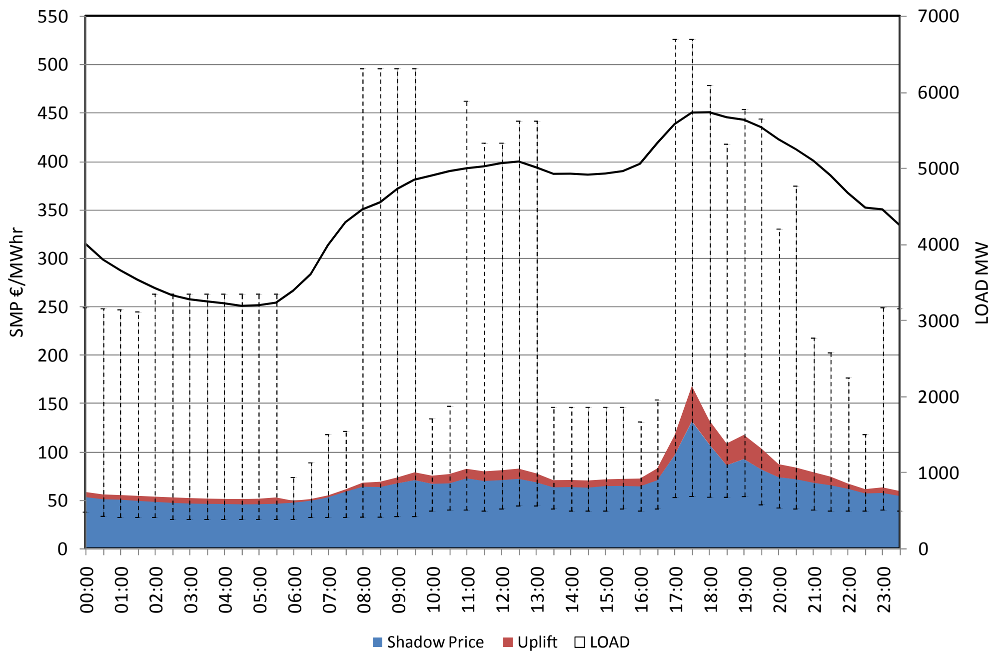
SEM Update: Report on First Six Months

To: SEM Committee

From: Market Monitoring Unit



22 July 2008

1. INTRODUCTION

This is the first six-month report of the Single Electricity Market (SEM) prepared by the Market Monitoring Unit (MMU). The aim of this report is to provide an unbiased assessment of the market.

This report covers the first six months of market activity since SEM Go-Live (1 November 2007 to 3o April 2008) and gives a statistical overview of the market, providing analysis and comparison of market prices to selected indices. The impact of carbon increases on prices and generator offers is also covered, along with an overview of the trends in commercial offers submitted by generators, generator market schedules, peak prices and some coverage of specific events. Constrained-on and off volumes are also presented and discussed for selected units.

Disclaimer:

This report is largely data-oriented. It is largely based on data provided to the MMU by SEMO (the Market Operator). Although every attempt has been made to ensure all data included in this report correct, the MMU cannot accept responsibility for the accuracy of the data presented in this report.

Table 1: Summary of Ownership of Generator Units Discussed in this Document:

[redacted]

CONTENT

2. PRICING & DEMAND

Overview

Demand-weighted average SMP[1] for the first six months was €76.43/MWh. The highest prices were considerably above this reaching €524/MWh on 24th November; the lowest price was €29/MWh and occurred on the 8th December.

Average system demand (or load) for the first six months of SEM was 4,455MW. Overall market wind generation met 6% of demand, with its contribution to meeting demand in individual half-hour trading periods varying between a minimum of 0.2% and a maximum of 18.3% over the entire six months.

Table 2: Market Summary

	System Demand (MW)	Wind Generation (MW)	SMP* (€/MWh)
Average	4,455	265	76.43
Minimum	2,501	9.2	29.31
Maximum	6,553	633	524.65

* Demand Weighted Average

[1] System Marginal Price (SMP): This is the market price, which includes the shadow price and uplift elements. The shadow price is calculated by the MSP Software as the marginal cost per MWh of production in each half hour, derived from a pass of the software which treats the unit commitment as fixed, thereby ignoring start-up and no-load costs. Uplift includes the start-up and no-load elements of generators' commercial offer data (COD) not otherwise recovered.

Figure 1 shows average SMP for each half-hourly trading period. The broken lines indicate the maximum and minimum SMP for each period. This illustrates the intraday price shape over the period.

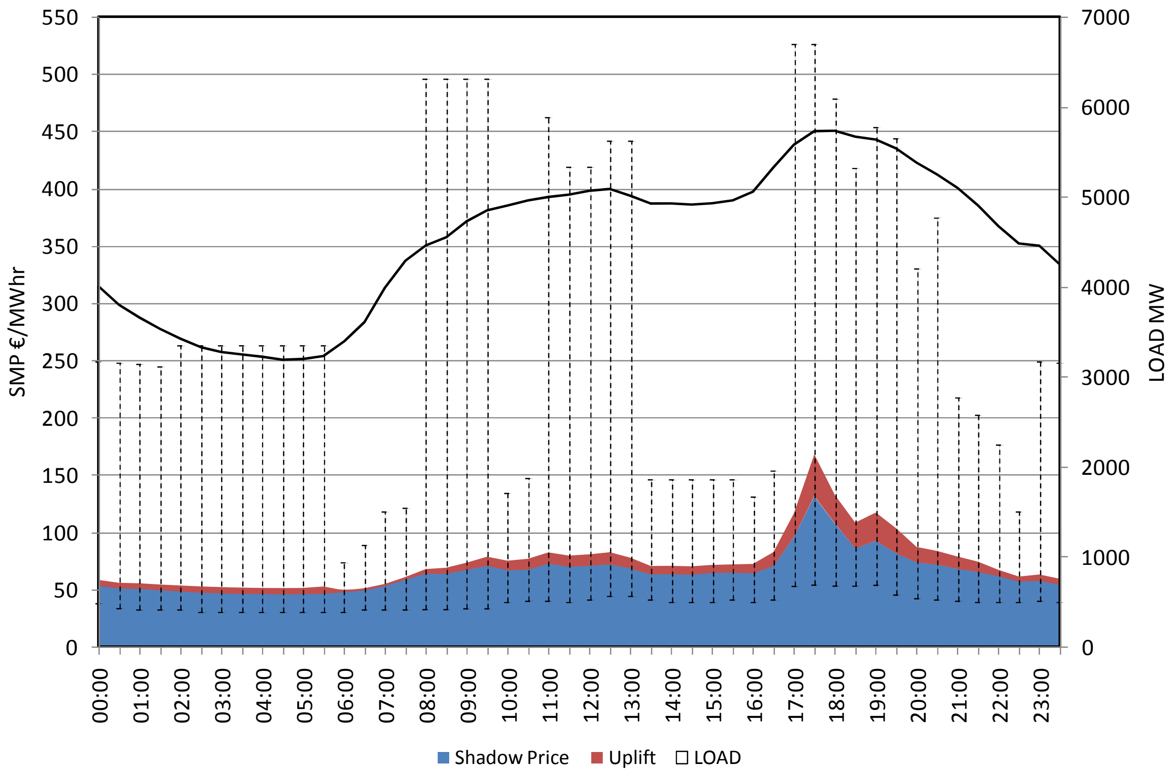


Figure 1: SMP, Uplift, Limits of SMP & Market Load

Intra-day peak prices generally corresponded with periods of highest demand. The range of prices was also greatest for these periods. Similarly, the daily lowest prices generally correspond with lowest demand. Discussion of the underlying drivers of SMP, peak prices and price setting is discussed below in more detail.

On one occasion overnight prices (00:00 – 05:30), when demand is generally at its lowest, were particularly high. This resulted from the way in which uplift is calculate and is discussed in more detail in Section 8. Generally other occasions where SMP rose above €300/MWh can be attributed to the scheduling of Kilroot at a price which reflects the costs of switching the plant to oil burning mode. In these instances there was little or no contribution from uplift to SMP. This is discussed in more detail in Section 6.

Load & Price Duration Curves

In the SEM prices are based on the (unconstrained) least cost production schedule. Prices are set by the marginal cost of meeting demand for each trading period (with uplift applied where start-up costs and no load costs are not fully recovered). This is a fundamental aspect of the pool mechanism chosen in the High Level Design. Meeting the peak in demand generally results in a higher price per megawatt hour – this is a result of to the need to incur start-up and no load costs as additional plant is needed to meet demand and/or using relatively expensive generation to meet demand as the availability of less expensive plant becomes limited. How peak prices are being set in the SEM is considered in more detail in subsequent sections.

The price duration curve in Figure 2 illustrates the percentage of time the SMP exceeds a particular value. For example, the SMP exceeded €100/MWh just over 11% of time during the first six months and SMP for the median trading period was €61/MWh. As already noted prices are generally highest at times of peak demand; figure 2 shows how the costs associated with meeting this demand affected the distribution of prices.

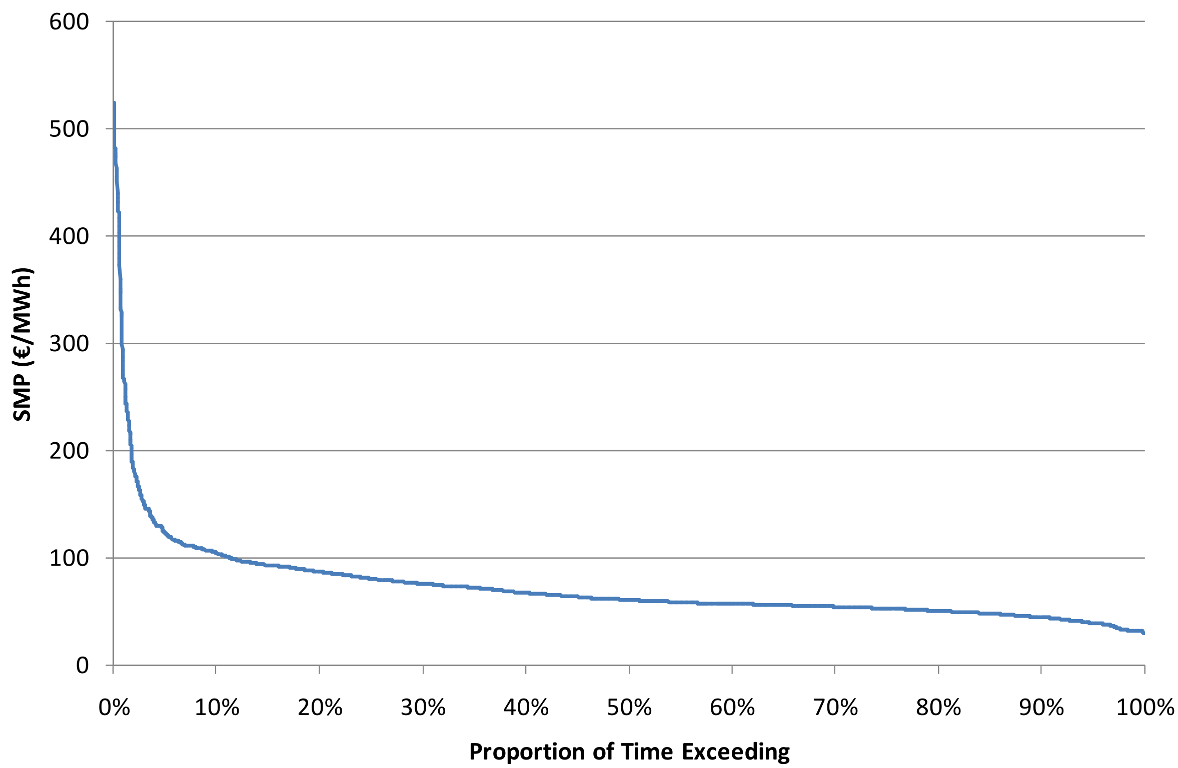


Figure 2: Price Duration Curve for All Periods

In Figure 3, the Price Duration graph is shown for peak periods – defined as 16.30 to 20.00 on business days in line with the definition used for the 2007/2008 Directed Contract process. As expected, prices during these periods are generally higher. The vast majority of peak prices were experienced during these periods. The relationship with load is also indicated by the fact that for these periods SMP exceeded €100 for 44% of time. As the SEM develops it will be possible to consider the implication of this price distribution in more detail.

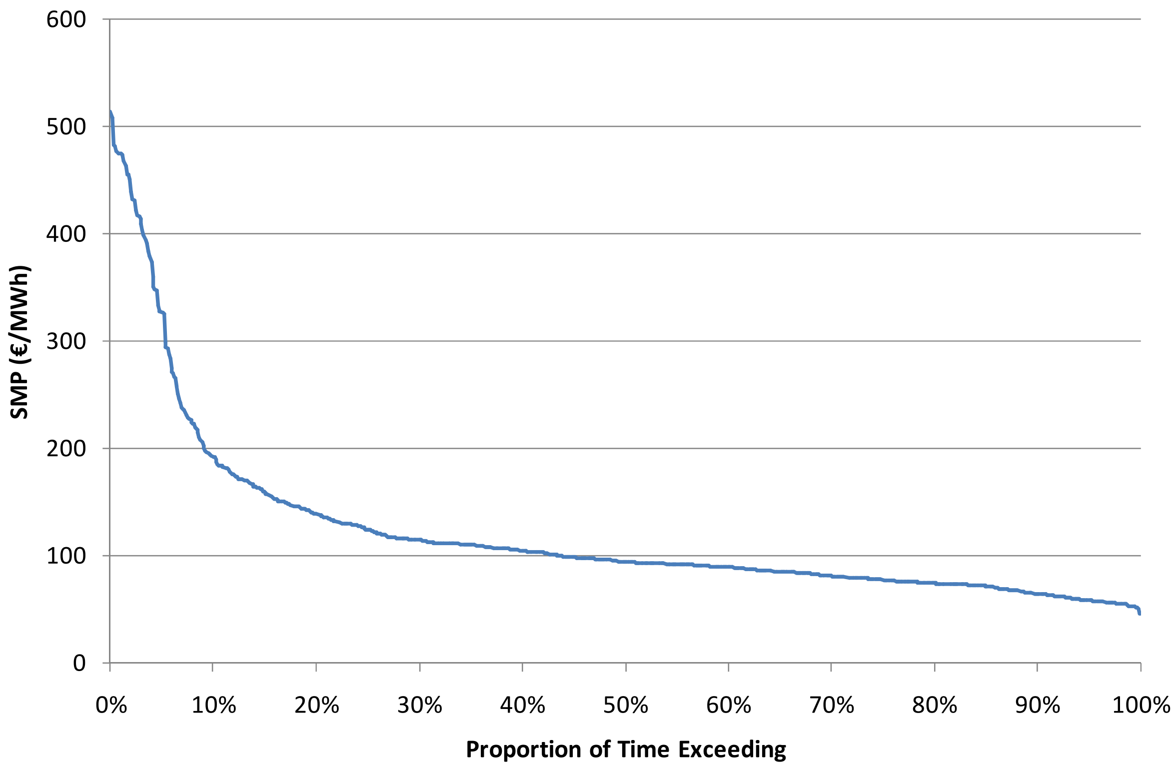


Figure 3: Price Duration Curve for Peak Periods

Figure 4 shows a Load Duration curve for the six months after the market started. This graph illustrates the relationship between the unconstrained market load and the utilisation of capacity needed to meet this load. For example, 6,000MW of capacity was required to meet load for 2% of time during the first six months. And for less than 2.5% of time the capacity required to serve load was below 3,000MW.

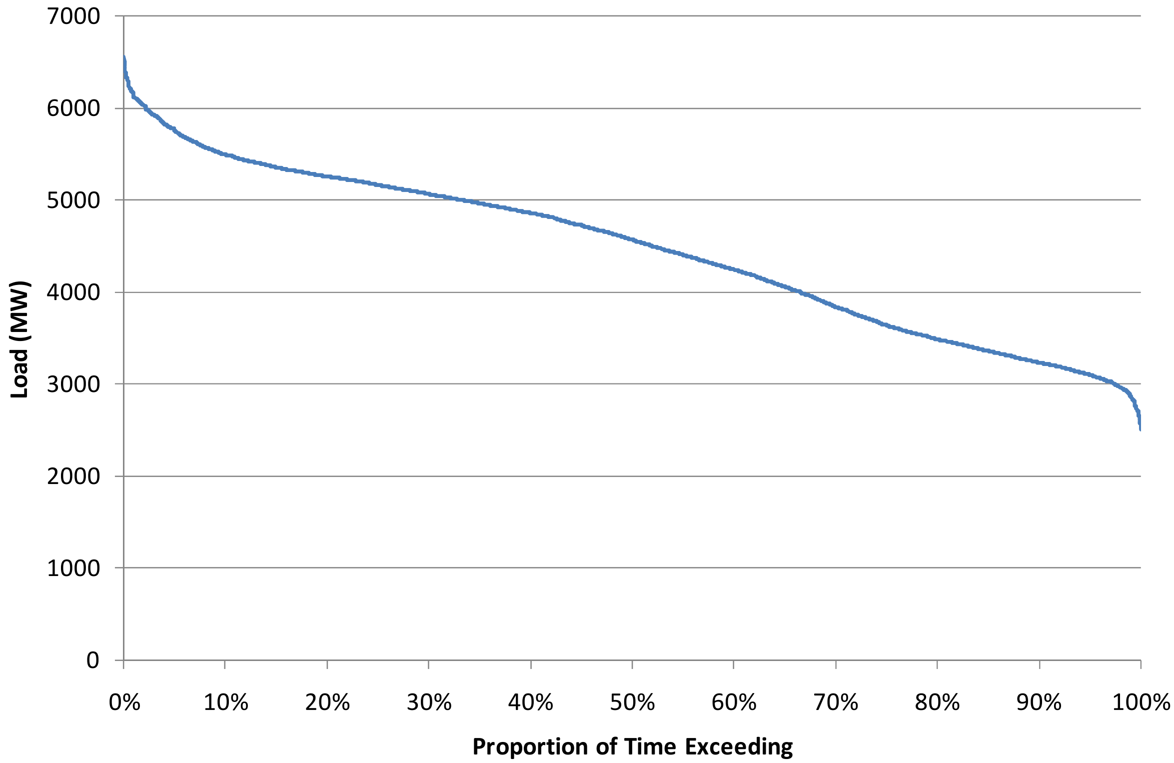


Figure 4: Load Duration Curve for All Periods

Load & Price

SMP and load, as well as having a clear intraday relationship, are also correlated across the entire 6-month period. Overall there is a correlation coefficient of 0.47 between half-hourly demand and SMP. *Table 3* shows this level of correlation for the period also applies to individual months – albeit with a weakening for March and April.

Table 3: Monthly SMP & Demand Summary

	Nov	Dec	Jan	Feb	Mar	Apr
Demand Weighted Average SMP (€)	67.96	66.34	81.19	76.17	78.90	88.79
Average Demand (MW)	4,528	4,408	4,605	4,595	4,363	4,242
Demand - SMP Correlation Coefficient	0.55	0.48	0.50	0.52	0.47	0.49

Figure 5 shows the weekly rolling average load against weekly rolling average SMP, which again demonstrates this correlation, as well as the weakening towards the end of the period.

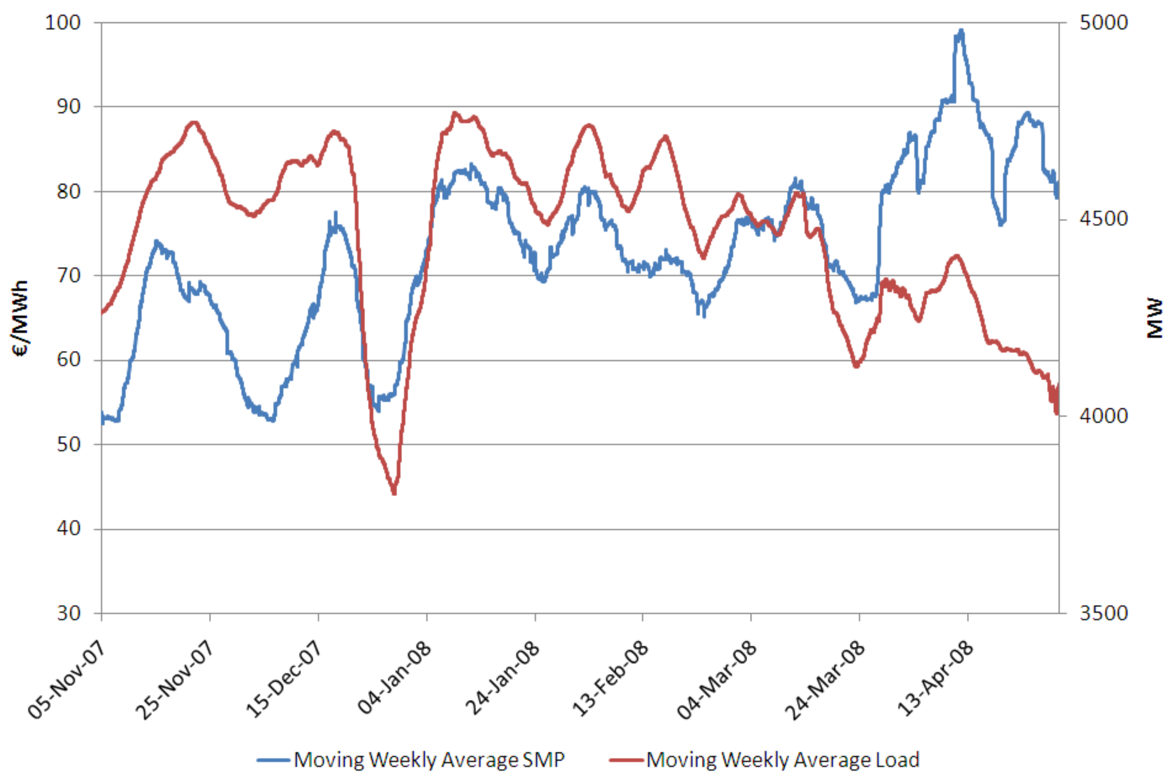


Figure 5: Weekly Rolling Average SMP & Load

From Figure 6 it can be seen that during the end of December the SMP was relatively low, as there was a lot of spare capacity available and demand could be met by the more efficient and less expensive plant available. On the other hand, during the end of March, when the Margin of spare capacity was low, the SMP was consistently high as less efficient and more expensive plant was required to meet demand. The correlation coefficient between half-hourly Margin and SMP was -0.51. The weakening of the relationship between load and SMP noted above can largely be explained by tightening margin, as base load plant is taken offline for maintenance at the end of the winter period. For example Moneypoint Unit 2 is on a long term outage associated with the installation of Flue Gas Desulphurisation (FGD) facilities.

Figure 6 shows the weekly rolling average SMP plotted against weekly rolling average Margin, where Margin represents the half-hourly difference between Eligible Availability and market load. As would be expected, there is a clear negative correlation, i.e. as the Margin decreases, the SMP increases (and vice-versa).

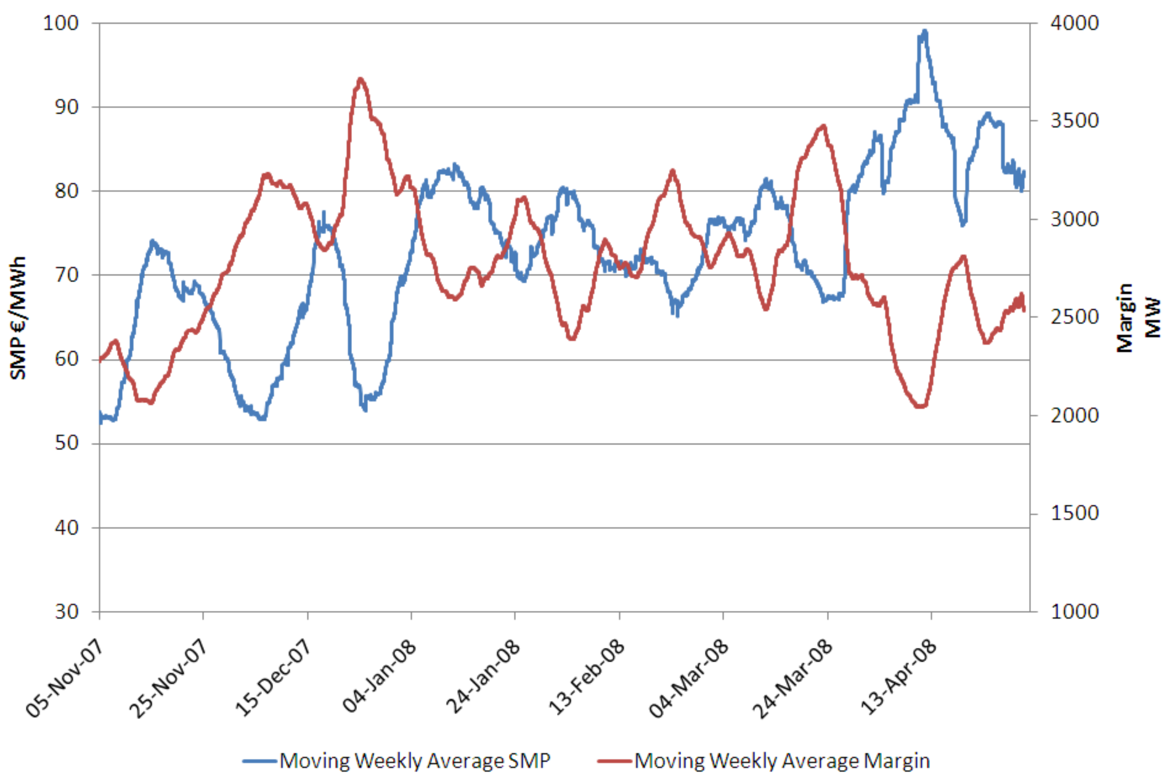


Figure 6: Weekly Rolling Average of Margin & SMP

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3. MARKET TRENDS

Capacity mix

Total dispatchable generation capacity available in the SEM is approximately 8,300MW, with the bulk of capacity available being gas-fired. An overall break down by fuel type is shown in Figure 7.

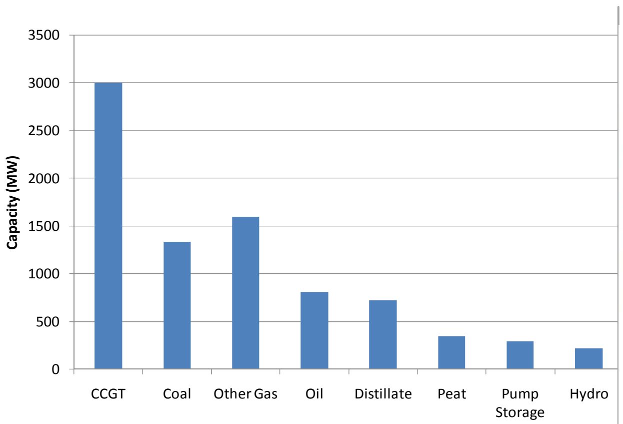


Figure 7: Dispatchable Plant Capacity

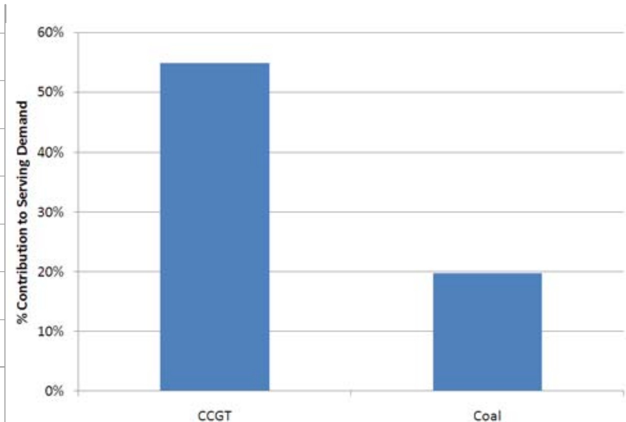


Figure 8: Load Served By CCGT & Coal Plants

Gas is by far the most important energy source for electricity generation on the island. Combined Cycle Gas Turbine plants alone served over 50% of total demand during the first six months of SEM. Coal-fired generation served about 20% of demand over this period (see Figure 8).

Gas Price Correlation

Given the above, fuel and (from 1st January 2008) carbon prices would be expected to be amongst the most significant drivers in setting SMP. The significant increase in carbon prices experienced from 1st January 2008 clearly caused the cost of generation to increase with an associated rise in SMP (this is discussed further later in this section). The correlation coefficient between the time-weighted daily average SMP and the carbon indexed gas price was 0.66 for the first six months of SEM. Figure 9 tracks both SMP and Gas prices adjusted to account for associated Carbon emissions. The divergence towards the end of the period is associated with the decline in availability at the end of the winter period noted above.

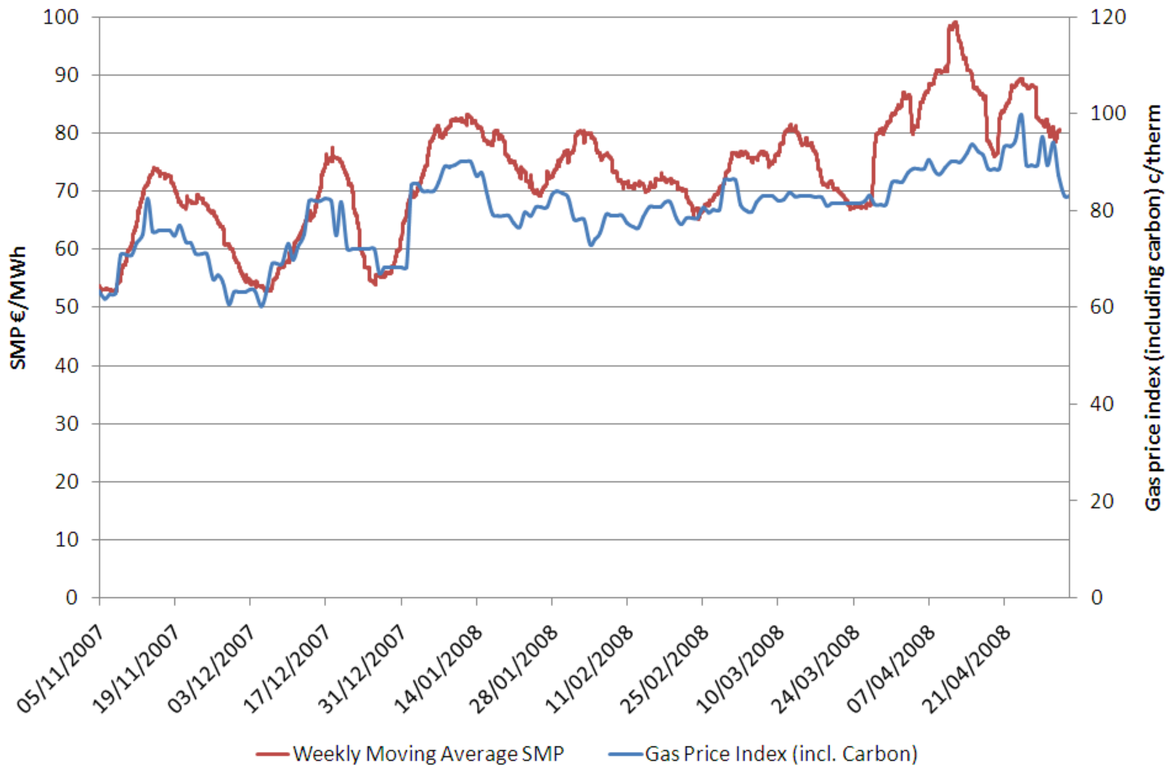


Figure 9: Weekly Moving Average SMP & the Carbon Indexed Gas Price

NOTE: The Gas Price (Carbon Indexed) is derived from the gas price and carbon price (See below for further detail).

Other Market Comparisons

Figure 10 shows daily time-weighted average SMP for SEM and the Elexon Market Index price, which reflects the price of wholesale electricity in Great Britain in the short-term market. There are clear similarities in price trends, fluctuations and volatility of daily average prices in the two markets, with the average SMP in the SEM for the study period generally within 3-4% of that in the GB market. The correlation coefficient between these prices was 0.66 – the same as the correlation between gas prices. There are good reasons to believe correlation in electricity prices between SEM and GB is probably driven not by a 'law of one price'[2], but by the strong underlying correlations in fuel prices in the two markets. Figure 10a shows there are also strong similarities between the intraday prices between the SEM and GB, even with the different market structures and pricing mechanisms.

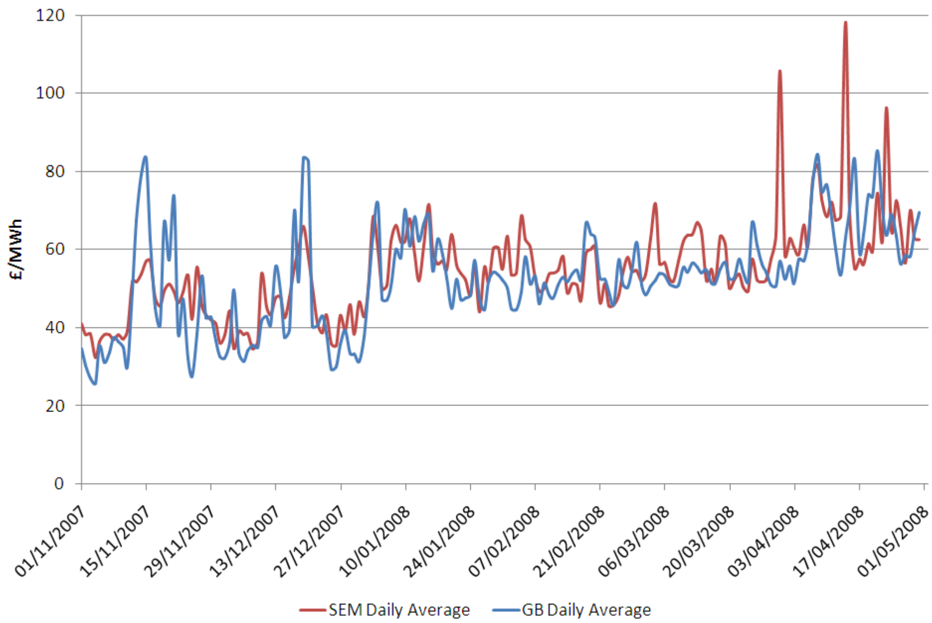


Figure 10: Price Comparison between SEM and GB Market

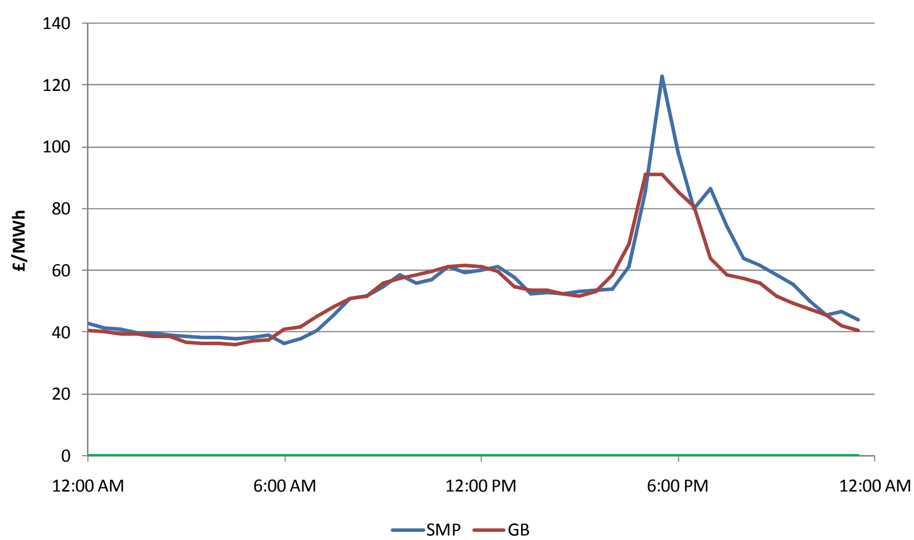


Figure 10a: Intra-day Average Price Comparison between SMP and GB Market

[2] There is currently limited use of the existing interconnection between the markets. East to west flows were around 600 GWh and west to east flows were around 44 MWh over the 6 month study period. This compares to a potential 845 GWh gross flow assuming full constant flow at the 400MW westerly limit.

Interconnection

Use of the Moyle Interconnector adds an additional cost onto bringing electricity into SEM. This cost varies and the table below shows average cost of Moyle capacity after the Single Electricity Market went live on 1st November.

An additional risk for importers into SEM is they may not be dispatched and therefore not entitled to a capacity payment which is payable only on actual interconnector flows rather than capacity or availability and so, having had to book and pay for Moyle capacity, the risk is there will be no dispatch and thus no payment and so the transaction makes a loss.

Table 4: Moyle Auction Results 2007/08 Tariff Year *Source: SONI Website: http://www.soni.ltd.uk/*

Moyle Import Capacity		**Moyle Export Capacity**	
Month	**Av Price £/MW-month**	**Month**	**Av Price £/MW-month**
Nov-07	£5,156.10	**Nov-07**	£500.00
Dec-07	No Bids	**Dec-07**	£2,095.33
Jan-08	£2,012.50	**Jan-08**	£501.50
Feb-08	£2,012.50	**Feb-08**	No Bids
Mar-08	£501.00	**Mar-08**	No Bids
Apr-08	£661.84	**Apr-08**	No Bids

European Prices

Figure 11 shows the daily averaged SMP in the SEM against the daily averaged spot price from Germany's European Energy Exchange (EEX). Again there is some correlation between prices in these two markets, with a correlation coefficient of 0.40, and the SEM daily average SMP less volatile than the daily average price in the EEX.

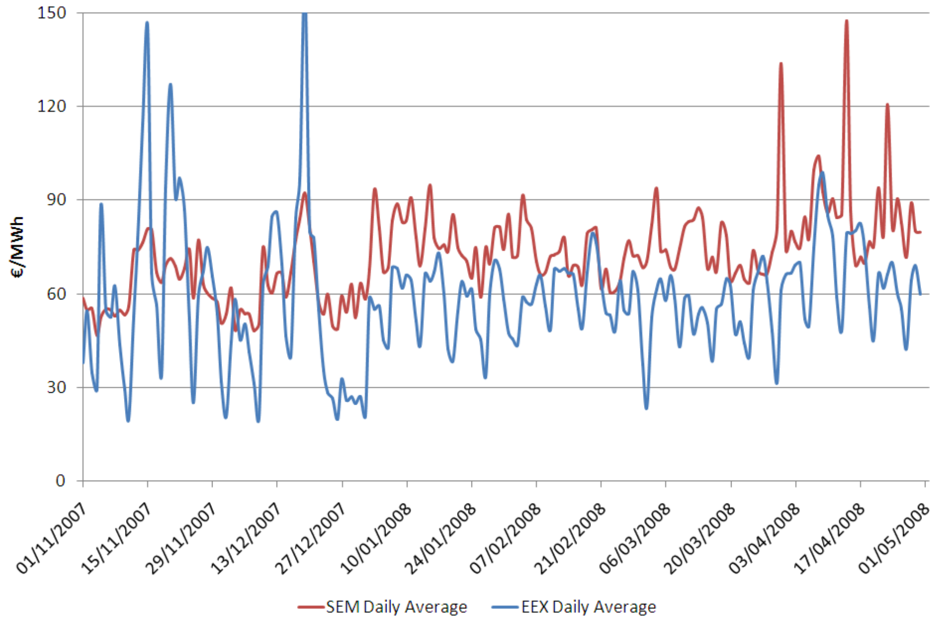


Figure 11: Price Comparison between SEM & EEX

Comparisons between prices in the SEM and those in other markets are indicative only. In particular the additional SEM payments and charges, most notably the capacity payments mechanism, increases the effective electricity price in the SEM above the SMP shown here.

Impact of ETS

From 1st January 2008 conventional fossil fuel generators have faced an increase in the opportunity cost associated with carbon emission as a result of Phase II of the European Union Emissions Trading Scheme (EU ETS). This increase in the costs of generation has been reflected in the bids submitted to the Market Operator.

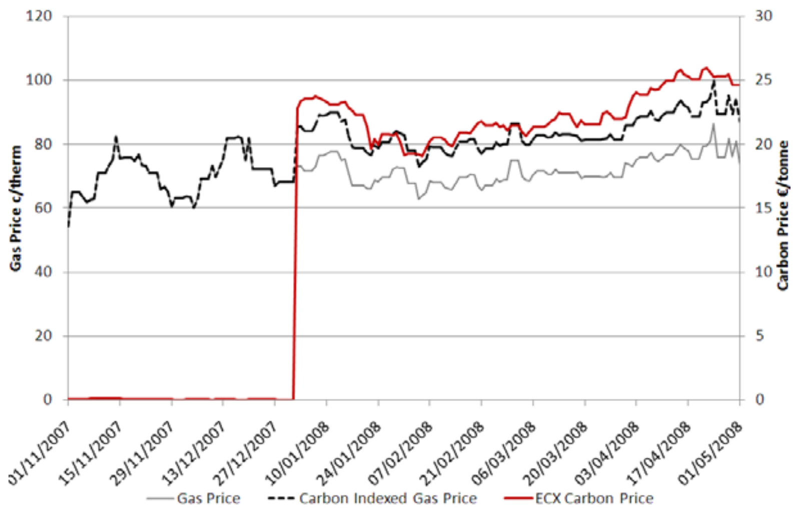


Figure 12: Gas Price & Carbon

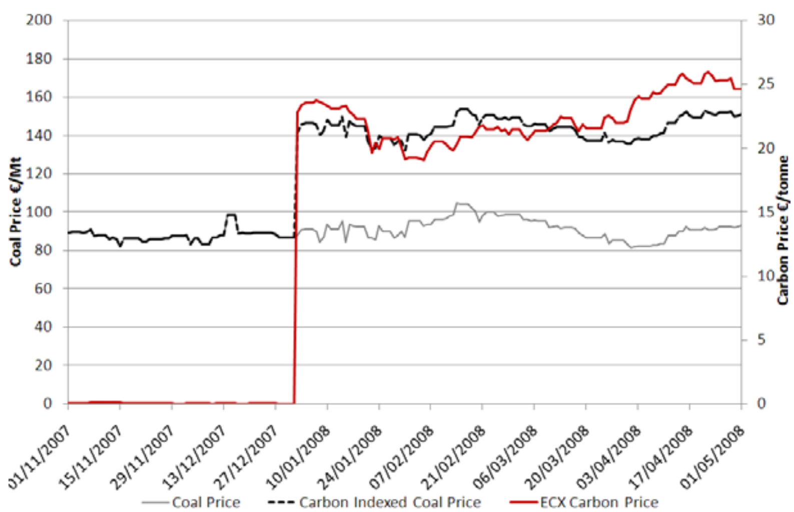


Figure 13: Coal Price & Carbon

Figures 12 and 13 show the increase in carbon price alongside gas prices and coal prices. Also shown are the associated carbon indexed prices, which are derived from combining the carbon and fuel prices using calorific values, emissions and oxidation factors for each fuel. This shows that from 1st January 2008 the carbon price increase led to an effective cost increase of around 17% associated for gas generation and around a 60% increase associated for coal based generation.

Carbon & SMP

Figure 14 shows average SMP over the period when Phase II of ETS came into force. While the majority of this increase can be attributed to the carbon increases, over this period, the average gas and coal prices both increased by around 2% and the average system demand increased by 8%. Overall the increase in carbon prices led to SMP approximately 20% greater for the first two weeks of January than that for the preceding two weeks.

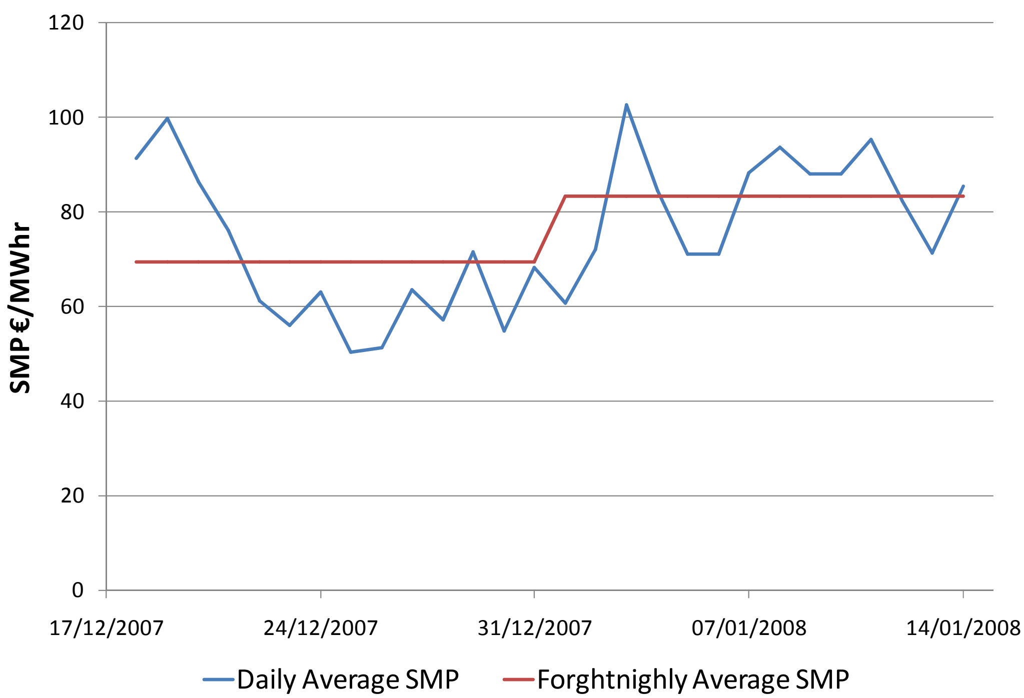


Figure 14: Change in SMP during Carbon Increase

The correlation between prices in SEM and other electricity markets, together with the correlation between SMP and input costs suggests SEM outcomes are broadly in line with what would be expected in a competitive market. Prices are mainly driven by production costs, demand and availability of generation capacity.

4. GENERATOR TRENDS

Market Share

A relatively small number of large coal and CCGT plants served the majority of load (75%). Figure 15 shows the breakdown of percentage contribution of a selection of plants to the scheduled and actual dispatched quantities over the first six months of SEM.

Schedule Quantity:

The scheduled quantity or MSQ (Market Schedule Quantity) is the quantity of output for generators, which is used to calculate generators energy payments. This is produced by the MSP (Market Scheduling and Pricing) Software run Ex-Post by the Market Operator. The MSP Software produces these MSQs on the assumption of an unconstrained system (ignoring transmission constraints, voltage and reserve requirements, etc). The Ex-Post Initial (D+4) MSQs are used throughout this report.

Dispatch Quantity:

Dispatch quantities are derived from Dispatch Instructions, which are provided to the Market Operator by the System Operator. These reflect the actual dispatch of generators, taking account of constraints of actual system operation.

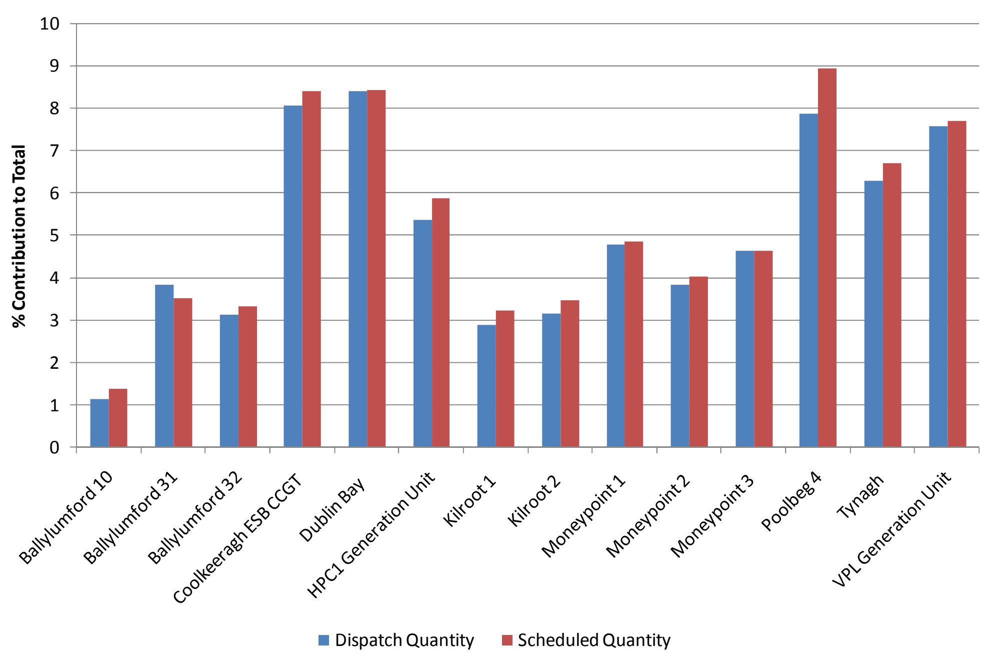


Figure 15: Demand Served by Large Coal & CCGT Units

Figure 16 shows a breakdown of the contribution of selected other plants to serving demand. This shows the significant contribution peat fuelled generation contributes to serving market load (7%), which is slightly more than the total for wind (6%). Overall, plant in ROI was scheduled to meet 72% of total SEM production and dispatched for 73%.

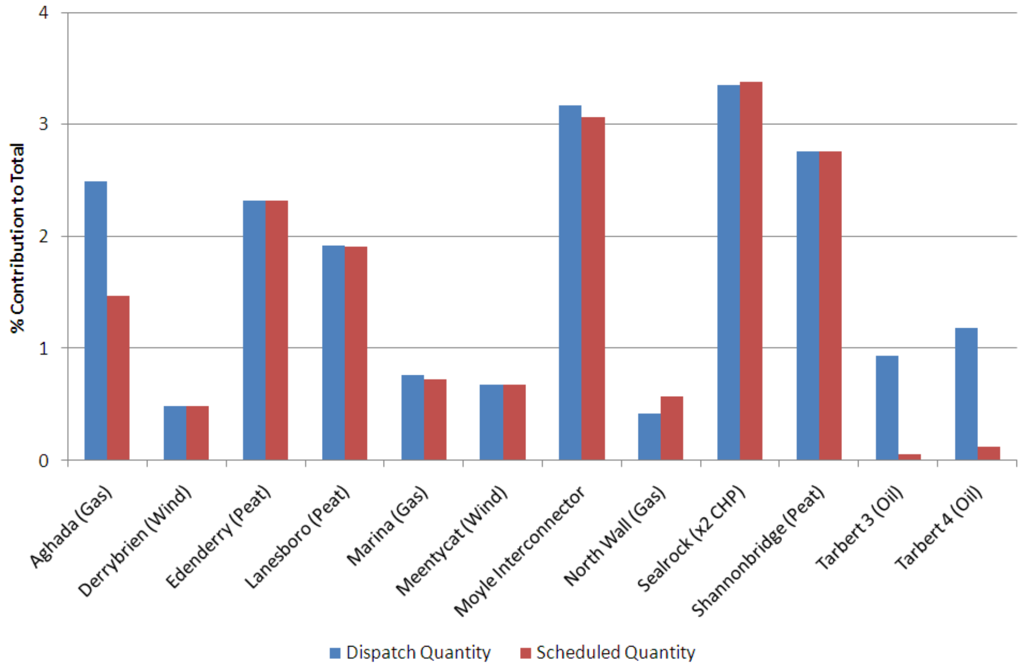


Figure 16: Demand Served by Other Selected Units

Generator Schedules

After SEM go-live a number of plants experienced a schedule pattern of running at full load during the day and then being shut down for overnight operation, this is known as 'two-shifting'. The following graphs illustrate how some plant have been scheduled for two-shifting, how others have been ramped back to part load for overnight operation, and how others have remained at virtually full capacity in the schedule for all periods. The figures below also show corresponding dispatch quantities (in red). The divergence between the two traces indicates the degree to which the unit(s) were dispatched differently to the market schedule.

> The Bidding underlying plant running regimes was the subject of a separate inquiry by the SEM Committee. This was announced on 4 December 2007 following complaints by several market participants. During the course of this inquiry, the SEM Committee engaged extensively with complainants and those against whom complaints were made. Based on the information it received and its own analysis of the issues involved, including a review of relevant legislation, Licences and codes, the SEM Committee has formed its decisions on the merits of the complaints and the requirements of the relevant Licence conditions. The SEM Committee published its final report 12 June 2008.

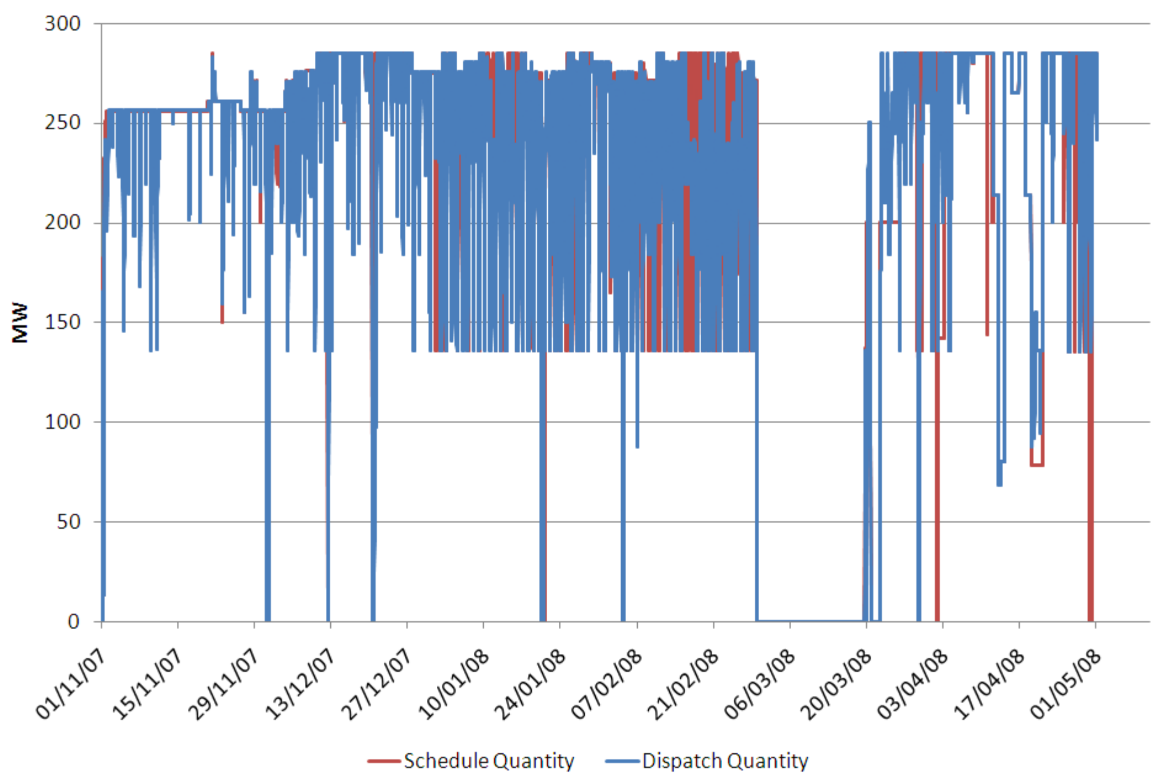


Figure 16: Moneypoint Unit 1's Market Schedule (Red) and Dispatch Schedule (Blue)

Figure 16 shows Moneypoint Unit 1's market schedule for the six months of SEM. A marked change during January and February is clear, as Moneypoint Unit 1 is ramped back to part-load for overnight operation on a more frequent basis than before. This aligns with the analysis in Section 7 on the impact of EU ETS for coal fired generation.

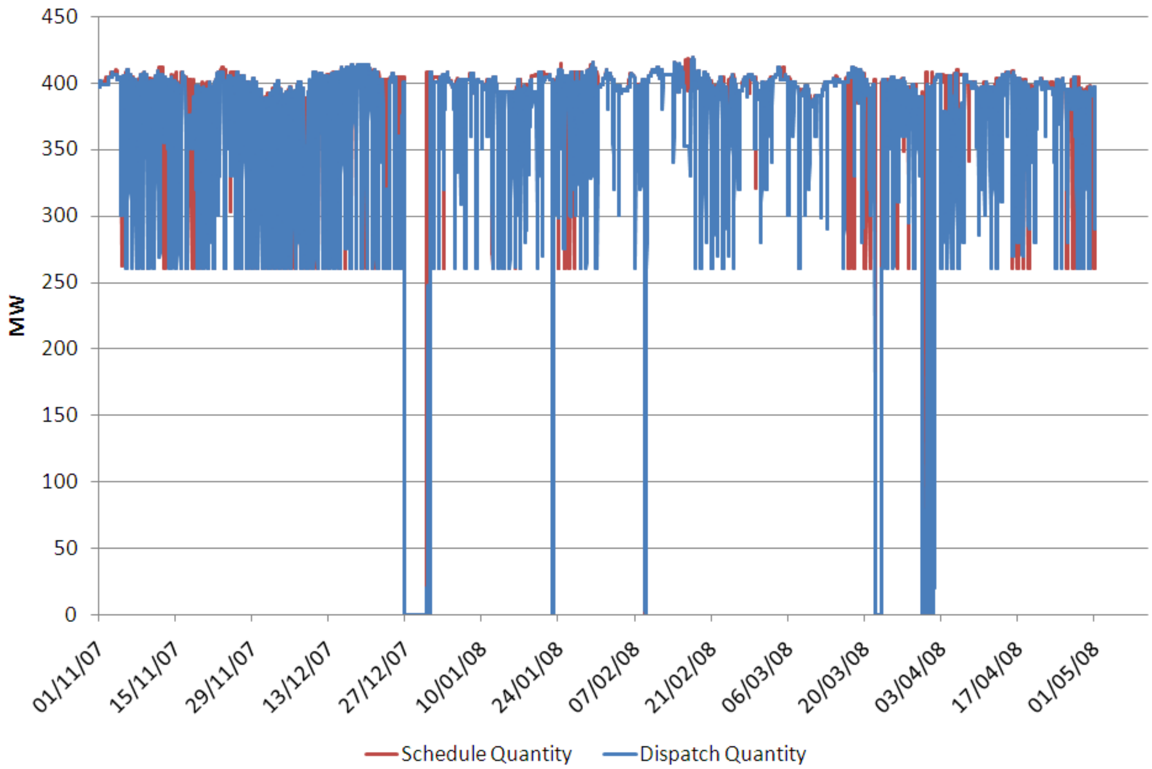


Figure 17: Coolkeeragh's Market Schedule (Red) and Dispatch Schedule (Blue)

Figure 17 shows Coolkeeragh CCGT's market schedule for the first six months of SEM. In contrast to Moneypoint's schedule, there is no significant change in the frequency of part-load scheduling for Coolkeeragh in 2008 after the introduction of ETS.

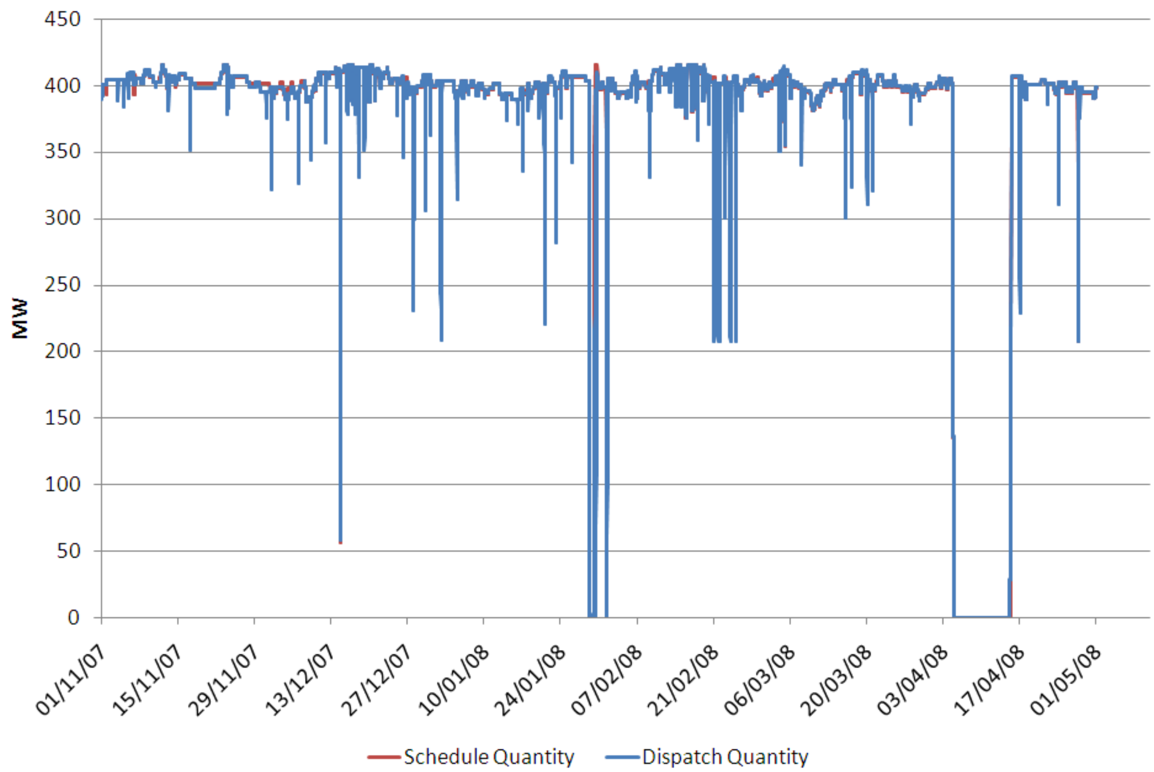


Figure 18: Dublin Bay's Market Schedule (Red) and Dispatch Schedule (Blue)

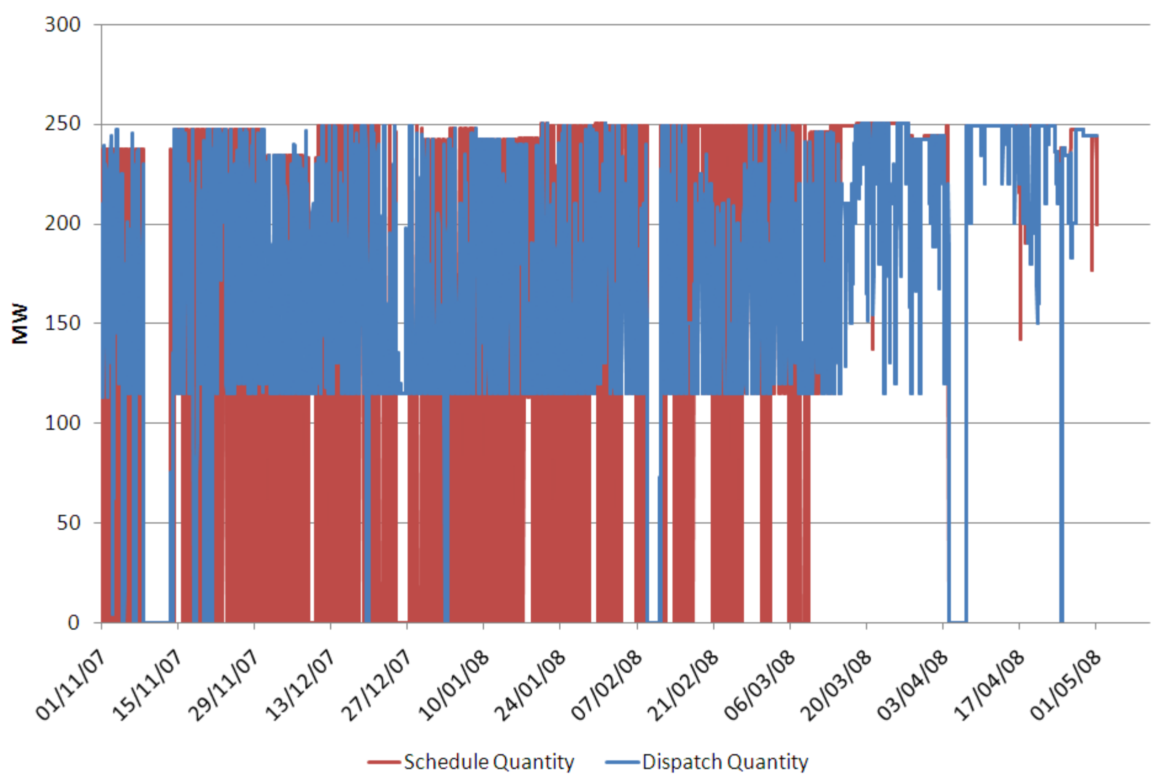


Figure 19: Ballylumford 32 CCGT's Market Schedule (Red) and Dispatch Schedule (Blue)

Figure 18 and 19 highlight the difference in Dublin Bay CCGT and Ballylumford 32 CCGT's market schedule Dublin Bay operates as continuous base load in the Market schedule. For various operational reasons it is often dispatched below it maximum capacity. Conversely, until March Ballylumford plant is scheduled in line with a mid-merit two-shifting cycle. Ballylumford's market-schedule shut-downs are not reflected in real-time dispatch by the System Operator. Instead, the units are usually dispatched to run at minimum generation; primarily this is driven by technical constraints, discussed later in the following section.

Constraints

The following Figures illustrate the Constrained-on and Constrained-off total MWh quantities of selected generators, highlighting the impact of constraints on generators' operation over the reporting period.

How to read the graphs:

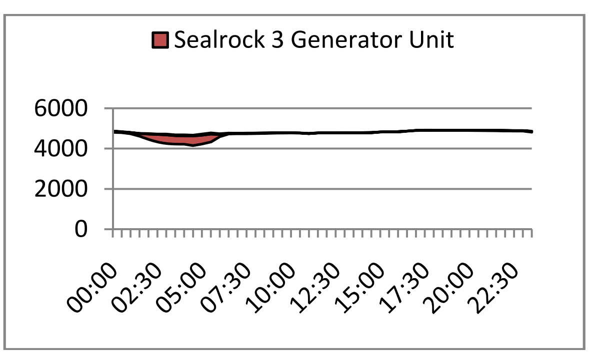
Ex-post Scheduled Quantity, Constrained-on and Constrained-off MWh quantities are shown in the figures below, split into weekday (left) and weekend (right) profiles for selected units on the system. The central black line in each figure represents the sum of scheduled MWh for the unit for each trading period (e.g. 07.30-08.00 on weekday mornings). The red area shows the amount of constrained-down energy volume, for that trading period while the blue shows the amount of constrained-up energy volume. The analysis covers the six-month period from the start of SEM.

Similar profiles exist for corresponding units not shown below; for example Moneypoint 2 and 3 have a similar pattern the Moneypoint 1 picture shown. An important exception is Ballylumford Unit 32 which is constrained on significantly more than Ballylumford Unit 31. These units are shown together in the last section.

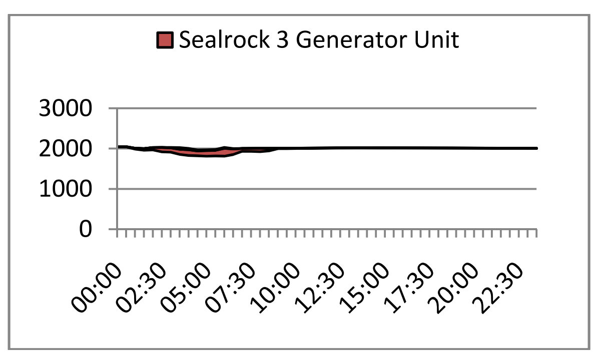
Key Baseload, Gas and Coal behaviour:

The units shown below have most often been scheduled and dispatched as baseload plant, which is operated for most or all times of day and week. As a consequence there is little deviation between the dispatched quantities and the scheduled quantities, as can be seen in the narrow red and blue areas.

Weekday Constrained On/Off Quantities

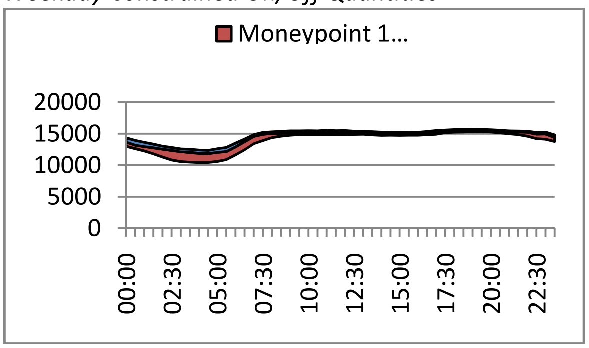


Weekend Constrained On/Off Quantities

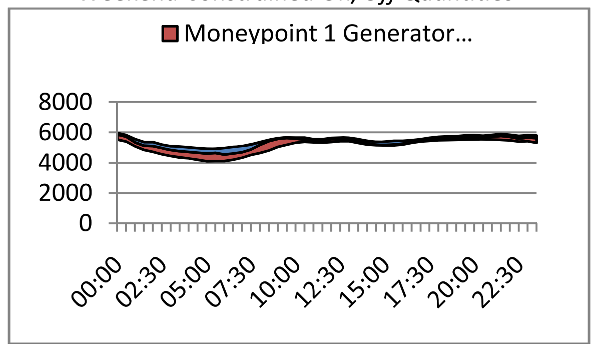


The Sealrock units operate at baseload in the schedule and are only marginally dispatched below full load overnight. .

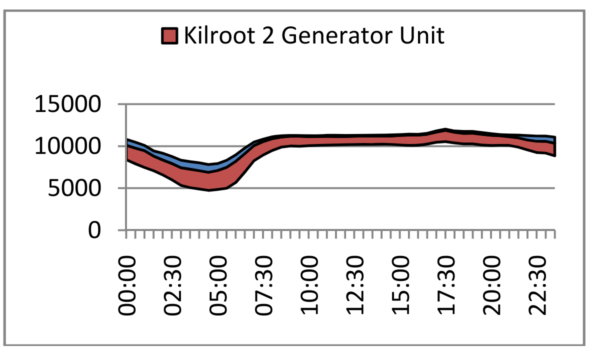
Weekday Constrained On/Off Quantities

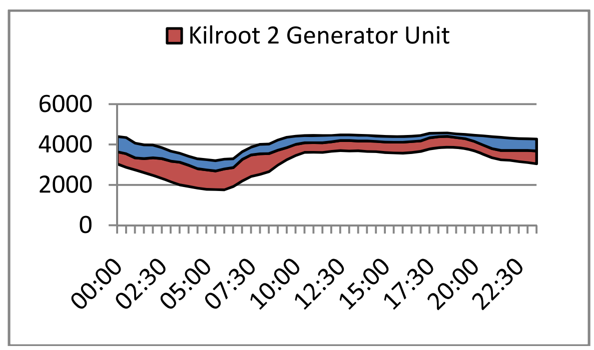


Weekend Constrained On/Off Quantities



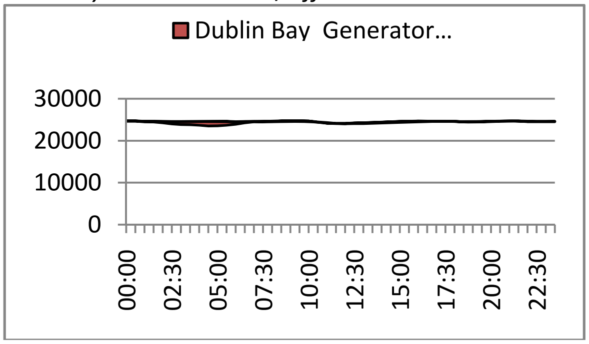
Moneypoint units generally operate continously in the market schedule, but but production is reduced below maximum generation for overnight periods. This pattern is broadly replicated in its dispatch profile. The System Operator's instructions result in relatively little contrainting either up or down .



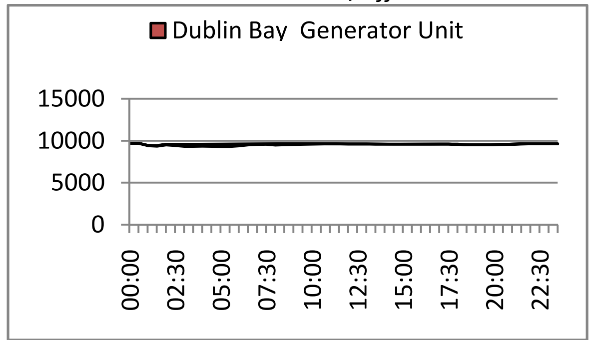


Kilroot units' market schedules are similar to their coal-fired counterparts at Moneypoint., However there is a difference in how the units are dispatched by the System Operator. This difference is likely due to different operational conditions in Northern Ireland. One important difference is that there is a requirement that at least three large units must remain online in shoulder periods. This will tend to result in an increased need to reduce Kilroot's output overnight compared to Moneypoint.

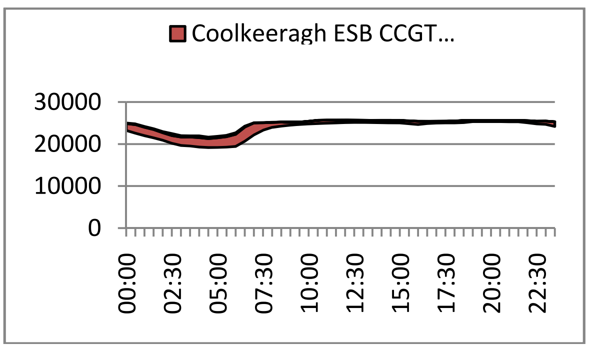
Weekday Constrained On/Off Quantities

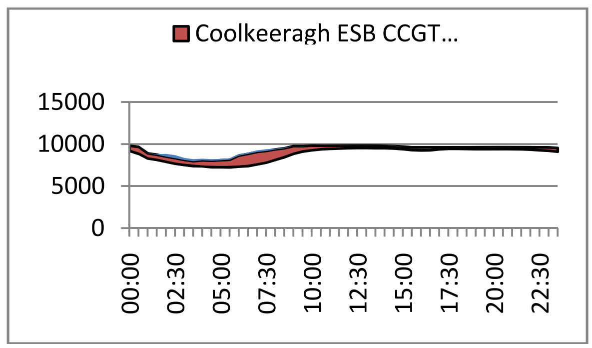


Weekend Constrained On/Off Quantities



Dublin Bay's very low costs, as indicated in its Commercial offer Data, compared to other thermal plant means it is generally operated at maximum capacity in the market schedule and according to dispatch instruction from the System Operator.

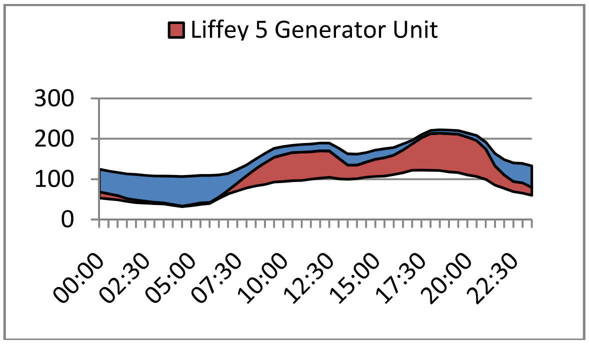


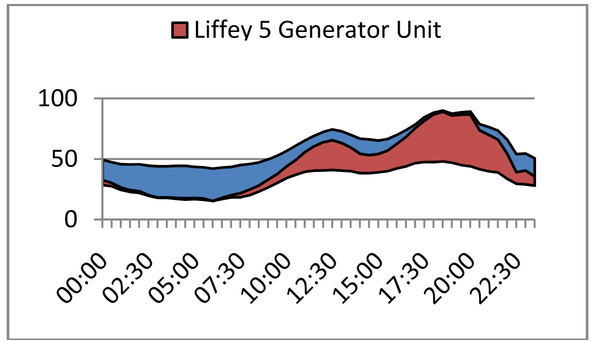


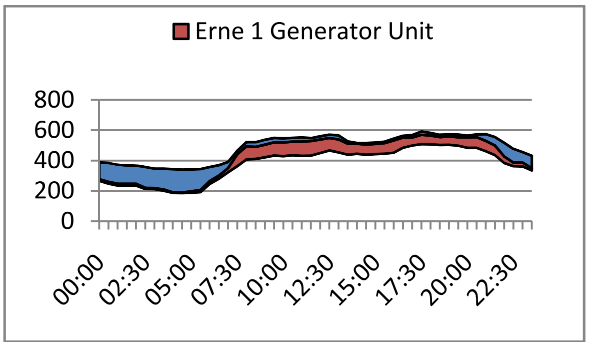
Coolkeeragh's treatment by the schedule and in dispatch is similar to Kilroot's, the relative constraining behaviour is lower. It is also interesting to note that Coolkeeragh is rarely constrained up. An inportant reason for this is the plant's distance from the major load centres in the eastern part of NI.

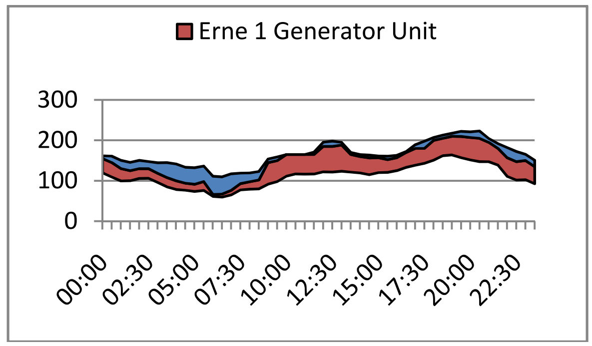
Key Hydro and Pumped Storage behaviour

Weekday Constrained On/Off Quantities *Weekend Constrained On/Off Quantities*





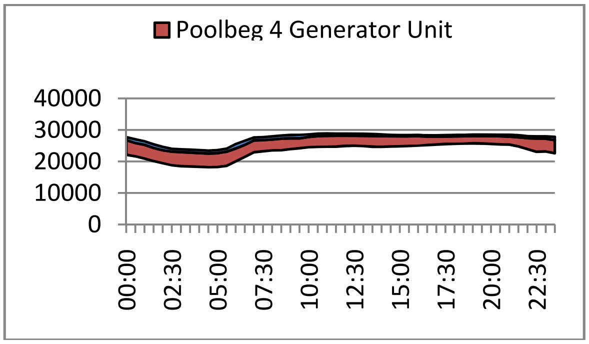


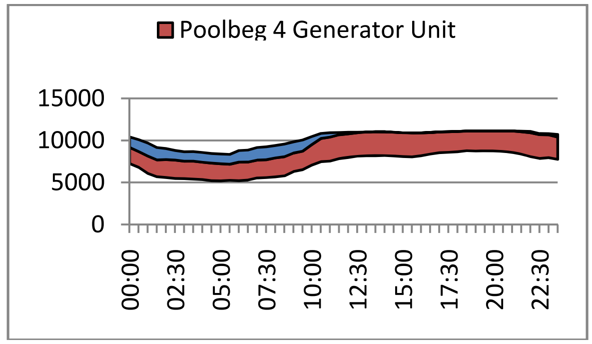


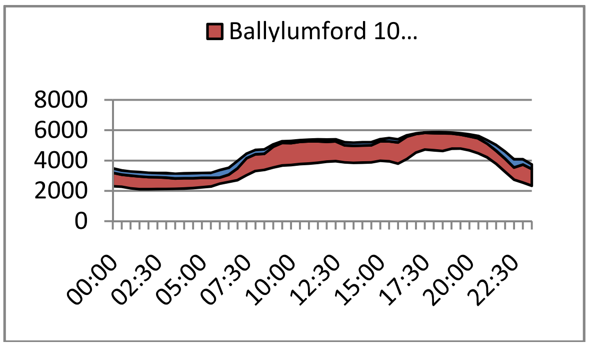
The thick blue and red bands in the above figures suggest the System Operators utilise the hydro units on the system to manage real-time requirements during peak periods when compared to the ex-post market schedule. It is also the case that the perfect foresight aspect of the ex-post market schedule is likely a key driver behind the significant deviation in scheduled and dispatched quantities for hydro plant.

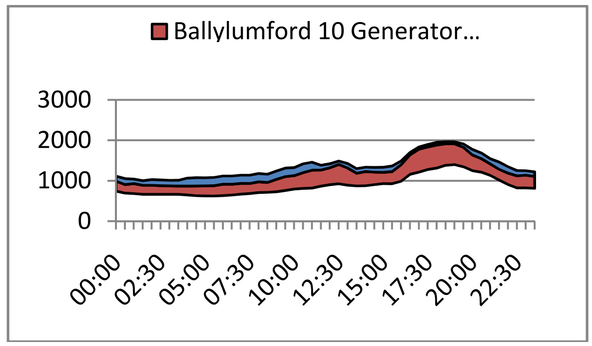
Key Constraining-Off behaviour

Weekday Constrained On/Off Quantities *Weekend Constrained On/Off Quantities*







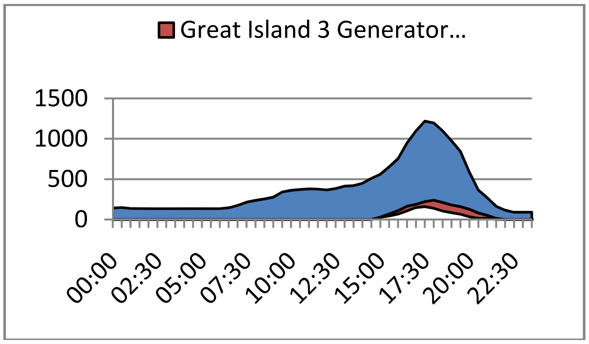


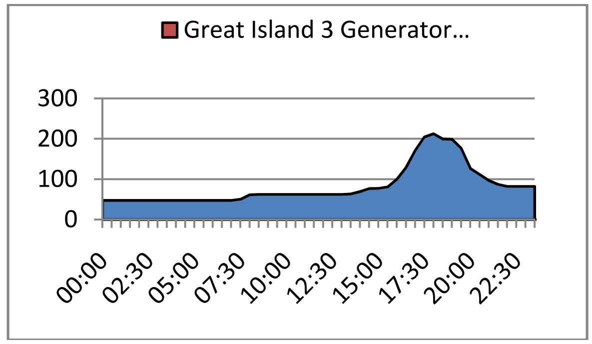
Ballylumformd unit 10 and Poolbeg Unit 4 were constrained down to maintain reserve on the system. Reserve is not considered by the market scheduling algorithm, and so it is usually the case that more plant will need to be spinning in real life than in the market engine. To facilitate this, flexible gas plant such as the above are frequently ramped back by the System Operator in real time.

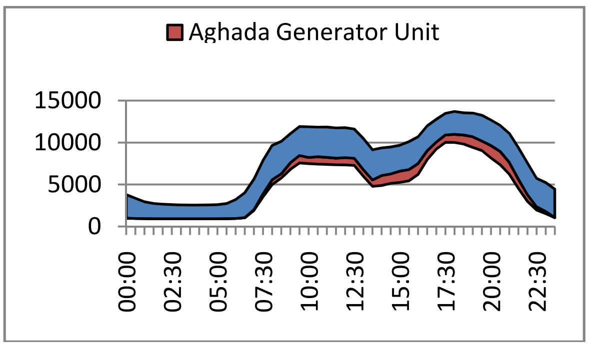
Key Constraining-On outcomes

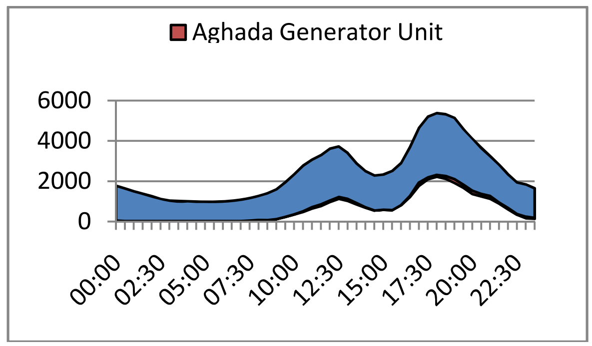
Weekday Constrained On/Off Quantities

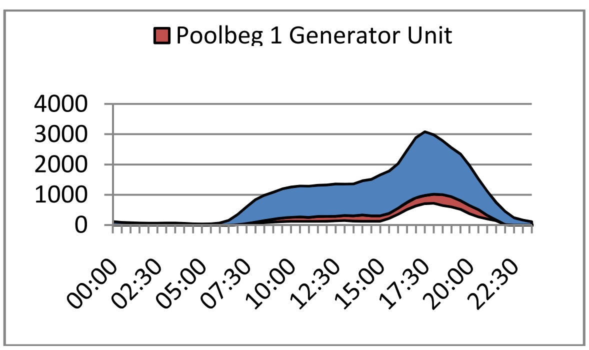
Weekend Constrained On/Off Quantities

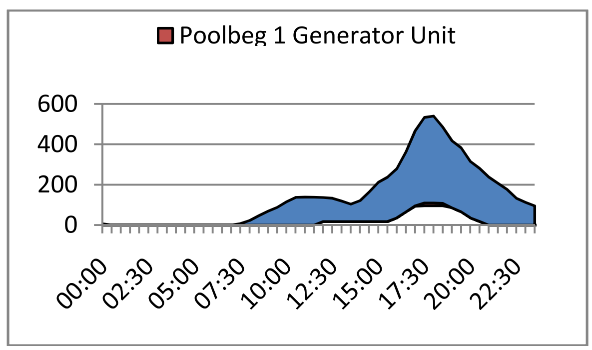


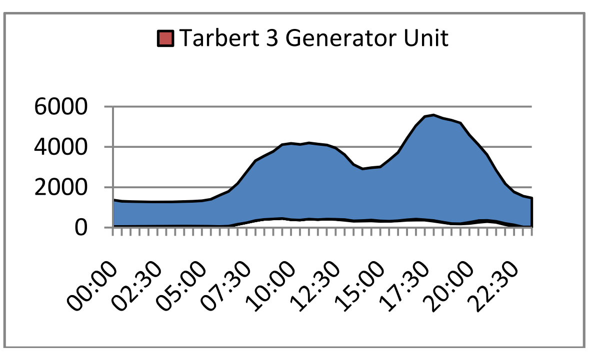


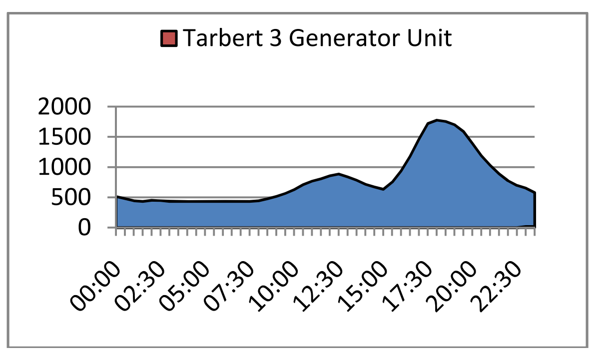




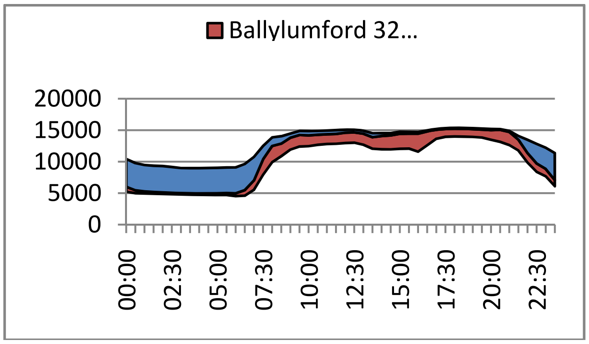


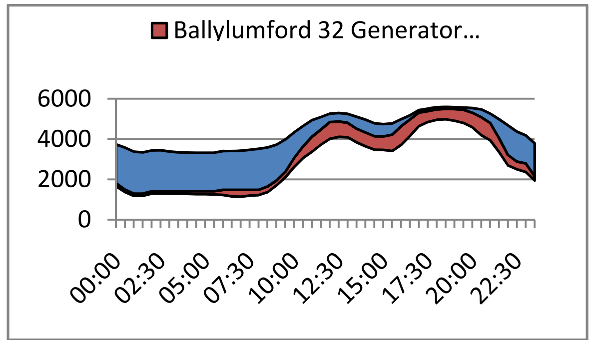




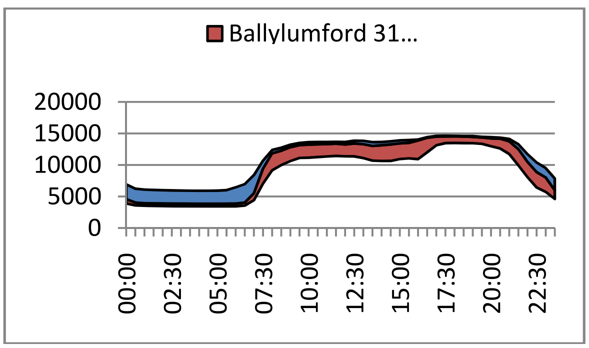


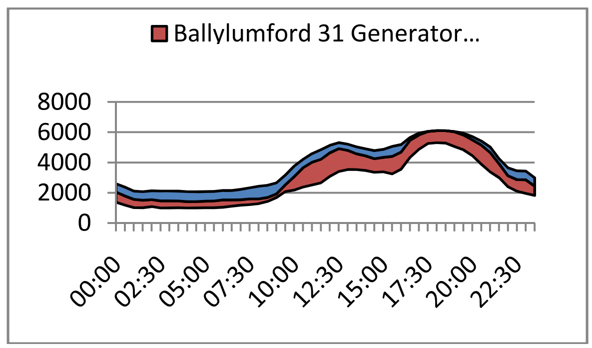
Aghada, Tarbert and Great Island are mostly constrained consistently on in order to maintain system security. They are situated at locations on the grid (Cork, West and South-East respectively) which require local voltage and dynamic stability support.





Similarly constraints led to Ballylumford Unit 32 being dispatched overnight despite not being in market schedule. Since the end of February, the unit has been scheduled to run overnight on a more frequent basis, leading to a closer relationship between schedule and dispatch. Ballylumford Unit 31's dispatch schedule follows the market schedule more closely.





Overall, deviations from the market schedule are significant across almost all of the conventional plant on the island. These are related to system requirements and environmental constraints.

5. COMMERCIAL OFFERS OF SELECTED GENERATORS

This section discusses the commercial offer data of selected generators in terms of No-Load Costs, Start-up Costs and incremental P/Q pairs. For the purposes of comparison, all commercial offers are expressed in Euro. Commercial offers submitted in sterling have been converted using the daily exchange rate published by the Market Operator.

As already mentioned, some of the bids discussed here were separately the subject of inquiry by the SEM Committee.

No-Load Costs:

No-load costs are represented as a cost per hour, for each hour the generator is running. They are recovered by infra marginal rent (if necessary as a result of uplift). Fuel usually constitutes the largest element of this cost. Figures 20 to 23 represent generators' indexed no-load costs over the first six months of SEM – that is the graphs show changes in submitted no-load costs relative to the base day. For reference the carbon indexed fuel cost is also shown in the graph.

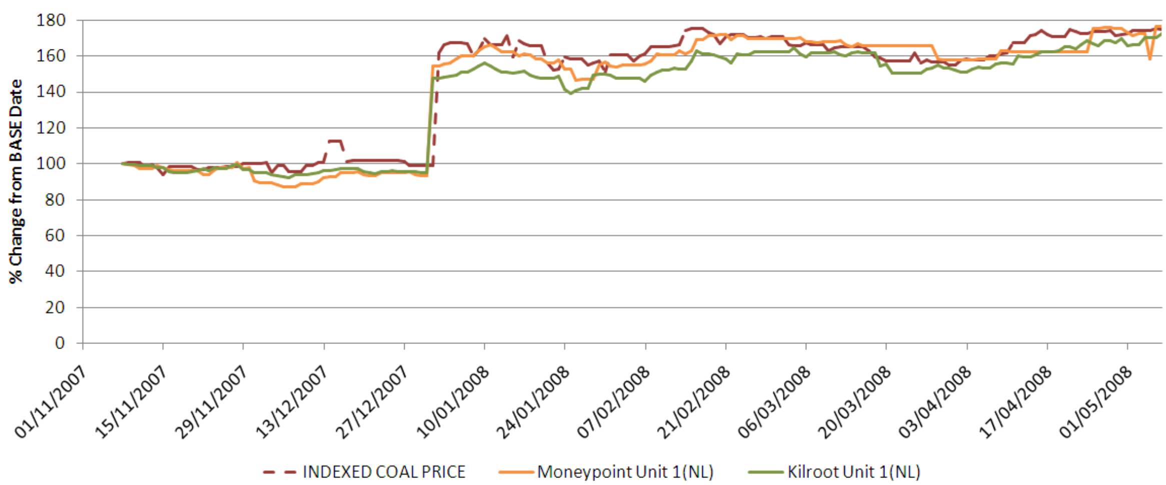


Figure 20: Coal Plants

No-load costs for Kilroot and Moneypoint have very closely tracked changes in international coal prices; the large step increase in January due to the increased cost of carbon. Several CCGT plant have submitted no-load costs which do not vary in line with movements in fuel and carbon costs. These are largely a result of issues considered in the SEM Committee's bidding inquiry.

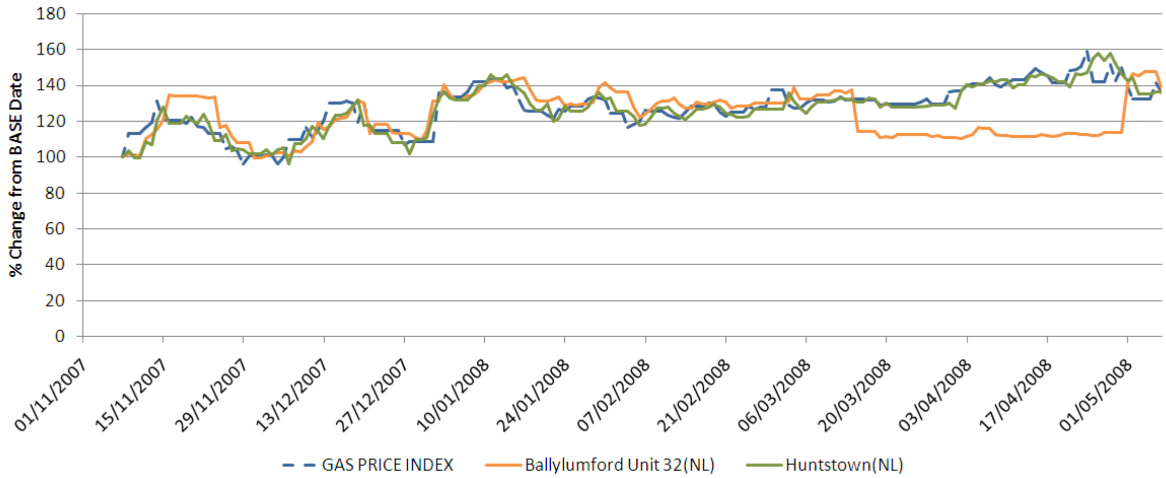


Figure 21: Ballylumford & Huntstown 1

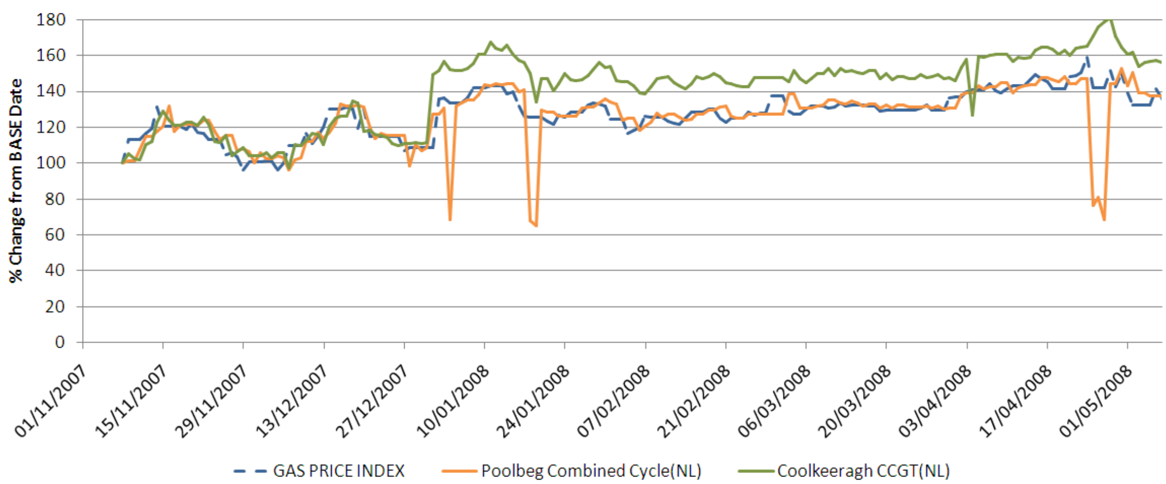


Figure 22: Poolbeg & Coolkeeragh

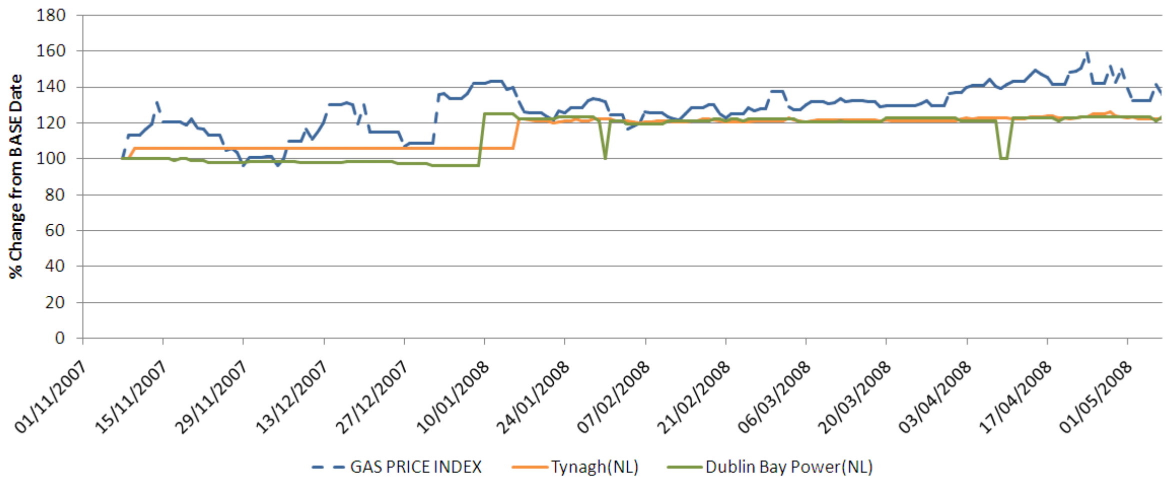


Figure 23: Tynagh & Dublin Bay

Start-up Costs:

Start-up costs are recovered through infra-marginal rent, and additionally through uplift, Start-up costs are represented as a cost per start. Generators offer separate costs for starts from the hot, warm and cold states. Fuel contributes a significant element to these costs, however for start-up other potential costs-items including the variable operating and maintenance costs can have a significant impact. For example many maintenance schedules are based on number of starts rather than hours run.

Figures 24 - 27 represent changes in cold start-up costs for selected generators. Cold starts would generally be expected to contain a larger fuel element than warm or hot starts – though the impact of other variable costs is proportionally larger than for other elements of commercial offer data.

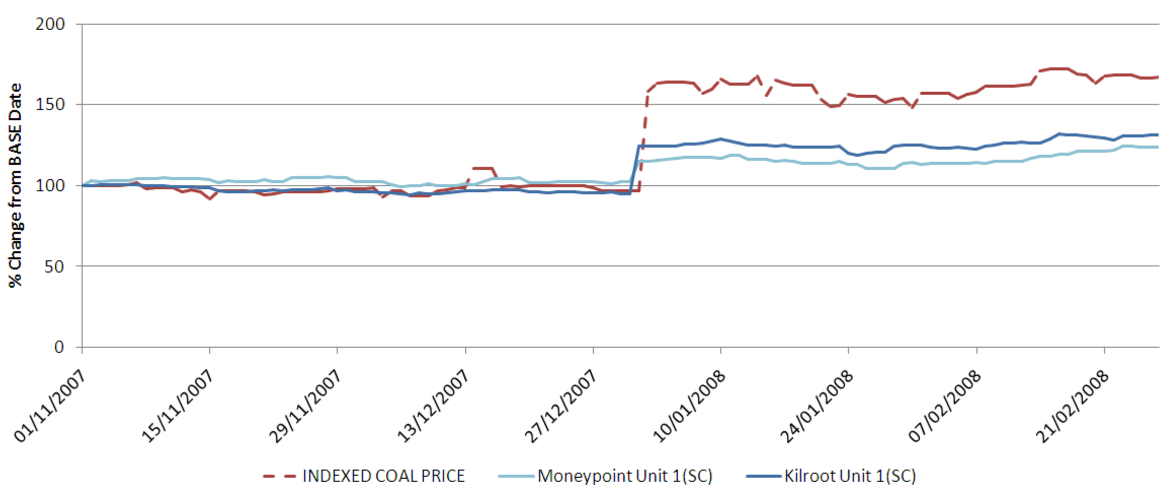


Figure 24: Coal Plants

Note: Start up costs for Kilroot coal fired units increased significantly at the end of February (not shown in the above graph). Changes in their submitted start-up costs reflect reviews by AES Kilroot of the impact of wear and tear and additional maintenance from frequent starts.

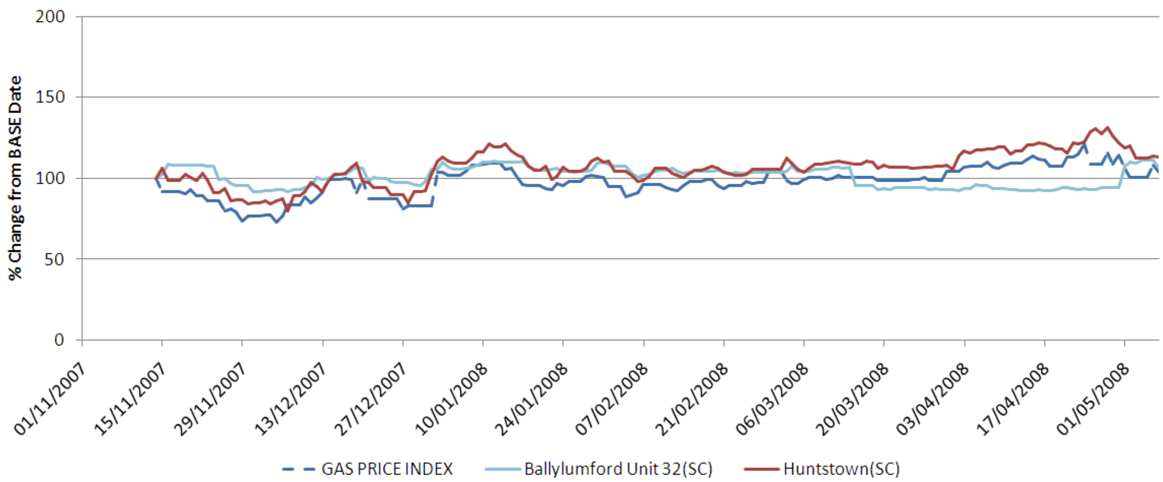


Figure 25: Ballylumford & Huntstown 1

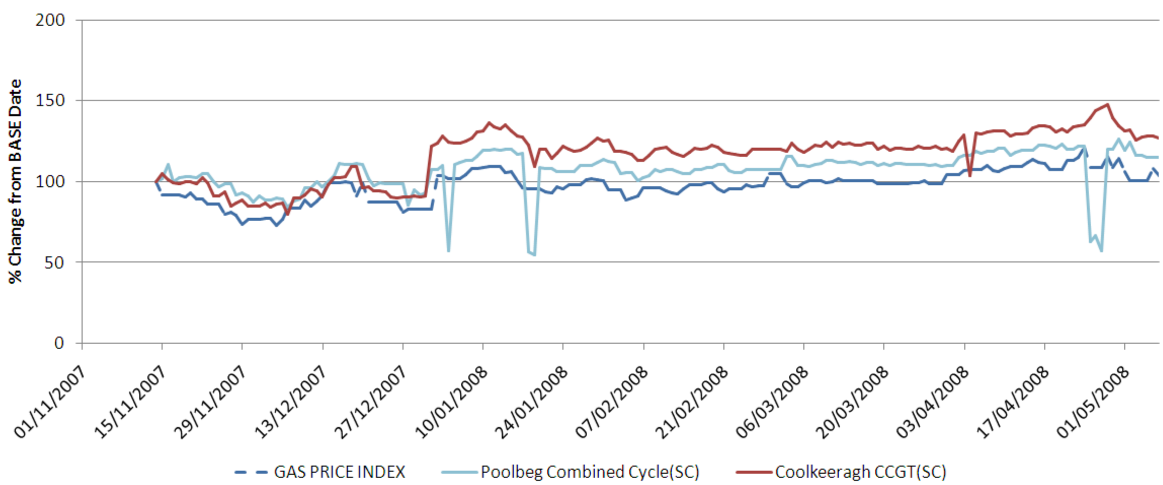


Figure 26: Poolbeg & Coolkeeragh

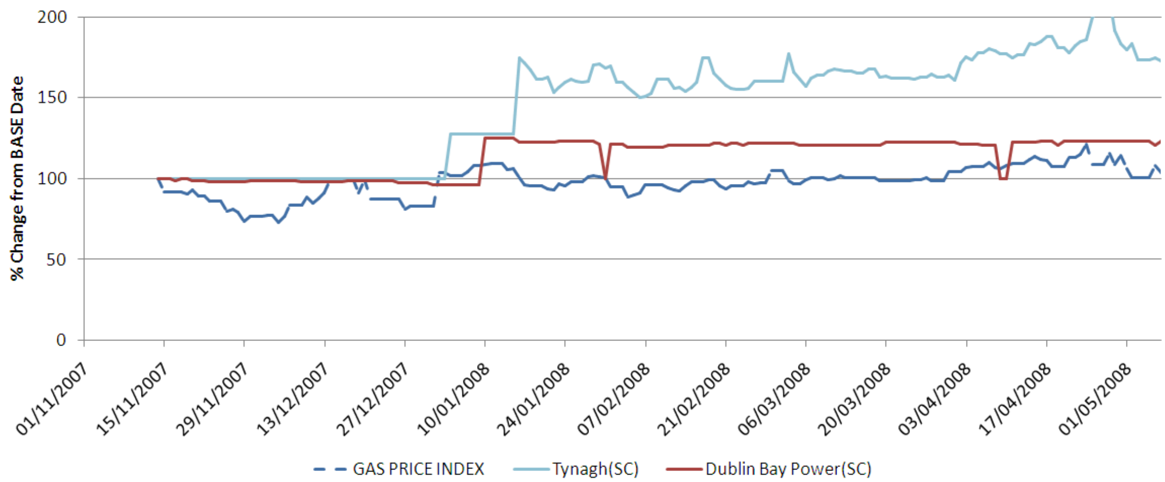


Figure 27: Tynagh & Dublin Bay

Commercial offers for cold start-up costs for Ballylumford 31 & 32's increased on 10th November 2007 by over 600%, Ballylumford 10's increased on the same day by 200%. On the 11th November 2007, Huntstown 1's offer increased by 55% and Huntstown 2's increased by almost 100%. These changes just after Go-Live reflect the adaptation of participants to potentially significant increases in cycling which was outside their control and attempts to reflect the costs of the impact of the change in operating regime in terms of costs per start. For this reason 14 November is used as the base day for the indexes in order to analyse relative price movements.

Incremental Price/Quantity (P/Q) Pairs:

Generators can offer up to ten P/Q pairs for incremental amount of generation. Effectively these are what set the shadow price in the SEM. In the graphs represented below relative changes in the first tranche P/Q pairs are shown.

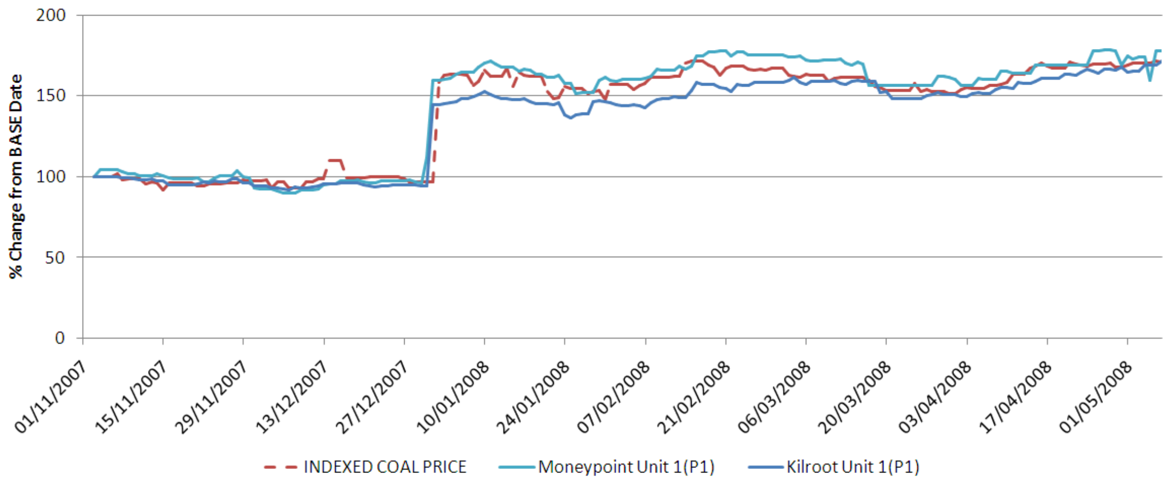


Figure 28: Coal Plants

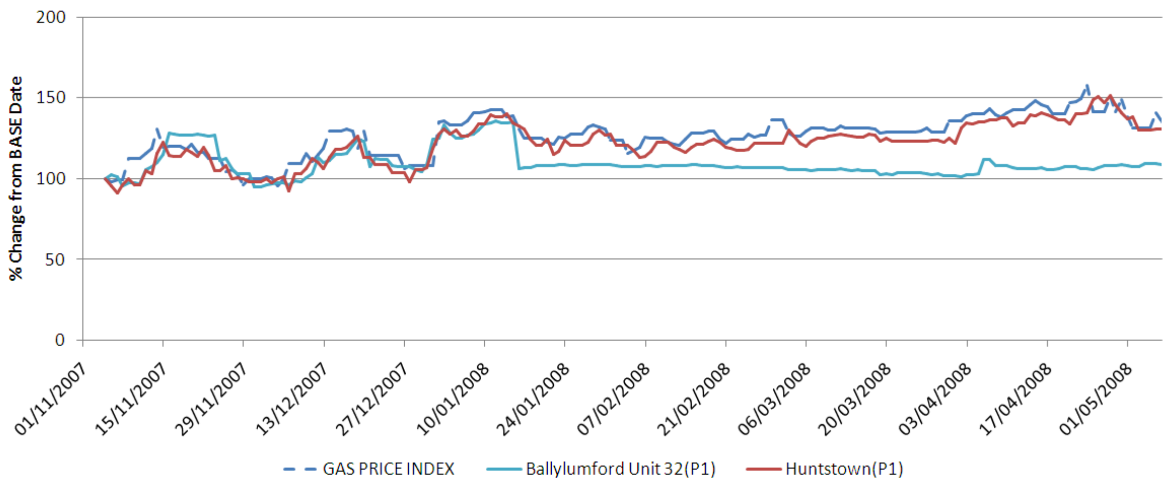


Figure 29: Ballylumford & Huntstown

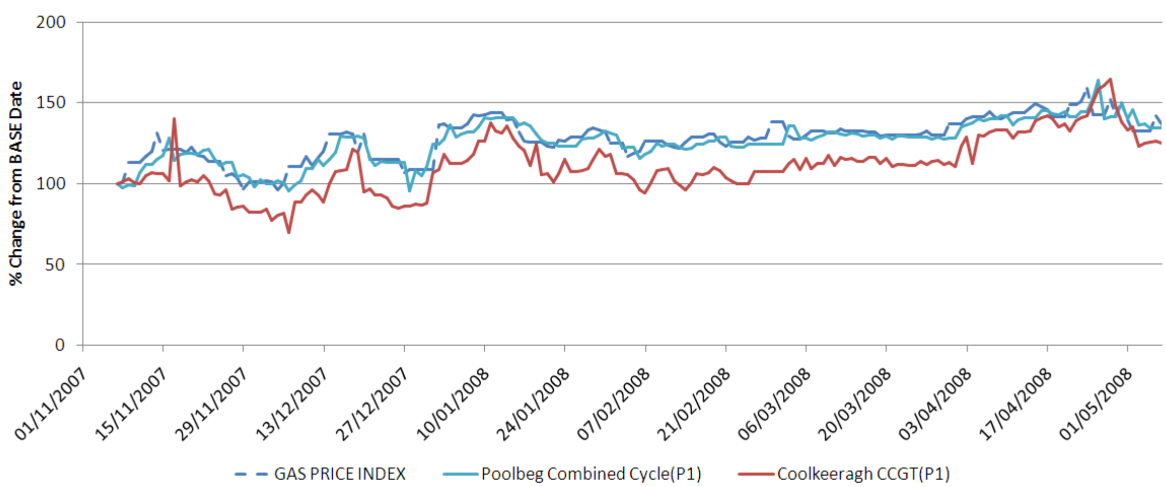


Figure 30: Poolbeg & Coolkeeragh

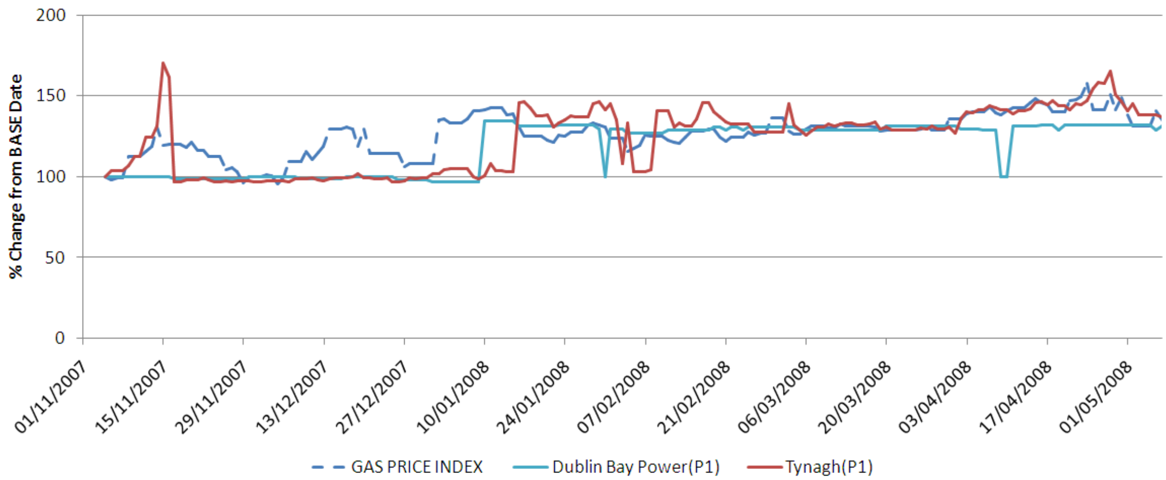


Figure 31: Tynagh & Dublin Bay

Although as illustrated in Figures 20 to 31, the commercial offers of most units closely track their associated fuel prices, there are clear instances where this is not the case. The majority of these divergences are related to the issues considered in the SEM Committee inquiry into bidding patterns and two shifting mentioned above.

Similarly, the incremental and no-load commercial offers for the 'base' dates broadly reflect the technical characteristics of each generator and their associated opportunity cost of fuel. Start-up offers on the other hand appear more subjective, with significant costs included to account for non fuel elements such as operating and maintenance costs associated with plant cycling.

6. PRICE SETTING

Merit Order

The merit order is a function of Commercial Offer Data (COD) submitted by generators and will vary depending upon divergences of input costs and bidding behaviour. Figure 32 illustrates the running costs (based on no-load and incremental COD) for selected units on the 30th April 2008, and gives an indication of the relative merit order of selected plant in the market on this day. Units such as Moneypoint 1 and 2 are not included as their bidding is generally in line with that of 'sister' plant (Moneypoint 3 in this case). Kilroot's highest price tranche for oil-firing is also not included.

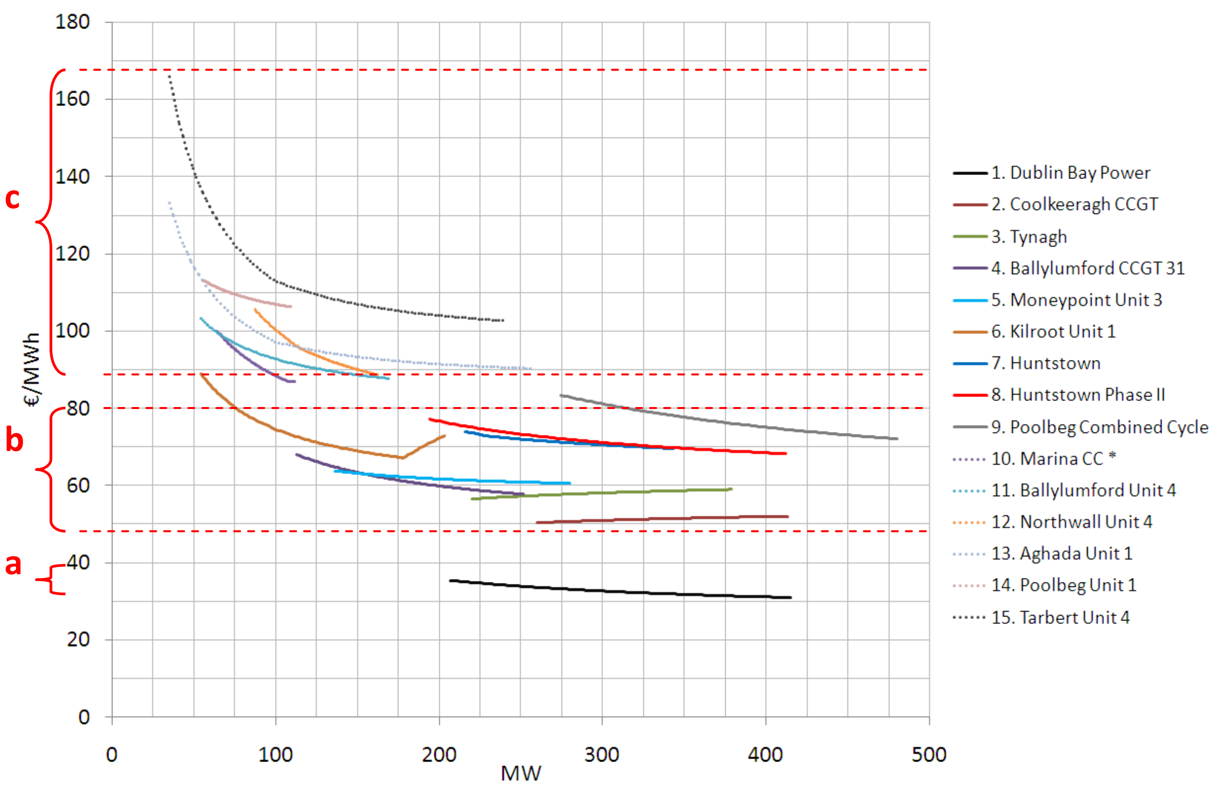


Figure 32: Cost Curves for Selected Units on 30th April 2008

From Figure 32:

a. Dublin Bay is an outlier with particularly low production costs and hence for the most part, when available, is scheduled at full capacity in the market.

b. The remaining large CCGT and coal plants compete within a band of about €30/MWh for baseload / lower mid merit operation.

c. Units in band c are usually scheduled for peaking operation or as back-up when the availability of plant in band b is low.

It is worth noting that there is little intersection of cost curves between bands b and c, hence, when the availability of plant in band b is low, a significant step increases in production costs and therefore SMP may be experienced. Also, the move up though merit in band c is more rapid than band b as the typical capacity of units in this band are lower, hence as availability becomes scare, prices become increasingly volatile.

<u>Peak Prices</u>

The majority of daily peak prices have occurred during periods of daily peak demand; however, there have been a number of exceptions to this. Table 5 lists the top ten SMP prices during the first six months of SEM.

Table 5: 10 Highest SMP Prices

[redacted]

All of these top ten prices and indeed over 90% of the top 50 prices can be attributed to the scheduling of Kilroot power station at its highest price band. This has been designed to account for the costs of switching to oil firing.

Table 6: Top 10 Incidents of Uplift

Top 10 Incidences of Uplift					
Start Date	*Start Period*	*Duration (Periods)*	*SMP €/MW/h*	*Shadow €/MW/h*	*Uplift € MW/h*
20/11/2007	17:30	1	347	128	219
31/03/2008	02:00	8	262	55	206
13/04/2008	23:00	14	247	62	186
05/02/2008	17:30	1	325	141	184
19/02/2008	18:00	1	327	149	179
06/12/2007	17:30	1	271	92	179
07/01/2008	17:30	1	287	109	178
11/03/2008	19:00	1	272	95	176
05/03/2008	19:00	1	266	92	174
12/01/2008	17:30	1	244	82	162

Table 6 shows the top ten incidents of uplift. This uplift is created by the start-up and no-load costs associated with scheduling a peaker unit to serve demand for a short period of time, usually during peak demand periods. The peak prices on the 31st March are discussed later in this document (high prices on the 13th April are caused similarly).

When Kilroot is scheduled in its "oil firing" range it is generally scheduled for less than 8MW above its offered coal overburn threshold, which has a significantly lower incremental cost. In comparison, when uplift is the cause of peak prices, the unit responsible is generally scheduled for at least 16MW. This is to be expected, as the market schedule software minimises production costs and not the cost to the consumer, so when Kilroot is scheduled in its "oil firing" range, the additional market cost is the extra scheduled quantity above coal burning, factored by the high price for these few additional megawatts. On the other hand, when a peaker unit is scheduled, creating a large amount of uplift, the production costs include the incremental cost per scheduled megawatt, along with start-up and no-load costs.

On no occasions were the Kilroot units actually dispatched for oil burning during the first six months of SEM. This is because the switchover between fuels takes a number of hours. This switching time is not fully represented in the software which calculates market schedules and prices.

Overnight Prices

Overnight periods are defined as 23.00 to 7:30 for this analysis, in line with Directed Contracts. Price was being set by a number of different generators, often interchanging on a half-hourly basis. Generally speaking, there is less uplift during overnight periods; hence shadow prices reflect closely the SMP during these times. Figure 33 illustrates the percentage of time various units or power stations were identified as setting the overnight shadow price.

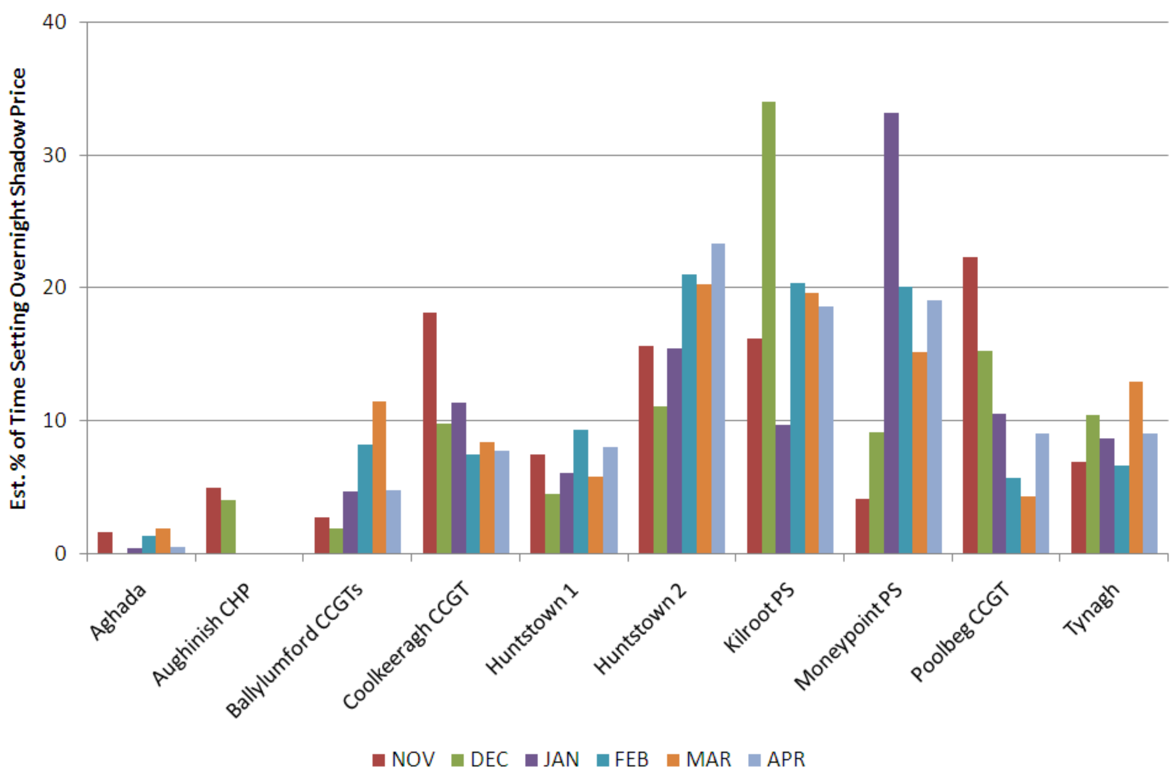


Figure 33: Est. Percentage of time a Plant is identified as Setting Overnight Shadow Price

Kilroot was detected as setting the overnight price more often than any other plant in December. Moneypoint Power Station sets overnight prices substantially less frequently in January, indicating a general shift in Moneypoint's position in the merit order. This follows from the increased costs associated with carbon, which coal plants experience more severely than CCGT plants. Changes in generator bidding, carbon and fuel prices, (and possibly exchange rate movements) have had an impact on price setting.

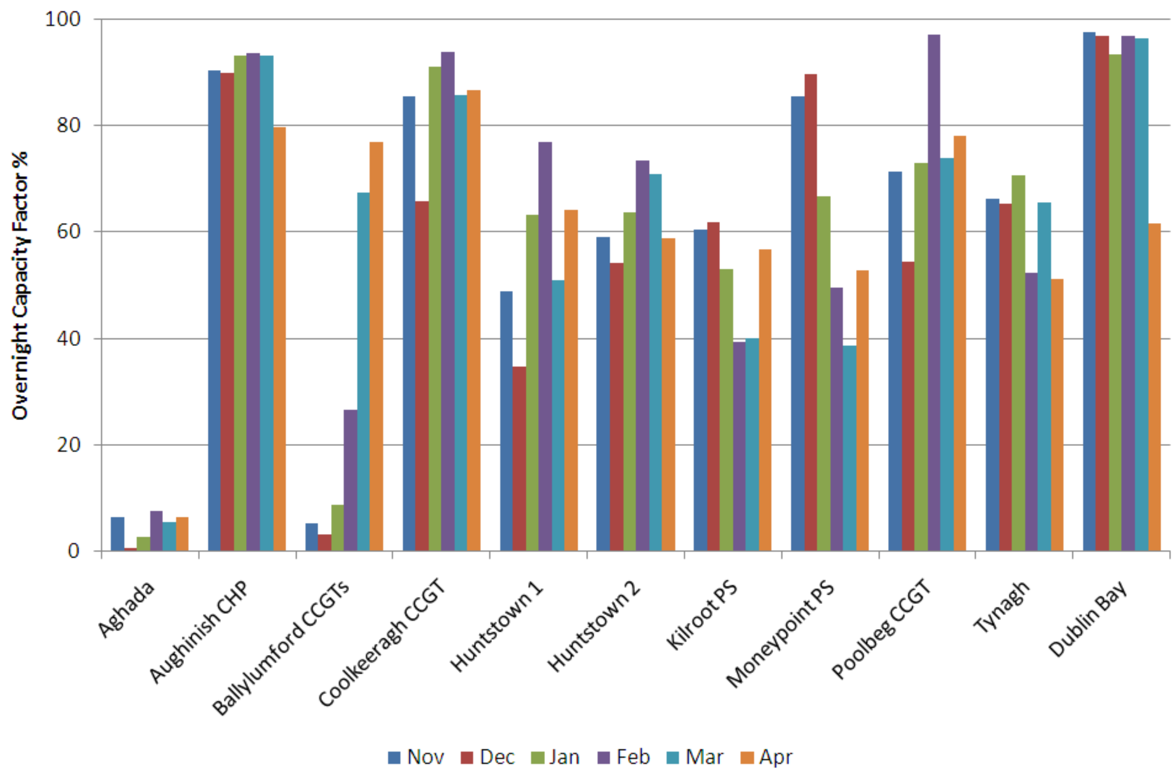


Figure 34: Overnight Capacity Factor of Selected Plants

Figure 34 shows the capacity factor of selected plant during the overnight periods of the first six months of SEM. This is a percentage figure of the scheduled megawatts for each plant bench-marked against their maximum capacity figure (which is taken from NERA's validation exercise for the Directed Contracts). Outages have not been accounted for in calculating available capacity.

It can be seen that Dublin Bay ran at almost full capacity during the overnight periods. Other plants, such as Huntstown and Tynagh have repeatedly been ramped back to part load during overnight period whereas Ballylumford CCGTs were seldom scheduled during the first three months to run overnight, instead two-shifting on a daily basis (see Section 5). During March and April, the Ballylumford CCGTs have moved to a more predominately baseload operation, in line with changes in their commercial offer data.

7. GENERATOR ENERGY REVENUE & CAPACITY PAYMENTS

Infra-marginal rent earned by generators is estimated in Figure 35. The infra-marginal rent is calculated by deducting generator production costs from the energy revenue they would expect to receive from the SEM. The production costs are based on the commercial offer data submitted by generators, which should be cost reflective. The energy revenue is simply MSQ for each generator multiplied by the SMP during each trading period. Constraint payments and uninstructed imbalances are not included in these figures.

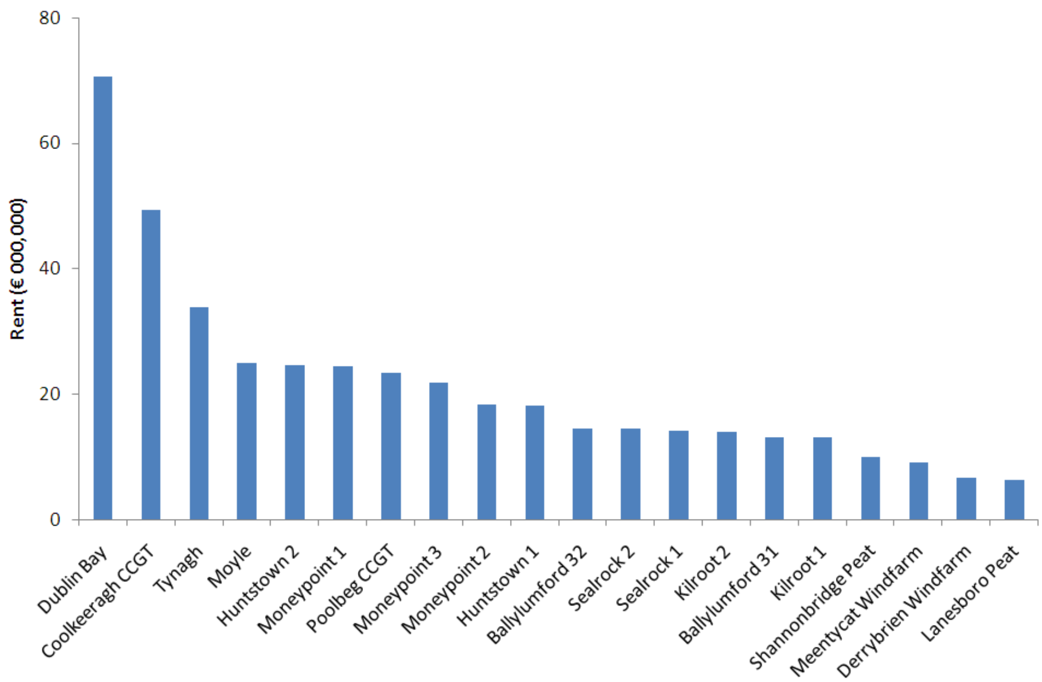


Figure 35: Largest Infra-marginal Rent Earners (Estimated) in first 6 months of SEM

Dublin Bay, Coolkeeragh and Tynagh have earned the greatest proportion of infra-marginal rent, although it must be noted that as part of the previously mentioned inquiry the bidding strategy of these three generators was examined. Notably the Moyle interconnector has earned a significant proportion of rent, even though it was be utilised less than expected over the first six months of SEM.

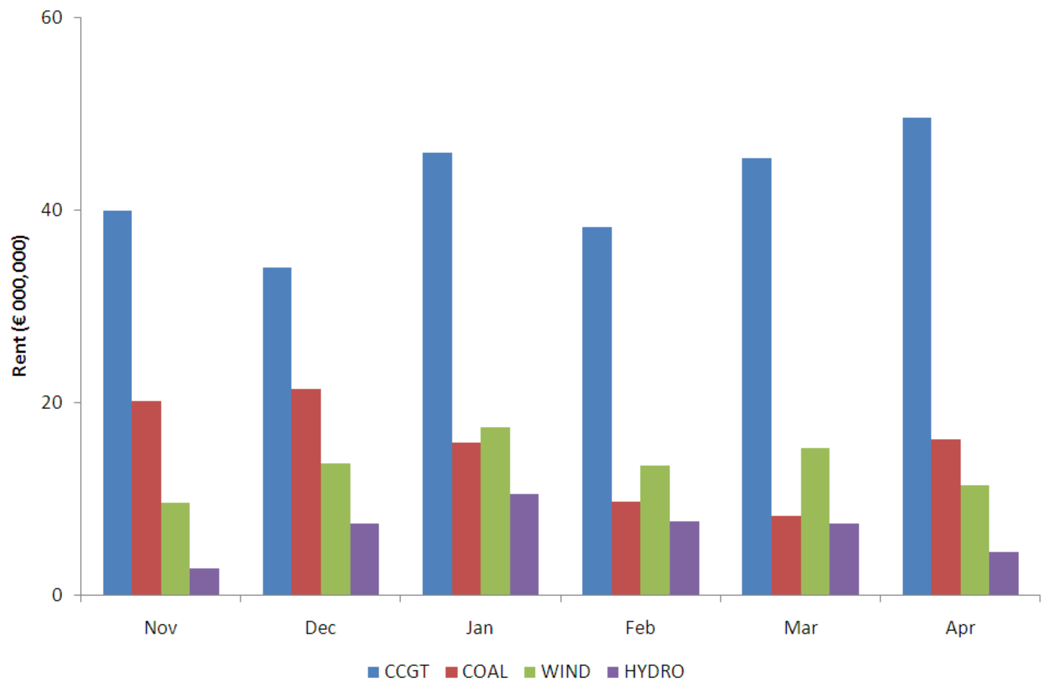


Figure 36: Estimated Rent Earned by Unit Type

Figure 36 shows the infra-marginal rent earned by generation type. As would be expected, given that over half of scheduled electricity production was from large CCGTs, they earned the most rent, earning in total just under 50% of total market rent for this period. Wind farms continue to earn proportionately high levels of rent compared to the dispatchable thermal and hydro plant. This is due to the short run marginal costs of wind being zero. There also appears to be a significant reduction in the rent earned by Coal plants during 2008, again likely to be associated with increase in carbon prices.

Capacity Payments

In additional to energy revenue, the capacity payment mechanism is a fixed revenue stream, where generators, are rewarded based on availability of plant in gross terms. Figure 37 shows estimates of the capacity revenue received by each generator for the first six months of SEM.

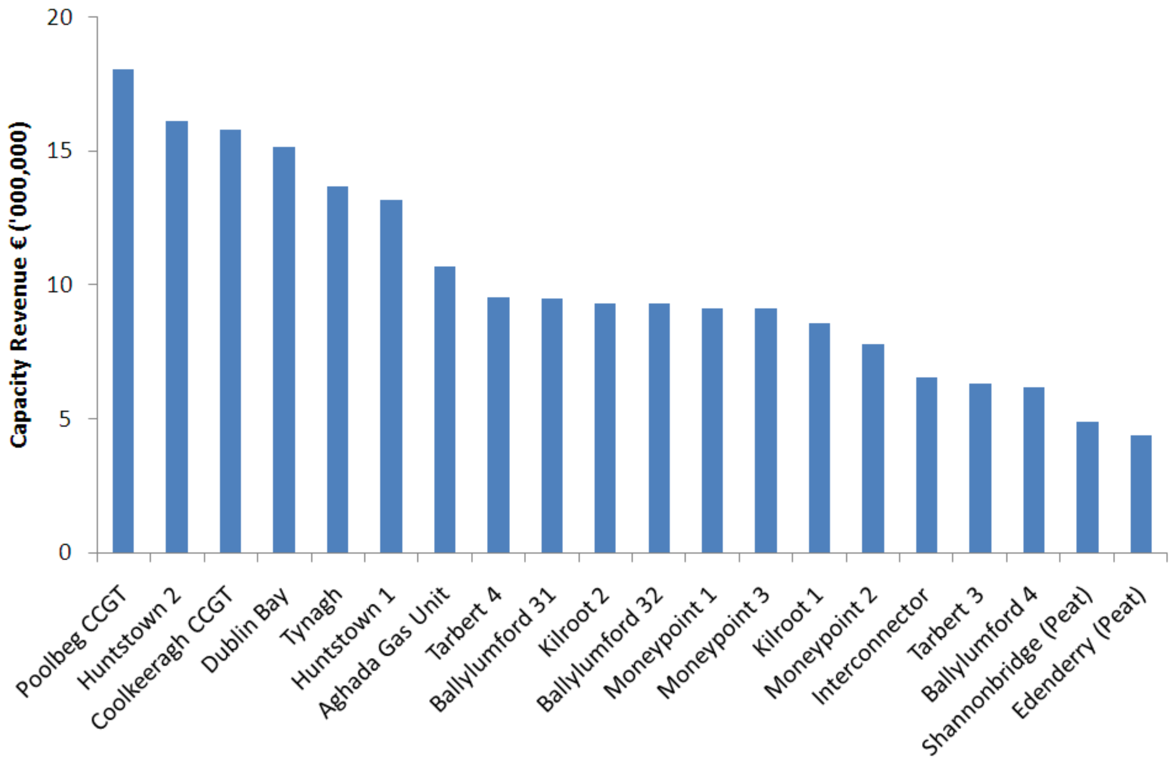


Figure 37: Capacity Revenue for Largest 20 Recipients

As to be expected the largest plants earn the most capacity revenue. The Poolbeg CCGT unit's capacity revenue was over 70% of its infra-marginal rent, compared to the Aghada Gas Unit's capacity revenue which represents over 600% of its infra-marginal rent. Table 1 in Section 1 of this report gives an overview of the ownership of selected units in SEM.

8. SPECIFIC EVENTS

Below a couple of specific intra-day events are explained, giving examples of the intricacies of the market.

High Overnight Prices (30-31st March 2008)

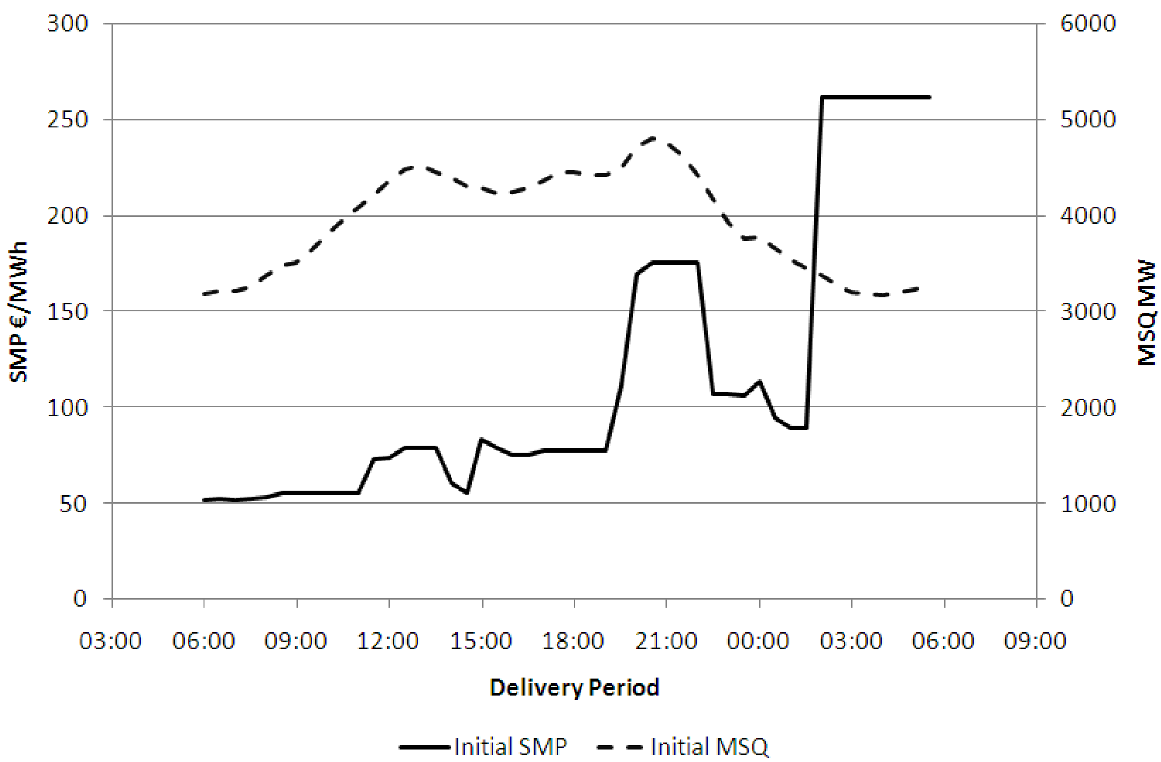


Figure 38: SMP and Load Profile

During the early morning period of 31st March 2008 (Trade Date 30th), SMP plateaued at €262/MWh when demand on the system was relatively low. Approximately 1,000 MW of baseload / near baseload plant was on a scheduled outage. At 15:00 on the 30th Coolkeeragh suffered a forced outage. This plant was not able to resume operations fully until 19:00 on Tuesday 1 April. At approximately 01:30 on the 31st Kilroot 1 redeclared availability to zero due to technical reasons. Resultantly, the SMP of €262/MWh from 0200-0600 is a result of uplift for Tarbert 3 which was started in the schedule and had to recover a large proportion of start-up costs in that trading day (i.e. overnight at low demand). It is unlikely that the precise schedule and SMP could have been predicted, and therefore a result of manipulation.

Example of Uplift (20th April 2008)

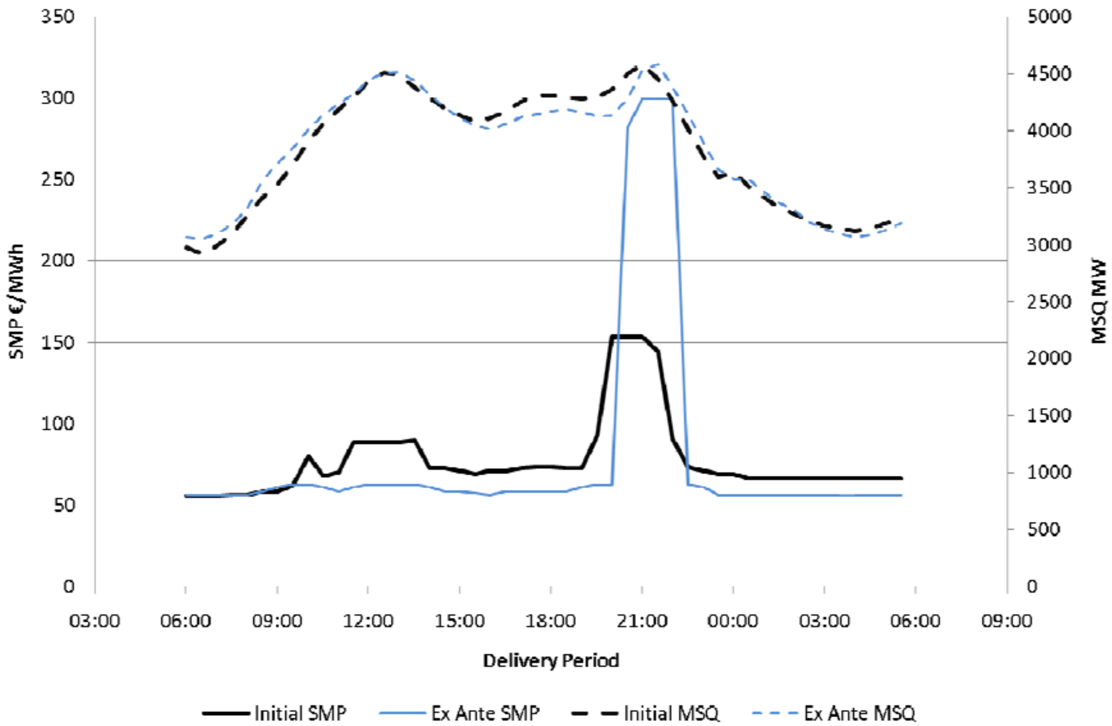


Figure 39: SMP and Load Profile

Figure 39 shows the Ex-Post Initial SMP and MSQs, which is produced by the Market Operator four days after trading day, and the Ex-Ante SMP and MSQ which is produce the day before trading day. Over the day both the demand weighted SMPs and average MSQs were similar (€79.77/MWh Ex Post vs. €81.77/MWh Ex Ante, and 3827MW Ex Post vs. 3833MW Ex Ante).

The main difference between the two schedules is the higher peak price in the ex-ante schedule. For both schedules the peaks can be largely attributed to uplift created by the scheduling of Ballylumford 4 OCGT to meet peak load and the requirement for it to recover all its start up, incremental and no load costs during the short period of running over these peak times. Unit 4 is scheduled to produce 108MWhrs of energy Ex Ante and 355MWhs Ex Post. When scheduled Ex Ante for fewer MWs, the uplift is greater than for the Ex Post as the start up and no load costs are spread across more MWs and hence the SMP is lower when the unit is scheduled to run more.