KEMA Limited

All Island Project

Market Simulation Model Validation

G06-1647 Doc 3 Rev 1.2

24 April 2007

Table of Contents

Revision History

Rev.	Date	Description	Author	Checker	Approver
1.0	28/3/2007	Draft – final	AP	NS	
1.1	16/4/2007	Incorporate comments & feedback	AP	MW	
1.2	24/4/2007	Incorporate additional Moyle analysis	AP		

Executive Summary

As part of their preparations for the new all-island single electricity market ("SEM"), the Regulatory Authorities ("RAs") require a market simulation model to support activities such as the pricing of directed contracts, the calculation of annual capacity payments, the review of tariffs, and market monitoring. The RAs have commissioned KEMA to validate the use of the PLEXOS model to simulate electricity prices under the SEM.

The purpose of this assignment is to provide the RAs with a validated model that is ready to accurately predict SEM electricity prices. The assignment comprises two parallel work streams: the validation of input data and modelling assumptions, and the validation of the PLEXOS model algorithms against the SEM market rules. This report summarises the model validation exercise that KEMA has conducted. A separate report summarises the results of the data validation work stream.

Model Validation Scope

The PLEXOS model algorithms have been validated against the SEM Trading and Settlement Code ("T&SC"). Version 1.2 of the draft T&SC has been used as the baseline for this exercise.

The validation exercise only related to the unconstrained PLEXOS model of the SEM, given the RAs' objective of simulating prices rather than transmission-constrained schedules. The model validation included reviewing the methodology for simulating the shadow price and Uplift components of SMP under the SEM. Constraint payments and capacity payments were outside the project scope. The project scope did not include the cross-validation of PLEXOS against the ABB "EPUS software" to be used by the SEM market operator.

In addition to validating the PLEXOS model, KEMA also undertook analysis of different PLEXOS configuration options in response to feedback from industry participants and the RAs.

Our starting data set for the model and data validation exercises was the AIP Modelling Project "Loop 2" data set. We have used variants and subsets of this data set to undertake the majority of our model validation analysis. In parallel, the data validation work stream has worked towards the development of an updated and validated data set. We populated the PLEXOS model with this new data set at the conclusion of our project.

The key deliverable of this assignment is a validated model and not SEM price forecasts. Although PLEXOS simulation results are presented in this report, these should not be interpreted as projections of SEM prices. For example, simplifying input assumptions have been applied in most model runs to facilitate the comparison of results with different model configuration options.

Finally, this project does not represent a validation of any external SEM market price forecast, including the AIP Modelling Project results.

Model Validation Approach

The approach to model validation comprised a number of steps, as set out below. In each step, we compared the methodology set out in the T&SC to that employed by PLEXOS. We then applied an empirical approach, testing PLEXOS outputs for specific sets of inputs.

1. ***Commercial Offers*** – We confirmed that PLEXOS can reproduce the Commercial Offer structure per the T&SC. We then validated that the short run marginal cost (“SRMC”) values reported by PLEXOS are consistent with those calculated externally using the same set of inputs. We also tested the materiality of multiple (hot / warm / cold) start costs and validated the functionality within PLEXOS for modelling loss factors.

2. ***Technical Offers*** – We confirmed that PLEXOS can reproduce the Technical Offer structure per the T&SC. We then validated that that PLEXOS produces technically feasible schedules consistent with plant integer and dynamic constraints such as Min Stable Level (“MSL”) and ramp rates.

3. ***Unit Commitment*** – We confirmed that PLEXOS can be configured to replicate the T&SC optimisation horizon, comprising a trading day starting at 06:00 plus a six hour look-ahead period. We found that the recent addition of the look-ahead feature in PLEXOS addresses the “edge effect” issues that were observed in the AIP Loop 2 results published last year (this look-ahead feature was not available for the AIP Loop 2 study). We also tested the materiality of the trading period duration, comparing PLEXOS results at hourly and half-hourly resolution.

4. ***Special Cases*** – We confirmed that PLEXOS has the capability to model non-thermal generation sources such as wind, hydro and pumped storage, as well as external interconnections. We also tested the options for modelling thermal “must-run” plant.

5. ***Shadow Price*** – We sense-checked that the shadow prices reported by PLEXOS are broadly consistent with a simplified stack model scheduling purely on SRMC. We then analysed the impact of technical constraints on the shadow price in PLEXOS. We examined PLEXOS output schedules to identify instances in which generator units were running despite their SRMC being above the reported shadow price for the period, and were able to confirm that such instances were due to units binding on a MSL or ramp constraint.

6. ***Uplift*** – We identified a number of potential discrepancies between Uplift as defined in T&SC v1.2 and as implemented in PLEXOS. These discrepancies largely arose because the

SEM Uplift algorithm in PLEXOS was developed on the basis of previous AIP documentation, notably the May 2006 Uplift paper, AIP-SEM-60-06.

- Two of these discrepancies – the inclusion of price takers in the cost objective function and the omission of the Rev Min constraint – are immaterial given the latest proposed Uplift parameters ($\alpha = 0$, $\beta = 1$, $\delta = 5$).
- Two more discrepancies related to differences in the formula for carrying forward start costs between the T&SC v1.2 and the previous AIP Uplift paper, but we understand that a T&SC modification is expected to revert to the previous formula.
- The remaining Uplift discrepancies related to the inclusion of price takers in the cost recovery constraint, loss factors, and the maximum number of days that start costs can be carried forward. We proposed a workaround for the first issue, and assumed that participants would internalise loss factors in their offers to adjust the Uplift break-even condition, effectively replicating the PLEXOS treatment (PLEXOS can model loss-adjusted revenues for Uplift cost recovery whereas the EPUS software does not). A PLEXOS code change was required to address the start cost carry forward discrepancy between T&SC v1.2 and the AIP-SEM-60-06 Uplift paper.

We validated the PLEXOS SEM Uplift algorithm for consistency with the T&SC Profile Objective and the Cost Recovery Constraint. Our validation tests were conducted at the hourly resolution, but we subsequently established that the PLEXOS Uplift algorithm could lead to cost under-recovery when a half-hourly trading period was modelled.

We maintained regular dialogue throughout the project with Elan Energy Consulting ("Elan"), the European representatives of PLEXOS developers Drayton Analytics. As issues arose, we raised them with Elan and sought to develop workarounds, where possible within PLEXOS. One of the SEM Uplift issues that we identified required a PLEXOS code change to limit the carry forward of start costs. This led to a new PLEXOS release, 4.898 R5, becoming available on 26th March. A subsequent PLEXOS release, 4.898 R14, became available in April after the completion of our model validation analysis to address the treatment of non-hourly trading periods in the SEM Uplift algorithm.

Model Configuration Recommendations

Highlights of our recommended configuration for SEM modelling with PLEXOS include:

1. ***Unit commitment*** – We believe the Rounded Relaxation (RR) method is the most appropriate unit commitment option for modelling SEM prices over an extended time-frame such as a year. Both the RR and the MIP unit commitment options in PLEXOS produce prices that are

fully consistent with the T&SC constraints of schedule feasibility and Uplift cost recovery. The significantly faster performance of the RR method facilitates running multiple scenarios to explore the impact of uncertain price drivers on the SEM over the medium to long term.

2. ***ST Schedule*** – We recommend configuring the ST Schedule in PLEXOS to replicate the T&SC, with a daily optimisation step, a six hour look-ahead period and a 06:00 trading day start. We recommend modelling a 60 minute trading period duration.

3. ***Hydro & Pumped Storage*** – We recommend running the model without MSL, Min Pump Load and Rough Running Range constraints for pumped storage plant, and without MSL, ramp limits or start costs for hydro plant. This should mitigate the risk of over-constraining the commitment problem, leading to infeasibilities and/or unserved energy. As such it will deliver more realistic model results.

4. ***Thermal "price takers"*** – We propose applying zero fuel and start costs for any thermal "must run" or "price taker" units. This is a workaround to exclude such plant from the SEM Uplift algorithm in PLEXOS.

5. ***Moyle interconnector*** **–** Moyle can be modelled in PLEXOS by simply defining the BETTA market as a node within the SEM region, and then attaching an externally derived BETTA price profile based upon quoted forward prices. However, to model the interactions between SEM and BETTA under multiple fuel price scenarios, we recommend using a simplified representation of the GB plant portfolio within PLEXOS. This will ensure that the BETTA price is internally consistent with the fuel and carbon price assumptions under each scenario.

6. ***Multiple start costs*** – Given that the inclusion of multiple start costs appears to have a material impact on the SMP results, we recommend that hot, warm and cold starts are modelled within PLEXOS. A step function workaround can be defined to replicate the T&SC treatment of multiple start costs.

7. ***TLAFs*** – We recommend using the PLEXOS loss factor functionality to specify TLAFs directly in the model. This will ensure that PLEXOS automatically incorporates loss-adjusted incremental costs in the schedule and loss-adjusted revenues in the Uplift cost recovery condition.

8. ***Uplift filters*** – We believe it is appropriate to apply the MSL and Ramping filters in the PLEXOS Uplift algorithm. The MSL and Ramping filters serve to prevent these "unrealistic" anomalies in the model schedule from impacting Uplift.

Conclusions

We have validated that PLEXOS has the capability to model the SEM consistent with the market rules as laid out in the T&SC v1.2.

One of the PLEXOS discrepancies that we identified during the model validation exercise required a PLEXOS code change. We have subsequently tested the new PLEXOS release 4.898 R5 to verify that this issue has been addressed, namely that the start cost carry-forward is limited to one day in the SEM Uplift algorithm.

Assuming our recommended workarounds are implemented, we believe there to be no PLEXOS issues outstanding of significant materiality. We therefore conclude that PLEXOS is an appropriate model for simulating unconstrained market prices in the SEM.

1. Introduction

1.1 Background

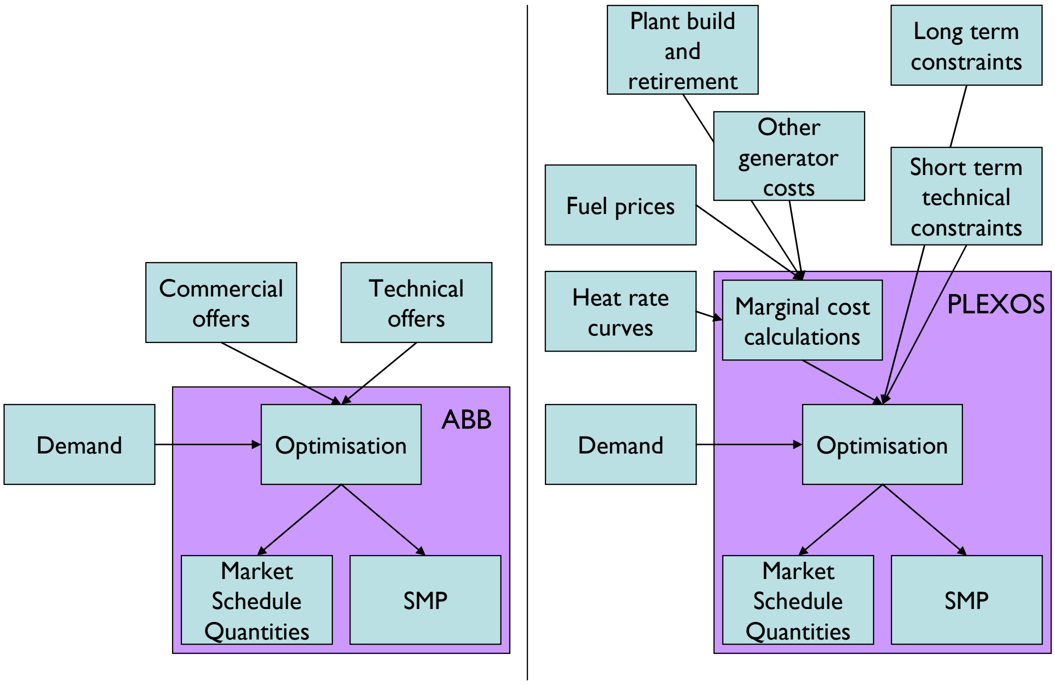
The Commission for Energy Regulation and the Northern Ireland Authority for Energy Regulation ("the RAs") are currently developing a single all-island electricity market (the "SEM") which is scheduled to come into operation on November 1st 2007. To facilitate their regulatory role under the SEM market design, the RAs will need to use a market simulation model to provide them with reasonably accurate estimates of the future market price.

The RAs and the System Operators currently use PLEXOS, a Windows-based market simulation software system, to model the SEM. We understand that the RAs intend to use the PLEXOS model to undertake market simulations which can provide them with estimates to support activities such as the pricing of directed contracts, the calculation of annual capacity payments, the review of tariffs, and market monitoring.

The RAs have commissioned KEMA to validate the use of the PLEXOS model to simulate electricity prices under SEM. The assignment comprises two parallel work streams: model validation and data validation. This report summarises the model validation exercise that KEMA has conducted on behalf of the RAs. A separate report summarises the results of the data validation work stream.

1.2 Validation of Model Algorithms

The RAs are seeking to validate that PLEXOS produces results that are consistent with the Trading & Settlement Code ("T&SC"). Under the SEM, EPUS software will be used to generate an unconstrained schedule and associated half-hourly SMPs, taking as input generators' commercial and technical offers, and optimising to find the least-cost schedule to meet demand. Each EPUS "run" will generate Market Schedule Quantities and prices for a 24 hour period, although the optimisation will include a "look-ahead" period extending into the following day. In PLEXOS, instead of generators' commercial offers being an input, a direct calculation is made of generators' costs, based on fuel and carbon prices, heat rate curves and variable O&M costs. An optimisation is then conducted based on these costs. In addition, in order to model prices over an extended period, PLEXOS needs to handle changes to plant on the system (through build or retirement), and to be able to optimise plant scheduling on a longer term basis to handle constraints such as fuel must-burn conditions, and compliance with emissions limits. This difference is illustrated in the following simplified schematic:



Our approach to validating the PLEXOS modelling software consisted of the following steps:

(i) Commercial offers & marginal cost calculation review

(ii) Technical offers & short term constraints review

(iii) Unit commitment review

(iv) Special cases review

(v) Shadow price calculation review

(vi) Uplift calculation review

In each step, we compared the methodology set out in the T&SC to that employed by PLEXOS. We then applied an empirical approach, testing PLEXOS outputs for specific sets of inputs. The project scope did not include the cross-validation of PLEXOS against the ABB EPUS software to be used by the SEM market operator.

PLEXOS is designed as a general power market modelling tool, and was not built specifically to match the SEM T&SC. Whilst certain features have been added to support SEM modelling (such as the Uplift functionality and the optimisation "look-ahead" period), we anticipated that there could still be a number of issues where there is not an exact match with the T&SC.

During the course of this project we have maintained regular dialogue with Elan Energy Consulting ("Elan"), the European representatives of PLEXOS developers Drayton Analytics. As issues arose, we raised them with Elan and sought to develop workarounds, where possible within PLEXOS.

1.3 T&SC Versions, PLEXOS Releases and Data Sets

We have used v1.2 (AIP/SEM/0707) of the Trading & Settlement Code as our baseline for comparing the PLEXOS model to the SEM market rules. This was the first published version of the T&SC to incorporate a detailed description of the EPUS software and Uplift.

All references to "the current PLEXOS release" in this document are to PLEXOS release 4.896 R3. We initially installed PLEXOS release 4.894 R2 at the outset of the project but subsequently upgraded to 4.896 R3 in February.

A new PLEXOS release, 4.898 R5, became available on 26th March. We tested this release to verify that it addressed an SEM Uplift discrepancy that we had identified during the course of the project. A subsequent PLEXOS release, 4.898 R14, became available on 20th April after the completion of our model validation analysis. We understand from Elan that the 4.898 R14 release is intended to resolve an issue with the treatment of non-hourly trading periods in the SEM Uplift algorithm. However, we have not had an opportunity to validate this release. The majority of our model validation tests have been conducted using an hourly trading period resolution.

Our starting data set for the model and data validation exercises was the AIP Modelling Project "Loop 2" data set. We have used variants and subsets of this data set to undertake the majority of our model validation analysis. The results we present in this report include generator unit references (e.g. "AD1" for Aghada Unit 1) per the starting data set. In parallel, the data validation work stream has worked towards the development of an updated and validated data set. We populated the PLEXOS model with this new data set at the conclusion of our project.

New Uplift parameter values were published by the RAs midway through our project. Some of the PLEXOS runs we present in this report incorporate the new parameter values per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$) while other runs were based on the previous values proposed in AIP-SEM-230-06 ($\alpha = 0.3$, $\beta = 0.7$). We have used footnotes to describe the parameters applied to each PLEXOS run.

None of the PLEXOS runs presented in this report should be interpreted as forecasts of market price outcomes under the SEM. PLEXOS results have been presented to enable a comparison of relative price outcomes for different model configuration options. Since this model validation exercise was not intended to project the absolute magnitude of SEM market prices, simplifying input assumptions have been applied in most model runs to facilitate the comparison of results. For example, the effects of planned and forced plant outages have generally been excluded from the analysis.

1.4 Structure of this Report

This model validation report is structured as follows:

– Section 2 describes each step of the model validation process in turn. At the end of this section, we outline the additional analysis of PLEXOS configuration options that was undertaken in response to participant feedback.

– Section 3 summarises the PLEXOS discrepancies that we identified during the course of the validation exercise, together with our proposed workarounds.

– Section 4 presents our conclusions and recommendations.

2. Model Validation

2.1 Commercial Offers & Marginal Cost Calculation Review

We have sought to verify that PLEXOS can capture the information required to replicate the commercial offer structure under the T&SC. We have also validated the production cost calculations within PLEXOS and benchmarked the reported short run marginal costs (SRMC).

2.1.1 T&SC comparison

Paragraphs 4.5 to 4.15 of T&SC v1.2 summarise the commercial offer structure while Table 12a in T&SC Appendix C describes the commercial offer data transaction.

Under SEM, participants will submit up to ten pairs of daily offer prices and quantities for each price maker generator unit, together with a single no load cost and up to three start costs (hot, warm and cold). The incremental offer prices must be monotonically increasing. In PLEXOS, generator offer prices and quantities can be entered directly if these are available, with a limit of 100 price-quantity pairs per generator unit. This capability may prove useful after SEM Go-Live to utilise published generator offer information for short term forecasts and to benchmark the model against observed market outcomes[1]. However, for forward-looking modelling in advance of Go-Live, offer structures need to be derived by calculating generators' production costs, based upon expectations of fuel and carbon prices, heat rate curves and variable operating costs. In theory, these calculations could be performed externally and then manually input in to the model, but in practice it is much simpler and more efficient to calculate production costs within PLEXOS itself.

The following table lists the T&SC commercial offer data items and the equivalent variables in PLEXOS. Note that in this table and throughout the report we have incorporated hyperlinks to relevant sections of the PLEXOS online reference guide (www.plexos.info) so that readers can easily find more information on each PLEXOS topic:

[1] In the current PLEXOS release, our understanding is that if offer prices and quantities are entered directly, Start Costs will still be considered in the optimisation but No-Load costs will not. If there is interest in benchmarking PLEXOS post SEM Go-Live with actual commercial offer data, it may be worthwhile exploring a PLEXOS change request to add a monetary no load offer property for inclusion with offer prices. However, this potential PLEXOS "discrepancy" is NOT relevant in the context of forward–looking modelling pre Go-Live and has not been considered further in this model validation exercise.

T&SC Variable	Comments	Applies to	PLEXOS Variable
Price Quantity Pairs	Minimum of one, maximum of ten, to apply equally to every Trading Period in the Optimisation Time Horizon	Price Maker Generator Units and Predictable Price Taker Generator Units, except Interconnector Units and Pumped Storage Units	Offers can be entered directly using bands of Offer Quantity and Offer Price. If user-defined offers are not input, production cost is defined using a heat rate function, fuel price, and variable operations and maintenance cost.
Price Quantity Pairs	Minimum of one, maximum of ten pairs for each Trading Period during the Trading Day per Interconnector Unit, where negative Quantities relate to exports from the Pool	Interconnectors Units only	[Not directly applicable if modelling interconnector in aggregate - see Special Cases]
Nomination Offer		Predictable Price Taker Generator Units and Generator Units Under Test	Fixed load and minimum load define a fixed or minimum dispatch profile. [See Special Cases]
No load costs		All Price Maker Generator Units and Predictable Price Taker Generator Units, except Interconnector Units, Demand Side Units, Pumped Storage Units and Generator Units Under Test	Heat Rate Base is the no load heat input used in defining the heat rate function
Start up costs	Minimum of one, maximum of three (specifying which applies to each type of start)	All Price Maker Generator Unit and Predictable Price Taker Generator Units, except Interconnector Units, Demand Side Units and Pumped Storage Units	Start Cost based on fixed monetary value and/or Start Fuel Offtake at Start based on GJ of fuel used. Option to vary both/either by warmth state.
Shut Down Cost	A single shut down cost	Demand Side Units only	[See Special Cases]
Pumped Storage Cycle Efficiency	One value per Trading Day, to apply to all Trading Periods within that Trading Day	Pumped Storage Units only	Pump Efficiency [See Special Cases]

T&SC Variable	Comments	Applies to	PLEXOS Variable
Target Reservoir Level at 06:00 D+1		Pumped Storage Units only	[Optimised inter-day by PLEXOS - see Special Cases]
Target Reservoir Level Percentage	One value per Trading Day	Pumped Storage Units only	[Optimised inter-day by PLEXOS - see Special Cases]

In this section, our focus is on Price Maker Generator Units, and in particular thermal plant. The "Special Cases" section describes the modelling of price takers and non-thermal units such as wind, pumped storage and interconnectors.

2.1.2 Heat Rate Functions

In the absence of user-defined generator offer prices, PLEXOS defines productions costs using a heat rate function, fuel prices and variable operations and maintenance (VOM) costs.

PLEXOS uses the following properties to describe heat rates:

- "Heat Rate Incr" denotes the marginal heat rate
- "Heat Rate" denotes the average heat rate
- "Heat Rate Base" denotes the no load cost
- "Heat Rate Incr2" and "Heat Rate Incr3" describe the quadratic and tertiary terms if the heat input function is input as a polynomial function

PLEXOS provides several different options for users to specify heat rate functions:

1. A linear heat input function with constant average and marginal heat rates (*specifying Heat Rate or Heat Rate Incr alone*).
2. A linear heat input function with constant marginal heat rate (*specifying Heat Rate Base and Heat Rate Incr*).
3. A polynomial heat input function (*specifying the coefficients Heat Rate Base, Heat Rate Incr, Heat Rate Incr2, and optionally Heat Rate Incr3*).
4. A set of marginal Load Point / Heat Rate Incr pairs plus the Heat Rate Base.

5. A set of marginal Load Point / Heat Rate Incr pairs plus the average Heat Rate at the Min Stable Level.

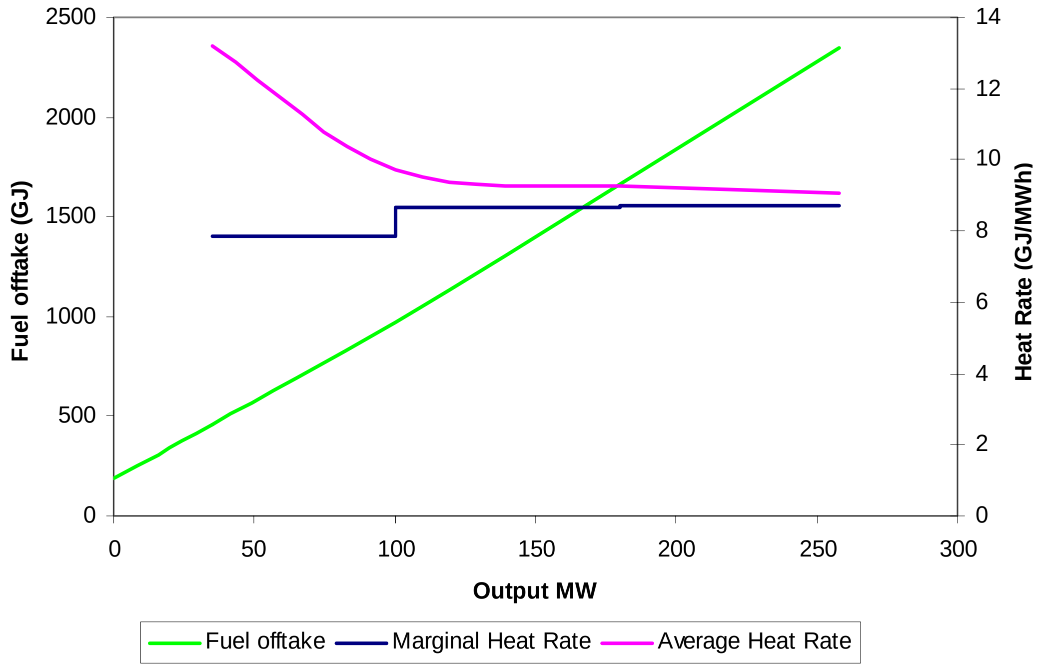
6. A set of average Heat Rate / Load Point pairs.

For this project, SEM participants have submitted heat rate data consistent with option (4), namely pairs of marginal heat rates and load points plus a no load requirement. This data describes the steps of a marginal cost function and is used directly by PLEXOS to model generators' heat input functions[2].

The PLEXOS input properties and corresponding heat rate curves for Aghada Unit 1 (AD1) are illustrated below:

Property	Value	Units	Band
Min Stable Level	35	MW	1
Max Capacity	258	MW	1
Heat Rate Base	187.17	GJ/hr	1
Load Point	35	MW	1
Heat Rate Incr	7.86	GJ/MWh	1
Load Point	100	MW	2
Heat Rate Incr	7.86	GJ/MWh	2
Load Point	180	MW	3
Heat Rate Incr	8.64	GJ/MWh	3
Load Point	258	MW	4
Heat Rate Incr	8.72	GJ/MWh	4

[2] By contrast, if heat rate curves had been specified using some of the alternative input methods such as polynomial functions or average heat rate sets, PLEXOS would need to generate a piecewise linear model of the marginal heat rate function from the input data. In this SEM project, participants have effectively determined the step approximation to the marginal heat rate function themselves in preparing their data submissions. Hence the input data can be used verbatim without the need for piecewise linear approximations within PLEXOS.



The "Heat Rate Base" is the y-axis intercept of the fuel offtake function and is also included in the average heat rate function.

Note that PLEXOS does not restrict the heat input function or the marginal heat rate function to be monotonically non-decreasing (i.e. convex). However, given the T&SC requirement for monotonically increasing offer prices, participants have been advised to modify non-convex marginal heat rates during the data validation exercise.

2.1.3 Fuel prices & Carbon costs

Having defined generator heat rates, PLEXOS requires assumptions on delivered fuel prices and carbon emission costs in order to calculate production costs.

The components of delivered fuel prices comprise traded market prices, delivery and transportation charges and excise taxes. It is possible to specify these components separately within PLEXOS, e.g. by defining transport costs for each generator unit. In the AIP Modelling Project, delivered fuel prices (€/GJ) have been calculated offline and then input to PLEXOS. Cost differentials (e.g. transportation) for plants located in Northern Ireland and the Republic of Ireland have been captured by setting up separate price series for ROI and NI.

The granularity (e.g. daily, weekly, monthly, seasonal, annual) of each fuel prices series in PLEXOS is completely flexible. Consistent with the AIP Modelling Project, the model validation exercise has generally applied annual fuel price series with seasonal prices for gas. PLEXOS does have the capability to generate stochastic price series but this feature has not been explored during model validation. Fuel price uncertainty was addressed in the AIP Modelling Project by running multiple scenarios. Within PLEXOS, the user can choose which set of scenarios to include in each model run.

Each generator unit in PLEXOS can be associated with one or more fuels. PLEXOS will optimise fuel use economically over time, taking the cheapest fuel first subject to any constraints on the supply of that fuel. In this project, fuel supply constraints or interruptions have not been modelled, and so “back-up” fuels would only be used if the secondary fuel was cheaper in a particular scenario.

Emission costs such as EUA carbon allowances can be modelled in a number of ways within PLEXOS. It is possible, for example, to specify a carbon price series, emission rates per fuel and/or generator unit and a pass-through parameter. In the AIP Modelling Project, carbon costs (€/GJ) have been calculated offline for each fuel and then input to PLEXOS. These calculations assumed 100% pass-through consistent with the SRMC bidding principles. Carbon price uncertainty was addressed via scenarios. PLEXOS treats the input carbon costs as a tax to be added to the delivered fuel prices before calculating production costs.

2.1.4 SRMCs

Short Run Marginal Cost (SRMC) is the incremental cost of generation at a given output level. PLEXOS reports generator SRMC at the (optimal) scheduled generation level in each trading period, computed as follows:

SRMC = Fuel Price × Marginal Heat Rate + VOM Charge

If a unit has zero generation in a period, PLEXOS reports the SRMC at Min Stable Level.

We have constructed Excel-based calculation tools to mimic the marginal cost calculation in PLEXOS and benchmark the SRMCs reported in PLEXOS results.

In the simplest case, this was done by modelling a single generator unit with a variable demand curve, and then validating the reported SRMC at each load point. For example, the table below shows the reported PLEXOS results for a system with only Aghada Unit 1 (AD1) available to meet demand:

Period	Demand (MW)	Shadow Price (€/MWh)	Marginal Heat Rate (GJ/MWh)	Generator SRMC (€/MWh)	Average Heat Rate (GJ/MWh)	Generation Cost (€k)	Average Cost (€/MWh)
1	35	67.75	7.86	67.75	13.21	95.63	113.85
2	95	67.75	7.86	67.75	9.83	193.2	84.74
3	105	74.48	8.64	74.48	9.68	210.27	83.44
4	175	74.48	8.64	74.48	9.26	335.39	79.85
5	185	75.17	8.72	75.17	9.23	353.34	79.58
6	255	75.17	8.72	75.17	9.09	479.62	78.37
7	260	300	8.72	75.17	9.09	485.04	77.73

At each output level, we validate that PLEXOS has applied the appropriate marginal heat rate given the input heat rate function (as illustrated for AD1 previously) and compare the reported SRMC to our own calculations[3]. Note that in this simple example, the shadow price reported by PLEXOS is always equal to the SRMC of AD1, except in the final period. In this period, demand has been set to be greater than the maximum capacity of AD1 (258 MW). The Shadow Price is capped at the Value of Lost Load (VoLL) for the region. We have used a nominal value of 300 €/MWh. Note that PLEXOS uses a much higher VoLL internally (See Section 2.5.6 for details).

The reported average heat rate in each period can also be validated by calculating the weighted average of the incremental heat rates at the output level and then adding the no load cost per MW of output.

We then moved on to validating the SRMC results in more complex multi-unit systems. Finally, we developed another Excel tool to validate hourly SRMC results from annual PLEXOS model runs for the full all-island system.

In each case that we have examined, there are no discrepancies between the reported SRMCs and our calculations.

2.1.5 Start Costs

SEM commercial offers include start costs in addition to incremental and no load costs. Participants can submit up to three start costs, reflecting the dependence of the start cost on the time since the last

[3] The Variable O&M charge has been excluded in this example so the SRMC is simply the product of the fuel price and the marginal heat rate.

period in which the unit generated. This variable is known as the warmth state and can be either hot, warm or cold, with the associated start up being a hot, warm or cold start, respectively.

In PLEXOS, start costs can be defined in monetary and/or fuel offtake terms. The total Unit Start Cost considered in the optimisation of unit commitment and dispatch is the sum of these two components:

Start Cost + Start Fuel Offtake at Start × Fuel Price

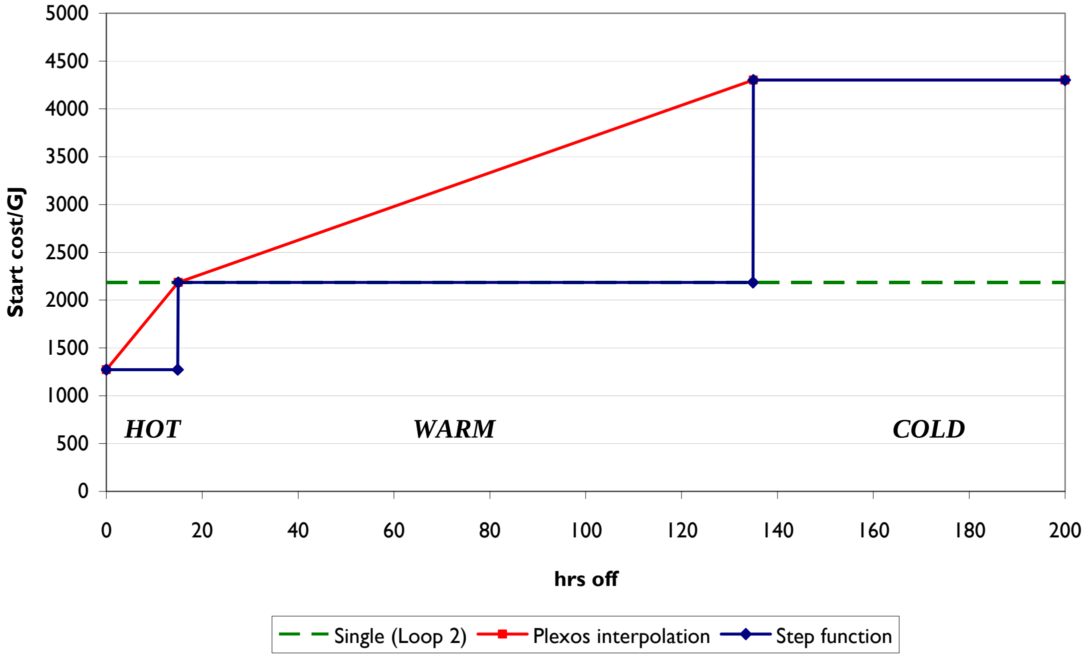
Given the fuel price dependency, it is appropriate to model the start fuel offtake in medium and longer term modelling studies. Thus, for the AIP Modelling Project, participants have been asked to submit offtake quantities for each warmth state. A start fuel is then defined for each generator unit in PLEXOS, which may differ from the primary fuel (e.g. the coal-fired units use oil as a start fuel).

To date, the AIP Modelling Project has used a single start fuel offtake value for each generator unit (namely the warm state value). Multiple start costs can be modelled in PLEXOS by specifying bands of costs together with Start Times to denote the incremental number of hours between warmth states. For this model validation exercise, we have sought to assess the materiality of the single start cost assumption. Having set up PLEXOS to model multiple start costs, we have also validated that the appropriate start cost is reported for a given unit down time.

By default, the current PLEXOS release linearly interpolates start costs between warmth states (i.e. the input cost values are applied at the cooling time boundary points with linear interpolation in between). Although interpolation may lead to a more accurate representation of the underlying plant start costs, it would appear to be inconsistent with the proposed treatment of start costs in SEM. T&SC v1.2 paragraph 4.108 simply defines the Market Start Up Cost (MSUCuh) to "be equal to the Accepted Start Up Cost for the relevant Market Schedule Warmth State". As a workaround within PLEXOS, we have constructed step functions using additional start cost bands to model a flat cost for each warmth state. For example, the following tables and diagram illustrate the step and linear start cost functions for Poolbeg Unit 3 (PB3):

LINEAR			
Property	**Value**	**Units**	**Band**
Offtake at Start	1273	GJ	1
Start time	0	hrs	1
Offtake at Start	2185	GJ	2
Start time	15	hrs	2
Offtake at Start	4302	GJ	3
Start time	120	hrs	3

STEP			
Property	**Value**	**Units**	**Band**
Offtake at Start	1273	GJ	1
Start time	14.9	hrs	1
Offtake at Start	2185	GJ	2
Start time	0.1	hrs	2
Offtake at Start	2185	GJ	3
Start time	119.9	hrs	3
Offtake at Start	4302	GJ	4
Start time	0.1	hrs	4



We then compared the model results for the three alternative approaches to modelling start costs:

1. Single (warm state) start costs, per AIP Loop 2 modelling

2. Multiple (hot, warm, cold) start costs, with default PLEXOS linear interpolation

3. Multiple (hot, warm, cold) start costs, with workaround step function

The table below shows the annual time-weighted average prices resulting from PLEXOS runs[4] with these alternative start cost approaches:

[4] Each model was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$).

Start Cost Model	SMP €/MWh	Uplift €/MWh	Shadow Price €/MWh	Relative PLEXOS run time[5]
Single: Warm only	61.08	6.97	54.12	1.00
Multiple: Interpolation	67.05	13.12	53.93	2.02
Multiple: Step function	66.67	12.77	53.90	1.77

As would be expected, the start cost model has little impact on the average shadow price. This is largely because shadow prices reflect the marginal or incremental costs of a given unit commitment schedule rather than start costs. Moreover, incremental and no load costs are generally more significant in determining the unit commitment schedule than start costs. However, it can be seen from these results that average Uplift is almost twice as high when multiple start costs are modelled, leading to higher SMP on average. Uplift is the mechanism through which start costs are recovered in the SEM market design, and hence this is where the choice of start cost model has an impact. The increased levels of Uplift when multiple start costs are modelled imply that, with this data set, the impact of (higher cost) "cold starts" outweighs (cheaper) "hot starts" compared to the "warm start only" scenario.

Average Uplift is around 0.4 €/MWh higher with the interpolation model compared to the step function. This is because in our model configuration, start costs under the interpolation model are always greater than or equal to step function start costs– as clearly illustrated by the diagram for PB3 above. Finally, it is noted that the PLEXOS run times are longer when multiple start costs are modelled.

Given that the inclusion of multiple start costs appears to have a material (c. 10%) impact on annual average SMP, we would recommend the three warm states are modelled within PLEXOS, despite the longer model run times. Although the two multiple start cost approaches we tested produced similar results on average, the step function replicates the T&SC treatment of start costs and is therefore recommended in preference to the PLEXOS default of linear interpolation.

A potential PLEXOS enhancement would be to add the option of switching off linear interpolation of start costs across warmth states. However, as shown above, the step function workaround can be applied in the current PLEXOS release with little additional manipulation of input data.

[5] The relative run times in this report are provided as an approximate guide for indicative purposes only. They are based on total elapsed run times rather than CPU times, and will therefore be dependent on any other processes that were running in parallel on our modelling machines.

2.1.6 TLAFs

The final section of our commercial offer review considers the application of Transmission Loss Adjustment Factors (TLAFs) in SEM and PLEXOS. Our understanding from T&SC v1.2 is that actual payments to generators will be loss-adjusted but that the EPUS schedule does not take TLAFs into account explicitly (T&SC Appendix N24). Consequently, generators can be expected to internalise TLAFs in their offer submissions, thereby ensuring loss factors are implicitly considered in the market schedule and resulting shadow prices. Loss factors are also relevant in the Uplift calculation, as discussed later.

The AIP Modelling Project to date has not modelled loss factors in the unconstrained schedule. Nevertheless, PLEXOS does allow a Loss Factor to be associated with each generator unit to model transmission losses from the station gate to the regional reference node. This loss factor divides the generator's incremental cost as considered in the dispatch optimisation. It also multiplies the market price received such that payments to generators are loss-adjusted. As with most properties in PLEXOS, loss factors can be defined with flexible time patterns, e.g. a monthly day / night pattern could be specified to model the proposed TLAF structure for SEM. However, the SEM market rules only allow generators to submit one set of offer prices per trading day, so participants will not be able to reflect day / night TLAF differentials in their offers.

The Loss Factor property in PLEXOS avoids the need to manually adjust input data for transmission losses. We ran a number of tests to verify that PLEXOS applies loss factors as would be expected:

1. We first modelled a simplified five generator system without loss factors as a baseline for comparison.

2. We then specified equal loss factors for all five generators and re-ran the model. As would be expected, the schedule did not change but the reported shadow price in each period increased by 1/(loss factor). Note that in our current configuration of PLEXOS, values such as load, generation, SRMC and price received are all reported at the station gate, while shadow prices (and Uplift) are reported at the regional reference node.

3. Next we varied the loss factors between generators such that the merit order would be expected to change on a loss-adjusted basis. We validated that PLEXOS produced a different schedule as anticipated. In each period, the shadow price was equal to the SRMC of the marginal generator divided by its loss factor.

2.2 Technical Offers & Short Term Constraints Review

Having verified that PLEXOS can replicate the commercial offer structure under the T&SC, we next sought to validate PLEXOS' handling of the constraints captured within generators' technical offers.

2.2.1 T&SC Comparison

Paragraphs 4.16 to 4.20 of T&SC v1.2 summarise the technical offer structure while Table 13a in T&SC Appendix C describes the technical offer data transaction. Additional technical parameters are specified in Agreed Procedure (AP) 4.

Key technical offer parameters for thermal generators include availability profiles, ramp rates, minimum stable generation levels, and minimum on / off times. As shown below, these parameters can all represented within PLEXOS. The T&SC defines numerous additional parameters such as Synchronous Start up Times, Dwell Times and Soak Times, some of which are not modelled within the current release of PLEXOS. However, we would not expect all the technical parameters specified in the T&SC to have a bearing on the market schedules and shadow prices produced by the EPUS software. This is because some of the parameters that are presumably required for ex-ante minute-by-minute dispatch by the system operators are not likely to be relevant for ex-post pricing at the trading period level. For example, start up and notice times should become moot for ex-post modelling, while dwell / soak times would be expected to be immaterial when modelling hourly or half-hourly blocks rather than minutes.

Since T&SC v1.2 does not identify a subset of the technical offer parameters for consideration in EPUS, our review has included all the parameters specified in T&SC Appendix C for completeness. The following table lists the T&SC technical offer data items and the equivalent variables in PLEXOS:

TS&C Variable	TS&C Notes	PLEXOS Variable	PLEXOS Notes
Minimum on time		Min Up Time	
Minimum off time		Min Down Time	
Synchronous Start up Time Cold / Warm / Hot		[Not modelled]	Notice times not relevant when simulating ex-post pricing rather than ex-ante dispatch.
Time to synchronise		[Not modelled]	
Ramp up rates and breakpoints, dependent on warmth state		Max Ramp Up	Static or variable across output range (up to 100 bands) Warmth state dependency not modelled.

TS&C Variable	TS&C Notes	PLEXOS Variable	PLEXOS Notes
Block Load Cold / Warm / Hot	Represents the amount that generators instantaneously put onto the system when Synchronised	Generally modelled block loading at Min Stable Level (by choosing not to model unit run up and down). Minimum load could be used to specify an alternative block load level.	The Production Ramp Includes Run Up and Down property toggles on/off consideration of generation between zero and Min Stable Level
Deload Break Point		Multiple bands of Max Ramp Down can be specified for load points below Min Stable Level if required.	The Production Ramp Includes Run Up and Down property toggles on/off consideration of generation between zero and Min Stable Level.
Deloading Rates (1)-(2)			
Dwell Times (1)-(3)	Time above Minimum Stable Generation for which a Unit remains at a constant MW level before continuing to increase or decrease output	[Not modelled] If required, a potential workaround would be to define a load point at the dwell time trigger point with lower ramp up / down rates.	Data validation exercise has not examined dwell times, but unlikely to be material when modelling one hour trading periods.
Dwell Time trigger points (1)-(3)			
End Point of Start Up Period	AP4: "This is not utilised in the systems. This can be left as NULL in the transaction"	[n/a]	
Load Up Break Points Cold (1)-(2)		Multiple bands of Max Ramp Up can be specified for load points below Min Stable Level if required. Warmth state dependency of run up rates is not modelled.	The Production Ramp Includes Run Up and Down property toggles on/off consideration of generation between zero and Min Stable Level.
Load Up Break Points Hot (1)-(2)			
Load Up Break Points Warm (1)-(2)			
Loading Rates Cold (1)-(3)			
Loading Rates Hot (1)-(3)			
Loading Rates Warm (1)-(3)			
Minimum Generation		Minimum load sets a minimum unit dispatch level subject to unit availability, Min Stable Level is the minimum stable generation level	

TS&C Variable	TS&C Notes	PLEXOS Variable	PLEXOS Notes
Maximum Generation		Max Capacity	
Ramp Down Break Points (1)-(4)		Load Point	
Ramp Down Rates (1)-(5)		Max Ramp Down	Static or variable across output range (up to 100 bands) [See Ramping paper for details]
Ramp Up Break Points (1)-(4)		Load Point	
Ramp Up Rates (1)-(5)		Max Ramp Up	Static or variable across output range (up to 100 bands) [See Ramping paper for details]
Soak Time Cold (1)-(2)	Time below Minimum Stable Generation for which a Unit remains at a constant MW level before continuing to increase or decrease output.	[Not modelled] If required, a potential workaround would be to define a load point at the soak time trigger point with lower ramp up / down rates.	Data validation exercise has not examined soak times, but unlikely to be material when modelling one hour trading periods. Soak times would only relevant if modelling unit run-up and run-down.
Soak Time Trigger Point Cold (1)-(2)			
Soak Time Hot (1)-(2)			
Soak Time Trigger Point Hot (1)-(2)			
Soak Time Warm (1)-(2)			
Soak Time Trigger Point Warm (1)-(2)			
Hot Cooling Boundary		Start Times	Denotes the incremental number of hours between warmth states
Warm Cooling Boundary			
Under Test Start Date		[Not modelled]	
Under Test End Date			
Forecast Availability Profile for each TP in the Optimisation Time Horizon		Rating overrides the Max Capacity, allowing periodic adjustments to a generator's capacity without affecting the calculation of the installed capacity.	

TS&C Variable	TS&C Notes	PLEXOS Variable	PLEXOS Notes
Forecast Minimum Output Profile for each TP in the Optimisation Time Horizon	AP4: (e.g. Pump Storage = Negative value for Pumping Units, all thermal units = 0, Interconnector Units = Maximum Export Capability)	Minimum load sets a minimum unit dispatch level subject to unit availability	
Forecast Minimum Stable Generation Profile for each TP in the Optimisation Time Horizon	Registered value & profile by Trading Period	Min Stable Level ("MSL")	
Nomination Profile	Variable Price Taker Generator Units only	Fixed load	
Maximum Reservoir Capacity	Pumped Storage Units only	Max Volume for Head Storage and Tail Storage	
Minimum Reservoir Capacity		Min Volume for Head Storage and Tail Storage	Optional parameter. May also specify Initial Volume.
Pumping capacity		Pump Load	Pump Units (if pump / generation configuration differ) and Min Pump Load (equivalent to generation MSL) are optional pumped storage parameters
Energy Limit	Energy Limited Generator Units only	Daily limits may be manually specified using either energy constraints (GWh) or Max Capacity Factor.	For longer term modelling, generally preferable for PLEXOS to optimise the output of energy-limited plant over a longer horizon (e.g. monthly) and then decompose to daily constraints. [See Special Cases]
Energy Limit Factor	A factor between zero and one applied to the Energy Limit to calculate the scheduled output of Energy Limited Generator Units between the end of the Trading Day and the end of the Optimisation Time Horizon. Restricted to 0.25 by T&SC¶5.86C.		
Energy Limit Start	06:00 on the Trading Day	[n/a]	Day Beginning defines the start of the trading day in PLEXOS.
Energy Limit Stop	06:00 on the next Trading Day		
Max Ramp Down Rate	Demand Side Units only	Purchaser properties such as ramp rates analogous to generators	Not relevant since not modelling demand side participation in SEM
Max Ramp Up Rate			

<table>
<tr><th>TS&C Variable</th><th>TS&C Notes</th><th>PLEXOS Variable</th><th>PLEXOS Notes</th></tr>
<tr><td>Minimum Down Time</td><td rowspan="2"></td><td rowspan="2"></td><td rowspan="2">energy market</td></tr>
<tr><td>Maximum Down Time</td></tr>
<tr><td>Aggregate Import Availability</td><td rowspan="4">Interconnector Agent only</td><td rowspan="2">Dependent on how interconnector modelled: e.g. Max Flow and Min Flow for lines, Max Sales and Max Purchases for external markets</td><td rowspan="3">See Special Cases section</td></tr>
<tr><td>Aggregate Export Availability</td></tr>
<tr><td>Aggregate Ramp Rate</td><td>Dependent on how interconnector modelled</td></tr>
<tr><td>Interconnector Unit Capacity Holding Data</td><td>[Not modelled]</td><td>Not relevant since modelling interconnector in aggregate</td></tr>
<tr><td>Maximum Interconnector Unit Import Capacity</td><td rowspan="2">Interconnector Units only</td><td rowspan="2">[Not modelled]</td><td rowspan="2">Not relevant since modelling interconnector in aggregate</td></tr>
<tr><td>Maximum Interconnector Unit Export Capacity</td></tr>
<tr><td>Short Term Maximisation Capability</td><td></td><td>[Not modelled]</td><td></td></tr>
</table>

One potential PLEXOS discrepancy with T&SC v1.2 identified in the table above is that ramp up rates in PLEXOS are not dependent on warmth state. However, we presume that "Ramp up rates and breakpoints, dependent on warmth state" in the T&SC is a typo and that ramp rates will not in fact depend on warmth state for output ranges above the Min Stable Level (MSL)[6].

Ramp up rates below MSL – termed "Loading Rates" in the T&SC – are also defined to be dependent on warmth state in the T&SC. This potential PLEXOS discrepancy would only be relevant if unit run up / down to and from MSL is modelled – as discussed below, we recommend maintaining the PLEXOS default setting of not modelling generator run up /down between zero and MSL.

Additional "Technical Offer" parameters in AP4 (v3.0) Appendix 2, Unit (Resource) Data & Generator Offer Data include:

6 Ramp Up rates (1) to (5) do not appear to be warmth state dependent in T&SC v1.2 Table 13a.

AP4 Variable	AP4 Notes	PLEXOS Variable	PLEXOS Notes
Start Forbidden Range (1)-(2)	MW level where restricted loading range starts. Unit must move through this range as quickly as possible.	Rough Running Point marks the start of a rough running range of output levels that must be avoided	Rough running ranges are only modelled on single unit generators (these properties will be ignored for multi-unit stations). Multi-band feature allows more than one rough running range on a unit.
End Forbidden Range (1)-(2)	MW level where restricted loading range ends. Unit must move through this range as quickly as possible.	Rough Running Range is the length of the range	

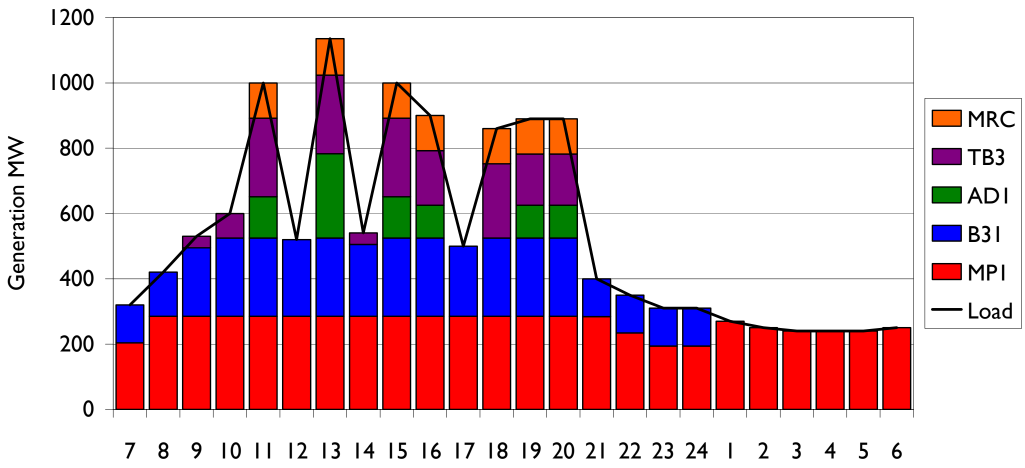
In this section, we focus on the technical constraints relating to Price Maker Generator Units, and in particular thermal plant. The "Special Cases" section describes the modelling of price takers and non-thermal units such as wind, hydro, pumped storage and interconnectors.

2.2.2 Short Term Constraint Tests

In order to validate PLEXOS' handling of the constraints captured within generators' technical offers, we created a series of unit tests to review each constraint in turn. The tests were designed to create situations in which the constraints were limiting (such as a plant that would be dispatched based on cost but limited by ramp-up rates). In each case, we reviewed the resulting generator schedules to check that the constraints were not breached.

Our initial testing modelled a simplified five generator system for a single trading day (plus look-ahead period). Here we present the generator schedules and key observations for each model run:

1. ***Model Run: No constraints, no start costs***



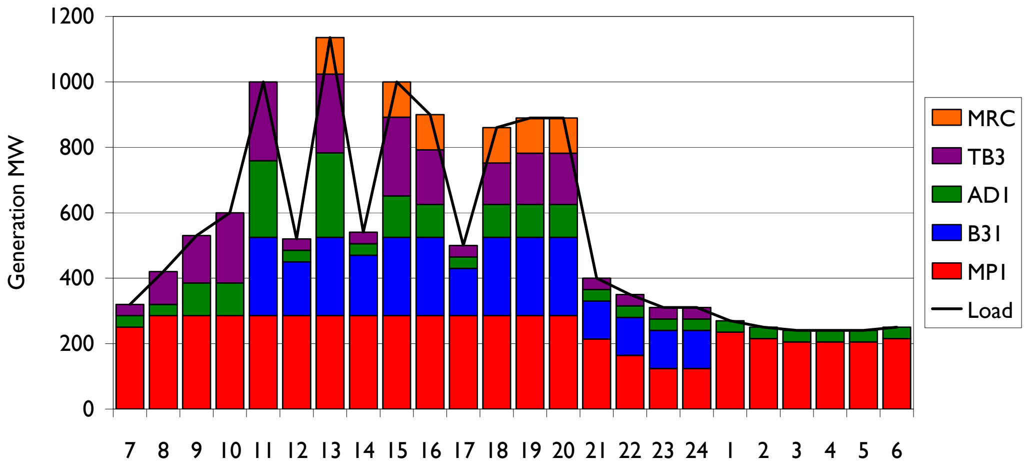
Comments:

– For this baseline run, Min Stable Level (MSL)[7] was the only generator constraint.

– Multiple starts for MRC (4), TB3 (3) and AD1 (4).

– MP1 displaced in shoulder periods (e.g. 7, 22 - 24) to accommodate B31 running at MSL.

2. *Model Run: No constraints*



Comments:

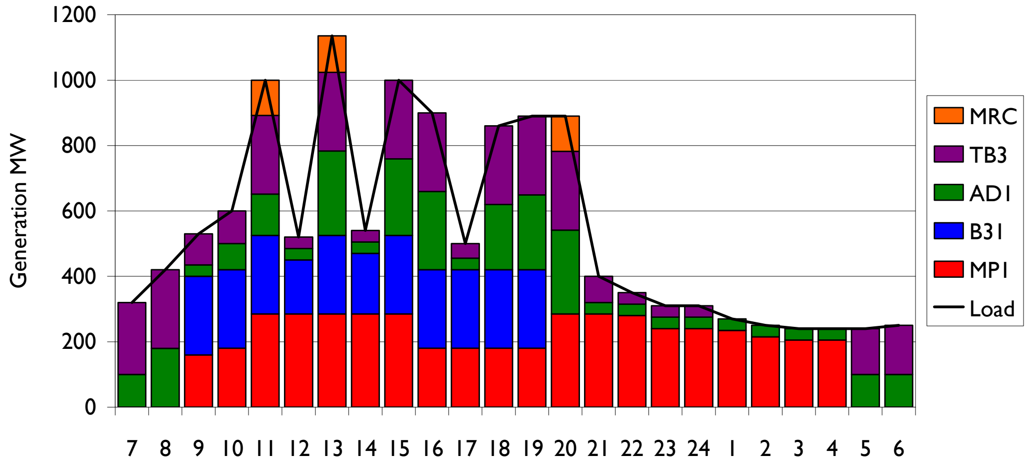
– Fewer starts for MRC (3), TB3 (0) and AD1 (0) due to inclusion of start costs.

– Unless initial conditions are specified or rolled over from a previous modelling run, PLEXOS ignores start costs for plant operating in the first period since these are assumed to have started already.

– B31 has a significantly lower start cost than the other units in this test. AD1 and TB3 have relatively high SRMCs but are scheduled in preference to B31 in periods 7 to 10, thereby avoiding their higher start costs. AD1 also stays on overnight (periods 1 to 6) to avoid starting up in the look-ahead period.

[7] Omitting MSL would remove the integer constraint from the unit commitment problem - the resulting linear solution may not provide a useful baseline for comparison.

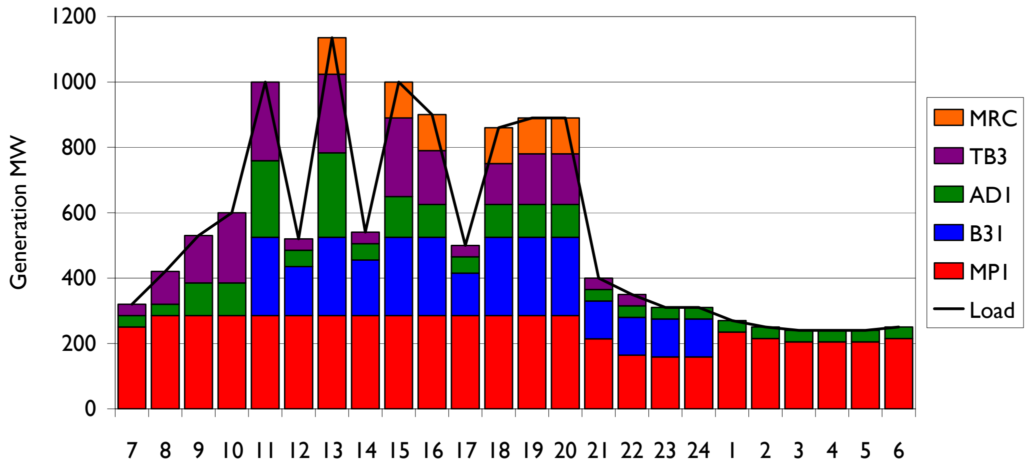
3. Model Run: Availability Profiles



Comments:

- B31 availability profile specified by time slice (max capacity PEAK, zero OFF-PEAK).
- MP1 availability specified with hourly profile.
- Validated that PLEXOS observes time-varying availability profiles.

4. Model Run: Min Stable Level Profiles



Comments:

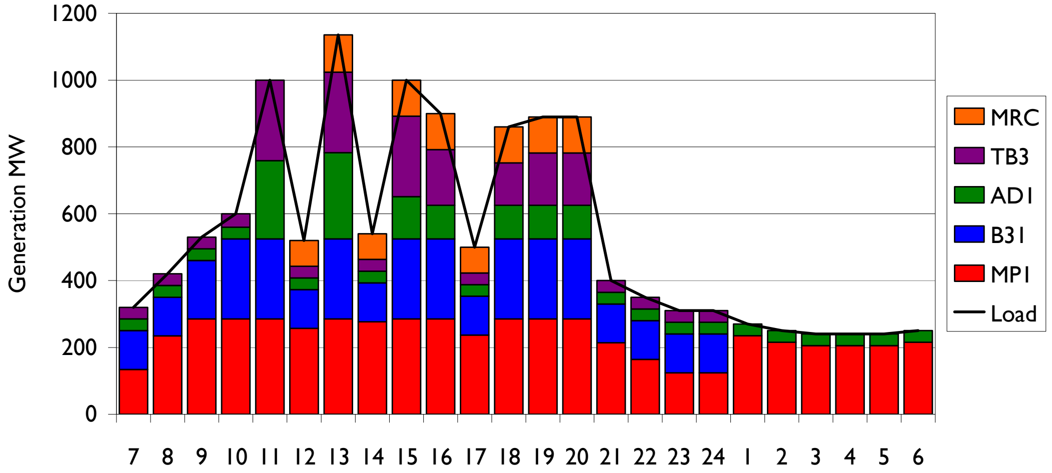
- AD1 MSL profile specified by time slice (50 MW PEAK, 35 MW OFF-PEAK).

– MP1 MSL specified with hourly profile in external file ("MP1 MSG.csv").

– MRC MSL flat at 110 MW (vs. 77 MW in base run).

– Validated that PLEXOS observes time-varying MSL profiles.

5. *Model Run: Min Up Time*

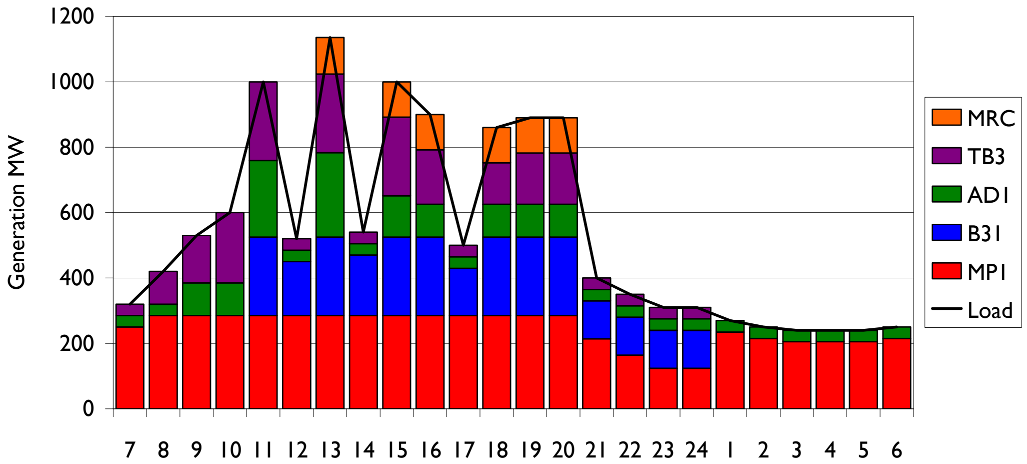


Comments:

– Fewer starts for MRC (1) due to Min Up Time constraint of 2 hours.

– Validated that PLEXOS observes Min Up Time constraints (ranging here from 2 hours for MRC to 10 hours for B31).

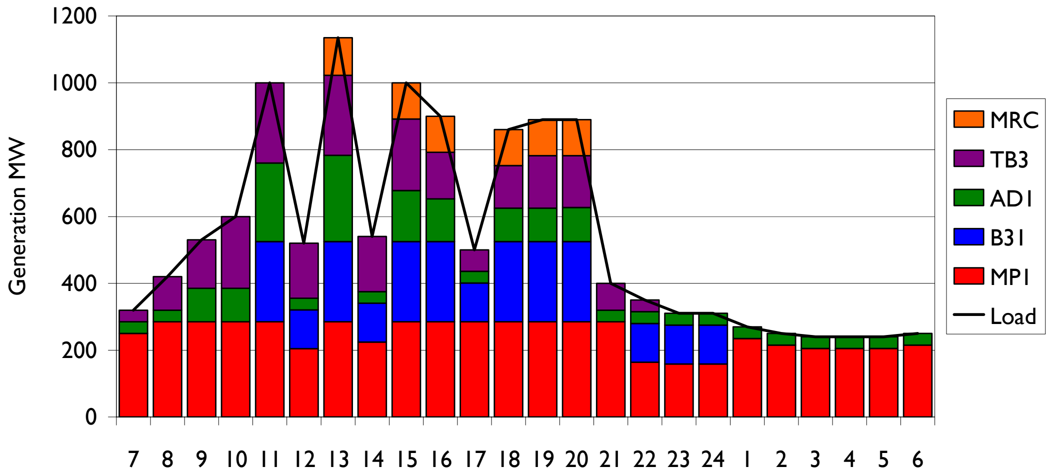
6. *Model Run: Min Down Time*



Comments:

- Unchanged starts for MRC (3) since Min Down Time of 1 hour is not binding.
- Validated that PLEXOS observes Min Down Time constraints (ranging here from 1 hour for MRC to 8 hours for B31).

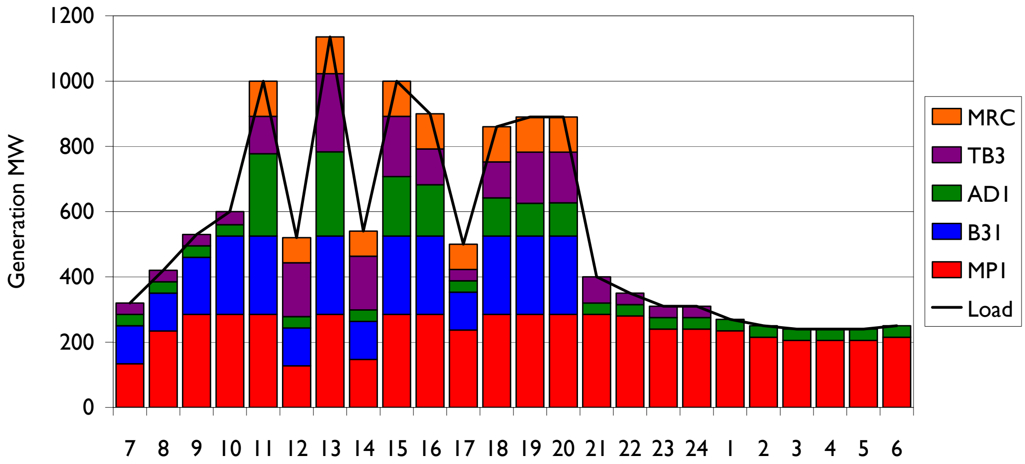
7. Model Run: Ramp Rates



Comments:

- Only TB3 has binding ramp rates among the five units in this data set, given the model assumption of an hourly trading period and ignoring run-up / run-down below MSL (i.e. TB3's ramp up and ramp down rates prevent it moving between MSL and max capacity within an hour).
- TB3 dispatched at higher output levels in shoulder periods (e.g. 12, 14, 21) in order to ramp up for adjacent peaks.
- Validated that PLEXOS observes Ramp Up and Ramp Down constraints.
- Significantly higher shadow price observed at the peak in this run (158.2 €/MWh in period 13 compared to 91.9 €/MWh in all previous runs). The reported SRMC of the most expensive generator in this period (MRC) is 91.9 €/MWh. This example of ramp rate constraints impacting prices is discussed further in the "Shadow Prices" section.

8. *Model Run: All dynamic constraints*



Comments:

- Ramp rate, Min Up Time and Min Down Time constraints have clearly changed the schedule compared to the baseline.

- As in the previous run with ramp rates, the shadow price in the peak period is above the SRMC of the most expensive generator.

Having confirmed that PLEXOS handled generator constraints in a simplified system, we developed a spreadsheet tool to validate generator dynamic constraints from annual PLEXOS model runs for the full all-island system.

In each case that we have examined, the PLEXOS schedules do not breach the input generator constraints.

It should be noted that the handling of generator dynamic constraints within PLEXOS is influenced by the choice of other model parameters such as the trading period duration and the run up / down property:

- ***Trading Period Duration***: We have generally modelled hourly trading periods, consistent with the AIP Loop 2 modelling. In our starting data set (AIP Loop 2), very few of the generator units have binding ramp rates at this resolution. Switching to a half hourly trading period would result in ramp rates becoming binding for additional generators, and may also change the impact of Min Up and Min Down time constraints. We compare model results with hourly and half-hourly trading periods in the following section.

– ***Run Up / Down***: By default, PLEXOS does not model unit run up from zero to MSL or run down below MSL. This means that in their first period of operation, units can effectively block load at MSL and can then continue ramping. We have observed cases in which generator units have appeared to breach our ramp rate checks by jumping from zero output to (MSL plus max ramp) between trading periods: our ramp constraint check looks for changes in output greater than the max ramp rate. For example, if the max ramp up is 1MW/min and MSL is 10MW, the unit can reach an output level of 70MW starting from zero in the previous hour. Unit run up and run down can be modelled within PLEXOS by changing the Production Ramp Includes Run Up and Down model property, as described below.

The T&SC v1.2 does not explicitly state if unit run up and run down will be modelled by the EPUS software. Our understanding from informal discussions with EirGrid is that the Unconstrained Unit Commitment (UUC) software will block load units to/from MSL regardless of their run up / down rate. In other words, having made the commitment decision to schedule a unit on or off, the economic dispatch does not consider the output range between zero and MSL. This implies that it would not be appropriate to model unit run up / down in PLEXOS.

The AIP Modelling Project applied the default PLEXOS setting of not modelling unit run up / down. To examine the materiality of this assumption, we switched on the Production Ramp Includes Run Up and Down property and compared the results to our baseline run. We observed a number of anomalies which reinforce our recommendation not to model unit run up / down in the current PLEXOS release:

– Significant spikes in Uplift were observed due to plant running below MSL recovering their no load and start costs from low output levels. The current PLEXOS release provides the option to filter out plant from the Uplift algorithm if they are only running at MSL (see Section 2.6.2) but this filter does not apply to plant running below MSL.

– Occasionally plant were observed to start running at levels below MSL and then switch off without ever reaching MSL during the period of operation.

– It was not readily apparent how the Min Up Time and Min Down Time constraints were being applied during run up and run down periods.

Finally, there may be a data consistency issue for start costs depending upon the setting of Production Ramp Includes Run Up and Down property. If unit run up and down is modelled then the fuel Offtake at Start should equal only the additional fuel used to start not reflected in the unit's heat rate.

Conversely, if run up and down are ignored, then it could be argued that Offtake at Start should equal the total fuel used during run up and down[8].

2.3 Unit Commitment Review

In the previous two sections, we verified that PLEXOS can replicate the commercial and technical offer structure for conventional, thermal generators or "predictable price makers" in T&SC terms. We next sought to validate PLEXOS' handling of other generator types including "price takers" and "special units" such as wind, hydro, interconnectors and pumped storage. However, before we present the "Special Cases" analysis, it is worth reviewing how unit commitment is modelled in PLEXOS.

2.3.1 T&SC Comparison

In the SEM, the market schedule and shadow prices will be determined on a daily basis by optimising unit commitment and dispatch over a time horizon comprising the Trading Day plus a 6 hour look-ahead period. The T&SC v1.2 Glossary defines the Optimisation Time Horizon as the "Thirty hour period starting at 06:00hrs on the Trading Day". Market schedule quantities and prices are established for each half-hourly Trading Period, defined as "a thirty minute period beginning on each hour or half-hour".

PLEXOS is a multi-purpose modelling tool capable of simulating power system operations over timescales ranging from several decades to less than a day. It therefore provides considerable flexibility in defining modelling time horizons, as well as a suite of scheduling modules that can be applied individually or in combination as appropriate for the particular study. For example, PLEXOS may be applied to optimise capacity expansion decisions (for longer term planning studies) or to optimise maintenance planning on a system-wide basis (if planned outage schedules are not specified manually as inputs). In this SEM project, the two PLEXOS scheduling modules of interest are the mid-term (MT) Schedule and short-term (ST) Schedule:

- The ST Schedule offers the most comprehensive treatment of unit commitment decisions and inter-temporal constraints, and is suitable for shorter term optimisation horizons (e.g. a day or a week).
- The MT Schedule provides a simplified treatment of unit commitment and generator constraints, and can be applied to longer term optimisation horizons (e.g. a month or a year).

ST Schedule is the appropriate PLEXOS algorithm to emulate market-clearing engines such as the SEM EPUS software. Later in this section we describe how PLEXOS can be configured to replicate the SEM Optimisation Time Horizon.

[8] This adjustment would not be trivial for units whose start fuel differed to their primary fuel.

Although the PLEXOS ST Schedule can be run for a single trading day, typically we are interested in simulating schedule and price outcomes for several days, weeks or months. When the ST Schedule is run for multiple days, each step – a day plus look-ahead period in this case – will still be optimised independently. However, the state of the system (e.g. each generator's final on/off status and output level) is rolled over from one step to the next, thereby defining the initial conditions for the next optimisation period. This is consistent with the T&SC description of how initial conditions are treated in the EPUS software, as stated in T&SC v1.2 Appendix N.12:

> "*Each Ex-Post EPUS Software Run in respect of a Trading Day will take starting conditions from the results of the Preceding EPUS Run. Specifically, the initial conditions at 06:00 on the Trading Day will be taken from the results at the same point in time that were produced by the Preceding EPUS Run that is used in Settlement*."

The PLEXOS ST Schedule alone would be sufficient to simulate the all-island market if we were only concerned with modelling conventional, thermal generator units without constraints on fuel availability or emissions. For such generators, there are no inter-day dependencies to consider other than the rollover of initial conditions each day. In reality, however, some SEM participants will need to optimise the commercial operation of their generation units over longer time horizons. Hydro units, for example, do not have unlimited availability to generate at full capacity, and so water usage on one day will reduce generation availability on subsequent days. Similar inter-temporal considerations are faced by thermal plant whose output is limited by annual emission limits or fuel availability.

In the AIP Modelling Project, the PLEXOS MT Schedule has been applied to handle these longer-term constraints on plant operation. The MT Schedule is run to optimise generation resources over a longer term horizon such as a year. PLEXOS then uses the results of the MT Schedule to decompose mid-term constraints – for example, monthly hydro energy limits or annual SO_2 emission limits – into daily constraints for consideration by the ST Schedule. The pain-staking manual alternative to utilising the PLEXOS MT Schedule would be to estimate the availability of each energy-limited generator unit for each day of the year and then input these values to the ST Schedule. Later in this section we describe the configuration of PLEXOS MT Schedule, while the modelling of energy-limited generation is addressed in the "Special Cases" section.

Like the SEM EPUS software, the PLEXOS ST Schedule aims to minimise the cost of meeting demand over the Optimisation Time Horizon subject to the constraints of generator availability and technical offer capabilities (ramp rates, etc). Paragraph 4.49 of T&SC v1.2 describes the objective function of the EPUS software

> *"When producing a Unit Commitment Schedule or Market Schedule Quantities, the objective of each run of the EPUS Software is to minimise the aggregate sum of Schedule Production Cost over the Optimisation Time Horizon, subject to the following constraints:*

1. to schedule Output by Price Maker Generator Units to match, in aggregate, Schedule Demand (as defined within Appendix N for the relevant run of the EPUS Software), in each Trading Period within the Optimisation Time Horizon;

2. to schedule each Price Maker Generator Unit at a level of Output between its Minimum Output (MINOUTuh) and its Actual Availability (AAuh); and

3. to schedule each Price Maker Generator Unit within the additional Technical Capabilities given within its Minimum Stable Generation (MINGENuh) and Technical Offer Data, including without limitation, Ramp Rates, Minimum On Times and Minimum Off Times, with consideration given to the Warmth State."

The calculation of "Schedule Production Cost" is outlined in Appendix N.24 of T&SC v1.2:

"Within this Appendix N and within the EPUS Software, the EPUS Schedule Production Cost (ESPCuh) for each Price Maker Generator Unit u in Trading Period h is calculated as follows (noting that within the EPUS Software, transmission losses are not explicitly taken into consideration):

$$ESPCuh = ((MSQuh \times MOPuh) + MNLCuh + MSQCCuh) \times TPD + MSUCuh$$

Where

*1. **MSQuh** is the Market Schedule Quantity for Generator Unit u in Trading Period h*

*2. **MOPuh** is the Market Offer Price of Generator Unit u in Trading Period h*

*3. **MNLCuh** is the Market No Load Cost for Generator Unit u in Trading Period h*

*4. **MSQCCuh** is the Market Schedule Quantity Cost Correction for Generator Unit u in Trading Period h*

*5. **TPD** is the Trading Period Duration*

*6. **MSUCuh** is the Market Start Up Cost for Generator Unit u in Trading Period h"*

Our understanding is that the inclusion of the MSQCC cost correction term ensures that the Schedule Production Cost is based upon the volume-weighted average incremental price of a generator unit operating at MSQ rather than simply the last accepted incremental price (the Market Offer Price).

In PLEXOS, the optimisation problem is dynamically constructed at run-time based on the inputs provided by the user. Thus, incremental costs, no load costs, start costs and VOM costs will all be included in the objective function if these costs have been specified. The schedule production cost considered by PLEXOS is equivalent to that defined in the T&SC with the MSQCC term, taking due account of the complete incremental cost curve.

Note the important distinction between the objective function and SRMC as to which costs are included:

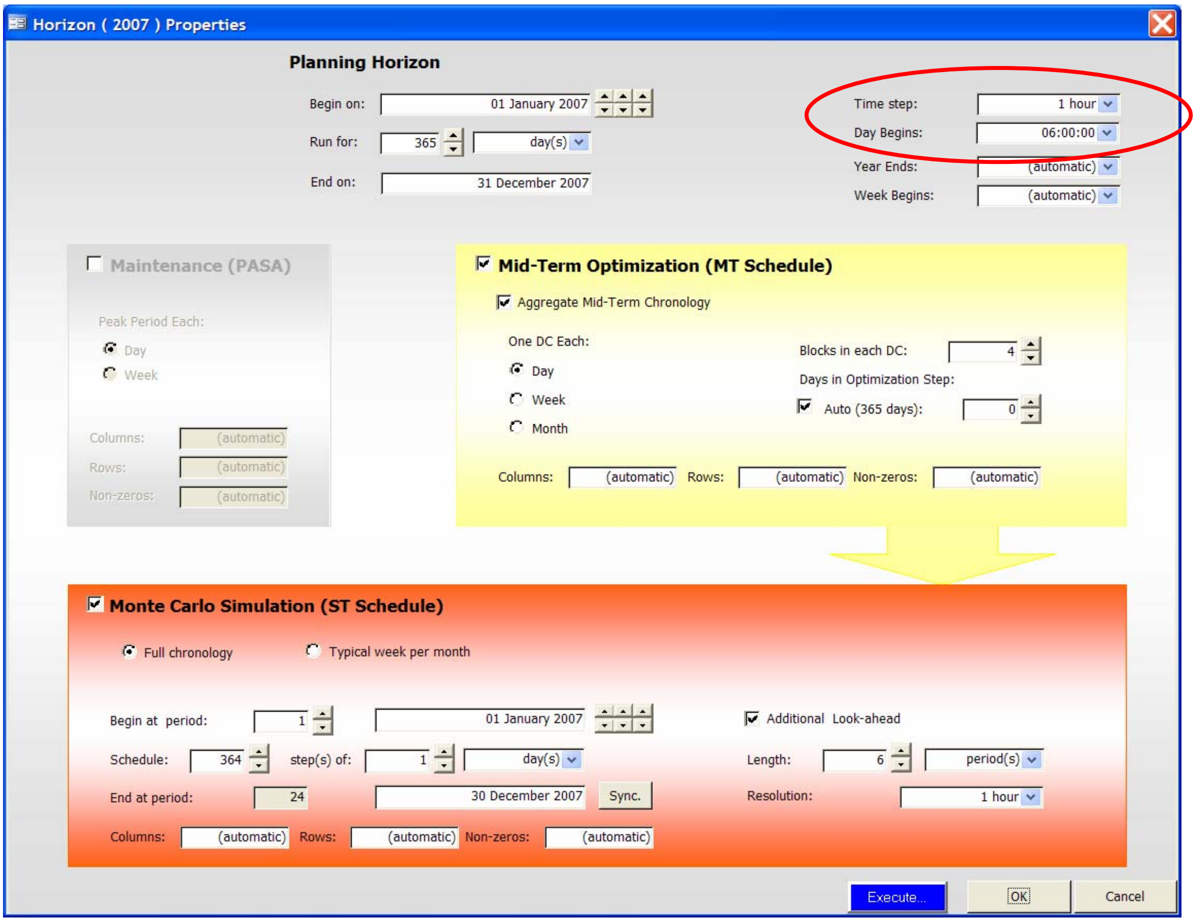
– ***Objective Function***: In both PLEXOS and the EPUS software, the objective function to be minimised by the optimisation engine comprises average incremental costs, no load costs and start costs.

– ***SRMC***: As illustrated previously, SRMCs in PLEXOS – and by extension shadow prices – are based upon the marginal incremental costs at the scheduled output level, and exclude no load and start costs. This is consistent with the T&SC definition of shadow prices.

Finally, there is a subtle discrepancy between our PLEXOS configuration and the EPUS software arising from the definition of Schedule Demand in the T&SC (Appendix N.6). The EPUS software is only required to optimise the market schedule output of "price maker generator units", with the Schedule Demand being calculated ex-post from the total actual output of price maker generator units. In effect, the output of wind plant and other price takers is netted off actual demand to determine the residual demand to be met by the price makers. This approach would be possible in PLEXOS if the relevant input data were available. However, for an ex-ante modelling exercise, we require PLEXOS to optimise the output of all generators to meet total forecast demand. In theory, PLEXOS could then be re-run with the subset of price maker generators and a residual demand curve, but we would not expect any significant changes in output schedules or prices under this iterative approach.

2.3.2 PLEXOS ST Configuration

The Horizon screen in PLEXOS is used to configure the overall modelling timeframe, the MT Schedule and the ST Schedule:



The circled region in the screenshot above highlights where the trading period duration and the trading day start are configured:

- Trading Periods per Day defaults to 24 (hourly "Time step") but can be set to 48 to model half-hourly dispatch if required. Per the AIP Modelling Project, we have generally modelled hourly trading periods but we have run a sensitivity at half-hourly granularity as described below.

- Day Beginning sets the hour of the day that market trading begins, configured here to 06:00 for consistency with the T&SC.

2.3.2.1 Trading Period Duration

As noted above, the default trading period in PLEXOS is one hour rather a half-hour per the T&SC. To test the materiality of this hourly approximation, we changed the time step in our base 2007 scenario to half-hourly and re-ran the model. Given that our starting data set included hourly profiles for demand, wind rating and BETTA prices, we assumed that these values remained flat within each hour (e.g. we did not seek to estimate half-hourly loads by interpolating the hourly values). We therefore anticipated that any differences we observed in the half-hourly run would be attributable to generator dynamic constraints such as ramp rates and min on/off times. For example, in our starting (AIP Loop 2) data set, we had noted that the ramp rates of the three Moneypoint coal units would become binding within a half hourly trading period. The table below shows the annual time-weighted average prices resulting from the half-hourly and hourly PLEXOS runs[9]:

Trading Period	SMP €/MWh	Uplift €/MWh	Shadow Price €/MWh	Relative PLEXOS run time
Hourly	61.17	7.16	54.01	1.00
Half-Hourly	60.51	6.29	54.22	2.08

The two model runs produced similar prices, with average SMP slightly lower (1%) in the half-hourly scenario. Although shadow prices were around 0.2 €/MWh higher on average in the half-hourly run, this was more than offset by lower Uplift on average. All other factors being equal, we would expect Uplift to be lower on average when shadow prices are higher since infra-marginal plant can recover more of their costs at the shadow price.

In addition to reviewing annual average prices, we compared the time-weighted seasonal[10] average prices for the hourly and half-hourly runs, as well as the averages using the peak and mid-merit definitions that have been specified for Directed Contracts ("DC Peak" and "DC Mid"):

BASE: Hourly							
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**	**DC Peak**	**DC Mid**
SMP	61.17	68.98	56.83	50.90	75.81	103.00	66.39
Uplift	7.16	6.91	7.29	5.85	9.02	25.82	8.22
Shadow Price	54.01	62.06	49.53	45.05	66.79	77.18	58.16

[9] Each model was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set. The results presented at the Final Conclusions Workshop on March 30th were taken from our original trading period sensitivity which assumed Uplift parameters per AIP-SEM-230-06 (α = 0.3, β = 0.7). We have subsequently repeated the sensitivity using the Uplift parameters per AIP-SEM-07-51 (α = 0, β = 1) and the new PLEXOS release (4.898 R5), the results of which are presented here.

[10] The seasonal definitions used here are consistent with the AIP Loop 2 data set: summer is the 7 month period March to September, peak is 08:00 to 19:00 weekdays.

Half-Hourly							
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**	**DC Peak**	**DC Mid**
SMP	60.51	68.24	56.22	49.60	76.08	101.59	65.69
Uplift	6.29	5.94	6.48	4.51	8.82	23.02	7.26
Shadow Price	54.22	62.30	49.74	45.09	67.26	78.57	58.43

Our initial analysis of the trading period duration – assuming the previous set of Uplift parameters – had shown a relatively immaterial change in SMP. Given that the price differentials appeared to be somewhat greater when the new Uplift parameters were applied, we also repeated the trading period sensitivity with the validated 2008 data set to establish whether this would warrant switching to a half-hourly resolution.

The following tables show the time-weighted seasonal average prices resulting from half-hourly and hourly PLEXOS runs[11] using the new data set for the November 2007 to September 2008 period:

BASE: Hourly							
€/MWh	**Total**	**Peak**	**Offpeak**	**Summer**	**Winter**	**DC Peak**	**DC Mid**
SMP	57.33	77.17	46.33	56.23	59.27	80.82	67.24
Uplift	15.13	25.27	9.51	16.19	13.25	26.07	20.65
Shadow Price	42.20	51.90	36.82	40.04	46.02	54.75	46.59

Half-Hourly							
€/MWh	**Total**	**Peak**	**Offpeak**	**Summer**	**Winter**	**DC Peak**	**DC Mid**
SMP	52.26	65.62	44.85	50.69	55.05	73.86	59.31
Uplift	9.51	13.47	7.32	10.10	8.47	17.79	12.13
Shadow Price	42.75	52.16	37.53	40.58	46.58	56.07	47.18

It is observed that Uplift is generally more significant with the new data set which can be partly attributed to the inclusion of non-fuel variable O&M start costs and also to our decision to model multiple warmth states in the new "Base" case. The material difference in Uplift between the hourly and half-hourly runs with the new data set was much larger than we anticipated. Given that our Uplift

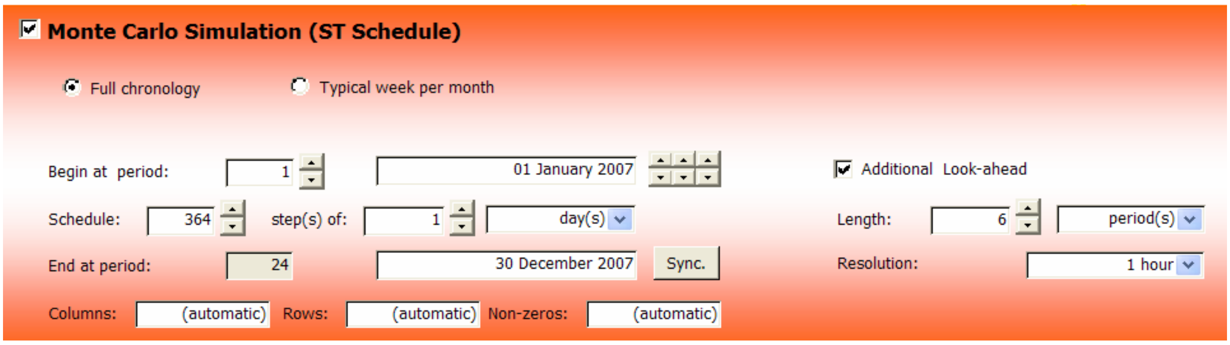
[11] Each model was run in "Rounded Relaxation" mode using the new PLEXOS release (4.898 R5), with demand and generator parameters based upon the validated data set, a base set of fuel price assumptions and Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$).

validation tests had been conducted at the hourly resolution (see Section 2.6.2), we contacted Elan to verify that the PLEXOS SEM Uplift algorithm was fully compatible with non-hourly trading periods. Elan's tests and code review revealed that there was an issue with the PLEXOS SEM Uplift algorithm if the trading period duration was not hourly, potentially leading to cost under-recovery in half-hourly runs. We believe this may explain the significantly lower levels of Uplift observed in the half-hourly runs with the new data set. Elan advises that this issue has subsequently been addressed in PLEXOS 4.898 R14 released on 20th April.

We have not had a full opportunity to validate the operation of the SEM Uplift algorithm with half-hourly trading periods in the latest PLEXOS release (4.898 R14). We also note that our hourly and half-hourly runs did not result in materially different shadow prices. We therefore recommend continuing to model an hourly trading period in PLEXOS as an approximation to the 30 minute trading period duration per the T&SC.

2.3.2.2 ST Step & Look-ahead

The optimisation time horizon for the PLEXOS ST Schedule is configured by setting the ST step size together with a look-ahead period (if selected). The ST Schedule Step Type can be set to weeks, days, hours, or minutes, with the length of each step controlled by the ST Schedule At a Time property. In order to be consistent with the T&SC, we selected a ST step size of one day in our base scenario as illustrated in the screenshot below[12]:



The ST Schedule Look-ahead indicator enables an additional look-ahead period in the ST Schedule. The length of the look-ahead period is configured by the ST Schedule Look-ahead Type and ST Schedule Look-ahead At a Time properties. Again for consistency with the T&SC, we have configured a 6 hour look-ahead in our base scenario. It is also possible to select a lower resolution for the look-ahead period by modifying the ST Schedule Look-ahead Trading Periods per Day property. For example, the look-ahead could be modelled with blocks of two hours compared to an hourly resolution in the trading day in order to make the simulation as fast as possible.

[12] Note that the period numbers in this screenshot are relative to the Day Beginning property set previously, so period 1 corresponds to 06:00.

The AIP Modelling Project also assumed a ST step size of one day. The trading day start was originally set to 00:00 (midnight) in the AIP Loop 1 analysis but then changed to 06:00 for Loop 2. The 6 hour look-ahead feature was not available in PLEXOS when the Loop 2 analysis was undertaken, so the optimisation time horizon was 24 hours rather than 30.

The AIP modelling team reported last year that shifting the PLEXOS model trading day start from 00:00 to 06:00 appeared to cause a number of "edge effects" between days, including unserved energy in the morning load rise. One explanation given for this was that units turned off in the early morning (at the end of a trading day) were unable to turn on for the morning load rise the following trading day due to min down time constraints.

We do not believe that it is absolutely essential that the ST Schedule in PLEXOS is configured to precisely replicate the terms of the T&SC. If inter-temporal constraints such as min down times and ramp rates are a significant feature of the generation data set, any generation optimisation program may struggle to find a feasible solution if the optimisation horizon starts at a time when demand is increasing (e.g. 06:00) rather than when demand is broadly flat or falling (e.g. 00:00).

Considering the special case of pumped storage, a daily optimisation horizon starting at 06:00 implies that generation will largely be dependent on utilising water that was pumped the previous trading day. However, without a look-ahead period, there may not be a strong signal to pump water for the following day. By contrast, if the optimisation horizon starts at 00:00, the decision to first pump and then generate is largely self-contained within the trading day.

There are arguments, therefore, for exploring different ST Schedule configurations such as a 00:00 start or even a weekly ST step size. If an alterative ST Schedule configuration produced a more "credible" or "realistic" schedule, it may be preferable to a configuration that attempts to closely mirror the T&SC. In reality, operators of generation plant such as hydro units and pumped storage will have the opportunity to re-optimise and submit new offers on a daily basis. It is plausible that alternative ST Schedule configurations will be better suited to model such forms of commercial behaviour.

Nevertheless, we recommend that the base scenario ST Schedule configuration is retained for the following reasons:

– We believe that the look-ahead feature in the current PLEXOS release addresses the "edge effect" issues that were observed in the AIP Loop 2 results;

– The Uplift results may become difficult to interpret if the ST step size or look-ahead period is modified, since these ST Schedule parameters are also used by the PLEXOS SEM Uplift algorithm to determine the Uplift optimisation horizon and the carry forward for start costs, etc.

– Any deviation from the T&SC parameters will require strong justification in order to attain "buy-in" from SEM participants, but it is extremely challenging to quantify the "credibility" or "realism" of different output schedules;

– Changing the ST Schedule configuration is likely to effect the optimisation of hydro and pumped storage generation, but there is no comparable operating data available to benchmark the PLEXOS results. For this project, we have not had access to detailed historic data on hydro and pumped storage output to facilitate a comparison of PLEXOS operating profiles with actual performance. Furthermore, past operating performance is unlikely to be a useful indicator of how hydro and pumped storage plant may operate commercially once the new SEM arrangements are introduced.

In order to test the effectiveness of the look-ahead period in the current PLEXOS release, we ran two variants of our base scenario for calendar 2007, firstly with an extended 24 hour look-ahead and secondly with no look-ahead. We then compared these runs to our base scenario with the 6 hour look-ahead. All three runs were based on a daily ST step size and a 06:00 start. The table below shows the annual time-weighted average prices, unserved energy and pumped storage output resulting from the three PLEXOS runs[13]:

Look-ahead Period	SMP €/MWh	Uplift €/MWh	Shadow Price €/MWh	Relative PLEXOS run time	Unserved Energy MWh	Pumped Storage Output GWh
6 Hours [Base]	61.08	6.97	54.12	1.00	0	143.6
24 Hours	59.43	5.38	54.05	1.41	8	162.2
None	69.47	12.74	56.73	1.03	9425	111.6

Significant unserved energy (over 9 GWh) was observed in the no look-ahead run, consistent with the AIP Loop 2 results. No or negligible unserved energy was observed in the two runs with a look-ahead period. It can be seen that pumped storage output increases with the length of the look-ahead period: with a 06:00 trading day start, a longer look-ahead period provides a stronger signal to pump water overnight for use during the peak periods of the following trading day.

As might be expected, the model run time was significantly (40%) longer with the 24 hour look-ahead but average shadow prices were virtually unchanged from the base scenario. Note that the Uplift and

[13] Each model was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$).

hence SMP results presented in this table should be treated with caution since the carry-forward of start costs in the Uplift algorithm is a function of the look-ahead period.

In addition to running sensitivities on the look-ahead period, we also assessed the effect of changing the ST Schedule step size from daily to weekly. The table below shows the annual time-weighted average prices, unserved energy and pumped storage output resulting from the two PLEXOS runs[14] with daily and weekly optimisation horizons:

ST Schedule Step size	SMP €/MWh	Uplift €/MWh	Shadow Price €/MWh	Unserved Energy MWh	Pumped Storage Output GWh
Daily [Base]	61.18	7.17	54.01	0	134.0
Weekly	65.68	12.91	52.78	241	127.2

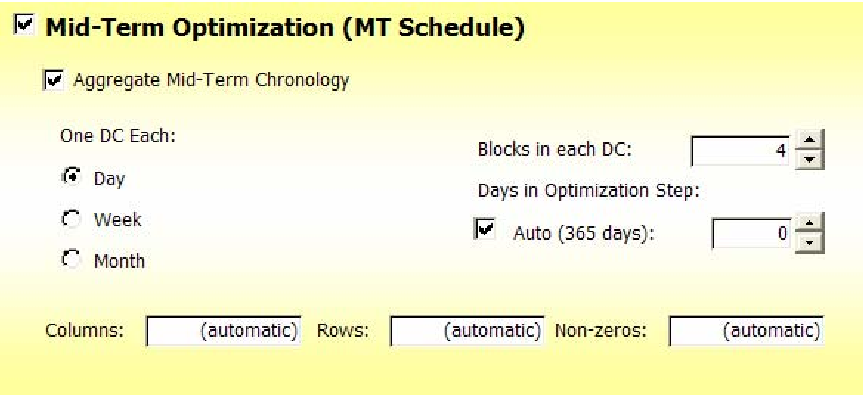
We observed that model results were materially different with a weekly ST Schedule step size compared to the daily optimisation period per the T&SC. As noted above with the look-ahead sensitivity results, the Uplift and hence SMP results presented in this table should be treated with caution since we have not validated how the SEM Uplift algorithm is applied over a weekly optimisation period.

2.3.3 PLEXOS MT Configuration

The PLEXOS MT Schedule uses a reduced chronology to quickly reach solutions that handle longer term constraints such as annual emission limits or seasonal hydro energy limits. The MT Schedule considers each day, week or month as a load duration curve (LDC) made up of a number of load blocks. The solver then schedules generation to meet the load inside these discrete blocks.

The resolution of the LDC is controlled by the properties MT Schedule Step Type and MT Schedule Blocks, as configured via the PLEXOS Horizon screen:

[14] Each model was run for calendar 2007 in “Rounded Relaxation” mode using the new PLEXOS release (4.898 R5), with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$).



After discussions with Elan, we configured the MT Schedule to run with a daily LDC of 4 blocks. For comparison, a monthly LDC of 10 blocks was used for the AIP Loop 2 modelling project. Elan recommended setting the LDC step type to match the ST step type (i.e. daily) to facilitate the decomposition of mid-term constraints into short-term constraints.

Note that the overall resolution of the MT Schedule is limited by the practical bounds on the mathematical problem size for the PLEXOS solver[15] as well as the physical memory available on the modelling computer. Thus, modelling daily LDCs of 24 blocks over an annual optimisation horizon is unlikely to be possible.

In order to test the effect of the MT Schedule configuration in PLEXOS, we ran a sensitivity of our base scenario for calendar 2007 using the AIP Loop 2 setting of a monthly LDC with 10 blocks. The table below shows the annual time-weighted average prices and pumped storage output resulting from the two PLEXOS runs[16]:

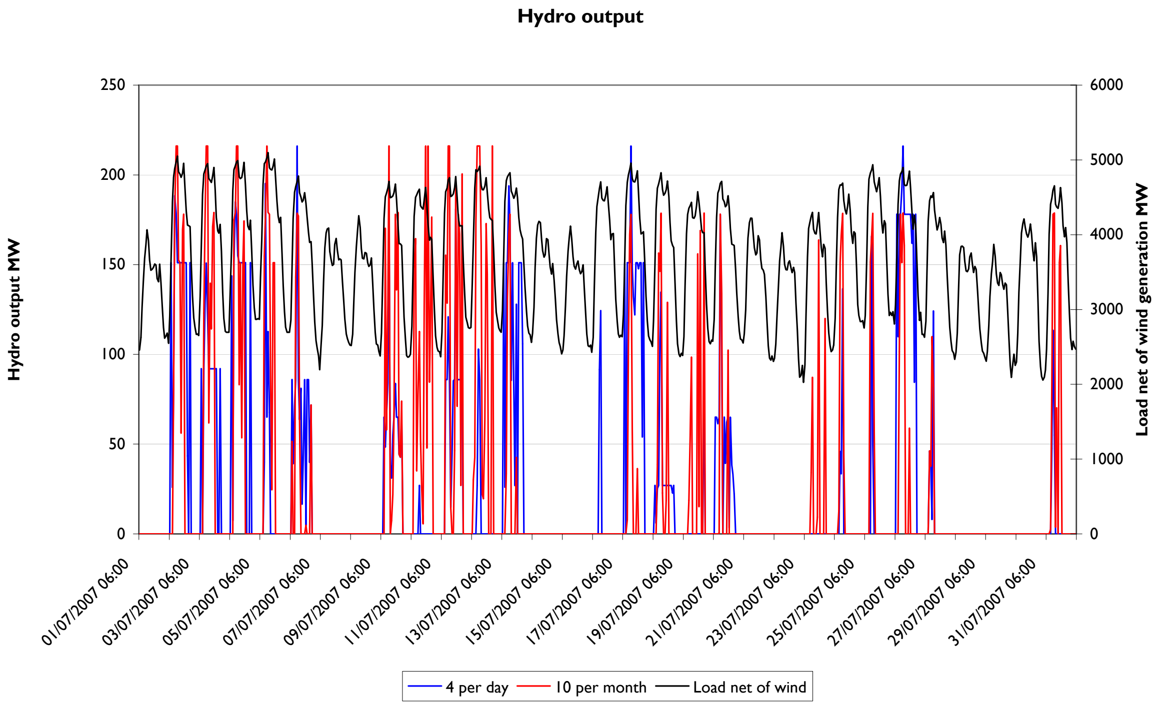
MT Schedule Load Duration Curve settings	SMP €/MWh	Uplift €/MWh	Shadow Price €/MWh	Relative PLEXOS run time	Pumped Storage Output GWh
4 blocks per day [Base]	61.08	6.97	54.12	1.00	143.6
10 blocks per month	61.35	7.29	54.06	1.16	123.5

[15] The MOSEK solver employed by PLEXOS generally performs best when problems have less than one million non-zeros.

[16] Each model was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 (α = 0, β = 1).

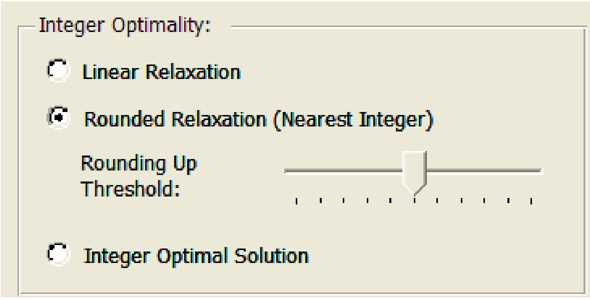
There is little difference observed between these two runs in terms of average prices. Annual pumped storage generation is 20 GWh lower in the monthly LDC sensitivity, implying that our base MT configuration with a daily LDC facilitates a more optimal utilisation of pumped storage assets. As noted previously, we have not had access to detailed historic records of pumped storage and hydro operation for benchmarking the PLEXOS results. Furthermore, it is unlikely that past performance would be a useful guide to the commercial operation of pumped storage and hydro plants under the new SEM arrangements.

In the absence of actual operational data for benchmarking, we compared the hydro operating profiles from the two PLEXOS runs to see whether the MT Schedule configuration had any impact on how the monthly hydro energy limits were handled. For example, the graph below shows the aggregated hydro output in each run during the month of July. Although differences in the dispatch are observed, in both runs the hydro is clearly operating at times of peak demand.



2.3.4 PLEXOS Unit Commitment Configuration

PLEXOS offers a choice of three different methodologies for unit commitment in the ST Schedule, as configured by the Production Unit Commitment Optimality setting:



These three options are described briefly as follows:

Linear Relaxation (LR)

– Integer restriction on unit commitment is relaxed.

– Unit start up variables are included in the formulation but can take non-integer values.

– LR is the fastest to solve but can distort the pricing and dispatch outcomes as semi-fixed costs (start and no load) can be marginal and involved in price setting.

Rounded Relaxation (RR)

– RR integerises the unit commitment decisions in a two-pass optimisation.

– RR is very fast compared to a full integer optimal solution.

– Drayton Analytics and Elan recommend this option for most situations.

Integer Optimal (MIP)

– Unit commitment problem is solved as a mixed-integer program (MIP).

– Unit on/off decisions are optimised subject to two user-defined tolerances, the optimality criteria (MIP Relative Gap) and the time spent solving each ST step (MIP Max Time).

Note that the RR and MIP options both produce completely integer solutions. Both involve multi-pass optimisations, first deriving a commitment schedule (the binary on/off decisions) and then solving for dispatch level.

In this model validation exercise, we have generally run PLEXOS in RR mode, per the AIP Loop 2 modelling project. However, we have run comparative tests of the LR and MIP options. The results of these tests are presented in Section 2.8.

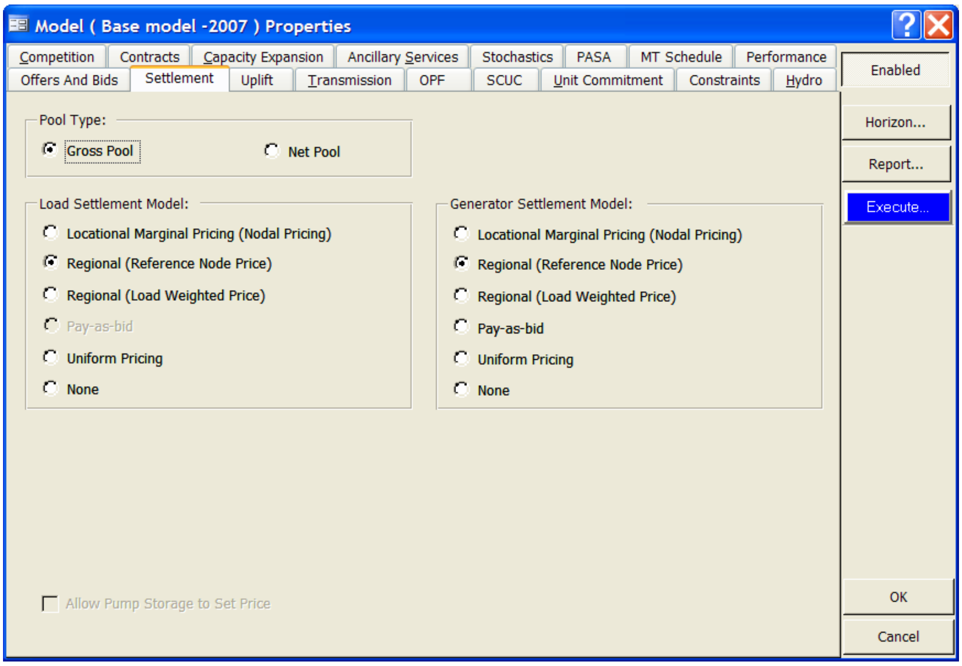
We did not test the LR mode extensively, since the relaxation of integer constraints such as Min Stable Level under this option is inconsistent with the T&SC. We also found in the LR mode that no load and start costs tended to be recovered through the shadow price rather than through Uplift. Our comparison of PLEXOS unit commitment options has therefore focused on the RR and MIP modes. Performance is a key drawback of the MIP option: typically we found that the model run times for annual simulations of the full all-island system were at least 25 times longer for MIP compared to RR.

Finally, in the RR mode, the rounding up threshold is user-configurable. Our recommendation is to start with the default (mid-way) value of 5. Very occasionally, we then lowered the threshold if material unserved energy was observed at the default setting.

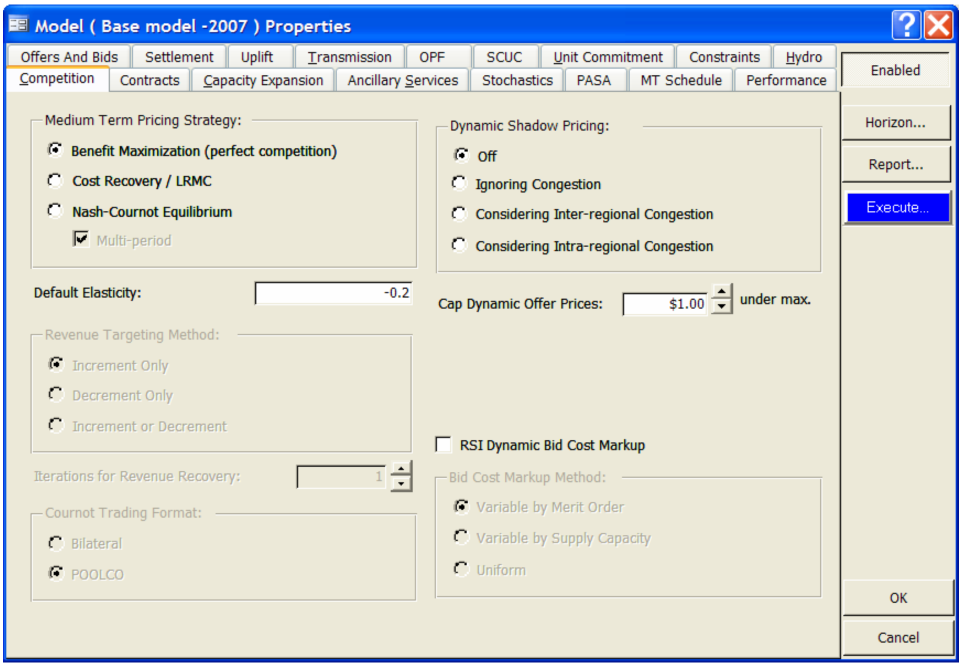
2.3.5 PLEXOS Market Configuration

PLEXOS is a generic power market simulation tool rather than a dedicated model for the SEM. It therefore supports a number of different market design features, including gross pools, net pools, capacity payments, locational marginal pricing and uniform pricing. It also incorporates pricing strategy and game theoretic algorithms that can be applied to explore how generators may recover their long run marginal costs (including returns on capital) by adjusting their offer prices away from short run marginal costs.

The Market Generator Settlement Model in PLEXOS defines what price is paid to generators. The "Regional (Reference Node Price)" setting is appropriate for SEM. Note that if static transmission loss factors (TLAFS) are defined in the model, each generator will receive the loss-adjusted regional reference node price.



Generator pricing strategy is configured by the Competition Equilibrium Model setting in PLEXOS. Given that SRMC Bidding Principles will apply to generators operating in the SEM, the "Benefit maximisation / Perfect competition" is the appropriate setting with "dynamic shadow pricing" switched off. This ensures that generator offers are based on short run marginal costs.



2.3.6 Generation Outages

Generation outages for planned and forced maintenance are likely to have a material impact on schedule and pricing outcomes when considering an extended period such as a year. It is therefore important that both planned and forced outages are incorporated in the modelling framework.

In PLEXOS, planned maintenance events for each generator unit can either be specified manually or optimised by the model given an input maintenance rate. For the AIP Modelling Project, planned outage schedules were determined externally and input into PLEXOS using the Units Out property together with effective dates to specify the start and end of each outage period.

Forced outage events in PLEXOS can be automatically created at random by switching on the Monte Carlo Outage Scope property. The number, timing, and duration of these outages is determined by the simulation engine according to the Forced Outage Rate, the repair time distribution (defined by Mean Time to Repair, and optionally Min Time to Repair and Max Time to Repair), and the outage severity (defined by Outage Rating) specified for each generator unit. The sequence of random outages used in each simulation can be repeated by setting the Monte Carlo Random Number Seed.

The Forced Outage Rate is defined as the fraction of time that the generator unit is expected to be unavailable due to random failures. The duration of each random outage can either be fixed or drawn randomly from a uniform or triangular distribution. For the AIP project, outage durations were fixed by only specifying the Mean Time to Repair for each generator unit. Outage Rating can be used to specify whether outages are partial or total – by default, outages are assumed to be total, as was the case in the AIP project.

Unless otherwise stated, the PLEXOS runs we have conducted in this model validation exercise have not incorporated planned or forced outages, in order to facilitate comparisons between different runs. However, we would recommend that the PLEXOS functionality for planned and forced outages is enabled when running the model to forecast actual outcomes under SEM.

2.4 Special Cases Review

The first part of our review focused on how PLEXOS handled conventional, thermal plant and generally involved running tests on sub-sets of the full all-island generator data set. In this section, we summarise our validation of PLEXOS' handling of other generator types including "price takers" and "special units" such as wind, hydro, interconnectors and pumped storage. For each generator type, we compared any specific terms set out in the T&SC to PLEXOS functionality, and ran unit tests as appropriate. Note that there is no need in PLEXOS to specify the type of each generator, other than as a category label for reporting purposes. Instead PLEXOS infers the type of generator unit from the properties and relationships assigned to it.

2.4.1 Wind

Our understanding is that wind plant will typically be classified under the T&SC as either "Variable Price Taker" or "Autonomous" Generator Units. As set out in T&SC v1.2 paragraphs 5.14 to 5.15, variable price takers will not submit commercial offers but will be required to submit their estimated generation as a "Nomination Profile". In common with other price takers, these plant will not be explicitly modelled by the EPUS software but will have the effect of reducing the residual demand to be met by the price maker generator units.

Wind plant can be modelled in PLEXOS by defining a generator unit and then assigning a rating factor to specify the expected output level. In order to model wind uncertainty, PLEXOS can be configured to simulate stochastic rating factors. Alternatively, a time profile of wind rating factors can be specified by the user to represent the variability in wind output.

In this model validation exercise, we have applied the 365 day * 24 hour profile of wind capacity factors that was developed for the AIP Modelling Project. For simplicity, the wind generator is set up with a Max Capacity of 1 MW and the hourly rating profile defined in an external file with values between 0 and 1. The total installed wind capacity is then defined in PLEXOS by specifying the number of generator units. This property can be date-effective to capture the commissioning of additional units within the modelling timeframe.

A single all-island wind factor profile was applied in AIP Loop 2. Given that we are only concerned with modelling the unconstrained system, we aggregated all the wind farms into a single generator record in PLEXOS in order to streamline the model data set. We understand that regional wind factor profiles are now available for AIP Loop 3, in which case at least one wind generator object per region will be required.

2.4.2 Small-scale Generation

Small-scale generation below a *de minimis* threshold will not be required to participate in SEM pool dispatch and settlement per the T&SC.

Such generation can be considered as netting off total demand. In PLEXOS, this can be achieved using the Fixed Generation property to represent the capacity of small-scale generation across the SEM region (other than small-scale wind projects already included in the installed wind capacity).

2.4.3 CHP & "Must run" Thermal Units

Generator units which have "Priority Dispatch" may chose to register as price takers, and then submit a "Nomination Profile" with their intended output schedule. In the AIP Loop 2 modelling project, the SK1 CHP unit was modelled as "must run" at full capacity. However, during the data validation exercise, it became apparent that this plant intends to operate as a price maker under SEM. There have also been discussions as to whether peat-fired plant should be modelled as "must-run" in order to achieve annual fuel burn targets.

There are a number of ways in which "must run" or "self-dispatch" thermal plant can be modelled in PLEXOS. The Must Run Units property specifies the minimum level of units that must be committed at a generator station – this will ensure that units are committed to run at least at Min Stable Level, but will not fix the dispatch quantity. The generator Fixed load property in PLEXOS is equivalent to the T&SC "Nomination Profile", specifying the schedule quantity for dispatch. Alternatively, a zero Offer Price can be paired with an Offer Quantity to achieve the desired dispatch level.

We ran tests in PLEXOS to validate that the Fixed load property could be used to achieve a time-varying output schedule, and to confirm that the zero Offer Price approach also led to the desired dispatch level.

Fuel-burn targets for peat plant could be modelled in PLEXOS by imposing an annual constraint on fuel-burn (GJ), generation output (GWh) or capacity factor (%). There would be no need to designate the plant as Must Run Units. Instead, the PLEXOS MT Schedule would optimise the peat-fired generation over the year and then decompose the annual limit into daily constraints for the ST Schedule. Note that if annual constraints are included in the PLEXOS model, it is important that the planning horizon for the MT Schedule is set to cover a full year (or years) to ensure that the constraint is properly optimised, even if the ST Schedule is subsequently run for less than a year.

As discussed in the Uplift section later, one issue that we have identified with the current PLEXOS release is that price taker generator units are included in the Uplift cost recovery constraint, contrary to T&SC v1.2. PLEXOS does not currently distinguish between "price taker" and "price maker" generator units in the T&SC sense. As a workaround, we recommend that any thermal plant in the SEM data set that are intended to be modelled as "price takers" should have their no load, fuel and start costs set to zero. This will not change the schedule of plant specified as "must run" but will prevent these generators from influencing Uplift.

2.4.4 Hydro

Per T&SC V1.2 paragraphs 5.84 to 5.87, a hydro plant shall be categorised as an "Energy Limited Generator Unit" if it is a Price Maker subject to a physical Energy Limit. Such generators submit a Trading Day energy limit for consideration by the EPUS software. This limit is also assumed to apply pro-rata (i.e. 25%) to the 6 hour look-ahead period. "Run-of-river" hydro units are categorised as variable generator units.

It is possible to apply daily limits to hydro generators in PLEXOS. However, in practice, it is assumed that energy limited hydro generators have some flexibility to optimise their operations over a longer time horizon. For example, water may be conserved over weekends in order to improve availability at peak times the following week. Consistent with the AIP Modelling Project, we have modelled hydro plant by applying monthly energy constraints. These limits are applied to the hydro station as a whole – so for a station with four separate generator units, the total output of all four units is bound by the monthly limit.

Modelling all the hydro units in this way assumes that the plants are completely free to optimise their output over the month. If in reality some plant have less flexibility in their operations, these restrictions could be handled by modelling additional constraints such as minimum hourly or daily flow limits within PLEXOS.

Incorporating a realistic degree of flexibility for hydro units is a difficult modelling challenge. This is clearly evident upon inspection of our SEM data set. On the one hand, the monthly hydro energy limits give the PLEXOS MT Schedule great flexibility in optimising hydro output day-to-day. On the other hand, all the hydro units in our starting data set (AIP Loop 2) have been defined with Min Stable Levels (MSL) and ramp rate constraints. These constraints limit the flexibility of the ST Schedule in reaching a unit commitment and dispatch solution.

Generally when modelling power systems it is good practice to ensure there is sufficient flexible generation available to accommodate and "work around" the block loading, ramp rates and other constraints typically associated with thermal generator units. Fast-start peaking units (e.g. CTs, GTs), hydro power and pumped storage are often the most flexible sources of generation available to the model optimisation engine (and indeed, the actual system operator) to facilitate system balancing. In the case of the SEM data set, the peaking units, hydro units and pumped storage units have all been specified with MSL constraints, and in some cases (e.g. LI5) binding ramp rates. There is therefore a risk of over-constraining the unit commitment problem, with the result that the model is at times unable to find a feasible solution and/or reports unserved energy.

In reviewing our starting data set, we noted that 11 of the 15 hydro units had been specified with a MSL of 5 MW or less, the lowest value being 0.2 MW. We questioned the materiality of modelling the hydro units with these MSL constraints, given that our modelling granularity is only hourly and none of the hydro units had been specified with binding Min Up Time constraints[17]. We ran some comparative tests[18] in PLEXOS to assess the impact of including MSL and ramp constraints on hydro units in the data set:

[17] One hydro unit (LI4) had a specified Min Up Time of 15 minutes, all the rest had no Min Up Time constraint.
[18] Each model was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-230-06 ($\alpha = 0.3$, $\beta = 0.7$).

Scenario	Pumped storage			Hydro		Unserved energy (MWh)	Infeasibilities
	MSL	Min Pump Load	Rough Running Range	MSL	Ramps		
BASE: relax PS & Hydro dynamic constraints	N	N	N	N	N	0	None reported
Hydro MSL & ramp constraints on	N	N	N	Y	Y	935	None reported

We observed that including MSL and ramp constraints for hydro units resulted in almost 1 GWh of unserved energy over the year. No infeasibilities were reported by the PLEXOS optimiser. We also compared the price results from the runs with and without hydro technical constraints[19]:

BASE					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	59.86	68.20	55.23	49.66	74.42
Uplift	5.71	6.16	5.46	4.41	7.56
Shadow Price	54.16	62.04	49.78	45.25	66.86

Hydro MSL & ramp constraints on					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	60.37	68.46	55.87	50.12	75.00
Uplift	5.89	6.31	5.66	4.74	7.55
Shadow Price	54.48	62.15	50.21	45.38	67.45

A small price increase is observed in the run with hydro technical constraints on. We consider this difference to be largely the result of the shadow price being set at VoLL (=300 €/MWh) in the 15 periods across the year where demand is not meet. These periods would cause a 0.4 €/MWh increase in the annual average shadow price compared to if these periods had been of average shadow price.

[19] The seasonal definitions used here are consistent with the AIP Loop 2 data set: summer is the 7 month period March to September, peak is 08:00 to 19:00 weekdays.

We would generally recommend modelling the hydro plant without MSL and ramp limits, in order to avoid the risk of over-constraining the commitment problem and seeing unserved energy. Note that in our starting data set, start costs were not defined for the hydro units. If hydro start costs are introduced in the new 2008 data set, the decision to relax the MSL constraint on hydro units may be complicated by the potential interaction with Uplift. Plant with start costs but no MSL can lead to Uplift spikes if they are scheduled at low output levels. However, given hydro MSL values as low as 0.2 MW in our starting data set, this is potentially an issue regardless of whether the MSL constraints are relaxed. In practice, Uplift price spikes caused by hydro plant running below 1 MW may well be removed by the SMP price cap. We therefore continue to recommend that hydro plant are modelled without MSL, ramp limits or start costs.

2.4.5 Pumped Storage

The offer format and scheduling arrangements for pumped storage plant are set out in T&SC v1.2 paragraphs 5.91 to 5.98. Pumped storage units are classified as "Predictable Price Maker Generator Units" but do not submit the standard Commercial Offer elements of price quantity pairs, start up costs or no load costs. Instead, pumped storage units submit a Target Reservoir Level for the end of the Trading Day and a Pumped Storage Cycle Efficiency. The Target Reservoir Level is treated by the EPUS software as a lower limit for the reservoir level at the end of the Trading Day (06:00). Pumped storage units also submit a Target Reservoir Level Percentage, fixed at 50% of the Target Reservoir Level, to specify a lower limit for the end of the look-ahead period (12:00). Additional Technical Offer components for pumped storage units include the Maximum and Minimum Reservoir Storage Capacity, and the Forecast Minimum Output Profile to represent the expected pumping capability.

In PLEXOS, pumped storage plant are configured by defining the Head Storage and Tail Storage, together with Pump Efficiency and Pump Load. The reservoir storage capacity limits are specified by the Max Volume and Min Volume properties. Since pumped storage is generally modelled as a closed system, Initial Volume should also be used to specify the head and tail reservoir levels at the start of the modelling timeframe. Pump Load represents the maximum pumping capability. An optional parameter, Min Pump Load, can be specified to set a minimum load while in pump mode, analogous to the Min Stable Level for generation. In common with other generation types in PLEXOS, pumped storage plant can be defined as either a single generator with multiple units or as several single-unit generators. If the pumped storage configuration involves different numbers of pumping and generating units, this distinction can be modelled by defining Pump Units as well as the standard generating Units.

PLEXOS does not currently have a standard property for pumped storage units analogous to the end-of-day Target Reservoir Level in the T&SC. PLEXOS does support user-defined constraints but we have not explored this possibility for pumped storage plant because of the difficulty of manually estimating suitable target levels for each day. Our preference is to give PLEXOS the flexibility to optimise the usage of pumped storage.

As noted in the unit commitment discussion in the previous section, the 06:00 day start effectively means that the pumping of water (typically overnight) and the generation using that water (typically at day-time peaks) are likely to occur on consecutive trading days rather than the same day – i.e. in different optimisation horizons for the ST Schedule. We are therefore reliant upon the look-ahead period (and to some extent the MT Schedule) to signal the value of pumping water for the following trading day.

In our starting SEM data set, the four Turlough Hill pumped storage units had a Max Capacity and Pump Load of 73 MW each, and a Min Stable Level of 5 MW. The head and tail storage reservoirs were shared between the four units. A Rough Running Range or "Forbidden Range" had also been defined, effectively raising the Min Stable Level of each unit to 40 MW. A Min Pump Load of 73 MW has been configured as a scenario variable.

As discussed previously in the context of hydro plant, we were concerned that over-constraining the model with technical limits on plant such as pumped storage would increase the risk of infeasible schedules and unserved energy. In any power system, pumped storage is generally regarded as one of the most flexible forms of generation. Applying all the properties defined in our starting data set would restrict each pumped storage unit to only pump at 73 MW (i.e. no flexibility to pump at any level between 0 and 73 MW) and only generate between 40 and 73 MW.

T&SC v1.2 does not appear to support either the Min Pump Load or Rough Running Range constraints for pumped storage plant. A "Forbidden Range" constraint analogous to the Rough Running Range in PLEXOS is defined in an Agreed Procedure (AP4) but it is not stated whether this constraint is handled by the EPUS software.

We ran some comparative tests[20] to assess the impact of the Min Stable Level (MSL), Min Pump Load and Rough Running Range constraints for pumped storage plant:

[20] Each model was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-230-06 ($\alpha = 0.3$, $\beta = 0.7$).

Scenario	Pumped storage			Hydro		Unserved energy (MWh)	Infeasibilities
	MSL	Min Pump Load	Rough Running Range	MSL	Ramps		
BASE: relax PS & Hydro dynamic constraints	N	N	N	N	N	0	None reported
PS MSL & min pump constraints on	Y	Y	N	N	N	12	Multiple days
PS all constraints on	Y	Y	Y	N	N	78	Multiple days
PS & Hydro all constraints on	Y	Y	Y	Y	Y	1,423	Multiple days

Introducing the additional technical constraints led to the PLEXOS optimiser reporting infeasibilities involving pumped storage constraints on several days. Unserved energy was also observed in each of the constraint scenarios, with the Rough Running Range constraint appearing to have a more significant impact than MSL and Min Pump Load. In our final scenario run, we included the additional constraints for both pumped storage and hydro plant. The result was significant unserved energy at 1.4 GWh.

We also compared the prices resulting from each of these runs:

BASE					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	59.86	68.20	55.23	49.66	74.42
Uplift	5.71	6.16	5.46	4.41	7.56
Shadow Price	54.16	62.04	49.78	45.25	66.86

PS MSL & min pump constraints on					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	59.99	68.31	55.37	49.77	74.58
Uplift	5.83	6.41	5.51	4.55	7.66
Shadow Price	54.16	61.90	49.86	45.22	66.92

PS all constraints on					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	60.29	68.71	55.61	50.16	74.74
Uplift	5.82	6.14	5.64	4.66	7.47
Shadow Price	54.47	62.57	49.97	45.50	67.27

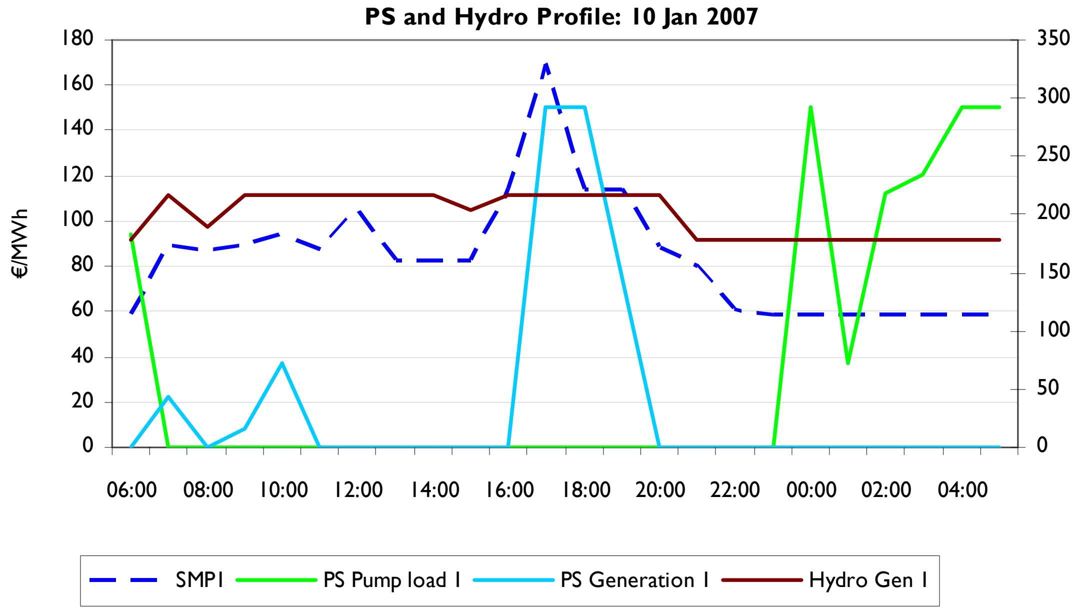
PS & Hydro all constraints on					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	61.99	68.96	58.12	51.13	77.49
Uplift	5.89	6.10	5.77	4.84	7.38
Shadow Price	56.11	62.86	52.35	46.29	70.12

As for the run with hydro technical constraints on, the increase in price observed is explained partially by the increase in the number of hours with unserved energy, where the shadow price is set at 300 €/MWh.

We recommend running the model without Min Stable Level (MSL), Min Pump Load and Rough Running Range constraints for pumped storage plant. This should mitigate the risk of infeasibilities associated with pumped storage constraints. Moreover, as noted above, the technical offer structure defined for pumped storage units in T&SC v1.2 does not appear to support either the Min Pump Load or Rough Running Range constraints. Our understanding is that when the PLEXOS optimiser encounters infeasibilities, it can automatically try to recover the model run by relaxing constraints until it finds a feasible solution. We have not validated this process of constraint relaxation, therefore we would recommend avoiding this situation. However the end result may not be too dissimilar to a model run without the additional constraints imposed at the outset, although the model performance will be slower.

When the AIP Loop 2 results were presented last year, one observation made at the time was that there were some periods in which the Turlough Hill pumped storage plant appeared to be pumping and generating simultaneously. We have checked our base annual runs (i.e. those without additional pumped storage constraints) for occurrences of simultaneous pumping and generating. We have not observed this phenomenon under different fuel scenarios (AIP “central” and “low”) or different PLEXOS solution options (RR and MIP).

For this model validation project, we have not had access to historic data on pumped storage operations to facilitate a comparison of PLEXOS operating profiles with actual performance. Even if historic data had been available, it is doubtful whether past operating performance would be a useful indicator of how pumped storage may operate commercially under the new SEM arrangements. However, we have inspected the pumped storage and hydro operating profiles from our full all-island system PLEXOS runs to "sense check" that plant were operating at appropriate times of day, as illustrated by this profile for a representative winter weekday:



Finally, we tested whether aggregating the pumped storage units had any impact on model performance. We set up a single pumped storage generator in PLEXOS with four units and compared the results to those obtained with the four separate generators. No material differences were observed when running in PLEXOS in RR mode, but we found there was an issue with the multi-unit generator when the MIP solution algorithm was used[21]. We understand this MIP issue has been fixed in a subsequent PLEXOS release, 4.896 R08. However, as a workaround for this issue, we simply retained the four individual generator objects for the remainder of our validation exercise.

2.4.6 Moyle Interconnector

At Go-Live, there will be one interconnection between the SEM and an external power system, namely the Moyle Interconnector between Scotland and Northern Ireland. The offer format and scheduling arrangements for interconnector units are set out in T&SC v1.2 paragraphs 5.32 to 5.75. Each interconnector unit is included in the EPUS Software as a "Predictable Price Maker Generator Unit". The Commercial Offer structure for interconnectors differs from other price maker generators as follows:

[21] We observed in the MIP solution that the maximum pump load in a period was restricted to 73 MW rather than 292 MW (4 x 73).

– Different Price Quantity pairs can be submitted for each half-hourly trading period (normally these apply to the whole trading day).

– Offer quantities can be negative to represent exports from the SEM Pool.

– No load and start costs are not submitted for interconnector units.

In the EPUS calculation of the Market Schedule Quantities, T&SC v1.2 states that the ramp rate for each Interconnector Unit is set to a value of 999.9 MW/min. We understand that the interconnector unit nominations resulting from the Indicative EPUS Software Run may be modified by the Market Operator on the day-ahead to ensure that the aggregate ramp rate for all interconnector units on any interconnector does not exceed the ramp rate specified for that interconnector. However, it is not readily apparent in T&SC v1.2 whether the ex-post EPUS run explicitly handles the aggregate ramp rate constraint.

In a modelling context, we need only be concerned with the aggregate import or export flow across the Moyle interconnector, summed over all interconnector users. Effectively we are assuming that all interconnector users act in an economically rational manner and that there is sufficient transparency and liquidity in the neighbouring market (i.e. BETTA) for users to see the same opportunities for price arbitrage across the interconnector.

There are several ways in which PLEXOS could be configured to model the interaction between the SEM and BETTA markets via the Moyle interconnector. These include:

1. Modelling a BETTA Market at a node within the SEM Region, with sale and purchase prices linked to an input file of BETTA prices. Market Max Sales and Max Purchases are used to limit import / export volumes. The Moyle interconnector is modelled as an intraregional line to connect the BETTA node with the SEM node.

2. Modelling BETTA as an external Region comprising a Market with sale / purchase prices linked to an input file of BETTA prices. The Moyle interconnector is defined as an interregional Line with Max Flow and Min Flow setting the import and export limits (overriding market Max Sales and Max Purchases limits).

3. Modelling a dummy "Moyle" generator and Purchaser within the SEM region, with offers and bids linked to an external file of BETTA prices. Standard generator / purchaser properties such as Max Capacity used to limit import / export volumes, as well as ramp rates.

4. Modelling BETTA as an external Region comprising a dummy load (say 200 MW) and a large dummy generator (say 1000 MW) with generation offers linked to an input file of

BETTA prices. The Moyle interconnector is defined as an interregional Line with Max Flow and Min Flow setting the import and export limits.

5. Modelling BETTA as an external Region comprising a dummy load and a simplified representation of the BETTA plant portfolio with generation offers linked to input fuel prices. The Moyle interconnector is defined as an interregional Line with Max Flow and Min Flow setting the import and export limits.

6. Modelling BETTA as an external Region comprising forecast load and a full representation of the BETTA plant portfolio with generation offers linked to input fuel prices. The Moyle interconnector is defined as an interregional Line with Max Flow and Min Flow setting the import and export limits.

For our validation exercise, we have focused mostly on the first of the above options since this was the approach adopted for the AIP Loop 2 modelling project.

Note that the first four options all rely upon an external profile of BETTA prices. In terms of data validation, it is important that this BETTA price profile is internally consistent with the fuel and carbon price assumptions incorporated in PLEXOS to model generators in SEM. Options (5) and (6) seek to avoid this problem by explicitly modelling the BETTA price as a function of input fuel prices. Section 2.4.6.5 reviews various approaches to modelling BETTA under multiple fuel price scenarios, including our own analysis using option (5).

Given the same import/export limits and external profile of BETTA prices, options (1) to (4) would be expected to produce identical results. However, the different options do enable various additional properties to be modelled if required. For example, a bid-ask spread can readily be modelled in PLEXOS using the "market" approach while ramp rates could be incorporated using a dummy generator.

We did identify a PLEXOS issue when we tested option (2) with the BETTA market defined as an external region. The issue only arose when we subsequently enabled the SEM Uplift functionality: it appeared that the current PLEXOS release did not support multiple regions (e.g. SEM and BETTA) once the Uplift calculation was enabled. Having raised this issue with Elan, our understanding is that the PLEXOS Uplift algorithm will fail if a region is defined without any load or generation, as was the case with option (2) above. We therefore tested option (4), again modelling BETTA as an external region but specifying a dummy generator and load rather than a market. We verified that the SEM Uplift functionality was compatible with multiple regions under this option. However, we continued to use option (1) for the majority of our analysis, defining the BETTA market at a node within the SEM region.

Having run PLEXOS for a subset of the SEM plant set including Moyle, we validated that the interconnector flows appeared logical given the input BETTA prices and reported SEM shadow prices. As discussed below, we have also investigated extending the modelling of Moyle to incorporate a bid-ask spread, line losses, ramp rates and BETTA price adjustments. Finally, we explored alternative options for modelling BETTA under multiple fuel price scenarios.

2.4.6.1 Bid-Ask Spread

When the AIP Loop 2 results were presented last year, one observation made at the time was that there were some periods in which BETTA sales and purchases appeared to occur simultaneously. In testing PLEXOS' handling of the Moyle interconnector, we occasionally observed simultaneous BETTA sales and purchases in our own results.

Our understanding from discussions with Elan is that simultaneous purchases and sales may take place if the same price applies to both purchases and sales. An optimal solution with gross purchases and sales will be equivalent to an optimal solution with net purchases (or net sales) since the optimiser cannot distinguish between them in terms of cost.

As a cosmetic workaround to remove the appearance of superposition, we tested adding a nominal Bid-Ask Spread to the BETTA price in PLEXOS. This enables the optimiser to distinguish between the net and gross solutions, hence avoiding simultaneous BETTA sales and purchases. Provided the specified Bid-Ask Spread is negligible (e.g. 0.001 €/MWh), we confirmed that there was no change in the overall net schedule or resulting shadow prices.

If required, the Bid-Ask Spread property could also be used to capture actual Moyle transaction charges (e.g. variable charges for use of the interconnector).

2.4.6.2 Line Losses

PLEXOS can model interconnector transmission losses in various ways. We tested applying Loss Incr and Loss Incr Back to approximate the transmission losses between the BETTA node and the SEM regional reference node. These marginal loss factors adjust the BETTA price for imports or exports, and also scale down the import and export limits (i.e. PLEXOS assumes that BETTA Market Max Sales and Max Purchases are defined at the Scottish end of Moyle).

2.4.6.3 Ramp rates

Our understanding is that the aggregate ramp rate for Moyle would not be binding at the hourly resolution, given our assumptions on maximum imports (400 MW) and maximum exports (80 MW). Accordingly, we have not sought to incorporate interconnector ramp rates in the model. If it did become necessary to add ramp rates for Moyle, one of the alternative modelling options involving dummy generators would likely be required in order to utilise the standard ramp rate functionality within PLEXOS.

2.4.6.4 BETTA price adjustments

We would expect Moyle interconnector users to adjust their offer and bid prices by their expectations of SEM Uplift and Capacity Payments. In effect, Uplift and Capacity Payments in SEM lower the BETTA price for efficient arbitrage across the interconnector, making imports into SEM more attractive and exports less attractive.

The reason for incorporating this adjustment is that interconnector users are ultimately settled on SMP (including Uplift) and Capacity Payments, but Uplift and Capacity Payments are both determined after the market schedule and shadow prices. The scheduling tool (PLEXOS or indeed the EPUS software) cannot explicitly consider Uplift and Capacity Payments in determining the optimal interconnector flow, so interconnector users will have to internalise their expectations of Uplift and Capacity Payments in their offers and bids. For example, if the SEM shadow price was 40 €/MWh and the BETTA price was 45 €/MWh, the market schedule would likely feature exports from SEM to BETTA. However, if Uplift and Capacity payments bring the final "all-in" SEM price to 50 €/MWh, with hindsight an interconnector user would prefer a reverse flow from BETTA to SEM. This situation may have been avoided by submitting a lower interconnector offer price adjusted by expected Uplift and Capacity Payments.

These adjustments to the external BETTA price curve will generally need to be performed outside of PLEXOS. However, PLEXOS could be run in an iterative fashion to estimate the Uplift adjustment (e.g. by seasonal peak/off-peak block). In addition, the Bid Spread property could be used to capture the differential in capacity payments applying to imports and exports. For example, if the BETTA price curve is adjusted outside of PLEXOS by the estimated capacity payments received by importers to SEM, a Bid Spread could then be applied within PLEXOS to reflect higher capacity payments paid by exporters from SEM.

Note that the Bid-Ask Spread and Bid Spread properties in PLEXOS are specific to the Market object. However, if one of the alternative BETTA modelling options is adopted, a Wheeling Charge can be applied to the Moyle transmission Line to achieve the same effect.

2.4.6.5 Modelling BETTA under multiple scenarios

As explained above, we have applied option (1) for the majority of our interconnector modelling analysis, defining the BETTA market at a node within the SEM region. This requires a BETTA price profile to be defined externally. We believe that this approach is generally appropriate for conducting base SEM projection runs. In such cases, the input prices for fuels, carbon and BETTA can all based upon the available market forward curves to ensure that the modelling assumptions are internally consistent. This becomes more challenging when multiple fuel price scenarios are to be modelled.

We have considered three approaches to modelling BETTA under multiple fuel price scenarios:

a. Applying a different BETTA price profile to each scenario run in PLEXOS. This approach was adopted in the AIP Loop 2 modelling project. It essentially relies upon an external model of the GB system being run to produce BETTA prices consistent with the fuel and carbon price assumptions incorporated for SEM generators in PLEXOS.

b. Fixing the Moyle flows to be consistent with the BETTA transaction volumes observed in the base scenario. The underlying assumption behind this approach is that delivered fuel prices for generators in SEM and BETTA are highly correlated, such that Moyle flows would not be expected to vary significantly across fuel price scenarios. Within PLEXOS, the Moyle flows can be fixed on an hourly basis, effectively netting the BETTA trades observed in the base scenario from the load profile. Alternatively, Moyle flows can be fixed over a longer timeframe by imposing constraints on BETTA sales and purchases (e.g. annual or monthly).

c. Modelling the BETTA market explicitly within PLEXOS. This approach requires a representation of the GB system within PLEXOS per options (5) and (6) above. PLEXOS will effectively arbitrage between SEM and BETTA on the basis of incremental generation costs in each market, subject to any assumptions on line losses and bid-ask spreads.

To compare the fixed flow and BETTA modelling approaches, we constructed a simplified representation of the GB system. We configured ten generator units in PLEXOS to model aggregrated tranches of coal, gas, oil, distillate and non-fossil capacity in the BETTA market. A GB load profile was created using published National Grid data. We ran this two regions model and the standard SEM-only model with a base set of fuel prices, using a BETTA price profile based on the current forward curve for the single region SEM model. We found that the two models produced comparable price results under the base scenario (e.g. the SMP averages were within 1 €/MWh).

We then tried fixing the hourly Moyle flows from the base scenario in the single region (SEM-only) model, and re-running PLEXOS without Moyle. We found that fixing the Moyle flows on an hourly basis led to increased unserved energy, and that both shadow prices and Uplift differed significantly from the base run. Annual average SMP in the fixed Moyle run was around 5 €/MWh higher compared to the base run, while peak average SMP was around 10 €/MWh higher. We noted that Moyle had been marginal in over 30% of the periods in our base run. The Moyle interconnector is effectively the most flexible dispatch option available to the optimiser in our SEM data set, given the various technical constraints imposed on both thermal and hydro plant. Fixing the Moyle flows on an hourly basis therefore reduces system flexibility, and prevents BETTA trades from setting prices in SEM.

Having concluded that it would be inappropriate to fix the Moyle flows on an hourly basis, we then imposed monthly constraints on BETTA sales and purchases in the single region model, using the monthly BETTA trade volumes observed in the base run. This approach retains Moyle's flexibility and price-setting role, subject to meeting the monthly constraints. Re-running the model under the base scenario, we found that the monthly Moyle constraints had a less significant price impact than the fixed hourly flows, with annual average SMP around 1.5 €/MWh higher compared to the base run.

Finally, we ran the two regions (SEM / GB) and single region (SEM-only) models with high and low gas price sensitivities, again imposing base scenario monthly constraints on the Moyle flows in the single region model. The resulting annual and seasonal average SMPs were generally lower in the two region model, reflecting the considerable scope for fuel switching in the GB system. For example, Moyle import volumes to SEM were observed to increase significantly in the high gas price sensitivity. Gas-to-coal switching in the GB system moderated the impact of the high gas price on the BETTA market price, increasing the relative attractiveness of exports to SEM.

Overall, we believe that the two regions model will provide a more realistic representation of the interactions between the SEM and BETTA markets under multiple fuel price scenarios, compared to the fixed flow approach. Our analysis has shown that even a simplified GB model comprising ten tranches of generation capacity can capture the potential for fuel switching within the GB system. This fuel switching capability is a significant feature of the GB system, as illustrated by the generation changes over recent years in response to changing gas, coal and carbon prices. The two regions model also has advantages over the single region model in terms of input data assumptions:

- BETTA forward curve data is generally only available on a peak/off-peak basis. This limits the granularity of the BETTA price profile used for the single region model, unless coefficients are applied to generate price shapes from quoted peak / off peak prices (e.g. by analysing the historical relationships between forward peak / off-peak and EFA block prices). The granularity of the BETTA price in the two regions model is effectively determined by the GB load profile (e.g. hourly) and the number of generation tranches.

- As discussed previously, we would expect Moyle interconnector users to adjust their offer and bid prices by their expectations of SEM Uplift and Capacity Payments. This is particularly relevant in the single region model since the quoted forward prices in the BETTA market are "all-in" rather than "energy-only" or "SRMC-based" prices. However, in the two regions model, PLEXOS effectively arbitrages between SEM and BETTA on the basis of incremental generation costs. It can be argued that in the two regions model, the BETTA price should only be adjusted by the relative spread applying to SEM imports and exports, rather than by an expectation of SEM Uplift and Capacity Payments in absolute terms. Pre SEM Go-Live, this relative bid-ask spread may be easier to estimate.

We therefore recommend using a simplified representation of the GB plant portfolio within PLEXOS to model the interactions between SEM and BETTA under multiple fuel price scenarios. This will ensure that the BETTA price is internally consistent with the fuel and carbon price assumptions under each scenario.

2.4.7 Demand Side Units

The T&SC does provide for Demand Side Units to participate directly in the SEM energy market. The Purchaser object in PLEXOS can be used to model price-sensitive load and has analogous properties (e.g. ramp rates) to a generator.

However, our understanding is that there is limited data available at this time to underpin the modelling of demand side units for SEM. Load management measures were implicitly considered in the AIP Modelling Project in defining system reserve requirements, but this form of demand side participation is not relevant for the unconstrained energy market. As a result, we have not tested the price-sensitive load functionality in PLEXOS for this model validation exercise.

2.5 Shadow Price Calculation Review

In this section we review how shadow prices are determined in the SEM T&SC and in PLEXOS. We describe how we constructed a simplified Excel-based "stack model" to sense check the shadow prices reported by PLEXOS. We also outline how we have examined the impact of technical constraints on the shadow price.

2.5.1 T&SC Comparison

The T&SC v1.2 Glossary defines shadow price as follows:

> *"A component of the System Marginal Price for each Trading Period, calculated by the EPUS Software as the marginal cost (excluding Start Up Costs and No Load Costs) of meeting Schedule Demand taking account of all constraints and limitations used within that run of the EPUS Software except those constraints used solely in the calculation of Uplift."*

The T&SC does not provide further details as to how the Shadow Price is calculated by the EPUS software. The T&SC does not, for example, lay out specific situations in which a "price maker" generator unit will or will not be considered in the determination of Shadow Price (e.g. can a unit running at Min Stable Level "set" the price?).

In PLEXOS, shadow prices are automatically determined as part of the solution to the optimisation problem. The price reported by PLEXOS represents the shadow price of the constraint that matches supply and demand. This can be considered as the change in the objective function for an incremental change in demand:

Δ (Objective Function) / Δ (Demand)

The prices reported by PLEXOS are therefore "true shadow prices" computed during the optimisation. It is not within the scope of our project to compare the pricing methodology of PLEXOS with the EPUS software or with other market simulation tools. However, we are aware that some market simulation tools do adopt a different approach to pricing. For example, prices may be determined by a separate algorithm after the optimisation, applying a set of rules to identify the marginal plant and then calculating its marginal costs. Inevitably we would expect to see some discrepancies arising from these different pricing methodologies if results are compared between simulation tools.

Since PLEXOS shadow prices are determined directly from the optimisation, PLEXOS does not need to apply a specific set of rules defining the circumstances in which a plant can be price-setting and the formula for calculating the price. Our general observations from analysing PLEXOS shadow prices can be summarised as follows:

– Typically, but not always, the shadow price is determined by the SRMC of a marginal generator (as illustrated in the SRMC examples previously);

– Typically, but not always, plant that are running on a constraint (e.g. Min Stable Level) do not "set" the shadow price;

– The shadow price in a given period can be "set" by multiple generators over multiple periods.

To illustrate the third observation and explain why PLEXOS shadow prices do not always equate to SRMCs, we provide two worked examples below.

2.5.2 PLEXOS Shadow Price Examples

Before reviewing PLEXOS shadow prices in detail, it is important to understand why the shadow price may not always equal the SRMC of a marginal generator.

Our first example involves an extremely simple, hypothetical model comprising a single trading period and only two generator units. As described in the text box below, even in this simple model the addition of an extra constraint results in a shadow price higher than the SRMC of the marginal generator. This is because both generators would be involved in changing the Objective Function (i.e. total cost) to meet incremental demand.

Why the shadow price may not equal the SRMC of the marginal generator: example (1)

Consider two generation plants A and B

	A	**B**	
Marginal Costs	10	20	€/MWh
CO_2 Emissions	2	1	kg/MWh

- **Problem:**

MIN cost	10 A	+	20 B			
subject to	A	+	B	=	12	(DEMAND)
			A	<=	10	(CAPACITY)
			B	<=	7	(CAPACITY)

- **Solution:** A = 10

  B = 2

- **Price:** If ↑ Demand by 1, need to ↑ B by 1

  Price = Δ Cost = 1 * 20 = **20**

Now consider adding a CO2 emission constraint

- **Revised problem:**

MIN cost	10 A	+	20 B			
subject to	A	+	B	=	12	(DEMAND)
			A	<=	10	(CAPACITY)
			B	<=	7	(CAPACITY)
	2 A	+	B	<=	19	(CO_2)

- **Solution:** A = 7

  B = 5

- **Price:** If ↑ Demand by 1, need to ↓ A by 1 and ↑ B by 2

  Price = Δ Cost = 2 * 20 - 1 * 10 = **30**

Our second example picks up one of the short-run constraint tests we presented previously. In a baseline daily PLEXOS run for a five generator system, we observed a shadow price of 91.9 €/MWh in the peak demand period, equal to the SRMC of the most expensive generator (MRC) in this period. However, the addition of a binding ramp rate constraint to one of the cheaper generators (TB3) increased the peak shadow price to 158.2 €/MWh, even though the highest reported SRMC in this period was still 91.9 €/MWh.

The 158.2 €/MWh peak shadow price can be validated by perturbing the peak period demand by 1 MW and re-running PLEXOS. It is found that the difference between the objective function values of the two ramp-constrained runs is € 158.2, i.e. the shadow price of the supply-demand constraint in the peak period.

Inspection of the dispatch schedules for the two ramp-constrained runs reveals the origin of this change in objective function values. The ramp-constrained plant TB3 is available to meet the incremental peak demand but, to do so, it must run at higher levels in three adjacent shoulder periods. This in turn displaces generation from cheaper plant such as MP1 and AD1 in the shoulder periods. The total change in generation costs for multiple generators over multiple periods therefore accounts for the observed 158.2 €/MWh peak shadow price.

2.5.3 "Stack Model" Sense Check

In order to sense check the shadow prices reported by PLEXOS, we constructed a simplified Excel-based "Stack Model" as follows:

– A seasonal supply stack created by ranking generation plant by their SRMC at full available load;

– Hourly hydro output "optimised" against the monthly load profile, assigning the available hydro energy to the highest demand hours over the month;

– Hourly pumped storage operation "optimised" against the daily load profile, flattening the load profile subject to the constraints of pumping efficiency and maximum generating hours;

– Hourly wind output derived from the AIP wind factor series;

– System "shadow" price determined by the intercept of the seasonal supply stack with hourly load net of wind, hydro and pumped storage;

– Hourly arbitrage with the loss-adjusted BETTA prices, with the SEM price re-calculated by shifting along the supply stack by the export/import volume.

The Stack Model makes a number of simplifying assumptions compared to PLEXOS:

– No load and start costs are not considered in formulating the supply stack[22];

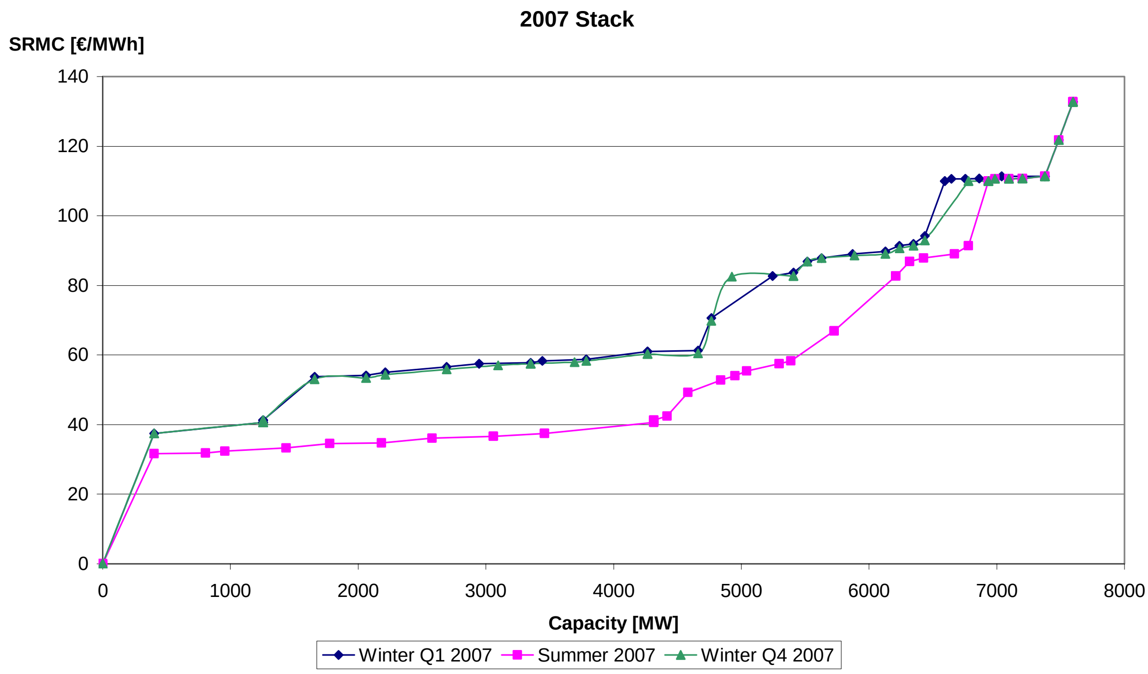
– Only the final (full load) incremental heat rate is considered[23];

– Plant technical constraints such as ramp rates and min up/down times are completely ignored;

– The same monthly energy limits are applied to all hydro generators;

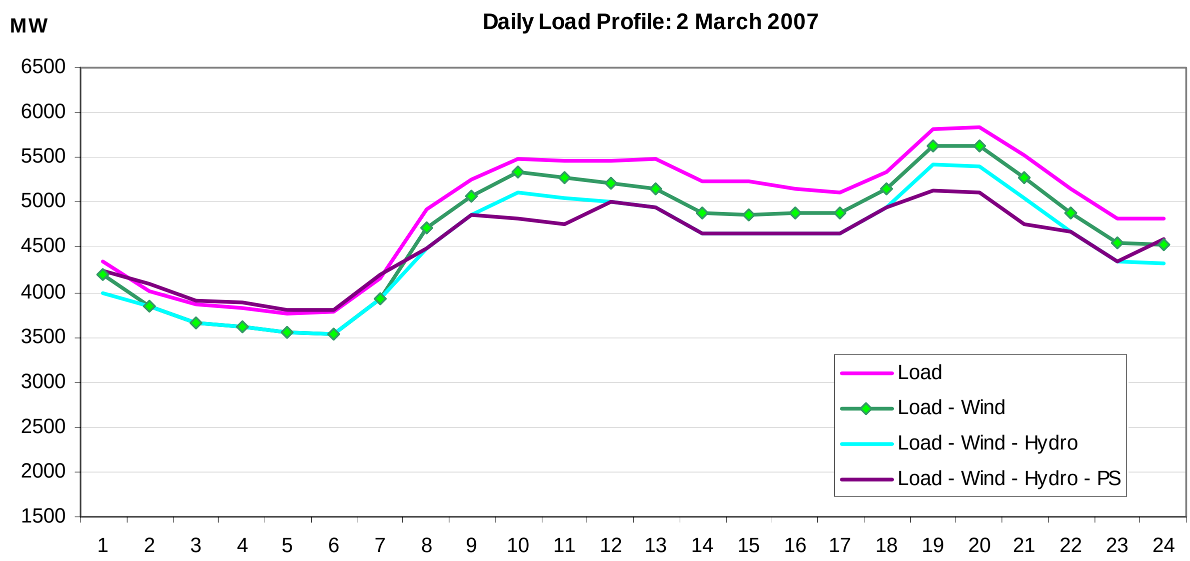
– Wind, hydro and pumped storage output are sequentially netted off the load curve rather than co-optimised.

The Stack Model was populated with same data set as PLEXOS, namely generator parameters plus seasonal fuel prices, and hourly load, wind factors and BETTA prices. For simplicity, the effect of planned and forced outages was excluded from both the Stack Model and PLEXOS. The diagram below illustrates the seasonal supply stacks resulting for 2007 (note that only the gas price is assumed to vary between seasons):



The diagram below illustrates the net load profiles for a representative day:

[22] A variant of the Stack Model was developed with schedules based on the average heat rate but the results presented here are based on purely SRMC schedules.
[23] This may be more problematic with the new data set given that some generator units have substantially increased their final incremental heat rates. The results presented here are based on the starting data set (AIP Loop 2).



We then compared the Stack Model prices to the shadow prices resulting from a PLEXOS RR run for calendar 2007, using the AIP Loop 2 "central" fuel price assumptions[24].

The time-weighted seasonal[25] average prices for each model were as follows:

CENTRAL	Stack Model SRMC Price			PLEXOS Shadow Price		
€/MWh	**All**	**Peak**	**Off-peak**	**All**	**Peak**	**Off-peak**
All	51.86	58.86	47.96	54.12	61.89	49.80
Summer	42.30	47.46	39.46	45.23	51.23	41.92
Winter	65.40	74.76	60.11	66.80	76.88	61.12

It can be seen that the Stack Model average prices are consistently lower than the corresponding PLEXOS results but only by between 1 to 3 €/MWh.

We repeated the comparison exercise using the AIP Loop 2 "low" fuel price assumptions for calendar 2007. The time-weighted seasonal average prices under this scenario were as follows:

[24] Both the stack model and PLEXOS utilised fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set.
[25] The seasonal definitions used here are consistent with the AIP Loop 2 data set: summer is the 7 month period March to September, peak is 08:00 to 19:00 weekdays.

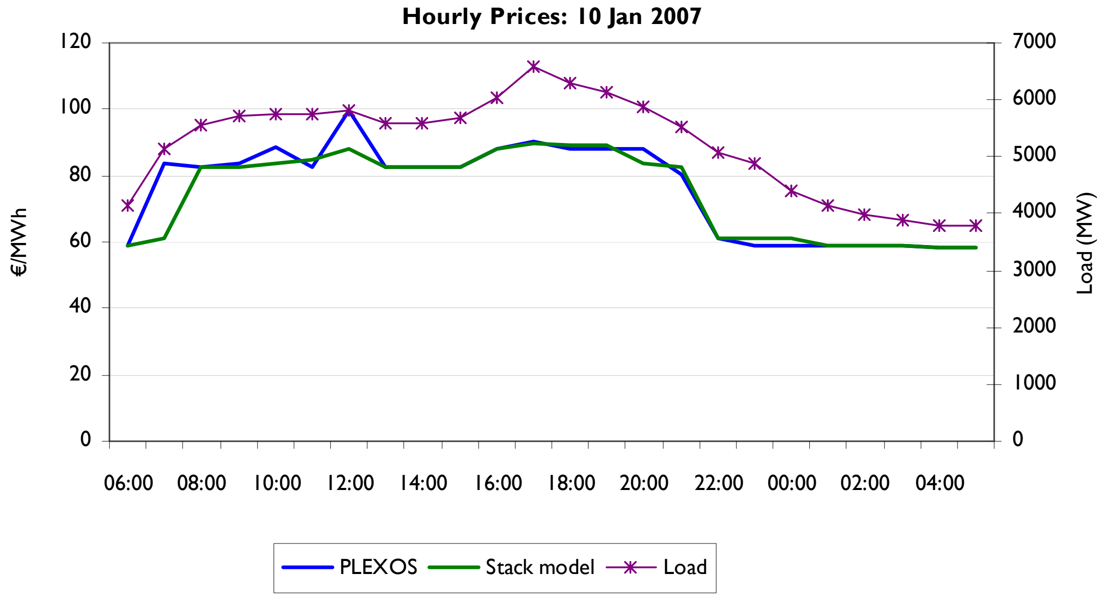
LOW	Stack Model SRMC Price			PLEXOS Shadow Price		
€/MWh	All	Peak	Off-peak	All	Peak	Off-peak
All	38.75	43.98	35.83	40.57	47.36	36.80
Summer	33.58	36.87	31.77	36.27	41.49	33.39
Winter	46.07	53.89	41.65	46.71	55.61	41.71

Under the Low scenario, the Stack Model average prices are within 0 to 4 €/MWh of the corresponding PLEXOS shadow prices.

These seasonal average results indicate that the shadow prices reported by PLEXOS are not significantly different from those produced by a Stack Model simply scheduling on the basis of generator SRMCs. It would, in fact, be surprising if the Stack Model results were too much closer to the PLEXOS shadow prices, given the numerous simplifications and approximations within the Stack Model.

Having "sense checked" the average shadow prices reported by PLEXOS, we then compared the price profiles for representative winter and summer weekdays.

1. ***Winter weekday (Central scenario): Wednesday 10th January 2007***



Comments:

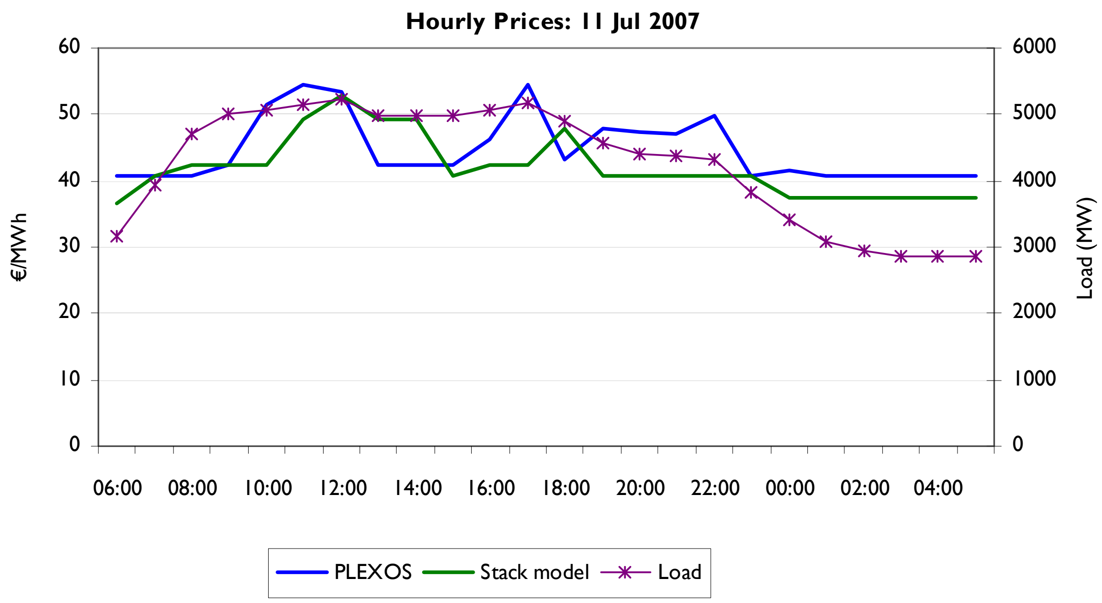
– The Stack Model generally tracks the PLEXOS price profile very closely.

– The largest differential is in period 07:00 when the Stack Model price is lower by 22.6 €/MWh. The PLEXOS shadow price at 07:00 does not correspond to the SRMC of any one generator but pumped storage appears to be "marginal", generating 42.81 MW. Block load, min down time, and ramp rate constraints are likely to be particularly significant during the morning load rise. PLEXOS may therefore need to call upon the flexibility of pumped storage to accommodate plant technical constraints. In the Stack Model, which ignores technical constraints, pumped storage is not scheduled in this shoulder period.

– There are some periods in which the PLEXOS price is below the Stack Model price. At 23:00, unit DBP sets the Stack Model price at 61.3 €/MWh while in PLEXOS, HNC sets the price at 58.8 €/MWh. PLEXOS reports DBP's SRMC at 61.3 €/MWh in periods when it is running at full load, but at 23:00 DBP is scheduled at an intermediate load point with a reported SRMC of 56.9 €/MWh. The Stack Model, by contrast, only schedules on the basis of final incremental heat rates.

– Inspection of the PLEXOS schedule reveals there are some periods in which plant are operating even though their SRMC is above the shadow price. At 23:00 B10 and B32 are both scheduled to run at their MSL before switching off by 00:00. These units do not set the shadow price in this period because HNC has spare capacity and a lower SRMC.

2. Summer weekday (Central scenario): Wednesday 11th July 2007



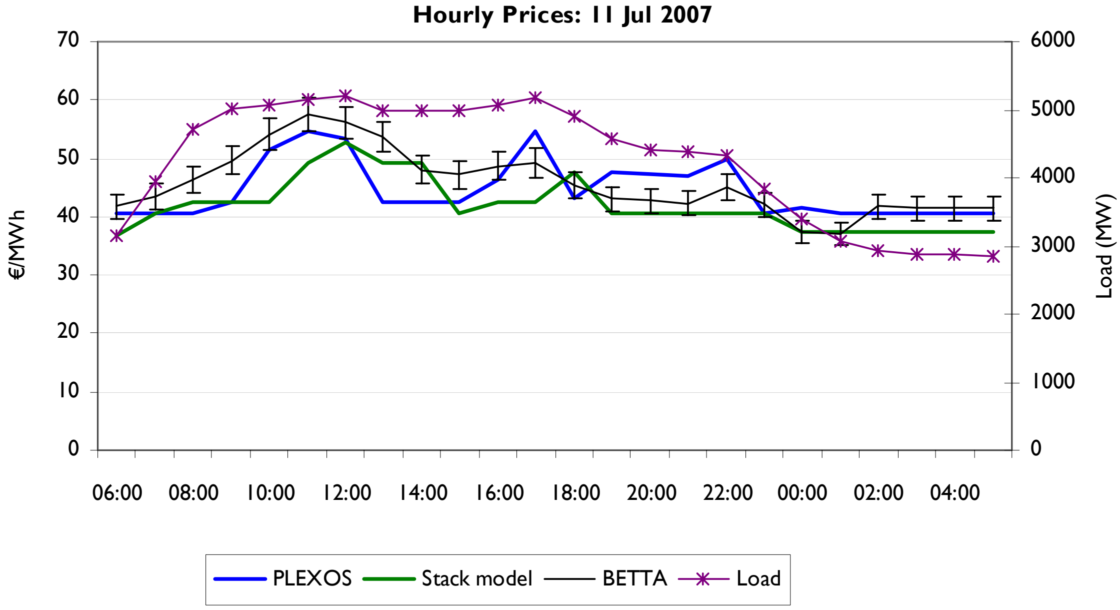
Comments:

- The largest differential is at 17:00 when the Stack Model price is lower by 12.2 €/MWh. The Stack Model schedules 292 MW of pumped storage and 214 MW of hydro output at 17:00, whereas the PLEXOS schedule has no pumped storage and lower hydro (181 MW) in this period. Moyle is marginal in PLEXOS at 17:00 with BETTA purchases of 14.9 MW. The Stack Model "optimises" pumped storage by flattening the net load profile rather than minimising total production cost. The pumped storage output depresses the Stack Model price at 17:00, such that SEM exports to BETTA during this period.

- The Stack Model price is above the PLEXOS price in some periods. At 14:00, unit NW4 sets the Stack Model price at 49.2 €/MWh while in PLEXOS, B10 sets the price at 42.5 €/MWh. NW4 is operating in the PLEXOS schedule at 14:00, but at an intermediate load point with an SRMC of 40.9 €/MWh. The Stack Model SRMC for NW4 is based on the unit's full load incremental heat rate.

- The differential in prices overnight may reflect the influence of start costs on the PLEXOS schedule. The overnight (01:00-05:00) price is set at 37.5 €/MWh by K1 in the Stack Model, whereas MP1 sets the price at 40.7 €/MWh in PLEXOS. The three MP units do not run overnight in the Stack Model since CCGTs running on summer spot gas have lower SRMCs. However, PLEXOS keeps MP on overnight, and instead switches off three CCGT units (CPS CCGT, B31, B32). Although these CCGTs have SRMCs some 5 €/MWh lower than MP, their start costs are insignificant compared to MP. PLEXOS optimises to minimise total generation costs, whereas the Stack Model simply schedules on SRMC.

- BETTA is marginal at different times for the Stack Model and PLEXOS, as illustrated below (error bars on the BETTA line indicate the loss-adjusted import/export prices).



We concluded that the shadow prices reported by PLEXOS are broadly consistent with those produced by our "sense check" Stack Model. The differences that are observed can be rationalised by studying price profiles and schedules for individual days. In many cases the explanations for the price differences reflect the limitations of the Stack Model: for example, the PLEXOS optimiser considers start and no load costs as well as incremental costs, and sets shadow prices based on multi-increment heat rate curves rather than just the full-load SRMC.

2.5.4 PLEXOS Shadow Price Analysis

Having "sense checked" the PLEXOS shadow prices against a simple "Stack Model" that ignores plant technical constraints, our next step was to further explore the price impacts of these plant constraints.

Initially, we sought to understand how constraints impacted the shadow price in a scaled-down PLEXOS model such as the five generator system we created for the short run constraint tests. The ramp rate example described previously was the most complex scenario we tested, with multiple generators in multiple periods involved in setting a peak shadow price higher than any generator SRMC.

We then sought to understand the impact of plant constraints in PLEXOS runs for the full all-island system. We aimed to resolve two questions:

– To what extent are generator units unable to set the shadow price because they are binding on a technical constraint?

– To what extent would shadow prices differ if we relaxed a given technical constraint?

To assess the first question, we analysed PLEXOS output schedules to identify instances in which generator units were running despite their SRMC being above the reported shadow price for the period. In these instances, we then checked whether the generator unit was either operating at its Min Stable Level (MSL) or was bound by a ramp rate constraint. For example, in our base "Rounded Relaxation" run[26] for calendar 2007, the breakdown of these instances by (thermal) plant type was as follows:

BASE (RR)	# of Periods					
Condition	**Total**	**Coal**	**Gas**	**Oil**	**Distillate**	**Peat**
Running (total generating hours)	*184,966*[27]	*42,674*	*73,522*	*1,734*	*114*	*10,729*
Running when SRMC > shadow price:	*7,225*	*1,471*	*3,252*	*562*	*69*	*1,871*
& when @ MSL	*6,997*	*1,471*	*3,252*	*355*	*69*	*1,850*
& when @ ramp limit	*207*	*-*	*-*	*207*	*-*	*-*
(delta)	*21*	*-*	*-*	*-*	*-*	*21*

The total number of generating hours is shown for comparison. It can be seen that in almost all cases, generation units are at MSL when their SRMC is above the shadow price. The only exceptions are oil plant bound by ramp constraints and a small "delta" discrepancy attributed to the ED1 peat plant. ED1 has a non-monotonically increasing heat rate function in this data set, which is inconsistent with the rules of the T&SC.

There are a number of reasons why the shadow price can be below the SRMC of a plant running at MSL. For example, when generation units are committed to start up and then block load at MSL, the output of cheaper generation units is often displaced to accommodate the block load constraint of the starting unit. These cheaper generation units would then have spare capacity available and be able to set the shadow price. Similar considerations apply when a generating unit is due to switch off: min up time constraints can cause a plant to be scheduled for longer than would otherwise be the case, as can high start costs or long min down time constraints. These constraints can all lead to a plant being scheduled at MSL rather than switched off at times when cheaper units are available to set the shadow price.

[26] PLEXOS was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$).

[27] Total includes non-thermal plant (wind, hydro, PS)

Investigating further, we found that plant operating at their MSL were not always prevented from setting the shadow price in PLEXOS. In the above example, we found there were 1,088 instances of generators setting the price (i.e. their SRMC equals the shadow price) while running at MSL.

We then ran some comparative tests[28] in PLEXOS to assess the impact of relaxing ramp and min up / down time constraints on the thermal units in the data set. The seasonal average prices resulting from these runs are shown below, together with the results for the base scenario with the constraints:

BASE					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	59.93	68.30	55.28	49.77	74.43
Uplift	5.81	6.40	5.48	4.53	7.63
Shadow Price	54.12	61.90	49.79	45.23	66.80

THERMAL RAMP CONSTRAINTS RELAXED					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	60.04	68.84	55.16	49.73	74.75
Uplift	5.84	6.72	5.35	4.54	7.68
Shadow Price	54.21	62.11	49.81	45.19	67.07

THERMAL MIN UP & DOWN TIME CONSTRAINTS RELAXED					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	57.67	67.84	52.02	46.89	73.05
Uplift	3.30	5.81	1.91	1.61	5.73
Shadow Price	54.37	62.03	50.11	45.29	67.32

It was observed that relaxing the ramp rate constraint had a negligible impact on the shadow prices reported by PLEXOS. This can be attributed to the fact that only a handful of generator units in our starting data set have binding ramp rates at the hourly resolution: namely, ED1, GI3, PB3, TB3 and TB4. Relaxing the min up / down time constraints had a modest impact on shadow prices, increasing the average winter price by around 0.5 €/MWh. As discussed above, min up / down time constraints

[28] Each model was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-230-06 ($\alpha = 0.3$, $\beta = 0.7$).

can lead to plant being run at MSL rather than switched off, and we've just seen that shadow prices are generally set below the SRMCs of plant running at MSL.

2.5.5 Marginal Plant

As discussed previously, PLEXOS does not automatically select a marginal generator (or generators) as part of the optimisation and shadow price computation. For reporting purposes, PLEXOS does have an Is Marginal property that provides an indicator of which generator was marginal in each period. PLEXOS identifies the marginal plant by running an algorithm *ex post*. For the purposes of this reporting property, PLEXOS assumes that a plant cannot be labelled "marginal" if any of the following conditions are true:

– The generator is off.

– The generator is operating at Min Stable Level.

– The generator is operating at full output (Rating or Max Capacity).

– Any generic constraint the generator is involved in is binding.

If there are several generators operating between Min Stable Level and full output in a given period, PLEXOS does not attempt to identify multiple marginal generators. Under these circumstances, no generator will be flagged Is Marginal for the period.

We have found in our test runs that there are frequently periods in which no generator is labelled marginal by PLEXOS. This is possibly because our starting data set has multiple generators with identical parameters (i.e. each unit of a plant has been configured as a separate generator in PLEXOS). Most generators have also been defined with multiple incremental heat rates, so it is relatively common to find periods in which multiple units of the same plant are sitting at an intermediate load point. Another reason why PLEXOS may not always identify a marginal generator in our data set is that the Moyle interconnector often appears to be marginal (see below). For these reasons, the Is Marginal reporting property should be treated with caution when applied to the SEM data set.

To supplement the PLEXOS Is Marginal reports, we have developed a post-processing spreadsheet tool to analyse PLEXOS schedules and flag when a generator's reported SRMC is equal to the shadow price. Often we find there are periods in which multiple generators can be considered "marginal" in this sense, e.g. three identical generator units from the same power station will have the same SRMC if they are dispatched to the same portion of their heat rate curve.

We also flag instances in which Moyle is marginal by looking for periods in which BETTA sales / purchases are between zero and the maximum export / import limits. In every case that Moyle is marginal according to this definition, we have found that there are no generators with SRMC equal to the shadow price.

We then analysed annual PLEXOS runs to determine the proportion of the year in which:

- the shadow price matches the SRMC of a generator (or generators), *or*
- the shadow price does not match the SRMC of a generator but Moyle is marginal, *or*
- the shadow price cannot be explained by a single SRMC or Moyle being marginal.

For example, in our base "Rounded Relaxation" run[29] for calendar 2007, these proportions were as follows:

BASE (RR)	
Generator SRMC	*65.9%*
Moyle marginal	*28.8%*
Delta	*5.2%*

In this run, multiple generators with the same SRMC were "marginal" for 25.0% of the year.

The "delta" periods are those in which inter-temporal constraints and multiple generator SRMCs are likely to be involved in setting the PLEXOS shadow price, as in the ramp rate constraint test presented previously. We have found these "delta" periods to be uncommon when running PLEXOS in "Rounded Relaxation" mode: in the majority of periods (over 90%), the PLEXOS shadow price can be attributed to either a single SRMC value or Moyle being marginal.

Our post-processing spreadsheet can also validate the PLEXOS-reported SRMCs for a given generator unit against the input data set, thereby giving further reassurance as to the source of the reported shadow prices.

2.5.6 Price Caps

SMP values will be subject to a market price cap and a market price floor, per T&SC v1.2 paragraphs 4.53 to 4.55. SMP will also be set to the price cap if an "Insufficient Capacity Event" occurs within the EPUS Software, meaning that the Schedule Demand cannot be met in full by Price Maker Generator Units.

[29] PLEXOS was run for calendar 2007 in "Rounded Relaxation" mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$).

In PLEXOS, the VoLL property is the value of lost load or shortage cost when the system has unserved energy. In some markets, VoLL is set to a relatively low value (we have assumed a nominal figure of 300 €/MWh in this exercise per the AIP Loop 2 project). In order to prevent unserved energy being chosen as an economic option ahead of generation PLEXOS uses a different value of VoLL internally, as defined by the Transmission Internal VoLL property. This can be set to a much higher value figure (e.g. 10,000 €/MWh here) to encourage PLEXOS to continue searching for a solution that avoids unserved energy.

The regional prices reported by PLEXOS are always capped at VoLL (not internal VoLL). One discrepancy with the T&SC that we have identified is that PLEXOS applies the price cap pre-Uplift. Shadow prices are therefore capped at VoLL but SMP will not be. Thus, a post-processing workaround (e.g. an Excel spreadsheet) will be required to cap SMP results from PLEXOS, particularly if the RAs intend to set the market price cap at a level likely to bind.

2.6 Uplift Calculation Review

The SEM market design includes an Uplift component that will be added to the Shadow Price to determine the System Marginal Price (SMP). The current PLEXOS release features a SEM Uplift module that was not available when the AIP Loop 2 modelling study was undertaken last year. In this section we review how the Uplift algorithm implemented in PLEXOS compares to that described in the T&SC v1.2. We also describe how we have tested the SEM Uplift functionality within PLEXOS, the potential discrepancies that we have identified and the workaround solutions we propose to address them.

2.6.1 T&SC Comparison

Appendix N paragraphs N.25 to N.38 of the T&SC v1.2 describe how the EPUS software will calculate an Uplift value for each trading period. The Uplift objective function is defined in Appendix N.38. It comprises a Cost Objective and a Profile Objective, and is subject to three constraints. The Cost Recovery Constraint requires that a generator unit should recover its costs of running from SMP revenues over each contiguous operating period within a trading day. The Rev Min constraint limits the ratio by which the total revenue including Uplift in any trading day may exceed the minimum level of revenue that meets the constraints (i.e. the level of revenue calculated with $\alpha = 1$ such that full weight is given to the Cost Objective):

Minimise:

$$\alpha \times \left[\sum_{p} \sum_{u \in p} \sum_{h \in t} \left((UPLIFTh + SPh) \times MSQuh \times TPD \right) \right] + \beta \times \left[\sum_{h \in t} (UPLIFTh)^2 \right]$$

by selecting values of UPLIFTh for each Trading Period h in the relevant Trading Day t,

Subject to the following constraints:

1. $\sum_{h \in k} \left[(UPLIFTh + SPh) \times MSQuh \times TPD \right] \geq CRukt$ for each Price Maker Generator Unit excluding Pumped Storage Units for that part of Contiguous Operation Period k that falls, partly or wholly, within the relevant Trading Day t ;
2. $UPLIFTh \geq 0 \qquad \forall h \in k \cap h \in t$; and
3. $\left[\sum_{p} \sum_{u \in p} \sum_{h \in t} \left((UPLIFTh + SPh) \times MSQuh \times TPD \right) \right] \leq \left[(1 + \delta) \times REVMINt \right]$

Our understanding from Elan is that the SEM Uplift algorithm in PLEXOS was developed on the basis of AIP documentation prior to T&SC v1.2, notably including the description of "Option D" in the May 2006 Uplift paper, AIP-SEM-60-06. As a result, we have identified a number of potential discrepancies between Uplift as defined in T&SC v1.2 and as implemented in the current PLEXOS release. We describe each of these discrepancies below, together with our proposals for workarounds:

1. Price Takers & Objective Function

In T&SC v1.2, the Cost Objective Function only applies to "Price Maker Generator Units excluding Pumped Storage Units and excluding Interconnector Units". The AIP-SEM-60-06 Uplift paper did not explicitly limit the summation over generation units to a subset of unit types, and so the implication was that the Cost Objective Function applied to all units. The SEM Uplift algorithm in the current PLEXOS release therefore assumes that all generators are included in the Cost Objective Function.

The PLEXOS Cost Objective Function will seek to minimise total system Uplift payments rather than just the subset of payments made to Price Maker generators excluding pumped storage and interconnector units. Reviewing a base PLEXOS run for calendar 2007, we found that relevant "price makers" represented some 92% of total generation on average[30]. However, this ratio was observed to vary on an hourly basis ranging from 69% to 100% over the year, largely driven by the variation in wind output.

[30] The relevant "price makers" generation excludes the output of wind and pumped storage. Interconnector imports are already excluded from our definition of "total generation".

By including "price takers" (and pumped storage) in the Cost Objective Function, the PLEXOS Uplift algorithm is effectively giving greater weight to the Cost Objective compared to the Profile Objective. If the results of the PLEXOS Uplift algorithm were compared to the results of an algorithm that excluded "price takers" per T&SC v1.2, we would also expect to see discrepancies due to the proportion of "price maker" output varying over the day.

We note this issue is immaterial given the new Uplift parameter values published per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$, $\delta = 5$). Setting α to zero removes the Cost Objective term from the overall Uplift Objective function.

This issue only remains relevant when we test the Rev Min constraint by running PLEXOS with α set to 1, as described below. However, the Rev Min constraint itself becomes immaterial at the proposed δ of 5.

2. Price Takers & Cost Recovery Constraint

As with the Cost Objective Function, the Cost Recovery Constraint in T&SC v1.2 is only applied to "price maker" generator units excluding pumped storage. Consistent with the AIP-SEM-60-06 paper, the current PLEXOS release considers all generators in the Cost Recovery Constraint.

In practice, only plant with non-zero incremental, no load or start costs will have any impact on the Cost Recovery Constraint in the PLEXOS Uplift algorithm. Thus, in our starting data set, wind generators, dummy interconnectors, hydro and pumped storage plant will all by definition be ignored by PLEXOS in setting this constraint.

Consequently, this discrepancy between PLEXOS and the T&SC would only apply if it was decided to model certain thermal plant (e.g. CHP or peat) as "price takers". We tested a workaround for this potential issue, which was to remove the fuel, start and no load costs for any thermal plant price-takers, thereby ensuring that such plant are removed from the Uplift Cost Recovery Constraint. Note that this workaround has no impact on the schedule or shadow prices since the plant concerned were already being modelled as must-run with zero offer prices.

3. Start costs – maximum number of periods to carry forward

T&SC v1.2 N.25 implies that if a unit is operating at the end of the optimization horizon, only the trading periods within the look-ahead (i.e. 6 hours) are considered in determining the proportion of start costs to be carried forward to the following trading day.

The approach set out in the AIP-SEM-60-06 paper – and implemented in the current PLEXOS release – is that if a unit is operating at the end of the optimization horizon, it is assumed to be on for the whole of the next trading day. Thus, the start cost carry forward calculation considers the unit to be running for 24 hours on D+1 rather than 6 hours per T&SC v1.2.

We understand there is now a proposed T&SC modification to revert to the AIP-SEM-60-06 treatment. Assuming this is approved, no PLEXOS workaround is required.

4. Start costs - carry forward over multiple days

T&SC v1.2 N.34 limits the carry forward of start costs to only the next trading day. Zero start cost is assigned to generators that began a contiguous operating period before D-1.

The AIP-SEM-60-06 paper did not explicitly deal with the scenario of a contiguous operating period spanning across more than two trading days. Consequently, the current PLEXOS release does not limit the start cost carry-forward to one day. As described later in this section, we have run tests to verify this T&SC discrepancy does arise with the current PLEXOS release.

A new PLEXOS release, 4.898 R5, has been developed to address this issue, limiting the start cost carry-forward to one day. We subsequently tested this release to confirm that start costs are not carried forward more than one day.

5. Start costs – carry forward formula

The formula for determining the proportion of start costs to carry forward appears to differ between T&SC v1.2 and AIP-SEM-60-06. The current PLEXOS release incorporates the AIP-SEM-60-06 formula.

T&SC v1.2 N.30 describes the formula for calculating the carry forward start cost:

$$CFCRukt = \sum_{hink,hint} MSUCuh \times \left(\frac{TPCOUNTt - UKSTARTuk + 1}{UKSTOPuk - UKSTARTuk + 1} \right)$$

This formula appears to pro-rate the next day D+1 share by the number of operating periods in day D, rather than by the balance of operating periods in D+1.

We understand that the T&SC v1.2 contains a typo to be corrected by a subsequent T&SC modification. Assuming this is approved, no PLEXOS workaround is required since the correction should revert to the AIP-SEM-60-06 formula.

6. Rev Min constraint

The current PLEXOS release does not incorporate the Rev Min constraint in SEM Uplift.

As described below, we have tested the Rev Min constraint by re-running PLEXOS with α set to 1 and then comparing the daily SMP revenues externally. Our analysis suggests that the Rev Min constraint is not binding at the proposed δ of 5. We therefore consider the omission of the Rev Min constraint in the current PLEXOS release to be immaterial.

7. TLAFs

Our understanding from T&SC v1.2 Appendix N is that the EPUS software does not take loss factors (TLAFs) into account explicitly, either in the optimisation to determine market schedule quantities (MSQs) and shadow prices or in the *ex-post* calculation of Uplift. Nevertheless, energy payments to generators will be loss-adjusted (per T&SC v1.2 ¶4.72).

As discussed previously, generators can be expected to internalise TLAFs in their offer submissions, thereby ensuring loss factors are implicitly considered in the market schedule and resulting shadow prices. In PLEXOS, this can be achieved automatically by specifying a Loss Factor for each generator unit. This loss factor adjusts the generators' incremental costs as considered in the PLEXOS dispatch optimisation, but does not adjust no load and start costs since these are not output-dependent.

An issue raised at the 2nd Participant Workshop in Belfast was whether generators would need to loss-adjust their no load and start costs as well as their incremental costs in order to break-even in the EPUS Uplift algorithm. We considered this issue algebraically as follows.

The Uplift Cost Recovery Constraint per T&SC v1.2 can be written:

SMP x MSQ >= CR

where the cost of running (CR) comprises incremental (INC), no load (NLC) and start costs (SUC).

CR = INC x MSQ + NLC + SUC.

Generators will actually get paid on a loss-adjusted basis:

SMP x MSQ x TLAF

Therefore, in order to break-even on a loss-adjusted basis, the Cost Recovery Constraint becomes:

SMP x MSQ x TLAF >= CR

or,

SMP x MSQ x TLAF >= INC x MSQ + NLC + SUC

We understand this is how the Cost Recovery Constraint is formulated in the current PLEXOS Uplift algorithm. Namely, if TLAFs have been specified within the model, PLEXOS will automatically loss-adjust SMP energy payments to ensure that generators are still able to recover their costs of running on a loss-adjusted basis.

If the Uplift algorithm within the EPUS software does not explicitly take account of TLAFs, then generators effectively need to loss-adjust their offers to ensure cost recovery:

SMP x MSQ >= CR / TLAF

or,

SMP x MSQ >= [INC x MSQ + NLC + SUC] / TLAF

We therefore conclude that generators would indeed need to loss-adjust their no load and start costs as well as their incremental costs in order to break-even in the EPUS Uplift algorithm.

By specifying TLAFs directly in the model, PLEXOS automatically incorporates loss-adjusted incremental costs in the schedule and loss-adjusted revenues in the Uplift cost recovery condition. The overall effect is equivalent to generators internalising TLAFs in their offer submissions. However, one potential discrepancy is that if, in reality, generators do loss-adjust their no load and start costs as well as their incrementals, EPUS and PLEXOS would then be scheduling on a different basis. No load, start costs and incrementals would all be (exogenously) loss-adjusted in EPUS whereas PLEXOS only applies TLAFs to incrementals.

A workaround for this potential discrepancy would be to manually loss-adjust all the generator cost inputs (e.g. heat rate curves, variable operating costs, no load, start costs by warmth state) rather than use the dedicated PLEXOS functionality for TLAFs. We considered this would be too impractical, particularly since TLAFs are time-varying over an extended modelling horizon.

Another workaround suggested at the Final Conclusions Participant Workshop in Dublin would be to use the Escalator function in PLEXOS rather than marginal loss factors to capture TLAFs. This would involve defining a separate Escalator index for each generator unit to represent its monthly TLAFs, and then attaching this index to the heat rate curves, variable operating costs, no load, and start costs by warmth state. This approach would involve less manual data manipulation than the first workaround. We have not had the opportunity to test the proposed escalator workaround since the Final Conclusions Workshop. One comment we can make having utilised the PLEXOS escalator functionality in other contexts is that specifying escalators may adversely impact model run times.

For simplicity, our recommendation is to use the TLAF functionality within PLEXOS to automatically apply loss factors in the schedule and Uplift algorithm. In addition to the benefit of modelling simplicity, it can be argued that there is currently insufficient data available to justify the complexity inherent in the alternative workarounds. At this time, provisional TLAF values have only been published for 2007, and it is not clear whether in practice generators will respond to the omission of TLAFs in the EPUS software by fully internalising loss factors in their no load and start costs.

2.6.2 Uplift Tests

In addition to comparing the T&SC v1.2 and PLEXOS Uplift methodologies on paper, we conducted several tests to support our analysis, as described below. It should be noted that all our Uplift validation tests were conducted with an hourly trading period, consistent with our base model.

Firstly we sought to confirm that generators were recovering their costs in each period of operation given the Uplift values determined by PLEXOS. We calculated the cumulative costs of running in a post-processing spreadsheet using the hourly Generation Cost and Unit Start Cost reported by PLEXOS, and then compared these to the generators' SMP revenues. We validated that generators were recovering their costs over each contiguous operating period within a single trading day (we tested operating periods spanning multiple days later, in reviewing start cost carry-forward). Note that PLEXOS reports start costs as occurring in the first period of operation, but this is not indicative of how start costs are allocated across multiple trading days in the PLEXOS Uplift algorithm.

We inspected the PLEXOS diagnostic files[31] to validate the specification of the Uplift objective function. We also validated the cost of running values included in the constraints, by comparison to the values we had calculated manually.

We then ran a scaled-down five generator model over a week with a demand curve constructed to ensure some units would run across multiple trading days. Once again, we calculated the cumulative costs of running over each period of operation, split by trading day where appropriate. For units that started operating on a previous day, the calculated running costs on subsequent days only reflect generation costs (i.e. incremental and no load costs) since the standard PLEXOS reports attribute the entire start cost to the first period of operation. To determine how PLEXOS had evaluated the start cost carry-forward for Uplift purposes, we extracted the generator's daily cost of running from the Uplift cost recovery constraint in the PLEXOS diagnostic files. The start cost allocated to each trading day was then given by the difference in the cost of running between the diagnostic file and our calculations.

We were therefore able to verify that the current PLEXOS release did allow start costs to be carried forward across multiple days, contrary to T&SC v1.2 (but consistent with the AIP-SEM-60-06 paper on which the PLEXOS Uplift implementation was based). For example, if a unit is on for the entire look-ahead period, we verified that PLEXOS calculated the start cost carry-forward as:

[31] The Uplift optimisation formulation in PLEXOS can be reviewed by checking the option box "LP Files in CPLEX Format" that can be found on the Diagnostics tab.

SUC (carry-fwd to Day 2) = SUC x 24 / (24 + number periods unit on in Day 1)

On Day 2, when the unit continues to run throughout the optimisation period, the current PLEXOS release repeats the same calculation as on Day 1, but replacing the start up cost with the carried forward start up cost:

SUC (carry-fwd to Day 3) =

SUC (carry-fwd to Day 2) x 24 / (24 + number periods unit on in Day 2)

Since the unit is on for the whole of Day 2, this formula reduces to:

SUC (carry-fwd to Day 3) = ½ x SUC (carry-fwd to Day 2)

Thus, in the current PLEXOS release, we found that half the start cost is included in the Uplift calculation for Day 2, and half is carried forward. If the unit continues to run throughout Day 3, the calculation is repeated again such that:

SUC (carry-fwd to Day 4) = ½ x SUC (carry-fwd to Day 3) = ¼ x SUC (carry-fwd to Day 2)

The start cost is therefore carried forward indefinitely for Uplift purposes in the current PLEXOS release, reducing by a factor of half each trading day but not reaching zero until the unit switches off.

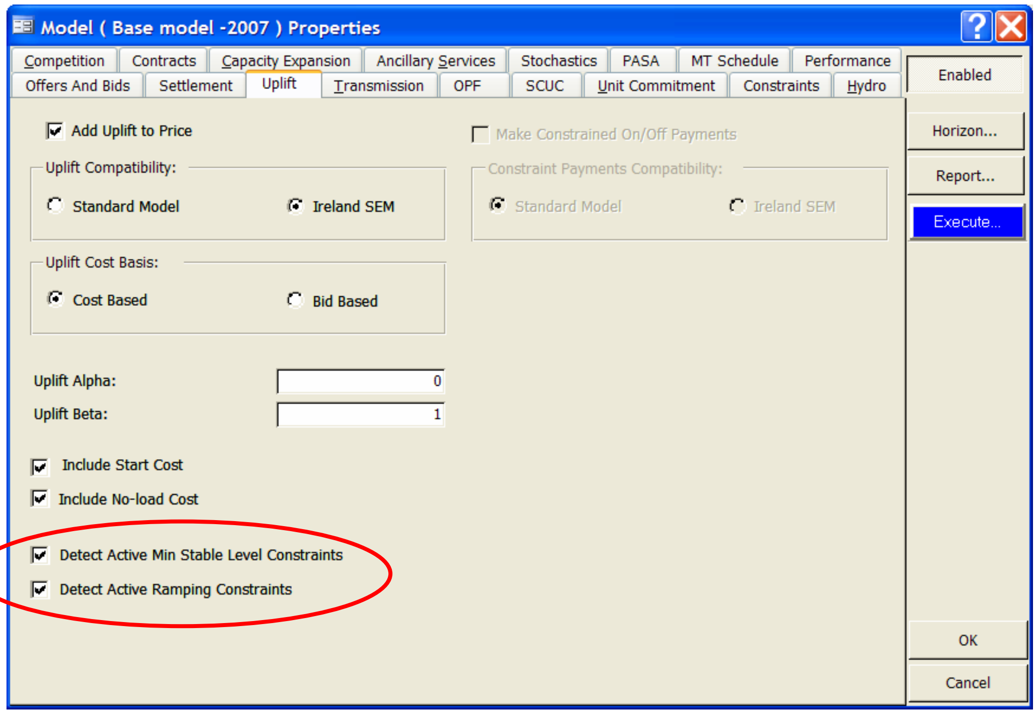
We subsequently repeated our start cost carry forward tests using the new PLEXOS release, 4.898 R5. We validated that this new release addressed the discrepancy that we had identified, limiting the start cost carry-forward to one day per T&SC v1.2.

Having investigated the start cost carry-forward discrepancy, we then tried to validate the Uplift values reported by PLEXOS in our scaled-down five generator model. We imported the generation output, shadow prices, generation costs and start costs reported by PLEXOS into a spreadsheet. We used Excel's in-built solver to optimise the Uplift Profile Objective subject to the Cost Recovery Constraint for each generator. The Excel solver was found to replicate the hourly Uplift values reported by PLEXOS.

We also tested and observed the impact of varying the SEM Uplift parameters (α and β) in annual PLEXOS runs for the full all-island system. Since the current PLEXOS release does not directly model the Rev Min constraint, we sought to estimate its materiality by re-running PLEXOS with the Uplift parameters set to minimise revenues ($\alpha = 1$, $\beta = 0$). We extended our post-processing spreadsheet to calculate the total generator SMP revenues by trading day, with the option to filter by "price maker" status. We then tested whether the Rev Min constraint would bind at different values of the δ parameter by comparing the daily SMP revenues from the "base" and "rev min" runs. Using our starting data set for calendar 2007, we found that the Rev Min constraint was not binding at the proposed δ value of 5.

One caveat on this Rev Min test as noted previously is that the current release of PLEXOS does not remove “price takers” from the Uplift Cost Objective Function. This discrepancy with the T&SC may have a minor impact on our “rev min” runs to the extent that the proportion of “price maker” output varies over the day.

Finally, we explored the effect of the Min Stable Level (MSL) and ramping filters available in the PLEXOS SEM Uplift module. These are available on the PLEXOS Uplift tab as shown below:



If selected, these filters will exclude a generator from setting Uplift if the unit is running at MSL or at Max Ramp for ALL hours in the continuous period of operation.

Unless otherwise indicated, all the PLEXOS Uplift results presented in this report were from PLEXOS runs with the MSL and Ramping filters enabled. To test the effect of these filters, we ran a variant of our base scenario for calendar 2007 with the Uplift filters switched off.

The table below shows the annual time-weighted average prices from the two PLEXOS runs[32]:

[32] Each model was run for calendar 2007 in “Rounded Relaxation” mode, with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 (α = 0, β = 1).

	BASE (MSL & Ramping Filters On)			MSL & Ramping Filters Off		
€/MWh	**All**	**Peak**	**Off-peak**	**All**	**Peak**	**Off-peak**
SMP	61.08	68.88	56.75	63.01	71.38	58.36
Uplift	6.97	6.99	6.95	8.89	9.49	8.56
Shadow Price	54.12	61.89	49.80	54.12	61.89	49.80

It can be seen that Uplift and hence SMP is around 2 €/MWh higher on average when the Uplift filters are removed. However, these average results do not reveal the most significant role of the filters which is to remove spikes in Uplift when generator units are scheduled for short periods of time at their MSL. For example, the SMP at the 17:00 peak on the 1st January is reported to be 161.4 €/MWh in the Base run but 444.6 €/MWh in the run without Uplift filters. The reported Uplift in this period is 74.5 €/MWh in the Base run but 357.7[33] €/MWh in the run without Uplift filters. Looking at the output schedule, we found that the AP5 peaking unit had been scheduled to run at its MSL of 5 MW at 17:00 but was not operating in the adjacent periods. We validated that the price spike was caused by AP5 recovering its incremental, no load and start costs over 5 MW in a trading period:

AP5 @ 17:00 1/1/07		
Property	**Value**	**Unit**
Output	5	MW
Start fuel offtake	50	GJ
Heat cost	322.3	€/MWh
Start cost per MWh	122.2	€/MWh
Break-even SMP	444.6	€/MWh

We believe it is appropriate to apply the MSL and Ramping filters in the PLEXOS Uplift algorithm.

When using the "Rounded Relaxation" (RR) method of unit commitment in PLEXOS, peaking units can be observed to block load and then remain scheduled at MSL. This has been noted previously in

[33] As noted previously, the current PLEXOS release can apply price caps to shadow prices but not SMP, so our nominal cap value of 300 €/MWh did not apply in this example.

public discussions of the AIP modelling results and in AIP Uplift papers such as AIP-SEM-230-06 and AIP-SEM-07-51. In fact, the Uplift decision paper (AIP-SEM-07-51) states that for the recent Uplift modelling exercise "filters were applied such that units which, for a continuous operating period, were scheduled not to exceed their minimum stable generation level, were excluded from the analysis in respect of that continuous operating period." The Uplift filters within PLEXOS provide the capability to make these adjustments automatically.

Our model results have highlighted that Uplift values can be highly sensitive to the underlying generation schedule. To the extent that schedules produced by PLEXOS in RR mode are felt to have some "unrealistic" features, the MSL and Ramping filters prevent these "anomalies" from impacting Uplift. We note that in practice, the application of a price cap to SMP values in the SEM may have a similar effect to the Uplift filters in PLEXOS. The RAs have yet to set the level of the SMP price cap for the new market. For this modelling exercise, we have assumed a nominal figure of 300 €/MWh to cap shadow prices per AIP Loop 2. If the SMP price cap is set around this order of magnitude, it would remove Uplift-related price spikes due to plant recovering their no load and start costs at low output levels, such as the AP5 example above.

It is of course possible to run PLEXOS in MIP mode instead of RR. As discussed later in Section 2.8, we have found that the average SMP results are similar in either mode, as is the frequency of SMP spikes.

2.7 Participant Feedback on PLEXOS Model Validation

KEMA's approach to this SEM model and data validation project was designed to be as inclusive as possible for all market participants within the timescales available for project completion. The approach included workshops and bilateral meetings as well as the opportunity for all market participants to respond in writing to questionnaire/data requests. The feedback received from market participants was mostly related to input data and modelling assumptions, as detailed in the Data Validation Report. However, some participants also raised issues about PLEXOS modelling algorithms, which we subsequently sought to address within the model validation exercise.

Two participants were particularly interested in the different configuration options available within PLEXOS, specifically the use of the Rounded Relaxation mode compared to alternative unit commitment approaches. We therefore undertook additional analysis to explore different configuration options, as presented in the following section.

Another participant was concerned to clarify how PLEXOS represented generator heat rate curves, particularly for plant with multiple increments. This participant had conducted a benchmarking exercise, running an alternative market simulation tool with the AIP Loop 2 data assumptions and then comparing the shadow price and schedule outcomes with the published PLEXOS results. The observed differences in shadow prices between the two models had led to their concerns on generator heat rate functions in PLEXOS. A specific concern related to the "Fan Approximation" method for computing piece-wise linear heat rate functions within PLEXOS, as referenced in the AIP modelling assumptions documentation.

We arranged a conference call with this participant to describe the tests that we had conducted to validate the SRMCs reported by PLEXOS given the input heat rate functions (see Section 2.1.4). We also outlined our understanding that the input format specified for heat rates in this project avoids any requirement for further piece-wise linear approximations within PLEXOS itself: i.e. the input step functions for plant with multiple incremental heat rates are used directly by PLEXOS in the optimisation schedule and in the calculation of SRMCs and shadow prices. As explained in the PLEXOS online reference guide, the "Fan Approximation" method is used within PLEXOS to compute a piecewise linear model of the heat input function if polynomial inputs are specified. This is not required when the linear steps of the incremental heat rate function are specified directly, as in the AIP Modelling Project and our analysis.

It was not within the scope of our project to benchmark PLEXOS against the EPUS software or indeed with other market simulation tools. However, by discussing this participant's methodology and assumptions for their benchmarking exercise, we were able to identify a number of factors that may have been responsible for the different pricing outcomes they had observed. These factors included differences in modelling algorithms, model configuration and input data assumptions, as outlined below:

1. ***Pricing algorithm*** – Unlike the "shadow prices" of the demand constraint reported by the PLEXOS optimiser, we understand that the alternative simulation model used for the benchmark exercise applies an ex-post algorithm to first identify a marginal plant and then set the price based on its SRMC. Although it is often possible to directly associate PLEXOS shadow prices with the SRMC of a particular plant, our own analysis has shown that there can be numerous periods in which the reported shadow price is not equal to a single generator's SRMC (see Sections 2.5.2 and 2.5.5). Moreover, PLEXOS does not need specific rules to control the operating circumstances in which a plant can set the shadow price (e.g. if running on a MSL or ramp rate constraint). The benchmark model requires such rules to identify the marginal plant in each period. Hence, the two models could report different prices even if the plant schedules were identical.

2. ***Optimisation horizon*** – PLEXOS was configured in AIP Loop 2 to model daily optimisation steps without a look-ahead, whereas the benchmark model optimised in weekly steps. Within PLEXOS, we have found that the ST Schedule configuration can have a material impact on the price results, as shown by our sensitivity tests with different look-ahead periods and daily or weekly optimisation steps (see Section 2.3.2.2). Price discrepancies arising from such

configuration differences are just as likely when the results of alternative simulation models are compared.

3. ***Moyle*** – We understand that for the benchmarking exercise, the load profile specified in the alternative model was net of the BETTA trades in the published PLEXOS AIP Loop 2 results. This was to ensure that differences in the treatment of interconnectors between the two models did not result in dissimilar Moyle flows. However, our own analysis using the Loop 2 data set in PLEXOS has shown that Moyle can be marginal for a substantial portion of the year (e.g. 29% in our base 2007 RR run). The BETTA market could not be involved in price-setting in the participant's benchmark model since load was modelled net of Moyle flows. Given the various technical constraints imposed on both thermal and hydro plant within our SEM data set, the Moyle interconnector is typically the most flexible dispatch option available to the optimiser. Fixing the Moyle flows in a simulation model therefore reduces system flexibility. As an experiment, we deducted the net BETTA trades from load and re-ran PLEXOS without Moyle. We found that both shadow prices and Uplift differed from our base run.

4. ***Start costs*** – The published AIP Loop 2 input data set included hot, warm and cold start costs but we understand that only the warm start costs were actually modelled in PLEXOS. The participant had modelled multiple warmth states for the benchmark exercise. Our PLEXOS sensitivity showed that including multiple start costs can have a material price impact (see Section 2.1.5).

5. ***Pumped storage*** – We understand that the participant's benchmark simulation model employs a post-processing algorithm to schedule pumped storage load and generation, whereas in PLEXOS pumped storage is co-optimised.

6. ***Constrained & unconstrained runs*** – The published AIP Loop 2 output data included results from both constrained and unconstrained model runs, although the distinction between output properties may not have been obvious to non-PLEXOS users. We believe this may have caused some confusion when comparing generation schedules with the benchmark model. The constrained output schedules in the AIP Loop 2 results are somewhat different from the unconstrained results since they include the effects of transmission constraints and ancillary service provision.

We concluded that several factors were likely to have contributed to the price differentials observed between the PLEXOS results from AIP Loop 2 and the participant's benchmark simulation model. We remained confident that the SRMCs reported by PLEXOS for plant with multiple incremental heat rates are consistent with the input data.

2.8 PLEXOS Configuration Review

The final part of our review focuses on exploring the different configuration options within PLEXOS, specifically the alternative approaches available for unit commitment. As indicated previously, the PLEXOS analysis we have presented so far in this report has been based upon running the model in Rounded Relaxation (RR) mode. This was the unit commitment approach adopted by the AIP Modelling Project and is the option recommended by Elan and Drayton Analytics for most situations.

Based on feedback from industry participants (and subsequently the RAs), we undertook the task of comparing the alternative PLEXOS unit commitment options in the context of SEM modelling. Here we present the results of our comparative analysis and discuss the pros and cons of each PLEXOS option.

2.8.1 Average Price

We begin by comparing seasonal average prices under the alternative unit commitment options. Applying the base scenario assumptions in our starting data set, we ran PLEXOS for the calendar year 2007 using four different approaches to unit commitment:

1. ***Mid-Term (MT) Schedule only***: annual optimisation with no daily ST Schedule unit commitment

2. ***Linear Relaxation (LR)***: annual MT Schedule followed by daily ST Schedule in LR mode

3. ***Rounded Relaxation (RR)***: annual MT Schedule followed by daily ST Schedule in RR mode

4. ***Mixed Integer Program (MIP)***: annual MT Schedule followed by daily ST Schedule in MIP mode

For clarity, it should be noted that the choice of PLEXOS unit commitment option only relates to the ST Schedule algorithm – the same ex-ante MT Schedule and ex-post SEM Uplift algorithms are applied in each case. The table below shows the time-weighted annual average prices and relative run times from the four PLEXOS runs[34]:

[34] Each model was run for calendar 2007 with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$). The RR run had rounding threshold set to 5. The MIP run had Relative Gap set to 0.5.

PLEXOS Mode	SMP €/MWh	Uplift €/MWh	Shadow Price €/MWh	Relative PLEXOS run time[35]
Mid-Term Only[36] (MT)	n/a	n/a	58.82	0.18
Linear Relaxation (MT + ST LR)	60.02	0.01	60.01	1.23
Rounded Relaxation (MT + ST RR)	61.08	6.97	54.12	1.00
Mixed Integer Program (MT + ST MIP)	62.49	1.32	61.17	41.73

It is observed that the annual average SMP results are much closer than the average shadow prices. In particular, the higher average shadow price for the MIP run is offset by lower average Uplift compared to the RR run. Average Uplift is negligible in the LR run. Note also that the very fast MT only run appears to produce a reasonable approximation of the annual average price.

There is a significant variation in model performance, with the MIP run taking substantially longer. To put this difference in absolute terms, the RR run took 9 minutes 48 seconds while the MIP run took 6 hours 49 minutes.

The table below shows the seasonal[37] time-weighted average prices for the LR, RR and MIP runs (results for the MT only run were not available on a comparable basis):

[35] The relative run times in this report are provided as an approximate guide for indicative purposes only. They are based on total elapsed run times rather than CPU times, and will therefore be dependent on any other processes that were running in parallel on our modelling machines.

[36] The SEM Uplift algorithm relies upon ST Schedule results, so Uplift and SMP are not available for the MT only run.

[37] As indicated previously, the seasonal definitions used here are consistent with the AIP Loop 2 data set: summer is the 7 month period March to September, peak is 08:00 to 19:00 weekdays.

Linear Relaxation (LR)					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	60.02	68.97	55.04	47.84	77.39
Uplift	0.01	0.00	0.01	0.00	0.01
Shadow Price	60.01	68.97	55.03	47.83	77.38

Rounded Relaxation (RR)					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	61.08	68.88	56.75	50.79	75.77
Uplift	6.97	6.99	6.95	5.56	8.97
Shadow Price	54.12	61.89	49.80	45.23	66.80

Mixed Integer Program (MIP)					
€/MWh	**Annual**	**Peak**	**Offpeak**	**Summer**	**Winter**
SMP	62.49	71.38	57.55	49.16	81.51
Uplift	1.32	1.94	0.97	0.99	1.78
Shadow Price	61.17	69.45	56.57	48.17	79.72

Comparing the RR and MIP runs, the seasonal average shadow prices are substantially higher in the MIP run. The MIP/RR shadow price differential is 13% on an annual basis but is higher during the winter at 19%. However, the shadow price differentials are largely offset by Uplift in each season. The winter MIP/RR SMP differential is 8% while the annual average SMP differential is 2%.

It is observed that seasonal average Uplift is negligible in the LR run. While the RR and MIP options produce completely integer solutions, the LR mode relaxes integer constraints such as Min Stable Level. No load and start costs tend to be recovered through the shadow price rather than through Uplift in LR runs. We did not test the LR mode extensively, since the relaxation of MSL and other constraints under this option are inconsistent with the T&SC.

Our detailed comparison of PLEXOS unit commitment options has therefore focused on the RR and MIP modes.

2.8.2 Price Shapes

It is important to compare the shape of prices as well as their average levels. In this section we examine the price shapes resulting the PLEXOS calendar 2007 runs under the RR and MIP unit commitment options.

The table below compares standard deviation and correlation statistics for the RR and MIP runs:

	RR	MIP
SMP Std Dev	24.20	23.52
Uplift Std Dev	17.03	4.39
SP Std Dev	14.35	22.78
Correlation Shadow Price to SMP	0.72	0.98
Correlation Shadow Price to Uplift	0.18	0.08
Correlation SMP to Load	0.55	0.62
Correlation Uplift to Load	0.17	0.22
Correlation Shadow Price to Load	0.73	0.59

The two sets of SMP results have very similar standard deviations. However, the standard deviations imply that shadow prices are more volatile in the MIP run while Uplift is more volatile in RR. It is interesting to note that the correlation between shadow price and load is considerably higher in the RR run while the SMP/load correlation is slightly higher in MIP.

The table below compares percentile and price "spike" frequencies for the RR and MIP runs:

€/MWh	SMP		Shadow Price	
	RR	MIP	RR	MIP
Median	57.02	57.45	52.80	56.23
90th percentile	86.87	89.74	79.84	88.29
95th percentile	99.72	99.47	83.34	97.24
99th percentile	148.64	132.33	93.72	123.40
Count hours > 75	1647	1981	1013	1880
Count hours > 100	431	385	37	313
Count hours > 150	85	73	0	57
Count hours > 200	12	18	0	16
Count hours >= 300[38]	9	2	0	2

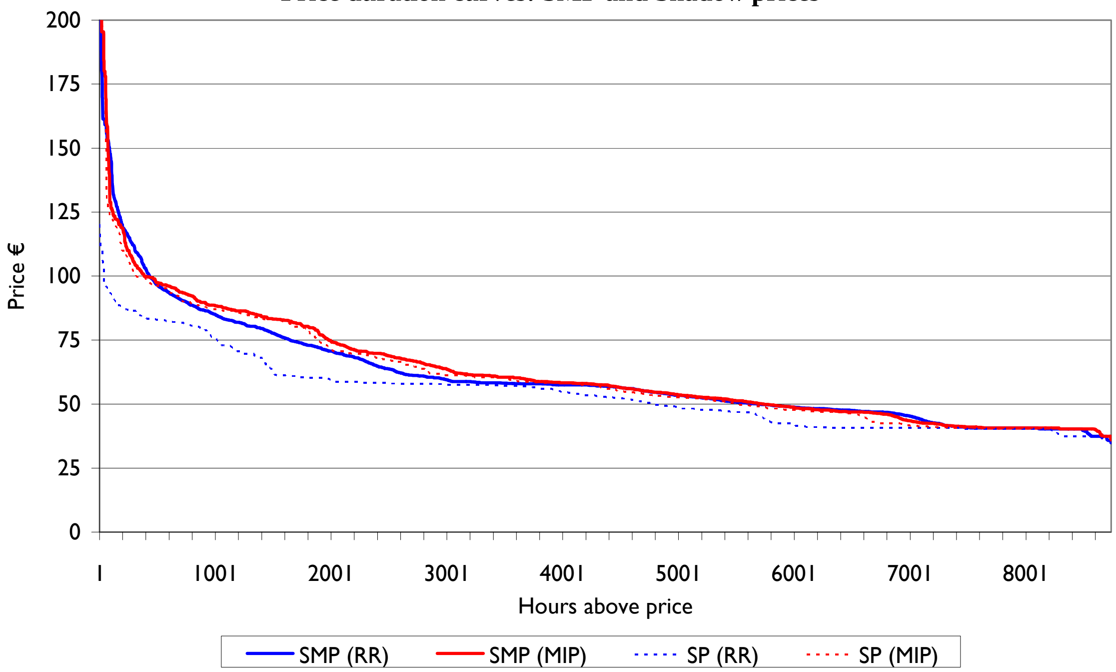
[38] The shadow price was capped at 300 €/MWh within these PLEXOS runs.

It can be seen that the SMP medians are somewhat closer than the annual average (mean) values presented previously. The SMP percentiles are also close, but the MIP shadow price percentiles are consistently higher. It appears that the MIP price "spikes" in this results set are largely driven by the shadow price, whereas Uplift is also a contributing factor to SMP spikes in RR.

As a reference point for these price spikes, we also examined the hourly generator SRMC values reported by PLEXOS. The highest reported SRMC in each run was associated with the Ballylumford GTs (BGT1, BGT2) at 135.1 €/MWh. These units were only scheduled for one hour in MIP and did not operate in RR (note that PLEXOS still reports a non-zero SRMC when a unit is not operating, quoting the SRMC at the MSL load point). In the MIP run, there were 60 periods in which the shadow price was above the SRMC of the Ballylumford GTs.

The chart below compares the price duration curves for the calendar 2007 RR and MIP runs. The SMP and shadow price (SP) values for each run have been independently sorted from high to low:

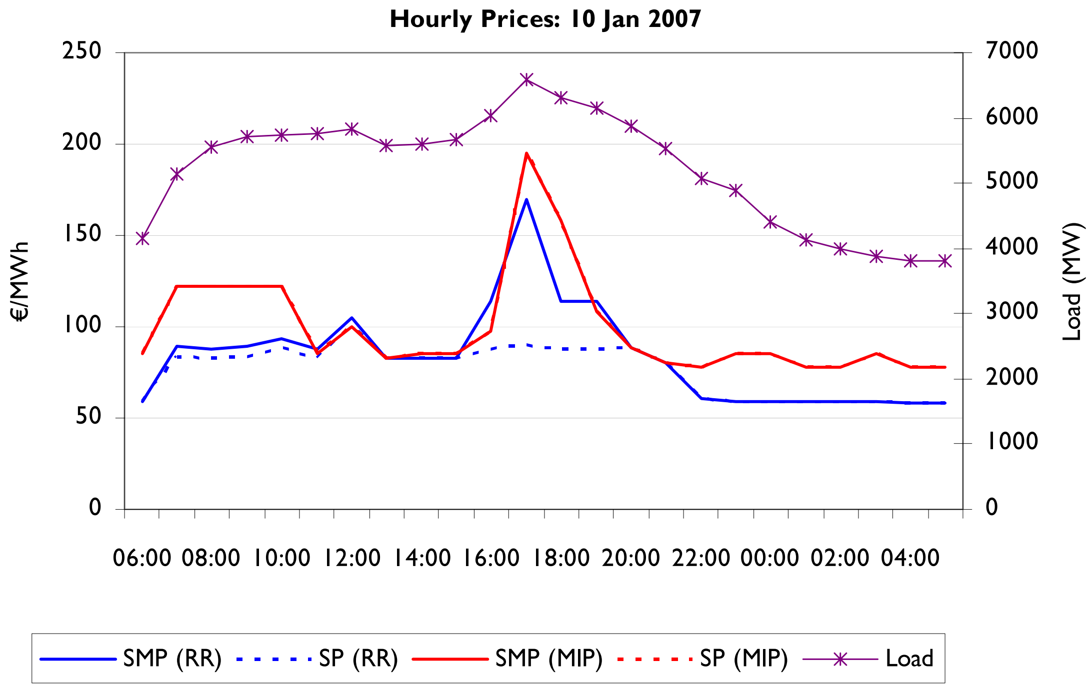
Price duration curves: SMP and Shadow prices



It is observed that the SMP duration curves for the two runs track closely over the year, particularly for prices below the median (e.g. beyond 4,500 hours) and at the peaks (e.g. top 500 hours). However, the SMP duration curve for the MIP run is consistently higher in the shoulder periods between 500 and 4,500 hours.

We also compared the price profiles for representative winter and summer weekdays:

1. *Winter weekday (Central scenario): Wednesday 10th January 2007*



Comments:

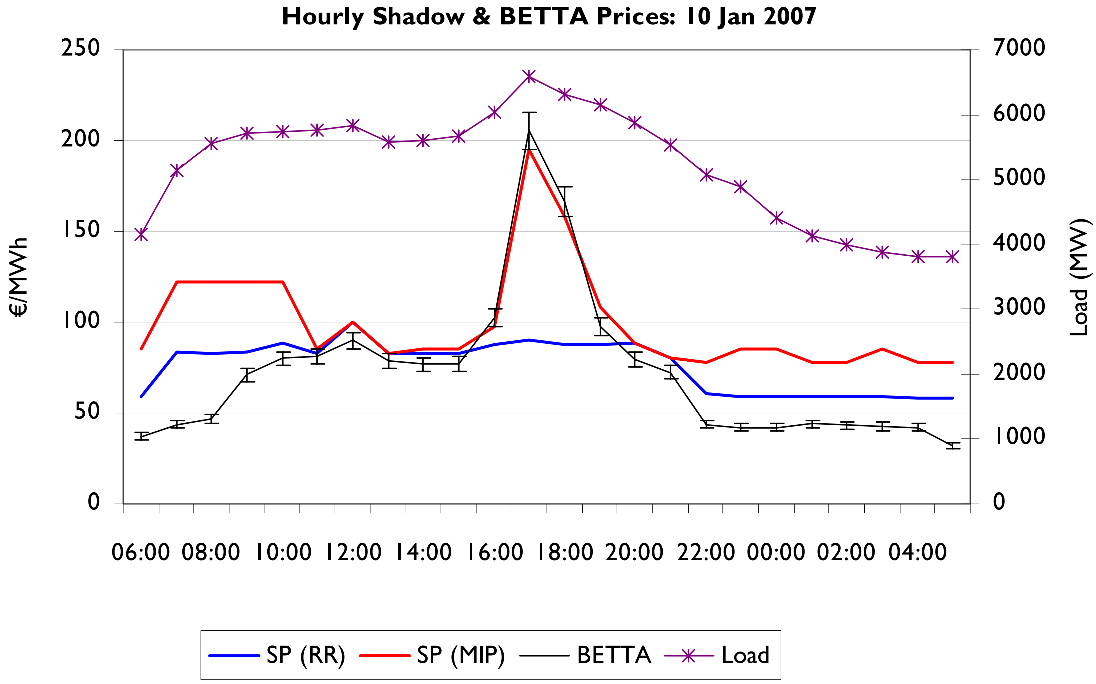
– The RR and MIP SMP profiles track reasonably closely for much of the day (e.g. 11:00 to 21:00) but the MIP SMP is significantly higher overnight and during the morning rise. Note that the MIP SMP and shadow price (SP) profiles are identical since Uplift is negligible on this day for the MIP run.

– Moyle is marginal in the MIP run at 12:00 and from 14:00 to 21:00. The diagram below demonstrates the relationship between the MIP price and the loss-adjusted BETTA price, with Moyle exports clearly setting the MIP price at the 17:00 peak.

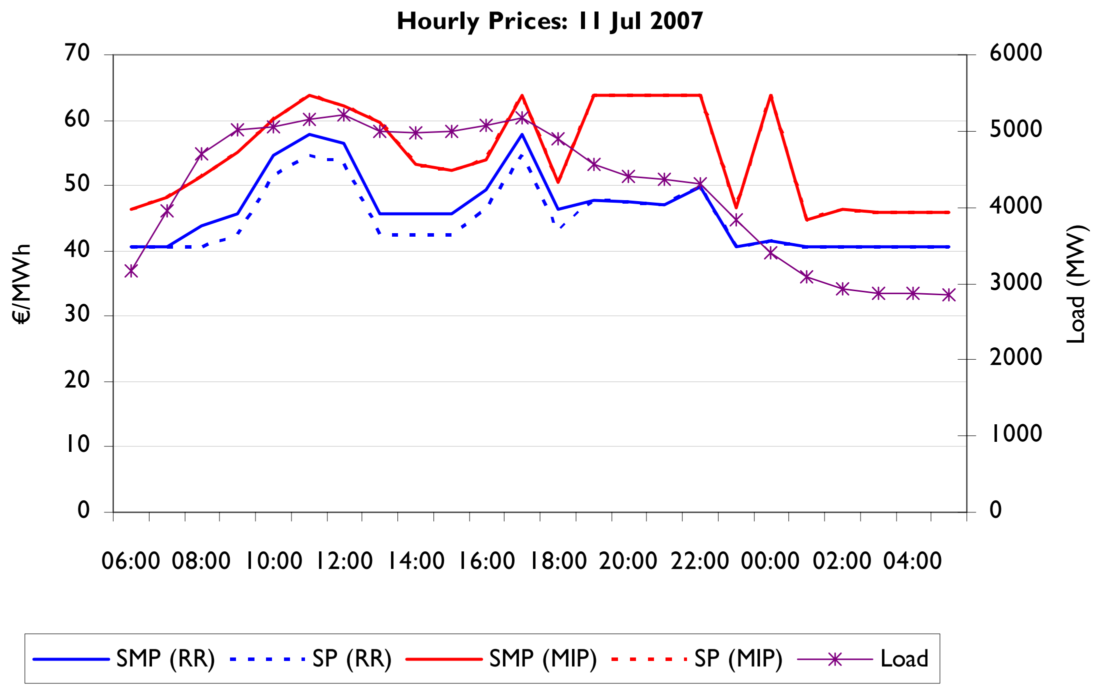
– The RR run has two extra plant committed at the 17:00 peak: PB3 (@ 242 MW) and AP5 (@ MSL).

– Three peaking plant (RH1, RH2, TP1) are committed for a single period at 17:00 in both the RR and MIP runs. However, these plant are scheduled at their maximum capacity in MIP but at their MSL in RR.

– The shadow price is equal to a generator SRMC value in just one period of the MIP run, compared to 17 periods in the RR run.



2. *Summer weekday (Central scenario): Wednesday 11th July 2007*



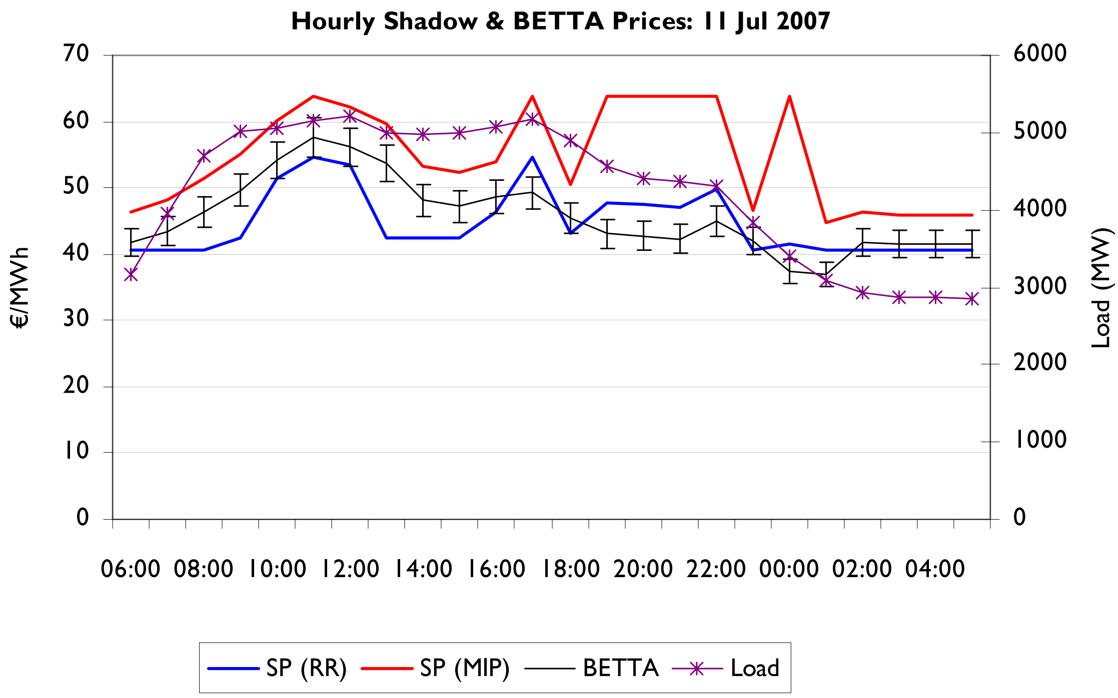
Comments:

– The RR and MIP SMP profiles track reasonably closely with the exception of the evening period (19:00 to 00:00) when the MIP SMP is considerably higher. Note once again that the MIP SMP and shadow price (SP) profiles are identical since Uplift is negligible on this day for the MIP run.

– Moyle appears to be marginal (i.e. flowing between zero and maximum) for 17 hours in the MIP (e.g. 06:00 to 16:00, 02:00 to 05:00), although the MIP price is consistently above the loss-adjusted BETTA price (see diagram below). Moyle is marginal for 10 hours in the RR run (e.g. 16:00 to 22:00).

– RR commits all 3 Moneypoint (MP) units at the 17:00 peak but only 2 MP units are scheduled in the MIP at this time. RR also schedules additional hydro output at 17:00 whereas MIP schedules pumped storage instead. Moyle imports are significantly higher in the MIP run at 17:00, substituting for the extra MP unit (285 MW) in the RR run.

– The shadow price does not equal a generator SRMC value in any period of the MIP run, but a SRMC match can be made in 17 periods of the RR run.



Having examined the price profiles for representative days, we found that it was generally harder to explain the levels at which shadow prices were being set in the MIP run. This was because there appeared to be fewer periods in which the shadow price could be matched to a generator SRMC value. To assess whether this was generally the case, we analysed the hourly shadow prices for both runs and determined the number of periods in which prices were equal to a generator SRMC value or in which Moyle was marginal (i.e. with an hourly flow between zero and the import/export limit). The results of this analysis are shown below on a proportional basis for the calendar 2007 PLEXOS runs:

Shadow Price Analysis	RR	MIP
Generator SRMC	*65.9%*	*31.4%*
Moyle marginal	*28.8%*	*37.5%*
Other (inter-temporal, multi-unit)	*5.2%*	*31.1%*

In this results set, the MIP shadow price matches a (single) generator SRMC value in only 31% of periods compared to 66% of periods in the RR run. It appears to be far more common in the MIP run for shadow prices to involve multiple generators and/or multiple periods. Note that this may also apply to periods in which we have deemed Moyle to be marginal: as illustrated by the representative summer weekday above, the shadow price is not necessarily set by the loss-adjusted BETTA price when the Moyle flow is marginal.

2.8.3 Schedule Comparisons

Here we compare PLEXOS schedules for the calendar 2007 runs under the RR and MIP unit commitment options.

The table compares various operating statistics for the two runs by plant type:

Plant Type	RR				MIP			
	GWh	% GWh	Gen Hrs	Hrs @ MSL	GWh	% GWh	Gen Hrs	Hrs @ MSL
Coal	10,018.5	26.5%	42,674	2,294	10,001.7	26.7%	41,074	564
Gas	22,804.3	60.3%	73,522	3,390	22,407.2	59.7%	70,793	639
Oil	222.4	0.6%	1,734	373	169.5	0.5%	1,082	25
Distillate	1.6	0.0%	114	83	2.4	0.0%	54	4
Peat	1,085.4	2.9%	10,729	1,945	1,192.0	3.2%	10,444	172
Wind	2,839.0	7.5%	8,733	-	2,839.0	7.6%	8,733	-
Hydro	718.4	1.9%	45,233	-	718.4	1.9%	45,243	-
Hydro PS	143.6	0.4%	2,227	-	188.6	0.5%	3,284	-
Total	**37,833.3**	**100.0%**	**184,966**	**8,085**	**37,518.8**	**100.0%**	**180,707**	**1,404**

It can be seen that the generation market shares for each plant type are broadly comparable. The largest difference is the extra 397 GWh of gas-fired generation in the RR run. This appears to be substituted by additional Moyle imports in the MIP run rather than by other plant types. For comparison, the net Moyle imports were 1,009 GWh in the RR run and 1,403 GWh in MIP.

In the context of AIP and Uplift modelling discussions, it has often been commented that the PLEXOS RR mode has a tendency to schedule units at their Min Stable Level (MSL). There is some evidence for this in the above table, with plant operating at MSL for 8,085 hours in the RR run (4.4% of total generating hours), compared to 1,404 hours in the MIP run (0.8% of total). In addition, we analysed the number of contiguous operating periods in which a generation unit did not operate above MSL. There were 154 such contiguous operating periods in the RR annual run (4.6% of total operating periods) compared to just 8 in the MIP run. This provides an indication of the number of occasions on which the Uplift MSL filter has been applied in the PLEXOS SEM Uplift algorithm.

As shown previously for the base RR run, we also compare the number of periods when generating units are running despite their reported SRMC being above the shadow price. These instances are almost always associated with plants running at their MSL, as shown below:

RR	# of Periods					
Condition	**Total**	**Coal**	**Gas**	**Oil**	**Distillate**	**Peat**
Running (total generating hours)	184,966[39]	42,674	73,522	1,734	114	10,729
Running when SRMC > shadow price:	7,225	1,471	3,252	562	69	1,871
& when @ MSL	6,997	1,471	3,252	355	69	1,850
& when @ ramp limit	207	-	-	207	-	-
(delta)	21	-	-	-	-	21

MIP	# of Periods					
Condition	**Total**	**Coal**	**Gas**	**Oil**	**Distillate**	**Peat**
Running (total generating hours)	180,707	41,074	70,793	1,082	54	10,444
Running when SRMC > shadow price:	1,171	309	614	66	4	178
& when @ MSL	1,117	309	614	23	4	167
& when @ ramp limit	43	-	-	43	-	-
(delta)	11	-	-	-	-	11

[39] Total includes non-thermal plant (wind, hydro, PS)

2.8.4 Start Cost Sensitivity

Consistent with the base scenario assumptions in our starting data set, the MIP and RR PLEXOS runs presented above do not model the warmth dependency of start costs. Each generator has been modelled with a single start cost (the warm state cost). However, as reported previously, modelling hot and cold starts appeared to have a material impact on the model results using PLEXOS in RR mode. We have therefore carried out a further sensitivity to establish whether multiple start costs also have a material impact on the MIP results.

The table below shows the annual time-weighted average prices resulting from PLEXOS RR and MIP runs[40] for calendar 2007 with the three alternative approaches to start costs that we described previously:

€/MWh	RR			MIP		
Start Cost Model	**SMP**	**Uplift**	**Shadow Price**	**SMP**	**Uplift**	**Shadow Price**
Single: Warm only	61.08	6.97	54.12	62.49	1.32	61.17
Multiple: Interpolation	67.05	13.12	53.93	64.39	1.61	62.79
Multiple: Step function	66.67	12.77	53.90	63.57	1.70	61.87

At the annual level, we note that the SMP increase when modelling multiple start costs is more significant with the RR mode than with the MIP mode.

We also compared the seasonal average prices for these six PLEXOS runs:

[40] Each model was run for calendar 2007 with fuel prices, demand and generator parameters based upon the central AIP Loop 2 data set, and with Uplift parameters per AIP-SEM-07-51 ($\alpha = 0$, $\beta = 1$).

€/MWh	Annual	Peak	Offpeak	Summer	Winter
RR: Warm start only					
SMP	61.08	68.88	56.75	50.79	75.77
Uplift	6.97	6.99	6.95	5.56	8.97
Shadow Price	54.12	61.89	49.80	45.23	66.80
RR: Interpolated start costs					
SMP	67.05	83.34	58.00	54.61	84.81
Uplift	13.12	21.60	8.40	9.40	18.41
Shadow Price	53.93	61.73	49.60	45.20	66.39
RR: Stepped start costs					
SMP	66.67	82.89	57.65	54.39	84.19
Uplift	12.77	21.39	7.98	9.23	17.82
Shadow Price	53.90	61.50	49.67	45.15	66.37

€/MWh	Annual	Peak	Offpeak	Summer	Winter
MIP: Warm start only					
SMP	62.49	71.38	57.55	49.16	81.51
Uplift	1.32	1.94	0.97	0.99	1.78
Shadow Price	61.17	69.45	56.57	48.17	79.72
MIP: Interpolated start costs					
SMP	64.39	74.97	58.52	52.80	80.93
Uplift	1.61	3.03	0.82	1.24	2.14
Shadow Price	62.79	71.94	57.70	51.57	78.79
MIP: Stepped start costs					
SMP	63.57	73.40	58.11	51.27	81.12
Uplift	1.70	3.16	0.89	1.06	2.61
Shadow Price	61.87	70.24	57.23	50.21	78.51

Once again the price impact of modelling multiple start costs is more significant in the RR runs than with MIP. In fact, the winter average SMP is slightly lower in the MIP runs when multiple start costs are modelled compared to the base MIP run with only warm start costs. In the RR runs, modelling multiple start costs pushes up the winter average SMP by around 9 €/MWh due to a substantial increase in Uplift. Modelling multiple start costs in the RR mode leads to a three-fold increase in average Uplift at peak times. The implication is that there is a higher incidence of expensive cold starts in the RR runs compared to the MIP, which then feed through into Uplift. Our analysis of the schedules from the stepped start cost runs revealed 157 cold starts in the RR mode and 61 cold starts in the MIP.

These sensitivity results suggest that the MIP unit commitment mode is able to find a more optimal solution when multiple start costs are modelled compared to the RR mode. This is confirmed by a comparison of the objective functions for the six PLEXOS model runs:

Objective Function (€m)	RR	MIP	*Delta*
Single: Warm only	2,103	2,099	*-0.19%*
Multiple: Interpolation	2,125	2,112	*-0.61%*
Multiple: Step function	2,123	2,105	*-0.83%*

The MIP unit commitment mode should generally always find a lower cost (i.e. more optimal) solution than the RR model. In fact, PLEXOS uses the RR mode to provide a feasible starting solution for the MIP optimisation. The table above shows that the total objective function for these annual model runs is around 0.2% lower for the MIP mode with a single start cost. However, the difference between the objective functions increases to 0.8% when stepped multiple start costs are modelled.

2.8.5 Observations & Recommendations

PLEXOS has multiple configuration options for modelling unit commitment. Of these, the RR and MIP methods are the most appropriate options for simulating the SEM daily unconstrained schedule. RR and MIP are both consistent with the T&SC in respecting integer constraints such as Min Stable Level, and both methods produce feasible integer solutions.

The price comparisons we have presented in this section were based upon a single base set of scenario assumptions for calendar 2007, including fuel prices, carbon costs and wind availability. Under our base scenario, the SMP results from the MIP and RR runs were broadly consistent in terms of means, medians, standard deviations and percentiles. The SMP duration curves were also closely matched for a large proportion of the year. However, the composition of SMP between shadow price and Uplift was somewhat different, with the higher shadow prices under the MIP option being offset by lower Uplift. Shadow price "spikes" were more commonly observed in the MIP run, while SMP "spikes" in the RR run tended to reflect higher contributions from Uplift.

When comparing SMP results between the two methods, we believe it is important to consider the role of the Uplift cost recovery constraint. Both the RR and MIP methods produce feasible schedules given the inputs for plant technical parameters. The cost recovery constraint within the SEM Uplift algorithm guarantees generators will break-even over each period of operation. Thus, if one of the PLEXOS unit commitment options produces lower SMP results on average, these prices are nonetheless consistent with both generator cost recovery and technically feasible schedules in accordance with the T&SC. Moreover, we do not take the view that the prices produced by the full integer MIP method are inherently the benchmark against which the RR results should be measured.

Once the SEM is operational, it will be possible to compare PLEXOS RR and MIP results with the actual prices produced by the EPUS software. Actual or even projected EPUS software results are not available pre SEM Go-Live. Furthermore, the specification of the EPUS algorithm has not been published in sufficient detail to enable a paper-based comparison with the two PLEXOS unit commitment options. Thus, at this time, it is not feasible to judge whether the RR or MIP method will provide the closest approximation of the SEM prices produced by EPUS.

One criticism that has been made of the PLEXOS RR method is that the resulting schedules can appear to have too many units scheduled at their Min Stable Level (MSL). Our base scenario analysis has confirmed that the incidence of generators running at MSL is indeed more prevalent in a RR schedule compared to a MIP schedule. One comment that can be made in response to this criticism is there are user-adjustable parameters within PLEXOS that can be applied to modify the outcome of RR runs. The RR algorithm will generally round on (i.e. commit) units to the extent required to prevent unserved energy. This is subject to a user-defined rounding threshold, so it is possible to fine-tune this parameter and find a solution that avoids unserved energy while minimising instances of plant being committed but then scheduled at MSL. Secondly, the MSL filter in the Uplift algorithm can be applied to ensure that Uplift is not set by units which are continuously operating at MSL.

Model configuration options aside, scheduling outcomes will clearly be dependent upon the structure of the input data. Generator inflexibilities such as MSL, ramp rates and min up times were specified for all the units in our starting data set, including peaking GTs, hydro and pumped storage plant. In other modelling contexts, technical constraints are often relaxed for flexible plant when modelling at hourly resolution. In our base scenario, we have relaxed constraints such as MSL for hydro and pumped storage but have retained the constraints on thermal peaking plant. It is possible that block loading at MSL could be avoided in the RR method if peaking units were modelled more flexibly. However, we have not explored this further in the SEM context because of the likely interactions with Uplift.

It is the case that the MIP unit commitment will almost always find a more optimal solution than the RR method. This is because the RR method is actually used to "hot start" the MIP. RR provides a feasible integer solution as a starting point which the MIP then tries to improve by applying a "branch and bound" technique. Within each branch, the MIP generally searches out the extremes of the solution space. One consequence of this as we have seen is that the shadow prices resulting from the MIP are often less "intuitive" than those produced by the RR method. RR shadow prices can generally be tied to the SRMC of a specific generator. In the MIP method, it would appear that the shadow prices are more likely to reflect objective function (i.e. schedule production cost) changes involving multiple periods and multiple generators.

Our start cost sensitivities provide some evidence that MIP was able to find a more optimal solution than RR when the warmth-dependency of start costs was introduced to the modelling problem. Given the apparently material impact of multiple start costs on Uplift when the RR method is used, it may be instructive to repeat this sensitivity with the newly finalised data set for 2008.

Performance time is probably the key drawback of the MIP commitment option. We have found that the model run times for annual simulations of the full all-island system are typically 25 to 50 longer for MIP compared to RR.

Ultimately, the choice of unit commitment option in PLEXOS will largely depend upon the particular goals of each modelling exercise. For example, the task of simulating SEM prices over a two year time horizon would invariably lead to a different choice of model configuration than a study of a specific generating unit's expected schedule over the next month. Although we have had no involvement with the RAs in the modelling of directed contracts, we understand that one of the RAs' modelling priorities is to quantify the relationships between input fuel/carbon prices and simulated SEM prices.

In any projection of future electricity prices over the medium to long term, uncertainty in the key data inputs is generally the most significant cause of deviations between outturn prices and the forecasts produced by the simulation model. In the case of SEM price modelling, the data validation project undertaken by KEMA has sought to verify the quality of generator input data. However, other key input variables such as daily spot fuel prices, hourly wind and hourly demand all remain subject to considerable uncertainty. In both the AIP Modelling Project and our own model validation simulations, these fuel, wind and load data inputs have been modelled deterministically within a scenario framework. Seasonal fuel price assumptions have been used in line with the granularity of data available in the forward traded markets, although in reality certain fuels such as natural gas can exhibit extremely high volatility in the short-term spot markets. To give one example of data uncertainty, last year's AIP Loop 2 modelling exercise assumed a carbon allowance price of €30/tonne for 2007, consistent with the forward market price at the time of the study. Less than twelve months later, the current market price for 2007 carbon allowances is below €1/tonne.

This uncertainty in key input variables leads us to make two observations. Firstly, when a simulation tool such as PLEXOS is used to model longer term electricity prices deterministically, it is essential that the uncertainty of key price drivers in explored via scenarios and sensitivities. Secondly, in comparison to data input uncertainty, we can reasonably expect that methodology choices and simplifying assumptions within the simulation model itself – such as the choice of unit commitment option or trading period granularity – will be of second or third order significance in influencing the accuracy of modelling outcomes.

To conclude, we would generally recommend the PLEXOS RR unit commitment option is used for modelling SEM prices over an extended time-frame such as a year. The RR method does produce SMP prices that are fully consistent with the T&SC constraints of schedule feasibility and Uplift cost recovery. In practical terms, it is likely that some 40 different combinations of fuel and carbon prices could be modelled using RR in the time taken by a single MIP run. The RR method is therefore the most appropriate option for exploring the impact of uncertain price drivers on the SEM over the medium to long term.

3. Summary of PLEXOS Issues

In this section, we present a summary of the PLEXOS issues that we identified, together with our proposed workarounds.

3.1 PLEXOS Discrepancies

The following table summarises the PLEXOS issues that we have identified during the course of this model validation exercise. For each issue, we outline a proposed workaround and estimate the materiality of the issue (assuming the workaround is implemented). If applicable, we also suggest future options such as PLEXOS development changes that could be pursued at a later date to supersede the proposed workarounds.

#	Category	Issue	Proposal	Estimated Materiality	Future Option
1.	Commercial offers	Start costs – PLEXOS currently interpolates between warmth states.	PLEXOS Workaround: input a step function to replicate T&SC commercial offer.	None	PLEXOS change request to add switch between step and interpolated start cost functions.
2.	Commercial offers	No load costs – if using PLEXOS with actual offer prices and quantities rather than heat rates and fuel costs, start costs will still be considered but no load costs will not.	Not relevant for forward–looking modelling pre SEM Go-Live. Potentially of interest post Go-Live for benchmarking with actual offer data.	None	PLEXOS change request to add monetary no load offer property for inclusion in unit commitment with offer prices.
3.	Technical offers	Certain plant operating parameters not handled in PLEXOS: dwell & soak times, etc.	Not expected to be material for modelling at hourly resolution but no data available for these parameters at present. Need to confirm if EPUS actually considers these parameters.	None expected	
4.	Technical offers	Warmth state dependency of run-up / ramp-up rates not modelled in PLEXOS.	Do not propose modelling run-up in PLEXOS. Need to confirm EPUS does not model (i) run-up and (ii) warmth dependency of ramp rates.	None expected	
5.	Schedule	Simultaneous buys / sells with BETTA external market	PLEXOS workaround: add a nominal bid-ask	None	

#	Category	Issue	Proposal	Estimated Materiality	Future Option
		observed. N.B. this does not impact net schedule or prices.	spread so the optimiser can distinguish gross and net solutions.		
6.	Schedule	Scheduling anomalies observed when modelling unit run up / down. E.g. unit scheduled below MSL throughout a period of operation.	Do not propose modelling run-up in PLEXOS. Need to confirm EPUS does not model run-up.	None expected	
7.	Schedule	With RR unit commitment, peaking units observed to block load and then remain scheduled at MSL.	PLEXOS workaround: units operating only at MSL can be filtered out of SEM Uplift. Can use MIP mode instead of RR, but average SMP results are similar. Note that RR chooses to round on units to avoid unserved energy.	Low	
8.	Schedule	With MIP unit commitment, multi-unit pumped storage generators appear to be restricted to pumping at single unit pump load. N.B. not an issue in RR mode.	PLEXOS release 4.896 R08 addresses this MIP issue. Previous workaround was to configure multiple single-unit pumped storage generators.	None	
9.	Prices	Price cap (VOLL) in PLEXOS applied to shadow price rather than SMP including Uplift.	External workaround: apply price cap in post-processing spreadsheet if relevant at proposed cap level.	Expected to be low (but dependent on cap level)	PLEXOS change request to add option of applying cap to price including Uplift.
10.	Uplift	Price Takers in Uplift Objective Function.	Not relevant for zero α. Still relevant for Rev Min test (α = 1) but this is immaterial at proposed δ.	None	PLEXOS change request to add “include in Uplift” flag as a generator property.
11.	Uplift	Price Takers in Uplift Cost Recovery Constraint.	PLEXOS Workaround: remove fuel, no load and start costs for thermal price-takers. Price-takers with zero fuel cost (e.g. wind) already excluded.	None	PLEXOS change request to add “include in Uplift” flag as a generator property.

#	Category	Issue	Proposal	Estimated Materiality	Future Option
12.	Uplift	Start costs – maximum number of periods to carry forward on D+1. 24 hours in AIP-SEM-60-06 / PLEXOS but limited to 6 hour look-ahead in T&SC v1.2.	Understand there is a proposed T&SC modification to revert to AIP-SEM-60-06 treatment. No action required if this is confirmed.	None	
13.	Uplift	Start costs - carry forward over multiple days. Per AIP-SEM-60-06, the current PLEXOS release does not limit the carry-forward to one day, unlike T&SC v1.2.	PLEXOS release 4.898 R5 resolves this issue, limiting the carry-forward to one day.	None	
14.	Uplift	Start costs – formula for carry over ratio differs between T&SC v1.2 and AIP-SEM-60-06 / PLEXOS.	T&SC v1.2 ratio formula appears incorrect. Understand there is a proposed T&SC modification to revert to AIP-SEM-60-06 formula. No action required if this is confirmed.	None	
15.	Uplift	Rev Min constraint not modelled in PLEXOS.	Not anticipated to be binding at proposed δ. Workaround Rev Min test: re-run PLEXOS with $\alpha = 1$, and compare results externally.	None	
16.	Uplift	Spikes in Uplift observed when unit run up / down is modelled. Units not filtered out if operating below MSL.	Do not propose modelling run-up in PLEXOS. Need to confirm EPUS does not model run-up.	None expected	
17.	Uplift	Unlike T&SC v1.2, PLEXOS includes TLAFs in the Uplift cost recovery constraint so that SMP revenues are loss-adjusted. This is the correct break-even condition for generators. Since EPUS ignores TLAFs, generators will need to loss-adjust their incremental, no load and	Ignore potential impact of loss-adjusted no load and start up costs on the schedule. A workaround would be to manually loss-adjust all generator inputs (e.g. heat rate curves, no load, start costs by warmth state) rather than use dedicated PLEXOS functionality for	Low	Modifying PLEXOS to apply TLAFs to no load and start costs likely to be undesirable for all non-SEM PLEXOS users, particularly as this change would only be due to the omission of TLAFs in the current EPUS software.

#	Category	Issue	Proposal	Estimated Materiality	Future Option
		start costs to achieve the same result. But this in turn may lead to scheduling differences between EPUS and PLEXOS (since PLEXOS applies TLAFs to incrementals but not to no load and start costs).	TLAFs. This is too impractical, particularly if TLAFs are time-varying over an extended modelling horizon.		
18.	Uplift	Look-ahead period results are not available in the Diagnostic files or reports. Would be useful to validate start cost carry-forward rules.	Use next day's schedule as proxy for look-ahead period.	Low	
19.	Uplift	PLEXOS SEM Uplift functionality appears not to work if an external market (e.g. BETTA) is configured as a separate region without generation or load.	PLEXOS workaround: define the BETTA market at a Moyle node within the SEM region. Alternatively, to model BETTA as a separate region, configure a dummy generator and load instead of using the market approach.	None	
20.	Uplift	Potential cost under-recovery and incorrect prices when the PLEXOS SEM Uplift algorithm is applied to non-hourly trading periods. Significantly lower Uplift levels observed in half-hourly compared to hourly runs.	PLEXOS workaround: use an hourly trading period duration rather than half-hourly. Elan advises that this non-hourly SEM Uplift issue has been addressed in PLEXOS release 4.898 R14.	None	

We have tested the new PLEXOS release 4.898 R5 to validate that issue (13) has been addressed such that the start cost carry-forward is limited to one day in the SEM Uplift algorithm.

Assuming our recommended workarounds are implemented, we believe there to be no PLEXOS issues outstanding of significant materiality.

4. Conclusions & Recommendations

In this section, we present the conclusions and recommendations of our model validation exercise.

4.1 Model Validation Conclusions

We have validated that PLEXOS has the capability to model the SEM consistent with the market rules as laid out in the T&SC v1.2. In particular, we have:

1. Confirmed that PLEXOS can reproduce the Commercial and Technical Offer structures per the T&SC.

2. Validated that the SRMC values reported by PLEXOS are consistent with those calculated externally using the same set of inputs.

3. Validated that PLEXOS produces technically feasible schedules consistent with plant integer and dynamic constraints such as Min Stable Level and ramp rates.

4. Confirmed that PLEXOS has the capability to model non-thermal generation sources such as wind, hydro and pumped storage, as well as external interconnections.

5. Sense-checked that the shadow prices reported by PLEXOS are broadly consistent with a simplified stack model scheduling purely on SRMC.

6. Tested the PLEXOS Uplift algorithm is consistent with the T&SC Profile Objective and Cost Recovery Constraint.

We therefore conclude that PLEXOS is an appropriate model for simulating unconstrained market prices in the SEM.

4.2 PLEXOS Configuration Recommendations

Our recommended configuration for SEM modelling with PLEXOS is as follows:

1. ***Unit commitment*** – We believe the Rounded Relaxation (RR) method is the most appropriate unit commitment option for modelling SEM prices over an extended time-frame such as a year. Both the RR and the MIP unit commitment options produce SMP prices that are fully consistent with the T&SC constraints of schedule feasibility and Uplift cost recovery. Given the considerable uncertainty in future fuel prices and other data inputs, a key advantage of the RR method over the MIP is the significantly faster model performance. This facilitates running multiple scenarios or even stochastic parameters within PLEXOS to explore the impact of uncertain price drivers on the SEM over the medium to long term.

2. ***ST Schedule*** – We recommend configuring the ST Schedule in PLEXOS to replicate the T&SC, with a daily optimisation step, a six hour look-ahead period and a 06:00 trading day start. We believe that the look-ahead feature in the current PLEXOS release addresses the "edge effect" issues that were observed in the AIP Loop 2 results. We also recommend modelling a 60 minute trading period duration. The results of our initial half-hourly sensitivities were inconclusive but we subsequently established that the PLEXOS SEM Uplift algorithm could lead to cost under-recovery in half-hourly model runs. We understand that this issue has been addressed in the latest PLEXOS release (4.898 R14) but we have not validated the operation of the SEM Uplift algorithm with half-hourly trading periods.

3. ***MT Schedule*** – We configured the MT Schedule to run with a daily LDC of 4 blocks to match the ST step type (i.e. daily).

4. ***Hydro & Pumped Storage*** – We recommend running the model without Min Stable Level (MSL), Min Pump Load and Rough Running Range constraints for pumped storage plant. We also recommend modelling hydro plant without MSL, ramp limits or start costs. This should mitigate the risk of over-constraining the commitment problem, leading to infeasibilities and/or unserved energy. The MSL values for pumped storage and hydro units in our starting data set were generally very low (5 MW or less). Given the flexibility of these units, their MSL values are likely to be more relevant for minute-by-minute dispatch by the system operators rather than for ex-post pricing at the hourly or half-hourly level. We also noted that Min Pump Load and Rough Running Range constraints do not appear to be supported in T&SC v1.2.

5. ***Thermal "price takers"*** – We propose applying zero fuel and start costs for any thermal "must run" or "price taker" units. This is a workaround to exclude such plant from the SEM Uplift algorithm in PLEXOS.

6. ***Moyle interconnector*** – Moyle can be modelled in PLEXOS by simply defining the BETTA market as a node within the SEM region, and then attaching an externally derived BETTA price profile based upon quoted forward prices. However, to model the interactions between SEM and BETTA under multiple fuel price scenarios, we recommend using a simplified representation of the GB plant portfolio within PLEXOS. This will ensure that the BETTA price is internally consistent with the fuel and carbon price assumptions under each scenario.

7. ***Multiple start costs*** – Given that the inclusion of multiple start costs appears to have a material impact on the SMP results, we recommend that hot, warm and cold starts are modelled within PLEXOS. A step function can be defined to replicate the T&SC treatment of multiple start costs, instead of the PLEXOS default of linear interpolation between warmth states.

8. ***TLAFs*** – We recommend using the PLEXOS loss factor functionality to specify TLAFs directly in the model. This will ensure that PLEXOS automatically incorporates loss-adjusted incremental costs in the schedule and loss-adjusted revenues in the Uplift cost recovery condition.

9. ***Uplift filters*** – We believe it is appropriate to apply the MSL and Ramping filters in the PLEXOS Uplift algorithm. Uplift values can be highly sensitive to the underlying generation schedule. The schedules produced by PLEXOS in RR mode occasionally have features that can be regarded as "unrealistic", such as plant being committed at Min Stable Level to meet peak load. The MSL and Ramping filters prevent these "anomalies" from impacting Uplift.

10. ***Unit run-up*** – We recommend the default PLEXOS setting of not modelling unit run up and run down. We believe this to be consistent with the EPUS software.