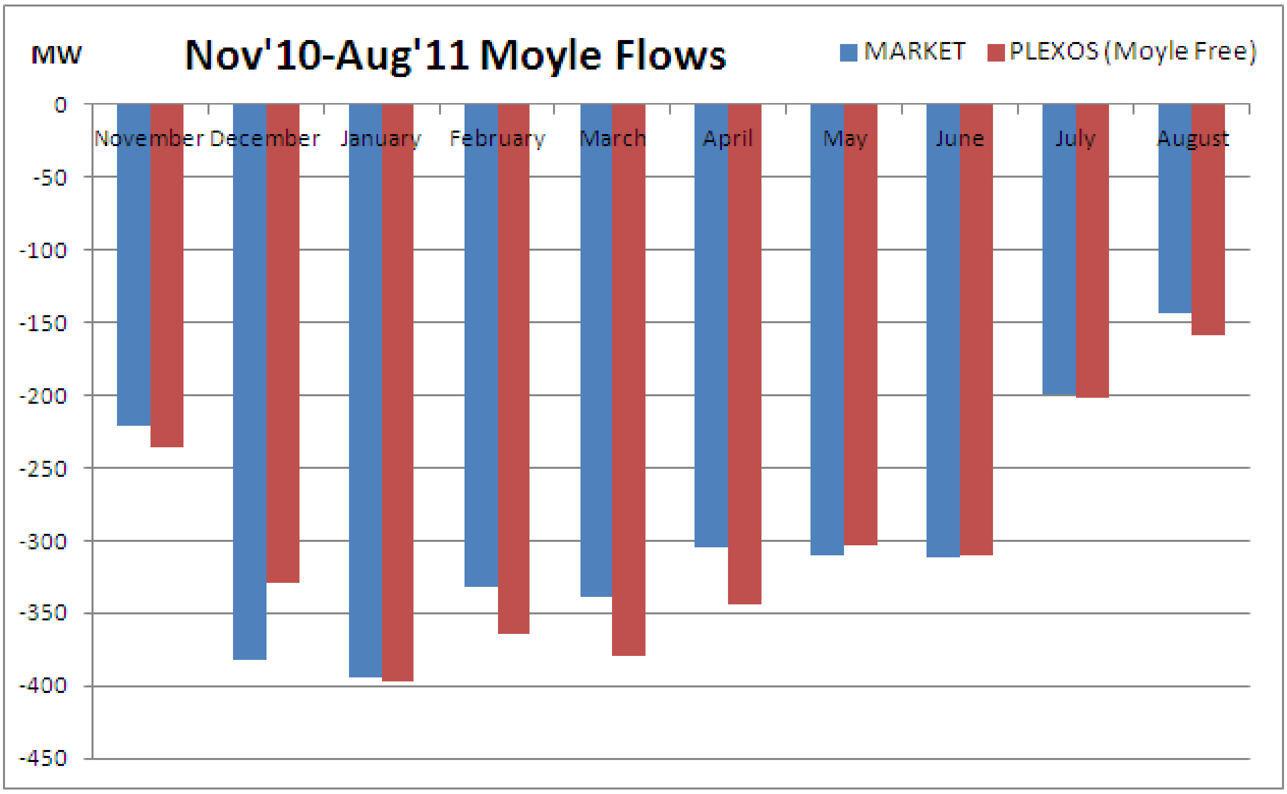

## Figure 15



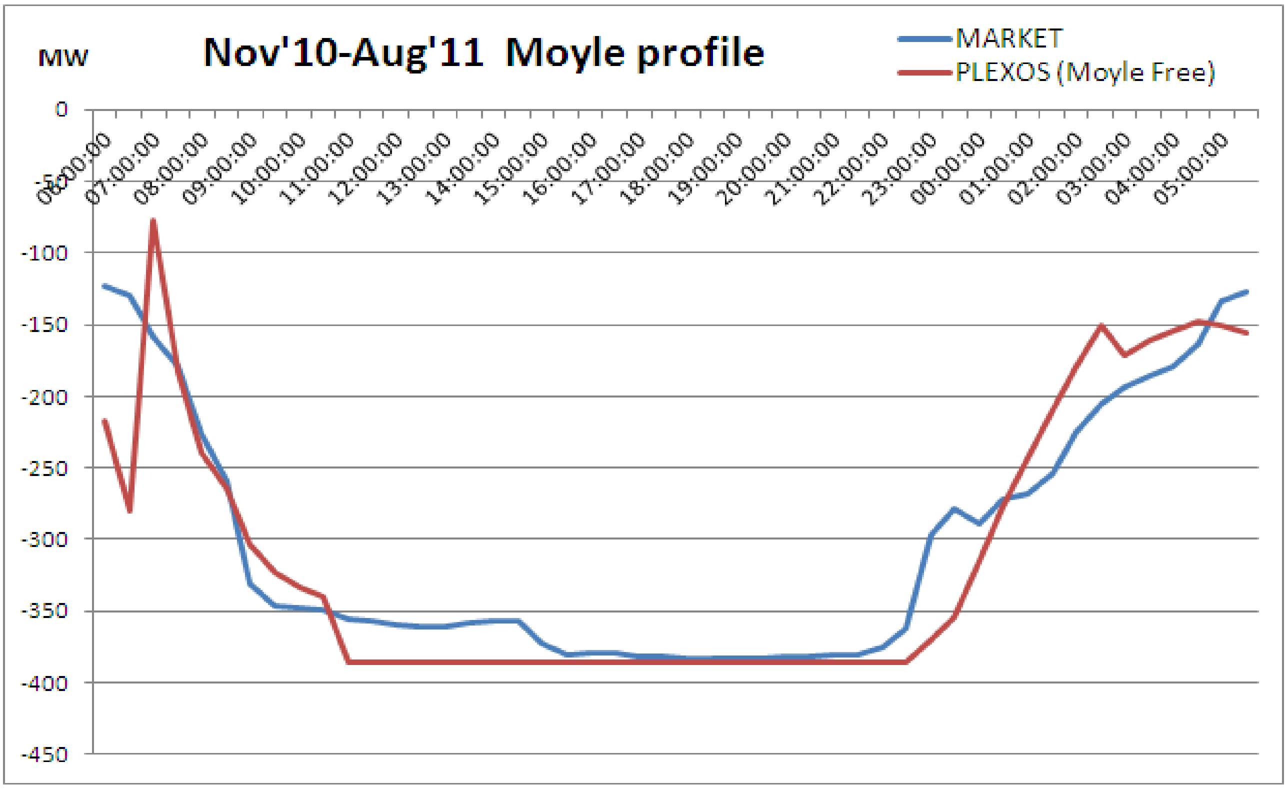
**Interconnection**

The Moyle interconnector went on forced outage during August 2011 and was also unavailable for September and October. Figure 16 compares the monthly average Moyle flows in PLEXOS with actual flows and Figure 17 compares the intraday shape of flows over the 10 months from November 2010. Note that a negative number indicates net flow from GB to SEM.

### Figure 16



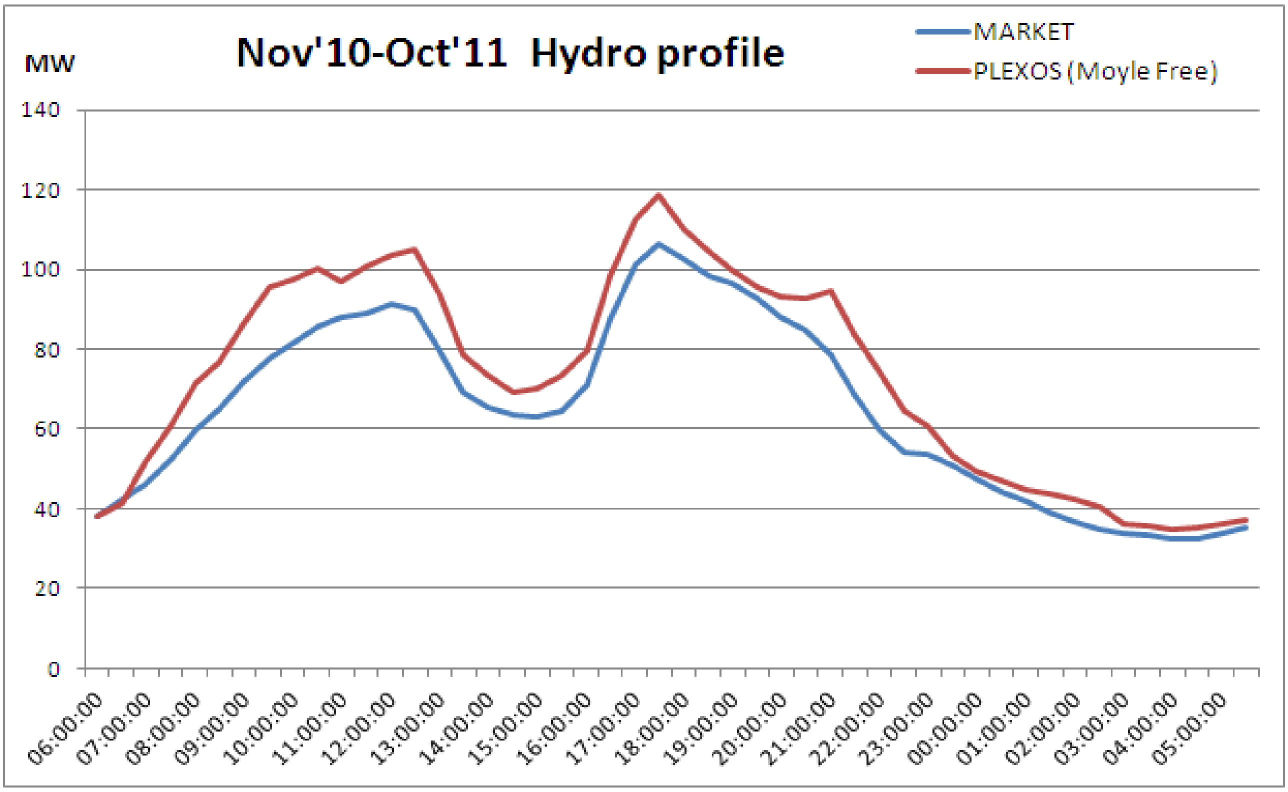

### Figure 17



**Hydro**

Figure 18 shows the intraday shape of hydro generation in PLEXOS, with Moyle flows free, and the market over the 12 months. When given the actual hydro 'daily limits', as explained in section 2.2.6, PLEXOS schedules the hydro units more than the market does using Lagrangian Relaxation (by approx. 12%) but the generation profile has a similar shape.

**Figure 18**



# 3 Validation of the Forecast model

## 3.1 Forecast model

In order to model SMP and other market outcomes for the last quarter of 2012, the whole of 2013, and further out (see Section 1.2), a validated forecast PLEXOS model is required, based on various assumptions for this period and using the calibrated backcast model configuration (discussed in section 2). Please note that some changes have been made to the assumptions discussed in Sections 3.1 and 3.2 for Round 2 of the quarterly DC auctions – these are explained in Section 3.3.

Whereas the calibrated backcast model uses detailed historic data, the forecast model is necessarily based on more general assumptions and up-to-date information provided by market participants. The differences in detail and type of data available lead to specific differences in the model set up, described in Table 2.

**Table 2 PLEXOS backcast and forecast model set up**

| Item | Backcast model | Forecast model |
|---|---|---|
| Demand | Uses Actual | Uses forecast assumptions |
| Max capacity | Uses Actual Availability | Uses submitted max capacity |
| Availability | Uses Actual Availability | Uses planned outage schedules and forced outage rates |
| Commercial Offer Data: | | |
| *Offer/quantity pairs* | Historic market data used directly | Calculated from Incremental heat rates/load points, delivered fuel prices, VOM charges and TLAFs |
| *No load costs* | Historic market data used directly | Calculated from no load heat rates, delivered fuel prices, VOM charges and TLAFs |
| *Start costs* | Historic market data used directly | Calculated from offtake at start, €/start VOM and TLAFs |
| Pumped Storage | Optimised by PLEXOS | Optimised by PLEXOS |
| Hydro | Optimised within day based on actual daily output | Optimised within day based on assumed daily output |
| Wind | Generation at actual output | Availability based on typical half-hourly output profile |
| Predictable Price Takers | No Commercial Offer data used | No heat rates, start costs etc used |
| Interconnectors | Representative GB price series based on historic spot gas and carbon prices | Representative GB price series, using calibrated parameters from the backcast exercise |

### 3.1.1 Data and assumptions required

The types of data and assumptions required and the providers of this data are shown in Table 3.

**Table 3 Data and assumptions required**

| Data/Assumption | Provider/Source |
| --- | --- |
| Generator data:<br>• Heat rates<br>• Technical parameters<br>• Forced outage rates<br>• Start fuel offtake<br>• Start and VOM costs | Generation companies |
| New entrants and retirements | System Operators and generation companies |
| Planned outage schedules | System Operators |
| Embedded generation | System Operators |
| Half hourly demand assumptions | System Operators |
| Wind capacity and half hourly wind profiles | System Operators |
| Daily Hydro Availability limits | System Operators |
| Pumped Storage limits | Published historic market data |
| Transmission Loss Adjustment Factors | Published values for 2012 |
| Interconnector capacity and scheduled outages | System Operators |
| Delivered fuel prices [Adjustments from index to delivered] | Public sources where available, and contact with generation companies where required/appropriate |

The following sections describe the validation process in more detail.

## 3.2 Generator Data

### 3.2.1 Validation process

On 12th December 2011 the RAs commenced the forecast validation process by sending each generation company the previous year's validated data for their units. The RAs asked the generation companies to review the data and provide updates where required with explanations. The RAs then proceeded to validate the updated generator data received, involving the analysis of changes in the data and iterate with generators on their explanations of these changes.

In cases where we found certain parameters that appeared to be anomalous or inconsistent in some way the RAs engaged with generators and we were in all cases able to resolve these situations in conjunction with the generators.

### 3.2.2 Key validation results

In Table 4 we have indicated some of the types of changes that have been made for certain parameters since the last validation exercise, the reasons for them, and examples of affected units. The changes made were agreed with generators.

**Table 4 Generator data changes**

| Property | Materiality of changes | Example of reason for change | Units affected |
|---|---|---|---|
| Max Capacity and MSL | Minor to Medium changes, | Based on knowledge of changes to generator performance | Aghada CCGT<br>Poolbeg Combined Cycle<br>Huntstown CCGT<br>Great Island Units 1,2 & 3<br>Ardnacrusha Units 1,2,3 & 4<br>Liffey Unit 4<br>Lough Rea<br>West Offaly Power<br>Tarbert Units 3 & 4<br>Meath Waste-to-Energy |
| No Load Heat Requirement (GJ/hr) | Minor Changes | | Coolkeeragh CCGT<br>Ballylumford Unit 4 |
| Capacity Point [MW exported] | Mostly minor changes | Mostly small changes to reflect updated performance. | Aghada CCGT<br>Huntstown CCGT<br>Moneypoint Units 1 ,2 &3<br>Northwall Unit 5<br>Marina No ST<br>Aghada Unit 1 |
| Incremental Heat Rate Slopes | Minor changes | Technical Review | Coolkeeragh CCGT<br>Huntstown CCGT<br>Ballylumford Unit 4<br>Cushaling<br>Aghada Unit 1 |
| Forced Outage Rate | Minor to medium changes | Latest data based on technical review and in some cases to align with commercial offer data | Aghada CCGT<br>Coolkeeragh CCGT<br>Moneypoint Units 1,2 & 3<br>Poolbeg Combined Cycle<br>Northwall Unit 5<br>Great Island Units 1,2 & 3<br>Marina No ST |

| | | | |
|---|---|---|---|
| | | | Rhode 1 & 2<br>Tarbert Units 1,2,3 & 4<br>Tawnaghmore 1 & 3<br>Aghada Unit 1<br>Aghada CT Unit 1,2 & 4<br>Lough Rea<br>West Offaly Power |
| Ramp Rates | Minor to medium changes | Changes made as a result of technical reviews and generator testing. | Aghada CCGT<br>Moneypoint Unit 1 ,2 &3<br>Whitegate<br>Ballylumford Units 10, 31,32 & 4<br>Ardnacrusha Units 1,2,3 & 4<br>Aghada Unit 1<br>Meath Waste-to-Energy |
| Min Up/Down Times | Minor to medium changes | Changes made to align with changes in generators commercial offer data | Dublin Bay Power<br>Whitegate<br>Tarbert Unit 3<br>Tarbert Unit 4 |
| Start Energy | Minor changes | Technical Review | Coolkeeragh CCGT |
| Boundary times | Minor changes | Technical Review | Whitegate |
| Start costs | Confidential data | Updated for consistency with Commercial Offer Data | Confidential data |
| VOM | Confidential data | Updated for consistency with Commercial Offer Data | Confidential data |
| Markups | Confidential data | Updated for consistency with Commercial Offer Data | Confidential data |

### 3.2.3 New entrants and retirements

Generators anticipated to enter and exit the market during the forecast period are indicated below. We asked new participants to provide the same set of unit parameters for these new units as we requested for existing units. Generally the submitted data for these units is necessarily based on expected unit characteristics rather than actual operation experience. Wind generation is detailed in section 3.2.6.

**Table 5 New generation units**

| Unit name | Fuel | Assumed Commissioning date | Capacity (MW) |
|---|---|---|---|
| Great Island CCGT | Gas | Oct-13 | 459 |

**Table 6 Generation units decommissioning**

| Unit name | Fuel | Assumed Decommission date | Capacity (MW) |
|---|---|---|---|
| Great Island Unit 1 | Gas | Oct-13 | 54 |
| Great Island Unit 2 | Gas | Oct-13 | 49 |
| Great Island Unit 3 | Gas | Oct-13 | 113 |

### 3.2.4 Confidential data

As in previous years, a number of participants marked certain data items as confidential. These were start costs (in €/start) and Variable O&M costs and mark-ups (in €/hr and €/MWh).

### 3.2.5 Market data & assumptions

**Demand**

Annual and peak electricity demand assumptions in ROI and NI were provided by the System Operators, based on SONI's and EirGrid's median demand forecast from the All-Island Generation Adequacy Report 2011-2020[5][6]. Average SEM demand is assumed to see no growth in 2012 compared to 2011 levels, and a moderate 0.6% increase in 2013. The assumptions are shown below.

**Table 7 Annual and peak demand assumptions**

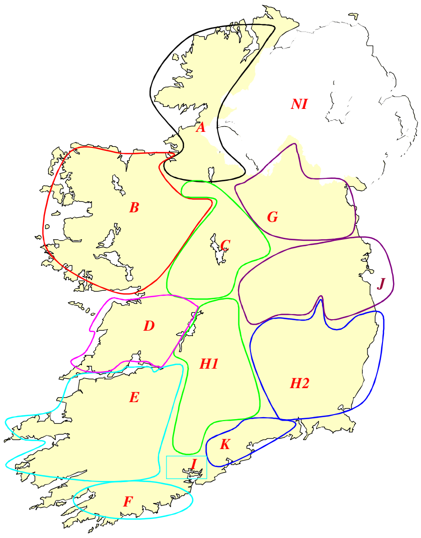
| Year | Annual demand (GWh) | | |
|---|---|---|---|
| | ROI | NI | SEM |
| 2012 | 27,050 | 9,507 | 36,557 |
| 2013 | 27,216 | 9,486 | 36,702 |

The demand is mapped to half hours based on the historic half hourly load shape in ROI and NI from 2007, with adjustments made by EirGrid for changes in peak demand. The load shapes for the subsequent years were not deemed suitable as the shape was heavily skewed compared to typical demand profiles, due to the impact of the economic crisis reducing demand.

### 3.2.6 Wind

Wind is modelled in aggregated form, split into the 12 regions shown in Figure 19. Each region has an associated half hourly profile which represents the wind availability in that region in each half hour, as a percentage of total installed capacity in that region.

**Figure 19 Wind regions[7]**



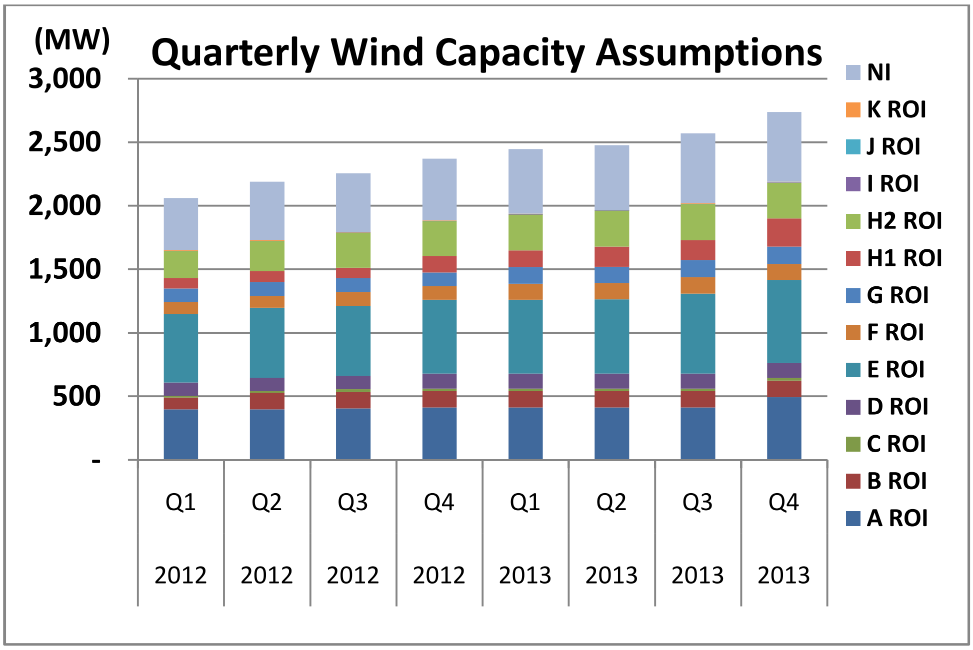

[5] Note that Eirgrid's GAR annual demand assumptions are based on a 52-week year. Therefore PLEXOS modelled values are slightly higher than the GAR published values.

[6] http://www.eirgrid.com/media/GCS%202011-2020%20as%20published%2022%20Dec.pdf

[7] [Picture provided by Eirgrid]

The installed capacity assumptions for each region change quarterly based on agreed connection dates (Figure 20). These figures include both Transmission- and Distribution-connected (Embedded) wind.

Figure 20 Quarterly wind capacity assumptions




### 3.2.7 Embedded generation

In previous year's the NI demand profile was net of generation from embedded/Small Scale Generation, and therefore an embedded generation profile is not required. However, this year NI embedded generation has been incorporated for the first time.

The ROI and NI demand assumptions include demand met by embedded generation and so an estimate of output from embedded generation must be included in the model. This estimate excludes embedded wind, which is included in the wind capacity assumptions. The All-Island embedded generation incorporates embedded generation in both jurisdictions and follows an hourly profile which is different for weekdays and weekends. The output varies in the range from approximately 112 to 211 MW in 2012 and from 123 to 224 MW in 2013.

### 3.2.8 Transmission Loss Adjustment Factors (TLAFs)

The latest available TLAFs, those for 2012, have been used for the validated period in question. This model applies TLAFs to both No-load and Start up costs in addition to the incremental costs of generators. This follows changes to the market rules and systems that now require this to be incorporated into generators bids. There is an XML file, PLEXOS_Param.xml, included with the forecast model which allows for TLAFs to be applied to all three properties.

### 3.2.9 Outages

SEMO provided a planned outage schedule for large thermal generation units for 2012 and 2013. Forced (unscheduled) outages in the model are based on the forced outage rates submitted by generators.

### 3.2.10 Hydro availability

Hydro availability is modelled with a daily energy limit, applied across the units that comprise each of the four hydro schemes. This energy limit varies by month, and we validated that the monthly shape reflects historic monthly output. The forecast PLEXOS model optimises the dispatch of hydro units subject to this constraint.

### 3.2.11 Interconnector capacity and scheduled outages

*Moyle*

Based on the data provided by the System Operators, the RAs set the capacity of Moyle to import to SEM as 450 MW in the winter and 410 MW in the summer (April –October inclusive), and 300 MW all year for export to GB. Planned outage assumptions were provided by the System Operators and checked against the data published on the Mutual Energy website.

*East-West*

This interconnector is due to commence commercial operation in September 2012, connecting Ireland to Great Britain (Wales). Based on data provided by the System Operators, the RAs set its capacity to import to and export from the SEM as 500 MW to GB with losses set at 6%.

In the decision paper on DC quantities and pricing[8] it was highlighted that the RAs consider that it would be timely to investigate reviewing the assumptions for IC flows and DC volumes. Hence the RAs published a consultation paper[9] in September 2012 on how interconnectors should be treated in future modelling for the purpose of calculating DC volumes. Any resulting change will not apply retrospectively to DCs.

### 3.2.12 Delivered fuel prices

The forecast model requires delivered fuel cost assumptions. These are built up outside the PLEXOS model based on:

- fuel price indices
- carbon price index
- currency conversions
- carbon emission rates for each fuel, and
- other adders, e.g. for transport costs or excise tax

The fuel and carbon price sources include:

**Table 8**

| Fuel | Source |
|---|---|
| Gas | ICE |
| Coal | Argus |
| Fuel oil | Reuters |
| Gasoil | Reuters |
| Carbon | ICE |

The 2012-13 Directed Contracts subscription rules[10] provide the detailed references for each of the fuels. These index values must be converted to delivered fuel prices for PLEXOS. A spreadsheet showing an example of these conversions was published alongside the forecast model.

The transport and excise adders are based on publically available data where possible, or on confidential data where this is more appropriate. Only the aggregate adders for each fuel will be published alongside this report.

[8] http://www.allislandproject.org/en/market_decision_documents.aspx?article=3bfde3ef-4ea1-4c1d-a0bc-dff77639f096

[9] http://www.allislandproject.org/en/market_current_consultations.aspx?article=42909a54-3e86-455d-94d9-2914025e185b

[10] ESB Power Generation 2012/13 Directed Contract Subscription Rules – SEM/12/050

### 3.2.13 Priority dispatch and non-firm capacity

The general approach in SEM PLEXOS modelling to date has been to model wind at zero price on the assumption that it will always run when available, due to its “priority dispatch” status.

In 2010 it was noted that the increasing level of installed wind capacity in SEM was beginning to have the potential to create situations where wind output could be close to the level of demand (e.g. in overnight periods). In the market schedule, very little thermal generation is required in these periods; however in the preceding and following shoulder and peak time periods the requirement for conventional thermal generation may be much higher. Due to the start costs of thermal units, the PLEXOS model solution might reduce wind generation rather than turning off a thermal unit and restarting it later, in order to minimise costs. However in the validated forecast model this was not an issue as wind was found to generate at its full available energy.

## 3.3 Quarterly DC Auctions – Round 2 changes

Several changes were made to the assumptions outlined in Sections 3.1 and 3.2 for Round 2 of the quarterly DC auctions. These were included as an Appendix to the Decision Paper on the quantities and prices for the September Auction - Round 2 - for Directed Contracts (DCs) Q1 2013 to Q4 2013:
http://www.allislandproject.org/en/market_decision_documents.aspx?article=915669ac-8422-4e66-91c3-312d6138d851

They are listed again below:

**Outages**
Generator outages have been updated with the latest information.

**Moyle Cable Outage**
One of the Moyle Interconnector's cables is on outage with no definite return date so its Max and Min Flow have been changed to 250MW and -250MW respectively.

**Price of Dump Energy**
Price of Dump Energy has been increased to -100,000 €/MWh.

**Demand File**
The demand CSV file has been updated to the 2013 load forecast published with the Decision Paper on BNE Peaker for 2013 here:
http://www.allislandproject.org/en/cp_decision_documents.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

**ED1 Max Capacity**
ED1's Max Capacity in the model has been changed from 117.6MW to 112MW. ED1 is a Priority Dispatch plant. Although it is available up to 117.6MW it is usually nominated to a maximum of 112MW so that it can provide frequency response and also most efficiently fulfill the terms of its PSO contract. Therefore it is usually scheduled to a maximum of 112MW in the SEM.

**Embedded Generation File**
The Embedded Generation CSV file which used patterns has been replaced with a full half hourly CSV file. This ensures that the correct values are used from 00:00am to 06:00am every day. This half hourly CSV file is published with this Information Note.

**Great Island CCGT**
The new Great Island CCGT has been removed from the model as its expected commercial operation date now falls outside the modelling period.

**PLEXOS Version**
PLEXOS Version 6207R03 is used.

# 4 Conclusion

The backcast modelling provided the validation of the PEXOS software against market outcomes in the SEM, with relatively small differences in SMP of

- 0.9% over November 2010 to October 2011 with Moyle flows fixed; and,
- 1.2% over November 2010 to October 2011 with Moyle flows free.

Hence the backcast PLEXOS model has been appropriately calibrated for use in the forecast period. The RAs are also confident that the dataset used in building the forecast model provides a reasonable and consistent representation of the market.

The following section summarises the key modelling approaches in the 2012-13 validated model.

## 4.1 Main Model Approaches

### 4.1.1 PLEXOS Software

The RAs have validated the 2012-13 SEM model using the PLEXOS software version 6.207 R03 and the Xpress MP solver with Rounded Relaxation.

### 4.1.2 Unit Commitment

The RAs have selected to use Rounded Relaxation, as in previous years, as the form of unit commitment. The new Self-Tuning feature is used.

### 4.1.3 Treatment of Interconnectors

The RAs have modelled interconnector flows through the use of a simple Great Britain generator and demand, similar to last year's model. The addition of the new interconnector between Ireland and Wales, the East West interconnector, is included from September 2012.

### 4.1.4 Start States

This validated model, using the above mentioned version of PLEXOS, utilises all 3 start states.

### 4.1.5 TLAFs

In this model TLAFs will be applied to generator start and no-load costs.

### 4.1.6 Confidential data

As with previous years, Variable Operation and Maintenance (V&OM) costs are considered to be confidential by a number of generators and are excluded from the published model. We recommend that users of the model incorporate their own estimates as they see appropriate.