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Electricity Market Reform: Generating Results

Balancing price, investment and policy

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Contents

Abstract

There is an enormous and growing need for investment within the UK energy sector. Whilst policy has progressed and the Electricity Market Reform (EMR) process is beginning to encourage investment, a lack of investor confidence still presents a significant blockage in delivering large scale capacity.

Given the time to implement EMR and the uncertainty that has been caused by the recent referral of the energy sector by Ofgem to the Competition and Markets Authority (CMA), this report does not suggest any large scale reform of the energy sector. To do so would be to further alienate potential investors and increase the risk that the UK will not be able to generate enough power to meet supply. Instead it suggests an extension of EMR based on the Contracts for Difference (CfD) mechanism for securing lower cost generation and capacity that is required.

This report also explores the role of the current energy companies in the generation and retail sides of the energy market. Based on this analysis, the report suggests a course that will bolster competition on the generation side and outlines how healthy competition can continue in the future.

Background

The UK continues to face a significant challenge within its energy sector, with over £100bn of investment required according to the 2013 National Infrastructure Plan (NIP)[i]. This investment is required to replace generation capacity, secure the UK's energy supply, limit the impact on our climate, and prepare the energy grid to meet the 15% renewable generation target by 2020.

Alongside this investment requirement is not only the 2020 renewables target but the longer term legally binding target to cut emissions by at least 80% by 2050.

Currently, the UK's primary energy supply (all energy consumed) is met by a combination of natural gas (35%), oil (32%), coal (20%), nuclear (7%), biomass and waste (4%) and wind, hydro and solar photo-voltaic (1%). Within this electricity accounts for approximately 19% of final energy consumption. This electricity supply, however, is increasingly under pressure. As highlighted in the NIP, 8% of generating capacity has closed under the Large Combustion Plant Directive since 2011, and a further 10%-12% of current power generating capacity will be lost over the coming decade. This is against a backdrop of peak electricity demand being projected to move from 63GW in 2013 to between 68GW and 73GW in 2030.

This demonstrates the scale of the challenge the UK has in front of it. This challenge also occurs at a time where many countries are investing in their energy networks and competition for resources and funds is high. As such the UK needs to provide a clear signal that it is going to invest in capacity and lock certainty into its energy system.

EMR was the government's response to this challenge. EMR created:

- New long-term, legally binding CfDs, providing generators with protection from fluctuations in wholesale prices increasing certainty and reducing risk.
- A Capacity Mechanism to help provide certainty to companies/generators who are prepared to offer capacity in the event of shortages.
- A reinforced carbon price by introducing a floor price.
- An Emissions Performance Standard, a regulatory measure providing a back-stop to limit emissions from unabated power stations.

Whilst EMR has finally started to deliver some investment with a number of projects having signed up to the mechanisms there remains concern. Will it drive significant investment in mainstream capacity?

Alongside this Ofgem's recent referral of the energy market also is likely to result in investors and energy companies delaying investment decisions. At a time of dwindling energy margins this should be of serious concern.

This report therefore asks that having had five years of reform and given the uncertainty of the current inquiry, can the UK tolerate another round of fundamental reform? If not, what can be done to drive investment, whilst developing competitive systems without undoing all the progress that has been made so far.

EXECUTIVE SUMMARY

Tariff costs, tariff types, and switching levels

Tariff rises continue to be of concern with the average dual fuel household bill rising from £1,057 in 2011 to £1,232 in 2012. These rises have been against a backdrop of low wage rate growth, employment uncertainty, and a general lack in consumer confidence, fuelling affordability concerns.

This report finds no evidence of regional pricing by the 'big six' companies, however, when analysing the differences between tariffs, it is found that the benefits of switching are relatively limited over time, with direct debit customers being the main beneficiaries. Looking at the rationale behind price changes, this report finds that the price reductions felt by consumers for direct debit tariffs are as a result of company's pricing policies and not simply inflationary changes.

Energy trading, liquidity and self-supply

This report finds that over time there has been a shift towards short term, 'spot' trading with increased volatility and cost owing to the higher price that can be demanded on a short term transaction. These costs have then been passed onto consumers with little explanation from the energy companies or the regulator as to why increases in this kind of activity have been allowed to occur. Policy makers can no longer ignore such a shift, given the implications this has for affordability. As such, intervention is required to encourage more competitive, longer term trading on an open and transparent market.

There is also an increasingly vague view as to what the energy mix in the UK will be, creating uncertainty and holding back the investment the country needs. Whilst in theory, with the government remaining technologically neutral, competition should be encouraged. In reality it has created a situation where only the most certain of projects (those with the lowest financial, political and planning risk) progress, with all others prevented from progressing while investors continue to seek the right signals.

Consolidated Segmental Statements

This report analyses in detail the Consolidated Segmental Statements of energy companies and finds that the costs and earnings of the generation arms of companies varies more significantly than that of their energy companies supply businesses.

Economies of scale and efficiency are generally cited in favour of vertical integration in the energy sector, yet the analysis in this report calls into question whether the actual benefit is passed through the system to the consumer.

In some circumstances the results even suggest that costs move in opposite directions for the different divisions of energy companies (e.g. generation and retail/supply), demonstrating that pricing signals are not efficient and the system is not responding to them as would be expected. Part of the reason behind this may be that companies are responding to media pressures and attempting to control costs at one end of the system. This, however, fundamentally undermines price and investment signals within the market.

The analysis also calculates the 'earnings' premium that is applied as prices pass through the system. That is to say that if generators charge more to suppliers, suppliers in turn charge more to consumers. For every extra £1 a generator earns in profit, a supplier is also able to make an extra £0.57p, making a total increase for consumers of £1.57. Given that more than 'base' costs are passed onto consumers the case for vertical integration and the efficiencies it brings within the market appears uncertain.

The correlation between generators' and suppliers' weighted average costs shows that as the former's average costs increase the latter's average costs do not change significantly. This suggests two possible scenarios, the first being that the average weighted cost of generators has no bearing on suppliers' average costs. Alternatively, supply businesses are able to hedge prices forward so effectively that they can absorb variations in generators weighted costs with little effect on their own. The second scenario is, however, questionable given the shift towards short term spot trading where it is more difficult to offset cost volatility.

International price comparisons and the effect of energy taxation

The UK is more or less exactly matching the IEA median for electricity prices, and has one of the lowest incidences of taxation on energy. As such, overall electricity prices in the UK may not be as overpriced as is feared. It also potentially indicates, that the UK is not proactive enough in reallocating resources from markets which are inefficiently accounting for the effects of climate change, pollution, and volatile prices, thus preventing movement towards a more stable and sustainable long term solution.

This report also compared the effects of taxation on the price of electricity and found that on average for every 1p increase per kWh in electricity taxes that occurs, there is also an increase of 0.53p in the electricity price. It should be noted, however, that this performance is significantly helped by Denmark, The Netherlands and Germany, where tax increases result in falls in electricity prices.

This compares with a rise of 7.4p per kWh in electricity prices for every 1p per kWh of extra taxes the UK government levies. This is also significantly more than any other country in the data sample below, with the next on the list (Ireland) experiencing an additional 4.3p per kWh rise for every extra 1p per kWh of taxation. The reason behind the UK's poor performance in this area is likely to be that companies are 'over insulating' themselves against tax and policy changes, highlighting that long term policy certainty is key.

The evidence suggests that as the level of tax increases, so more investment takes place, the level and pace of research and development speeds up, and there is a lowering of long term costs, reducing the effect on electricity bills above and beyond the incidence of the tax.

The price of electricity in the UK on the 'open' market, i.e. not including tax, is one of the highest amongst the countries analysed. This is likely to be due to a lack of strategic planning as no one company considers investment in the UK as a whole at the macroeconomic level. As such, any investment outcome from the sector will favour individual companies' investment strategies and not one that is efficient for the UK as a whole.

Policy – competition, EMR, CfD, capacity, price and consumers

This report suggests a way forward which attempts to balance the needs identified within the EMR framework, including:

- The need for a policy which will secure a reasonable baseload and invest in solutions which can 'store' energy.

- The need to address capacity issues without radically reforming policy again and therefore increasingly delay and uncertainty which is a major problem for investors.
- Ways to improve and implement effective competition in the generation market by creating a secure base that lowers costs and allows technologies to compete where appropriate.
- The need for increased transparency within the market, allowing the retail side to access and buy from a number of sources.

This report proposes that five Generation Investment Vehicles (GIVs) with a combined value of £8bn are created to ensure that in the short to medium term project finance is secured. In order to secure medium to long term investment to 'lock' long term cleaner energy into the UK's generation system, this report also proposes that three Tidal GIVs (TGIVs) with a combined value of £21bn be created.

These vehicles could be used to finance for any type and combination of projects, for example:

- Six CCGT plants at an approximate cost of £3bn (providing approx. 7,500MW).
- Eight waste to energy plants at an approximate cost of £4bn (providing approx. 575MW).
- £21bn of funds towards the building of tidal/lagoon assets (providing approx. 2,000MW to 3,000MW).
- A £1bn fund for community projects, where money would be raised via crowd sourced funding.

The three £7bn TGIVs for example could finance:

- The roll out of either smaller tidal schemes or more economically the construction of a Severn Barrage (with a target price of 16% below the current £25bn estimated cost) to lock in lower cost long term electricity not only for this generation but also the next few.

Introducing a secure supply has to be accompanied by increased transparency and ultimately improved competition within that part of the market where competition for variable electricity demand takes place.

This paper proposes a Priority Auction Mechanism (PAM) where:

- A new structure of two open market traded exchanges where government has to purchase 50% of the capacity put forward in the first round, 75% in the second round, and all remaining capacity then having to compete OTC.
- The first round of purchasing will be on contracts longer than 24 months, while the second will see providers enjoy contracts of longer than 12 months' duration. This will have the dual impact of providing certainty of revenue for generators and encourage future investment whilst also encouraging a transparent and efficient pricing mechanism for the electricity market.

DELIVERING THE UK'S ENERGY NEEDS

The UK faces a significant challenge in its energy sector. There is a significant need for investment, but rising consumer prices at a time of below inflation wage growth would not be a popular policy.

Such pressures are part of the reason for announcements such as the one made by Ed Miliband at the 2013 Labour Party conference to freeze energy prices for 20 months for consumers should a Labour Government be elected in 2015.

A recent report by the Institute for Public Policy Research (IPPR)[ii] highlighted the issue of rising bills, noting that the cost of an average energy bill has risen dramatically in recent years; "from £605 in 2004 to £1,060 in 2010".

Of this IPPR further note "The government's independent advisers, the Committee on Climate Change (CCC), calculated that the wholesale cost of gas added £290 to the average energy bill between 2004 and 2010, compared with £75 for environmental and social policies.[iii]"

Whilst policies designed to limit price rises will be popular with the public, these announcements are not good for investor certainty, and in reality may cause issues for energy companies should wholesale prices rise at a significant pace during the period of any price freeze.

In essence it is important to get the balance of investment, pricing, competition and profit right to ensure the most efficient outcome, however, many would argue that the current balance is incorrect. Recently, Which? and the Federation of Small Businesses (FSB) wrote to the Office of Fair Trading (OFT), Ofgem, and the Competition and Markets Authority, highlighting how energy bills were a major concern of businesses. They concluded that with the 'big six[iv]' energy companies accounting for 95% of the market, the wholesale market was essentially broken, and uncompetitive.

Exploring these market shares in more detail (appendix A), it is revealed that the "big six" companies individually hold between approximately 10% and 25% each in the electricity sector, and between 10% and 16% each in the gas sector.

The limited number of players and their potential to exert considerable influence over the market is part of the reason that Ofgem recently referred the sector to the Competition and Markets Authority. The findings raise serious concerns with Ofgem stating:

- "In summary, we [Ofgem] have found weak competition between incumbent suppliers. This arises from market segmentation and possible tacit co-ordination. While we might expect competitive pressure from consumers or new suppliers, we have also found barriers to entry and expansion (including vertical integration) and weak customer pressure."[v]

Whilst consumer groups and small businesses will welcome Ofgem's referral of the energy market, there are serious concerns as to what this means for future investment and policy.

For example, as a result of the anger, expressed by consumers and small businesses with regards to continued rising energy pricing, many groups are calling for further fundamental reform of the energy market.

The UK should question, whether, the UK can survive another round of fundamental reform having had five years of uncertainty as EMR took place? This emphasises the importance of recognising and addressing uncertainty as policy changes take place.

First, the referral of the market by Ofgem will create an investigation expected to last 18 months. With energy companies unable to judge if future returns will be viewed as excessive, and the threat of possible action to break them up investment will stall.

It is important to remember that the "big six" companies are expected to make the majority of energy investment, leveraging private balance sheets. The ability to raise such capital would be almost impossible when facing a competition inquiry.

Second, the knock on effect of groups calling for more fundamental reform could see five years of energy policy development wasted. Investors would move money away from the energy sector until the new regime is finalised and conditions more certain. They cannot make judgements on profitability and affordability if the goal posts keep moving.

So when it is asked if the UK can survive another round of fundamental reform, the answer is probably not, especially given the amount of potential generation the UK is expected to lose in the next decade.

So whilst embarking on a new round of wholesale reform would probably be simpler in policy making terms, what is actually required is a detailed analysis of the market and its fundamentals, in order to assess where manageable changes could be made.

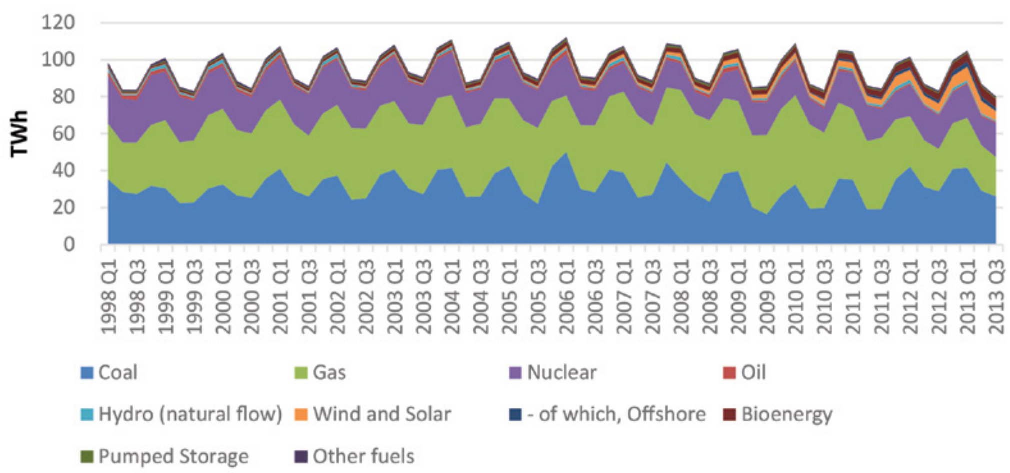
The UK through this process needs to bolster its energy policies to improve consumer and investor confidence. Transparency is the only way to do this with the current level of data available on how prices are derived in the energy market being very poor.

This report therefore will explore in detail the figures behind energy usage to see if the current policy direction is realistic. It will also show why consumers and businesses feel so disconnected from the market, analyse pricing and importantly explore in detail the relationship between the wholesale and retail sectors.

To explore the direction of energy policy it is important to understand the challenges the energy sector is facing.

Looking at the generation figures in the chart below, it can be seen that whilst households may have more energy efficient devices, and individuals attempt to reduce electricity demand alongside an increase in micro/renewable generation, in reality the trend for generation remains broadly unchanged since 1998.

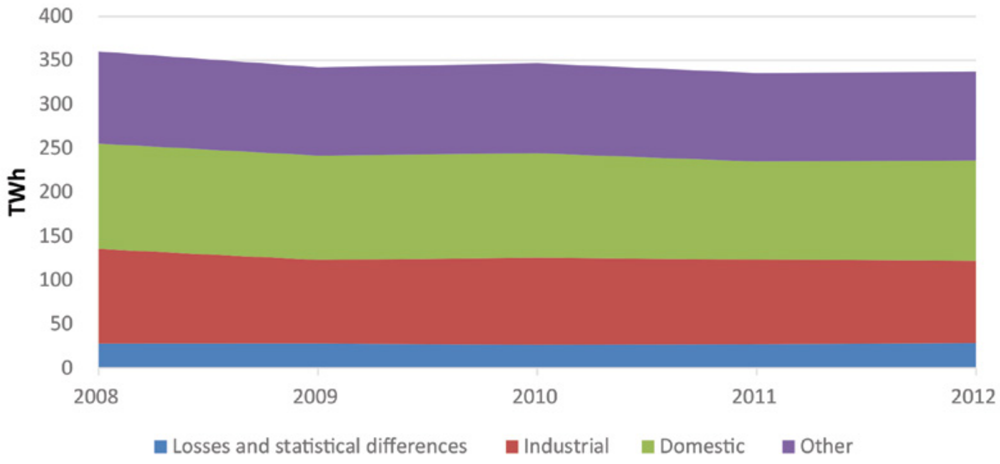
Electricity generation in TWh – domestic supply



Source: Data from DECC energy market statistics

The same is also true if you look at the figures for the availability and consumption of electricity figures.

Availability and consumption of electricity



Source: Data from DECC energy market statistics

The rationale behind this is likely to be that, whilst individuals and companies are consuming less electricity per product or device, the number of devices used has increased. For example, households no longer have one computer but three or four items such as desktops, laptops, and tablets. Overall, while this can mean that energy reduction is actually limited psychologically individuals believe they are reducing consumption as each product is more efficient than its predecessor.

Much of this confusion is because consumers do not have enough information to realise that savings are not materialising. This is where further demand side measures such as smart meters, insulation, etc should continue to be encouraged through energy policy.

Environmental Industries Commission – Energy efficiency potential

The ‘generation gap’ can be met either by installing new generation or by reducing demand. Likewise for heat, energy efficiency reduces UK gas imports. Although new generation will clearly be needed, energy efficiency is generally more cost effective so should be maximised as far as possible.

Historically, demand reduction has been limited due to the ‘rebound effect’ – i.e. increased energy efficiency means that consumers decide to buy increased ‘energy services’ (warmer homes, use of additional electrical devices) for the same spend, rather than reduced spend.

However, given the potential scale of the generation gap and the need to decarbonise, we must find ways to overcome the rebound effect. Rising energy prices will also help do this.

The Committee on Climate Change have proposed the following priorities:

Residential indicators

- Insulation of all lofts (10.5 million) and cavity walls (8.1 million) by 2015.
- Insulation of 2.3 million solid walls by 2022.
- Replacement of 12.6 million old inefficient boilers by 2022.
- 58% of the stock of wet appliances rated A+ or better and 45% of cold appliances rated A++ or better by 2022.

Non-residential indicators

- Implementation of all cost-effective measures to reduce emissions from lighting, appliances, heating and cooling in the public and commercial sector by 2018.

Progress against these indicators has been slow, due in part to problems with the Green Deal and ECO scheme. ACE's sister organisation, the Environmental Industries Commission, has published recommendations for improving the green deal and ECO.

EIC has also studied ways to ensure that the smart meter roll out to businesses is effective in delivering energy use reductions. EIC's findings are that behaviour change in companies and the publication by government of aggregated benchmarking data by building type are needed to achieve this.

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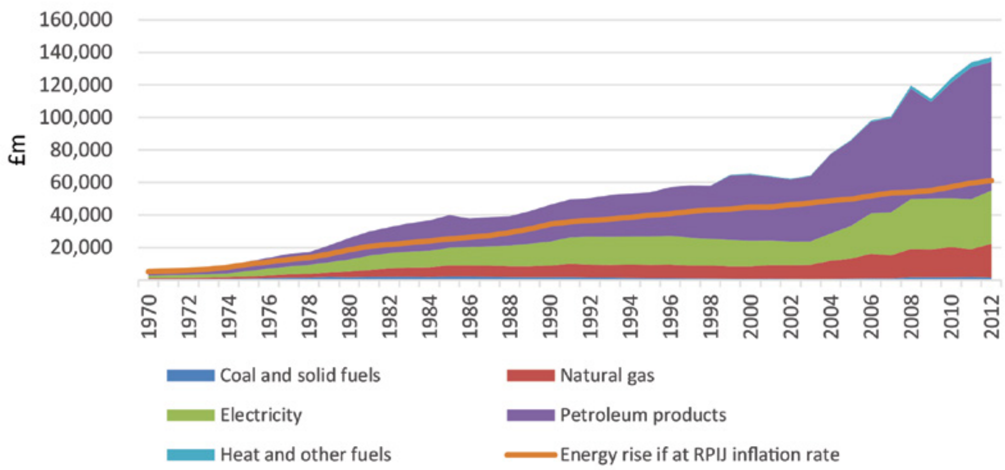
Individuals, however, are not likely to consider significant demand reduction 'energy saving measures' effective if it merely stops bills rising, most would be expecting bills to fall at least in the short term.

This raises two issues that should be integrated further into current energy policy:

- First, that the communication of energy measures should be around stopping bills rising.
- Second, given individuals' expectations, energy policy should pursue a rate of price growth that can be offset by demand management.

Part of the need for embedding such expectations is shown when exploring in more detail the expenditure of final energy users. The chart below shows that total expenditure on energy across all types (including petrochemical and other fuels) equates to almost £140bn in 2012, but if the figures are inflated using RPIJ[vi] the 2012 figure would have only equated to approximately £61bn, demonstrating the scale of energy price rises over time compared to the wider economy.

Expenditure on energy by final user – all users



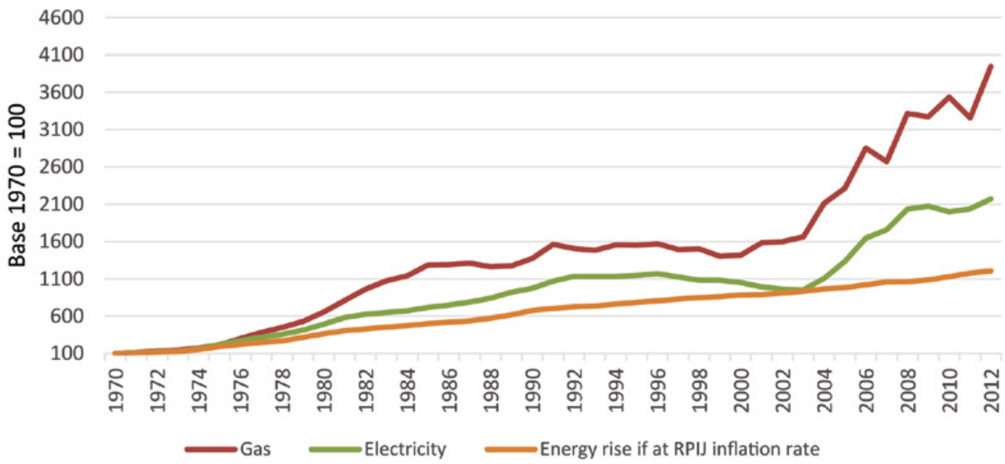
Source: Data from DECC energy market statistics

This is a substantial difference, and will have been felt by consumers over the past 40+ years, however, the analysis above compares the stacked (or total accumulative) final energy expenditure by end users to inflation.

Many consumers and businesses consider electricity and gas prices to be the key issue in the energy market rather than the costs of all energy products. As such, it is important to compare both electricity and gas expenditure to the overall rate of inflation that individuals have experienced over time.

As can be seen below, once total spending on electricity/gas and the rate of inflation have all been rebased (1970 = 100) and the subsequent growth rates in both the electricity and gas sectors have outperformed general inflation.

Expenditure on electricity and gas by final user vs RPIJ (1970=100)



Source: Data from DECC energy market statistics

Gas expenditure has fared much worse than electricity. Whilst there was some stability during the period 1991 to 2001, prices increased significantly following this period. Whereas, electricity expenditure for the period 2002-2003 was actually on par with overall inflation, before also rising significantly.

If these forward projections are converted into expenditure it is revealed that total energy expenditure by end users should currently be approximately £18bn as opposed to £32bn and gas approximately £6bn as opposed to £21bn. This shows the long term scale of the increase that has been experienced by consumers.

Whilst overall demand, supply and expenditure are important a lot of the frustration around energy policy has come from the unclear relationship between the actual cost and the need to finance investment up front, versus the long term cost and transparency of how these costs feed through the system.

To help to build an understanding of this relationship the report will explore in more detail:

- The cost of energy to individuals, tariff types, and how these have changed.
- The role of trading and liquidity within the system and the ability of suppliers to self-supply.
- The conditions the energy companies face within the different divisions they operate.
- How taxes on energy affect long term costs and how the UK compares internationally.
- What can be done to resolve the capacity investment issue and what this could mean in terms of potential costs.

TARIFF COSTS, TARIFF TYPES, AND SWITCHING LEVELS

Key findings

Tariff and cost breakdown

- Tariff rises continue to be of concern with data from Ofgem showing that the average dual fuel household bill has risen from £1,057 in 2011 to £1,232 in 2012.
- Public concerns around rising bills since 2008 have been reinforced by low wage rate growth. These concerns were reinforced by reductions in the wholesale cost element of bills which fell in each year between 2009 and 2011.
- Data from Ofgem shows that in 2013 wholesale costs accounted for 47% of bills, network costs 22%, supplier operating costs 13%, environmental and social obligations 7%, supplier pre-tax margins 7% and VAT 5%.
- There is no single policy that will reduce costs across all these areas and in reality policies may positively affect one area whilst having a negative impact in another. Reducing environmental and social obligations, for example, may reduce bills but it is likely to result in a less diverse energy mix which is more reliant on fossil fuels and will lead to the wholesale portion of energy bills becoming more costly as commodity prices rise and potentially more volatile.

Assessing competition

Policy needs to shift away from the basic idea that the extent of competition in a market is shown by the rate of switching.

Further clarification around retail market reform is required, with a clearer sense of what the energy market is trying to achieve. Ofgem states that the Retail Market Review's policies are meant to increase engagement, or active engagement, within the energy market. Yet there is little sense of what is an efficient or optimal level of active engagement, or if this engagement feeds into the governments higher level strategic energy policy.

Different types of tariff and the effect this has had over time – electricity

The direct debit tariff over time has remained the cheapest, reflecting the benefits to the suppliers of stable, predictable payment without the need for credit or pursuing payment.

When looking at real price data the benefit of a direct debit tariff falls to £32 (cash terms £39) and the prepayment tariff falls to £7 (cash terms £9).

Using the standard tariff as a baseline and accounting for inflationary effects between tariffs, but negating overall price changes within the market, it is revealed that:

- Cash rates show that since 1996 the prepay tariff has fallen by £1.56 per year, compared to the direct debit rate which has fallen by £2.26.
- Over the period 1996 to 2013 there has been a downward effect on bills to the extent of £0.47p a year for direct debit customers compared to the standard tariff. This is attributable to the pricing policies of companies between the tariffs and not inflation, and means that £1.79 of the calculated £2.26 annual reduction in cash terms (between the direct debit and standard credit tariff) is attributable to inflationary conditions.

- Over the period 1996 to 2013 for prepayment customers the result was an upward effect of £0.15 a year occurring due to the pricing policies of companies between tariffs. This means that the £1.56 reduction (when looking at the total differential in cash terms) would have been £1.71 if only inflationary conditions were taken into account.
- The above is not intended to be used for a rationale behind the actual level of prices in the energy market, but it does show that that there have been positive improvements in for direct debit customers above and beyond those which would have occurred if only inflationary effects had been taken into account between tariffs.

Different types of tariff and the effect this has had over time – gas

For domestic gas bills, in cash terms, it was found that direct debit customers in 2013 were £72 better off by being on a direct debit tariff, as opposed to prepay customers that were only £4 better off than those on the standard credit tariff. Looking at the real data, accounting for inflation, direct debit customers are £60 better off and prepay customers by £3.

Using the standard gas tariff as a baseline and accounting for inflationary effects between tariffs but negating overall price changes within the market it is revealed that:

- Since 1998 in cash term direct debit customers have benefitted by £2.42 per year beyond the standard tariff. This compares to prepay customers which are £0.91 per year better off than in 1998.
- When looking at the difference between the real and cash effects between the tariffs it is revealed that of the £2.42 almost half £1.11 is due to company policies between tariffs beyond the effects of inflation. As such, £1.31 of this £2.42 can be attributed to normal inflationary conditions.
- For prepay customers there was a positive upward price effect of £0.14 which can be attributed to companies pricing policies between tariffs. This means that the £0.91 reduction (when looking at the total differential in cash terms) would have been £1.05 if only inflationary conditions were taken into account.
- Again the above is not intended to be used for rationale behind the actual level of prices in the energy market, but does show that that there have been positive improvements for gas customers above and beyond that which would have occurred if only inflationary effects had been taken into account between tariffs.

Regional pricing

Looking at regional pricing it was found that the difference between the highest and lowest price narrowed significantly over the financial crisis period but has since returned to previous levels.

There is little evidence to say that the way regional pricing occurs has changed since 1998. The trend for both the maximum and minimum regions in each case are consistent with applying the same pricing policy and price changes. As such this suggests that there has not been an increase in aspects such as discriminatory pricing on a regional basis.

Analysis

Looking more specifically at recent years and actual bill levels per household, data from Ofgem's investigation reveals that the average dual fuel bill in 2012 stood at £1,232, up significantly on the 2011 figure of £1,057.

Such rises, at a time when wages have been constrained and households continue to be placed under cost pressures, are part of the reason why consumers have reacted with anger at the extent of energy price rises.

Average duel fuel household bills 2009-2012

Source: Chart from Ofgem

The issue, however, is that energy prices are made up of a number of aspects such as wholesale market costs, distribution costs, operating costs etc.

For example, in March 2014 the average duel fuel bill[vii] consisted of:

- Wholesale costs – 47%
- Network costs – 22%
- Environmental and social obligations – 7%
- Supplier operating costs – 13%
- VAT – 5%
- Supplier pre-tax margin – 7%

As such there is no single policy that will reduce costs across all these areas. In reality policies will not only affect areas differently, but may actually have the opposite effect in different areas.

Reducing environmental and social obligations, for example, may reduce bills but it is likely to result in a less diverse energy mix which is more reliant on fossil fuels and will result in the wholesale portion of energy bills becoming more costly as commodity prices rise and potentially more volatile.

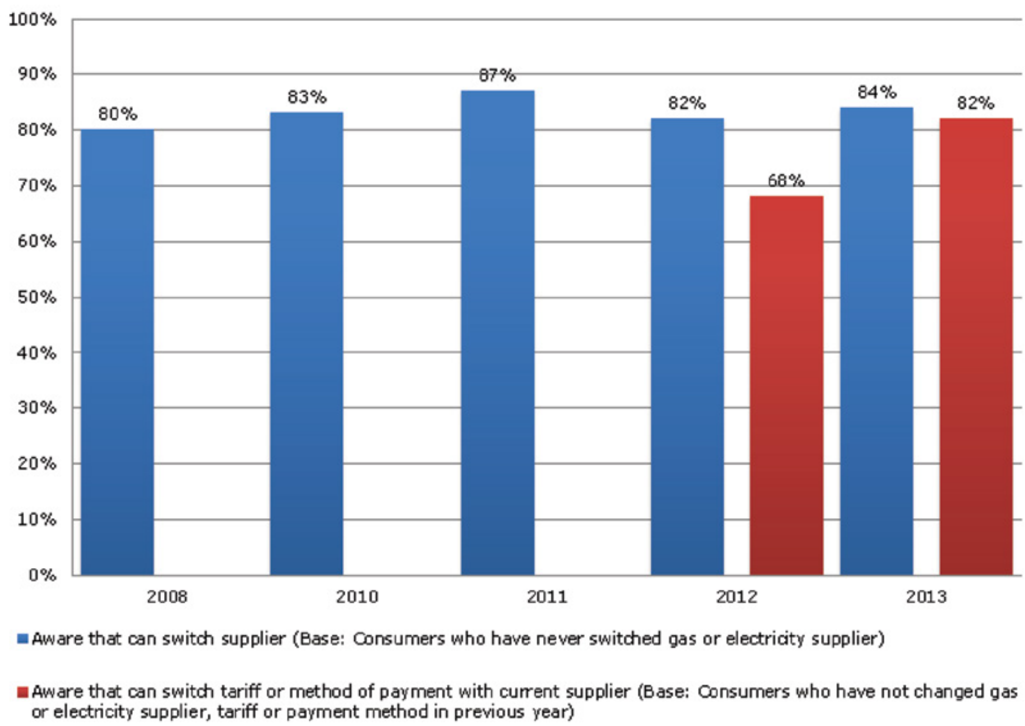
One way consumers have been encouraged to drive down prices is by switching suppliers. In fact a lot of Ofgem's recent review focuses on switching as one of the means of judging the level of competition within the market.

Policy needs to shift away from the basic idea that the extent of competition in a market is shown by switching rates.

It is generally assumed, for example, that those consumers who do not switch have not got the correct information to enable them to do so. This, however, ignores consumer regard for service quality, the cost of switching (such as time involved) and the basic psychological behaviour of individuals who resist change up until a tipping point where savings become significant. There is also the uncertainty created within switching to be considered. Deals can change significantly over time, and so consumers are continually left with limited information on the real drivers of costs and how these affect the 'best time' to switch.

Ofgem provides data in its market assessment that shows that over 80% of people are aware they are able to switch both between providers and across tariffs within a supplier[viii]. The results shown in the chart below, therefore, suggest that in reality consumers no longer feel that the benefits of switching are offset by the perceived costs and time taken to do so.

Awareness of ability to switch



Source: Chart, Ofgem, – data, Ipsos MORI, Customer Engagement with the Energy Market – Tracking survey 2013

The reason this is important is because the regulator has taken steps to make switching as easy as possible. In theory, this should reduce the economic cost of switching and so consumers should be more willing to switch for even marginal savings.

Looking at the issue of switching in more detail, below are some of the key findings on attitudes to switching supplier and the inferences this has for consumer behaviour:

- 62% of customers felt that there were too many tariffs, despite recent improvements in reducing their number. This perception is important as it affects the associated economic cost an individual places on switching supplier.
- 45% of customers were completely or fairly happy with their understanding of tariff choices, with a further 35% saying they had not very much understanding and 19% had no understanding at all. So despite almost half of customers understanding their tariff and options for switching the majority still do not switch, with only 11-12 per cent of consumers reporting switching supplier in 2012. If all the customers who understood their tariffs were to switch the rates would be significantly higher. This could therefore suggest that after initially switching there is only marginal benefit to further switching of supplier. It also suggests that the continued reforms to improve the quality and simplicity of information to consumers are required.
- Whilst the level of switching between companies fell between 2008 and 2013 the level of switching between tariffs provided by the same provider increased. This suggests that individuals perceive the process of 'intra company' switching to be less risky or time consuming and so holds a lower economic cost.
- The main reason for switching given by consumers (75% electricity and 76% gas of respondents) was to save money. Whilst this is what would be expected given the energy market's message for years that switching can save individuals money, it is concerning that no other reasons come close to price. For example, switching supplier for better service, or the provision of smart meters or energy efficiency advice. In a competitive market you would expect each of the "big six" suppliers to market themselves differently, carving out niches to promote switching. This has not occurred.
- Whilst the level of switching has declined 30% of customers trust or tend to trust their suppliers with a further 27% saying they neither trust nor distrust them.
- 62% of customers have never recalled ever switching supplier.
- 37% of electricity customers are still supplied by their regional incumbent
- 40% of gas customers are still being supplied by Centrica more than 15 years after market liberalisation.
- 55% of customers report that the reason for not switching is they are happy with their supplier. This again displays the psychological behaviour of individuals to reward a company that they trust or that has provided them a good service with loyalty. It further suggests that price differentials need to be significant to make individuals switch supplier[ix].

The views above from individuals suggest how weak the assumption has become that switching alone constitutes competition. Despite this there are still a significant number of individuals that have never switched, and so it is important to explore how the potential benefits between tariffs have changed over time.

Is the reason for the lack of switching purely as individuals suggest, a lack of information, and a reluctance to leave their current supplier? How significant are the benefits of switching intra supplier between tariffs?

Action on tariffs

Following a number of years of reductions in switching rates, Ofgem has taken action to further encourage consumers to switch. Measures included as part of the Retail Market Review Evaluation included:

- Simplifying consumers choice by limiting the number of tariffs available;
- Standardising tariff structures;
- Rules relating to dead tariffs, and transferring individuals onto current tariffs;
- Making supplier communication with consumers clearer and more frequent;
- Development of tools such as personal spending projections and further tariff information.[x]

Following the implementation of the above measures, recent switching rates have increased. It still, remains uncertain, however, as to whether this rise is driven by improved information or are a reflection of the continued squeeze on living standards and the needs to economise. It therefore remains unclear if recent improvements will continue into the future as the economy improves.

So whilst the above are important in terms of encouraging consumers to switch there were some parts of the review that could provide more benefits going forward. For example:

- Ofgem wishes to establish a clear baseline on which changes in market and consumer behaviour can be established. Whilst this is a welcome step forward the question has to be asked why such a baseline has not existed to monitor changes since privatisation given consumer choice and competition were two of the main drivers behind privatisation.
- Another area being explored is the ability to isolate the impact of specific policies. Whilst Ofgem accepts this will be difficult given that retail market reform is implemented as a package, its willingness to look at detail and ensure policies are operating as required is an important one. This is not only key to improving the operation of the energy market and its own performance as a regulator but also because it should limit the extent to which private companies can capture policies.

The one area where further clarification around retail market reform is required feeds into a comment throughout this report of what the energy market is trying to achieve. Ofgem states in the Retail Market Review Evaluation that policies are to increase engagement, or active engagement within the energy market.[xi] Yet there is little sense of what is an efficient or optimal level of active engagement, or if this engagement feeds into the governments higher level strategic energy policy.

To give an example, if a consumer is happy with the level of service they receive and is prepared to pay a slight premium on their energy bill, despite having information that they could switch to a cheaper supplier is this active engagement within the market? Such a decision, for example, would not show in switching numbers?

Also, as was shown previously, recent figures suggest that customers may be more willing to switch their type of tariff but not necessarily supplier. If this person has market information this would be an active market choice, but if they are only basing this decision on limited information on their current supplier are they really actively engaged in the wider market.

As such it is also important to look at how different types of tariffs themselves have changed over time.

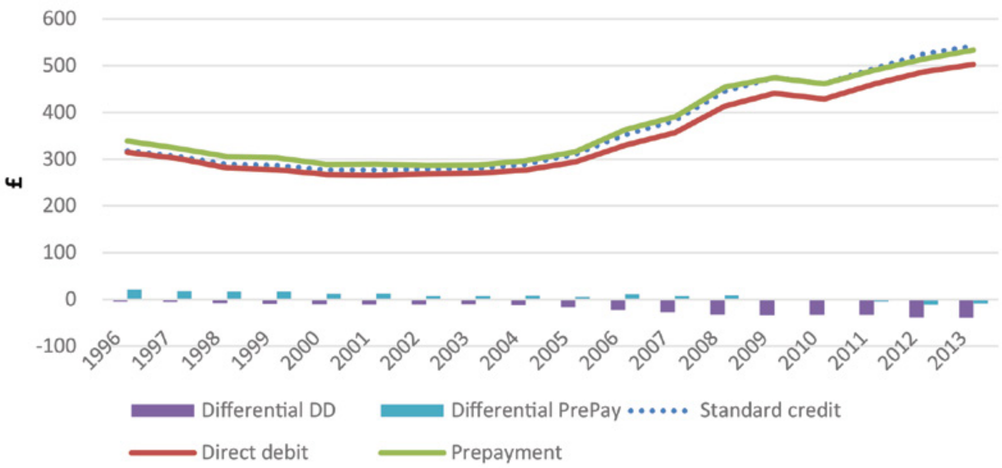
Tariff analysis over time

Below is analysis of the price difference over time between direct debit, standard credit and prepayment tariffs. As one would expect the direct debit tariff over time has remained the cheapest, reflecting the benefits to the suppliers of stable, predictable payment without the need for credit or pursuing payment.

What is more interesting is the differential between the direct debit and the standard credit tariff has been widening since 1996 and continues to do so. The effect of this is that moving from a standard tariff to a direct debit tariff in 2013 resulted in bills being £39 a year lower.

Alternatively, if you are a prepayment customer your bills were generally higher than the standard credit tariff until 2009, but in 2013 were £9 a year lower

Average annual domestic standard electricity bills for the UK – cash terms

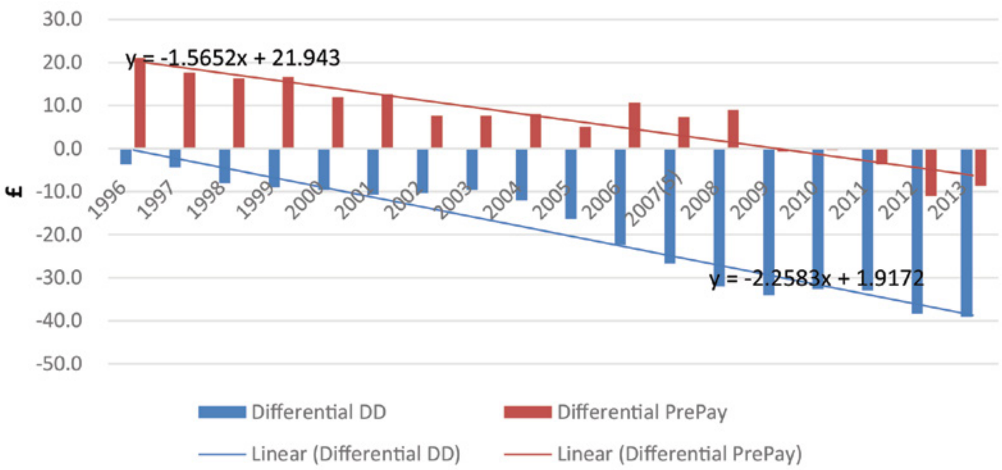


Source: Data from DECC energy market statistics

This switch in the differential between these two tariffs is likely to reflect the continuing efforts of the regulator to crack down on the prices of prepay tariffs. This was undertaken because households with prepay tariffs are generally poorer and more likely to suffer from fuel poverty.

Looking at cash rates (unadjusted for inflation) in more detail the chart below shows that since 1996 the prepay tariff has fallen by £1.56 per year, compared to the direct debit rate which has fallen by £2.26 per year.

Average annual domestic standard electricity bills for the UK – tariff differential – cash terms



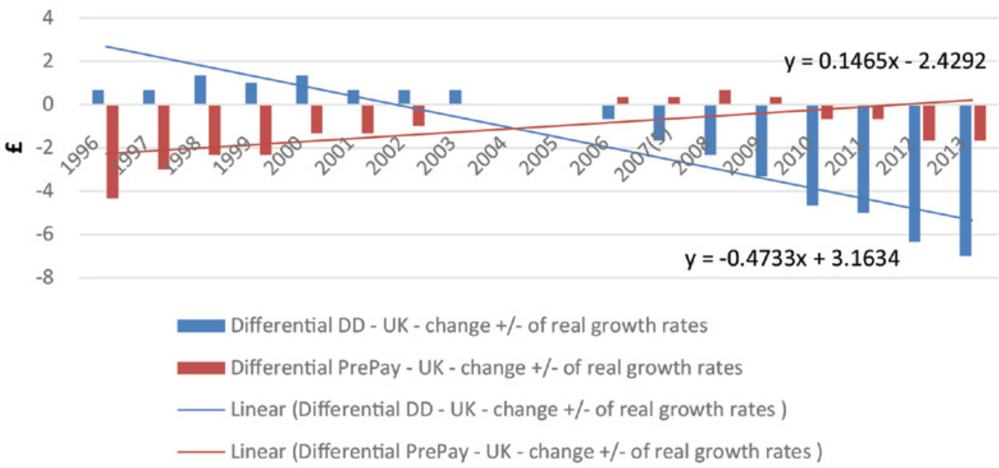
Source: Data from DECC energy market statistics

When inflation adjusted data is plotted the benefit of a direct debit tariff falls to £32 and the prepayment tariff falls to £7.

By setting the standard tariff as a baseline it is possible to produce an analysis of the inflationary and non-inflationary effects between tariffs[xii]. This should provide insight into the extent of how pricing has changed beyond wider inflationary price conditions.

The results show there has been a downward effect on bills to the extent of £0.47p a year for direct debit customers compared to the standard tariff. This is attributable to the pricing policies of companies between the tariffs and not inflation, and means that £1.79 of the calculated £2.26 annual reduction in cash terms (between the direct debit and standard credit tariff) is attributable to inflationary conditions.

Differential of Direct debit and Pre-payment from the standard credit option, over time, compared to real rate of price growth (change +/- of real growth rates) – electricity



Source: Data from DECC energy market statistics

For prepayment customers the result was an upward effect of £0.15 a year occurring due to the pricing policies of companies between tariffs. This means that the £1.56 reduction (when looking at the total differential in cash terms) would have been £1.71 if only inflationary conditions were taken into account.

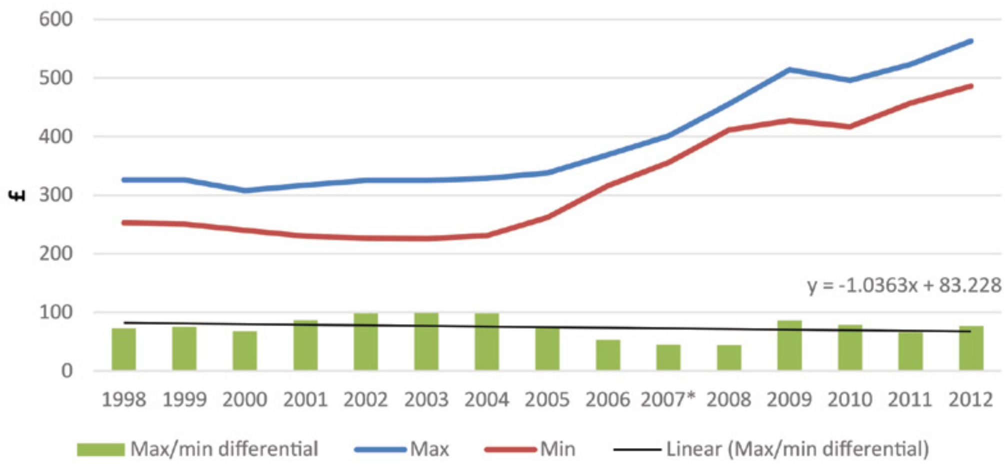
Whilst the above is not intended to be used for any rationale behind the actual level of prices in the energy market, it does show that that there have been positive improvements in pricing for consumers who switch to different tariffs above and beyond that which would have occurred if only inflationary effects had been taken into account.

This suggests that over time there has been a sustained benefit to switching to payment by direct debit. Switching between payment methods is easily done within energy companies various tariffs and so may explain the degree of knowledge and increasing willingness to switch between a suppliers tariffs.

Given one of the possible side effects of a lack of competition is price discrimination, it is necessary to explore the maximum and minimum differential between regional prices and how this has varied over time.

The chart below shows the trend for standard credit tariffs since 1998. The distinct closing of the differential between regions occurs in 2006-08 but despite this over the entire period the actual difference between the maximum and minimum region has only reduced by £1.04 a year.

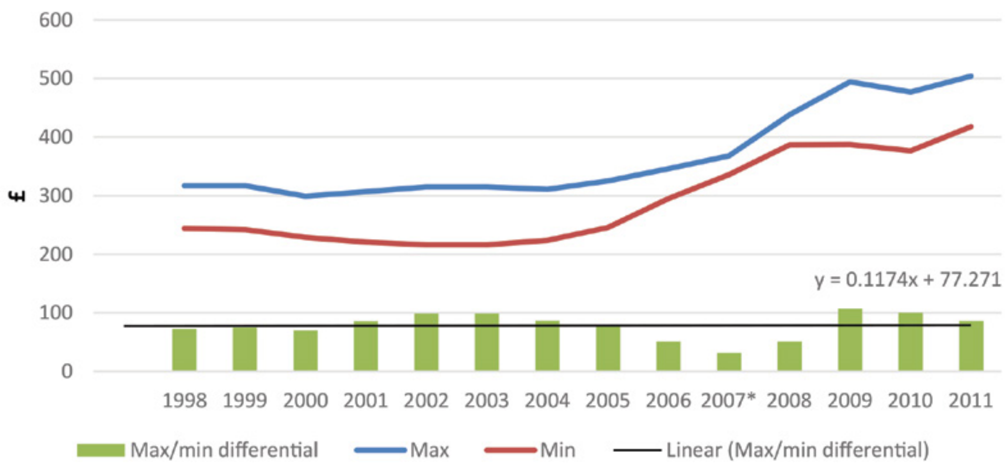
Average annual domestic standard electricity bills – credit – location based max min differential – total bill price



Source: Data from DECC energy market statistics – (Locations used Aberdeen, Belfast, Birmingham, Canterbury, Cardiff, Edinburgh, Ipswich, Leeds, Liverpool, London, Manchester, Newcastle, Nottingham, Plymouth and Southampton)

For direct debit tariffs the same trend is observed as with standard credit tariff, with a narrowing of the regional difference in 2006-08 but with a slightly less flat trend over time suggesting a narrowing between the regions of £0.11 a year.

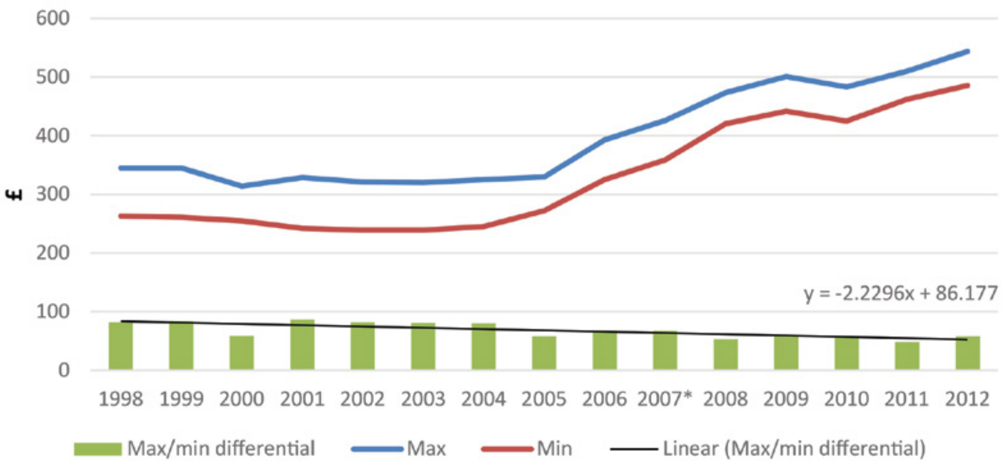
Average annual domestic standard electricity bills – direct debit – location based max min differential – total bill



Source: Data from DECC energy market statistics – (Locations used Aberdeen, Belfast, Birmingham, Canterbury, Cardiff, Edinburgh, Ipswich, Leeds, Liverpool, London, Manchester, Newcastle, Nottingham, Plymouth and Southampton)

Pre-payment customers saw the greatest narrowing of the regional differential with the gap shrinking by £2.23 a year. They have also experienced a more gradual narrowing of this gap over time and did not experience the 2006-08 trend observed earlier.

Average annual domestic standard electricity bills – prepayment – location based max min differential – total bill



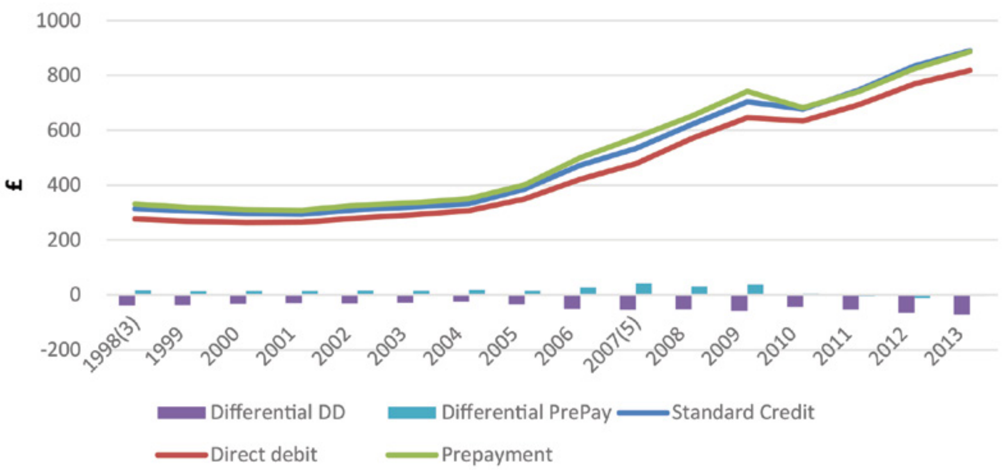
Source: Data from DECC energy market statistics – (Locations used Aberdeen, Belfast, Birmingham, Canterbury, Cardiff, Edinburgh, Ipswich, Leeds, Liverpool, London, Manchester, Newcastle, Nottingham, Plymouth and Southampton)

The above data suggests that there is little evidence to say that the way regional pricing occurs has changed since 1998. The trend for both the maximum and minimum regions in each case are consistent with applying the same pricing policy and price changes. As such this suggests there has not been an increase in aspects such as discriminatory pricing on a regional basis.

It is important to remember that electricity costs are not the only energy cost households face. Gas is also an important part of energy bills and in many cases accounts for a greater proportion of total bills. It is also a lot more volatile given the exposure of the UK to wholesale market gas prices. Below is the same analysis undertaken on the electricity market on the gas sector to see if similar results are obtained.

Again prices were plotted along with the differential between a direct debit, prepay and standard credit tariff. As with the electricity sector it was found that direct debit customers benefitted in comparison to those on the standard credit tariff.

Average annual domestic gas bills for the UK (excluding NI) – cash terms

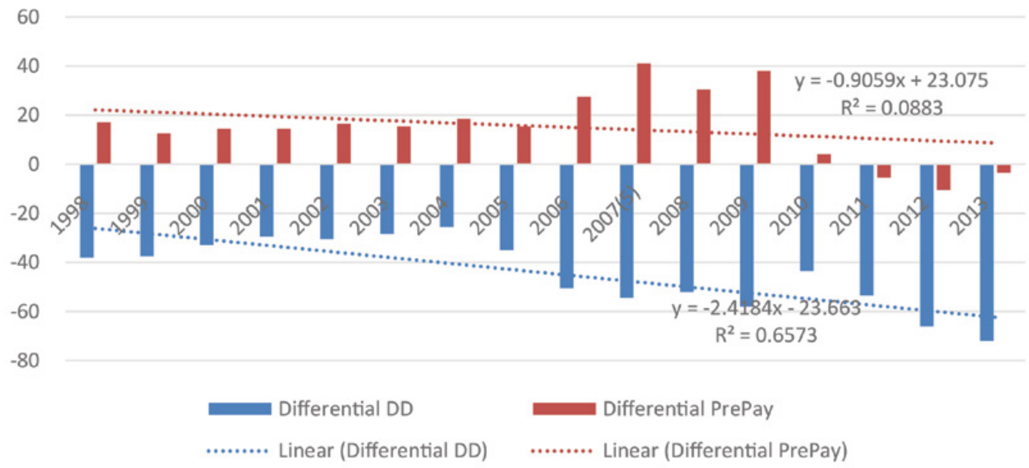


Source: Data from DECC energy market statistics

Direct debit customers in 2013 were £72 better off by being on a direct debit tariff, as opposed to prepay customers that were only £4 better off than those on the standard credit tariff. In real terms, debit customers are now £60 better off and prepay customers £3.

Again this report looks to explore what this real differential reduction means over time and how it compares with the real effect. The data below reveals that since 1998, in cash terms, direct debit customers have benefitted by £2.42 per year beyond the standard tariff. This compares to prepay customers which are £0.91 per year better off than in 1998.

Average annual domestic gas bills for the UK – tariff differential – cash terms



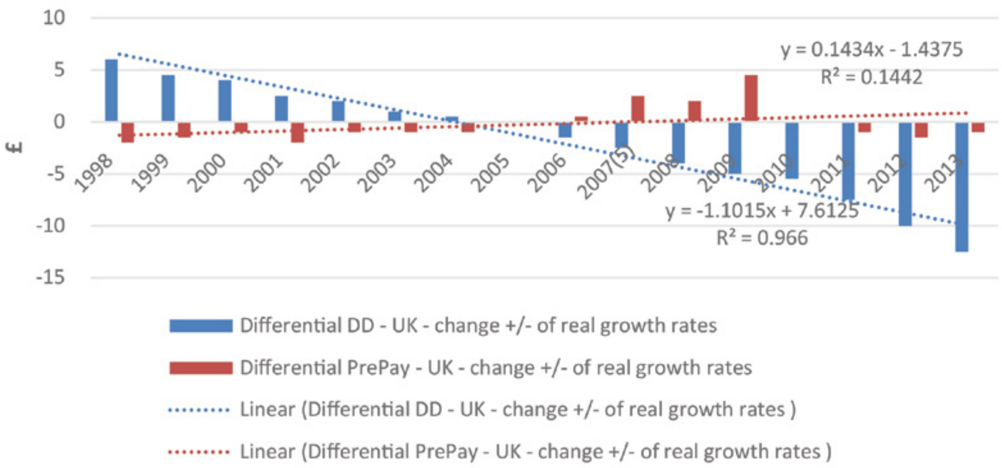
Source: Data from DECC energy market statistics

So what degree of this change in differential is due to general inflationary conditions and what is the affect above and beyond this?

When looking at the difference between the real and cash effects between the tariffs it is revealed that of the £2.42 almost half £1.11 is due to company policies between tariffs beyond the effects of inflation. As such, £1.31 of this £2.42 can be attributed to normal inflationary conditions.

For prepay customers there was a positive upward price effect of £0.14 which can be attributed to companies' pricing policies between tariffs. This means that the £0.91 reduction (when looking at the total differential in cash terms) would have been £1.05 if only inflationary conditions were taken into account.

Differential of Direct debit and Pre-payment from the standard credit option, over time, compared to real rate of price growth (change +/- of real growth rates) – gas



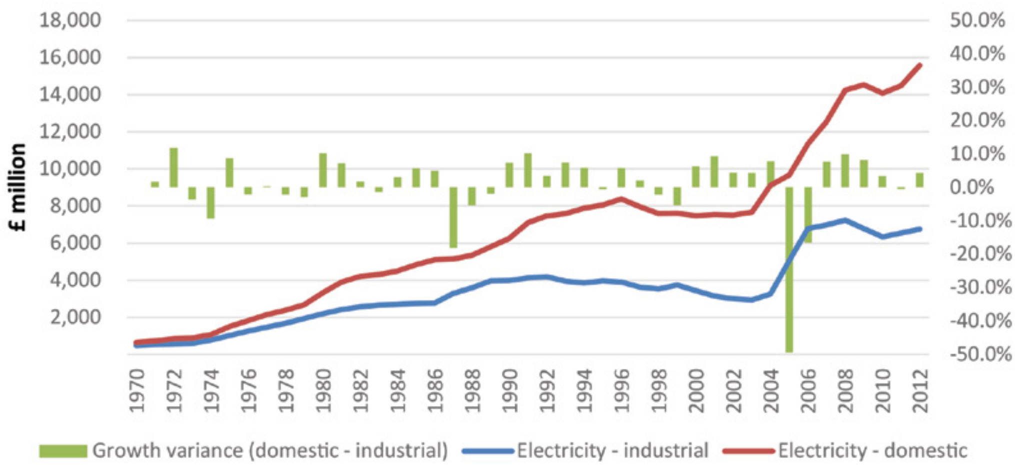
Source: Data from DECC energy market statistics

The analysis above has so far looked at changes for domestic final users, however, suppliers of gas and electricity do not only service households they also service industry. In the interest of understanding how the two sectors compare this report will analyse final expenditure of both groups since 1970.

Below is a chart of the expenditure of the domestic and industrial sectors, and the difference between the domestic and industrial growth rate.

As can be seen from the chart below the domestic sector accounts for approximately £16bn in expenditure, whilst the industrial sector is approximately £7bn. Over the period there were 27 years where domestic electrical growth exceeded industrial price growth.

Expenditure on energy by type of final user and comparison of growth rates – electricity

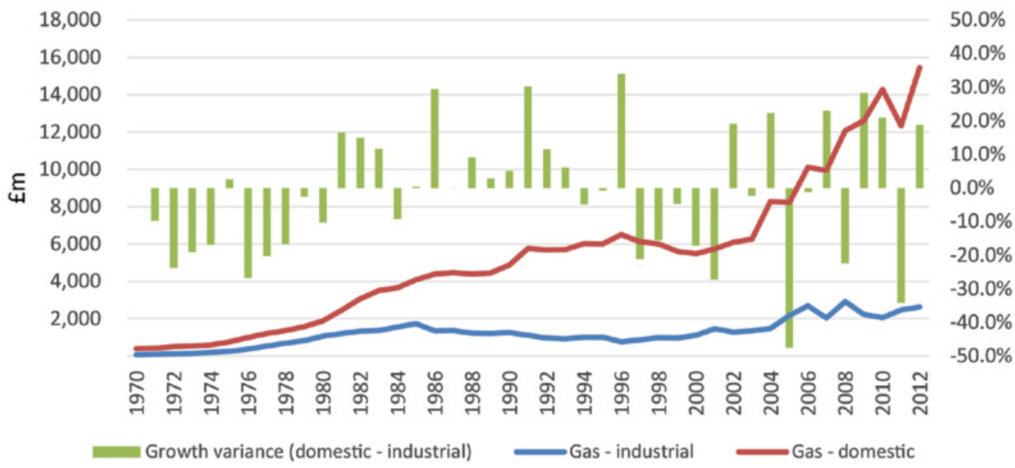


Source: Data from DECC energy market statistics

Looking at the gas market, expenditure in the domestic sector equates to approximately £16bn whilst the industrial sector equates to approximately £2.5bn.

Over the period the difference in the growth performance of the domestic and industrial sector was much more mixed than that of energy and had greater volatility. There were 19 periods in which domestic growth exceeded industrial growth in expenditure terms.

Expenditure on energy by type of final user and comparison of growth rates – gas



Source: Data from DECC energy market statistics

The interesting difference between these results is while the industrial sector has been better at controlling expenditure in the gas sector, it has had less success in the electricity market.

This may be because industry can undertake actions like installing combined heat and power plants, or use the scale of their purchases to negotiate better deals with suppliers. Such deals are generally easier to negotiate in the gas sector as there is a greater degree of trading and a wider array of domestic and international suppliers, whereas electricity generation has to be taken off the grid from domestic suppliers where choice can be limited.

Price and its fairness, however, cannot simply be judged on growth rates. There are significant costs associated with the finding, refining, transporting, transformation and ultimately the sale of both gas and electricity.

This is where it is key for regulators and government to understand the investment requirement, the return required on capital and how wholesale prices feed through into the energy sector.

This report will therefore explore the recent pricing conclusions from Ofgem before exploring in detail the trading of energy, wholesale prices and generation factors and finally retail and generation conditions and margins. This will enable a judgement to be made on whether current energy policy is encouraging the right behaviours to ensure long term investment at the lowest and most efficient cost.

Firstly, to frame this discussion below are some of the key conclusions on pricing that were included in the Ofgem market assessment:

- Announced price changes have become more similar in size between different suppliers over time.
- There is no evidence of a single supplier consistently taking the lead in announcing price changes.

- Prices charged by different suppliers appear to be strongly correlated over time, 0.93 for gas and 0.84 for electricity.
- There has been an increase in the time between the announcement of a price change and 'effective-by' date.
- There is a significant relationship between price and the amount of time that occurs between announcements, even once demand and cost movements have been accounted for. This implies there is an increased likelihood of price announcements occurring as time passes, even if demand and costs remained static.
- Companies are quicker to raise prices when wholesale costs rise, but do not adjust prices as quickly when costs fall.[xviii]

These conclusions suggest that pricing decisions are moving towards a common position, but if wholesale pricing across the industry affects all companies in the same way this is to be expected.

It also suggests that price transfers occur more quickly when prices rise than fall, but as discussed before such a trend also has to be explored in light of how companies' trading positions have changed. Is this competition not working or are market conditions driving similar positions?

Having analysed pricing, current switching levels, and the dominance of several market players which all provide very similar products, it is difficult to come to any conclusion other than that the regulated energy sector, with increasingly controlled tariff based switching make it harder for competition to flourish.

Energy policy in this regard has become vague. Where does the UK want competition and what is the desired outcome?

If we take the UK's energy investment need, for example, competition in the retail market and switching between suppliers as prices change do little, if anything, in terms of promoting a competitive appetite to invest in generation.

To look at this aspect of competition it is more useful to explore the amount of trading that occurs within the market, compared to the degree of generation. This is generally referred to as the velocity or "churn" of the market.

ENERGY TRADING, LIQUIDITY AND SELF-SUPPLY

Key findings

Energy trading pattern changes

- What appears to have been overlooked by policy makers is that whilst it is perfectly acceptable for a market to respond and use short term trading to balance demand requirements, there has actually been a significant shift to shorter term trading. The cost implications for this have then been passed on to consumers with little explanation from the energy companies or regulator as to why such activity has been allowed to occur.
- The UK currently does not have a sufficient forward market for trading, and so any competition that is occurring is not feeding through into investors' expectations.
- Given the limited transparency of the market and over the counter (OTC) nature of trades it is difficult to judge the scale of the effect that speculative trades have. The issue again is the extent to which the "big six" can also influence speculative trading.

Trading policy implications

Current trading data suggests the following in terms of energy policy going forward:

- Marginal (off peak) trading is acting as expected and the increase in spot trading is likely to reflect the greater availability of renewable technology.
- The baseload market has not developed sufficient forward markets to provide the level of price stability consumers and businesses require.
- Energy trading liquidity and volumes whilst currently being two to three times that generated, is mainly between the "big six" energy companies. This means that whilst no one company may have an overriding influence on traded volumes, when acting under similar strategies (to policy and international conditions) they can have significant impacts on the market.
- Since 2007 electricity trading "churn" has been approximately 3 times generation, well below gas trading "churn" which 12-20 times supply, and lower than Germany despite having only 4 large vertically integrated players. This therefore suggests that, whilst the UK has had 12 new entries to the market, churn alone is not the primary driver of entry. What appears to be key to a competitive energy sector is not just the number of players but also a more positive attitude towards trading between these businesses to drive efficient pricing.

Uncertainty and the associated pricing risk

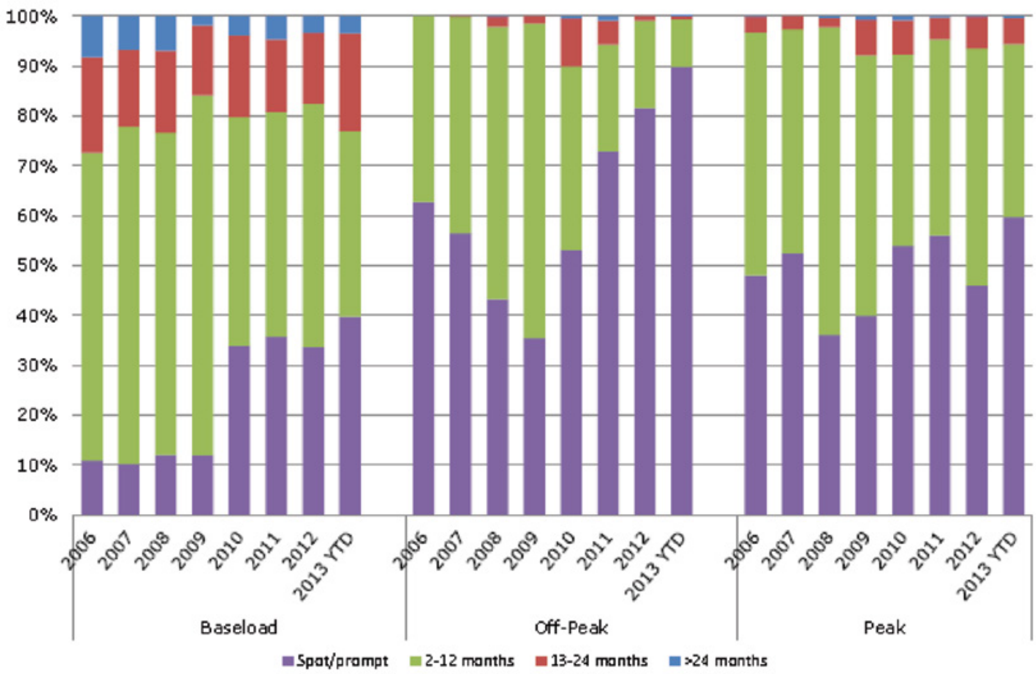
- There is an increasingly vague view as to what investment mix the UK actually needs. Whilst in theory government remaining technologically neutral should encourage competition, in reality it has created a situation where only the most certain of projects progress with all others 'waiting' for the right signals to invest.
- Any price increase above and beyond inflation at a time when consumers are already expressing concern at costs means it is problematic for companies to pass on cost increases. This makes the business case for new investment difficult (as risks rise and margins fall) at a time when the UK's capacity margin is dwindling.

Analysis

Ofgem's recent State of the Market Assessment[xiv] shows that the degree of traded energy is above that of the level of generation, which should suggest some degree of liquidity and competition. Traded volumes, however, are not the whole story and it is the percentage of volumes traded in each market reported in Ofgem's analysis from which one can draw some more interesting inferences.

As can be seen from the chart below, the volumes of energy traded on the spot market are lowest for baseload, which in itself is to be expected with contracts favouring 2-12 month periods. The rationale here is that this constant 'need' of the energy system has to be met and as such, companies prefer not to leave themselves open to the volatility of the spot market.

Percentage of volumes traded OTC by period of delivery



Source: Chart, Ofgem – data, ICIS Heren

That was up until 2011, the amount of base load spot traded increased from averaging around 10% to over 30%. This means that ultimately end user prices become more volatile, not only at the margins of peak and off peak requirements but as part of the main baseload majority of energy supply.

The key here is the cost element. Ofgem has previously stated "trading for the purposes of hedging is a core activity of energy generation and supply businesses and we [Ofgem] would expect these revenues, costs and profits – but not those of speculative trades – to be reflected in the segments presented in the statements[xv]"

What appears to have been overlooked by policy makers is that whilst it is perfectly acceptable for a market to respond and use short term trading to balance demand requirements. There has actually been a significant shift to shorter term trading. The cost implications from this have been passed onto consumers with little explanation from the energy companies or regulator as to why such activity has been allowed to occur.

These trading decisions should have been questioned further by the energy regulator. In competitive markets one would expect companies to be pushing for more advanced forward markets (in excess of 12 months) to provide certainty and stability. After all this was the premise behind energy market liberalisation, price hedges, and market price formation.

Looking more specifically at peak and off peak trading it is revealed that as expected much more energy is traded on the spot market. This is to be expected, as supply companies are more willing to take pricing risk to meet short term demand fluctuations. It is also interesting to note that the extent of off peak spot trading has increased from an approximate average level of 50% between 2006-2010 to almost 90% in 2013, whereas, such a transformation has not taken place in peak trading.

While this may be due to increased availability of renewable electricity on the spot market at off-peak times, this electricity is not only easily available but cheaper given lower operational costs and so long term deals are less relevant outside the baseload and peak periods.

The final aspect which needs consideration is that of speculative energy trading. Whilst Ofgem states that this is not included in the Consolidated Segmental Statements[xvi], it is important to realise that such speculative trades will be inbuilt into the price paid for energy by suppliers. Thus speculative trading will have an effect on the differential between the price at which energy is generated and the price that is paid by the supply businesses.

Given the limited transparency of the market and the over the counter (OTC) nature of trades it is difficult to judge the scale of the effect that speculative trades have. The issue here again is the extent to which the 'big six' can also influence speculative trading.

The combination of the data above suggests the following in terms of aspects for energy policy going forward:

- First, marginal (off peak) trading is acting as expected and the increase in spot trading is likely to reflect the greater availability of renewable technology.

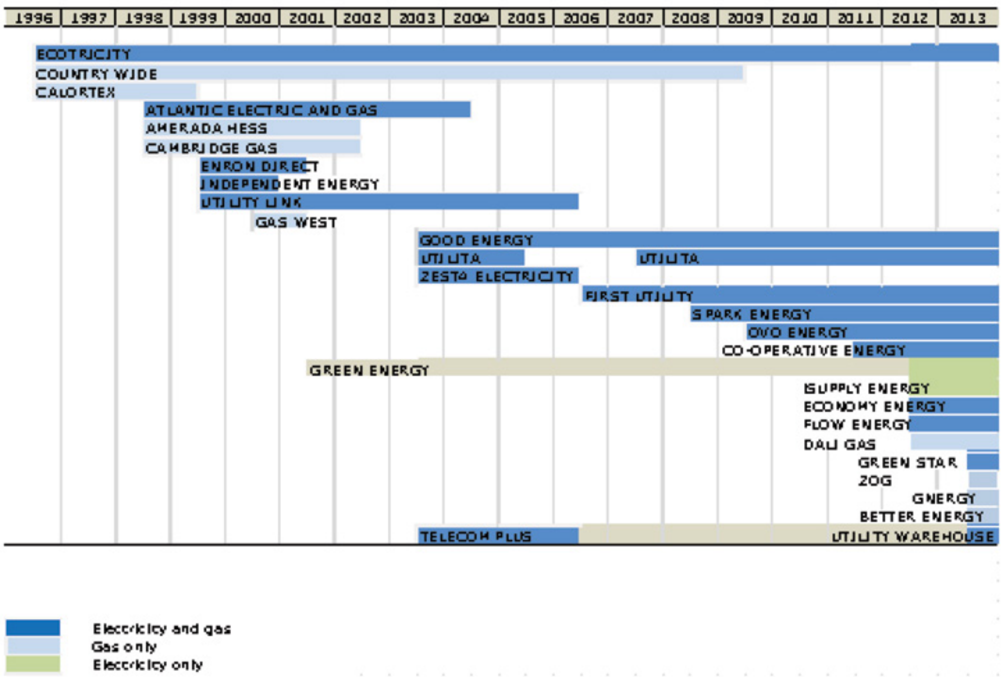
- Second, the baseload market has not developed sufficient forward markets to provide the level of price stability consumers and businesses require. For example, with almost 80% of electricity traded 2-12 months forward, trading is not occurring in a manner that is even sufficient to cover the popular suggestion by Labour for an 18 month price freeze. As such energy companies are open to significant market risk, which is part of the rationale behind their concerns.

- Thirdly, energy trading whilst currently two to three times the amount of electricity generated, mainly takes place between the 'big six' energy companies. This means that whilst no one company may have an overriding influence on traded volumes, when acting under similar strategies (to policy and international conditions) they can have significant impacts on the market. For example, 9 out of 10 of the earlier smaller competitors operating in the market started operations before the year 2000 when the churn rate was approximately 2 times generation, yet only two years later when churn peaked at over 6 times generation only 4 of these companies were still in operation (and only one survived to 2014).[xvii] This shows that increased liquidity by a small number of influential suppliers has the ability to potentially 'lock out' smaller suppliers in the market. Such an implication is interesting given most small suppliers emphasise that liquidity is the barrier to their operations.

- Since 2007 electricity trading churn has been approximately 3 times generation, well below gas trading churn which 12-20 times supply, and lower than Germany despite having only 4 large vertically integrated players. This therefore suggests that, whilst the UK has had 12 new entries to the market, churn alone is not the primary driver of entry. What appears to be key to a competitive energy sector is not just the number of players but also a more positive attitude towards trading between these businesses to drive efficient pricing.

Another area raised by smaller suppliers is the need for collateral during trades, which can impact on their ability to engage in a liquid wholesale market. Such collateral requirements which can be high for smaller players put a strain on their finances and can create a considerable block. As such, if the regulator wanted to provide a significant boost to the market it should explore options such as regulating what a reasonable collateral requirement is, thereby creating a level playing field. Below the entry and exit of small suppliers into the market is shown:

Non-incumbent entry and exit to the GB domestic gas and electricity markets



Source: Chart Ofgem

Alternatively as was pointed out in Ofgem's analysis some companies have managed to mitigate such requirements by signing long term (ten, twenty etc. year) supply deals. Again if the baseload market were to be refocused towards long term security and stability this would aid smaller suppliers in this area.

The scale and type of trading is important to generation investors. This is because it is this trading that will supply their future revenue stream. Given this, the more developed the forward and long term markets the better as they provide some degree of certainty over potential returns.

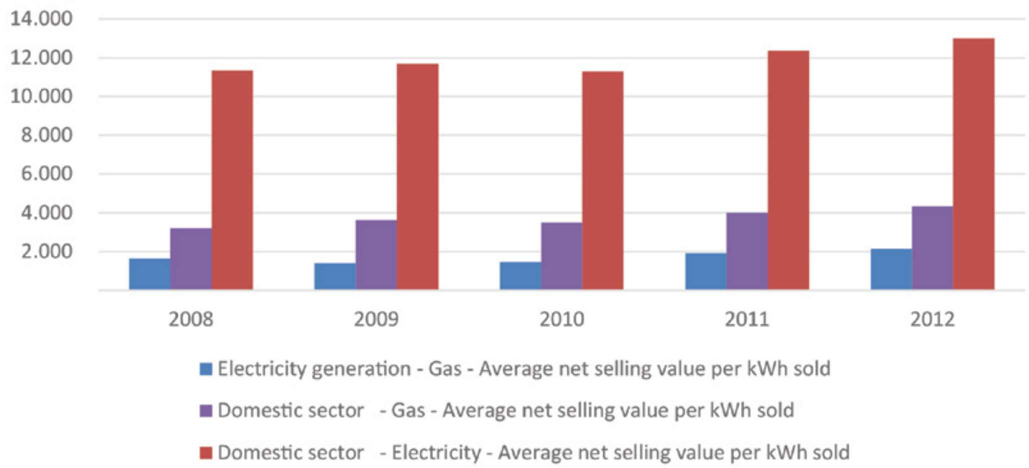
The UK currently does not have a sufficient forward market for trading, and so any competition that is occurring is not feeding through into investors' expectations.

There is an increasingly vague view as to what investment mix the UK actually needs. Whilst in theory government remaining technologically neutral should encourage competition, in reality it has created a situation where only the most certain of projects progress with all others 'waiting' for the right signals to invest.

One of the main concerns is that of covering base load requirements, and whilst the government has put in place a Capacity Mechanism, this in reality only accounts for there being a short term marginal difference and is not actually about long term capacity.

For example, if the scenario of a potential gas generator is considered, as the chart below shows, there could be a significant margin to be made between the generation cost and the domestic price.

Net selling value – gas generation vs domestic electricity selling value

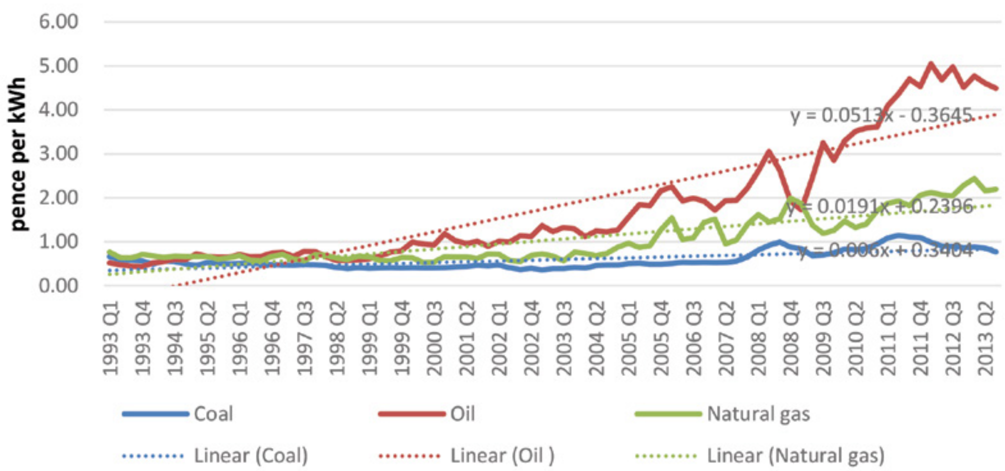


Source: Data from DECC energy market statistics

Future fuel prices have proven to be uncertain, however, as can be seen below. Both in cash and real terms the price of gas has risen considerably.

Whilst the cost of oil rises gas prices also rise 1.9 pence per kWh per year in cash terms and 1.29 pence per kWh per year in real terms.

Average prices of fuels purchased by the major UK power producers and of gas at UK delivery points – cash terms



Source: Data from DECC energy market statistics

Any price increase above and beyond inflation at a time when consumers are already expressing concern at costs means it is problematic for companies to pass on cost increases. This makes the business case for new investment difficult (as risks rise and margins fall) at a time when the UK's capacity margin is dwindling.

This outlines some of the key debates, for instance what really are the energy companies' margins, where are they made and is the current energy policy providing enough incentive to invest?

It is not as simple as headline profit and loss figures, however, in reality energy companies whilst being financially separate from generators buy and sell energy from one part of the company to another, thus displaying a degree of virtual vertical integration.

There is significant debate as to how this benefits or damages, consumers, investment and both large and small suppliers.

Currently the energy market is broadly separated into generators, upstream suppliers, trading arms and domestic supply (retail) businesses. To demonstrate the extent of vertical integration, the 'big six' suppliers directly own about 70 per cent of electricity generation capacity[xviii].

The recent report by Ofgem noted that as energy suppliers have all chosen to undertake a route of vertical integration, there should be benefits such as reducing the cost of capital, reducing volatility, and integrating supply chains.

Such integration, however, has also reduced the potential for competition, reduced liquidity in the market and acted as a barrier to entry for any new competitors.

What is of concern is that whilst the benefits and negatives are discussed as part of the recent State of the Market Assessment, it is stated that there is no attempt to weigh the costs and the benefits of vertical integration in electricity markets.[xix]

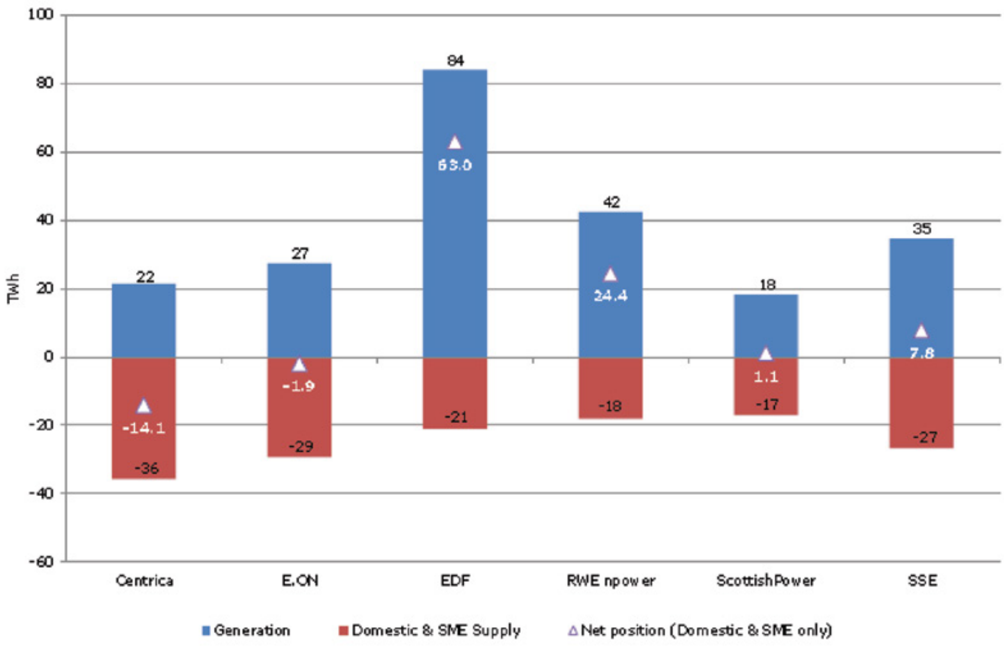
Given the regulators role and scope for competition, value for money, supervision of development and regulation for the delivery of regulatory schemes it should have a clear and established position on this area of the market.

This again suggests that there is no clear direction for the energy sector, and that decisions are more likely to be made based on the political environment. This generates significant uncertainty and risk for investors underlying their willingness to finance and fund energy projects.

It could, therefore, be the case that vertical integration is not to gain efficiency or reduce cost but actually a reaction to ensure security by energy companies given the constantly changing policy landscape.

The chart below from Ofgem's assessment reveals that the majority of the 'big six' providers are able to self-supply and so can secure their positions. It has to be asked, if competition were working sufficiently and wholesale markets operated in a fair and transparent manner would such self-supply be necessary.

Aggregate balance between GB electricity demand and supply for the six largest energy supply companies for 2012 (TWh)



Source: Ofgem, Consolidated segmental statements, Datamonitor

As is pointed out by Ofgem the ability to self-supply is likely in reality to be greater than that of the position presented above because that chart measures actual generation output, whereas generation capacity will be larger. When considering domestic supply only, Centrica is the only one of the 'big six' which does not have the capacity to self-supply for their domestic customer base.

Having explored key aspects and requirements that take place within the energy market, it is important to take a more detailed look at the market players and their operations within it.

Does the overall macroeconomic picture align with the realities of the challenges energy providers face? Are retail price rises shown in the costs the suppliers face? To what extent is there evidence of vertical integration? Are the companies all operating in a similar manner?

CONSOLIDATED SEGMENTAL STATEMENTS

Key findings

Analysis by Ofgem shows that margins across other sectors vary between 0.5% and 4.8%, with the higher number reported, in a study of European utilities. This does not, however, consider the relationship between margins and the level of investment requirement. Given the private sector is being asked to finance the largest ever renewal of UK energy capacity the discussion needs to reflect the complexities and risks such investments would place on company balance sheets and credit ratings.

Direct fuel costs – generators

- Data for the generating arms of the companies show that EDF's non-nuclear generation and Centrica's generation costs follow a similar trend. This is interesting given that EDF's non-nuclear generation has a greater coal balance whilst Centrica's is gas based. Whereas, Scottish Power has a more comparable gas/coal balance to EDF but has significantly higher direct fuel costs that were rising in 2011 when EDF's and Centrica's were falling. Given the significant drop off that occurred in Scottish Power's costs in the following year, however, it could be that this was a result of inefficient forward trading.

Direct fuel costs – electricity supply businesses

- Data for the domestic electricity market shows that Centrica and SSE have higher fuel costs with EDF, Scottish Power, and RWE Npower at the lower end. Such a range of costs could occur simply due to the scale of their customer base and the varied demand for fuel, or alternatively because of different hedging strategies.
- Centrica does appear out of line with the other market players between 2010-12 when direct fuel costs rise significantly, even though other companies with significant gas generation capacity experienced broadly flat or reduced costs.
- It should also be noted that the fuel costs for the electricity supply businesses are between 1.2 and 3.6 times greater than that of the generators.

Direct fuel costs – gas supply businesses

- All companies show similar trends. The difference between the costs incurred again are likely to reflect the scale of the customer base.

Fuel cost correlation between generators and supply businesses

- Generation cost is shown to be negatively correlated to the domestic supply cost, suggesting that as generators direct fuel costs rise, the direct fuel cost to the domestic business falls[xx].
- This implies that either companies are not as vertically integrated as they suggest, or that the benefits of such integration are not being passed on. As such, the process where price signals flow from generators to the supply businesses is not working as it should.

Earnings Before Interest and Tax (EBIT) – generators

- EDF Nuclear posted the greatest earnings for generators, but has a unique position and so is difficult to compare. Below this there is a range of generators making between approximately £150m and £400m, however, there was also a period where EDF non-renewable, and RWE Npower's generation assets were loss making. Whilst sustainable for a short period such losses are not sustainable for investors in the long term.
- The figures suggest that 2009 was a difficult period for generators but pressures generally do not appear to have been purely cost based with revenue from the sale of electricity and gas suffering in a number of cases. Part of the reason behind this will be the reduction in consumption during this period, and the inability of generators to push cost increases onto suppliers given public pressure around energy prices.

EBIT – electricity supply businesses

- Whilst there does appear to be some scope for the pricing mechanism to transfer from the generation sector through to the retail sector, there is some concern that this transfer is inefficient. Looking at the EBIT for the domestic electricity sector it can be seen that a number of companies earnings for the electricity supply side were at their best in 2009.
- Looking more specifically at trends within the electricity supply sector, it can be seen that the earnings are much more volatile than those of the generators. Again SSE appears to show the most consistent trend (albeit of earnings falling slowly over time), with other companies such as RWE Npower experiencing a wide variance of earnings results (from positive £104m to negative £148m).

EBIT – gas supply businesses

- When analysing gas domestic margins it can be seen that earnings have been in a similar range to that of the electricity supply part of the business but have generally been on an upward trend since 2009.

EBIT – total supply businesses

- Energy companies have indicated that they look at the balance of their activity across their total supply business and so it is important to look at the amalgamation of their operations. Once both gas and electricity suppliers for domestic, non-domestic operations are aggregated the company's performance overall is better and much more stable.

EBIT – regulatory stance

- In Ofgem's market assessment it states that: "in the time available we [Ofgem] have not been able to conclude whether these profits are excessive."
- Given a key aspect of Ofgem's remit is to "promote value for money" and "the supervision and development of markets and competition" it is concerning that they do not already hold a full and detailed view of profit margins and performance within the market.

EBIT correlation – generators and total supply businesses

- First, looking at 'total generation EBIT' vs 'aggregate supply EBIT' it is found that as the former rises so too does the latter EBITs[xxi]. This suggests that rises in earnings filter through the whole system. That is to say that if generators charge more to suppliers, suppliers in turn charge more to consumers. For every extra £1 a generator earns in profit, a supplier is also able to make an extra £0.57p. This means that in total consumers would experience a rise of £1.57.
- Whilst there is no strong relationship between generators earnings and aggregate supplier's earnings, the balance of the evidence suggests a positive relationship where suppliers earnings do not suffer as generators earnings increase, i.e. costs are passed through the system with each party benefitting. As such, it is hard to make a case for vertical integration playing much of a role in efficiency within the market.

EBIT correlation – generators and electricity supply businesses

- For every £1 that electricity generators earnings increase, electricity suppliers earnings also rise £0.25. This suggests that there is less willingness on the part of suppliers to pass on further price rises. Consumers would therefore see a rise in costs of £1.25.

EBIT correlation – domestic gas and electricity EBIT's vs aggregate EBIT

- The domestic gas division's earnings of a company explain far more of the overall earnings data (63%) than that of the domestic electricity division's earnings (39%). This is due to the companies exposure not only to gas as a product to sell but also as a fuel for generation. This demonstrates the extent to which gas prices and volatility in the gas market are important for a company's overall level of earnings.

Weighted average cost of fuel

- Overall the weighted average cost for generators is lower than that of the supply businesses. This is to be expected to some degree as margins get added as costs pass through the system, however, the degree of cost rises will be important to consumers. Interestingly if you look at the generators average weighted costs they still vary significantly depending on technology and fuel costs, which is to be expected.
- The same is not true for the weighted average costs of gas and electricity for the domestic supply divisions on the companies. These are similar across all the companies, despite the fact that earlier analysis on purely 'direct fuel costs' shows wide disparities between the companies.

Correlation – weighted average cost of fuel

- The correlation between generators weighted average costs and overall weighted costs of the supply businesses shows that as generators average costs increase the aggregate supply businesses average costs do not change significantly.
- This could suggest two possible scenarios, the first is that the average weighted cost of generators has no bearing on supply businesses average costs. Alternatively, the supply businesses are able to hedge prices forward so effectively that they can absorb variations in generators weighted costs with little effect on their own. The second is, however, questionable given the shift towards short term spot trading where it would be more difficult to offset cost volatility.
- What it may suggest though is that the differential between the generators' average weighted costs and those of the supply business are sufficient enough that they can maintain a similar level, thus not reflecting actual cost conditions.
- This has quite serious implications for competition, as it reveals that there is little differential between the supply business average costs, while there is significant differential in the generators average costs, and a sufficient margin in between. This, therefore encourages little efficiency and competition despite each company having different input costs.
- Whilst this may not be intentional and reflect how similar suppliers have to be on price to maintain their consumer base it does not encourage an efficient cost based energy system.

Analysis

Actions to improve transparency in the market are continually taking place. For instance, the introduction of the Consolidated Segmental Statements was a significant step forward.

For the 2013 Consolidated Segmental Statements, each of the 'big six' has agreed with Ofgem that they will as a minimum commission external auditors to check their statements correctly.[xxii] This helps to ensure the accuracy of the information and that it represents actual activities carried out.

As such this report has analysed in further detail the Consolidated Segmental Statements (CSS).[xxiii] These statements are provided by the energy companies and are submitted to Ofgem.

The following is mentioned with regards to the accuracy of the consolidated segmental statements (CSS):

- "The CSS reports are not audited but have to be reconciled with audited group accounts. …. However, Ofgem, its advisors and industry analysts have reviewed the data. Ofgem's advisors, BDO, concluded that it was not possible to provide complete assurance on the segmented accounts."[xxiv] However, it said it saw "no evidence… that profits are being unduly excluded from the CSS" and "no evidence that would suggest that the CSS do not represent a true and fair view of the split of profitability".[xxv]

The data provided in the accounts can therefore be viewed as an accurate representation of the split of a company's costs and profits.

Whilst this data is useful, however, concerns are raised:

- "Even with complete accounting assurance, the allocation of costs between different business segments remains, to some extent, subjective. For example, it is not obvious when good wholesale energy trading performance should be realised as lower costs to the supply business, higher revenues to the generation business or profits in the trading business".[xxvi]

Ofgem also recognises that within this different transfer pricing models will be used, allocating risk differently across companies. As such they comment that the segmental statements will not necessarily be directly comparable.

This being said Ofgem has revealed that they have found a number of aspects of the behaviour of the six largest suppliers that would appear to be consistent with tacit coordination between them. If this is the case such information should be apparent from these statements? This is one of the areas this report explores further.

In terms of how companies were perceived to be specifically involved in tacit coordination the following are highlighted:

- Announced price changes around the same time and of a similar magnitude.
- Profitability has increased for all of the large suppliers, and domestic supply margins have converged.
- Large suppliers appear to raise prices more quickly and fully when costs increase than they reduce them when costs fall.

When considering why companies would coordinate in such a manner Ofgem pointed out reasons ranging from firms face similar incentives, react to shocks in similar ways, that firms to know what competitors are up to, the need to create market stability, and the possibility of firms wishing to prevent new entrants.

So whilst this report will provide further analysis and draw some conclusions from the data, it is apparent that the degree of vertical integration potentially causes issues. Such issues should not be the case as the European Union sets out clearly in its Third Energy Package the liberalisation of EU energy markets and the separation of companies operations in different areas.

Given the premise behind this legislation it should be possible for the energy regulator to make judgements of how the transfer of pricing is occurring between these companies.

In addition, if vertical policies were so integral to energy pricing and energy companies faced such pressures, given their various generation mixes one would expect price changes in the consumer market to be less aligned. That is to say changes in price would occur to reflect the companies' hedging policies and not the movement of the overall market or other companies pricing.

Similarly retail margins should not be squeezed to the point of non-profitability when wholesale prices rise. Such conditions should be passed onto the consumers. Currently the price transfer mechanism through the market is unclear, and as such it is hard to work out if the margins being made are reasonable.

Ofgem has stated publically that there "remains a public concern that companies can use their transfer pricing policies to unduly influence the profit figures they report for their supply and generation businesses."[xxvii]

Further recent analysis in Ofgem's market assessment demonstrates varying margins and their potential transfer across other areas of the energy sector:

- "Based on this analysis, Ofgem concluded that estimated retail margins were materially higher on average during 2000 to 2004 – at around 15 per cent of sales on average. Ofgem noted that this was a period of lower and more stable wholesale prices and consequently lower generation profits. A number of large non-vertically integrated generation businesses went into receivership over this period. As electricity and gas prices increased, supply margins were squeezed but by 2006 were more than compensated for by higher generation profits."[xxviii]

These results, demonstrate that companies appear to be constantly shifting their margins and operations to try and account not only for the wholesale price but also for their ability to pass prices onto consumers and satisfy political needs at that point in time.

The shifting of operations in this way does not necessarily mean they are operating efficiently, however, recently IPPR reported that:

- "Evidence shows the difference between energy suppliers spending on operational costs was in fact greater in 2010 than in 2007. In 2007, Ofgem found that the least efficient supplier was spending 90 per cent more on each customer account than the supplier with the lowest costs. We estimated figures for 2010 and found that the least efficient supplier was spending 113 per cent more than the most efficient."[xxix]

This demonstrates that there is a valid concern that efficiencies are not occurring and that energy companies, whilst appearing to be facing similar market conditions and implementing similar price movements at the retail end of the market, are not facing similar operational costs.

Before further analysing data on costs and company performance it is useful to understand the potential margins that investors require to invest in assets.

Below is the benchmark analysis carried out by Ofgem on supplier's margins over time and how they compare with other industries.

The analysis shows that margins across other sectors varies between 0.5% and 4.8%, with the highest reported in a study of European utilities.

Margin benchmarking

Market Commentator	Company / sector	Proposed Margin
Monopolies and Mergers Commission (1996/97)	Scottish Hydro/NI Supply	0.5%
Ofwat (2014)	Domestic water	1.0%
Utility Regulator Northern Ireland (2011)	Phoenix Supply	1.5%
Utility Regulator Nothern Ireland (2011)	Power NI	1.7%

Source: Table Ofgem

Market Commentator	Company / sector	Proposed Margin
Ofgem / Offer (1998)	Energy retail	1.5%
Ofwat (2014)	Non domestic water	2.5%
Ofgem RMR adjusted benchmark analysis (2011)	Energy retail	3.0%
Study carried out by Oxera for EDF (2014)	Energy retail	3.0%
Water Industry Commission Scotland (2005)	Water	3.2%
Morgan Stanley Research Europe Utilities Report (2013)	GB Commodity Retailers	4.8%

Source: Table Ofgem

The problem with looking at margins in this way is that it does not illustrate its relationship to investment, and little evidence of how this relates to actual generation.

For this reason the focus of this report's analysis of the CSS statements will focus on the comparisons between generators and retail providers.

To do this it is important to understand the composition of the generation portfolios of companies, as they will have a direct impact on items such as exposure to fossil fuel prices.

As can be seen from the chart below Centrica, E.ON, RWE Npower and SSE all have significant Combined Cycle Gas Turbine (CCGT) generation assets. This means that in theory they have higher exposure to the wholesale gas market than their competitors. As such you would expect these companies to be under the greatest pressure to raise prices when wholesale costs rise, and the most likely to cut costs when they fall.

EDF and SSE have the most significant exposure to coal price fluctuation, with Scottish Power, RWE Npower and E.ON all also having a reasonable exposure as a proportion of their power generated by coal is lower.

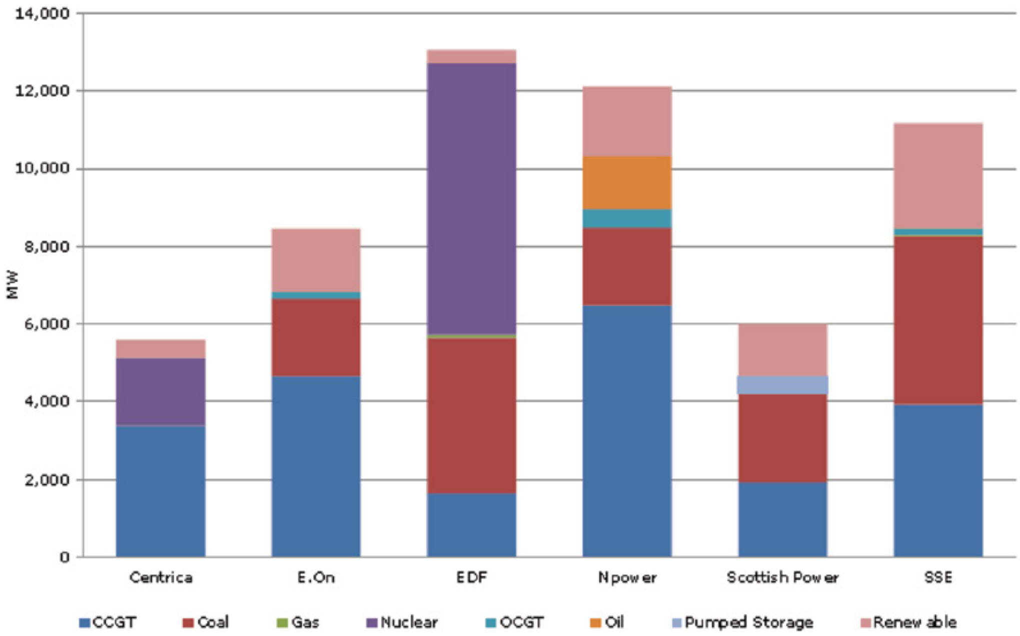
What is not always considered in relation to these two areas of generation is that the carbon price is generally considered to act as an incentive for generators to switch from coal to cleaner gas.

Nuclear generation assets are held by Centrica and EDF but whilst these will have lower fuel costs it is important to remember that the initial cost of the asset is far greater and so the depreciation and amortisation of these assets is higher.

Renewables are also beginning to form a larger part of suppliers' generation assets, with E.ON, Scottish Power, RWE Npower and SSE having significant scales of generation in this area.

Renewable assets form an interesting part of the market as whilst there is not a guaranteed generation capacity owing to variability in, for example, wind conditions, they can provide low cost electricity. Having said this the technologies vary in cost and implementation meaning mechanisms have to be provided by government to encourage development. This will also need consideration in light of companies performance.

Composition of generation portfolios – main suppliers



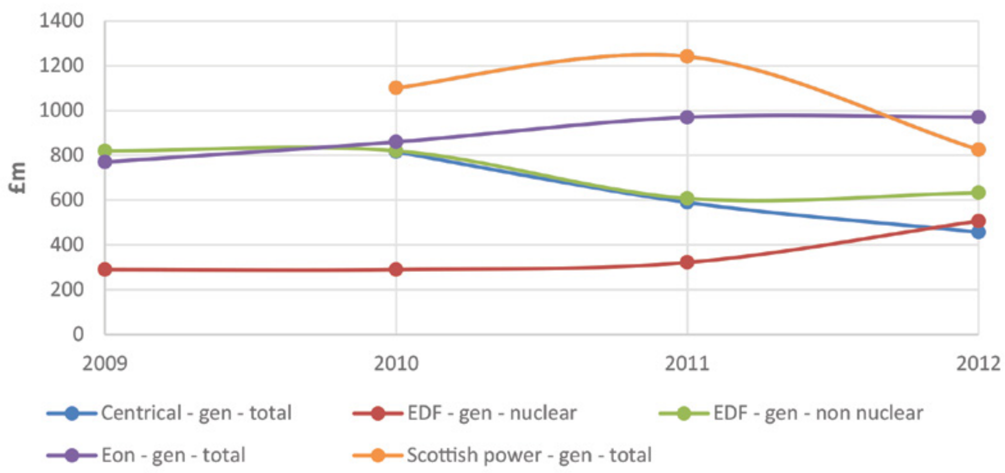
Source: Chart, Ofgem – data, DUKES table 5.11, OCGT abbreviates open cycle gas turbine, NPSHYD not pumped storage hydro and CCGT combined cycle gas turbine

Given the scale of gas and coal generation it is important to look at direct fuel costs within the CCS statements where data is available.

Looking at data for the generating arms of the companies, whilst the data is split between different types of generation it can be seen that EDF's non-nuclear generation and Centrica's generation costs follow a similar trend. This is interesting given that EDF's non-nuclear generation has a greater coal balance whilst Centrica's is gas based.

Scottish Power on the other hand, which has a more comparable gas/coal balance to EDF, has significantly higher direct fuel costs, which were also rising in 2011 when EDF's and Centrica's were falling. Given the significant drop off that occurred in Scottish Power's costs in the following year (2012), however, it would be reasonable to assume that this was a result of inefficient forward trading.

Direct fuel costs – generators



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

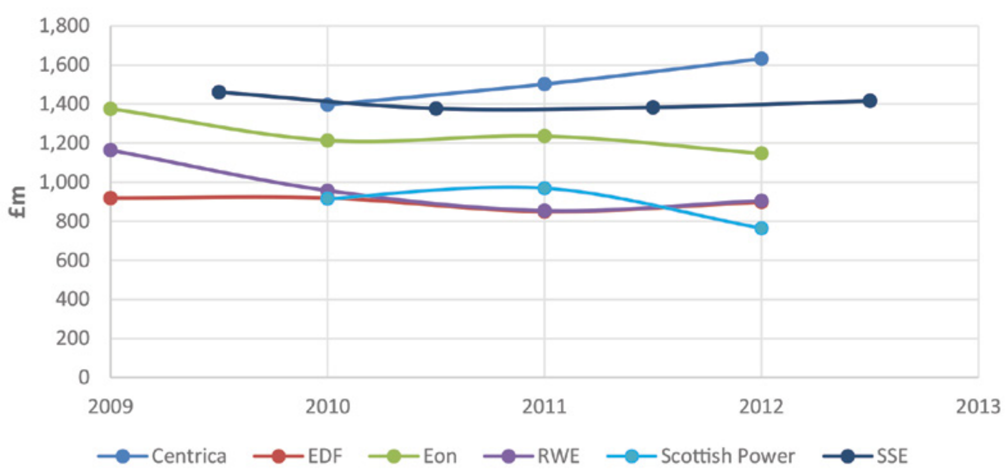
So how do the generators direct fuel costs compare to the electricity and gas domestic markets?

If you plot direct fuel costs for the domestic market for electricity you find that Centrica and SSE have higher direct fuel costs, with EDF, Scottish Power and RWE Npower at the lower end. Such a range in cost could occur simply due to the scale of their customer base and the varied demand for fuel, or alternatively because of different hedging strategies.

Centrica does appear out of line with the other market players (2010-12) with direct fuel costs rising significantly even though most other companies with significant gas generation capacity experiencing broadly flat or reduced costs.

It should also be noted that the fuel costs for the electricity supply businesses are between 1.2 and 3.6 times greater than that of the generators.

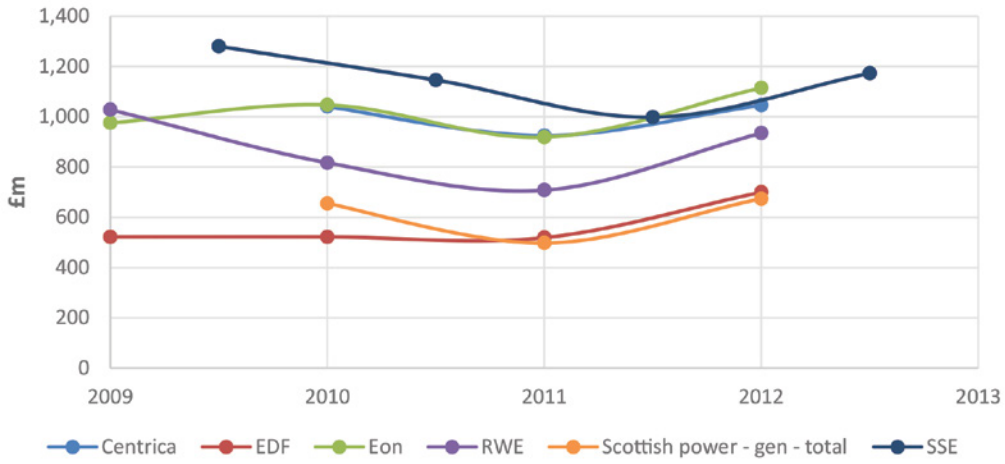
Direct fuel costs – electricity domestic



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Looking to the domestic gas supply business this show similar trends across all of the companies. The difference between the costs incurred again are likely to reflect the scale of the customer base.

Direct fuel costs – gas domestic

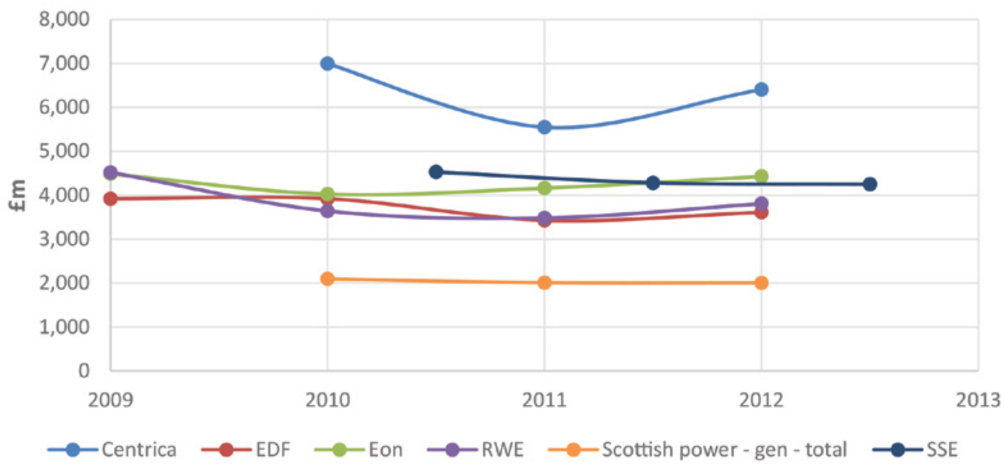


Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Whilst all the providers may utilise slightly different hedging strategies, most will consider their supply business as an aggregate entity.

Interestingly when plotting the aggregate outcome from supply businesses (which also includes non-domestic electricity and gas production) it is found that the direct fuel costs of companies are relatively flat. This suggests that no matter what the scale of the operation the company runs in absolute terms, they are all relatively successful at hedging to control costs across the business as a whole.

Direct fuel costs – aggregate supply – domestic and industrial



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Another interesting way to compare the costs across the chain of the vertically integrated companies is to plot their direct costs as a result of their generation activities against the fuel cost they incur within their aggregate, gas and electricity businesses.

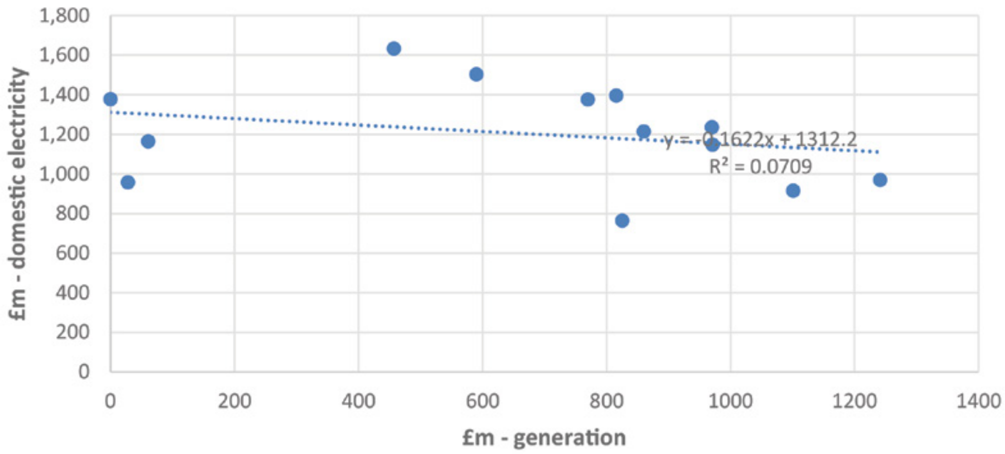
Undertaking such analysis provides some interesting results. You would expect that as the direct fuel costs of generation increased so too would the direct fuel costs of the supply business. This suggests that competition is occurring, pricing is transparent and efficient, and importantly being passed onto the consumer in a rational way.

This, however, is not the result that is achieved.

Whilst some interesting inferences can be made from the following data, caution should be exercised given the low R^2 (R-squared) value and limited sample size[xxx].

As the chart below shows the generation cost is negatively correlated to the domestic supply cost, suggesting that as generation direct fuel costs rise the direct fuel cost to the domestic business falls.

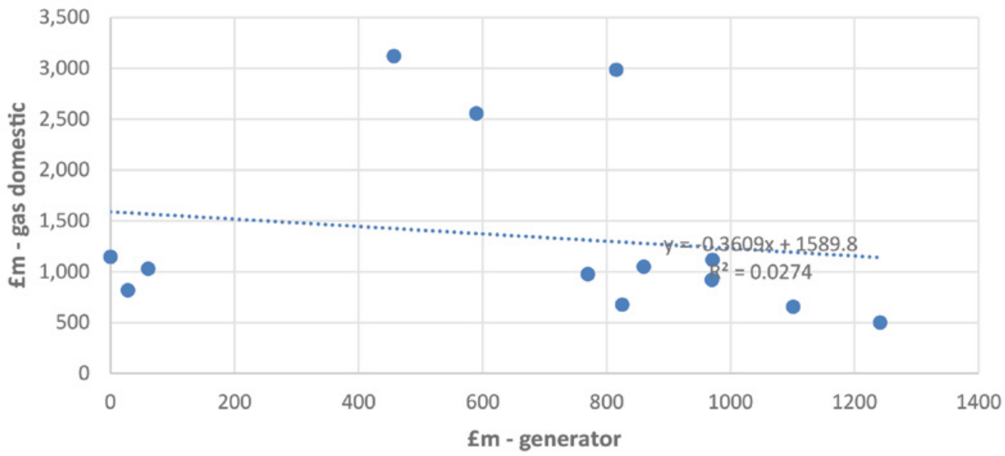
Generation direct fuel costs vs domestic electricity supply fuel costs



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

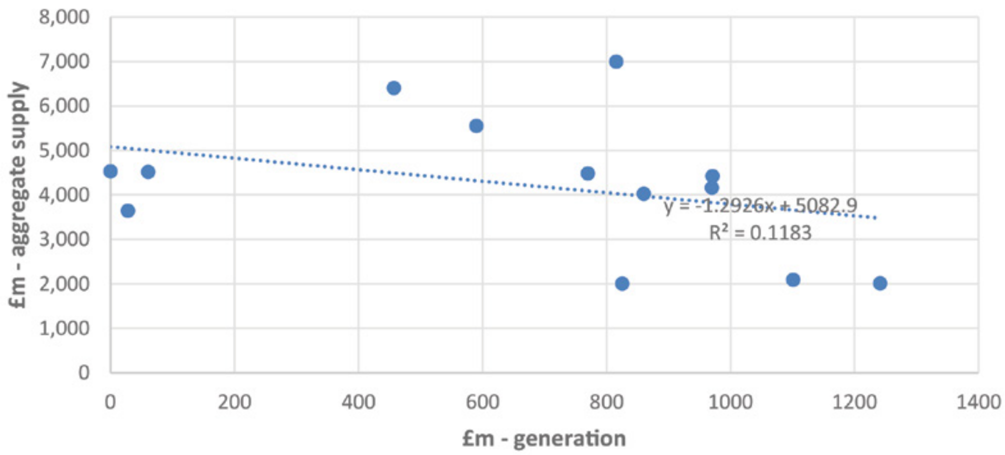
The same trend is also observed separately in both the domestic gas and electricity supply markets for direct fuel costs when compared to the generation fuel costs.

Generation direct fuel costs vs domestic gas supply fuel costs



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Generation direct fuel costs vs aggregate supply fuel costs



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Another interesting observation that can be inferred is that either companies are not as vertically integrated as they suggest, or the benefits of such integration, including the process through which the companies pass the benefits of integration are not acting efficiently. As such, price signals are not being passed through from generators to the supply businesses as expected.

Direct fuel costs, however, are only part of the story with the majority of the focus in the media being on overall profit levels.

It is clear that reasonable profits are required for investors to continue to invest in the UK, however, more attention needs to be given to where the profits are made and what this means in relation to specific investment signals.

EBIT analysis

Before performing further analysis, the following general conclusions were made by Ofgem as part of its recent study into the EBIT levels of companies:

- "We have also observed an increase in the aggregate reported profits of the six large vertically integrated suppliers"[xxxi]

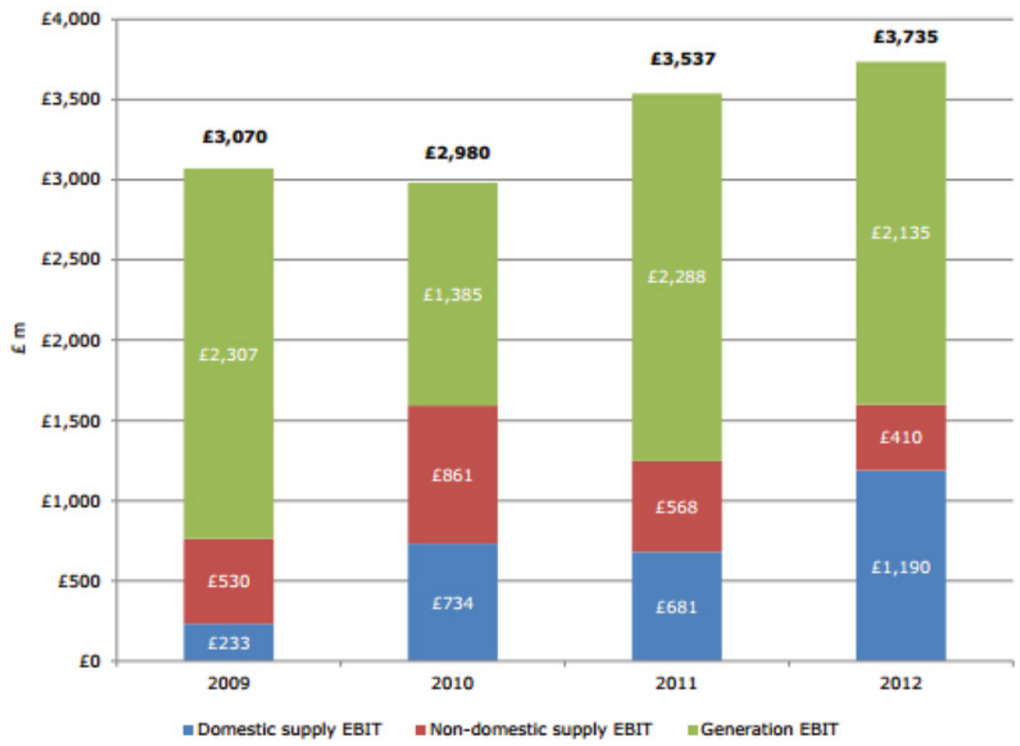
Within, this three important observations are made:

- Combined EBITs of the six largest suppliers from generation and supply increased from £3.0bn (2009) to £3.7bn (2012).
- Generation and non-domestic supply profits have fallen slightly over the period.
- Domestic supply profits have increased from £233m to £1,190m, with EBIT margin for domestic supply having increased from 0.9 to 4.3 per cent.

These results are shown graphically below, but it is felt that on average the EBIT figures, whilst useful as a broad measure, do not get to the heart of:

- Whether energy companies are experiencing similar market conditions and so rises are justified.
- How each market player manages the degree of vertical integration
- Whether there is evidence of vertical integration, and does it benefit consumers?

EBIT of the six largest suppliers



Source: Chart Ofgem

In attempting to answer such questions, it is important to look at the data for companies across the sector to judge conditions and within individual companies operations to see if any conclusions can be drawn.

First this report will look at the EBIT of the generating arms. This after all is where the UK requires investment.

The generator with the greatest EBIT is EDF's nuclear generating arm. Its growth from 2010 to 2011 was mostly the result of increased revenue growth, with some of the rise offset by increased costs in 2012.

Whilst such earnings could be seen as a potential warning for the UK given its endeavour into a new nuclear programme, there is a rationale behind why the EBIT of such a plant is greater than others. This is due to the significant upfront capital costs and lower fuel costs as opposed to coal and gas plants which have lower upfront costs but higher fuel costs.

Looking at the second highest company EBIT (SSE), it is revealed that their trend is relatively stable over time at approximately £400m. They have also maintained this level despite rising costs during the period.

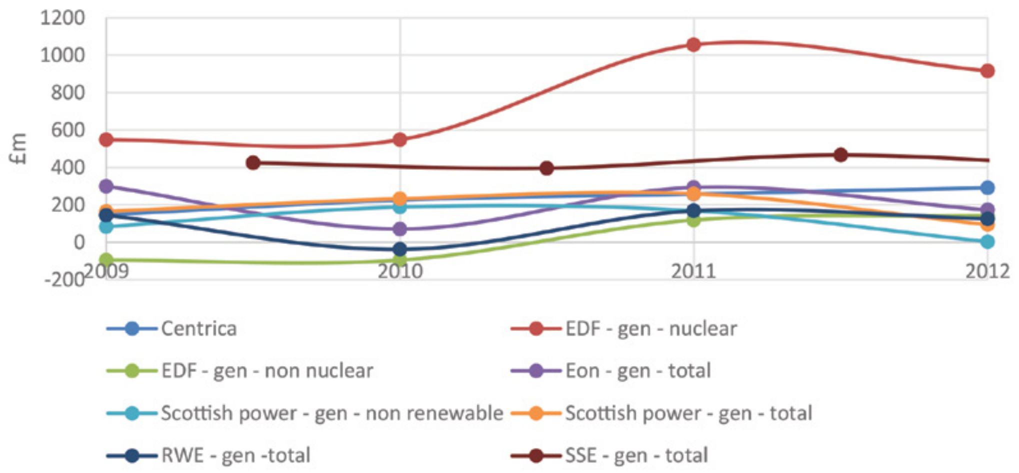
This suggests that they are doing a good job as a generation company in targeting a return for their assets and maintaining that return. It should also be noted that SSE has significant renewable generation assets, with CCGT and coal based generation abilities to cover any shortfall. Given the more equal balance of gas and coal assets they own, the company can easily engage the cheaper assets first, while being able to reduce radical swings if commodity prices vary significantly between coal and gas.

Below these two higher end companies there is a range of generators making between approximately £150m and £300m. There was also a period, however, where EDF's non-renewable and RWE Npower's generation assets were loss making. Such losses, whilst sustainable for a short period, for example, in the event of a significant hike in commodity prices, would not be tolerated by investors in the long term.

Overall the figures suggest that 2009 was a difficult period for generators, but pressures generally do not appear to have been purely cost based with revenue from the sale of electricity and gas suffering in a number of cases.

Part of the reason for this may be that 2008-9 saw disposable incomes squeezed and so consumers, whilst not necessarily reducing consumption significantly, tried to limit increases in their expenditure. This was also the period when energy companies, under pressure from consumers and the media, reduced prices. As such, any cost increases generators did incur are unlikely to have been passed down to suppliers given public feeling on price rises. This appears to have been the case with reduced revenues for generators squeezing margins in this period.

EBIT – generators



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

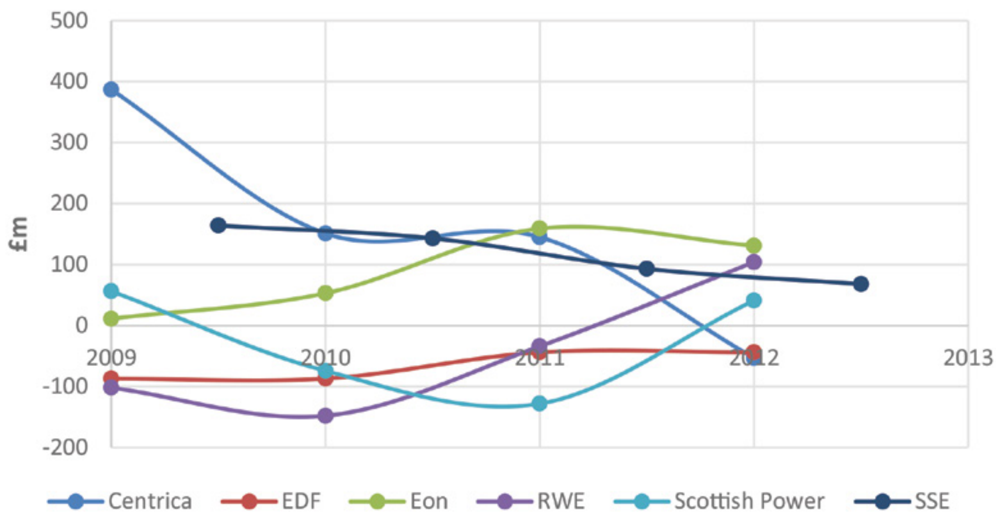
The above suggests that there might be some scope for the pricing mechanism to transfer from the generation sector through to the retail sector and vice versa. It is, however, not quite that simple. Looking at the EBIT for the domestic electricity sector, a number of companies earnings for the electricity supply side were at their best in 2009.

This then falls significantly for a number of companies in 2010, but does this make sense with generators being squeezed in 2009?

In short, yes, as companies are likely to have taken action up to 12 months before to squeeze their costs down the chain in light of reducing prices. As reported earlier given the short forward period over which energy is traded such results can be explained.

The following year's fall in EBIT is consistent with the price changes reducing margins whilst revenues paid to generators started to increase.

EBIT – electricity domestic



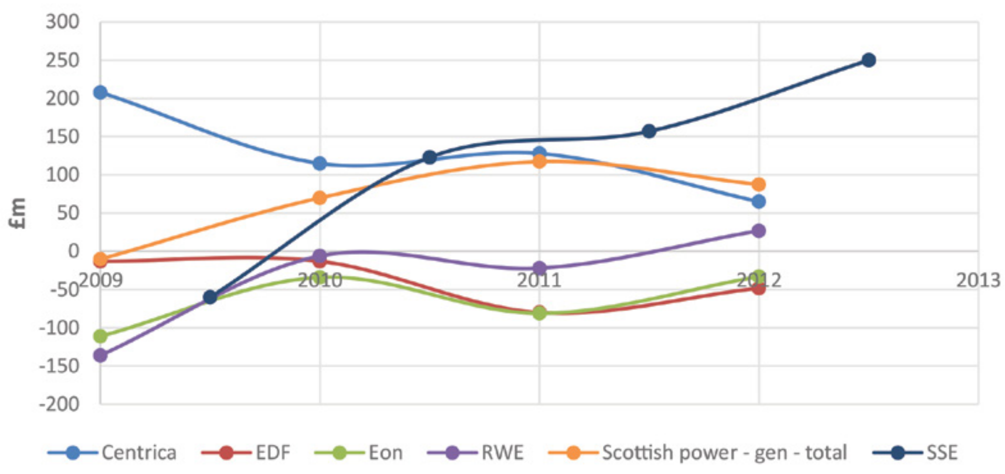
Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Looking more specifically at trends within the electricity supply sector it can be seen that their earnings are much more volatile than that of the generators. Again SSE has the most consistent trend, albeit of earnings falling slowly over time, with other companies such as RWE Npower experiencing a wide variance of earnings results.

This would appear to contrast with the earlier 'average earnings' but this, as can be seen in the chart, includes the domestic gas market and non-domestic supply operations.

When analysing gas domestic margins it can be seen that earnings have been in a similar range to that of the electricity supply part of the business but have generally been on an upward trend since 2009.

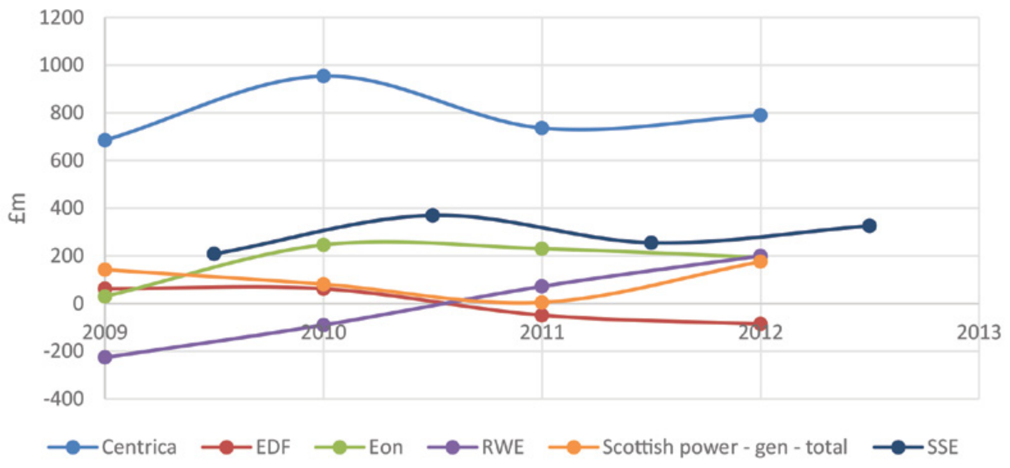
EBIT – gas domestic



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Energy companies have indicated that they look at the balance of their activity across their total supply business and so it is important to look at the amalgamation of their operations. As can be seen from the chart below once both gas and electricity suppliers for domestic, non-domestic operations are aggregated, company performance overall is better and much more stable.

EBIT total



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

The information above from the Consolidated Segmental Statements on domestic margins, aligns with the view in Ofgem's market assessment that:

- There remains a wide variation in supply margins.
- Domestic electricity margins fell during the period, from 2.2 per cent to 1.8 per cent, however, domestic gas margins have increased significantly, from -0.3 per cent to 6.7 per cent over the period.

Whilst the above analysis is welcome, it is concerning that the market assessment states that: "in the time available we [Ofgem] have not been able to conclude whether these profits are excessive".[xxxii]

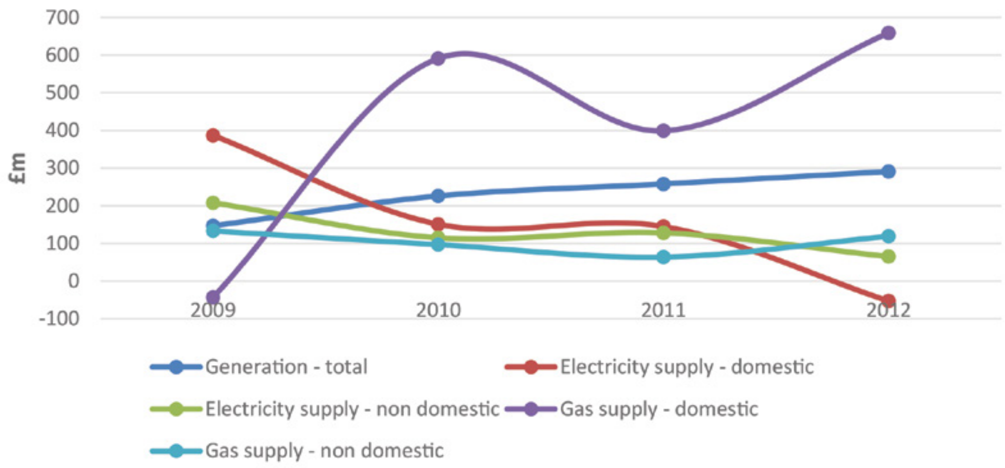
Given a key aspect of Ofgem's remit is to "promote value for money" and "the supervision and development of markets and competition" it is concerning that they do not already hold a full and detailed view of profit margins and performance within the market.

To understand the earnings the companies are making across their operations more fully the following charts plot each companies EBIT across the various divisions they operate.

Looking at Centrica, its domestic gas operation has gone from making a loss in 2009 to a profit of over £600m within three years. Its domestic electricity supply business, however, has gone from making approximately £400m in EBIT to a loss making position in 2012.

Non domestic supplies have been a lot less volatile continuing to make broadly consistent earnings. Meanwhile generation earnings have risen from below £200m to over £300m.

EBIT comparison – Centrica



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Looking more closely at the numbers within its domestic gas division[xxxiii], the direct fuel costs between 2010-12 varied between £1,046m (2012) and £925m (2011), indirect operational expenditure (opex) costs £721m (2012) and £623m (2011), other direct costs[xxxiv] between £1,289m (2010) and £1,362m (2012). This resulted in total operating costs varying from around £2,565m (2009) to higher levels of between £4,486m (2011) and £5,201m (2012) for the three year period.

Across these 5 years, however, total revenue also went from a level of around £2,522m (2009) to an increased level of between £4,903m (2011) and £5,884m (2012).

Broad based revenue growth that exceeds cost growth is the main aspect that has increased the EBIT of the gas supply division, whilst the electricity supply EBIT has fallen as revenues have struggled to match costs.

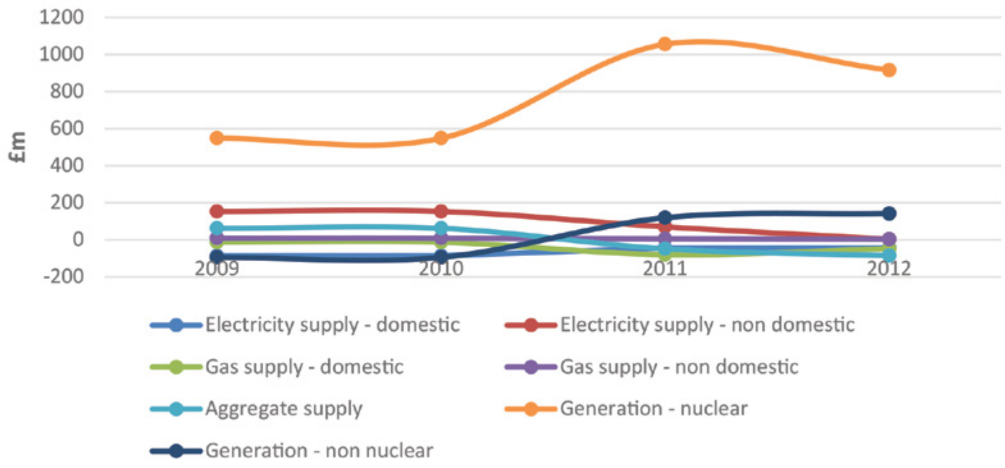
Rising bills and items such as renewables obligations have actually remained relatively stable between 2010-2012.

Looking at EDF's results a clear difference can be seen as the nuclear generation earnings from its operations outperform other areas. As discussed earlier the reason behind this is likely to be having the maximum time possible on the grid as one of the most reliable baseload providers.

In terms of its other operations EDF has seen its non-nuclear division go from running a loss in 2009 to making a profit of approximately £150m. Again given the scale of investments in generation facilities investors would expect to be making positive margins.

The retail side of EDF's business is probably the most consistent out of all company results. Within this, however, it should be noted that EDF's domestic and non-domestic gas businesses are nowhere near the scale of other companies, so it would not experience the same dramatic cost swings as wholesale gas prices fluctuate.

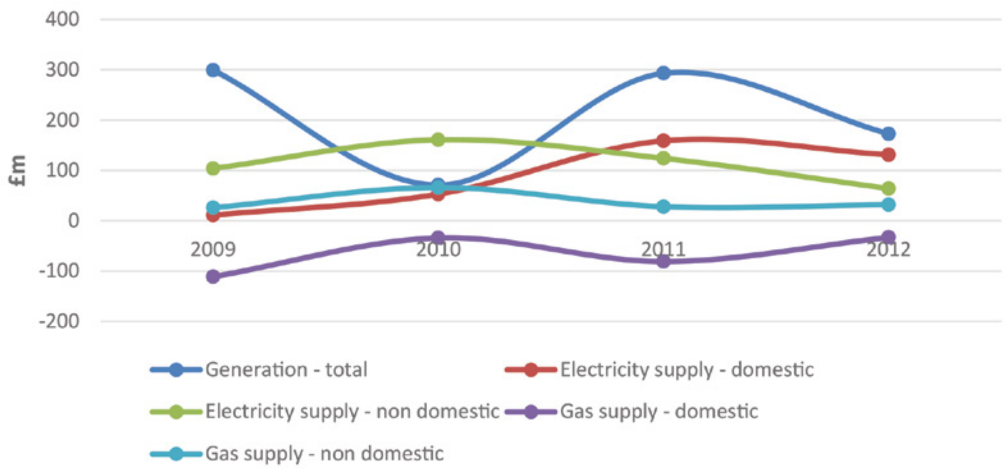
EBIT comparison – EDF



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

E.ON, RWE Npower and SSE all show a similar pattern when looking at the EBIT from their generating divisions. Earnings fall in 2010, rising again in 2011 before falling slightly once more in 2012. The only differentiating factor is scale, suggesting that all three are experiencing similar forces in the market. Whilst data on the direct fuel costs incurred by these companies is incomplete, the higher exposure of these companies to gas-fired generation suggests that input costs and forward hedging are a likely source of some of these cost pressures.

EBIT comparison – E.ON



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Unlike Centrica, E.ON's domestic gas division continues to have a negative EBIT, but what is noticeable is again the peaks and troughs follow the same annual pattern suggesting that while market pressures are consistent, the scale of the exposure to market conditions is also important. In terms of its performance in domestic electricity supply the company performed better than most. Maintaining a reasonable and positive EBIT across the four year period were other companies where having to deal with falling margins or having to pull operations out of loss making areas.

Interestingly the results show that as EBIT increases (fuel/gas input pressures falling) for generation activities, downward pressure is exerted on gas supply margins, which is what would be expected from a functioning market. The extent of the change appears to be bigger on the generation side, and shallower for supply operations. However, this is what you would expect from a company trying to cross subsidise parts of its operations to provide stable consumer prices.

When first looking at RWE Npower's results below they appear to shift quite dramatically, however, the scale of the shifts from positive to negative are smaller than other companies. For example the results vary between positive earnings of approximately £170m to a loss of approximately £150m. This £320m range is much smaller than that of other energy companies; EDF approximatly £1,200m, Centrica £700m; and SSE £500m.

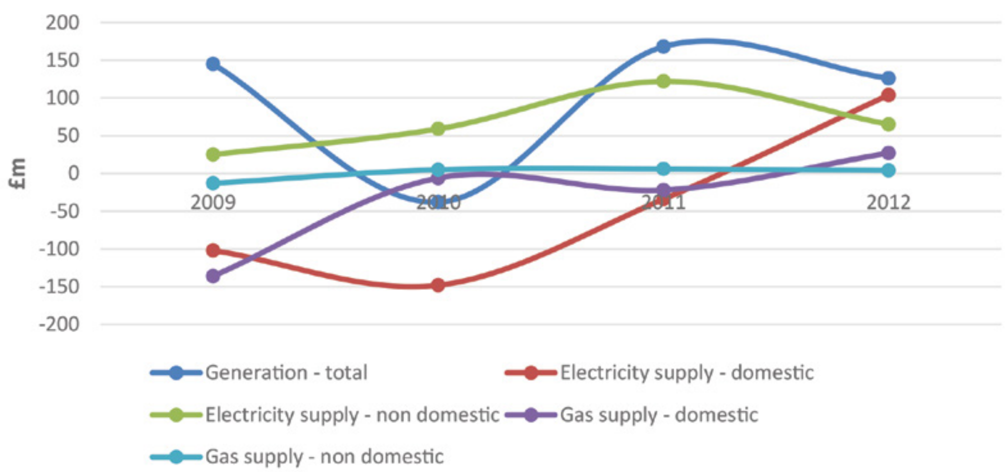
Again the gas supply business for RWE Npower is not significant in scale compared to some other competitors, however, the company was able to keep earnings flat within its non-domestic division and turn a £136m loss in its domestic gas supply division into a £27m profit by the end of the four year period.

The significant noticeable change is in the domestic electricity supply business which saw losses of approximately £100m in 2009, and £150m in 2010 translated into a £100m profit by 2012.

Part of the rationale behind this was reducing indirect operational costs from approximately £500m in 2009 to £300m in 2012, whilst broadly maintaining other costs[xxxv] and increasing revenues from gas and electricity from £768m in 2009 to £1,993m in 2012.

When looking specifically at their generation as well as the previously mentioned gas link RWE Npower is the only company to have any significant amount of oil based generation. As such, the company is more likely to suffer pressures from price shifts surrounding political uncertainty in oil producing regions and possibly increased transport costs.

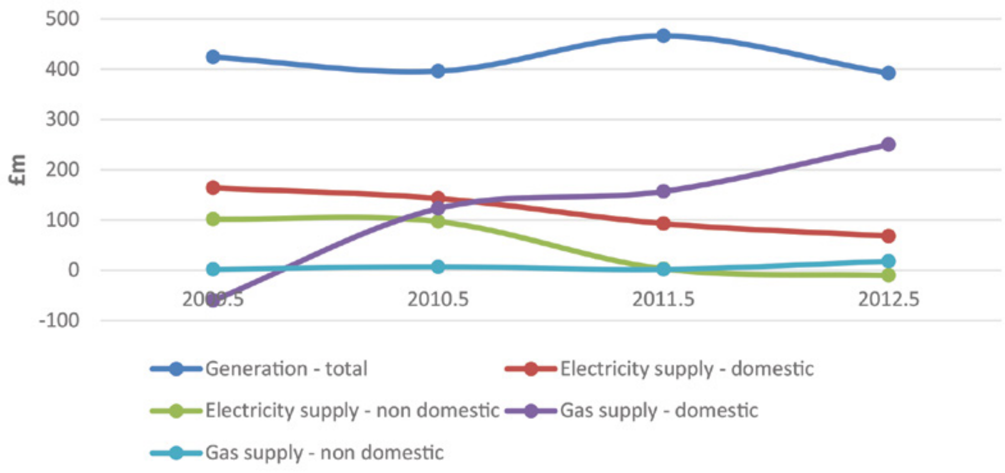
EBIT comparison – RWE Npower



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

SSE has like other companies, seen its earnings from its electricity supply divisions eroded over the four year period, with combined domestic and industrial earnings falling from approximately £260m to approximately £90m. As a non-domestic gas supplier their level of activity and earnings remains small and relatively stable. Their domestic gas supplier activities, however, have seen earnings rise from a £60m loss to a £250m profit. As this has occurred direct fuel costs have varied between £998m (2011/12) to £1,280m (2009/10), opex costs increased from approximately £130m in 2009/10 to around £200m (2010/11) before stabilising, and other direct costs remained relatively stable at around £500m. Revenue over from the sale of gas this time increased from approximately £1,900m to around £2,200m in 2012/13. Again this suggests that growth is coming from revenue generation.

EBIT comparison – SSE

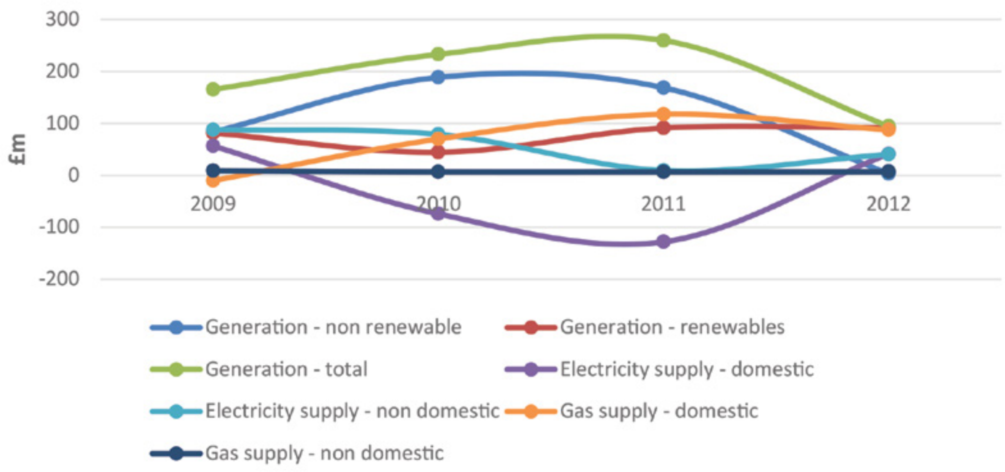


Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Finally, Scottish Power is another firm that has a relatively small differential between its supply businesses. Most notably Scottish Power sees a fall in its earnings for its non-renewable generating operations. Interestingly at the same point its domestic electricity supply business improves significantly, having made negative profits for the previous 2 years.

The fall in earnings within the generating arm is primarily driven by revenues from the sale of gas and electricity falling from £1,677m to £1,183m, whereas revenues in the electricity supply business increased from £1,489m to £1,617m.

EBIT comparison – Scottish Power



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

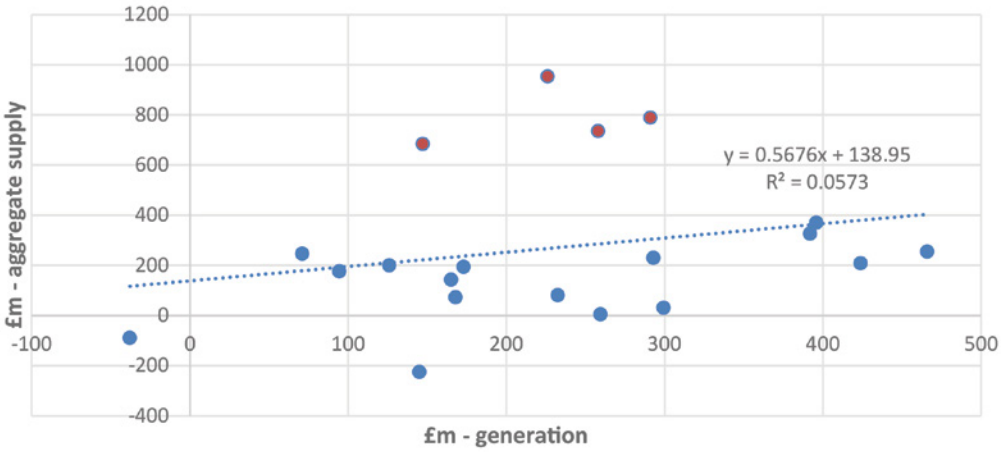
Again, this report will correlate generation EBITs against those of the supply business, both in aggregate and separately for electricity in an attempt to draw some conclusions about the industry. It is important to note that due to the sample size the results can provide inferences but further data would be required to make conclusive statements.

Given the scale of the difference that was shown by E.ON's nuclear generation EBIT in its results, it has been excluded from the analysis, however, comment will be made at each point as to what does occur if it is included.

First, looking at 'total generation EBIT' vs 'aggregate supply EBIT' it is found that as generation EBITs rise so too do supply EBITs. Again the R^2 value is low suggesting some caution should be taken when interpreting the results but it suggests that rises in earnings filter through the whole system, so if generators charge more to suppliers, suppliers in turn charge more to consumers.

For every extra £1 a generator earns in profit, a supplier is also able to make an extra £0.57p. This means that in total consumers would experience a rise of £1.57.

Generation EBIT vs Aggregate supply EBIT



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Whilst the above results exclude nuclear, if nuclear were to be included the R^2 value falls further, and the trend is reversed, suggesting that as generation profits increase the supplier's profits fall. That is to say for every extra £1 a generator earns suppliers earnings fall by £0.23p. This means that in total consumers would experience a rise of £1.23.

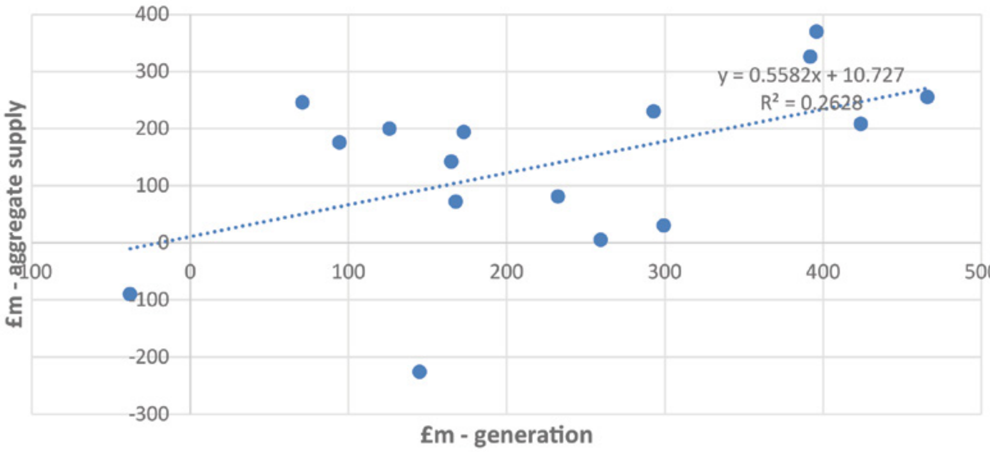
Such a result is consistent with parts of the business cross subsidising others and would demonstrate an advantage of vertical integration.

To explore this trend in more detail the analysis removed perceived outliers above (in red) both with and without the inclusion of nuclear.

With the inclusion of nuclear this adjusted correlation (red outliers removed) continues to have a poor R^2 value (0.0364) and the trend continues to be negative. For every £1 extra generators earn suppliers would also see earnings fall by £0.10. This means that in total consumers would experience a rise of £1.10.

Once nuclear is also excluded (and the red outliers removed), however, the trend is positive and more of the data is explained by the analysis (improved R^2 value). This result shown below shows that for every £1 extra a generator earns suppliers also earn £0.55 extra. This is not, however, significantly different from the initial result.

Adjusted – Generation EBIT vs Aggregate supply EBIT



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links – removed Centrica 2009-2012 points which were consistently above market trend, nuclear also excluded.

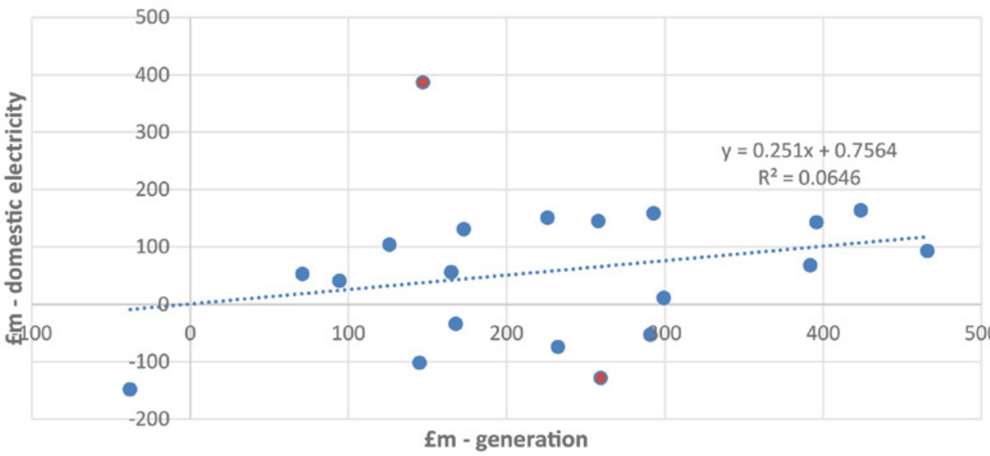
Whilst there is no strong relationship between generators earnings and aggregate supplier's earnings, the balance of the evidence would suggest a positive relationship where supplier's earnings do not suffer as generators earnings increase. That is to say costs are passed through the system with each party benefitting. As such, it is hard to make a case for vertical integration playing much of a role in efficiency within the market.

Does the same, however, hold true for each side of the aggregate business? For example, could the market support a gas or electricity only retailer to compete with the 'big six', or do retail divisions need to be integrated across the market to ensure they can balance earnings volatility?

First this report will look at electricity supplier's vs generators as the connection between the two is less obscure than gas.

As can be seen below, again the result is achieved that as generators profits increase, so too do electricity suppliers. For every £1 electricity generators earnings increase, electricity suppliers earnings also increase £0.25. This means that in total consumers would experience a rise of £1.25.

Generation EBIT vs domestic electricity supply EBIT

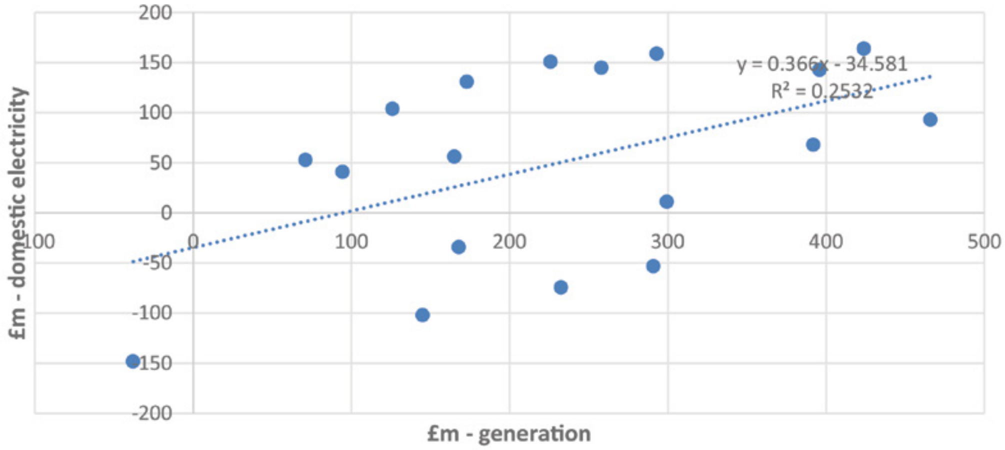


Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

When the nuclear generators results are included the trend is reversed. Although it is worth noting that the extent of this downward trend is less than that of the aggregate market overall. This suggests that there is potentially less willingness, or companies are not able to avoid margins suffering as generators prices rise.

As with previous results, however, caution is again urged given the low R^2 value. This report therefore again takes the approach of removing outliers (in red in the above chart) to see if correlations improve.

Adjusted – Generation EBIT vs domestic electricity supply EBIT



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links – removed Centrica 2009 point which was considered above market trend, removed Scottish Power 2011 point which was considered below market trend, excluding nuclear.

With the removal of two points, the data R^2 improves to over 25% and the trend remains positive (although not as positive as the aggregate result). For every extra £1 generators earnings increase suppliers earnings also increase £0.25.

This shows that electricity suppliers are able to increase earnings as generators increase earnings. This suggests that price rises can and are able to be passed through the system, but with each tier up the chain adding their own margins.

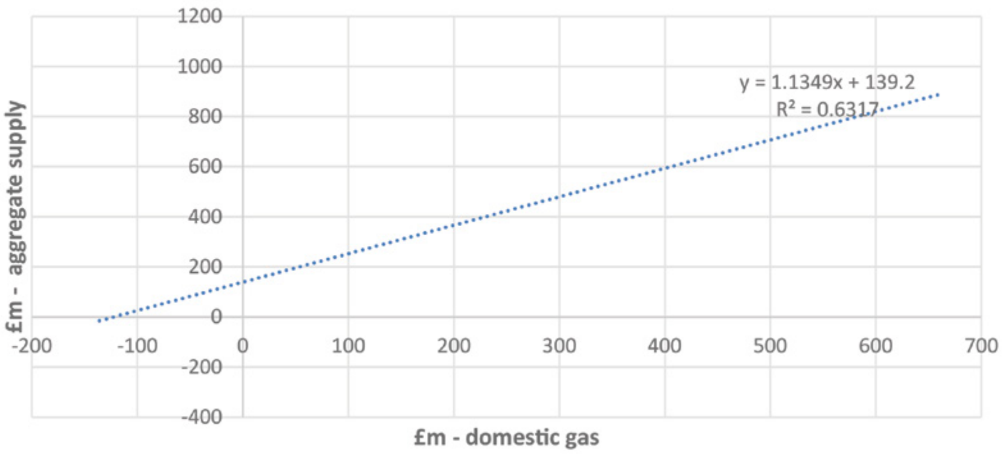
In theory the same analysis could be run for gas suppliers and generators, though, whilst there is a large degree of gas fired generation which could potentially influence gas prices such analysis would assume direct causality.

So whilst there is a link between the gas prices generators and suppliers pay, this is not the same as a generator paying wholesale price adding his margin and then a supply business having to go through that entity to sell to the consumer market. For the gas sector both generator and domestic supplier are in theory competing against each other in the open wholesale market.

Another interesting analysis to run is to compare the domestic supply business to the overall aggregate business. Whilst the results will be correlated as one expects, given that each of the divisions make up part of the total business' earnings, it is interesting to see the scale of the correlation and the difference between the effect of the electricity and gas divisions earnings on overall earnings.

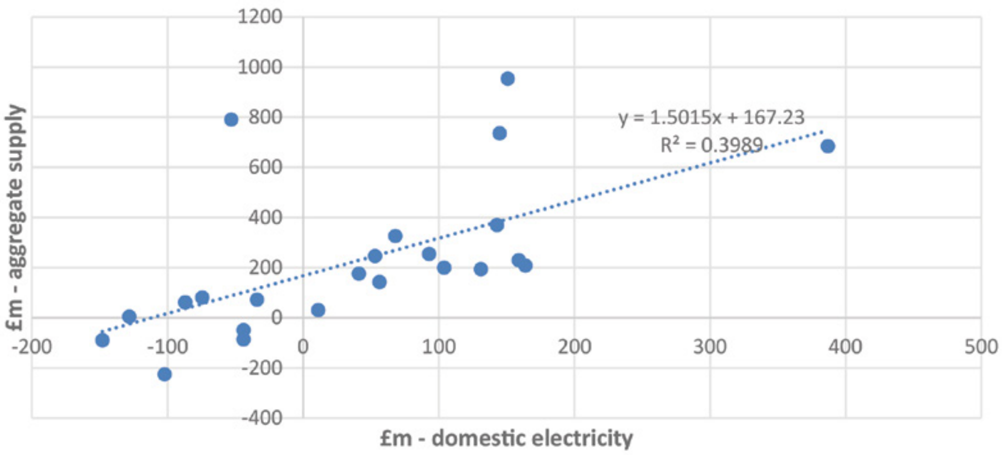
As can be seen from the charts below the domestic gas division's earnings of a company explain far more of the overall earnings data (63%) than that of the domestic electricity divisions earnings (39%).

Domestic gas EBIT vs aggregate EBIT



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Domestic electricity EBIT vs aggregate EBIT



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

This demonstrates the extent to which gas prices and volatility in the gas market is important for a company's overall level of earnings. These earnings results therefore align with previous evidence discussed in this report around fuel costs and short term trading as being two of the key reasons that price pressures occur.

Given the continued debate around earnings and what is reasonable given the investment required the regulator is currently undertaking an investigation into whether a Return on Capital Employed (ROCE) measure should be included within the Consolidated Segmental Statements.

Return on Capital Employed

The ROCE measure is well known by investors, and as such is useful in demonstrating the potential investment benefit. This is important as the majority of investment required in the UK market is at the generation level, will need to be privately financed and must occur within the next ten years.

Whilst there is concern that such a measure could be used as a proxy for determining reasonable profit levels at the generation stage, it is important that industry has an open and informed debate about the actual costs we are locking into the energy system for the next 25 years. The UK cannot continue to build generation based on an 'ad hoc' approach with little sense of an overall strategy for meeting the different types of power needs (base load, peak, offpeak) whilst also trying to balance security of supply.

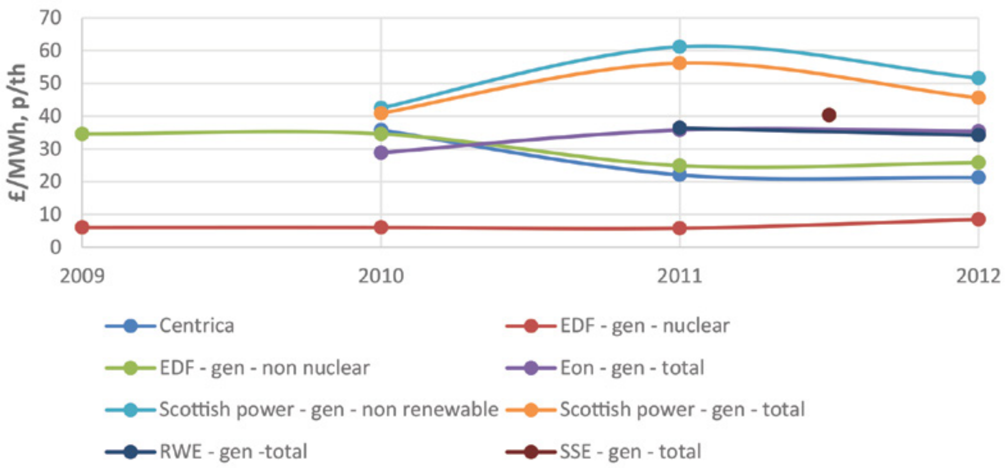
If a strategic approach is not undertaken the market will deliver an inefficient outcome and will see the UK move towards the most expensive energy market in the EU.

Looking beyond earnings

Another measure included within the consolidated segmental reports is that of the weighted average cost of fuel for both gas and electricity across the various generating and supply divisions. This measure includes the cost of direct fuel, and wholesale energy in total and also accounts for losses incurred.

Overall the weighted average cost for generators is lower than that of the supply businesses. Interestingly if you look at the generators' average weighted costs below, they still vary significantly depending on technology and fuel costs, which is to be expected.

Weighted average cost of fuel – generators

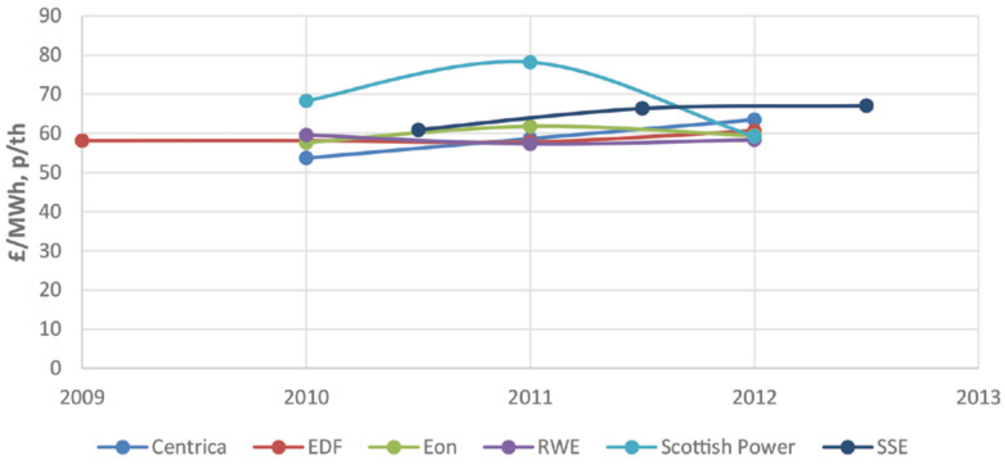


Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

The same is not true for the weighted average costs of gas and electricity for the domestic supply divisions on the companies.

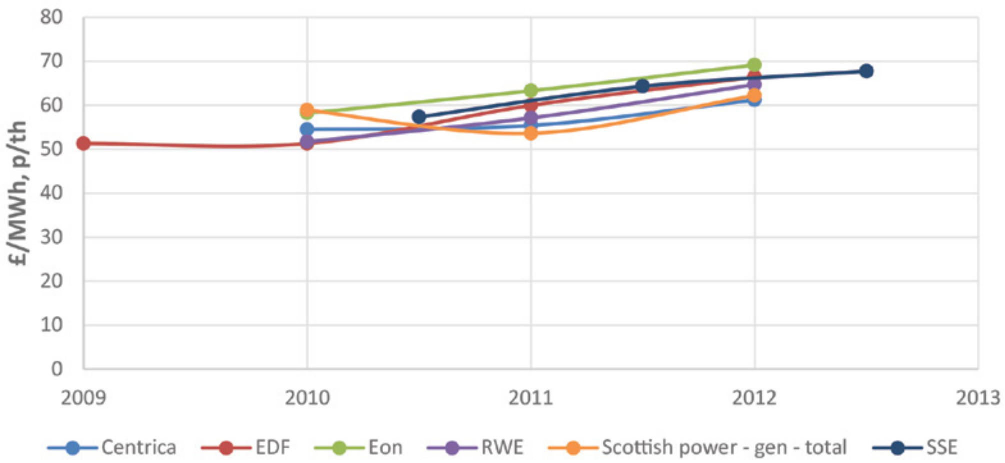
As can be seen from the charts below the weighted average costs for the gas and electricity sectors are similar across all the companies, despite the fact that earlier analysis on purely 'direct fuel costs' showing wide disparities between the companies.

Weighted average cost of electricity – electricity domestic



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Weighted average cost of gas – gas domestic



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

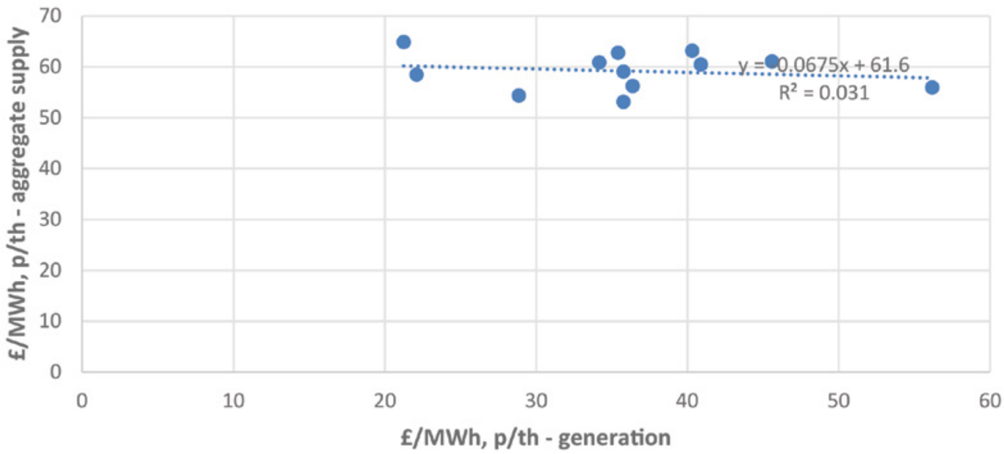
Part of the reason for this is that direct fuel costs are an absolute figure and so vary depending on the size of the customer base, whereas average weighted costs remove this scale effect.

Further analysis of the weighted added costs of gas and electricity across the various supply businesses and generators provides some interesting results.

First, when looking at a correlation between generators' weighted average costs and overall weighted costs of the supply businesses (below), it is surprising that as generators average costs increase the aggregate supply businesses' average costs do not change significantly.

This could suggest two possible scenarios. The first is that the average weighted cost of generators has no bearing on supply businesses average costs, or secondly that the supply businesses are able to hedge prices forward so effectively that they can absorb variations in generators weighted costs with little effect on their own.

Generation weighted average cost vs Aggregate supply weighted average cost

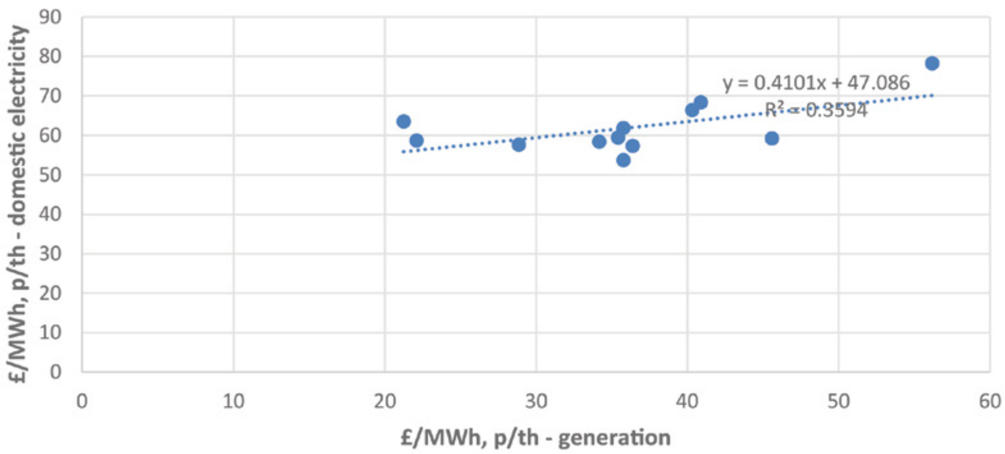


Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

Given the previous evidence that more supply is being traded on the spot market and focused on short term trends it is therefore unlikely that the second is the most probable scenario.

What it may suggest though is that the differential between the generators average weighted costs and those of the supply businesses are sufficient enough that they can maintain a similar level thus not reflecting actual cost conditions.

Generation weighted average cost vs domestic electricity supply weighted average cost



Source: Ofgem and energy companies – Consolidated Segmental Statements – see endnotes for full list of links

This has quite serious implications for competition, as it reveals that there is little differential between the supply businesses average costs, while there is significant differential in the generators average costs, and a sufficient margin in between. Therefore encouraging no efficiency and competition despite each company having different input costs.

It could be argued that there is effectively a 'buffer' created between generators and suppliers which allows for costs to be aligned, and pricing strategies to be similar. Whilst this may not be intentional and reflect how similar suppliers have to be on price to maintain their consumer base it does not encourage an efficient cost based energy system.

INTERNATIONAL PRICE COMPARISONS AND THE EFFECT OF ENERGY TAXATION

Key findings

International price comparison

- The UK is more or less exactly matching the IEA median for electricity prices, and has one of the lowest incidences of taxation on energy.
- Given the IEA data electricity in the UK may not be as overpriced as is feared. It also, however, potentially indicates that the UK is not proactive enough in reallocating resources from markets which are inefficiently accounting for the effects of climate change, pollution and volatile prices towards a more stable and sustainable long term solution.

The incidence of taxation

- Amongst the countries explored in this report for every 1p increase per kWh in electricity taxes that occurs, there is also an increase of 0.53p in the electricity price. It should be noted, however, that this performance is significantly helped by Denmark, The Netherlands and Germany.
- If the UK government were to increase the incidence of tax by 1p per kWh electricity prices would also rise by 7.4p per kWh. This is significantly more than any other country in the data sample below with the next country (Ireland) performing at an additional 4.3p per kWh rise for every extra 1p per kWh of taxation. The reason behind the UK's poor performance in this area is likely to be that companies are 'over insulating' themselves against tax and policy changes. Again highlighting that long term policy certainty is key.
- The evidence suggests that as the level of tax increases, so more investment takes place, the level and pace of research and development speeds up, and there is a lowering of long term costs reducing the effect on electricity bills above and beyond the incidence of the tax.

The need for strategic planning

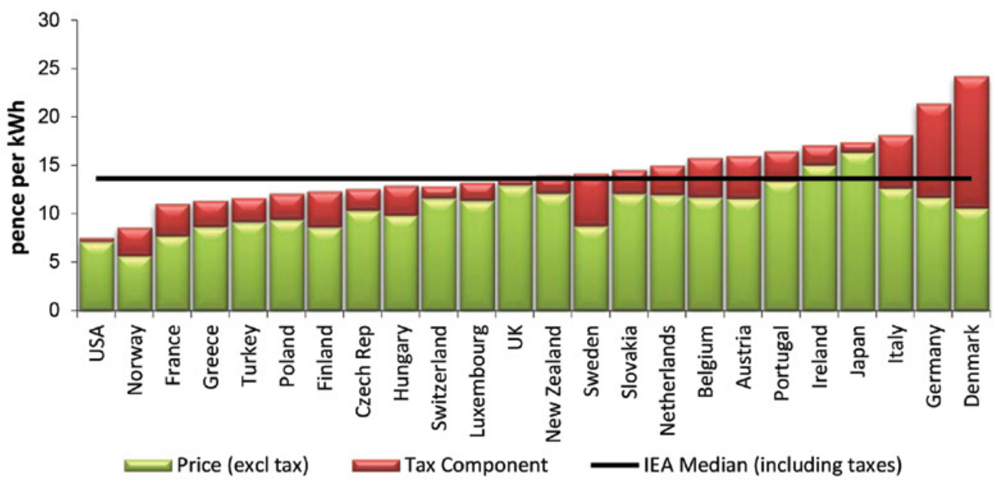
- Electricity prices in the UK on the 'open' market (not including taxation) are one of the highest amongst the countries analysed. This is likely to be due to a lack of strategic planning. This is because no one company considers investment in the UK as a whole at the macroeconomic level. As such, any investment outcome from the sector will favour individual companies investment strategies and not one that is efficient for the UK as a whole.

Analysis

Another important aspect to understand is that energy markets are no longer limited to local conditions. The price of commodities such as gas and coal are now influenced significantly by international demand. Domestic policies therefore have to account for potential price volatility that is beyond the control of their national government, unless a country has significant national resources.

The International Energy Agency (IEA) figures[xxxvi] for the price of domestic electricity both with and without the tax component (generally levied by governments as part of energy policy), shows that the UK is more or less exactly matching the IEA median for electricity prices. It should also be noted that the UK has one of the lowest incidences of taxation on energy.

Average IEA Domestic Electricity Prices in 2012



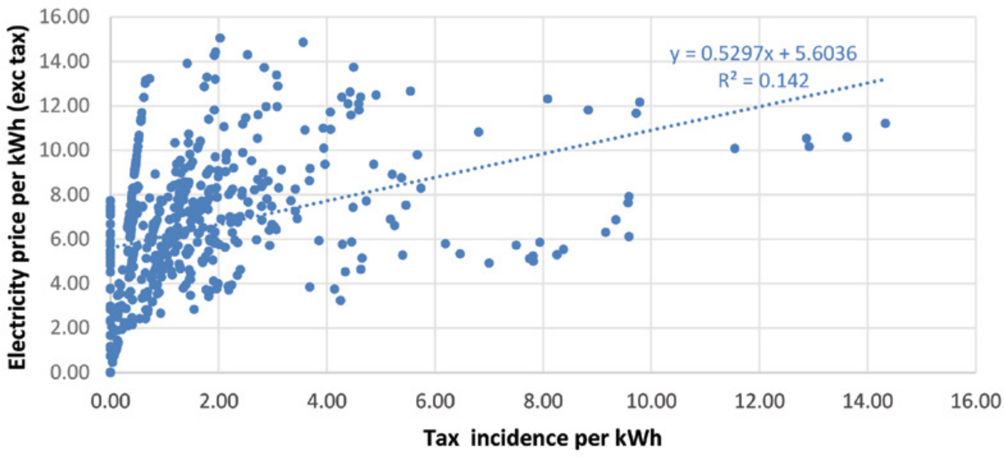
Source: DECC, GOV.uk, IEA

This suggests that electricity may not be as overpriced as is feared. It also potentially indicates that the UK is not proactive enough in reallocating resources from markets which are inefficiently accounting for the effects of climate change, pollution and volatile prices, towards more locally sourced, stable, low carbon based outcome.

To analyse this in more detail this report will plot the international data for the price of domestic electricity against the incidence of taxation placed on domestic energy supplies. As can be seen from the plot below, across all nations the incidence of tax increases as the price of electricity increases, as one would expect.

Interestingly, amongst all the countries for every 1p increase per kWh in electricity taxes that occurs there is also an increase of 0.53p in the electricity price. It should be noted, however, that this performance is significantly helped by Denmark, The Netherlands and Germany. If raising taxes these countries see an additional increase in energy prices below that of the incidence of the tax, whereas all other countries see rises in energy prices above and beyond the rise in the tax rate.

Price of electricity excluding taxes, versus the tax component of prices in IEA countries since 1979 – average linear results



Source: DECC, GOV.uk, IEA

This suggests that if governments pursue policies that lead to a higher incidence of tax there will also be an additional rise that occurs in the price of electricity. This finding is consistent with many governments acceptance that in the near term taxes are levied to finance renewable investment in less economically developed technologies (given the negative effects of burning fossil fuels) which initially have a higher (subsidised) electricity price.

Over time, as the funding or long term purchase cost of these technologies should fall, so too should the additional cost incurred on energy bills as a result of the investment.

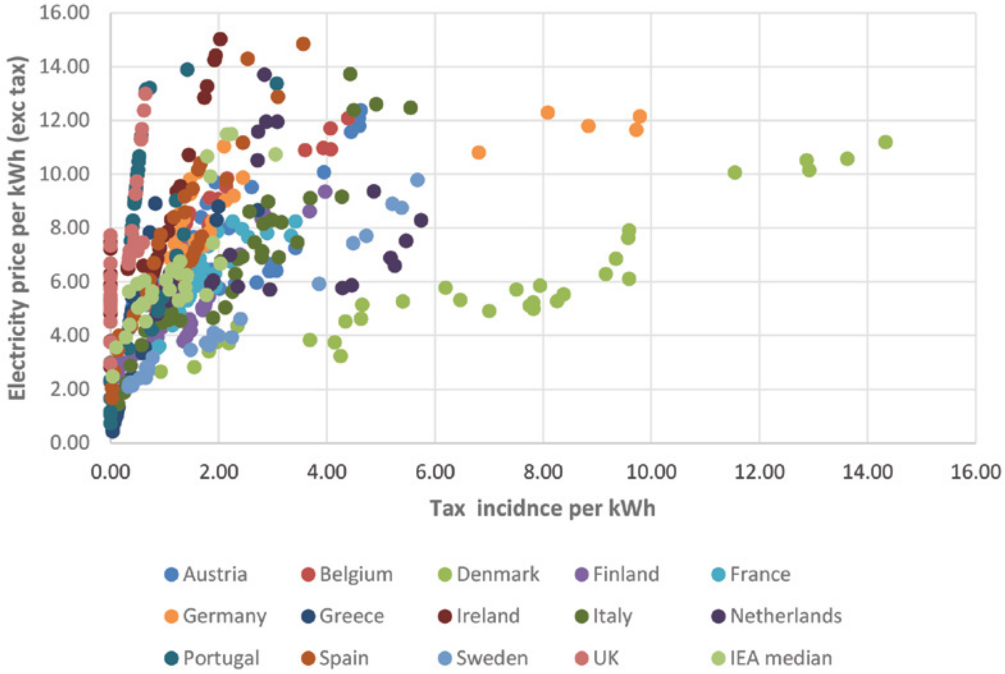
The question therefore has to be asked if there is any evidence of such changes occurring across international datasets given the difference between countries tax rates, and energy pricing.

If we plot the same data again but identify each country with an individual colour and the above assumption holds true, what should be seen is that as the incidence of tax increases the extent of market growth begins to slow.

That is to say as the level of tax increases, so more investment takes place, the level and pace of research and development speeds up, and there is a lowering long term costs reducing the effect on electricity bills above and beyond the incidence of the tax.

As can be seen from the data below as a countrys level of energy tax increases it does appear that the spread of their data flattens. Thus suggesting that the theory above is correct as increased investment takes place the additional effect on electricity bills declines.

Price of electricity excluding taxes, versus the tax component of prices in IEA countries since 1979 – plot



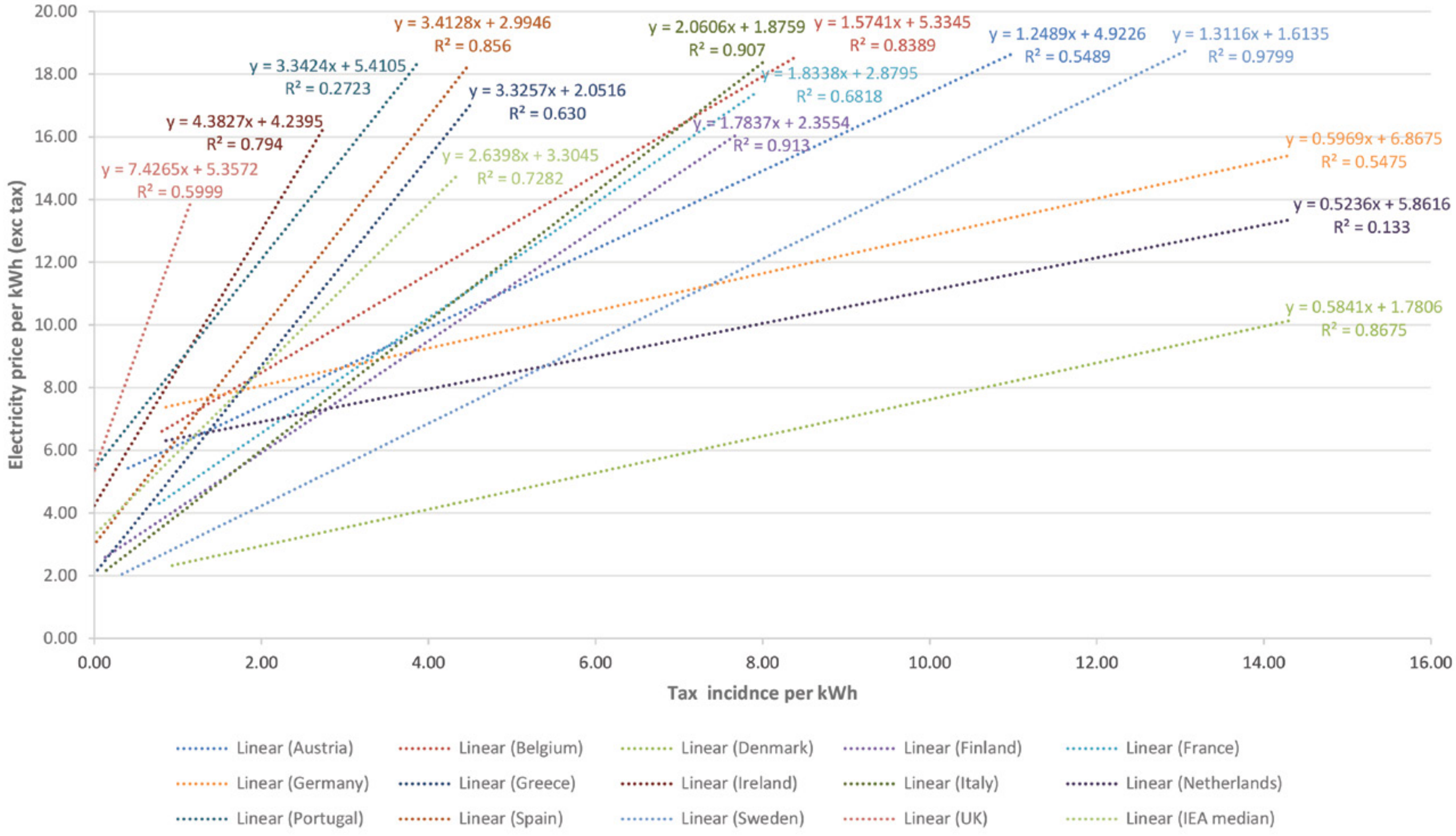
Source: DECC, GOV.uk, IEA

It should, however, be noted that the above does not suggest that bills will fall. What it does hold the potential to do in the future though is to reduce long term increases to a level that is below the rate of increase of commodities such as gas and coal, and even possibly below that of ordinary inflationary pressures.

To explore where each country lies on this international spectrum, and to assess the impact of taxes and energy price rises this report has plotted each countries trend result.

As can be seen from the data below the UK is the worst performing country in terms of the effect tax has on subsequent energy price increases. If the UK government were to increase the incidence of tax by 1p per kWh electricity prices would also rise by 7.4p per kWh. This is significantly more than any other country in the data sample below with the next country (Ireland) performing at an additional 4.3p per kWh rise for every extra 1p per kWh of taxation.

Price of electricity excluding taxes, versus the tax component of prices in IEA countries since 1979 – linear results



Source: DECC, GOV.uk, IEA

Looking at countries such as Denmark (flattest green linear result) and Germany (flattest orange linear result) it is found that they have a significant incidence of taxation and have the highest prices in the IEA data. This investment, however, has also meant that for every penny per kWh they add in taxation prices only rise by between 0.52p and 0.6p per kWh.

The following questions therefore have to be asked of the UK:

- Why is the UK so out of line with Denmark and Germany, especially considering it has significant natural gas resources? Why has the UK not been able to capitalise on such an advantage?
- Why is the UK energy price component (excluding tax) so high (one of the highest in Europe), with only little or low taxes reducing the UK back to the median?
- Why does the incidence of tax in the UK result in such steep energy price rises within the 'open' energy market?

Each of the above can be attributed to the UK's historic lack of future planning in its infrastructure. The UK's gas resources could have been better managed as an asset to ensure combined investment and longer term affordability.

Energy prices in the UK on the 'open' market are one of the highest amongst the countries analysed. This is likely to be due to a lack of strategic planning as no one company will consider investment in the UK as a whole at the macroeconomic level. As such, any investment outcome from the sector will favour individual companies' investment strategies and not one that is efficient for the UK as a whole.

It is more difficult to explain the effect of the incidence of tax on energy prices. Given the analysis on the structure of companies and their earnings, a reason for this could be that the variability of policy in the UK leaves companies with little choice other than to 'over insulate' themselves against tax and policy changes. Again investment and policy certainty would be key to reducing this tax insulation premium.

Environmental Industries Commission: the role of renewables: key points should be:

- Under the Climate Change Act, the UK must reduce emissions by 80% from 1990 levels by 2050
- In addition, 15% of total energy consumption (not just electricity) must be from renewable sources by 2020 under the EU Renewables Directive.
- Renewables, along with other sources of low carbon energy such as nuclear and potentially fossil fuels with CCS therefore need to become an increasing part of UK energy mix.
- Most renewables are currently more expensive than unabated gas and coal plants (though cost profile is different as renewables by definition tend to have low or zero fuel costs). Most governments committed to tackling climate change, including the UK's therefore offer subsidies to bring forward investment in renewables. The need for these subsidies should diminish as technologies move along the development curve and costs fall. Indeed, the Committee on Climate Change has calculated that a UK generation plan weighted towards renewables during the 2020s would be a low cost no-regrets strategy under all scenarios except those where gas prices are very low during the 2020s.

- There are also social judgements to be made, eg onshore wind is much cheaper than offshore wind but is unpopular with some local communities. Govt must trade off the impact on energy bills vs local amenity issues.
- EIC/ACE broadly support the EMR plan to use CfDs to support renewable investments as amended by the recommendations in this report. IN addition, the Climate Change Committee's 2030 decarbonisation target of 50g/Kwh should be made statutory to give renewables investors more confidence.

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POLICY – COMPETITION, EMR, CFD, CAPACITY, PRICE AND CONSUMERS

Key findings

This report suggests a way forward which attempts to balance the needs identified within the EMR framework, including:

- The need for a policy which will secure a reasonable baseload and invest in solutions which can 'store' energy. This helps to reduce the pressures caused by relatively expensive early technologies, and focuses the market on getting technologies to a cost level where they can compete openly/freely.
- The need to address capacity issues without radically reforming policy again and therefore reduce delay and uncertainty which is a major problem for investors.
- Ways to improve and implement effective competition in the generation market by creating a secure base that lowers costs and allows technologies to compete where appropriate. Additionally, redefining the role of efficient markets and how they interact between the various policies.
- The need for increased transparency within the market, allowing the retail side to access and buy from a number of sources. This should allow suppliers to hedge according to different strategies, creating different market positions and niches and moving away from the current situation where the majority, if not all players, shift prices at the same time.

The addition of Generation Investment Vehicles (GIVs)

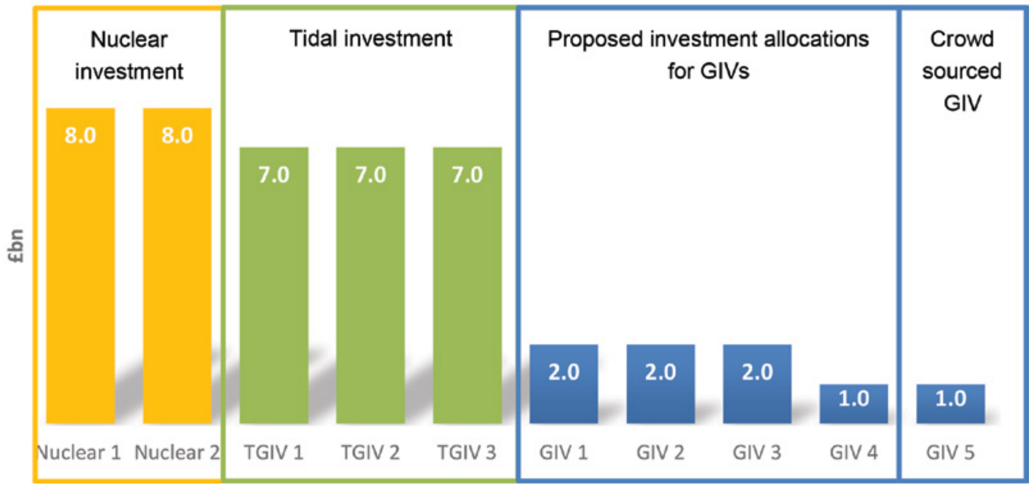
This paper proposes that the government initiate a number of Generation Investment Vehicles (GIVs). These vehicles would encourage investors to come forward and invest in generation given a pre-defined long term return that is set for a long term period in excess of 30 years, and also allow a percentage of generation to be subject to competition.

The key to efficient future investment and competition is to ensure that the projects within these GIVs are operational as the second and third wave of CfD mechanisms open up to competition. Thus the government has its secured supply in place and various technologies are in a position to compete.

The GIVs would work alongside and complement the current certainty the government is trying to provide for a nuclear programme.

This report proposes that five Generation Investment Vehicles (GIVs) with a combined value of £8bn are created to ensure that in the short to medium term project finance is secured. In order to secure medium to long term investment to 'lock' long term cleaner energy into the UK's generation system, this report also proposes that three Tidal GIVs (TGIVs) with a combined value of £21bn be created.

Generation Investment Vehicles



These vehicles could be used to finance for any type and combination of projects, for example:

- Six CCGT plants at an approximate cost of £3bn (providing approx. 7,500MW)
- Eight waste to energy plants at an approximate cost of £4bn (providing approx. 575MW)
- Provide a £21bn fund towards the building of tidal/lagoon assets (providing approx. 2,000MW to 3,000MW)
- Provide a £1bn fund for community projects, where money would be raised via crowd sourced funding.

The three £7bn TGIVs for example could finance:

- The roll out of either smaller tidal schemes or more economically the construction of a Severn Barrage (with a target price of 16% below the current £25bn estimated cost) to lock in lower cost long term electricity not only for this generation but also the next few.

Improving transparency, competition and encouraging trade

Introducing a secure supply has to be accompanied by increased transparency and ultimately improved competition within the part of the market that competes for variable electricity demand.

The GIVs would be owned and operated by private investors or a group of investors, competing against existing generation owners, which would be prevented from investing.

The real question is how to provide certainty, securing a base of power whilst also encouraging trading. That is why this paper suggests an exchange mechanism and priority system to drive investment as the market opens up to competition.

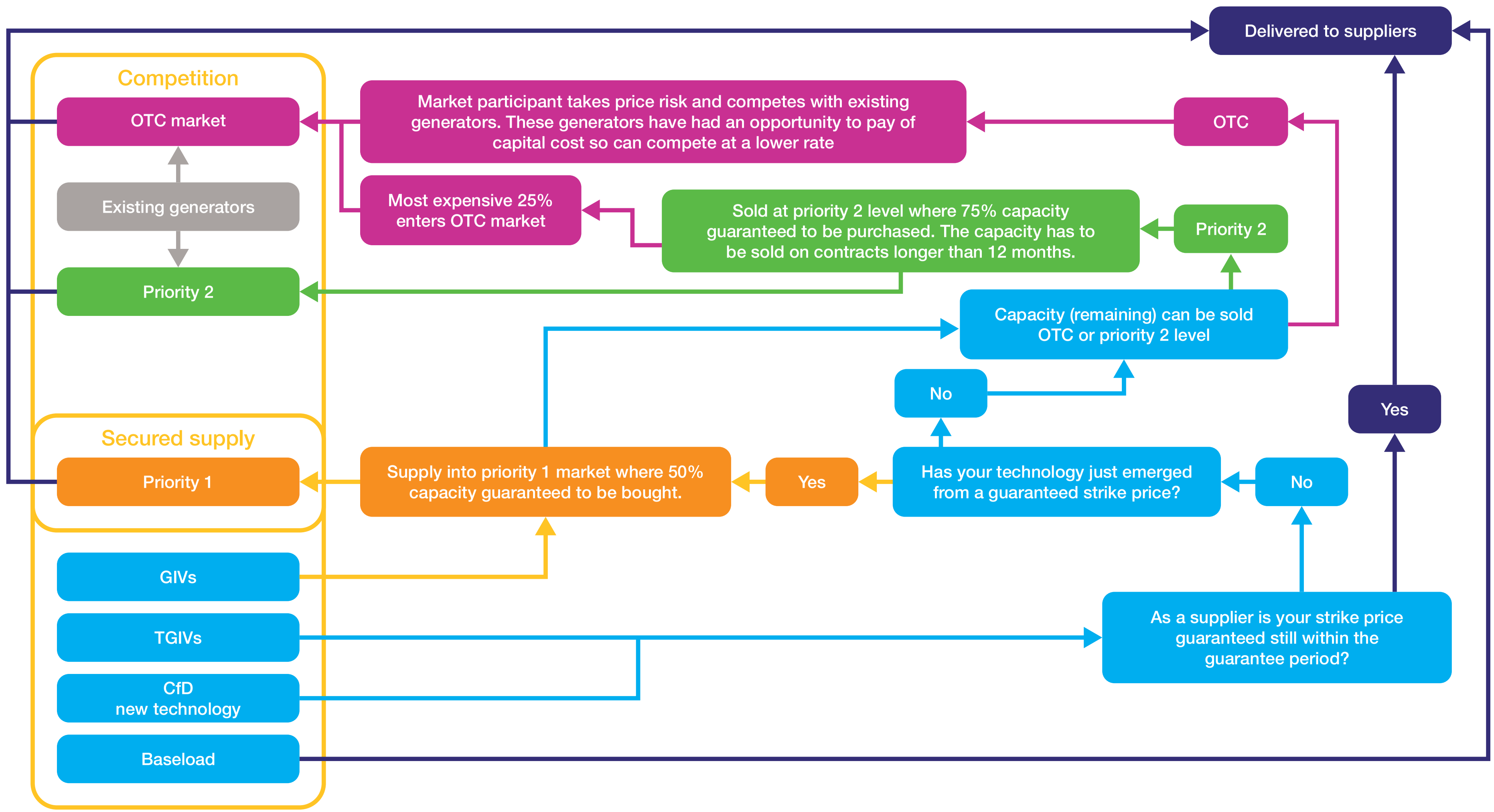
This paper proposes a Priority Auction Mechanism (PAM) where:

- A new structure of two open market traded exchanges where government and energy providers guarantee and have to purchase 50% of the capacity put forward in the first round, 75% in the second round, and all remaining capacity then having to compete OTC.

The mechanism works as follows:

- If a generator has a guaranteed strike price as a baseload provider, or is in the early technology stages of CfD their cost and supply is shared by the retail market. Essentially as the current EMR framework puts in place.
- GIV generators would be supported via a guarantee to buy but would be encouraged to build a competitive and transparent strike price within the energy sector.
- GIVs would trade into a priority one market where 50% of all supply is purchased and passed through to suppliers, thus guaranteeing capacity and providing investors with some certainty.
- Once this has taken place these same GIVs and CfD generators have the option to enter the priority 2 market or go straight to complete OTC.
- The priority two market has the benefit of offering a guaranteed purchase of 75% of capacity entered into it, however, energy must be sold on at least 12 months' supply deals. These would also be in competition with a number of existing generators who could apply for priority 2 trading licences, with the supply of such licences controlled to encourage a competitive pricing mix. Again this provides GIVs and CfD providers with certainty as they have a guaranteed potential to sell their capacity.
- Following this stage all other capacity at this point (including those GIVs that choose to enter the OTC market as opposed to the priority two market) and the most expensive 25% of priority two market capacity is sold OTC at various contract lengths.
- This establishment of two base markets will over time help establish a clear and transparent reference price.
- The benefit of defining such a trading system is that it builds on top of the generators capacity that is locked in through the baseload, and allows the flexible generators within the GIVs to enter markets where there is a significant chance of selling capacity. Only if a GIV were to price at completely unrealistic levels would it not sell any capacity until it hit the OTC market.
- This therefore shifts the focus of spot trading back towards being short term again, whilst locking in lower prices within a competitive market and encouraging transparent longer term trading.
- This is the missing part of EMR, the ability to build significant capacity, lock in lower prices and not just to simply assume competition is working in trading but to actively encourage it.

Creating competition through policy – The Priority Auction Mechanism (PAM) – diagram



Analysis

As is highlighted in the NIP, 8% of generating capacity has closed under the Large Combustion Plant Directive since 2011, and a further 10%-12% of current power generating capacity is due to close over the coming decade. This is against a backdrop of peak electricity demand being projected to move from 63GW in 2013 to between 68GW and 73GW in 2030.

Alongside the above capacity challenge is the requirement for the UK under the 2008 Climate Change Act to reduce the UK's greenhouse gas emissions by at least 80% (from the 1990 baseline) by 2050.

This demonstrates the scale of the challenge the UK has in front of it, a challenge that also occurs at a time where many countries are investing in their energy networks and competition for resources and funds is high. As such the UK needs to provide a clear signal that it is going to invest into capacity and lock certainty into its energy system.

A number of policies have been put in place by government to address this challenge going forward which include:

The Green Investment Bank (GIB)

The GIB was established by government to address some of the challenges projects face in accessing finance following the financial crisis, sharing technology and lessons learnt and to bolster investment in low carbon forms of generation.

Importantly, the GIB can facilitate investment that would otherwise have not taken place. Whilst an investor would typically reject such an investment, the GIB is looking at the investment with a view to removing risk, improving future market conditions, spurring growth and innovation and so could therefore be considered as providing value for money over the longer term to government and society.

Below are some of the key facts and figures for the GIB:

- Its mission will be to provide financial solutions to accelerate private sector investment in the green economy.
- Initial capitalisation – £3bn, with the level of funding available now at £3.8bn
- The GIB is one of the government's key policies to help it meet its environmental objectives and promote economic growth.
- The GIB's priority sectors are offshore wind, energy efficiency and waste.

Electricity Market Reform (EMR)

The second significant change to energy market policy is the implementation of the government Electricity Market Reform (EMR) set of policies. These include:

- New long-term, legally binding Contracts for Difference (CfDs), providing generators with protection from fluctuations in the wholesale prices, increasing certainty and reducing risk.
- A Capacity Mechanism to help provide certainty to suppliers who are prepared to offer in the event of shortages.

- A reinforced carbon price by introducing a floor price.
- The Emissions Performance Standard, a regulatory measure that provides a back-stop to limit emissions from unabated power stations.

Whilst EMR has finally started to deliver some investment with a number of projects having signed up to the mechanisms there remains concern as to if it will drive significant investment in mainstream capacity.

There have been a number of conflicting needs in the energy market over the past decade. Significant weight has been placed behind the role of competition, and the need for low carbon generation whilst energy systems have been allowed to deteriorate to the point where the scale of system investment is such that doing nothing is no longer an option.

This chapter of the report starts by exploring these elements building on the earlier analysis which shows that competition in the retail market has not been as effective as initially hoped.

The role of auctions and competition in electricity generation

Starting with competition, auctions for energy are generally assumed to be one of the more efficient ways of encouraging competition. By allowing the market to determine the price of supply and align it with what companies and consumers are willing to pay the market should result in an efficient outcome.

Under such auctions, cheaper forms of energy are used first, with more expensive energy providers left to ‘fight it out’ on the margins of the open spot markets.

In reality, however, such an open mechanism will struggle to exist within the energy sector for the following reasons:

First, baseload energy is required constantly to meet demand, and is at such a scale that the majority of generators will never have to compete to sell. Generators therefore have a ‘soft’ monopoly knowing that there will be a buyer at the price they demand most of the time.

Second, for major investment such as nuclear, where the government is not willing to directly invest and take the demand risk, private investors will require a long term power purchase agreement. Such agreements undermine the concept of a totally open market where all individuals are able to trade based on their cost, aligning with demand price signals where necessary.

Third, there are considered to be significant externalities in the energy sector. The most obvious of these is that of climate change and pollution. Government must therefore intervene to counter such effects which, by definition, are not accounted for within the price of energy. This does, however, raise the issue of how a pricing mechanism can be efficient when action is required to ‘judge’ where actual prices should be.

Finally, there is the issue of investment and the risk of undersupply. Consumers and voters would react very strongly to brownouts or blackouts, while it is in the energy sector’s interest to leave investment decisions until the last possible opportunity. Governments and policy makers will always therefore have to step in to ensure that the system does not fail ‘on their watch’. While last minute investment may solve the problem of generation capacity it does so in an unplanned, inefficient and costly manner.

This links our first area of competition to EMR and the price of CfD and baseload capacity. An example of the complex nature of this relationship can be found in recent research by Policy Exchange[xxxvii] where they noted that:

- "The government recently offered the first contract for new nuclear reactors at a strike price slightly below that offered to onshore wind in the next five years, but guaranteed it for more than twice as long, and supplemented it with other government guarantees, meaning that by the time Hinkley C comes online it is almost certain to be more expensive per MWh generated than onshore wind (although direct comparisons are not straightforward)"

Their report advocates an increased role for auctions and competition within the CfD mechanism, and argues that auctions should move away from being technology specific to a full open mechanism as soon as possible. This would help to drive down prices, encourage lower operating and technology costs and improve efficiency.

The CfD mechanism its funding and its link to competition

The idea behind the Contracts for Difference (CfD) mechanism is that it sets an administratively determined strike price for a period, which should be sufficient to encourage investment in those areas of the energy sector. Under this mechanism the price would be topped up if below the agreed price, but would also see suppliers paying money back if market prices exceeded this value.

Strike prices

CfD Strike Prices (£/MWh, 2012 prices)

Technology	2014/15	2015/16	2016/17	2017/18	2018/19
Advanced Conversion Technologies (with or without CHP)	155	155	150	140	140
Anaerobic Digestion (with or without CHP) (>5MW)	150	150	150	140	140
Biomass Conversion	105	105	105	105	105
Dedicated Biomass (with CHP)	125	125	125	125	125
Energy from Waste (with CHP)	80	80	80	80	80
Geothermal (with or without CHP)	145	145	145	140	140
Hydro (>5 MW and <50MW)	100	100	100	100	100
Landfill Gas	55	55	55	55	55
Sewage Gas	75	75	75	75	75
Offshore Wind	155	155	155	140	140
Onshore Wind (>5 MW)	95	95	95	90	90
Solar Photo-Voltaic (>5MW)	120	120	120	110	100
Tidal Stream	305	305	305	305	305
Wave	305	305	305	305	305
Scottish Islands – onshore wind (>5MW)	-	-	-	115	115

Source: DECC EMR

The above prices are set within a Levy Control Framework (LCF) which allows government to control public expenditure, thereby not placing an excessive burden on consumer bills.

The LCF sets an annual limit on overall costs of the Department for Energy and Climate Change's (DECC) policies and includes the Renewables Obligation (RO), small scale Feed In Tariffs (ss-FITs), Investment Contracts for Final Investment Decision Enabling for Renewables[xxxviii] (FIDeR) and CfD.

As is made clear in the EMR Delivery Plan the LCF will in the future also include the capacity market mechanism, with expenditure not due to start until 2018.[xxxix]

The government expects that following National Grid's modelling based on the set strike prices, it should spend less that the LCF cap. The spending profile set out within the EMR Delivery Plan is shown below.

LCF Committed Spend and Projected Funds

£m 2011/12 prices	2015/16	2016/17	2017/18	2018/19
RO/CfD/ss-FITs LCF cap	4,300	4,900	5,600	6,450
Estimated ss-FITs expenditure (committed)	760	760	760	760
Estimated RO expenditure (committed)	2,900	2,790	2,790	2,790
Total estimated committed expenditure	3,660	3,550	3,550	3,550
Total remaining for new entrants up to LCF cap (all schemes)	**640**	**1,350**	**2,050**	**2,900**
ss-FITs projected new build spend	40	130	200	260
Projected available for new build large-scale generation up to LCF cap (RO, CfDs and FIDeR)	**600**	**1,220**	**1,850**	**2,640**
Of which FIDeR affordability cap	260	450	720	1,010
Projected available for new build large-scale generation up to LCF cap (excluding FIDeR)	**340**	**770**	**1,130**	**1,630**

Source: DECC EMR

As can be seen from the above the committed spending accounts for £3.6bn of the LCF expenditure in 2015/16 with approximately 15% allocated to new entrants. The new entrants' money then increases to account for 45% of projected expenditure by 2018/19.

Within this DECC has allowed itself 20% flexibility in a given year assuming that they maintain the overall expenditure profile.

Under the CfD scheme if the number of projects get close to or exceeds the allocated/ expected annual expenditure the government will start to limit the projects that are able to secure the outlined price and eventually would operate a 'sealed bid' process where the lowest cost suppliers were favoured. In theory this should disincentivise the market from oversupplying in any particular technology.

In terms of CfD length, the contracts are currently expected to be for 15 years, with some early Carbon Capture and Storage (CCS) projects expected to renegotiate after the first decade of operation.

The first projects to be undertaken via the CfD mechanism include[xl]:

- Beatrice offshore wind, Outer Moray Firth
- Burbo Bank offshore wind, Liverpool Bay
- Drax second biomass conversion unit, Selby

- DudgE.ON offshore wind, north of Cromer
- Hornsea offshore wind, off the East Yorkshire coast
- Lynemouth biomass conversion, Ashington, Northumberland
- Teesside biomass with combined heat and power, Middlesbrough
- Walney extension offshore wind, off Walney island

Looking beyond the first stage of CfD (beyond 2018/19) as mentioned previously the government wishes to introduce competition. The parameters under which this competition should occur remain unclear, but in the EMR Delivery Plan the government does outline that it envisages some form of 'maxima' (caps) and 'minima' (floors) process for particular technologies or groups of technologies.

Of vital importance going forward is recognition of where competition has a role to play in the energy sector and how the various schemes interact with competition.

This highlights the significant issue of capacity and how much we need not only to meet baseload, but also to account for renewables where output is dependent on external factors.

The Capacity Mechanism

Another pillar of EMR is the Capacity Mechanism. The aim of this mechanism is to protect consumers against the risk of supply shortages by ensuring investors receive certainty through constant revenue streams and therefore provide the required capacity.

The scale of the capacity in this mechanism is to be informed by an enduring reliability standard. The idea is that the government wants to be able to provide a mechanism which can spot when supply might fall short, whilst also balancing the cost of having such supply sitting idle waiting to be turned on.

This would be administered through the system operator with their knowledge of requirements. It effectively creates a 'supplier of last resort' in a similar way that the Bank of England is the lender of last resort to the finance sector.

All generators with the exception of those in CfD, ss-FITs and RO would be allowed to submit capacity into the mechanism, with successful bidders awarded capacity agreements. There is even suggestion that in the long run interconnectors could be allowed to participate in the Capacity Mechanism. This could mean that in the future, when the UK's interconnector capacity is expanded significantly, and the price placed on capacity rises, interconnectors could fill a short-term gap if actual generation investment does not occur.

Whilst the mechanism secures revenue it would also impose financial penalties if a supplier is unable to provide capacity when required. DECC states that:

- "The Capacity Market will operate alongside the electricity market – which is where most participants will continue to earn the majority of their revenues. There will also remain a need for the System Operator to contract short term balancing services to ensure the moment to moment balancing of the system."[xli]

This suggests that the Capacity Mechanism as proposed in no way addresses the fundamental need for significant investment in wider generation capacity. Although it does appear later in the same technical document that whilst not helping to address the issue of investment, the Capacity Mechanism allowance will have some relation to capacity, stating that:

- “DECC will set out how much capacity will be required 4.5 years ahead of the delivery year, informed by the analysis from the System Operator taking into account how capacity is expected to be available outside of the Capacity Market (e.g. capacity supported by Contracts for Difference (CfDs), and expected imports via interconnectors) and therefore how much should be auctioned through the Capacity Market.”[xlii]

As the Capacity Mechanism will therefore be reliant on the energy market’s existing capacity and pricing, but is likely to have a significant effect on investment (as the market itself will be small and contract prices are likely to provide insufficient long term returns), there is the need to look at the how the UK ensures long-term investment and efficient wholesale pricing.

Pricing, investment, generation needs and consumers

Energy prices are increasingly of concern to consumers, with rise in prices attracting significant attention.

Government, as part of the rationale behind its EMR reforms, is attempting to balance investment needs with future consumer costs. It feels EMR will dampen the effect of volatile fossil fuel prices, reduce the risk of costly supply shortages, and allow low-carbon generation to be more cost effective.

The government expects EMR to reduce annual household electricity bills by an average of £41 (6%) over the period 2014 to 2030 and lower businesses’ bills by an average of around 7% to 8%.[xliii] It should be noted, however, that as government is looking at real prices over time it is reducing the scale of the price rise and not actually reducing bills.

Looking at absolute values within the EMR Delivery Plan, by 2020 EMR will add to the annual household energy bill:

- Around £26 for CfD payments.
- Around £12 for Small-scale Feed-in Tariff (FITs) payments.
- Around £37 for legacy Renewables Obligation payments.
- Capacity Market payments of around £19 to £26.

The above highlights an important point, the investment choices we make today will be locked into the system for years to come. As such, it is important that the UK makes the right choices to ensure that it not only meets its electricity demand requirements but additionally in a clear and strategic way that is affordable for households.

When looking at the interaction between different technologies, the EMR delivery plan states that:

- “In general, an electricity system with more low-carbon generation results in lower average wholesale prices, because low-carbon capacity typically has very low, or no, fuel costs. A higher carbon price, while supporting low-carbon investment, pushes up wholesale prices, and tighter capacity margins similarly push up wholesale electricity prices.”[xliv]

The pricing statement above is supported by the analysis this report has conducted on international energy price trends. That is to say that the greater the incidence of tax on energy (for investment in low carbon technologies), the lower the extent of the additional market price rise. So countries with more advanced investment in renewables have lower price trends accumulated through the system as a result of tax. They are locking in lower future rises by investing in the required generation now.

EMR should help to achieve such a shift when it comes into operation by taking advantage of the following:

- The continuing rise in the price of fossil fuels, which will continue to drive up the cost of energy in the UK.
- The fall in technology costs as EMR increases investment, locking in lower prices in each subsequent round.

The issue with EMR in this respect is that whilst it provides significant assistance through the CfD mechanism, and puts in place a Capacity Mechanism, it does not address the more fundamental issue of having to replace a significant amount of the UK's generation capacity or address what this will mean in terms of prices.

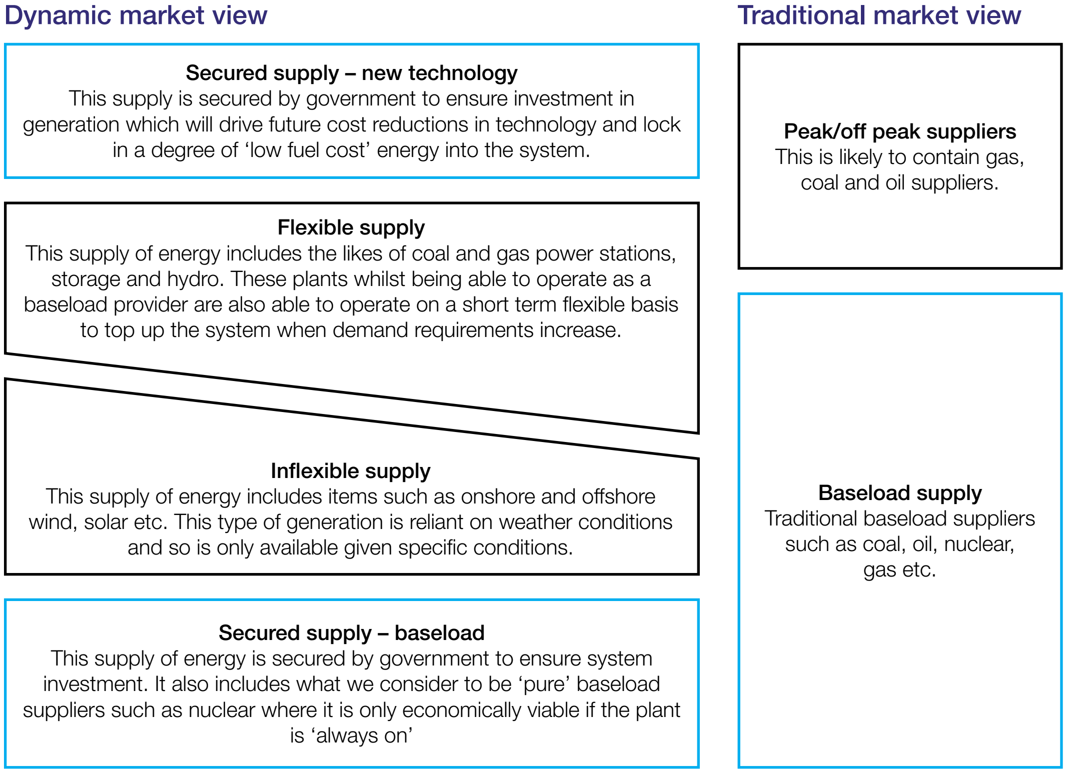
Defining new capacity, building generation, balancing competition and EMR – 'locking in' efficient energy prices

The UK therefore needs to look in more detail at how it defines and treats various forms of generation capacity. Traditionally the view has been that there is a baseload supply with a number of generators using spare capacity to produce additional energy to cover extra demand at peak and off peak times.

This view given the scale of renewables investment, and the need for investment to allow for more inflexible forms of generation, requires the UK to consider a new market format. One where there is:

- A secure baseload where technologies are either:
  - Reliant on constant demand to ensure they are run at their most economically viable and the costs of not doing so would increase at a rate deemed unreasonable to treat them as anything but baseload providers.
  - Or too costly to encourage investors to finance projects given an insufficiently long-term return required, but where externalities, public benefits and locking in lower fuel costs are considered great enough to energy consumers that investment should occur.
- Inflexible supply that will account for those generators that are either on or off as a result of items such as weather conditions. These generators are not able to produce power 'as required' and so cannot be relied upon as meeting peak and off peak cycles.
- A series of flexible generators that need to be able to enter and leave the market as demand requires. In addition, the margins in this area need to be sufficient to allow them to make a reasonable return whilst not operating all of the time.

This dynamic is shown graphically below:



It should be noted that some technologies can fit in more than one area (e.g. offshore wind could currently be classified as either inflexible supply and secured technology) depending on the view that is taken by government on the need and scale in each area.

Further to this we can explore the coverage of the current EMR framework to see where there will be issues in addressing this more dynamic view of the market going forward.

As can be seen from the next diagram the CfD mechanism addresses the new technology area, the nuclear deal currently under negotiation fits within the secured baseload requirement, and the Capacity Mechanism acts as the final buffer guaranteeing a small margin to generators that are prepared to provide the certainty of being the 'supplier of last resort' within the competitive flexible market.

Dynamic market view

Secured supply – new technology
This supply is secured by government to ensure investment in generation which will drive future cost reductions in technology and lock in a degree of 'low fuel cost' energy into the system.

Covered by the CfD mechanism in EMR

Flexible supply
This supply of energy includes the likes of coal and gas power stations, storage and hydro. These plants whilst being able to operate as a baseload provider are also able to operate on a short term flexible basis to top up the system when demand requirements increase.

Inflexible supply
This supply of energy includes items such as onshore and offshore wind, solar etc. This type of generation is reliant on weather conditions and so is only available given specific conditions.

Area where competition is efficient. Supply and demand can vary based on market conditions and willingness to supply/pay

Competition is due to be built in CfD mechanism but a large degree of uncertainty remains. It is also unclear how flexible suppliers will compete and based on what price when technology cost neutrality is met

Secured supply – baseload
This supply of energy is secured by government to ensure system investment. It also includes what we consider to be 'pure' baseload suppliers such as nuclear where it is only economically viable if the plant is 'always on'

Nuclear is the closest the UK has to securing a strategic baseload. More is needed to be done if the government wishes to encourage price efficiency in a competitive market

Whilst renewable generators have been given greater certainty, and the Capacity Mechanism has created a 'supplier of last resort' scenario, there remains significant uncertainty. Firstly, how the competitive flexible and inflexible parts of the market will work and secondly to what extent a secure supply needs to be attained to allow effective competition where demand does not consistently exceed supply, limiting market effectiveness.

Such uncertainty continues to causes significant problems for investors as it is extremely difficult to calculate what the long-term return will be. The proposed nuclear plant at Hinkley, for example, is currently progressing only because the government was willing to provide certainty over the strike price, even when financed by the private sector.

This report therefore suggests a way forward which attempts to balance the needs identified above with the EMR framework. Including:

- The need for a policy which will secure a reasonable baseload and invest in solutions which can 'store' energy. This helps to reduce the pressures caused by relatively expensive early technologies, and focuses the market on getting technologies to a cost level where they can compete openly/freely.
- The need to address capacity issues without radically reforming policy again and therefore increasing delay and uncertainty which is a major problem for investors.
- Ways to improve and implement effective competition in the generation market by creating a secure base that lowers costs and allows technologies to compete where appropriate. Additionally, redefining the role of efficient markets and how they interact between the various policies.
- The need for increased transparency within the market, allowing the retail side to access and buy from a number of sources. This should allow suppliers to hedge according to different strategies, creating different market positions and niches and moving away from the current situation where the majority, if not all players, shift prices at the same time.

Developing policy for the final part of market reform – capacity

As has been shown above capacity will be key to securing supply within UK energy policy, but will also be vital in determining the price consumers pay in the future.

As has been discussed previously EMR is already ‘locking in’ some future prices into the energy sector, but whilst this policy is being used to secure and encourage developing technologies, little action is being taken to lock in cheaper and baseload supply into the mix.

This will cause a significant issue if it is not addressed as it encourages prices up towards the current ‘emerging’ rates rather than accepting prices that are based on the cost of production.

Action is required to address the level of competition and transparency within the generation market. Whilst consumer choice in the retail market is important it does not encourage investment in the generation market.

Generating arms of companies sell energy to suppliers, but pricing around these sales is not transparent. At the same time the market has shifted towards short term spot trading, the most expensive and volatile form of energy purchasing.

Alongside this there is a continued message that profits are vital for investment, whilst the scale of such profits is confusing and does not help when trying to gain public trust. When looking at the market in purely economic terms, the companies generating arms are earning profits which should account for the original cost of the asset, operation and future investment. Too often the focus of the profit/investment debate is on suppliers (the retail arm of companies) rather than generators where the actual investment is required.

It is therefore important that policy focuses on this part of the market given the UK’s generation need rather than the retail side which only passes on energy with a margin to customers.

The main finding of this report is therefore that competition and investment need to be encouraged between generation companies.

The CSS released by the energy companies, whist showing various earnings and cost profiles across the different suppliers, display little concrete evidence of suppliers actually using vertical integration to an advantage.

While in theory there are benefits to scale and the position of being a natural monopoly, in reality the energy companies are required to separate their operations and so such cross subsidisation is not viable.

Therefore if the UK wishes to get the best out of its generations and energy market it needs to leverage the benefits that such a vertically integrated system would bring whilst encouraging competition.

This report suggests doing this by creating a secured supply policy similar to CfD for baseload suppliers where economies of scale for costs or low costs, can be locked into the system, placing downward pressure on future bills.

By developing a secure supply the government effectively removes a chunk of the energy market which in reality is never subject to competitive pressures. As such, it is better operated to the benefit of consumers with a holistic view of pricing and securing supply.

What remains therefore are inflexible and flexible developers covering a smaller proportion of the market where demand varies. This means that a supplier has the possibility of not being able to sell their output, thus encouraging lower prices and allowing actual competition to occur. Given this, only efficient and established technologies will come to compete in this area of the market, hence the vital role government will play in supporting the development of new technologies in the first place.

Examples of inflexible suppliers left in this market in the future will include onshore wind, future offshore wind and solar plants. These suppliers will experience lower costs of investment, given technology improvements secured via the previous CfD investments.

Flexible suppliers that would operate in this area (coal, gas CCGT plants) will make judgements on the amount of 'supply' required to be profitable against, original investment, age of the asset, fuel costs, and the demand for covering inflexible supply. As such they will enter and leave the market as the margins vary, securing the best outcome when possible.

This new market segment should truly embrace the concept of competition and allow marginal players to compete for business.

One of the aspects that was mentioned and is quite important in this respect is the cost of fuel. These (for both gas and coal) will vary significantly based on supply and demand not only in the UK, but also in international markets.

This is the context in which shale gas has become part of the energy mix debate. By allowing companies to extract shale gas the available supply in the UK is increasing and should push down gas prices, as can be seen in the US.

The mechanism we discuss in this paper talks about locking in a secured supply not only based on CfD but also based on the economics of providing a secure baseload requirement. By basing the new system on the CfD mechanism it should reduce the time needed to implement such a policy.

Whilst nuclear is the example of where economies of scale are required and so locking them into this area would be a positive step, shale gas holds the potential to lower gas prices in the future.

If significant price reductions did occur in the cost of gas, it would not only be reasonable but economically efficient to 'lock in' some percentage of CCGT baseload as part of the secured supply. This downward price effect is important as it helps to counter the upward price effects of other policies.

This brings the UK to the vital question as to how it secures this supply and encourages competition. One of the criticisms of ERM has been that it does not provide enough certainty with regards to the energy mix. As such, investors are unwilling to hedge their money on any particular technology with the possibility of government policy favouring another area of investment.

The mechanism proposed in this report starts to address this issue by having the government outline a number of secured providers. This will not only start to push much needed investment but will also provide a signal to the market that these technologies will be investible and supported within policy in the future.

Then there is the question of competition in the market. Currently focus has been on energy companies retail arms and consumer competition, which, whilst useful, does little to fundamentally affect the long term operating costs of electricity generation.

This focus away from actual investment has allowed energy companies to gain positions where they cover their demand positions almost entirely, trade obscurely over the counter with little transparency and effectively have a combined control over the liquidity in the market.

If the UK is to secure the energy investment it requires and secure any form of competition going forward this situation has to change.

The difficultly with creating competition is that the companies already in the sector have a significant advantage. As such a significant push is required to shift the paradigm within the market.

The formation of Generation Investment Vehicles (GIVs)

This paper proposes that the government initiate a number of Generation Investment Vehicles (GIVs). These vehicles would encourage investors to come forward and invest in generation given a pre-defined long term return that is set for a period in excess of 30 years, and also allow a percentage of generation to be subject to competition.

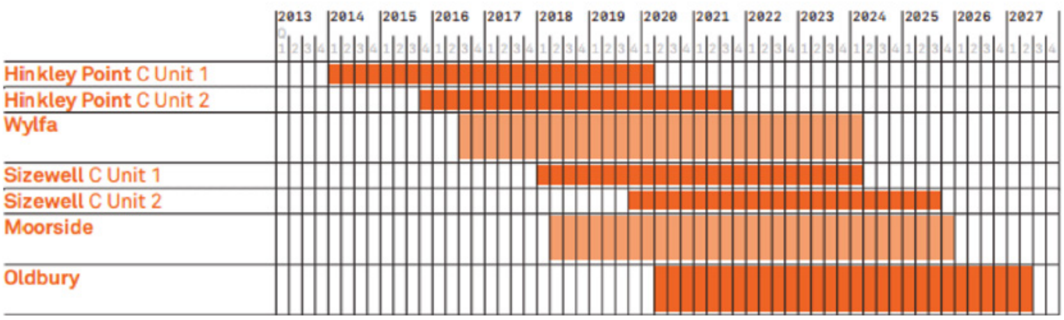
The key to efficient future investment and competition is to ensure that the projects within these GIVs are operational as the second and third wave of CfD mechanisms open up to competition. Thus the government has its secured supply in place and various technologies are in a position to compete.

As mentioned previously these GIVs would work alongside the current certainty the government is trying to provide for a nuclear programme. Currently nuclear accounts for around a fifth of electricity generation and the Nuclear Industry Association's estimates:

- "There are currently plans to build about 16GWe of new capacity, replacing the current 8GWe fleet of AGR and Magnox reactors, which are scheduled to reach the end of their lives in the period up to 2023, and the 1.2GWe PWR at Sizewell B, due to close in 2035."[xlv]

This 16GWe of new capacity occurs across five sites currently planned by EDF Energy, Horizon and NuGeneration (see graphic below).

NIA Assumed programme



Source: NIA

The EDF plant at Hinkley includes two reactors which are estimated to cost £16bn in total, with a combined capacity of capacity of 3260 MW[xlvi] and an agreed strike price of £92.50 per megawatt-hour at 2012 prices[xlvii].

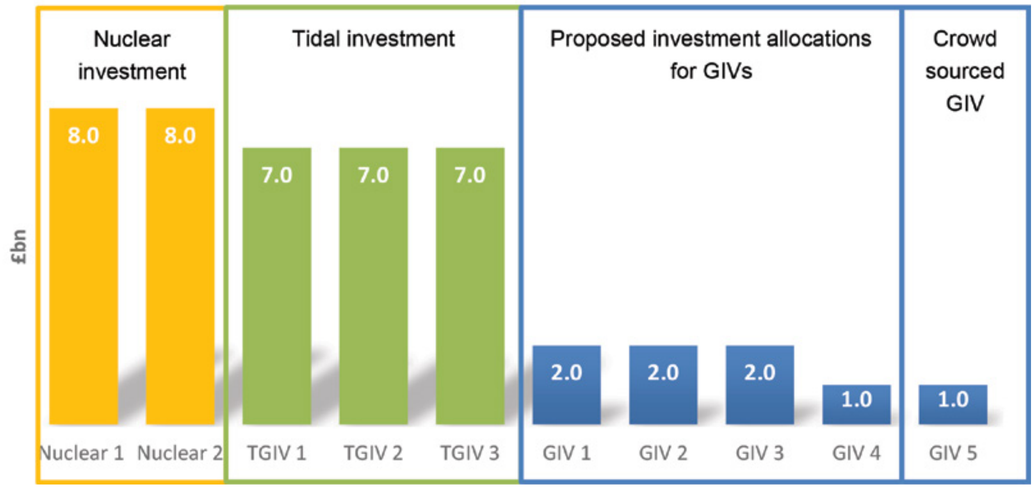
Whilst this appears to be lower than the current strike prices set within the CfD mechanism it should be noted that there is provision for inflationary increases over the period of the construction and operation of the contract which would see this price rise. The value for money of this deal, however, will depend on the degree to which commodity prices (gas, coal, oil) run at a level far higher than inflation over this period. Nuclear plants are generally considered to have a higher capital cost but lower fuel costs over their operation.

Despite these variables if the UK wishes to pursue nuclear as an option it will need to be considered as part of the secured supply remit to ensure economic viability.

As such the cost for the commitment to the current nuclear agreement is included within the projection for the mechanism proposed in this paper to ensure generation capacity is secured, building towards a competitive market.

As can be seen from the diagram below the future nuclear investment commitment currently stands at £16bn. This report proposes that five Generation Investment Vehicles (GIVs) with a combined value of £8bn are created to ensure that in the short to medium term project finance is secured. In order to secure medium to long term investment to 'lock' long term cleaner energy into the UK's generation system, this report also proposes that three Tidal GIVs (TGIVs) with a combined value of £21bn be created.

Generation Investment Vehicles



It is important to note that at this point these costs are finance/investment costs and not the annual cost that would be incurred by these investments to consumers/taxpayers which are explored in more detail soon.

When exploring what this £29bn in GIVs and TGIVs could purchase it is important to consider the profile of the closure of existing generation. Whilst opinion varies as to the scale and precise timing of closures, the UK could potentially see half of its generation capacity closed by 2030. For example:

- "To summarise the capacity retirement picture, it is likely that at least 15 GW of coal, oil and nuclear plant will close by 2016, with 20GW closing by the end of the decade. In addition there is the potential for a further 20-25GW of mostly CCGT capacity to retire by 2020. If, for the sake of argument, half of these potential closures eventuate, it would increase total plant retirements to around 20GW by 2016 and 30GW by 2020."[xlviii]

The £29bn TGIVs and GIVs then are an important step in addressing the area where EMR is currently weakest, i.e. getting reasonable capacity investment moving.

This report has discussed that the GIVs should be deployed in a way which locks some lower cost and flexible baseload generation into the system, and also provide funds for demonstration or more advanced projects that could help to mitigate the area of storing energy as the extent of inflexible supply increases.

To help estimate what could be achieved with the proposed £12bn of GIVs below the report explores a number of recently completed projects as examples of costs and generation output.

The recently completed £500m Isle of Grain CHP plant at 1,275MW is one of the world's largest and is an example of how new technology is improving efficiency[xlix]. For each CCGT plant built of this size the UK would be supplying over one million homes and meeting about 3-4% of its energy needs.

Cory's Riverside Resource Recovery facility is now fully operational, following successful completion of commissioning and trials period in May 2013. The facility processes 670,000 tonnes of waste from across London and has a generation potential of up to 72MW of electricity.[l] The facility reached financial close on the 31 July 2008 with finance of £470m[li] provided for the project.

Several tidal barrages have been proposed for the UK. These range from a proposed £850m project for Swansea Bay (320MW, 120 year design life), a £2.3bn project based in Colwyn Bay and a third costing £4bn located in the upper Severn estuary. The largest project proposed to date is that of a Severn Barrage with various proposals having put forward.

Given the above the £12bn could for example finance:

- Six CCGT plants at an approximate cost of £3bn (providing approx. 7,500MW).
- Eight waste to energy plants at an approximate cost of £4bn (providing approx. 575MW).
- A £21bn fund towards the building of tidal/lagoon assets (providing approx. 2,000MW to 3,000MW).
- A £1bn fund for community projects, where money would be raised via crowd sourced funding. Whilst such funds are a relatively new concept, there are examples not only general funds, such as, Funding Circle[lii] but also examples of renewable specific funds including; Trillion Fund[liii] and Abundance.[liv]

Given these figures the total generation capacity secured would equate to approximately 10,000MW and 11,000MW or the equivalent to approximately 12% and 13% of the UK's installed capacity (without nuclear) and between 16% to 17% with the current nuclear agreement with EDF.[lv]

This would secure a significant amount of generation and cover a large extent of that which is due to close over the next two decades, whilst also leaving a proportion of future investment in the hands of a purely market driven approach to compete on pricing. As mentioned previously, this generation would compete with technologies that have matured following support from the CfD mechanism.

Assuming this approach were to be taken, what could be the possible cost to the consumer? Looking at the work undertaken by DECC on generation costs in 2012 it is estimated that:

Gas CCGT is estimated to cost around £80/MWh rising to approximately £90/MWh by 2030.[lvi]

Waste to Energy and Waste to Energy CHP are currently estimated to cost approximately £35/MWh and remaining at this level through until 2030.

Tidal is estimated in the 2012 document as requiring between £130/MWh and £229/MWh, whist there is a CfD strike price for tidal stream set at £305/MWh (for the first 50MW) DECC specifically states:

- "Tidal range projects, which include both tidal lagoon and tidal barrage technologies, do not have a published strike price. Instead, given the lack of cost data available DECC will consider how best to price CfDs and the appropriate length of contracts for these projects on a case by case basis." Adding "The strike prices for Tidal Stream and Wave are intended for the first 30MW capacity of any project."

These prices, however, may not reflect the true long term cost of such a project given their long design life. For example, the proposal for £12bn worth of smaller projects including Swansea Bay estimated that they would require a price of £156/MWh[lvii]. This is within the range that DECC published back in 2012.

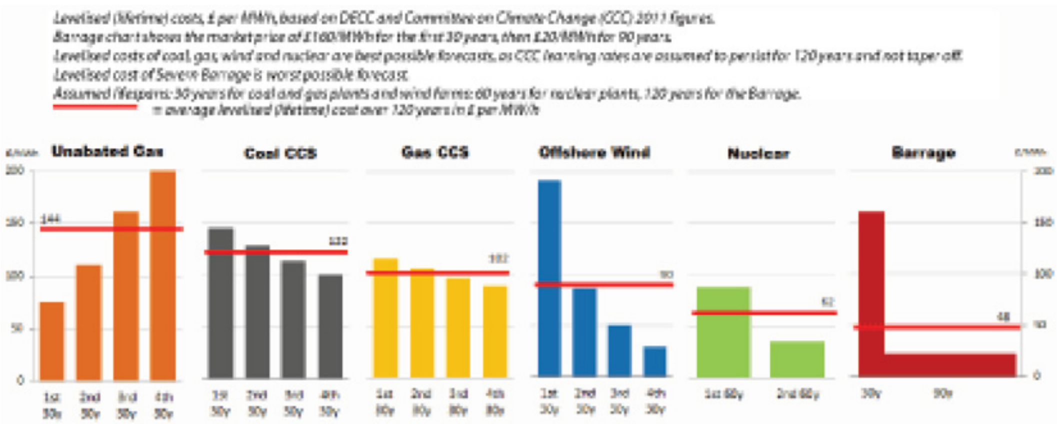
Discussions with industry have, however, suggested that this figure may be high as the price is considered over a shorter period than the significant design life of the project. For example whilst a CCGT plant may be running for 30 years a tidal lagoon would have a design life of 120 years. As such the equivalent price of energy would fall significantly, and could even approach the level of the current proposed price for nuclear and even possibly CCGT plants.

Such evidence has been presented by Hafren Power to the Energy and Climate Change Committee select committee:

- "Uniquely, price support lasts for less than 25% of the barrage's minimum working life. After the initial period of price support, it will produce inexpensive clean electricity at around £20/MWh—a quarter the price of coal, gas or nuclear—for over 90 years."[lviii]

As can be seen from the chart below the Seven Barrage whilst having an initial strike price of around £160/MWh for an initial 25 year period, following this energy would be produced at around £20/MWh. This is significantly below the comparison for other technologies. The UK would therefore be able to lock in this generation at or below the strike prices being offered for various technologies under CfD. This effectively places downward pressure on prices in the future for customers, minimising future price rises.

Strike price comparison taken over a longer time frame



Source Energy and Climate Change Committee – written evidence submitted by Hafren Power

As such this report proposes that three £7bn TGIVs are created to fund the roll out of either smaller schemes or the construction of a Severn Barrage (with a target price of 16% below the current £25bn estimated cost) to lock in lower cost long term electricity for this generation and subsequent. This will embed the kind of forward thinking that is required in the energy sector.

This report has therefore proposed locking in costs at £48/MWh (although the strike price may be higher initially and fall over time) for Tidal over a 120 year period, locking in gas CCGT to replace closing plants at approximately £75/MWh and energy from waste projects at £80/MWh. These rates are still be below the majority of the strike prices set under CfD in the 2018/19 period.

Also, because this capacity is securing a 'baseload' and is therefore intended as a replacement to existing plant closures a significant amount of this cost should be covered by money already paid as part of consumer bills for generation.

It is also important to recognise within the position outlined above that as plant closures start to occur and energy availability tightens wholesale prices will rise. As such, government taking clear action to secure generation not only prevents future price rises but also ensures that capacity that is not closing does not benefit from a price rise which has been created by a lack of planning.

How would these GIVs be provided with certainty and how would they trade to improve competition?

Introducing a secure supply has to be accompanied by increased transparency and ultimately improved competition within that part of the market that competes for variable electricity demand.

As such, it is envisaged that each of the GIVs would be allocated a number of projects or be part owners of a significant project constituting their total value with government providing certainty over the sale of capacity through a prioritised auction system, reducing risks.

The GIVs therefore would provide a mechanism for government to unlock investment by addressing issues around the allocation of risk in the private sector, thus allowing potential projects and investors to come forward, balancing the need for finance, funding and projects. Given the need for generation in the UK, and the financial and alternative investments markets' appetites for profitable projects, achieving a healthy degree of competition within this mechanism should also be possible to ensure value for money for the taxpayer.

These GIVs would be owned and operated by the private market by investors or a group of investors, competing against existing generation owners which would be prevented from investing.

The real question is then how to provide certainty, securing a base of power whilst also encouraging trading. That is why this paper goes onto develop a Priority Auction Mechanism (PAM) to drive investment as the market opens up to competition.

This paper proposes a new structure of two open market traded exchanges where government and energy providers guarantee and have to purchase 50% of the capacity put forward in the first round, 75% in the second round with all remaining and existing capacity then having to compete OTC.

This would be a bold step for the UK as it would force the creation of an open and transparent 'priority' market. This transparency would also have the effect of setting a benchmark price for the secondary market and OTC trades.

The mechanism described in the following two diagrams and works as follows:

If a generator has a guaranteed strike price such as a baseload provider, or is in the early technology stages of CfD their cost and supply is shared by the retail market, essentially as the current EMR framework puts in place.

The difference then occurs when considering the role of securing supply via GIVs and TGIVs. This is because the idea is to lock in low prices of secure supply whilst also allowing investors some certainty to start competing within the open market.

Given the need to lock in lower prices and the potential of tidal power to do this it is proposed that the combined £21bn in the TGIV investment vehicles is signed up to a low negotiated strike price with a minimum 60 year term with a review each 20 years allowing up to a 10% maximum revision in the negotiated rate. After this period the next 20 year period would be considered as part of the priority one auction process providing some certainty but allowing the gradual introduction of competition. This would lock in lower electricity prices for a significant period, and provide considerable back up for inflexible supply as the CfD mechanism encourages renewable investment.

GIV generators would be supported via a guarantee to buy but would be encouraged to start to build a competitive and transparent strike price within the energy sector.

GIVs would trade into a Priority One (P1) market where 50% of supply is purchased and passed through to suppliers. This guarantees capacity and provides investors with some certainty, however, energy must be sold on supply deals of at least 24 months'.

Once this has taken place these same GIVs and CfD generators have the option to enter the Priority 2 (P2) market or go straight to compete on an OTC basis.

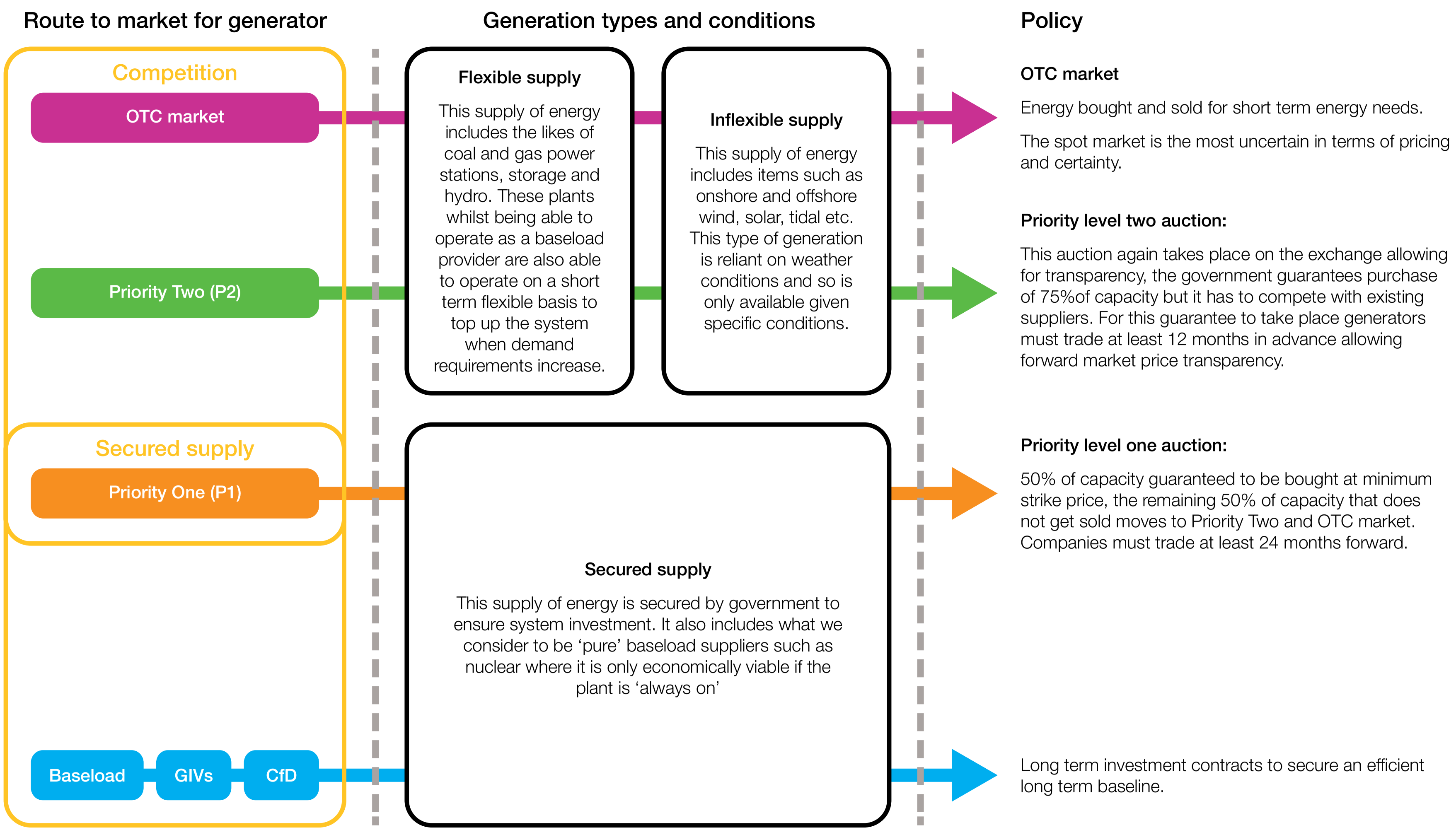
The P2 market has the benefit of offering a guaranteed purchase of 75% of capacity entered into it, however, energy must be sold on supply deals of at least 12 months'. There would also be competition with a number of existing generators who could apply for P2 trading licences, with the supply of such licences controlled to encourage a competitive pricing mix and competition. Again this provides GIVs and CfD providers with certainty as again they have a guaranteed potential to sell their capacity.

Following this stage all other capacity at this point (including those GIVs that choose to enter the OTC market as opposed to the P2 market) and the most expensive 25% of P2 market capacity is sold OTC at various contract lengths.

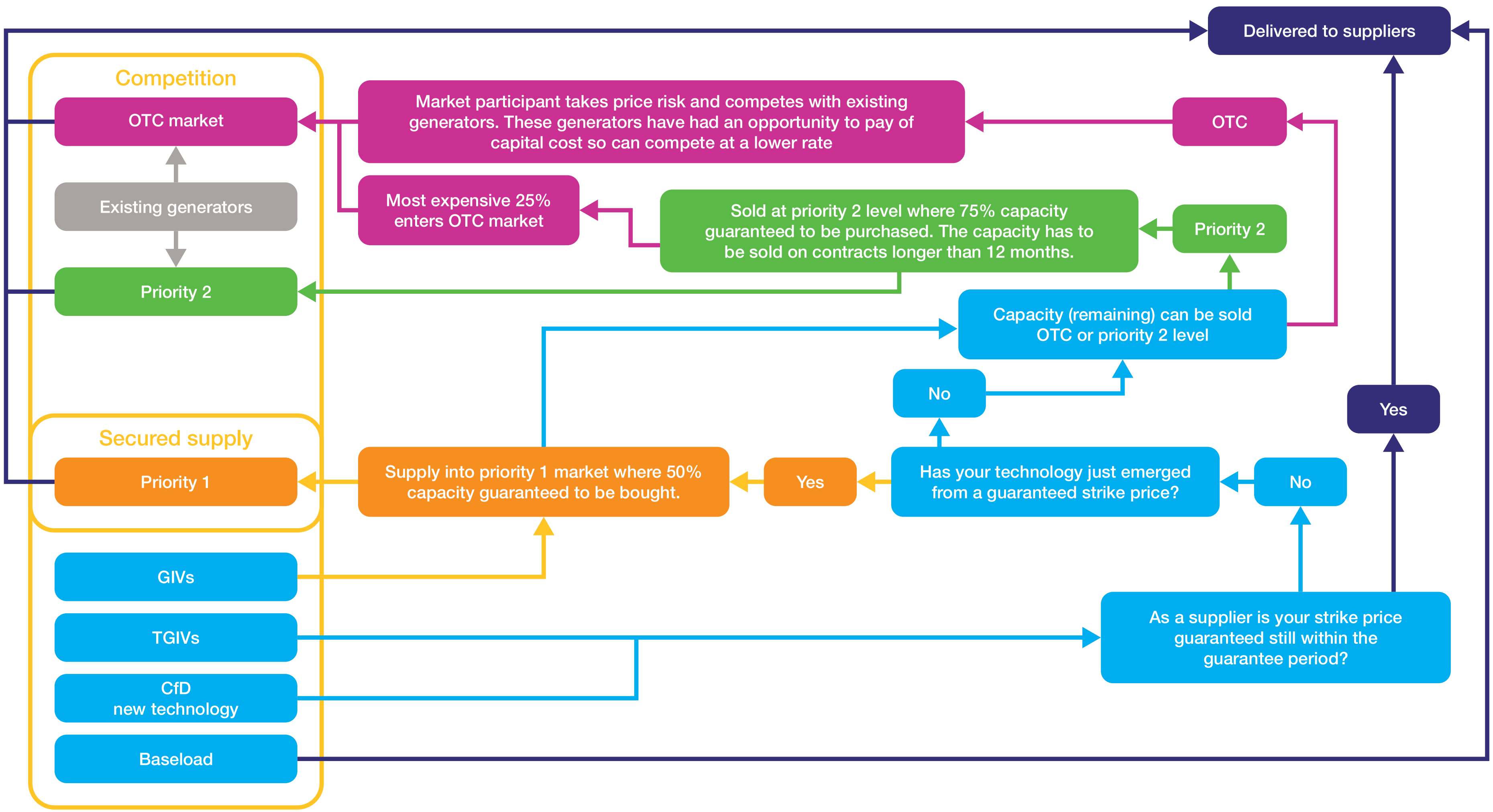
This establishment of two base markets will over time help establish a clear and transparent reference price.

The benefit to defining such a trading system is that it builds on top of the generators capacity that is locked in through the baseload and technology benefits, and allows the flexible generators within the GIVs to enter markets where there is a significant chance of selling capacity. Only if a GIV were to priced at completely unrealistic levels would it not sell any capacity until it hit the OTC market.

Policy overview diagram



Creating competition through policy – The Priority Auction Mechanism (PAM) – diagram



This therefore shifts the emphasis of spot trading towards the short term again, whilst locking in lower prices within a competitive market whilst encouraging transparent longer term trading.

Any exchange system such as this does not need to be run by Government with providers such as APX and ICE Endex offering energy market trading platforms. It would therefore be possible to tender competitively to have an exchange provider run the facility for a pre-defined period.

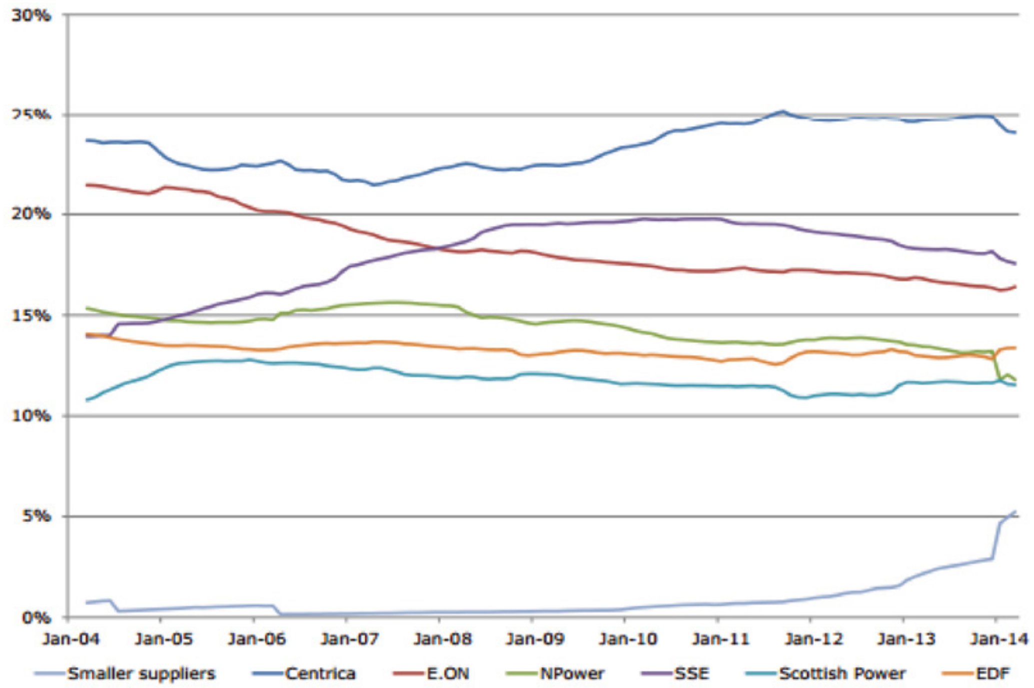
This is the missing part of EMR, the ability to build significant capacity, lock in lower prices and not just simply assume competition is working in trading but too actively encourage it.

This competition on these new exchanges will not only provide transparent prices but will also allow smaller suppliers within the retail market access to capacity. Currently such companies have to rely on the 'big six' suppliers or negotiate independent deals which can take time and require significant collateral guarantees.

Finally the introduction of new generators will improve liquidity, ensuring that trading is occurring as companies are operating within the market. This avoids the current issue where the 'big six' suppliers can effectively end liquidity in the market by deciding not to trade.

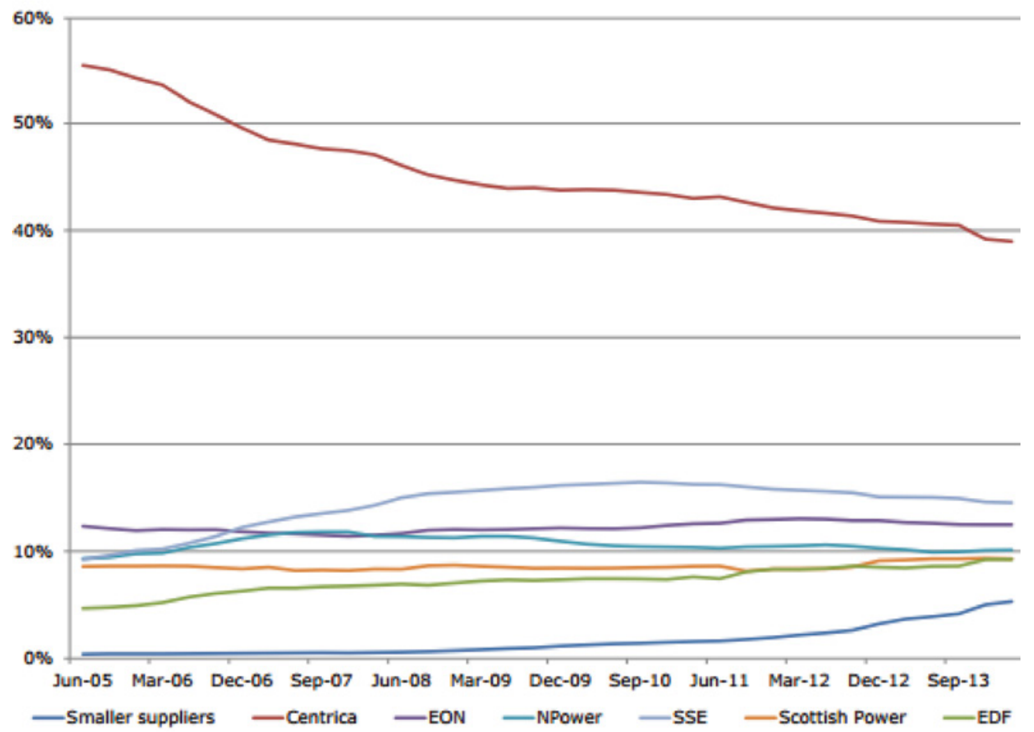
Appendix A – Energy market shares by company

Domestic electricity supply market shares



Source: Chart, Ofgem – data, Meter Point Administration Number (MPAN) data from Distribution Network Operators (DNOs)

Domestic gas supply market shares



Source: Chart, Ofgem – data, gas supply point data provided by Xoserve

Endnotes

[i] HM Treasury, National Infrastructure Plan, 2013 **(click here)**

[ii] IPPR, The true cost of energy, 2012 **(click here)**

[iii] Committee on Climate Change, Household energy bills – Impacts of meeting carbon budgets **(click here)**

[iv] 'Big six' – Centrica, EDF, RWE Npower, Scottish Power, SSE, E.ON

[v] Ofgem, State of the market assessment, 2014 **(click here)**

[vi] The new RPIJ measure of Consumer Price Inflation, replaces the older RPI index which is no longer considered a national statistic for further information **(click here)**

[vii] Ofgem, Market indicator, 2014

[viii] Ofgem, State of the market assessment, 2014 **(click here)**

[ix] Ipsos MORI, Customer Engagement with the Energy Market – Tracking survey 2013 **(click here)**

[x] Ofgem, Retail Market Review Evaluation, 2014 **(click here)**

[xi] Ofgem, Retail Market Review Evaluation, 2014 **(click here)**

[xii] This means that if prices are rising, all tariffs would be increasing, however, as the difference between the tariffs changes what affect can be attributed to inflation and what is due to changes in companies pricing policies. The analysis therefore only looks at the differential and the overall rise in price.

[xiii] Ipsos MORI, Customer Engagement with the Energy Market – Tracking survey 2013 **(click here)**

[xiv] Ofgem, State of the market assessment, 2014 **(click here)**

[xv] Ofgem, Open letter – Actions to improve the transparency of energy company profits, 2014

[xvi] The Consolidated Segmental Statements are provided by the energy companies on an annual basis and provide accounts of their various operations

[xvii] Ecotricity, Country Wide, Calortex, Atlantic Electric and Gas, Amerada Hess, Cambridge Gas, Enron Direct, Independent Energy, Uitlity Link and Gas West

[xviii] Ofgem, Retail Market Review: findings and initial proposals **(click here)**

[xix] Ofgem, State of the market assessment, 2014 **(click here)**

[xx] Whilst there are some interesting inferences in the following data, caution should be noted given the low R2 value and limited sample size.

[xxi] Whilst there are some interesting inferences in the following data, caution should be noted given the low R2 value and limited sample size.

[xxii] Ofgem, Open letter – Actions to improve the transparency of energy company profits, 2014 **(click here)**

[xxiii] Consolidated Segmental Statements:

Centrica, 2012 **(click here)**, Centrica, 2011 **(click here)**, Centrica, 2010 **(click here)**, Centrica, 2009 **(click here)**, E.ON, 2012 **(click here)**, E.ON, 2011 **(click here)**, E.ON, 2010 **(click here)**, E.ON, 2009 **(click here)**, EDF, 2012 **(click here)**, EDF, 2011 **(click here)**, EDF, 2010 **(click here)**, EDF, 2009 **(click here)**, RWE, Npower 2012 **(click here)**, RWE, Npower 2011 **(click here)**, RWE, Npower 2010 **(click here)**, RWE, Npower 2009 **(click here)**, Scottish Power, 2012 **(click here)**, Scottish Power, 2011 **(click here)**, Scottish Power, 2010 **(click here)**, Scottish Power, 2009 **(click here)**, Scottish and Southern Energy, 2012-13 **(click here)**, Scottish and Southern Energy, 2011-12 **(click here)**, Scottish and Southern Energy, 2010-11 **(click here)**, Scottish and Southern Energy, 2009-10 **(click here)**

[xxiv] Ofgem, State of the market assessment, 2014 **(click here)**

[xxv] Ofgem State of the market assessment **(click here)** – reference to – BDO LLP Final Report, 16 January 2012

[xxvi] Ofgem State of the market assessment **(click here)** – reference to – BDO LLP Final Report, 16 January 2012

[xxvii] Ofgem, Open letter – Actions to improve the transparency of energy company profits, 2014 **(click here)**

[xxviii] Ofgem State of the market assessment – reference to – BDO LLP Final Report, 16 January 2012

[xxix] IPPR, The true cost of energy, 2012 **(click here)**

[xxx] The R2 (R-squared) value is a statistical measure of how close the data fits the regression line.

[xxxi] Ofgem, State of the market assessment, 2014 **(click here)**

[xxxii] Ofgem State of the market assessment **(click here)** – reference to – BDO LLP Final Report, 16 January 2012

[xxxiii] Detailed breakdown only available for 2010-2012 period

[xxxiv] Other direct costs include items such as Feed in Tariffs (FIT), Renewable Obligation Certificates ROCs), Community Energy Saving Programme (CESP), Carbon Emission Reduction Target (CERT) and balancing services

[xxxv] With the exception of 2009 where costs were reported to be significantly lower but so too were revenues.

[xxxvi] Gov.uk, International energy market statistics **(click here)**

[xxxvii] Policy Exchange, Going, Going, Gone The role of auctions and competition in renewable electricity support, 2013 **(click here)**

[xxxviii] The FIDeR mechanism has been put in place by government to help developers of low carbon electricity projects make final investment decisions ahead of the start of the Contract for Difference regime

[xxxix] DECC, Electricity Market Reform Deliver Plan, 2013 **(click here)**

[xl] BBC, Eight renewable energy projects approved, 2014 **(click here)**

[xli] DECC, Electricity Market Reform: Capacity Market – Detailed Design Proposals, 2013 **(click here)**

[xlii] DECC, Electricity Market Reform: Capacity Market – Detailed Design Proposals, 2013 **(click here)**

[xliii] real 2012 prices

[xliv] DECC, Electricity Market Reform Deliver Plan, 2013 **(click here)**

[xlv] NIA, capability of the UK nuclear new build supply chain, 2012 **(click here)**

[xlvi] EDF, Hinkley Point C – An Opportunity to Power the Future, 2013 **(click here)**

[xlvii] Gov.UK, Initial agreement reached on new nuclear power station at Hinkley, 2013 **(click here)**

[xlviii] Timera Energy, The UK generation capacity crunch in numbers **(click here)**

[xlix] E.ON, E.ON's Grain CHP plant generates first electricity, 2010 **(click here)**

[l] Cory Environmental, Riverside Resource Recovery Facility – operation, 2014 **(click here)**

[li] Cory Environmental, Riverside Resource Recovery Facility – case study, 2014 **(click here)**

[lii] Funding Circle, 2014 **(click here)**

[liii] Trillion Fund, 2014 **(click here)**

[liv] Abundance, 2014 **(click here)**

[lv] UK generation number used for calculation is 81.7 GW (81,700MW)

[lvi] DECC, Electricity Generation Costs, 2012 **(click here)**

[lvii] Guardian, World's largest power-generating lagoon planned for Swansea Bay, Feb 2014 **(click here)**

[lviii] Energy and Climate Change Committee, Written evidence submitted by Hafren Power, 2014 **(click here)**

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