Observations on variations in grid carbon intensity

Sam Cooper, 21/10/2011

Introduction

The amount of carbon dioxide released in the generation of electricity has a clear implications for the emissions associated with the operation of systems which use electricity. Selection of an appropriate value for this quantity, the "carbon intensity", is necessary to inform judgements regarding the emissions that should be associated with different actions. This intensity varies with time as different generating plants are turned on and off, reacting to variations in demands and other operational considerations. Additionally, the intensity of the electricity from plant which is turned on or off to meet increases and decreases in demand, the "marginal intensity" is often significantly different to the mean intensity of electricity generation.

In an attempt to better understand the characteristics of the electrical supply and the variation which causes the carbon intensity to vary, half hourly generation data for 2009 and 2010 has been studied. Using the assumptions noted below, the mean marginal emissions rate for electricity generated in 2009 – 2010 can be calculated to be **697g_{CO2}**/kWh. This is 45% higher than the mean emissions rate of **480g_{CO2}**/kWh calculated from the same data.

Although more consideration is given to the varying contribution from gas and coal plant (page 9), it has been difficult to identify the operating strategy with certainty and attempts to predict the response to longer term changes in demand are difficult.

Additional observations regarding the relative contribution of other generation types (wind, oil, nuclear) are included from page 11.

Background

Various carbon intensities are available. DEFRA (2011) suggest **485g$_{CO2}$**/kWh for 2009 with a five year rolling average of **523g$_{CO2}$**/kWh (direct emissions). This increases to **594 g$_{CO2}$**/kWh if indirect emissions are included. The Carbon Trust (2010) suggest **545g$_{CO2}$**/kWh (at point of use, five year rolling average from data similar to DEFRA). SAP 2009 (BRE 2010) suggests that **517g$_{CO2}$**/kWh should be used for supplied electricity and **529g$_{CO2}$**/kWh for displaced electricity (a reduction from **568g$_{CO2}$**/kWh in SAP 2005). DUKES 2009 (DECC 2009) estimates **497g$_{CO2}$**/kWh (supplied) in 2009, slightly up from 2008 but down from **510g$_{CO2}$**/kWh in 2007. A state of the art CCGT unit (see for example, Siemens AG 2010) operating at 60% (NCV) efficiency with 7% transmission and distribution losses has an effective intensity of **366g$_{CO2}$**/kWh. Hawkes (2010) suggests a marginal (see below) intensity of **690g$_{CO2}$**/kWh for 2002 to 2009.

The marginal intensity at a given instant is effectively the intensity of electricity that can be attributed to measures that increase or decrease demand for electricity at that time. If the marginal rate is consistent, it is usually the appropriate rate to use in considering the impact of choosing these measures relative to an alternative (i.e. appropriate to *consequential* LCA studies). However, if the marginal rate is not predictable this is more problematic; for example the decision to turn on power plant with high carbon intensity may be determined by factors other than the change in demand (e.g. changing the plant which is generating for operation & maintenance reasons).

However, a marginal intensity figure is usually less appropriate for *attributional* LCA studies. That is, in comparing the impact of an action in the context of the range of concurrent activities, it is generally appropriate to assign each of them the mean intensity, given that they all contribute towards the carbon emissions and that increasing or decreasing the demand from any of them will have the same effect on emissions.

To complicate matters further, the long term effect on emissions of an action may be different to the immediate effect. For example, introducing a substantial long term additional demand to the system may initially result in an increase in emissions proportional to the marginal intensity but in the longer term may result in investment in newer, more efficient plant. This is a complex problem.

In considering the effect of moving the timing of demands in order to reduce overall emissions by taking advantage of lower intensity electricity, it is appropriate to use the marginal intensity. Adjusting the timing will decrease demand at one point (decreasing emissions by the marginal rate effective at that instant) and increase it at another (increasing emissions by the marginal rate effective at that point).

Method

Half hourly data on UK electrical generation aggregated by plant type for 2009 and 2010 was obtained from the balancing mechanism website (Elexon 2011). Data from approximately 40 hours per year was discarded as either the timestamp was irregular or the generation data was unreported. The mean marginal rate was assumed to be constant across the larger timesteps created by the discarded data.

The carbon dioxide emitted by the generation in each half hour was estimated as the sum of the product of the generation from each fossil fuel type in that half hour and the average operational emissions rate from it taken from DUKES (DECC 2009) (405g_{CO2}/kWh for Gas, 915g_{CO2}/kWh for Coal, 633g_{CO2}/kWh for Oil, including transmission and distribution losses). That is:

$$C_t = l_t \sum_n f_n P_n \qquad \text{Equation 1}$$

where C_t is the total emissions during time period, t. l_t is the length of the time period (30 minutes), f_n is the average operational emissions rate from fuel n (Gas, Coal or Oil) and P_n is the average power generation from that fuel type during the time period.

Additional lifecycle carbon emissions (such as construction and disposal) are ignored by this methodology, as are emissions caused by electricity supplied by the French and Irish interconnectors and by the production of fuel for nuclear plant.

The marginal emissions rate was calculated as the difference between the emissions in that half hour and the previous one divided by the difference between the electricity generated that half hour and the previous one. That is:

$$c_{Mt} = \frac{C_t - C_{t-1}}{E_t - E_{t-1}} \qquad \text{Equation 2}$$

where c_{Mt} is the marginal emissions rate during time period, t, and E_t is the total electricity generated in the same period.

When the difference in generation between periods is low but there is a change in emissions (due, for example, to coal fuelled plant being replaced in the mix by gas), the marginal rate can be extremely large (and either positive or negative). When considering the average marginal intensity, it is therefore useful to weight each of the half-hourly marginal rates by the *absolute* value of the change in generation over the period it relates to. That is:

$$c_{Maverage} = \sum \frac{(C_t - C_{t-1})}{E_t - E_{t-1}} \frac{|E_t - E_{t-1}|}{\sum |E_t - E_{t-1}|} \qquad \text{Equation 3}$$

The use of pumped storage significantly reduces the marginal emissions if it is treated as a zero carbon source. However, it is more appropriate to consider the emissions associated with pumping as occurring when the electricity is used. A simpler method is to reduce the emissions associated with electricity generation when pumping is occurring by the same amount but to attribute the current marginal rate to electricity generated from pumped storage systems. This is effectively the same as removing the pumped storage from calculations of marginal rate.

The mean marginal rate, weighted as per Equation 3 is the same as the average gradient of the plot in Figure 1.

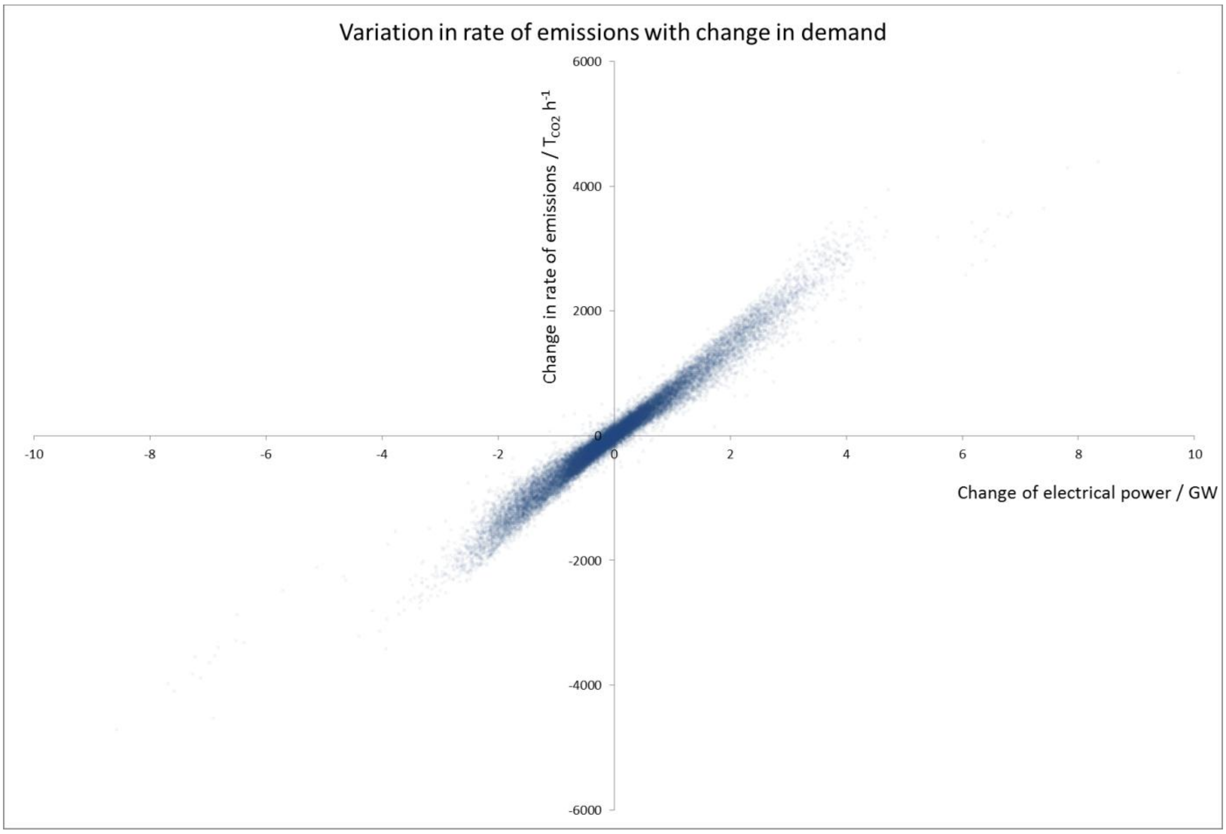

Figure 1 Change in emissions with generation

Observations

Variation in marginal emissions rate with system load

The marginal rate varies considerably with the total system demand (Figure 2). As might be expected, the emissions rates converge at higher demands as more plant is in operation and there is less opportunity for variation in the mix. Notably, the mean marginal rate is consistently higher than the mean total emissions rate and increases from a minimum of 550 g_{CO2}/kWh when demand is low (about 23GW) to a peak of about 750 g_{CO2}/kWh when demand is about 36GW before dropping back down to about 560 g_{CO2}/kWh when demand is 55GW.

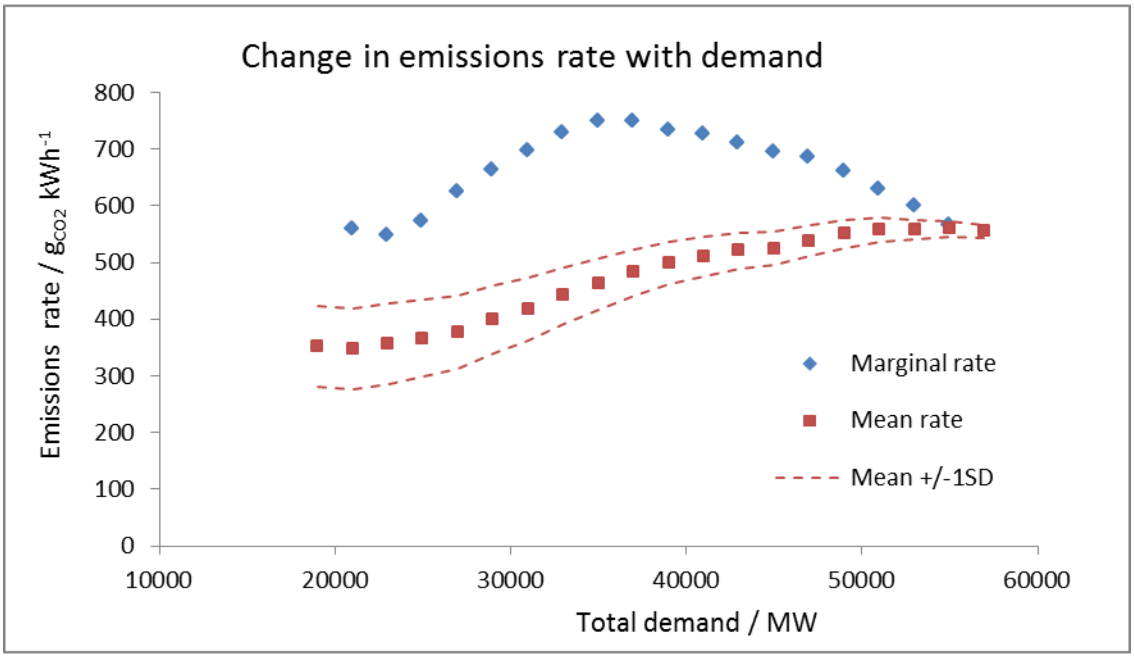

Figure 2 Change in emissions rate with demand

The situation is more complex when variation with each month is considered (Figure 3). Some of the months (October, March, December) have reasonably similar minimum marginal emissions rates despite these occurring at different minimum demands. This implies that in each case, a similar mix of generation is used to meet initial increases in demand above the baseload. In each case, the marginal rate increases at a similar gradient, implying that the mix of plant used to meet additional load also follows the same pattern of becoming more coal orientated. However, in May and August, the marginal rate starts lower before increasing at the same gradient. This may imply that when the load is 20 – 25GW, some of the CCGT used to provide baseload supply is ramping up to supply the additional load before coal is brought online. In January and February, the marginal rate starts relatively high. This may imply that coal plant is already operating during the baseload condition and that it is ramped up to meet initial increases in demand. In most cases, the marginal rate decreases for total demands above 35 - 36GW. It may be that coal is used to meet the majority of the mid-range (30 – 45GW) variations in power due to economic factors such as reluctance to cycle the power output of

CCGT plant. At higher demand levels, there is a higher probability that plant operators will need to use all of their available capacity but also that they will have more flexibility to choose which to use for ancillary services such as load following.

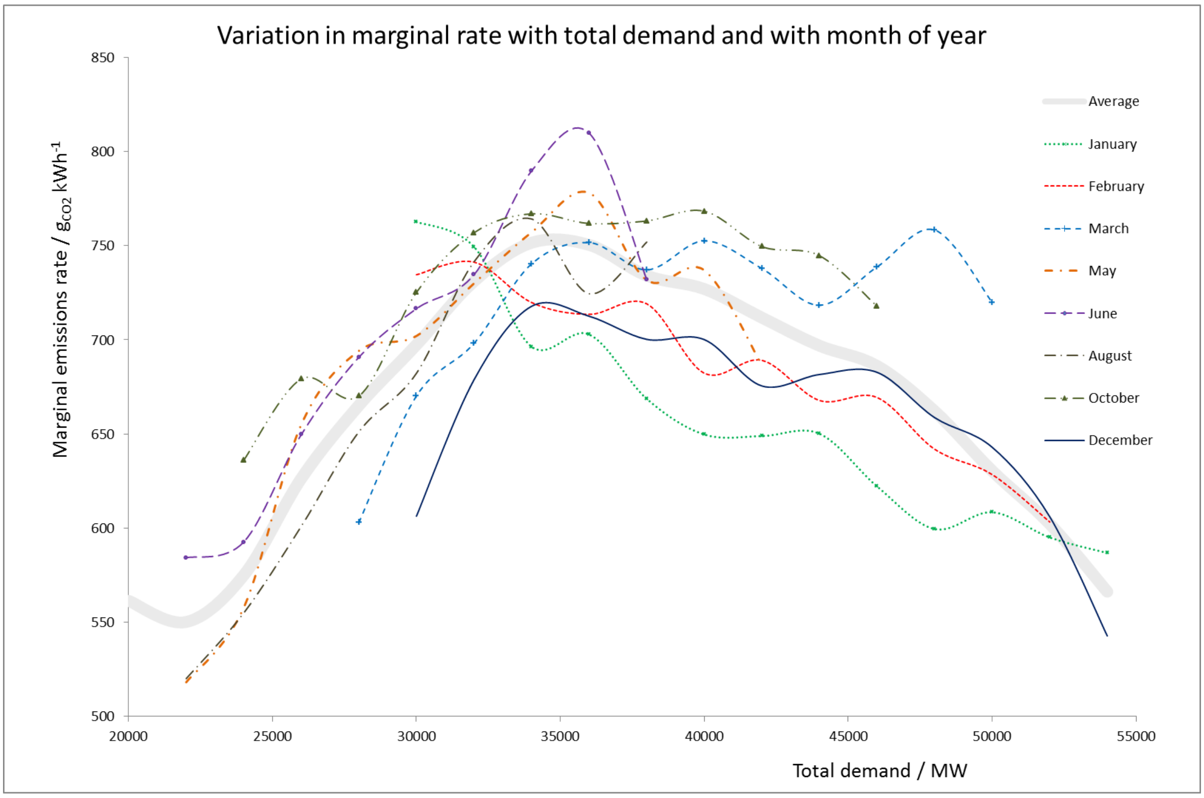

Figure 3 Variation with month

This makes it problematic to assess the likely effect of introducing a large, regular demand into the system. It is possible that the marginal rate would increase while the average rate decreases (for example if CCGT is used to supply the consequent larger baseload but coal is used to load follow the variations just above it).

There is a small difference between the marginal emissions rate observed as the load is increasing to when it is decreasing (Figure 4). It appears that the type of plant turned on and off to follow demand is generally the same but at mid-loads there is a slight increase in the proportion of gas used to meet increases in demand rather than decreases (i.e. once turned on, CCGT are slightly less likely to be turned off, relative to coal plants).

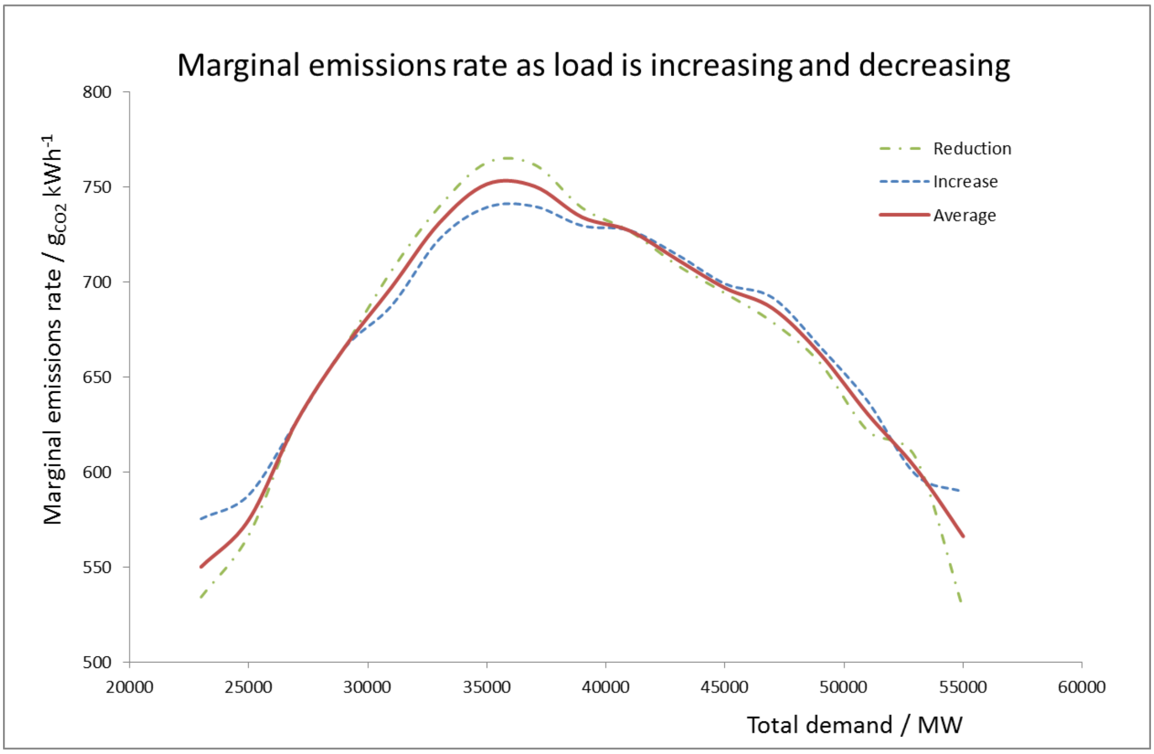

Figure 4 Marginal rate as demand increases and decreases

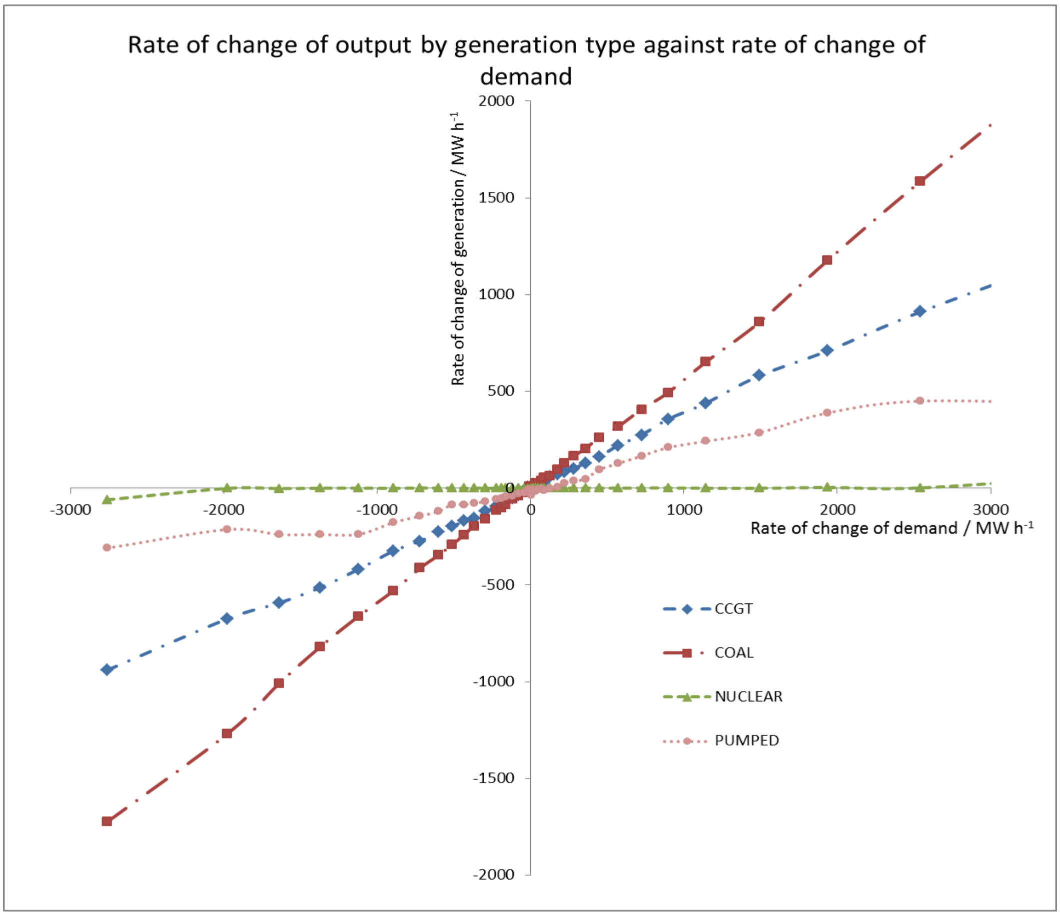

Figure 5 Rate of change of generation against rate of change of demand

There is good relationship between the rate of change of demand and the rate of change of generation from coal and gas plant (Figure 5). As might be expected, nuclear, wind, hydro, ocgt and oil plant do not contribute significantly to meeting changes in rate of demand.

However, for 30% of the time, the rate of change was lower than +/- 200MW / hr. Considering this in more detail (Figure 6), it becomes clear that for the 15% of the time in which the rate of change of demand is less than +/-100 MW/hr, coal and gas plant respond almost equally to the changes in demand.

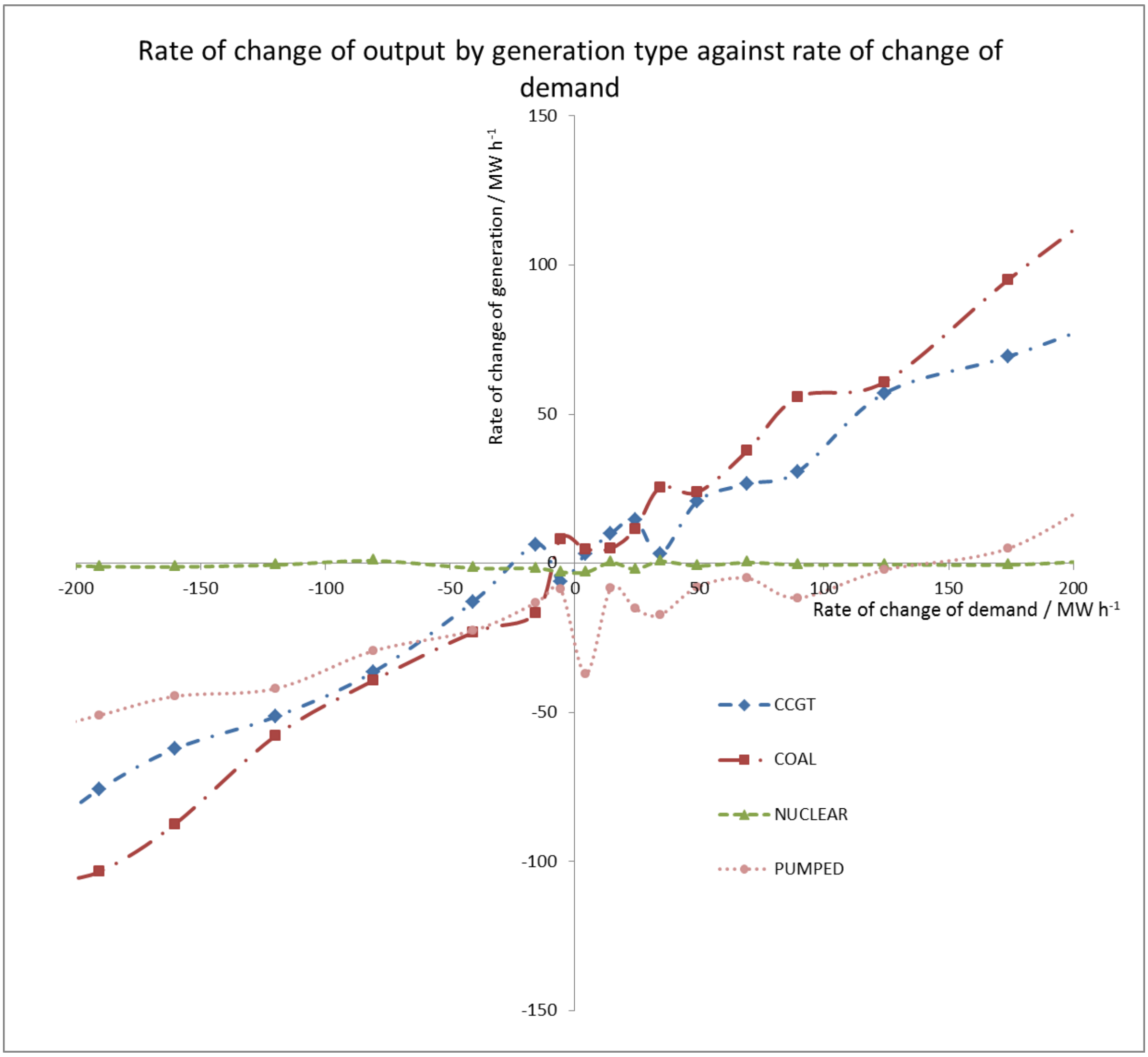

Figure 6 Rate of change of power, up to 200MW/hr

Variation in relative contribution from coal and gas

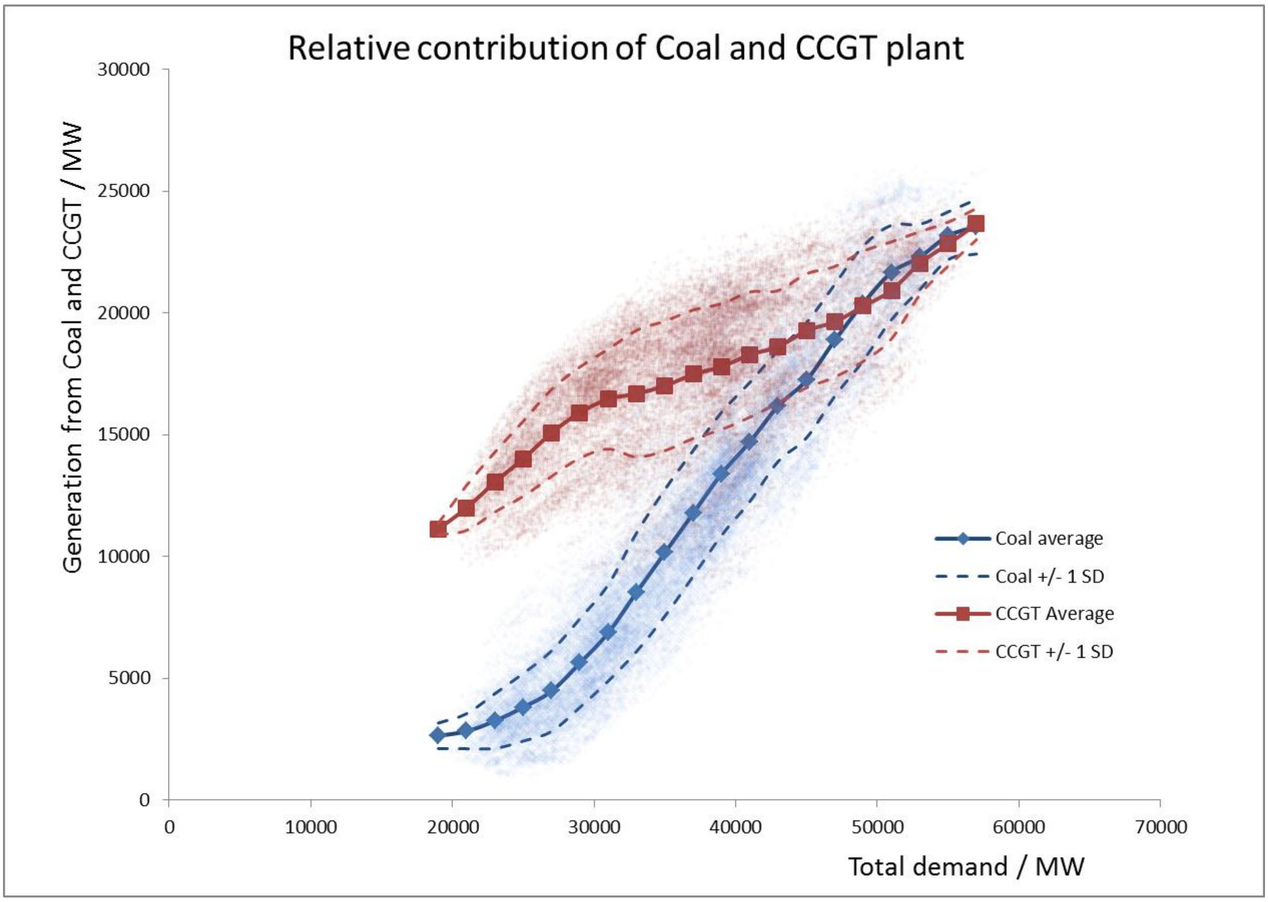

Figure 7 Relative contribution of Coal and CCGT plant

When system demand is lowest (about 18 – 20GW), the majority of the fossil fuel generation is from CCGT plant (Figure 7). As demand increases up to about 28GW, most of this is met by an increase in generation from CCGT but with an increasing contribution from coal plant. Above 30GW demand, CCGT plant continues to increase output but the majority of the increase in demand is met by the coal plant. At very high loads (above 50GW), coal and CCGT make approximately equal contributions to meeting further increases in demand. This fits with the observation from Figure 6 that the rate of change of CCGT is less than coal except for lower rates of change of demand. This is possibly a financial consideration on the part of the plant operators to reduce the variation in loading from the CCGT plant in order to minimise fatigue issues.

It could be speculated that a "structural" (i.e. large, predictable) increase in load when the demand is currently low might be met largely by CCGT plant. This would *decrease the average grid intensity but probably increase the marginal intensity* as changes in demand above the baseline would potentially be met by a greater fraction of coal. However, examination of the difference in supply characteristics between different months (in which there is significant change in the lowest load), reveals that currently, this is generally not the case (Figure 8). Rather, the average output from CCGT for a given hour of the day is relatively consistent for each month of the year and seasonal variation is primarily achieved (at least for 2009 & 2010) by coal plant.

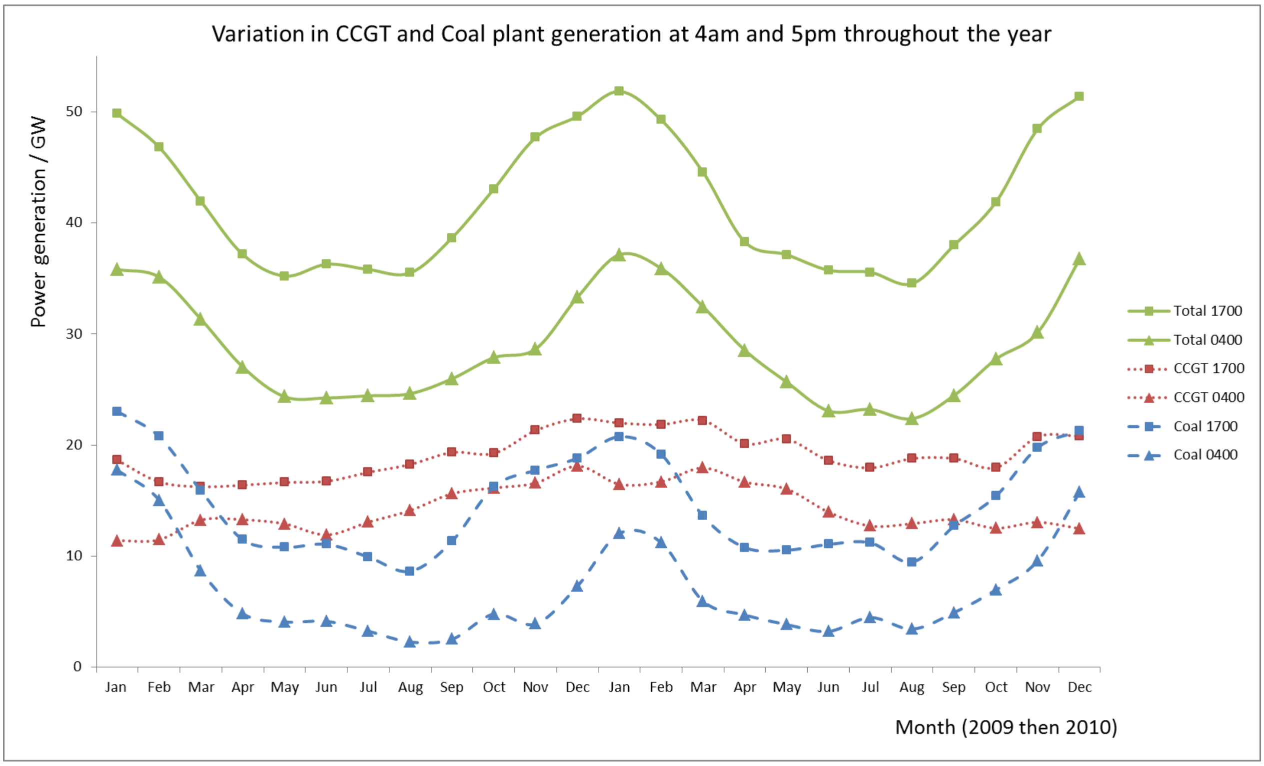

Figure 8 Variation in power generation throughout the year

It is possible that the increase in the proportion of gas used in the winter 09/10 period is due to a decrease in its price relative to coal since early 2009.

Other aspects of supply

Pumped storage

The operation of pumped storage was observed to follow a diurnal pattern, generally following the demand pattern. Maximum power consumption (i.e. rate of storage) generally occurs around 0400, transitioning to generation between 0600 and 0800 with a morning peak followed by the main afternoon peak at 1700 – 1900 before transitioning back to storage at about 2200.

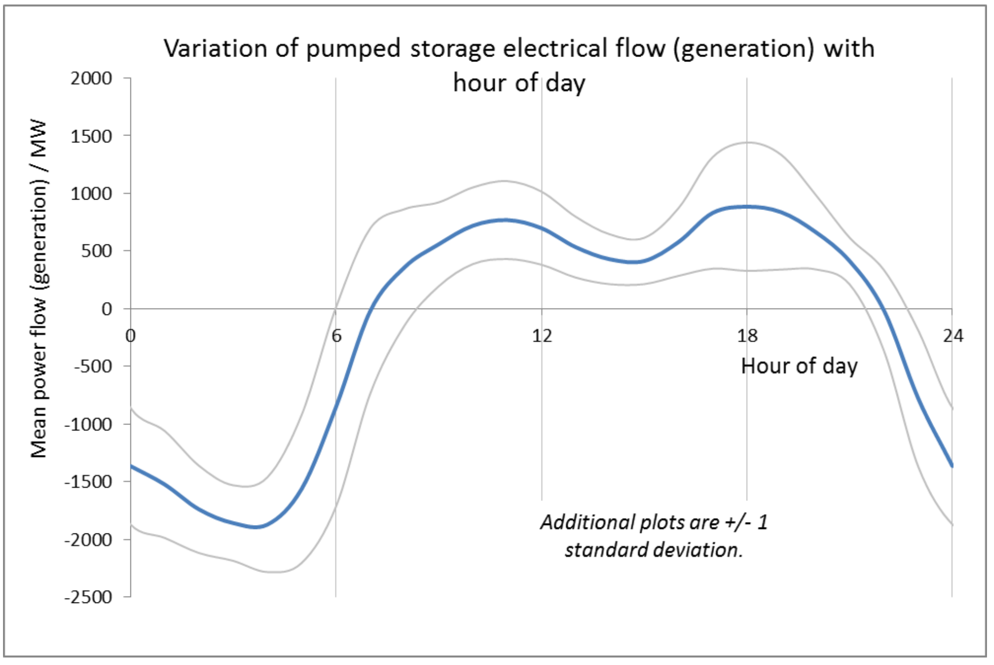

Figure 9

There is a large spread of data points. Although there is some correlation between total demand and the output from pumped storage, there are clearly other factors applying and it appears that the step changes often apply. This fits with the observation that for more than 11% of the year, power output is within 10% of 320MW (i.e. a range of 1% of the observed operating range), potentially either one of Dinorwig's turbines or all of Ffestiniog's. The pumping tends to occur at specific times at a relatively high rate (1.5GW to 2.4GW) implying that small-scale demand management has limited potential to alter its operation.

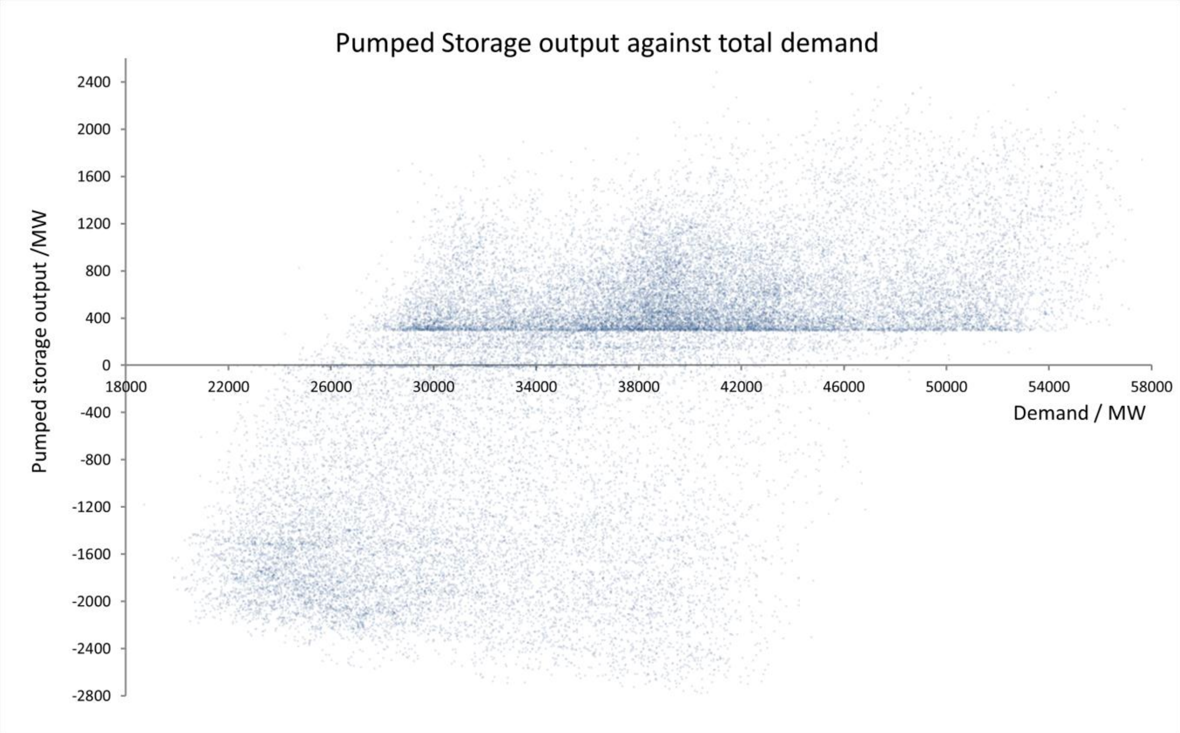

Figure 10

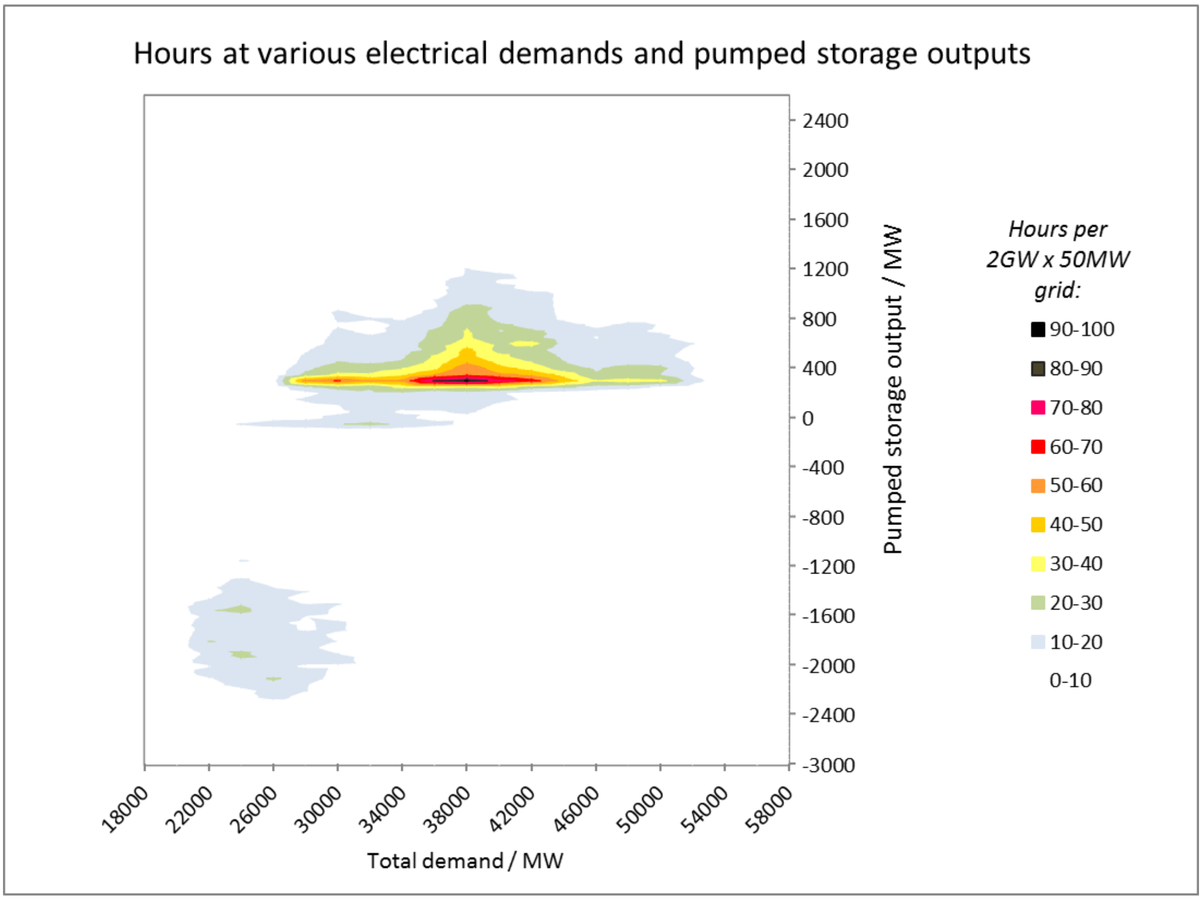

Figure 11

Wind, OCGT and Oil

These show wide variation across the range of total demands.

Note that variations in capacity are not corrected for in this analysis, this is especially relevant to wind.

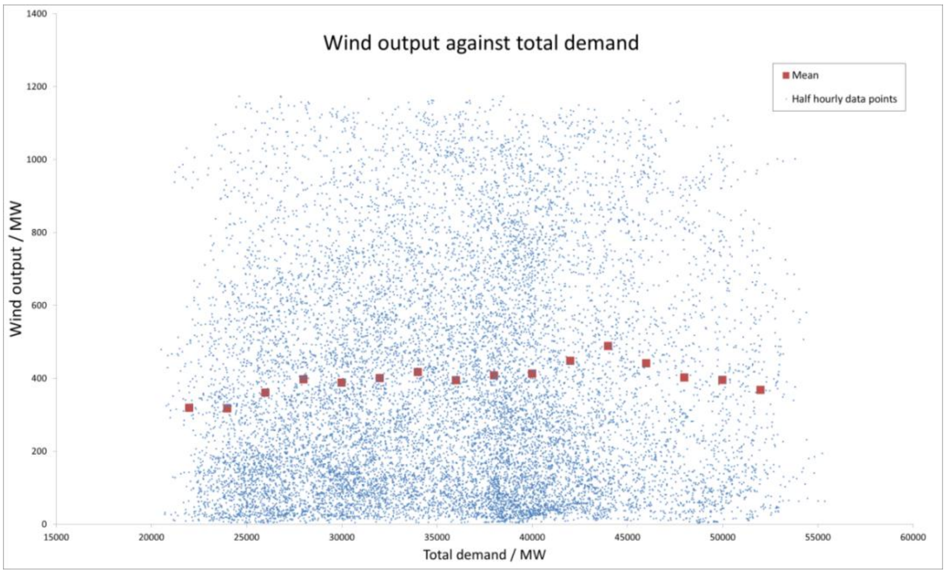

Figure 12

It was expected that if OCGT plant is used primarily to provide quick response to fluctuations in demand that there would be good correlation between the OCGT power output and the half hour periods with large variations in total demand from the previous half hour. In general this was not observed although there is correlation between the OCGT output and rate of change of demand if only the times it is operating are considered (the OCGT >0 plot on the graph).

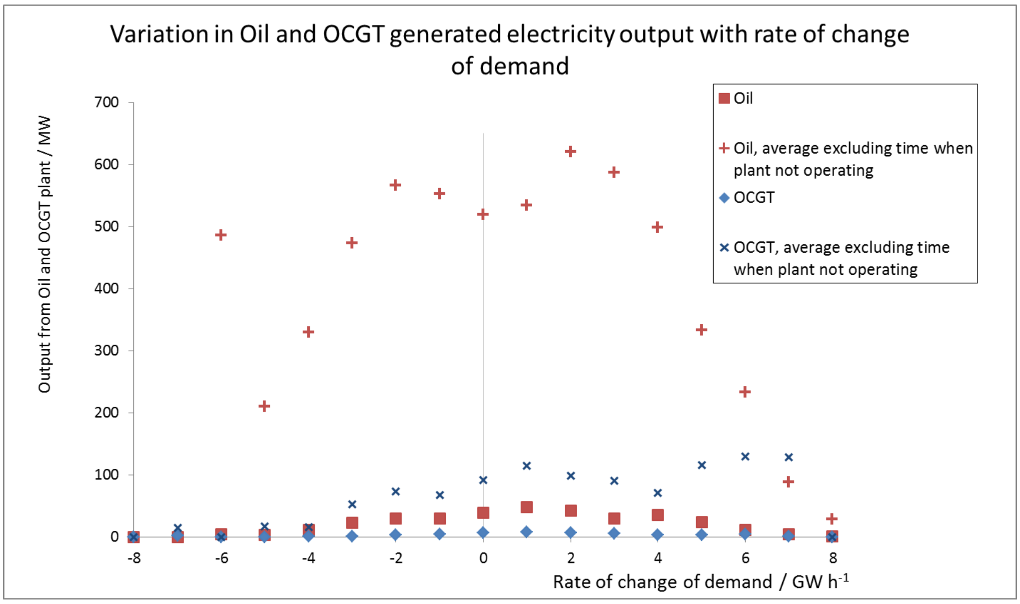

Figure 13

Nuclear

The output from nuclear plant varied considerably over the course of 2009-2010. There is slight positive correlation with demand. However, the variations do not follow a daily pattern and the rate of change is typically very low (less than +/- 16MW/h, i.e. 0.2%/h, for 72% of the time).

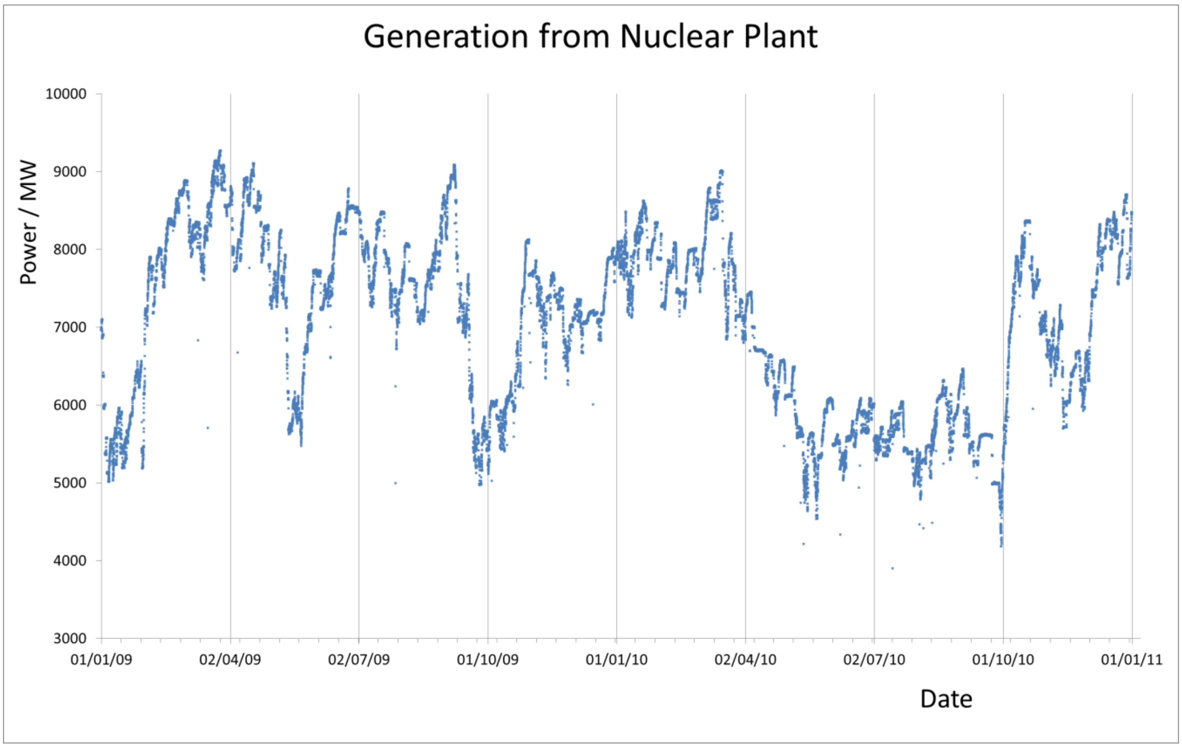

Figure 14

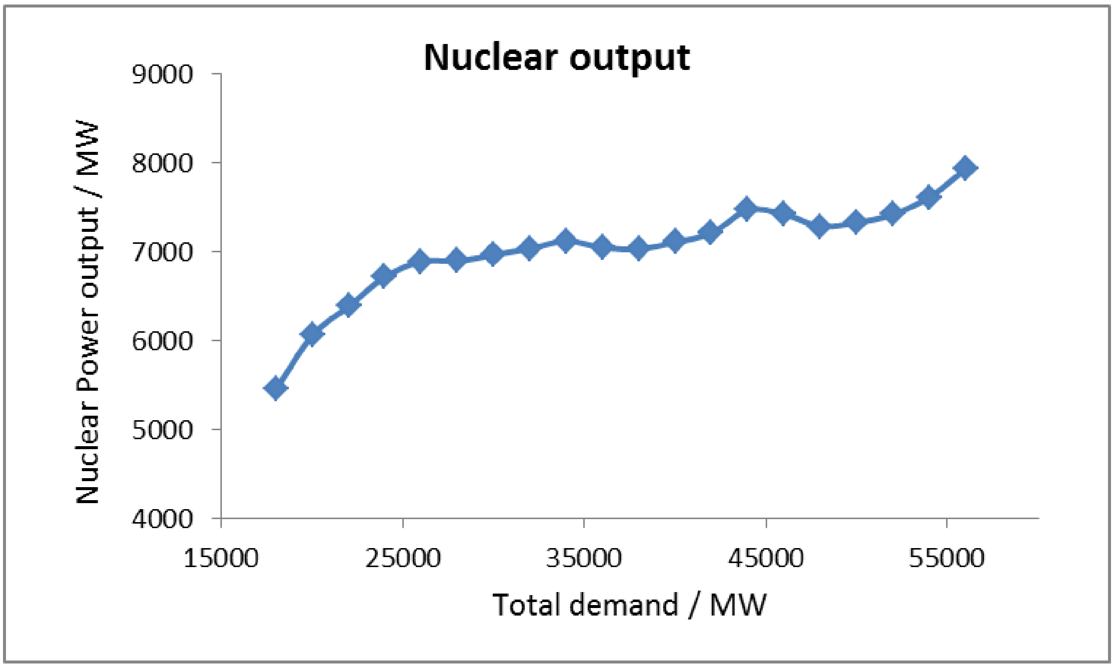

Figure 15

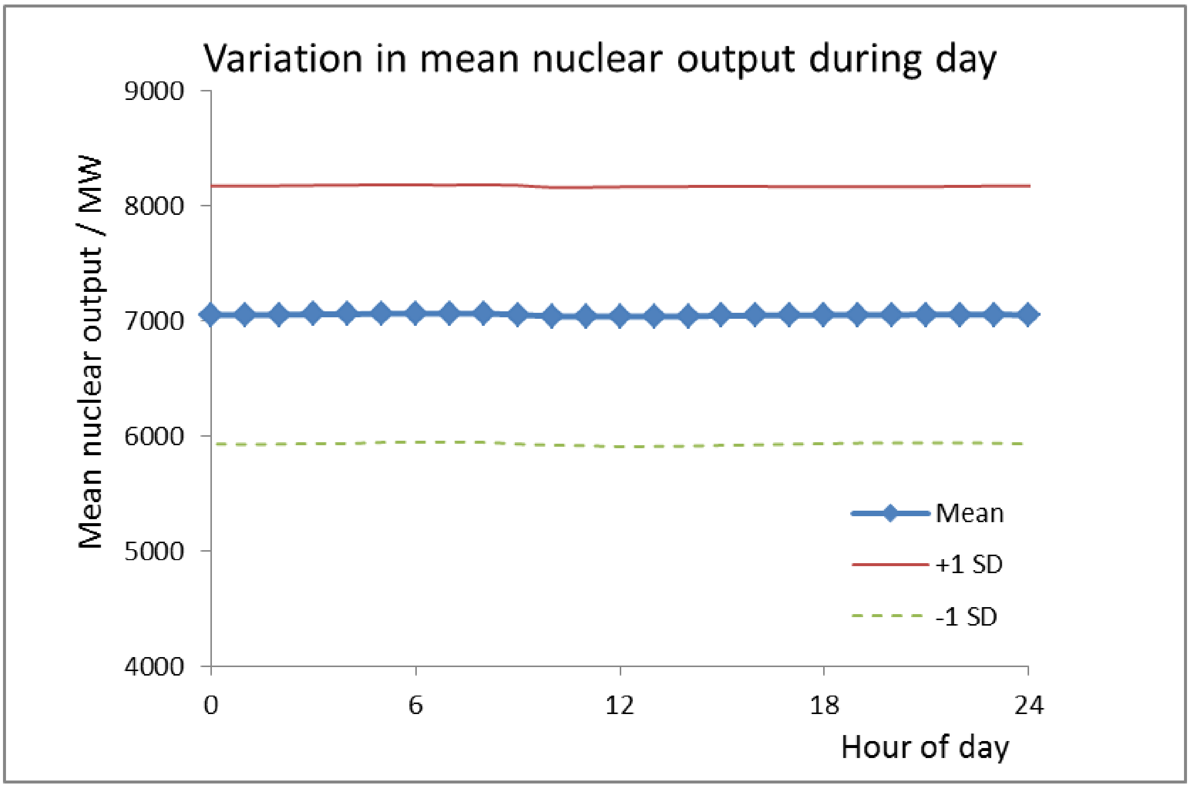

Figure 16

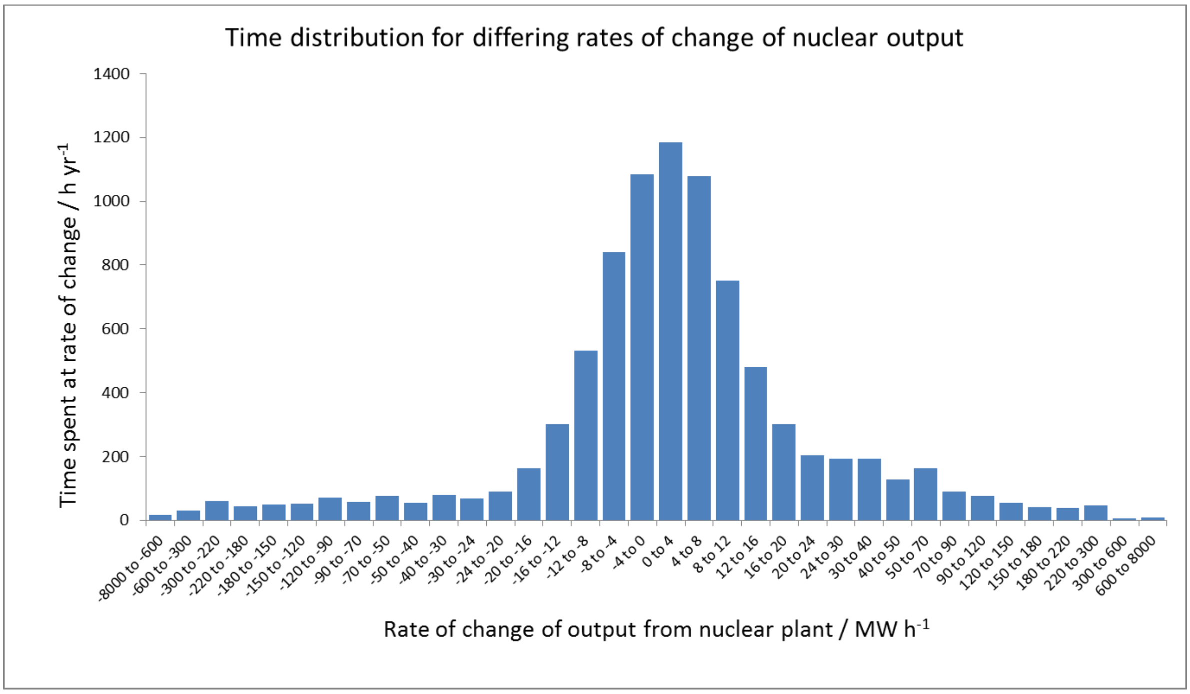

Figure 17

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