



Roles of Small Embedded Peaking and CCGT Plants in the GB Power Market

23rd September 2016

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1. Executive Summary

Since 2010 levels of generation at fossil fueled power stations in the UK have fallen by almost forty percent, dropping from 289TWh in 2010 down to 177TWh in 2015. This report discusses why that is the case and future developments in the market and why embedded power stations play an important role in the current and future market.

This reduction has been driven by two main factors:

- a 53TWh reduction in demand for **all** sources of electricity generation (driven by power imports and industry closures) and
- a 53TWh increase in levels of generation from renewable sources (as capacity has grown).

The market has been changing since 2010 and is set to continue to change as offshore wind farms continue to come online and boost the renewable fuel mix changing. This should result in the following core trends:

- Baseload CCGT and coal generation is disappearing and will continue to disappear because of increased renewables. New nuclear will also remove any residual baseload opportunities.
- Using power stations designed for baseload operation to meet the requirement of peak power during low renewable output will lead to an inefficient market outcome for the following reasons:
 - To operate baseload stations for peaking requires extended run times and reduction in generation at other stations either side of the peak
 - Operating baseload stations in peaking mode requires drastic reductions in efficiency typically to levels equivalent to gas reciprocation or worse.
 - Plants targeting embedded benefits are suited to short runs, which is where the largest market for future peaking generation is expected to be. This market grows as renewable capacity also grows creating a security of supply challenge for the overall system.

2. Summary

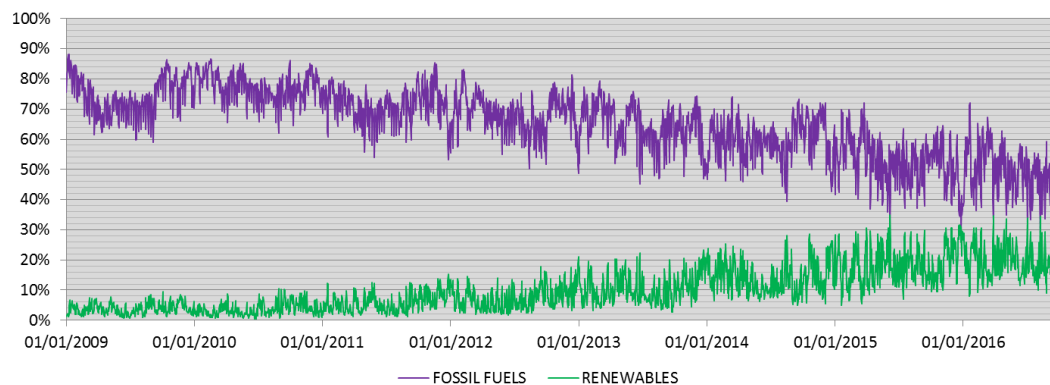
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This reduction has been driven by two main factors: a 53TWh reduction in demand for **all** sources of electricity generation (driven by power imports and industry closures) and a 53TWh increase in levels of generation from renewable sources (as capacity has grown).

As the share of total generation provided by renewables has grown, this has reduced the share of generation provided by fossil fuels, reducing the potential run hours that would otherwise be achieved at CCGT plants in future years, affecting their viability.



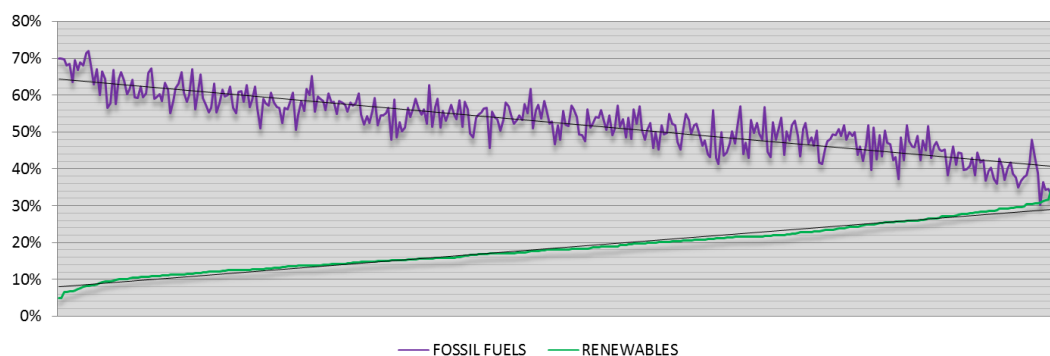
FOSSIL FUEL VS RENEWABLE SHARE OF TOTAL GENERATION, %



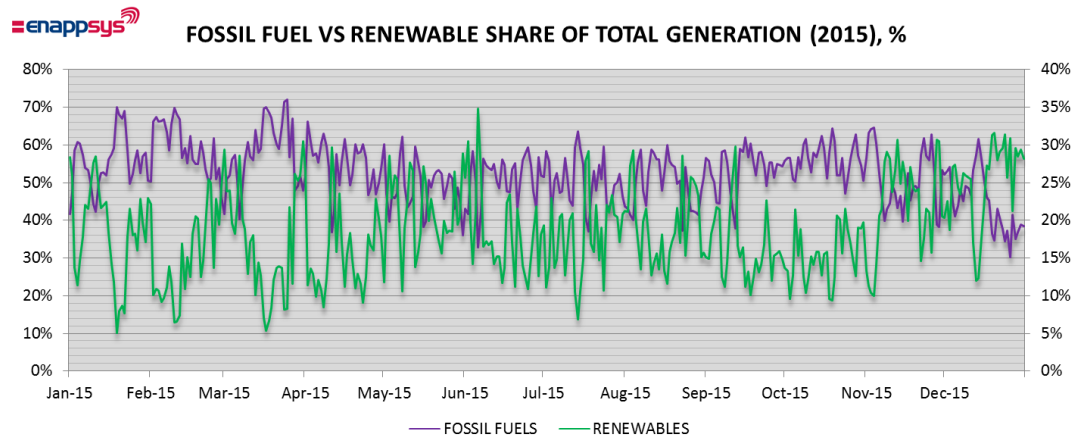
In 2015, as levels of renewable generation increased, levels of fossil fuel generation decreased; with a 30% increase in renewable share from the lowest to highest value translating into a 37% reduction in the share of generation from fossil fuel sources. This trend between the fossil fuel and renewable generation shares of total generation (ordered by renewable share - small to large) was as shown below:



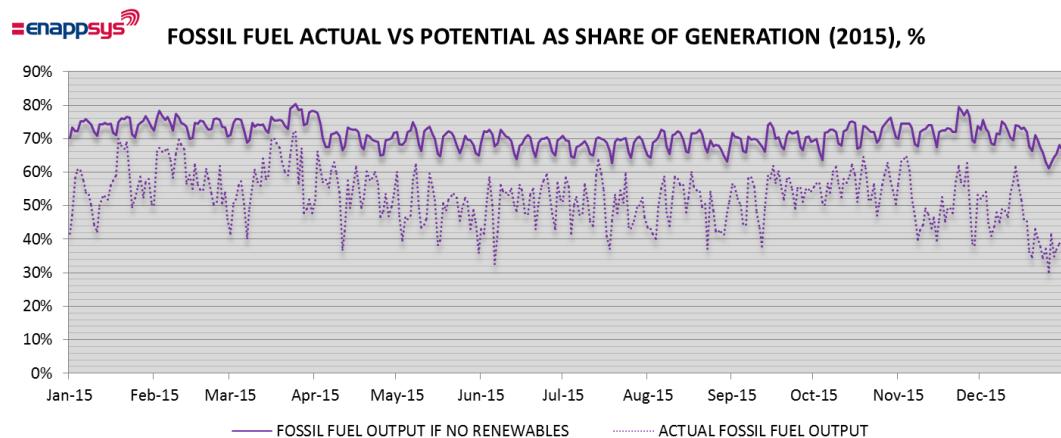
**FOSSIL FUEL VS RENEWABLE SHARE OF TOTAL GENERATION
(2015 ORDERED BY RENEWABLE PERCENT), %**



Renewable output levels are not uniform, but instead move about through the year (in line with changing weather conditions). The peaks and troughs in fossil fuel generation vary throughout the year as renewables force fossil fuel plants offline, resulting in unpredictable periods of inactivity at lower efficiency plants; reducing run hours and potential generation levels.



This renewable activity has turned what would be a very flat requirement for fossil fuel generation (only varying in line with changing levels of demand) into a highly variable output that moves in line with changes in renewable activity. This can be seen in the following chart showing what fossil fuel output would be on a daily basis with (dashed line) and without (solid line) renewables:



As renewable output has climbed from 27TWh in 2010 to 80TWh in 2015, average levels of generation from fossil fuels have declined; but the system retains a requirement for peak generation to cover a cold, low wind day. Recent winter periods have been particularly mild, but there remains this potential for very cold winter evenings that coincide with negligible levels of renewable generation.

On the 12th December 2012 such a day occurred and within day power prices peaked above £200/MWh as cold temperatures coincided with low wind. Throughout the day, imports from France were negative as the French electrical heating load pushed up prices on the continent and the requirements placed upon the system were large, with fossil fuel generation peaking at 46GW; well above the norm for the year.

In warmer conditions, September 2016 has seen balancing mechanism prices hit £1,500/MWh, while day-ahead power prices have reached £999/MWh as margins have tightened due to closures at fossil fuel plants that have seen insufficient running hours to justify continued operation.

This September activity occurred outside the winter period in which triad periods are active and embedded generators and demand reduction was not incentivised to reduce the evening peak (in both cases to earn triad income); this meant that the system had to be more pro-active in bringing online generators for these high prices to meet peak demand, resulting in higher costs.

10th March 2016 also saw activity of interest with National Grid bidding down 2GW of generation for prices of £27/MWh at 5pm, whilst simultaneously offering on 1.5GW of generation for £602/MWh. This was a spread of £575/MWh despite a net decrease in generation and resulted from the system having insufficient spare margin in the system, which it then had to artificially create by bringing on coal stations from cold and turning other stations down to their minimum stable export levels. This approach is becoming increasingly common.

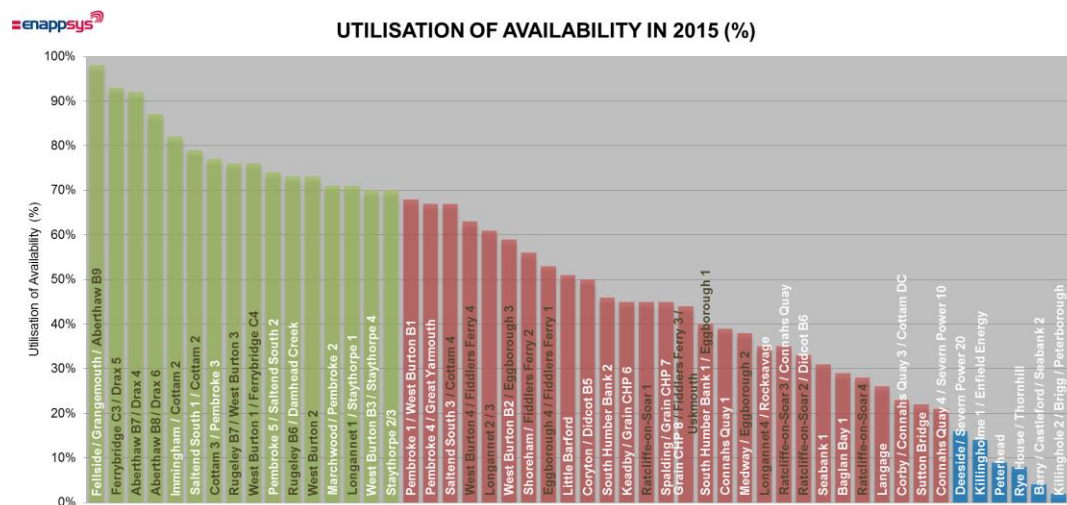
This activity was carried out in order to artificially create margin at a cost of £863k per hour, so that when demand increased in the evening there would be enough plants online and able to increase their output to meet demand requirements. These costs were the result of closures at coal and CCGT plants that did not expect to see sufficient running hours to meet their fixed /maintenance costs and justify continued operation, with this reducing system margins.

Typically, large CCGT and coal plants require minimum run times in the order of hours so can sit outside the market at high prices in times of scarcity to provide spinning margin for the peak period. These minimum run times create inefficient market outcomes as they have to run for a significant length of time either side of the events to guarantee operation for the required small period of time.

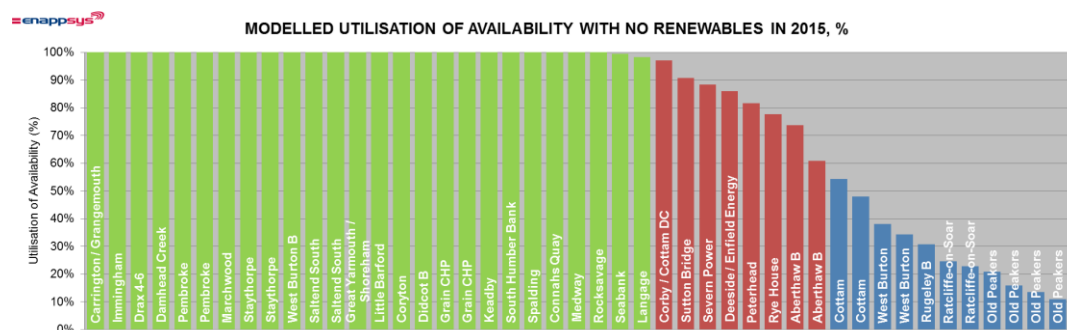
The challenge facing the market is that as renewables grow, existing large CCGT and coal plants are pushed down the stack, dropping the least efficient large CCGT and coal plants into a position where the running hours available are insufficient to allow them to justify continued operation via conventional revenue streams (power or balancing markets) and potentially out the market.

This impact is amplified by the construction of new CCGT plants, which whilst better and more efficient, do not solve capacity issues as they merely push existing marginal plants out of the bottom of the stack down to unviable levels of generation and closure.

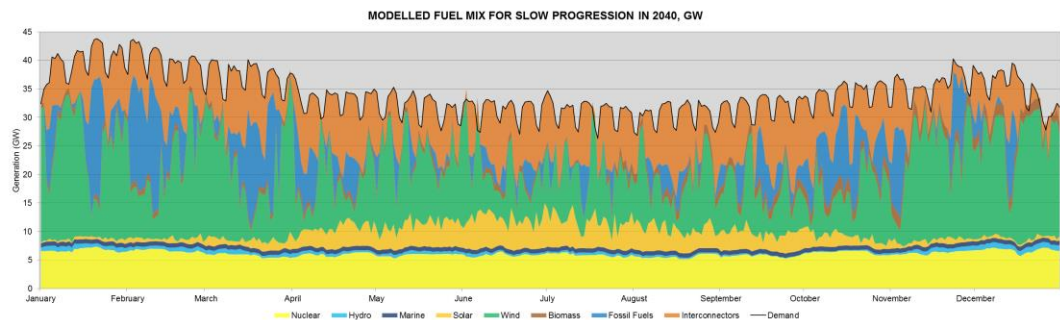
In 2015 this stack can be seen in the following chart where each column represents a GW of installed capacity and where green indicates mostly baseload operation, red indicates peak hours operation and where blue indicates running hours that are unlikely to be sufficient to support a large CCGT plant (with these plants being potential candidates for closure):



EnAppSys has modelled the market in 2015 to replicate the above actual chart as if renewables did not exist in the GB power market, with numerous plants able to generate following a baseload profile:



As a comparison against actual levels, this chart is replicated below with the actual 2015 fuel mix with a black line indicating the difference against the position that would exist with no renewables:



Continued growth of power sources such as offshore wind will increase levels of renewable output across the winter months of the year, but with the temporary loss of generation across periods during winter months when wind speeds are low; with a number of large offshore wind farms set to come online from 2017.

The challenge facing the market going forwards is to ensure that capacity is able to continue to participate in the market despite having limited generation opportunities.

In the longer-term, it is likely that storage will become a key component of the GB power sector, importing power during high renewable periods and then exporting power into the system when renewable output is reduced. However, storage technologies and renewable electricity volumes are not yet at the point where such market activity would be viable.

There remains a requirement for a source of power generation that can provide infrequent additional capacity to the market, supported by high levels of fixed revenue and benefiting from low capital and fixed/running costs.

At the moment three types of plants provide this sort of capacity within the power market. These types include:

1. Older CCGT stations with 45%+ efficiencies but higher fixed/running/maintenance costs operating at low run hours
2. Gas reciprocating engines with ~40-42% efficiency but low fixed/running/maintenance costs operating at low run hours
3. Open Cycle gas stations with ~30% efficiency but low fixed/running/ maintenance costs operating at low run hours

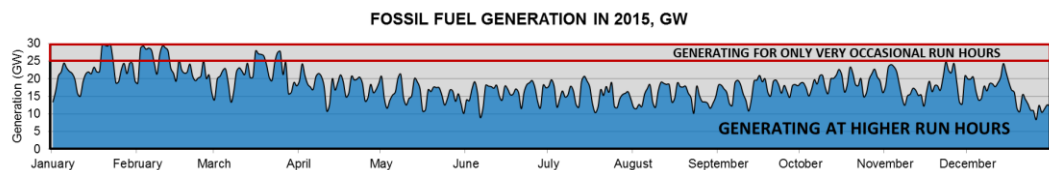
Where these plants are not able to earn embedded benefits they must compete against existing plants in markets such as the balancing mechanism, supplemented by Capacity Mechanism payments.

This most commonly occurs with plants of the third OCGT type – which can start from cold faster than more efficient CCGT plants - enabling them to out-compete CCGT plants when speed of delivery is a key consideration; although many such plants have been struggling and are closing due to the low Capacity Mechanism prices. Gas reciprocating engines have even faster start times and so can take a similar approach and some new entrant

reciprocating engine specialist players are now participating directly in day ahead, intra-day, balancing and other post gate closure markets in addition to the more traditional STOR / FFR and embedded benefits.

As renewables continue to reduce overall demand for fossil fuel generation and as individual plants see reducing load factors (down towards nominal levels), the support to keep plants online despite having lower utilisation rates will need to increase over time.

This market evolution has led to the creation of two distinct sub-sections of the market that exist for distinct purposes and based upon different principles; with almost no overlap between the two markets:

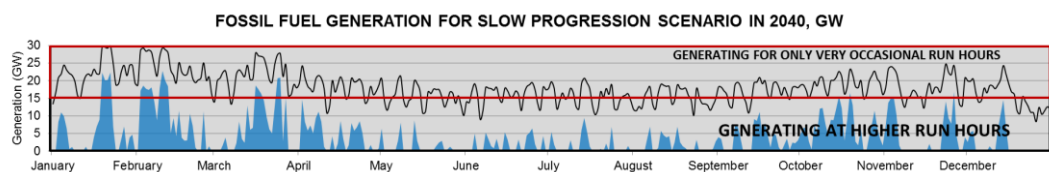


With almost no overlap between these two sub-markets, the impact of embedded generators upon higher efficiency plants is nominal and predominantly manifests in reducing the peak prices and Capacity Mechanism prices that might otherwise be earned by other plants in the market.

Currently embedded benefits provide support to units that generate for the demand peaks, both reducing prices and balancing requirements during the peaks and providing targeted support to plants whose primary role is to provide reserve power to the grid.

Removal of this support, targeted towards providing reserve power during peak days, is likely to place significant additional costs on consumers as the Capacity Mechanism is paid at the cleared price and as lower embedded generation over winter peak will place a larger strain on balancing the grid, pushing up cash out and balancing prices significantly.

As the market progresses, the number of plants generating for rare and very occasional run hours is expected to increase, while the number of plants generating for a higher number of run hours will decline over time.



All this activity shows a transformational shift in the underlying operation of the market from 2010 to now and continuing into the future.

This creates a requirement for plants that are able to generate profitably despite only achieving a very limited set of run hours and operating to reduce the demands placed

upon the system during high demand periods. This need is set to increase over time as larger CCGT and coal plants are forced out of the market as they are unable to recover their fixed/maintenance costs from fewer hours having been displaced by renewables. These plants are ultimately expected to close as the renewable fleet grows in size.

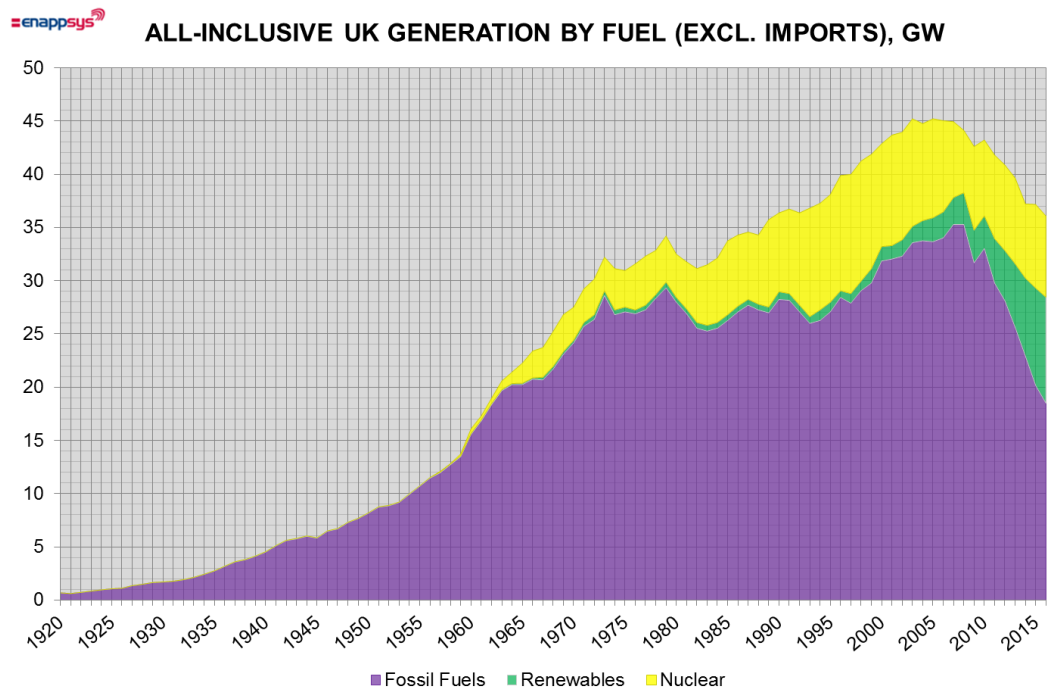
3. General Market Trend

The five year span between 2010 and 2015 has been a period of unprecedented change in the GB power market with total levels of electricity generation dropping to volumes not seen since 1994 and with levels of coal-fired power generation dropping to levels not seen since the early 1950s.

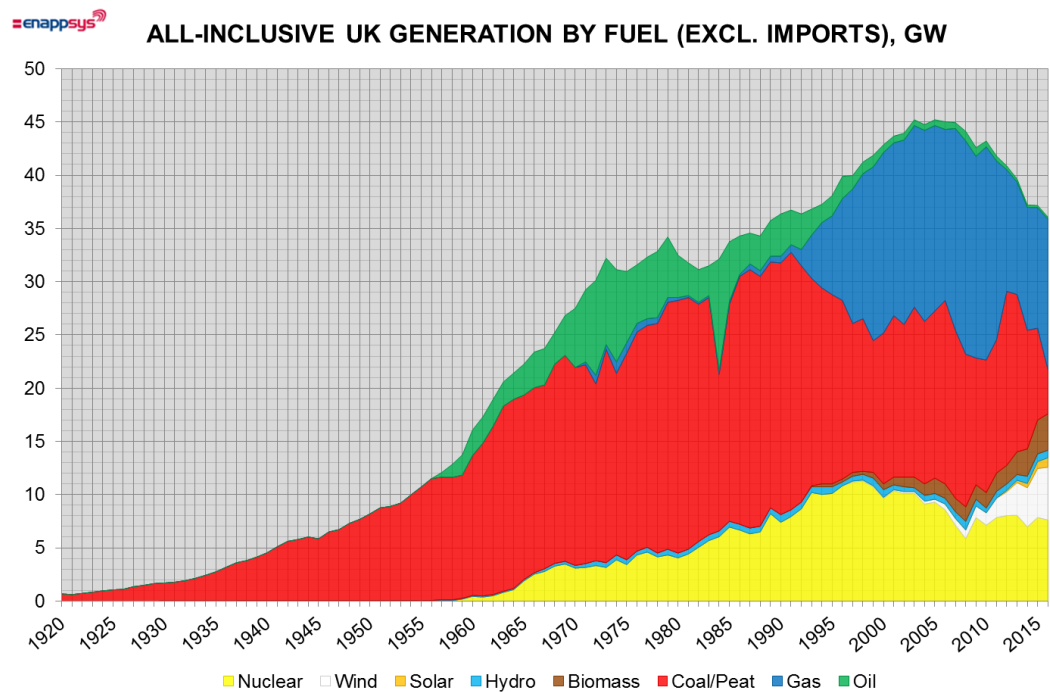
This has been driven by four key trends:

- Falling levels of electricity demand (having modified to include embedded generation that is typically otherwise removed)
- Growth in levels of renewable generation
- No reduction in levels of nuclear generation in response to the above
- Changes in the market arising through the introduction of government policies, such as subsidies for renewable plants and increased carbon costs making coal plants uneconomic

This activity can be seen in the following chart which plots generation at **all sources of generation** including estimates for embedded generation within the UK power market (using data from DECC and National Grid):



Broken down by source this fuel mix is as summarised in the following chart, with this chart showing average levels of generation per hour (measured in GW):



This chart broken down by fuel type shows how renewable sources of electricity have increased since 2010, whilst levels of overall requirements for electricity generation have reduced at a similar rate.

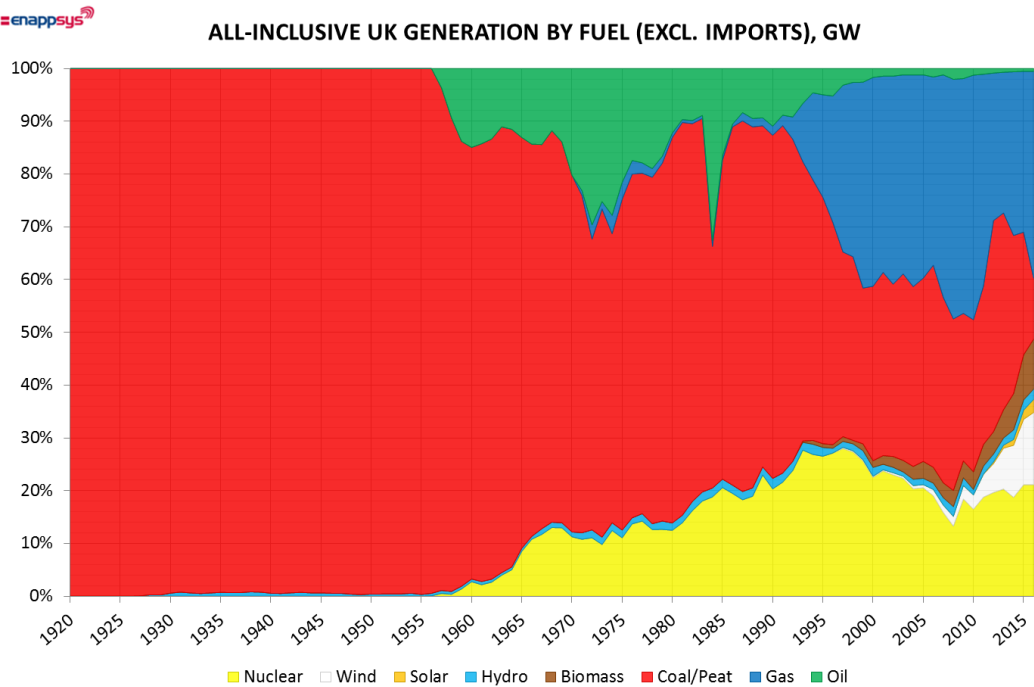
The reduction in overall electricity generation requirement has mainly arisen through industrial sites reducing in size within the UK and through improvements in levels of energy efficiency.

This data includes estimates and actual generation levels for all power generators within the market and so reflects the true requirements for electricity generation (rather than the more restrictive demand definition provided by market operators). Much of this drop comes from reduced electricity usage from heavy industry that has now closed or moved abroad, with these sites previously having had high electricity demands. It does not include power imports which have increased since 2010; however this growth is only a small contributor towards the overall decline.

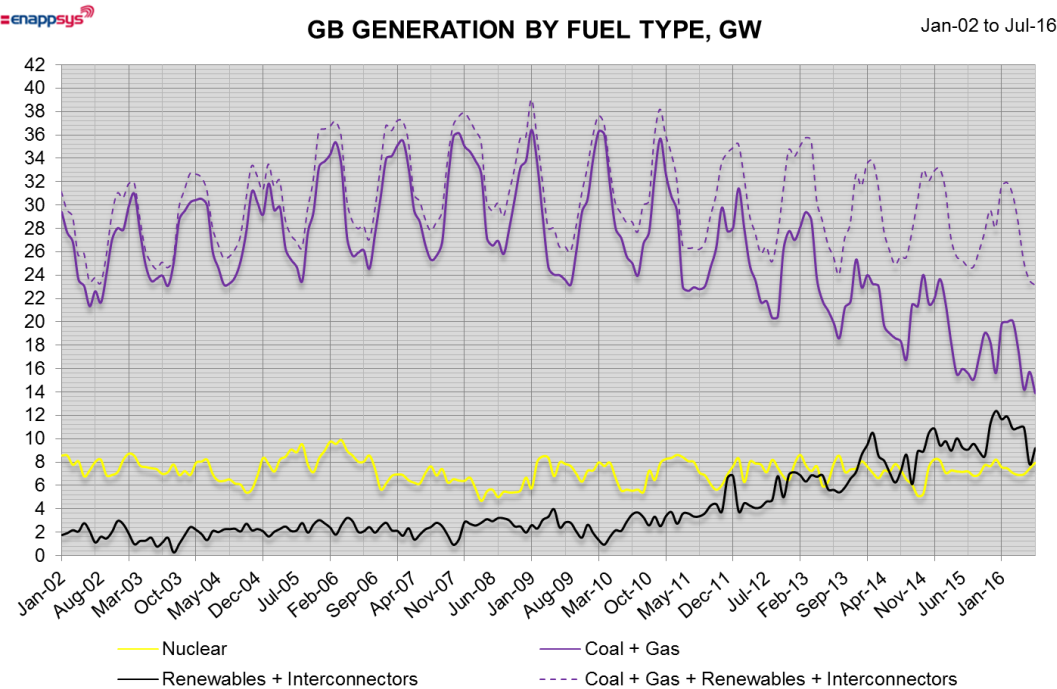
The embedded generators with the best embedded benefits can see utilisation rates reaching 15% of potential generation, but many plants see lower utilisation rates at around 5% of potential generation. As a result their generation levels are very small in terms of the overall fuel mix and do not have a significant impact as 1GW of capacity will only generate 50-150MW of power. This amounts to 0.14-0.41% of total generation in 2015 per 1GW of capacity.

The net impact has been a large reduction in levels of fossil fuel generation, with almost 50% of power generation now sourced from renewable or nuclear sources.

This can be seen in the following chart showing levels of generation by fuel on a by percentage basis:

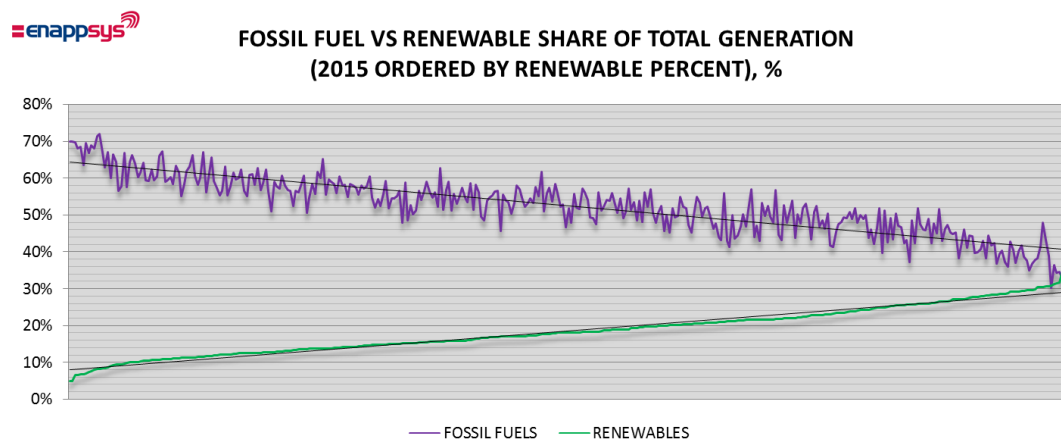


The impact of this growth on a monthly basis can be seen since the start of 2002 in the following chart:



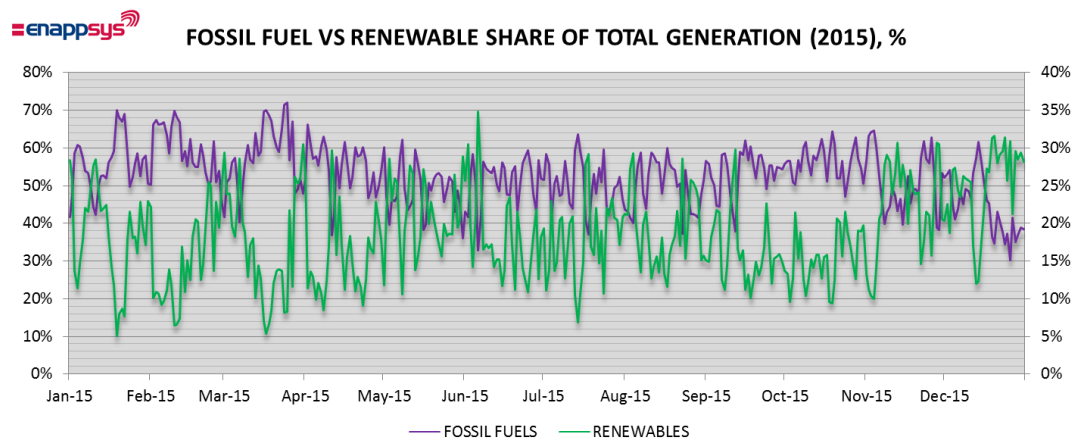
This shows how renewables and interconnectors have grown and how levels of combined coal and gas generation have come down as a result of this growth. The most recent winter has particularly seen dramatic reductions in fossil fuel activity, with the levels of renewable generation set to continue to rise in future years as offshore wind farms come online and as new renewable technologies emerge.

Across 2015 the direct relationship between renewables and levels of fossil fuel generation can be seen in the following chart (with only a nominal share of the gas-fired portion of the fossil fuel generation not coming from CCGT or OCGT plants).



This chart plots the share of total generation from fossil fuels and renewables across 2015, but ordered from the lowest renewable share to the highest renewable share to clearly highlight the trends across the year.

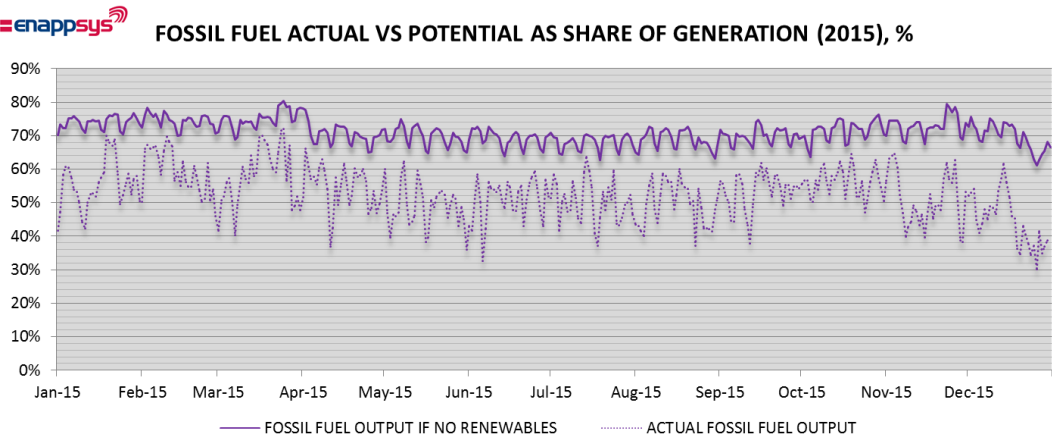
Plotted as continuous time series, the changes in renewable output are much more volatile, with increases and decreases occurring throughout the year as weather patterns change.



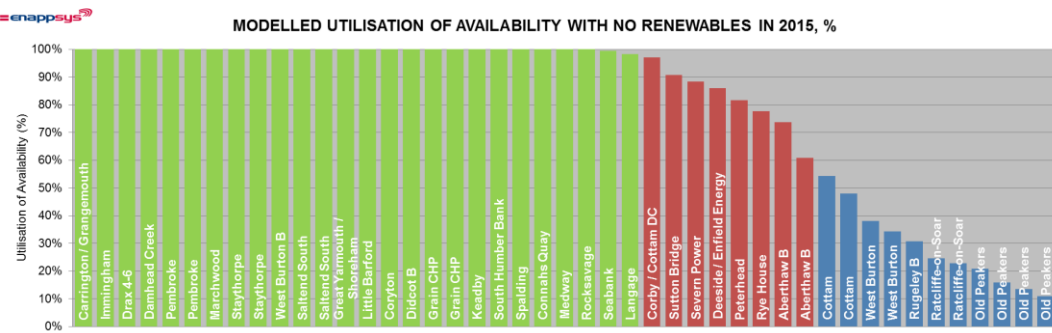
Since renewables have nominal variable costs (supported by fixed subsidies), where these renewable plants can generate they do so displacing CCGT and coal-powered stations.

This takes what had previously been a very predictable pattern for fossil fuels, generating around changing demand either via a baseload profile or across a peak profile running from 7am till midnight, and replaces it with a generation profile that varies depending upon changing levels of renewable generation.

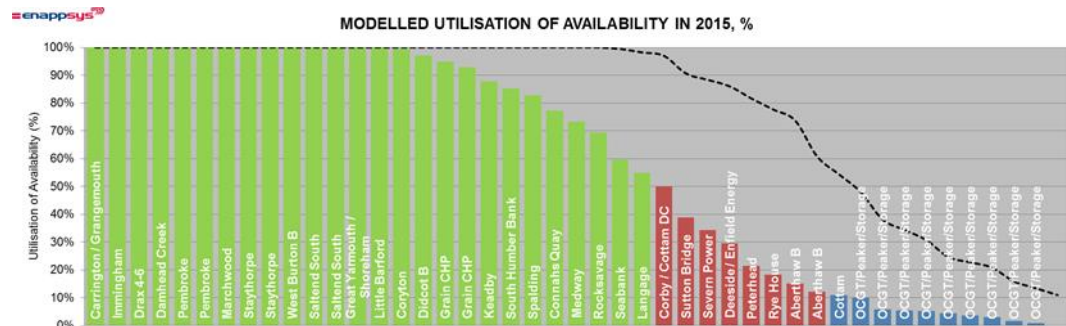
This shift can be seen in the following chart showing what fossil fuel output would be on a daily basis with (dashed line) and without (solid line) renewables:



In 2015, levels of generation drop from being heavily based upon providing baseload power, as shown in the following chart, plotting utilisation of availability in a modelled scenario that matches 2015, but with no renewables:



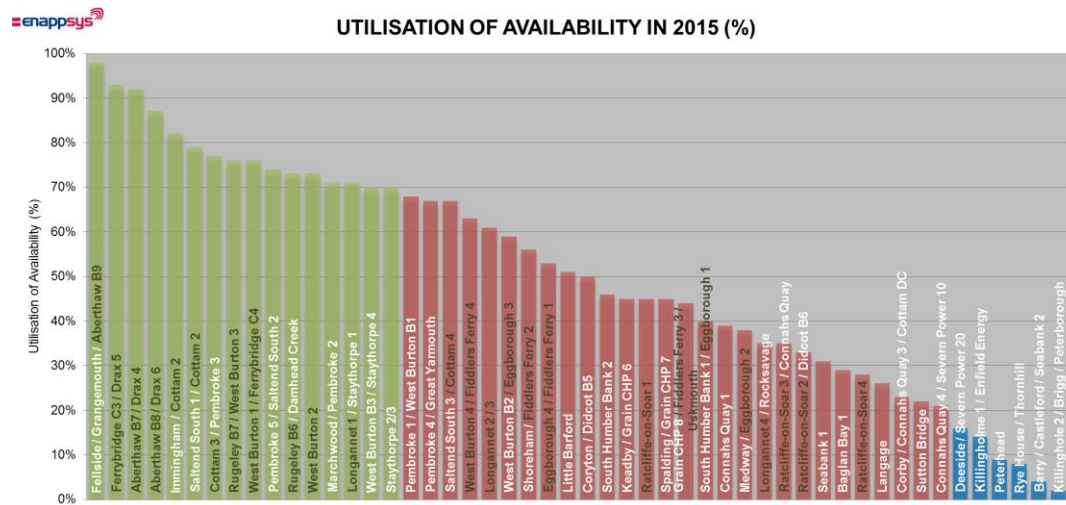
As a comparison the following chart models for 2015 based upon the actual fuel mix that occurred.



The black line in this chart shows the activity that would be expected with no renewables, and levels of activity on a per plant basis fall at a faster rate against the historic norms as the efficiency of the plants decline.

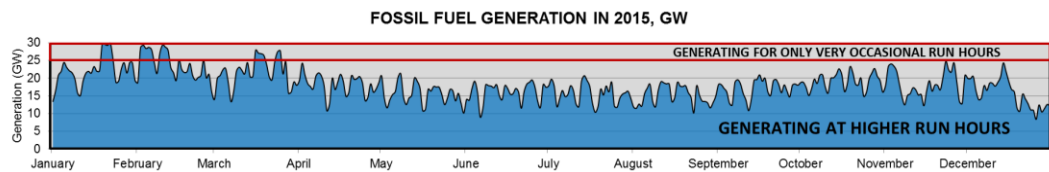
These CCGT plants are well suited to generating for baseload operation, with their higher maintenance and fixed costs offset by the increased amount of activity occurring across the year. Once the activity declines, the reduced generation struggles to cover the costs of running a combined cycle gas turbine and so the plant becomes less viable.

The actual recorded activity in 2015 is seen in the following chart with a greater slope on the curve as plants compete with each other and don't have such a well-defined stack as that used in modelling:



Plants that have historically dropped too far down the stack have now closed with the two Killingholme CCGT plants towards the end of the stack being in the process of exiting the market.

What results is a fossil fuel generation shape that still has baseload generating opportunities, but with a growing requirement for plants that only generate very occasionally across the year.



The above chart plots at daily level, but at half-hourly level, the demand peaks result in a higher requirement for power generation to cover the highest half-hourly demand peak of the year, with these peak half hours creating the greatest challenge.

3.1 Peak Electricity Demand

While levels of fossil fuel generation at both coal and CCGT stations have been in decline, levels of peak demand have continued to present a challenge for the system; resulting in tight margins in recent winters and issues of NISMs in winter 2015/16 despite the mild weather conditions that occurred.

Relatively rare winter spells that result in very high demand due to very cold weather and low levels of wind generation present a challenge to the system as it requires a volume of capacity that can only expect to see very low levels of market activity; these cold low wind periods are typically replicated across much of Europe.

On these days it is important that the system retains the capability to provide sufficient generation in order to keep the lights on.

The last example of such a cold low renewables day occurred on the 12th December 2012; on this day within day market prices peaked above £200/MWh. Across the day, imports from France were negative as the electrical heating load in France pushed up prices on the continent (where renewable generation was also low) and the requirements placed upon the system were large, with fossil fuel generation peaking at 46GW; well above the norm for the year.

In much warmer conditions, September 2016 has seen balancing mechanism prices hit £1,500/MWh, while day-ahead power prices have reached £999/MWh as margins have tightened due to closures at fossil fuel plants that have seen insufficient running hours to justify continued operation.

This September activity occurred outside the winter period in which triad periods are active and embedded generators and demand reduction was not incentivised to reduce the evening peak (in both cases to earn triad income); this meant that the system had to be more pro-active in bringing online generators for these high prices to meet peak demand, resulting in significantly higher costs.

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generation and resulted from the system having insufficient spare margin in the system, which it then had to create by bringing on coal stations from cold and turning other stations down to their minimum stable export levels.

These actions were inefficient because for a large amount of the time the generators were creating excess energy because of their need to have a minimum run time of between 4 and 8 hours meaning other stations had to be turned down to minimum stable generation to keep the system in balance.

This process also involves bringing online large power stations from cold, which is a process that results in notably reduced efficiencies; as a portion of the fuel most used to start the generator up rather than simply using fuel to generate electricity. At large high efficiency stations the loss in efficiency at start up is large as the plants are optimized for continuous rather than occasional operation.

This activity was carried out in order to artificially create margin at a cost of £863k per hour to ensure that when demand increased in the evening there would be enough plants online and able to increase their output to meet demand requirements. These costs were the result of closures at coal and CCGT plants that did not expect to see sufficient running hours to meet their fixed /maintenance costs and justify continued operation, with this reducing system margins

The challenge facing the market is that as renewables grow, existing large CCGT and coal plants are pushed down the stack, dropping the least efficient large CCGT and coal plants into a position where the running hours available are insufficient to allow them to justify continued operation via conventional revenue streams (power or balancing markets) and potentially out the market.

This impact is amplified by the construction of new CCGT plants, which whilst better and more efficient, do not solve capacity issues as they merely push existing marginal plants out of the bottom of the stack down to unviable levels of generation and closure.

These older CCGT plants increasingly have higher efficiencies as the least efficient CCGT plants have now exited the market, so these older CCGTs will always be able to outcompete embedded generation outside of peak hours when embedded benefits are available (mainly in evenings November – February), so embedded plants do not contribute to this large scale reduction in generating hours at the older CCGT stations. Instead the result stems from the changes in demand and renewable growth.

In a market where levels of fossil fuel generation are declining due to renewable growth, the levels of revenue earned at less efficient CCGT plants reduces as they transition from having historically been generating during all high demand periods to only generating during high demand periods that also see low levels of renewable activity (a much less frequent occurrence).

Wind speeds generally peak across the winter period and remain consistent across most of December and January, so this has reduced the typical hours of generation at such plants as the renewable capacity has grown.

As a result these plants must either earn higher income per MWh generated or must earn higher fixed income to compensate for the loss of generation and must be set up so as to reduce their fixed costs to further compensate for the lost generation opportunity due to the introduction of renewables which are at least 25GW in capacity and growing. Even with enhanced capacity mechanism payments it is unlikely that there will be enough extended generation runs available to make the plants viable in the future.

These CCGT and coal plants then become those that will be relied upon during these peak electricity demand periods that also coincide with low renewable generation to keep the lights on. Aside from their role in keeping the lights on, such plants do not otherwise have a sufficient purpose within the market to justify their continued operation and so generally have access to limited market revenues. With continued cost reductions in renewables and storage solutions, investing in large inflexible CCGTs makes increasingly less sense.

A large coal or CCGT plant will need to run for at between 4 and 8 hours so cannot be used to offset a day's demand peak without generation reductions elsewhere in the market. An embedded generator plant, being designed to generate around the demand peak to secure triads, is specifically designed to generate across a short peak demand period before going offline again.

The inability of large plants to run over short periods has driven the large offer cashflows in the market with plants seeing extended periods at £1,000/MWh+ when not necessarily being needed by the market as they need to be online over a prolonged period that will include, but not be restricted to, the day's demand peak. This can reward generators with figures in excess of £1m for a single run.

The design of CCGT plants has been based around long run hours with costs and technology optimised to suit these long hours. By contrast technology such as gas reciprocating engines is much simpler, enabling faster starts and stops, with the minor efficiency loss being compensated for by the very fast response times and the ability to do short runs.

The current market dynamics, and much of the current market regulation aside from embedded benefits, remain focused around plants designed to generate across long uninterrupted periods

This regulation approach suited the market back in 2010, but increasingly does not suit a market in which it becomes hard to operate plants profitably on the very margins of the market.

The latest generation of highly efficient CCGT plants alongside the existing large thermal fleet was designed for periods of extended baseload running. The market now swings around renewables so needs flexible generation to fill in the gaps in demand. This market is different to the market that a highly efficient CCGT plant is designed to operate in; even with significant capacity support payments the long term viability of a large CCGT is undermined by the need for responsive plants that can reliably start from cold quickly. What the market now needs is lots of cheap flexible MWs and CCGTs are not cheap MWs, but instead highly optimised machines.

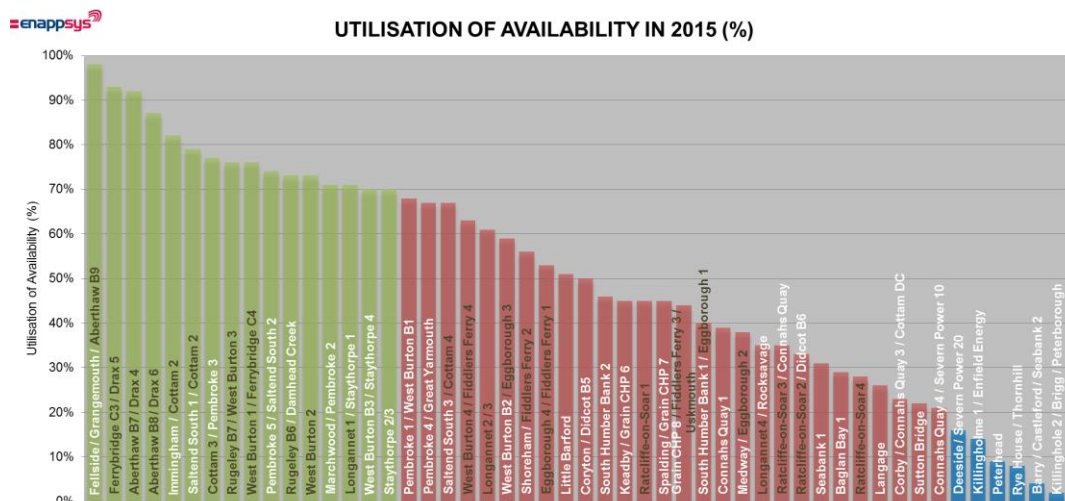
4. Future Evolution of the Market

Each year, National Grid publishes their Future Energy Scenarios (FES), projections of possible GB energy mixes and timescales of change under different scenarios. A range, rather than a single projection, is used, as potential developments depend on political, economic, technological and social factors, which can be interdependent and various.

In 2016, NG produced four scenarios Gone Green, Slow Progression, No Progression and Consumer Power, using four potential paths GB might take to project the possible fuel mixes that these paths would result in.

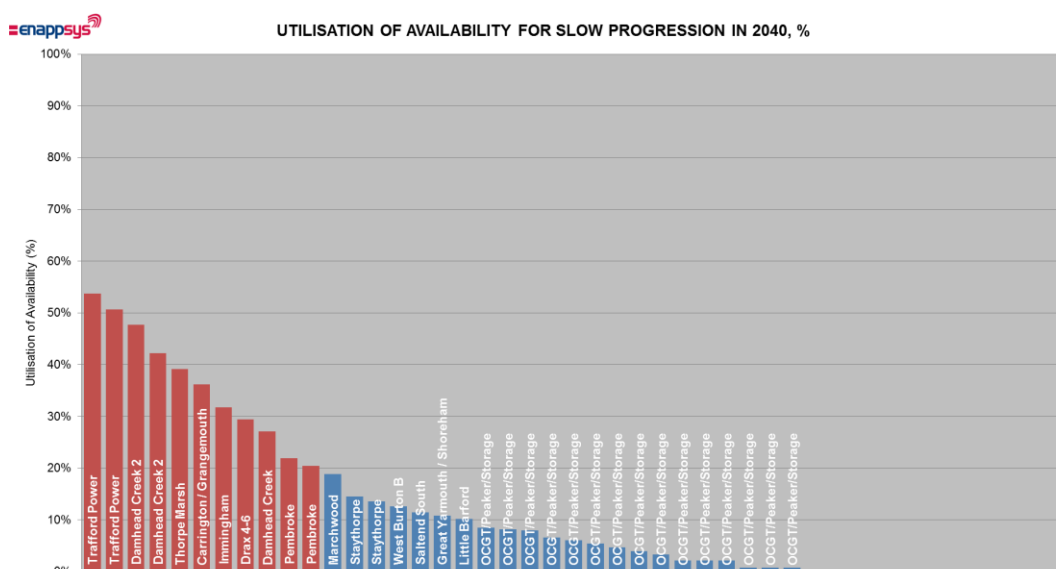
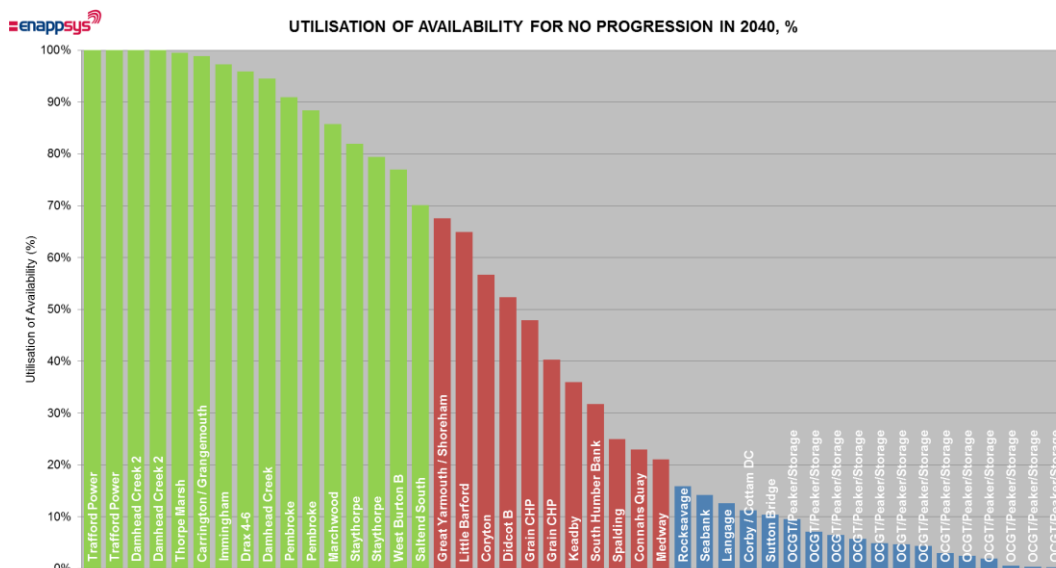
From this EnAppSys has modelled the expected progression of thermal plants within the market as a result of changing levels of electricity imports, nuclear generation and renewable installations.

In 2015 the thermal plants in the market saw the following utilisation of availability with each column representing a GW of installed capacity:

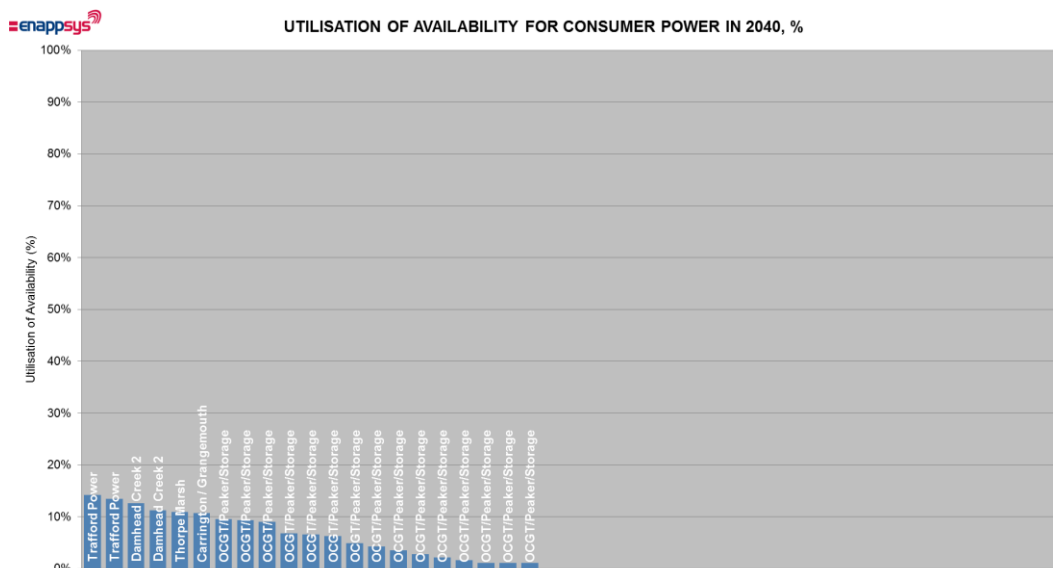


In this chart the columns coloured in green indicate plants that are generating predominantly at baseload. The red columns indicate plants generating across peak hours and columns in blue indicate plants on very low running hours.

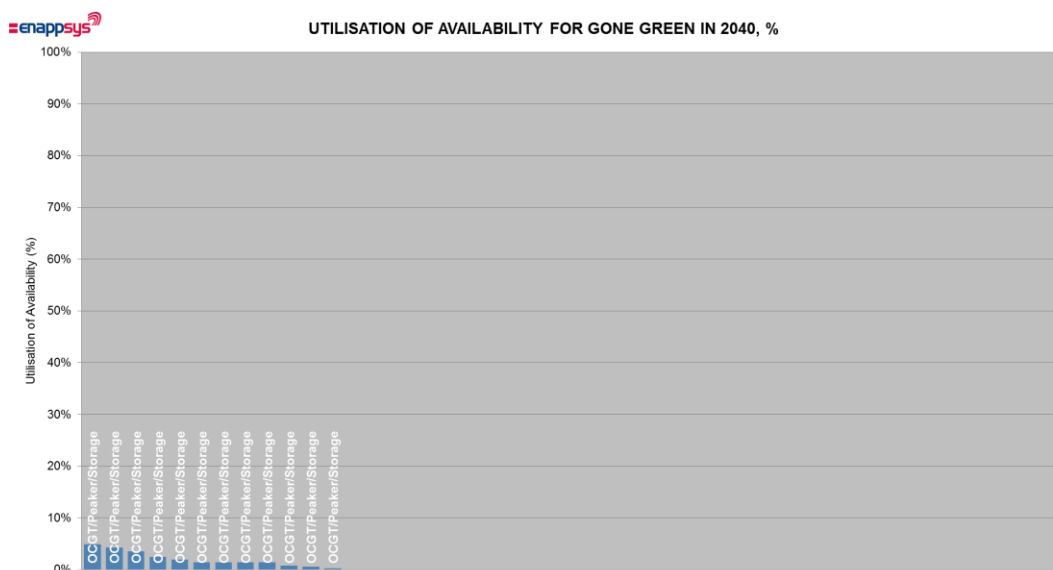
The four National Grid scenarios (from the best future for fossil fuels to the worst) give an expected utilisation by availability in 2040 as follows:



Consumer Power 2040:

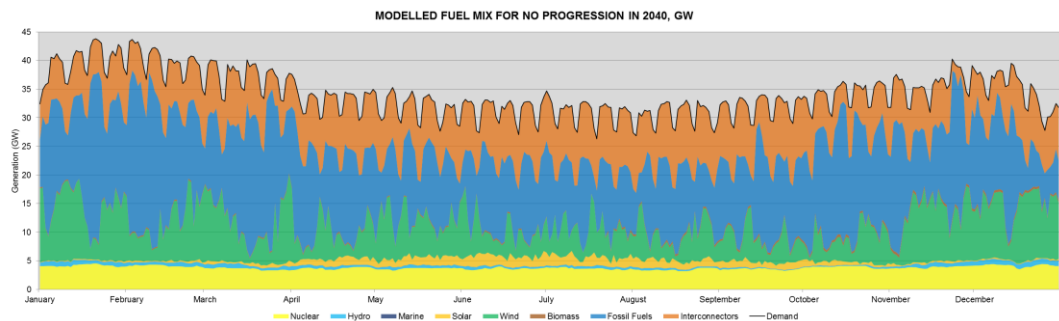


Gone Green 2040:

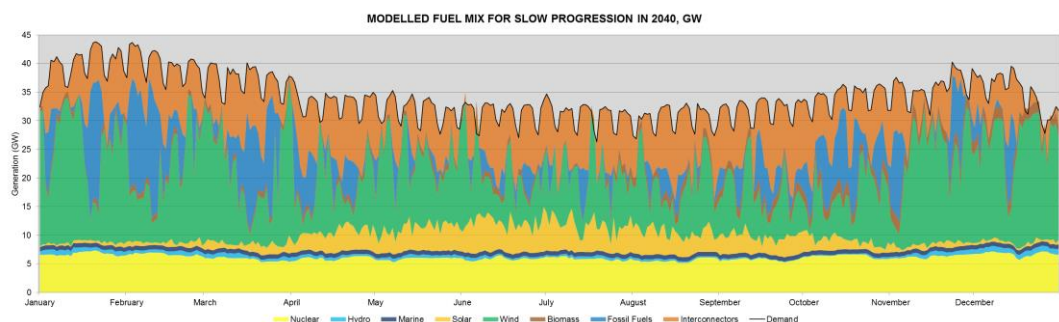


The anticipated fuel mixes that produced these modelled results were as follows:

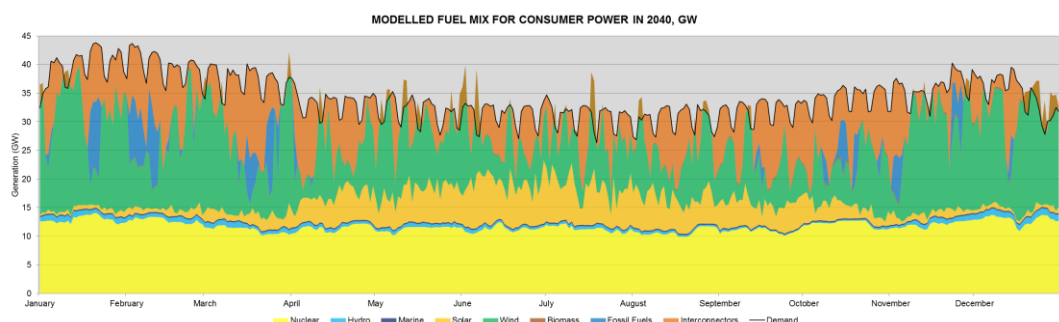
No Progression 2040:



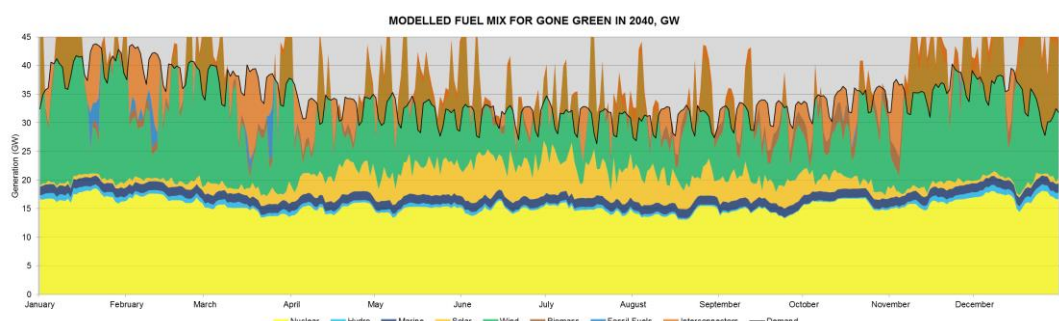
Slow Progression 2040:



Consumer Power 2040:



Gone Green 2040:



Of the above scenarios Gone Green sees very limited thermal generation beyond generating for half-hourly demand peaks, but the rest of the scenarios present a range of generation profiles for thermal plants.

In most of these scenarios renewables are expected to increase to a point where CCGTs will no longer be viable in the market, except in cases where they can adapt to become suited to only generating when the renewable output fails to be sufficient to support the system. These adaptations would be achieved either by changing to OCGT mode which is less efficient than a gas reciprocating plant or by operating as a low efficiency CCGT station which is at best only marginally more efficient as gas reciprocating plant.

These scenarios show that National Grid views the future of the market as being very different to the state of the market back in 2010 when large thermal plants generated in line with changing levels of demand.

Instead the system will become increasingly dominated by renewables with gradual erosion in levels of activity at CCGT plants; fossil fuel generation is projected as being increasingly used to fill the in occasional gaps in power output rather than providing stable generation profiles.

This will see a market shift away from long prolonged periods of generation to much shorter, more occasional and interrupted operation.

CCGT plants are designed around the principle of ensuring maximum efficiency by operating in a manner that compromises speed of delivery, ability to operate over short periods and ability to resume generation having come offline. This delivers better efficiencies, but increases fixed and in particular maintenance costs operating the plant, whilst being less flexible versus gas reciprocating engines. These costs increase and efficiencies decrease the more a CCGT plant is repeatedly started up.

As gas reciprocating engines are much simpler technology, this reduces the maintenance costs involved and allows them to start up in minutes and to repeatedly be able to be operating for recurring short periods of time. The cost of this flexibility is that efficiencies are typically ~40-42% (estimated) compared to up to the 52% efficiency rates recorded at CCGTs currently in the market which are operating at part load or full output for significant periods of time.

There comes a point where the cost to the system of accommodating plants unsuited to short generation runs becomes so high as to make it necessary to move towards plants capable of shorter generation runs at lower efficiency but with reduced externalities on the operation of other generating stations in the market.

Already the system is at times spending up to £1m per hour, turning up high cost fossil fuel generators at prices up to £1,500/MWh, while turning down identical volumes at other plants

in order to create a sufficient deliverable margin in the market and paying a premium to sidestep the lack of flexibility at these larger plants.

Use of baseload optimized plants to provide reserve services is inefficient as the additional generation has to be brought for an extended of typically 6 hours to meet a one or two hour demand peak. For the period around the demand peak other generators in the market need to be part-loaded. It is this requirement that drives high spending levels to meet short term power requirements.

Currently the most likely source for revenues for both embedded generation and storage plants is embedded benefits, with the case for storage particularly strengthened by embedded benefits; since these plants have similar expected generation profiles to embedded generation focused around demand peaks during low renewable periods only differing in the way they absorb power during oversupplied periods.

The other option would be to use flexible generation to fill that peak demand, either storage or embedded reciprocating gas engines. This would be more efficient because of the reduced fuel consumption, however, storage and a large proportion of the embedded reciprocating gas engines are allocated to other reserve services so is frozen out of the market. A large build out of gas reciprocating engines and storage would have to compete in this market driving market efficiencies.

This results in a situation where plants are effectively being rewarded for their lack of flexibility, with slower and longer running plants being those most able to extract maximum value out of the current market dynamics and weaknesses. When there is not a requirement for the margin these essentially baseload plants are unable to operate profitably. There is a glut of baseload generation for a baseload market that is disappearing due to renewables and a shortage of peaking generation for the demand peaks that are increasingly priced at a high value.

5. Low vs High Run Hours Operation

A new CCGT plant, such as ESB's new Carrington plant (that started operation in 2016) will typically have an efficiency in excess of 50% and on the 8th September 2016 (gas day – 5am to 5am) the gas flows into Carrington against the power exports indicated an efficiency of 51.9%.

Older plants such as Coryton have reduced efficiencies just above 45%, with Coryton's efficiency on the 8th September being calculated at 46.5%.

The oldest (dash for gas) plants in the market that have been closing have efficiencies of just above 40%, with some of these plants having re-configured to be open cycle power stations, resulting in lower efficiencies of around 30%, but faster response times.

For instance Peterborough was a CCGT, but is now an OCGT with an efficiency of 31.2% noted on the 21st August 2016. Peterborough is currently in STOR and the faster response times gives the plant a commercial advantage that can allow it to compete against more efficient plants in the main balancing markets. The increased market opportunities and better cost structure more than offsets the reduction in efficiencies for these plants and if generation levels fall too far it makes sense to convert a CCGT to open cycle operation to make it more flexible, despite the efficiency cost.

The same analysis cannot be run for embedded power stations which are smaller and do not have their own gas exit points, but their efficiencies are generally reported to be in the 40-42% range. These small embedded generators have very fast response times (minutes), but have tended not to participate in wholesale markets and the balancing mechanism preferring STOR and FFR. Some new entrant specialist companies are recognising the value opportunity that gas reciprocators present in the market and are now using these assets to participate in the wholesale and balancing markets.

This gives a range of efficiencies of thermal plants in the market:

- 3rd Generation Power Stations – 50%+ (slow start from cold)
- 2nd Generation Power Stations – 45%+ (slow start from cold)
- Gas Reciprocating Engines – 40-42% (very fast start from cold)
- 1st Generation (Dash for Gas) Power Stations – 40%+ (slow start from cold)
- OCGTs – 30% (fast start from cold)

The high efficiency large power stations typically generate as often as they are available to do so, but levels of generation typically reduce as efficiency levels decline as they move to a higher marginal price in the stack.

As levels of renewable generation and power grow, the size of the thermal market has been shrinking and so many of the oldest power stations such as Killingholme have been

closing and exiting the market, whilst many of the coal fleet that existed in 2010 has also now closed and / or moved into SBR.

As coal plants have closed, CCGT plants have taken up some of the generation lost from these plants, but most of the generation gains in the absence of coal stations has been at the renewable plants.

Existing CCGT plants are expected to continue to see reduced hours, both as new higher efficiency plants are built and as the overall size of the fossil fuel powered section of market continues to shrink, even as the overall market demand for electricity is forecasted to increase in the long-term increase in size as heat and transport are electrified.

To meet peak demand a form of generation will still be required to be there for peak days whilst being inactive for most of the year.

In the long-term, it is likely that storage will become a key component of the GB power sector, importing power during high renewable periods and then exporting power into the system when renewable output is reduced. However, storage technologies and renewable electricity volumes are not yet in the position where such market activity would be viable.

For the next 20-30 years there will remain a requirement for a source of power generation that can provide infrequent additional capacity to the market, supported by high levels of fixed revenue and benefiting from minimal capital and fixed/running costs.

5.1 Providing Reserve Generation

At the moment three types of gas plants provide this sort of capacity within the power market. These types include:

1. 2nd Generation CCGT stations with 45%+ efficiencies but higher fixed/running/ maintenance costs and slow start times from cold
2. Gas reciprocating engines with ~40-42% efficiency but low fixed/running/ maintenance costs and very fast start times from cold
3. Open Cycle gas stations with ~30% efficiency but low fixed/running/ maintenance costs and fast start times from cold

5.1.1 Reserve Generation without Embedded Benefits

Where these plants are not eligible to earn embedded benefits, they must compete against existing plants in markets such as the balancing mechanism, supplemented by Capacity Mechanism payments. This most commonly occurs with plants of the third OCGT type – which can start from cold faster than more efficient CCGT plants - enabling them to out-compete CCGT plants when speed of delivery is a key consideration.

This typically involves using the balancing mechanism or balancing services such as STOR where these plants will provide additional power to the market if there is loss of

generation at any large stations otherwise expected to generate or in situations where electrical demand turns out to be higher than expected (with dispatch via services such as STOR being controlled by National Grid).

5.2.1 Reserve Generation on Embedded Benefits

The plants that do earn embedded benefits are instead more typically active via ancillary services such as STOR, which involves much reduced running hours compared to main market operation at CCGT plants.

The fixed revenue at these plants is dominated by embedded benefits which means that these plants do not need to achieve high Capacity Mechanism prices in order to justify continued operation, reducing the overall cost to the system of providing capacity that can remain active in the market despite low levels of utilisation.

Instead these plants are paid to generate on the three peak demand days each year providing targeted additional generation for the system on the days when the balance between supply and demand is at its tightest limit. Whilst triads cost money it can be shown that if they are removed, value from triads has to be replaced elsewhere in the market through higher power prices in the peak, these higher power prices may not be sufficient to maintain an aging large CCGT and coal fleet and / or encourage building new CCGTs without significant capacity payment subsidies.

Since Capacity Mechanism payments are paid to all generators regardless of need or requirements, they can act as an inefficient means of ensuring that the specific requirements of the power system are met.

Such a generating profile reduces the degree to which these plants impact upon the main market, with this approach having been a key means through which the stability of the electricity system has been maintained on peak demand days in recent years.

This means that with the growth of renewables, there now effectively exists two sub-markets for thermal generators; one market based upon high levels of generation in the main power markets and another focused on occasional short runs in order to provide reserve power only when the rest of the market is unable to provide an adequate supply.

The optimal means of supporting these two markets is unlikely to be via the same market mechanism, as the generation approaches range from 90%+ utilisation of availability to less than 5% across the two categories.

At the same time demand-side users that reduce their usage during peak demand days similarly benefit from the same benefits used by embedded generators, encouraging a smarter approach to electricity consumption by large electricity users.

In recent years the size of the payments paid to embedded generators and charged to demand has risen, which has caused issues by making such generators more profitable

than other generators in the market. However the growth of renewables means that the market has evolved to the extent that it increasingly has more use for plants suited to low running hours than those suited to constant operation. The baseload market is now not sufficient to reward a fleet designed to operate in baseload mode whilst the peaking market is not served by enough assets to meet the requirement for peaking operation and so baseload units have to participate inefficiently in this market.

Large scale reduction of the embedded benefits earned by these plants is likely to translate into a follow on impact upon the Capacity Mechanism. Even with the growth in the number of embedded generators, if there are 5GW of plants earning embedded benefits then each £1/kW lost off embedded benefits that needs to be recovered from the Capacity Mechanism will also be paid out to the 45GW of plants winning capacity contracts (since all market participants receive the Capacity Mechanism clearing price).

In the above scenario, the cost to the system of making payments to all generators (irrespective of their generation approach) would be 9 times as high as making targeted payments only to generators providing power during peak demand periods.

To reduce the cost to consumers it is likely to be optimal to use a more targeted approach focused on plants that only generate during the peak hours as these plants will otherwise be unable to achieve satisfactory income in the market without the creation of excess benefits for more efficient plants that are running different generation strategies.