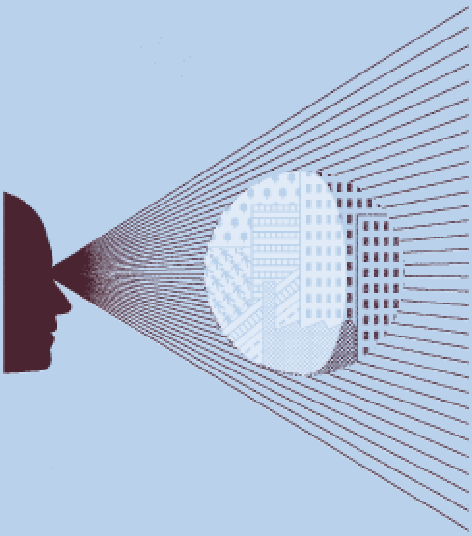
GB capacity mechanism design

Meeting future flexibility requirements to secure a low-carbon transition

Prepared for members of the Independent Generators Group

March 9th 2011



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Note **that DONG Energy and ESBI fully endorse the Oxera analysis of the issue but** ***do not*** **support the solution proposed.**

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Executive summary

This report, prepared for members of the Independent Generators Group (IGG), provides an analysis of DECC's preferred approach to the introduction of a capacity mechanism in the GB electricity market. It examines the appropriateness of narrowly targeting capacity payments to certain reserve capacity in order to meet a centrally determined target capacity margin.[1]

The report provides an initial assessment of the change in system conditions, and the accompanying risks that may be caused by increased wind generation alongside the expansion of nuclear and carbon capture and storage (CCS) projects in the GB electricity market.

In particular, analysis is presented to examine the extent to which system 'flexibility requirements' are likely to change over time. That is, the hourly and daily changes in demand net wind, as well as the economic incentives that may be present in order for existing and potential flexible capacity to be available to meet this requirement—a challenge that is distinct from the need to provide a capacity margin above system peak demand.[2]

The analysis provides a starting point with which to undertake an initial assessment of whether DECC's preferred targeted capacity mechanism (TCM) might alleviate or exacerbate these risks, and the scope for potential price distortions and the impact that this may have on investment incentives.

The report then sets out some initial considerations on an alternative mechanism that could be better equipped to address the flexibility challenge posed by the possibility of early retirement of existing flexible plant, and weakened investment incentives that may otherwise deter investment in sufficient new flexible capacity to deliver longer-term security of supply.

Flexibility requirements

With regard to system flexibility requirements, the key findings of the analysis are that:

– changes in the generation mix could increase GB flexibility requirements, which are governed by short-term variations in demand net wind, and as such, are different to the traditional need to meet system peak demand;

– flexibility can be provided by flexible generation and demand-side response (DSR), with short-term responsiveness on the generation side governed by the difference in plant's maximum and stable export limits, with further constraints determined by plant ramp rates and whether the plant are already synchronised;

– a 'flexibility gap'—defined in this report as the situation in which short-term responsiveness from flexible capacity could be insufficient to meet hourly demand-net-wind variations—could emerge by around 2020, regardless of whether system capacity is sufficient to meet peak demand.

Figure 1 below shows a projection of total de-rated capacity for flexible thermal plant, and the supply and demand of hourly flexibility (or responsiveness). The analysis is based on

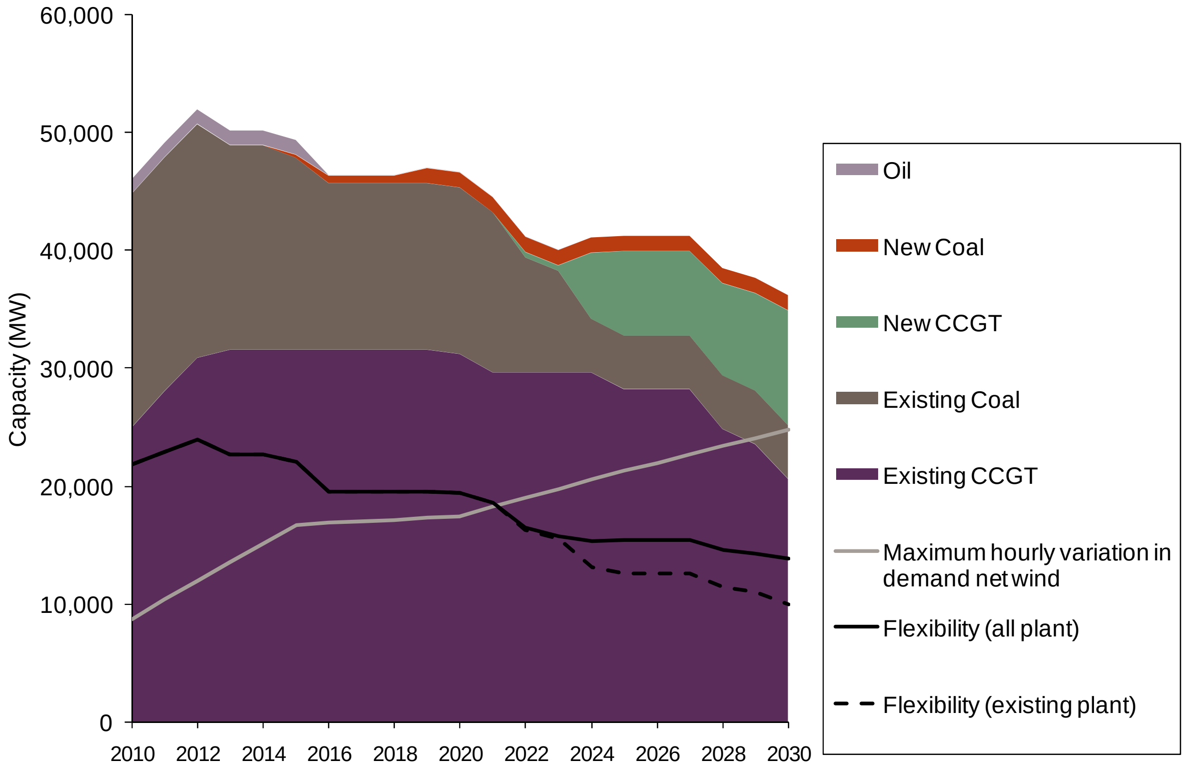
[1] Department of Energy and Climate Change (2010), 'Electricity Market Reform. Consultation Document', December.

[2] Flexibility requirements are likely to include the ability to meet hour-to-hour variations as well as increased variation in daily peaks and troughs of demand net wind. The analysis in this report focuses on the ability to respond to hourly variations.

commodity price assumptions reflective of current forward prices, and investment in new CCGTs based on current price dynamics and revenue expectations that assume perfect foresight and efficient dispatch.

The figure highlights the increase in system flexibility requirements over time, and the decrease in the supply of flexibility (measured as the difference between plant's maximum and stable export limits) alongside the decrease in total flexible capacity.

Figure 1 Supply and demand for hourly flexibility



Note: Retirement profiles of existing plant and investment in new plant are based on efficient dispatch and existing price dynamics that reflect the historical relationship between price levels and capacity margins, and absent possible price distortions. Capacity is de-rated to reflect average availability. Capacity figures exclude nuclear and CCS, which are deemed to be inflexible (both due to technical restrictions and because they are likely to operate at high load factors and to have limited scope to provide additional output). It also excludes pumped storage, which cannot be drawn on frequently once depleted, and is often used to provide shorter-term (sub-hourly) response.
Source: IEML, and Oxera analysis.

Increased wind penetration is also likely to exacerbate the total peak-to-trough changes in demand net wind over the duration of a typical day. The analysis in this report suggests that the maximum simulated daily range of demand-net-wind levels could increase by around 40% compared with 2009.

Flexibility investment incentives

With regard to flexibility investment incentives, the key findings of the analysis are that:

– absent intervention, there might be insufficient incentive to invest in adequate flexibility. This is because thermal plant could be required to rely increasingly on short-term revenues that encompass increased risks that may not be hedged, and are subject to the threat of distortions from 'out-of-market' actions;

– specific risks include the ability to capture short-term price spikes caused by wind variations, and the increased risk to plant performance from more frequent output variations;
– these risks could be larger for non-integrated and non-portfolio players—uncertainty over future operating conditions could reduce the scope to contract forward and sell power sufficiently far in advance at attractive terms, as well as hedge price risk.[3]

DECC's preferred TCM does not attempt to mitigate these risks, and may exacerbate the risk of price distortions. Out-of-market actions (or even the potential for such actions) by the operator of capacity contracted under the proposed TCM, can directly affect price and volume expectations for balancing and ancillary services. In particular:

– they may reduce balancing volumes procured through the market, and hence expectations of balancing mechanism prices;
– there may also be a reduction in other reserve contracts and ancillary service requirements, leading to reduced price expectations for contracts outside the proposed mechanism.

The Electricity Market Reform (EMR) consultation recognises that potential distortions could arise through the effect of dispatch of the targeted capacity on peak prices, and that these distortions, along with the risk that an increasing proportion of capacity may need to be contracted under the proposed mechanism, 'could undermine the mechanism's ability to ensure secure supplies of energy'.[4]

DECC's proposed TCM is similar to the Swedish model, which makes use of peak load reserves. There is evidence from regulators and academic studies that potential price distortions remain a risk under this model and that peak load tendering should generally be avoided.[5]

An alternative flexibility mechanism

A broader-based mechanism, designed to reward flexible capacity, could provide the necessary investment incentives and mitigate the increasing market risks faced by providers of flexibility. Basic, technology-neutral eligibility criteria could be defined, and plant receiving FITs could be deemed ineligible to avoid over-rewarding low-carbon capacity.

In the EMR consultation DECC states that it would assess the effectiveness of the market reform options along four broad principles:

– cost-effectiveness;
– durability and flexibility;
– practicality;
– coherence.

In this context, an appropriate flexibility mechanism might be expected to:

– mitigate the increased risks faced by flexible plant as wind penetration increases;

[3] Hart (1988) describes how the firm as an institution can be thought of as arising from the incompleteness of contracts and the need to allocate residual control rights. See Hart, O. (1988), 'Incomplete contracts and the theory of the firm', *Journal of Law, Economics and Organization*, **4**(1), spring.

[4] Department of Energy and Climate Change (2010), op. cit., p. 94. The EMR consultation recognises that the potential effects on peak prices and the 'slippery slope' effect could undermine the performance of the proposed TCM.

[5] See, for example, Svenska Kraftnät (2002), 'Effektförsörjning på den öppna elmarknaden, Utredningsrapport', January 10th. Johansson, T. and Nilsson, M. (2010), 'Signs of stress II: The customer strikes back', April 9th. Nord Pool Spot (2010), 'Handling of the peak load reserves in the spot market', October 1st. Botterud, A. and Doorman, G. (2008), 'Generation Investment and Capacity Adequacy in Electricity Markets', International Association for Energy Economics. Energy Markets Inspectorate (2006), 'Price Formation and Competition in the Swedish Electricity Market', report 2006:13. NordREG (2009), 'Peak Load Arrangements, Assessment of Nordel Guidelines', report 2/2009. NordREG (2010), 'Assessment of Nordel's revised Guidelines for transitional peak load arrangements', March.

- minimise entry barriers that could accompany a non-market-based and discretionary mechanism such as the TCM;
- provide the greatest signals to invest as the flexibility requirements from intermittency increase;
- accommodate increased DSR, and spur innovation and increasing participation from the demand side.

Based on the initial considerations in this report, a fixed revenue mechanism might be able to strike an appropriate balance between creating the right investment signals for providers of flexibility while minimising complexity and the risk of gaming. Such a mechanism could be implemented as follows.

- An annual flexibility requirement (in GW) could be calculated based on wind penetration and expected variations in output, inflexible demand variations, and a security standard (eg, a requirement to meet three standard deviations (or 99.7%) or expected hourly variations in demand net wind).

- A total annual revenue amount could be determined based on system flexibility requirements and the costs of the marginal provider of flexibility.

- The revenue pot could be split between different time periods, based on a combination of anticipated flexibility requirements and ex post demand and wind outturn (so that greatest revenues are available when flexibility requirements are highest).

- All flexible generation and demand participants available within a given period could be eligible to receive a share of the revenue available in that period.

The advantages of such a mechanism are that:

- a degree of stability could be introduced into the flexibility payments through tailoring the revenue split between a fixed element and one related to ex post system conditions;
- the mechanistic calculation of annual revenues based on wind penetration, demand growth and known statistical distributions could help promote longer-term investment signals;
- short-term signals could be generated to create the incentive for flexible generation and demand to be available through the ex post revenue allocation.

The potential drawbacks of such an approach are the administrative costs of annual forecasting and operation of the scheme. This would be likely to be a feature of any broad-based mechanism, but could be smaller for mechanisms that are relatively less complex.

A useful area for further analysis would be to consider the timeframe over which flexibility requirements should be defined.

Next steps

This report provides an initial analysis of the potential flexibility gap facing the GB electricity system, and the risks that are likely to be faced by owners of existing flexible capacity and developers of new plant. The provision of future flexibility has been assessed based on existing price dynamics.

Useful further work would be to refine the estimates of future GB flexibility requirements, based on a more detailed analysis of flexible plant operating capabilities, and the manner in which prices may respond to a potential flexibility shortfall and the implications of this for plant returns. This would also facilitate a full cost–benefit analysis of alternative flexibility mechanisms.

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1 Introduction

Oxera was commissioned by the Independent Generators Group (IGG) to analyse DECC's preferred approach to the implementation of a capacity mechanism, [6] a key feature of which is the targeting of capacity payments to certain plant, which may be necessary to meet a centrally determined target capacity margin.[7]

This report follows Oxera's earlier work for the IGG on alternative capacity mechanism designs, which highlighted a number of factors that are expected to contribute to the need for reform of existing market arrangements, including the following.[8]

– The GB market is an 'energy-only' market in which, up to now, new efficient fossil plants have had the prospect of some years of high utilisation and economically viable returns, before being pushed down the 'merit order' by newer, more efficient plant.

– The expansion of subsidised intermittent renewable and relatively inflexible nuclear generation capacity means that new flexible plant is expected to run at lower lifetime levels of utilisation than has been the case in the past, as well as increase operating risks due to a greater reliance on short-term revenues as a result of the uncertain variations in wind output.[9]

– The need for flexible plant to rely on the capture of high prices for the few hours in which they run and the increased risk of exposure to the missing money problem—that is, the tendency for energy-only markets not to deliver those very high prices, either because of non-price, out-of-market interventions by the system operator or because of regulatory intervention to curtail high prices.[10]

A key policy challenge to be addressed therefore is how best to respond to the challenge that increased wind generation, alongside the expansion of nuclear and carbon capture and storage (CCS) projects, may hasten the retirement of existing flexible plant and worsen the incentives to deliver the flexibility required to complement wind power and deliver longer-term security of supply.

These flexibility requirements could be provided by flexible generation or demand-side response (DSR). Significant electrification in transport and heat could increase the scope for DSR participation, but would also create additional generation requirements to meet this demand.

[6] ConocoPhillips European Power Ltd, DONG Energy Power (UK) Ltd, Drax Group plc, Eggborough Power Ltd InterGen, International Power plc

[7] DECC (2010), 'Electricity Market Reform. Consultation Document', December.

[8] Oxera (2010), 'Electricity market reform: does the GB electricity market need a capacity-based mechanism, and what form should it take?', note prepared for the IGG, October 5th.

[9] The Energy Market Assessment and Ofgem's Project Discovery did question whether the existing wholesale electricity market arrangements are likely to deliver the government's objective of maintaining security of supply alongside the requirement for substantial market penetration of intermittent plant to decarbonise the sector. See HM Treasury/Department of Energy and Climate Change (2010), 'Energy Market Assessment', March; and Ofgem (2010), 'Project Discovery: Options for delivering secure and sustainable energy supplies', February.

[10] Rewarding existing and new capacity is likely to be a key component in creating the appropriate investment incentives—not only to avoid distortions to market operation through the possible discrimination between plant, but because mechanisms targeted at a subset of plant that have the potential to depress the returns to existing plant can be expected to weaken the incentives of that support due to uncertainty over future expropriation.

However, significant demand growth from electrification is omitted from DECC's analysis. To the extent that increased electrification might impose additional generation requirements that are equal to the potential flexibility it could in turn provide, this would be an appropriate assumption that would require further analysis. However, this is outside the scope of this report. Instead, the report considers the way in which a wider-base mechanism than that proposed by DECC could promote innovation and participation by the demand side. To assess the extent to which DECC's preferred approach would be able to address this policy challenge, and whether an alternative mechanism may be more appropriate, this report has therefore sought to:

– analyse the requirements for flexible capacity (as opposed to simply more capacity) in Great Britain;

– set out the rationale for intervention to support secure development of sufficient generation capacity that is also flexible by assessing potential market distortions arising from the Electricity Market Reform (EMR) policy proposals;

– estimate the impact of these market distortions on the economics of existing flexible plant and new build;

– develop a design for a potential mechanism that could meet the challenge of delivering more flexible capacity, and could be compatible with the current GB market context and other aspects of DECC's reform proposals.

The remainder of this report is structured as follows.

– Section 2 provides an analysis of GB flexibility requirements.

– Section 3 sets out the potential market distortions that could arise from current EMR proposals, and how they may affect plant economics.

– Section 4 quantitatively assesses the economics of flexible plant.

– Section 5 puts forward a possible GB flexibility mechanism.

– Section 6 concludes.

2 GB flexibility requirements

Increasing wind capacity is likely to result in an increase in the variability of load on thermal plant, thereby creating a greater need for flexibility (ie, the ability to respond to demand-net-wind variations). This section assesses the scale of possible flexibility requirements and provides an estimate of the 'flexibility gap'—defined as the difference between system capability and the requirement to meet hourly demand-net-wind variations, and the ability of the system to meet the flexibility challenge in the period up to 2030.

Box 2.1 summarises the key messages of the section.

Box 2.1 Key messages on flexibility requirements

GB flexibility requirements

– Wind penetration is required to increase significantly in order to meet the UK's renewables and low-carbon targets.

– Wind variability creates new system flexibility requirements from generation and demand participants.

– This system requirement is governed by short-term variations in demand net wind, and is therefore different to the traditional need to meet system peak demand.

– The supply of flexibility from generation can be estimated based on the difference in plant's maximum and stable export limits, with further constraints determined by plant ramp rates, and whether the plant is already part- or fully-loaded.

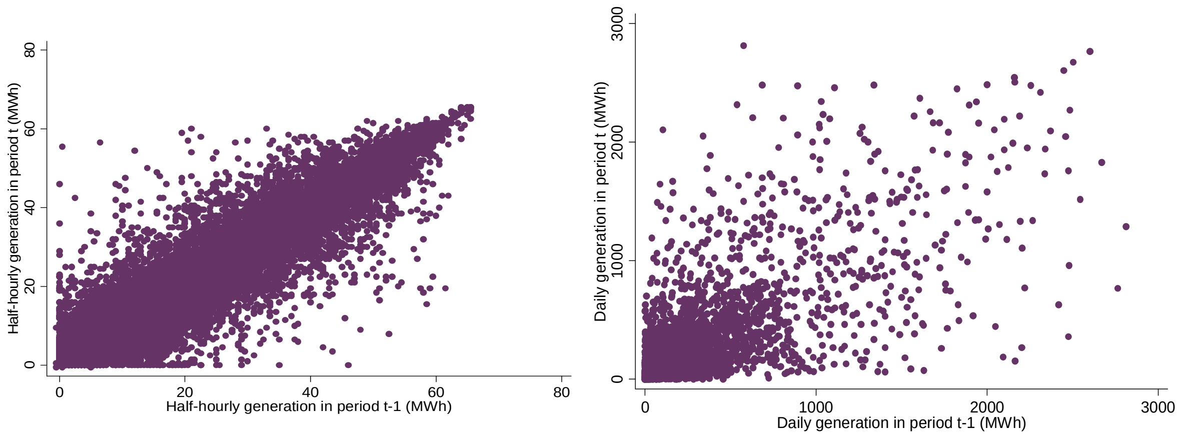
– The flexibility provided by existing and new plant may be insufficient to meet system requirements, despite that capacity's ability to meet peak demand.

2.1 Wind variability

The extent to which increased wind capacity might be expected to affect variations in demand net wind depends on the degree of variability of wind output.

Figure 2.1 below compares wind output over consecutive half-hours and consecutive days. When comparing wind output over consecutive days the degree of correlation falls, with the extent of variability increasing substantially.

Figure 2.1 Historical wind output variations (2008–09 data)



Note: Analysis based on maximum export limit of wind plant from 2008 to 2009.
Source: BMRS, and Oxera analysis.

2.2 Impact of wind variability on variations in load

The load on thermal and nuclear plant is determined by the level of demand net wind. Given potential uncertainty around both demand and wind levels, the level of demand net wind during the day and in a given year can have a wide range.

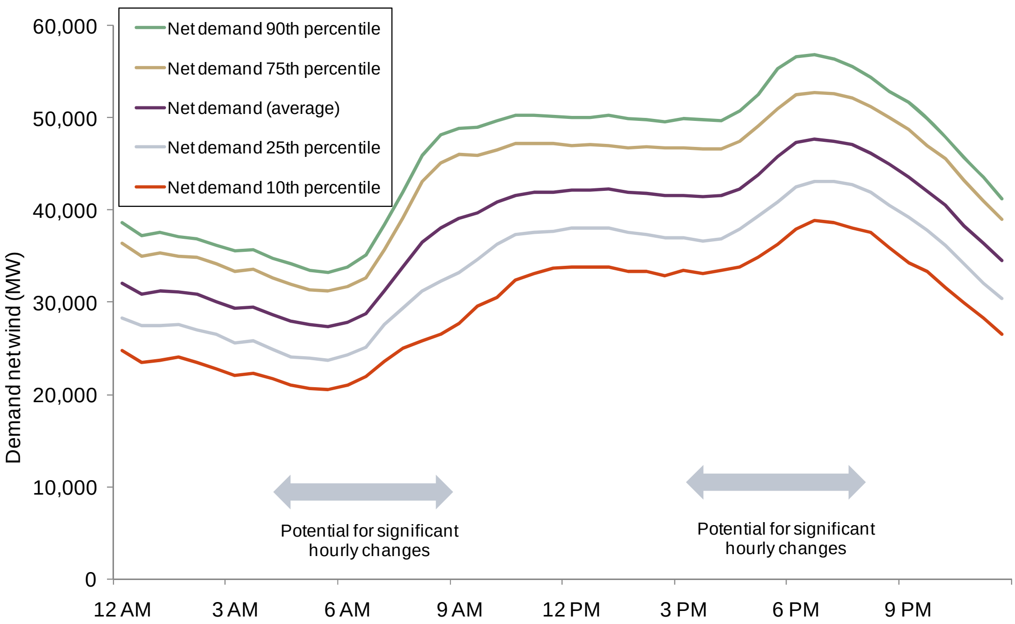
Figure 2.2 below presents demand-net-wind curves for a representative winter day in 2020. The shapes of the curves and their distributions are based on Monte Carlo simulations of demand and wind output over a representative day. The simulations are based on the historical distributions of demand and wind output, and incorporate correlations between demand and wind across consecutive periods as implied by historical patterns.

Wind capacity has been modelled to grow from its existing level of around 5GW to 20GW by 2020 under the existing Renewables Obligation. Demand is assumed to grow at a rate based on National Grid's Seven Year Statement, and is broadly consistent with DECC's assumptions. This equates to a compound annual growth rate of 0.2% between 2010 and 2020.

The figure highlights:

– the potential range and uncertainty in load on thermal plant by presenting alternative points on the distributions of demand net wind (defined by percentiles);
– the potential for significant hourly changes in demand net wind when going from peak to off-peak periods and vice versa within a particular distribution of demand net wind.

Figure 2.2 Demand-net-wind distributions, winter 2020



Source: BM reports, National Grid, and Oxera analysis.

Instances of relatively high demand net wind might be expected to lead to potential price spikes, and profitable opportunities for flexible plant to provide output to meet this demand if they have sufficient foresight and responsiveness. Periods of low demand combined with high wind create the risk of low (or negative) power prices.

These dynamics affect the revenue potential of thermal plant, as well as their costs, since variations in load are likely to increase the operating and maintenance costs of plant as a result of increasing ramp-up and -down at frequent intervals, as well as the loss in thermal efficiency that can arise from operating below maximum output. The impact of increasing wind capacity on plant economics is explored in further detail in section 4.

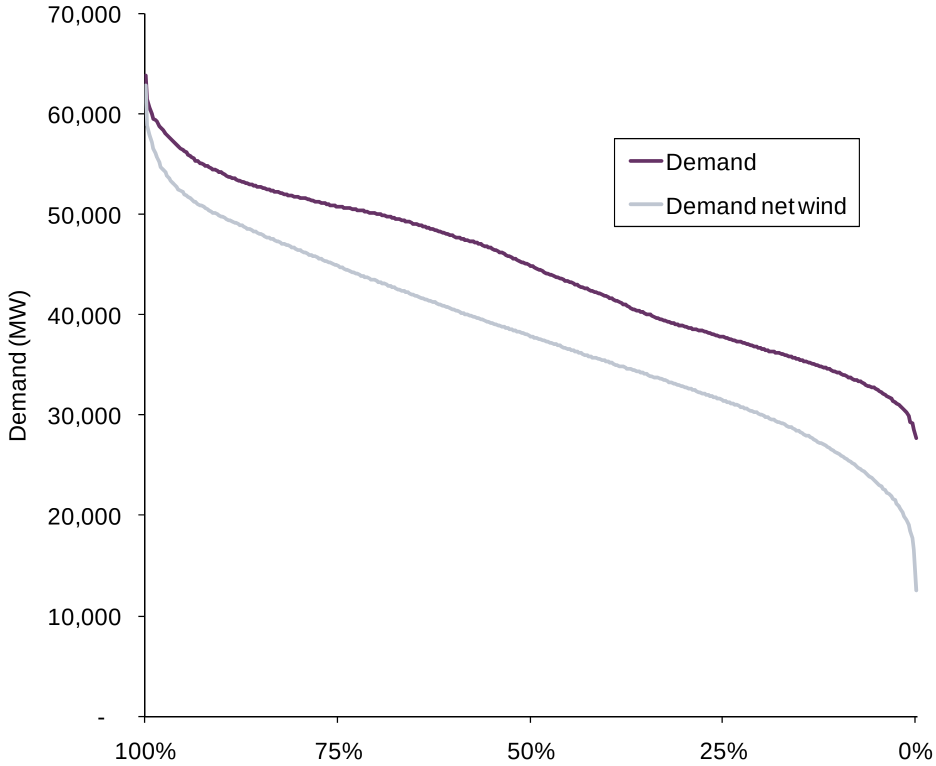
2.3 Impact of wind variability on system requirements

Figure 2.3 below assesses the impact that wind capacity might have on peak demand. It presents demand-net-wind distributions based on Monte Carlo simulations of demand and wind patterns.

Distributions of wind utilisation and demand have been constructed based on historical data, including correlations between subsequent time periods. Monte Carlo simulations have then been used to sample from these distributions within a typical day, and the results scaled up to reflect the impact on demand net wind in future years, based on demand growth and wind penetration assumptions.

The analysis highlights that by 2020, peak demand requirements remain largely unchanged in the presence of wind. However, peak plant are required to operate for fewer hours in peak periods, implying that that they would need to be remunerated with higher prices over shorter periods to provide sufficient returns.

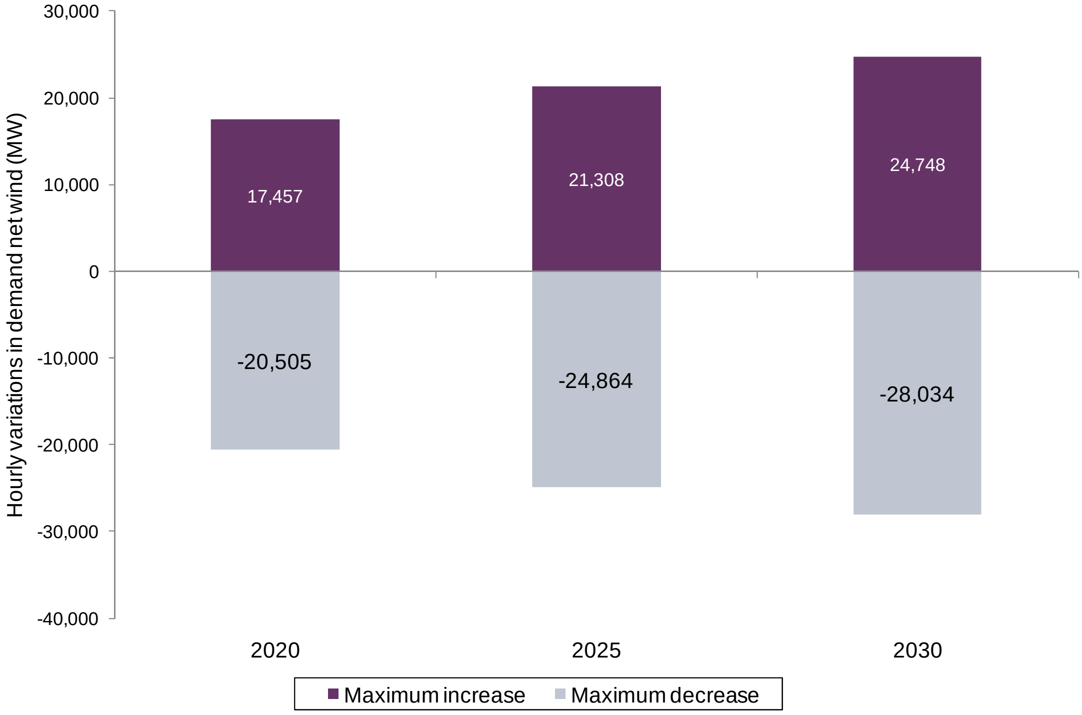
Figure 2.3 Load duration curves, winter 2020



Note: Wind deployment has been modelled to equal 20GW based on Oxera modelling of the Renewables Obligation under central power price and demand assumptions.
Source: National Grid, BM Reports, and Oxera analysis.

Although peak demand remains unchanged with increasing wind capacity, there is a substantial increase in the potential variations in demand. Figure 2.4 below presents the distribution of hourly increases in demand and demand net wind in winter 2020, 2025 and 2030. It shows that at the extreme, the hour-to-hour increases in demand net wind could be around 17GW in 2020 as a result of increasing wind capacity. By 2030, increasing wind deployment could result in the hour-to-hour increases in demand rising to around 25GW due to the increase in wind capacity.

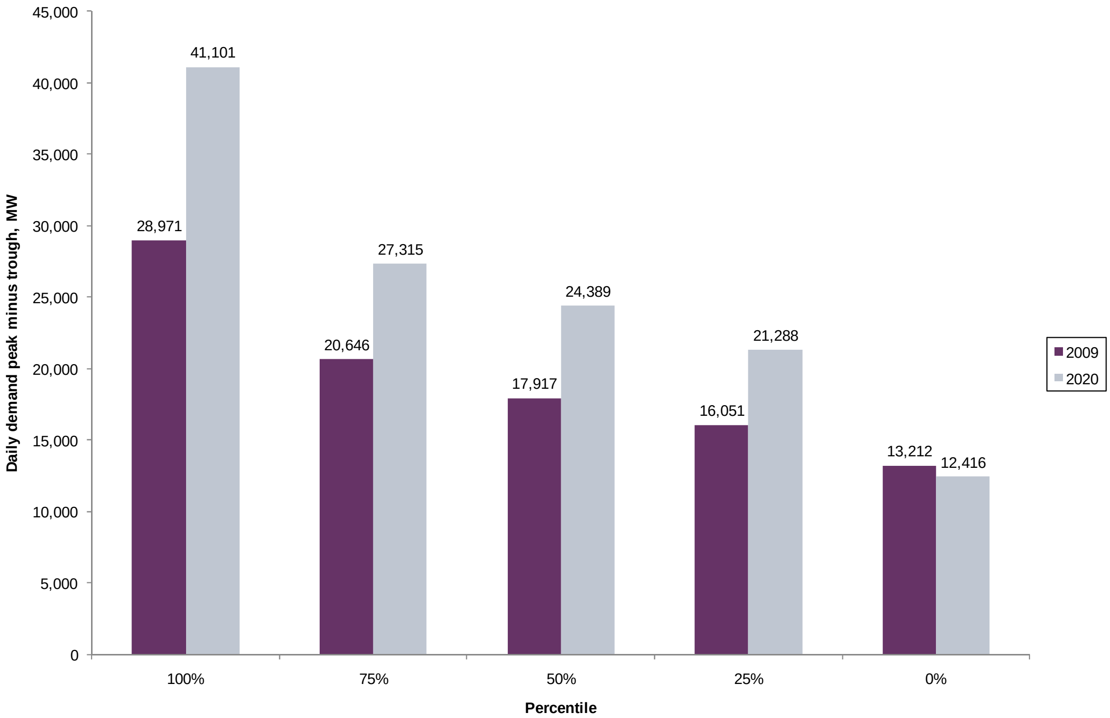
Figure 2.4 Hourly demand-net-wind variations, winter



Source: National Grid, BM Reports, and Oxera analysis.

Increased wind penetration is also likely to exacerbate the total trough-to-peak changes in demand net wind over the duration of a typical day. This is highlighted in Figure 2.5, which shows that the maximum simulated daily range of demand-net-wind levels in 2020 could increase by around 40% compared with 2009.

Figure 2.5 Daily range in demand net wind, winter



Source: National Grid, BM Reports, and Oxera analysis.

Therefore, with peak demand remaining unchanged, the primary impact of increasing wind capacity on the system is likely to be increased variability of system load and the need for the system to become more flexible as a result. Furthermore, although peak demand remains largely unaffected, peak plant will have to be remunerated sufficiently for operating in fewer periods.

2.4 Ability of system to meet flexibility requirements

The analysis above highlights that the potential range of hourly variations in demand net wind and peak-to-trough within-day variations can be significant.

The ability to meet extreme hourly variations in demand net wind is likely to be the binding constraint in meeting these requirements. The analysis below provides a preliminary assessment of the ability of the generation side to meet these possible variations.

The analysis focuses on the ability of the generation side to flex up (ie, increase output), rather than flex down, as this more likely to be a binding constraint on the operation of the system than reducing the output of generation.

The ability of the generation side to meet these flexibility requirements is assessed in Table 2.1, along the following two dimensions.

– **Flexibility** is defined as the capacity available to meet short-term variations in demand net wind, and measured as the difference between a plant's maximum export limit (MEL) and stable export limit (SEL).

– **Responsiveness** represents a further constraint on the available capacity to reflect the rate of change at which each plant can change output. It is calculated by scaling up estimated plant ramp rates (MW/minute) to measure hourly variations, constrained by the average size of a plant, and the difference between its maximum and stable output (MEL minus SEL).

Table 2.1 highlights that, based on the plant assumptions shown, the constraining factor in meeting hourly variations in demand net wind is likely to be the total flexible capacity (ie, the difference between MEL and SEL) rather than plant ramp rates.

Table 2.1 Flexibility and responsiveness of typical flexible plant

	Existing coal	Existing CCGT	New CCGT	Oil
Flexibility				
Plant flexibility (percentage of rated capacity) [1]	60%	35%	40%	40%
Average plant flexibility (MW)	840	280	400	400
Responsiveness				
Ramp rate (MW/minute)	15	17.5	20	20
Implied hourly ramp rate (MW/hour)	900	1,050	1,200	1,200
Ramp rate constrained by average plant capacity (MW/hour)	900	800	1,000	1,000

Note: [1]Plant can flex down to 40% of maximum continuous rating. The figures above are based on the following average plant capacities: existing coal (1,400MW), existing CCGT (800MW), new CCGT (1,000MW), oil (1,000MW).
Source: IEML, and Oxera analysis.

These estimates provide a useful starting point to assess system flexibility. However, in practice system flexibility may be lower than the estimates presented in Table 2.1 for the following reasons.

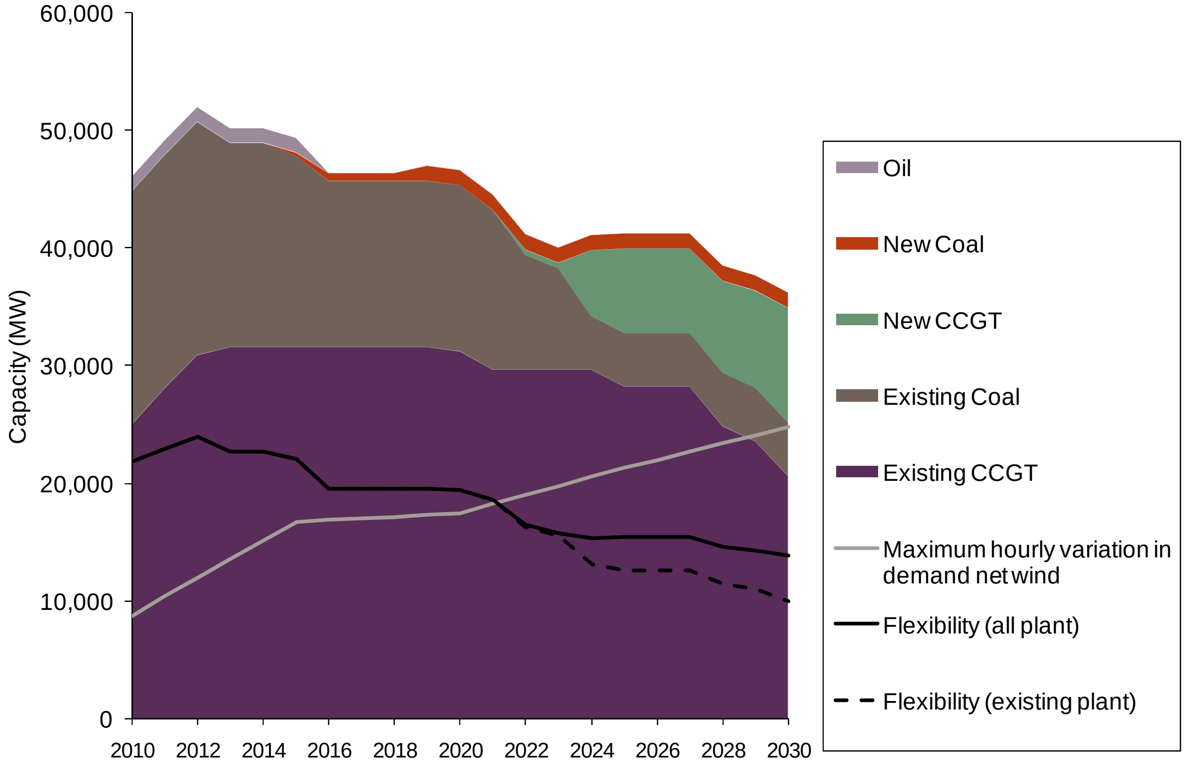
– The ability to flex up at short notice is provided by plant that are part-loaded. Available flexible capacity should therefore be scaled down to reflect the extent to which plant are already operating above their stable minimum output (ie, SEL) and further scaled down to reflect the fact that plant cannot provide hourly flexibility unless it is on-load.

– The provision of flexibility may be limited by restrictions on plant operations within long-term service agreements and manufacturers' guarantees that place limits on the number of cold starts or other operating behaviour.

A measure of the system to deliver future flexibility requirements, and the scale of any flexibility gap can be assessed by comparing the simulated system flexibility requirements with projections of the level of future flexible capacity.

An assessment of the future flexibility gap is set out in Figure 2.6. The figure shows that system flexibility is likely to decline over time due to a reduction in thermal capacity, despite some investment in new plant; while flexibility requirements are expected to increase as a result of increasing wind capacity.

Figure 2.6 Supply and demand for hourly flexibility



Note: Retirement profiles of existing plant and investment in new plant are based on efficient dispatch and existing price dynamics that reflect the historical relationship between price levels and capacity margins, and absent possible price distortions. Capacity is de-rated to reflect average availability. Capacity figures exclude nuclear and CCS, which are deemed to be inflexible (both due to technical restrictions and because they are likely to operate at high load factors and to have limited scope to provide additional output). It also excludes pumped storage, which cannot be drawn on frequently once depleted, and is often used to provide shorter-term (sub-hourly) response.
Source: IEML, and Oxera analysis.

Figure 2.6 also highlights that:

- in the absence of investment in new flexible plant in the next few years, system flexibility could become tight from around 2020;
- investment in new and existing capacity would be essential to provide required flexibility beyond 2020;
- flexible capacity may be insufficient to meet demand variations by 2030, regardless of whether system capacity is sufficient to meet peak demand.

As noted above, the outturn supply of flexibility may be lower than that shown in Figure 2.5, where flexible capacity is already operating above its SEL, or has reduced responsiveness if it must start from cold.

2.5 Summary

Assuming wind output distributions similar to those observed historically, and generation investment and retirement decisions based on current market dynamics, the analysis in this section suggests that:

- greater deployment of wind plant is likely to result in increased variability in output provided by thermal plant;
- peak demand is likely to remain unchanged as a result of increasing wind generation, although peaking and mid-merit plant are required to operate and recover their fixed and capital costs over fewer hours;
- the main impact of wind capacity would therefore be to significantly increase the flexibility requirements on the system instead of on its ability to meet peak demand;
- system flexibility is expected to decline over time as existing flexible (ie, thermal) plant shut down and there is increased deployment of inflexible (ie, wind) plant;
- by 2030, a flexibility gap could develop, based on investment and retirement decisions under the current forward curve for gas and coal prices, and short-term flexibility provision by generating plant equal to the difference between plant's maximum and stable export limits and ramp rates. This would be due to closures of existing thermal capacity, with insufficient volume of new CCGT expected to be built;
- new CCGTs are expected to provide around half of the system flexibility by 2030;
- any market distortions that lead to early closures of thermal plant or dampen investment incentives are therefore likely to reduce system flexibility and to hamper the ability of the system to respond to demand variations. Such closure and investment incentives are explored in section 4.

3 Rationale for intervention

The EMR consultation suggests that a targeted capacity mechanism (TCM) would only be required to procure a small amount of capacity and that any potential distortions would therefore be relatively small. This section considers the nature of the risks that could be faced by flexible plant as wind penetration, and nuclear and CCS generation increase, and whether potential distortions to scarcity prices could be significant.

Box 3.1 summarises the key messages of the section.

Box 3.1 Key messages

Rationale for intervention

– The role of flexible generation is likely to change as wind penetration increases and this is likely to create a fundamental shift in the investment case for thermal plant, and could hasten the retirement of existing plant.

– Revenue and cost risks to flexible generation are likely to increase as wind intermittency increases, due to the inability to anticipate system conditions far in advance and the impact that increased output variability may have on plant costs, some of which may not be hedged in the market.

– Under the current proposals, the risks could be larger for non-integrated and non-portfolio players due to the difficulties in writing complete contracts and the benefits of portfolio diversification.

The following dynamics are considered in turn.

– The extent to which increased wind penetration may lead to an increase in the reliance of flexible thermal plant on short-term trades (particularly for independent generators).

– Whether the nature of wind intermittency may create new risks around price capture for flexible plant, as well as increase imbalance risks and, therefore, the level of prices that would be required by generators providing power on a short-term basis.

– The extent to which the presence of a subset of reserve capacity could lead to lower expectations of forward power prices and ancillary service due to the threat of 'out-of-market' actions from the operator of that capacity.

3.1 Increased reliance on short-term revenues

With increased wind penetration, short-term variations in wind output are likely to increasingly determine system operating conditions. Flexible plant operating at low load factors that have traditionally operated in relatively well-foreseen periods of high demand (eg, winter peak periods), are more likely to be required to generate in periods of system tightness, driven more by hourly wind variations than the underlying levels of demand.

This uncertainty for flexible plant over their future operating patterns in the days and months ahead of real time might be expected to reduce the scope for such plant to contract in forward markets to sell this power ahead of time, as well as hedge against possible price levels in those periods. The difficulty may arise in specifying within a long-term contract exactly under what conditions the plant should operate given the number of possible supply and demand conditions.

This prospect could be more acute for independent generators than vertically integrated companies, where the supply affiliates of the latter can draw on their generation portfolio in circumstances that are difficult to anticipate or define far in advance.

This phenomenon reflects the widely recognised notion that where complete contracts cannot be specified in sufficient detail in advance, market transactions are more likely to break down and be replaced by internal contracts established through vertical integration.[11]

3.2 Increased risks of short-term revenues

Increased reliance on short-term trades, especially for independent generators, as described above, might also be expected to be accompanied by greater risk associated with those revenues, as well as on the cost side. These include:

- the risk of a plant being unavailable at short notice to meet changes in demand net wind in order to capture price spikes;
- the risk of distortions to scarcity prices during periods of system tightness caused by out-of-market actions (discussed below);
- increased stresses imposed on plant stemming from variations in load, and thereby leading to higher maintenance costs;
- increasing operation below maximum thermal efficiency as plant are required to operate for increased periods below maximum output.

Furthermore, the penalties associated with imbalance positions are likely to increase with the anticipated growth in penetration of intermittent generation since the system as a whole is more likely to be long or short by a greater amount in any given period. This might be expected to increase the risk of more severe penalties for individual generators finding themselves out of balance.

To the extent that the risk from individual plant imbalances can be diversified by holding a portfolio of generation, or self-balancing through vertical integration, this dynamic could act to promote the need for a portfolio of generating plant, thereby increasing barriers to entry in generation.

3.3 Potential price distortions

The EMR consultation suggests that a TCM would only be required to procure a small amount of capacity and that any potential distortions would therefore be relatively small.[12]

Increased reliance on short-term trades and the possibility that the revenues associated with those trades may become increasingly risky with greater wind penetration may exacerbate the potential threat of price distortions from the proposed TCM.

Figure 3.1 below highlights that even if the direct effect of contracting for reserve capacity may arise in the provision of ancillary services, a ‘chain of arbitrage’ could be expected to lead to potential distortions in spot and forward markets, thereby affecting the revenues of all plant outside the mechanism. The figure captures the following dynamics.

[11] Hart (1988) describes how the firm as an institution can be thought of as arising from the incompleteness of contracts and the need to allocate residual control rights. See Hart, O. (1988), ‘Incomplete contracts and the theory of the firm’, *Journal of Law, Economics and Organization*, **4**(1), spring.
[12] Department of Energy and Climate Change (2010), op. cit., p. 90.

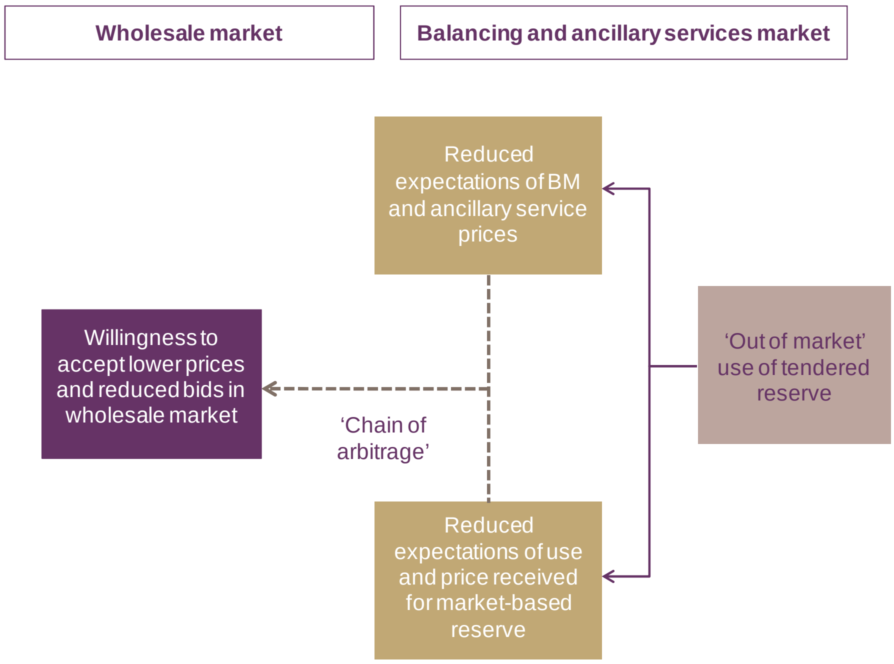
– Out-of-market actions (or even the potential for such actions) by the operator of capacity contracted under the proposed TCM, can have a direct impact on price and volume expectations for balancing and ancillary services. In particular:

  – it may reduce balancing volumes procured through the market, and hence expectations of balancing mechanism prices;

  – there may also be a reduction in other reserve contracts and ancillary service requirements, leading to reduced price expectations for contracts outside the proposed mechanism.

– Capacity that would otherwise be expected to receive balancing mechanism (BM) or reserve contract revenues may therefore be prepared to accept lower prices in wholesale markets rather than risk receiving depressed prices for balancing and ancillary services.

Figure 3.1 Potential price distortions from the TCM and the 'chain of arbitrage'



Source: Oxera.

The EMR recognises that potential peak price distortions could arise through the dispatch of the capacity contracted under the TCM, and that these distortions 'could undermine the mechanism's ability to ensure secure supplies of energy'.[13] This effect is widely referred to as the missing money problem and is described in more detail in Box 3.2 below.

The modelling that supports the EMR consultation does not suppose that there is any such distortion. Prices and investment decisions are assumed to be determined in a well-functioning wholesale market, and 'top up' capacity is assumed to be contracted under the proposed mechanism without prior investment decisions and price expectations being affected.

DECC suggests that potential distortions from the proposed TCM may be able to be mitigated through mechanism design, based on experience in the Swedish market. However,

[13] Department of Energy and Climate Change (2010), op. cit., p. 94. The EMR consultation recognises that the potential effects on peak prices and the 'slippery slope' effect could undermine the performance of the proposed TCM.

Box 3.3 below highlights experiences from the Swedish market which suggest that possible distortions may still be a risk.

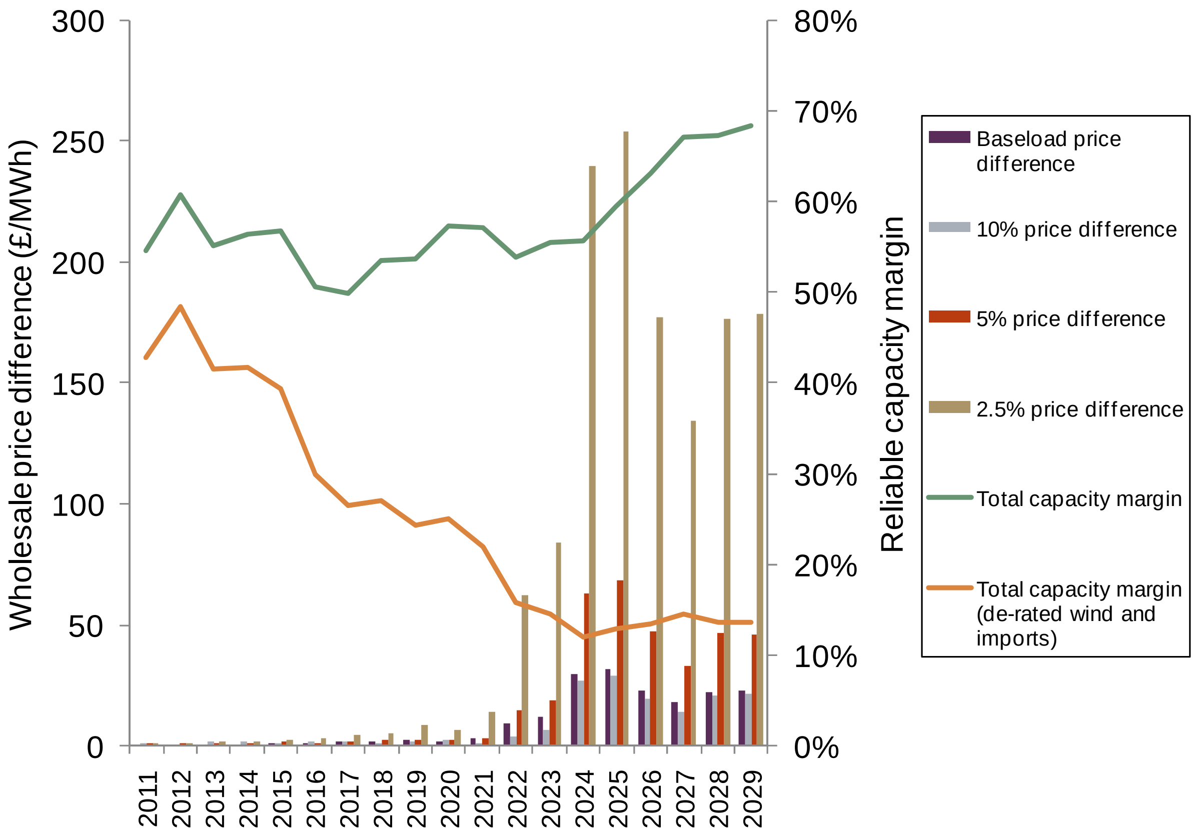
An illustration of the level of price distortions that could arise from this additional capacity can be seen by comparing the impact on the scarcity component of prices with and without the additional capacity that is contracted under the proposed mechanism.

Analysis undertaken for the EMR suggests that between 5.4GW and 10.7GW could be required under the proposed targeted mechanism.[14] This represents around a 5–11 percentage point increased in the capacity margin in 2025 (based on total capacity of 96GW), or 7–15 percentage point increase in the total reliable capacity margin (based on reliable capacity of 70GW).

Figure 3.2 highlights the impact that an additional 5.4GW could have on prices if this capacity were to be fully reflected in the scarcity component of prices. The price impact might be expected to be greatest when capacity margins are tight, such as in 2024 and 2025. The effect of this additional capacity could be to decrease peak prices (specifically those that are only observed 2.5% of the time or less) by up to £250/MWh (relative to a base case of around £1,000/MWh), and depress baseload prices by as much as £30/MWh.

If these effects were to feed into investors' price expectations, there could be the risk that tendered capacity would 'crowd out' market-driven investments.

Figure 3.2 Illustrative price distortions from out-of-market actions (5.4GW)



Note: Total capacity margin represents the excess of total capacity (including imports) as a percentage of peak demand. A total capacity margin is also shown after adjusting for the capacity credit of wind (which varies according to wind penetration), and de-rating imports.
Source: Oxera.

[14] See Redpoint (2010), 'Electricity Market Reform - Analysis of Policy Options', p. 98.

Box 3.2 The missing money problem and rationale for capacity payments

In an energy-only electricity market, generators earn all of their revenues through the sale of energy, with no additional mechanisms to cover generators' fixed and capital costs.

The electricity markets in Australia, the Nordic countries, and Great Britain (since the implementation of NETA) are examples of energy-only markets.

An important feature of the energy-only market model is that high electricity prices during peak hours provide generators with an incentive to invest in an efficient level of production capacity.

Although price spikes may occur relatively infrequently, such spikes make a significant contribution to the recovery of capital charges and so help to secure acceptable rates of return to investors in generation assets. As a result of their impact on returns to existing generators, price spikes provide a signal of the need for more generation capacity and thereby incentivise new market entry.

Consequently, if high prices during peak hours are not realised due to interventions by system operators or regulatory authorities, generators may earn revenues that are insufficient to cover their costs. This phenomenon is commonly referred to as the missing money problem. The ultimate effect of such interventions could be that available generation capacity is insufficient to meet demand.

Various regulatory mechanisms have been implemented in a number of markets to mitigate the missing money problem and to strengthen investment in generation capacity, including capacity payments.

Capacity mechanisms are used in the New England, PJM, and the Irish SEM to encourage investment. Further descriptions of the US markets are provided in the appendix.

Source: Joskow, P. (2008), 'Capacity payments in imperfect electricity markets: Need and design', *Utilities Policy*, **16**:3, September.

Box 3.3 Lessons from the Swedish experience of peak load reserves

The wholesale electricity market in the Nordic countries (Nord Pool) is an energy-only market in which the transmission system operators can use additional emergency reserve capacities in order to meet security of supply objectives. Peak-load reserves are designed to reduce the risk of shortage situations and help to avoid excessively large energy prices.

The Swedish TSO, Svenska Kraftnät, is entitled by law (Lag 2003:436) to procure a peak power reserve of up to 2,000MW; although this legislation was originally intended to be temporary and was designed to last until 2008. It was later extended until 2011.

During winter 2009/2010, peak load reserves were used on Elspot on three occasions and for a total of eight hours; although Svenska Kraftnät had frequently activated them as reserves during that winter due to insufficient electricity production elsewhere.

A number of views from regulators and academics on the potential distortions of this system are set out below.

– The Energy Markets Inspectorate (the Swedish regulator) set out in a report submitted to the Swedish government in 2008 that emergency power reserves will be required in the short term in order to cope with risks of power failures. However, the report went on to conclude that in the longer term, the peak load system should be abandoned in favour of a market-based solution. The report recommends that the peak load reserves should be gradually reduced from winter 2011/2012 and be completely shut down after winter 2019/2020.

– Nordel, the association of Nordic TSOs now part of entso-e, shares the view that a peak load arrangement should generally be avoided. It admits, however, that such an arrangement is currently needed in order to avoid load shedding. It was Nordel's view that peak load arrangements should only be temporary and generally not be in place for longer than three years, with the length of the arrangement reflecting the availability of commercially driven investments.

– Similarly, the view of NordREG, the association of Nordic energy regulators, is that non-market interventions such as peak load reserves have considerable adverse effects on the functioning of energy markets and should only be implemented if security of supply cannot be obtained through incentives in the market.

– Nord Pool Spot (2010) also points out that since peak load reserves limit market prices, their use discourages consumption reductions in times of high demand and thereby removes flexibility from the market. This increases the risk that the market will not be able to cope with strained situations after the system of peak load reserves is abandoned.

– Botterud and Doorman (2008) suggest that capacity investment has slowed down since liberalisations in the mid-1990s and that this may explain higher average prices in recent years. One explanation for the low levels of investment set out in the report is the missing money problem resulting from the use of peak load reserves; although it notes that quantifying this impact is likely to be challenging as there could be a number of other factors present in the Nordic market that also impede investment.

The Energy Markets Inspectorate has previously identified potential causes of lower investment in generation capacity, including municipalities' veto rights, political uncertainty due to changes in the energy tax system, and the slow approval process for new investments.

Source: Svenska Kraftnät (2002), 'Effektförsörjning på den öppna elmarknaden, Utredningsrapport', January 10th. Johansson, T. and Nilsson M. (2010), 'Signs of stress II: The customer strikes back', April 9th. Nord Pool Spot (2010), 'Handling of the peak load reserves in the spot market', October 1st. Botterud, A. and Doorman G. (2008), 'Generation Investment and Capacity Adequacy in Electricity Markets', International Association for Energy Economics. Energy Markets Inspectorate (2006), 'Price Formation and Competition in the Swedish Electricity Market', report 2006:13. NordREG (2009), 'Peak Load Arrangements, Assessment of Nordel Guidelines', report 2/2009. NordREG (2010), 'Assessment of Nordel's revised Guidelines for transitional peak load arrangements', March.

3.4 Summary

The analysis in this section suggests that:

– the role of thermal generation is likely to change due to the greater deployment of wind generation, making their ability to operate in a flexible and responsive manner increasingly relevant;

– the nature of wind generation could make flexible generators more reliant on short-term trades and ancillary service revenues;

– prices for power sold closer to real time and in response to uncertain variations in wind output might be expected to be higher because of the greater risks involved, notably the greater stresses and maintenance costs imposed on plant stemming from variations in load and uncertain operating patterns;

– price capture may become a significant risk to flexible generators if it is difficult to anticipate periods of system tightness from variations in wind output far in advance;

– the proposed TCM could exacerbate these risks by increasing the threat of potential price distortions through out-of-market actions (or even the potential for such actions) by the operator of contracted reserve capacity—illustrative calculations suggest that potential price distortions could be as high as 25%;

– these risks could be larger for non-integrated and non-portfolio players.

4 Flexible plant economics

As set out in section 2, increased wind capacity may result in a reduction in operating hours of thermal plant, with a greater requirement for plant to operate in a flexible manner. Given demand variability, investment in new thermal plant may be necessary to ensure that the system is able to meet its flexibility requirements.

This section evaluates the extent to which plant operating patterns are likely to change in response to increased wind output. It then considers the manner in which price distortions caused by out-of-market actions by the system operator, reduced plant availability, and increased operating costs might affect incentives for existing thermal plant to remain open, and those for investment in new thermal plant.

Box 4.1 summarises the key messages of the section.

Box 4.1 Key messages

Flexible plant economics

– As in the EMR, wholesale electricity market modelling is typically based on assumptions such as perfect foresight, efficient pricing and dispatch. These assumptions can suggest that there could be a viable investment case for existing flexible plant life extensions and new build.

– Relaxing these assumptions highlights how fragile the investment case could be.

4.1 Typical modelling assumptions

Modelling of power markets typically involves a number of simplifying assumptions, including:

– perfect foresight by market participants of future price levels;
– efficient dispatch of plant, such that plant is dispatched whenever prices are greater than its short-run marginal costs;
– given perfect foresight and efficient dispatch, plant can capture high spot prices.

However, the potential price distortions and difficulties in price capture explained in the previous section, together with the additional efficiency losses and costs from more variable plant running, could affect the stylised levels of return suggested by the modelling.

This section, therefore, assesses the likely impact of these considerations on returns to existing and new thermal plant.

4.2 Existing plant

This sub-section evaluates the incentives for existing thermal plant to stay open and is set out as follows.

– Section 4.2.1 assesses the decline in load factors of existing plant over time.

– Section 4.2.2 reviews the required increase in operational flexibility of plant as demand variability increases over time.

– Section 4.2.3 estimates the impact of reduction in plant load factors on generation costs.

– Section 4.2.4 highlights the growing importance of the scarcity component of power prices.

– Section 4.2.5 evaluates the extent to which plant economics may worsen with the introduction of a TCM.

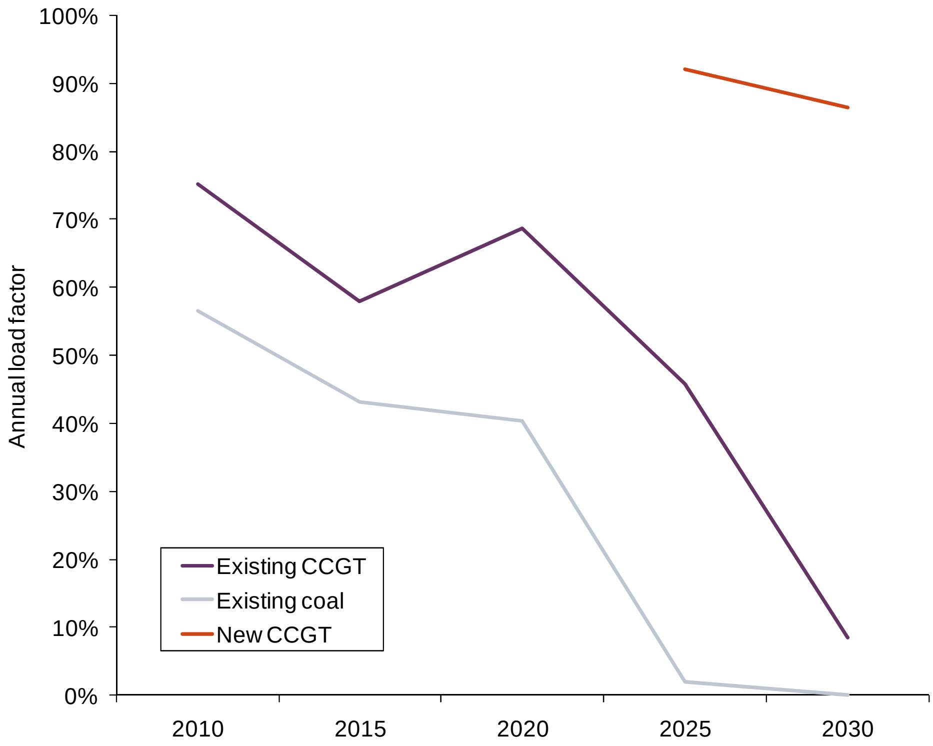
4.2.1 Trends in annual average load factors

The possible impact of increasing deployment of wind on the operating patterns of selected thermal is set out below. The analysis is carried out for an existing CCGT of 51% efficiency and an existing coal plant of 37% efficiency. The entry of a new CCGT in 2025 (55.5% efficiency) is also shown.

The modelling assumes that expected gas and coal prices remain at levels implied by the current forward curve (coal prices stabilising at $114/tonne and gas prices at 58p/therm from 2013 onwards), with carbon prices increasing to €60/tonne by 2030 with the introduction of a carbon price support mechanism.

The trends in annual average load factors of the plant examined are set out in Figure 4.1.

Figure 4.1 Annual load factors



Note: CCGT availability is assumed to equal 94% of total capacity in winter and 90% in summer. Coal plant availability is assumed to equal 85% in winter and 70% in summer.
Source: Oxera analysis.

Existing CCGT

The analysis highlights the following for the existing CCGT.

– The load factor of the existing CCGT declines in the modelling during the period from 2010 to 2015 due to new CCGT entry in the intervening years.

– Subsequently, closures and operating constraints on coal plant which have opted out of the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED), alongside closures of nuclear plant, could lead to a period of increasing operating hours of the CCGT.

– This could be followed by a period of substantial decline in load factors with a fall from around 80% in 2010 to 10% by 2030, resulting from a combination of factors. There could be a substantial decline in average daily demand net of wind from around 39GW to 31GW as wind capacity increases. In addition, entry of more efficient new CCGTs from 2024 onwards would displace the relatively less efficient existing CCGT.

Trends in the load factor of a less efficient CCGT (efficiency 47% or below, which comprises around 8GW of CCGT capacity) have also been assessed.

For the less efficient plant, load factors were projected to lie in the range of 0–30% based on current forward prices, highlighting the potential incentive for early closure of a large volume of CCGT capacity if it is unable to be sufficiently remunerated while operating at such low load factors.

The likelihood of this risk is explored later in this section by comparing the return on plant with their ability to recover their fixed costs.

Existing coal (opted-in under LCPD)

The load factor of the existing coal plant could decline continuously from 2010 to 2030 (from around 55% to 0%). As in the case of the representative CCGT, this can largely be explained by a combination of declining demand net wind and increasing entry of more efficient new CCGTs, as detailed below.

– Entry of committed new CCGTs in the period between 2010 and 2015, and subsequently in the period from 2025 onwards.

– Although the closure of nuclear and opted-out coal plant would tend to push up the load on the representative coal plant, this would be counter-balanced by rising carbon prices over time that tend to raise the costs of running a coal plant relative to those of other technologies.

– The substantial increase in wind capacity would result in a decline in demand net wind faced by all thermal plant.

The load factors of the remaining (less efficient) coal plant could be expected to decline even more rapidly, potentially creating the incentive for some coal plant to shut down in the early part of the period of their limited-life opt-out from the IED.

New CCGT

The new entrant CCGT would be expected to operate baseload on entry, with a slight decline in load factors over time due to further entry combined with declining demand net wind.

The trend of declining load factors suggests that the shift of existing thermal plant towards increasingly operating in peak periods could increase their dependence on prices in peak periods to be sufficiently remunerated to enable them to stay open.

4.2.2 Impact of demand variability on plant operation patterns

Variability in demand is likely to result in increased requirements on thermal plant to ramp up and down in order to be able to generate in periods when prices are greater than their marginal costs. Technical constraints that prevent frequent ramping up and down are likely to either prevent plant from benefiting from peak prices or require them to operate in low price periods in expectation of higher prices in future periods.

This section assesses the potential impact of demand variability by considering plant operating patterns under three alternative demand patterns:

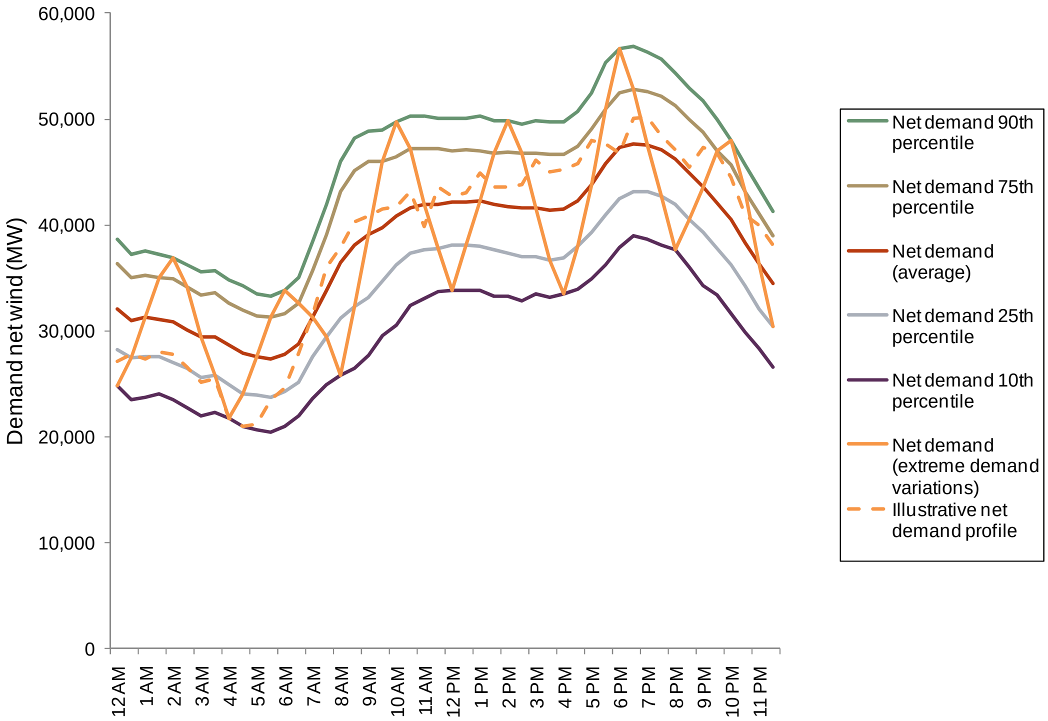
- average demand—this estimates average demand levels for each half-hour from the Monte Carlo simulations of half-hourly demand;
- extreme demand variations—this assumes that demand shifts from one percentile of its distribution to the next from half-hour to half-hour, and as such may be considered an extreme case due to correlations in wind output across consecutive half-hours;
- representative net demand profile—this presents a representative demand-net-wind pattern obtained from the Monte Carlo simulations of demand and wind. While this distribution shows greater variations than the ‘average demand’ distribution, the demand variations are less extreme than in the ‘extreme demand variations’ case.

These demand patterns are set out in Figure 4.2, which presents demand-net-wind distributions in winter 2020 for a range of points across the Monte Carlo simulations of half-hourly demand and wind patterns. The figure highlights the greater variability in the ‘illustrative net demand profile’ distribution than in the ‘average demand’ profile, with the greatest variability being in the ‘extreme demand variations’ profile.

The figure highlights the extent of flexibility requirements by 2020, showing:

- large variations in demand across a day, with average demand ranging from 27GW to 48GW;
- large hour-to-hour variations in demand, with maximum hourly changes of up to 17GW.

Figure 4.2 Demand net wind distributions, winter 2020

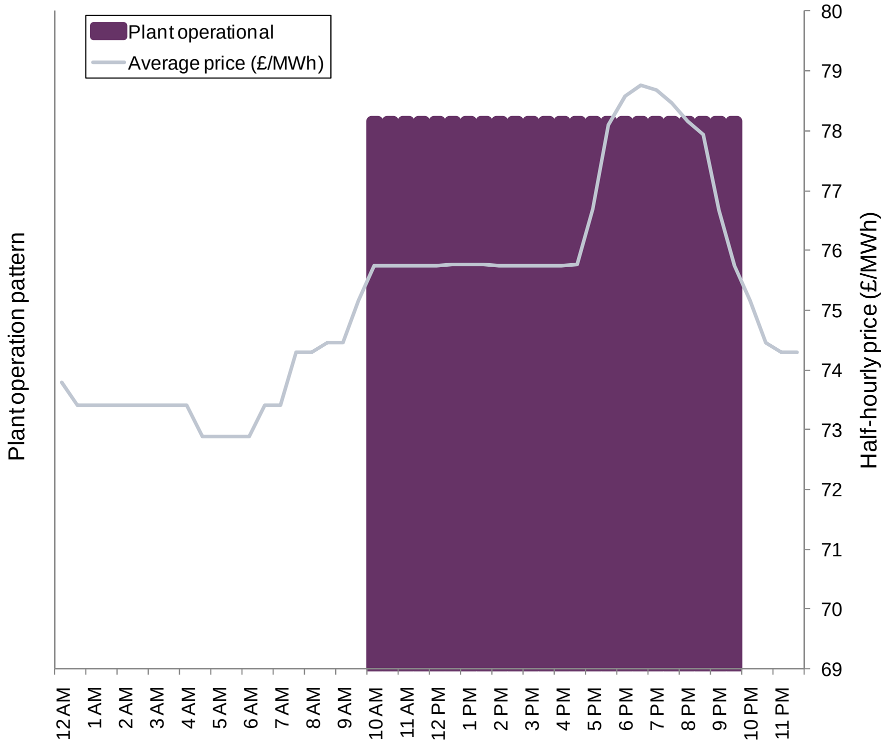


Note: The illustrative net demand profile shows the hourly variation in demand net wind for a single simulation based on Oxera modelling, and highlights that extreme within-day and hour-to-hour variations are possible.
Source: Oxera analysis.

Figures 4.3 to 4.5 assess plant operating patterns across the three demand profiles described above. They highlight that flexible plant is required to ramp up and down more frequently under the illustrative and extreme demand distributions to enable recovery of prices associated with high demand/low wind conditions.

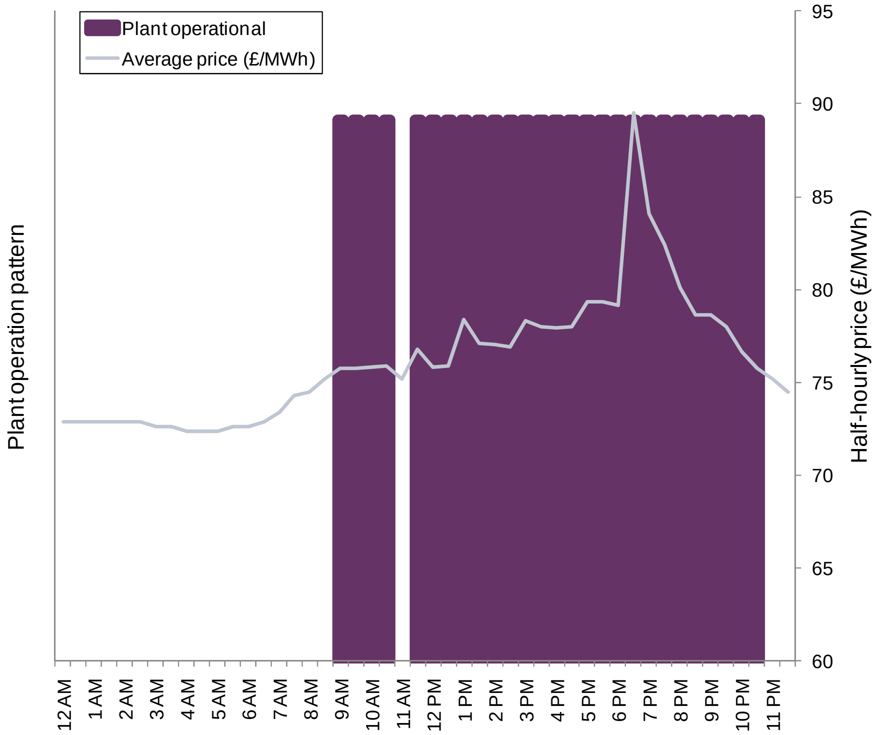
In practice, it is likely that plant will continue to operate part-loaded at low demand/high price periods, creating the risk of operating during low or negative price periods.

Figure 4.3 Daily operating patterns of existing CCGT, average demand conditions, winter 2020



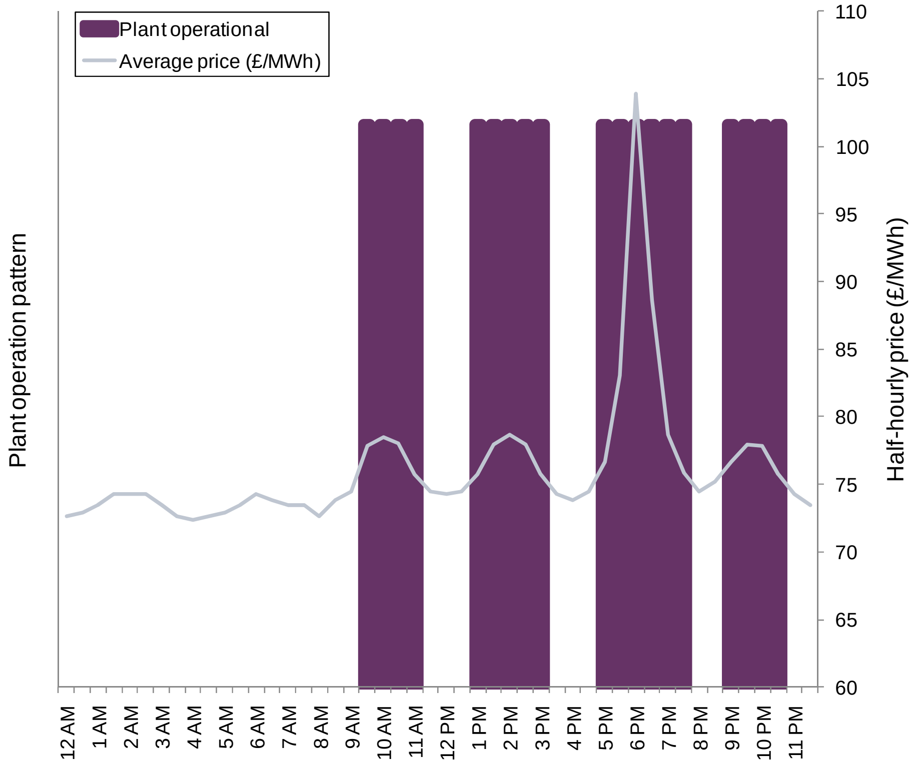
Source: Oxera analysis.

Figure 4.4 Daily operating patterns of existing CCGT, illustrative demand profile, winter 2020



Source: Oxera analysis.

Figure 4.5 Daily operating patterns of existing CCGT, extreme demand variability, winter 2020



Source: Oxera analysis.

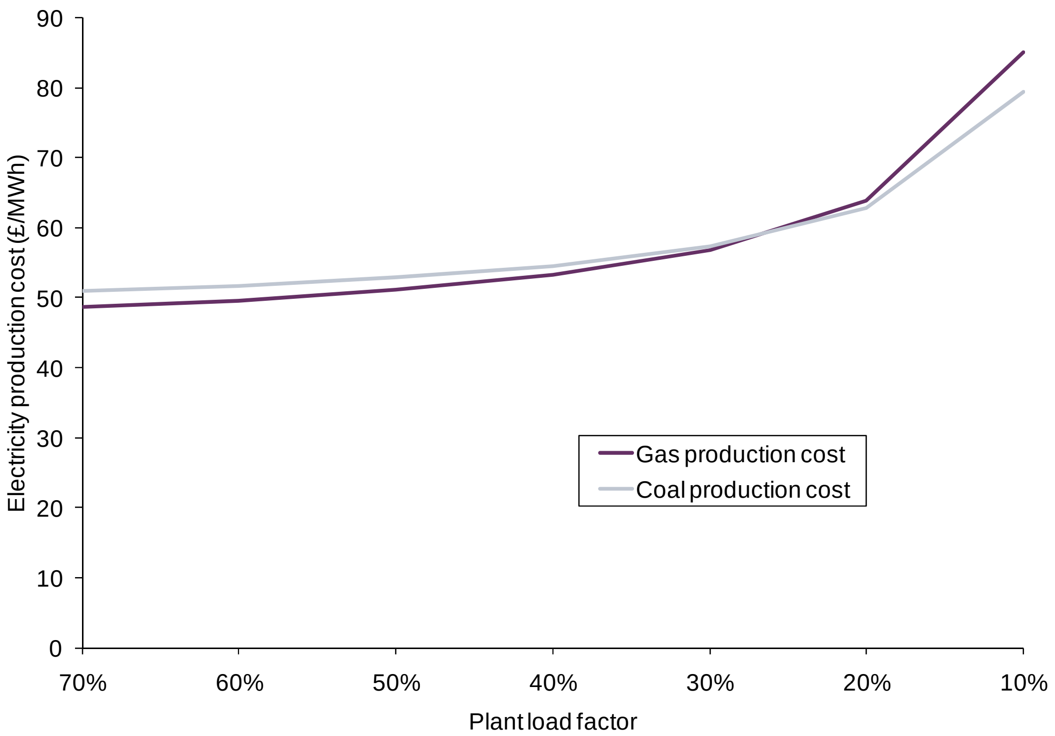
4.2.3 Impact of reduced operating hours on plant performance

The reduction in average load factors of plant is also likely to result in an increase in generation costs and in NOx emissions from plant.

– **Increased generation costs**. IEML modelling suggests that a decrease in CCGT load factor from 60% to 20% (broadly representative of the decline in CCGT load factors during the 2020s) could increase total production costs by 30%, as shown in Figure 4.6.

– **Increased NOx emissions**. All NOx emission reduction technologies are less effective at low plant output, and only partial abatement is possible in the early stages of start up. In the case of selective catalytic reduction technologies, the catalyst must reach the required operating temperature before NOx emissions are reduced. As a result, some plant that could otherwise meet the IED requirements under baseload operation may not be able to meet those requirements under the operating regimes caused by increased intermittency. This could also undermine the incentive to invest in turbine upgrades that reduce NOx emissions.

Figure 4.6 Impact of reduced output on performance



Source: IEML.

4.2.4 Prices realised by plant

Power prices are a function of a combination of the short-run marginal costs of marginal plant and the scarcity of capacity relative to demand (or the ‘capacity premium’).

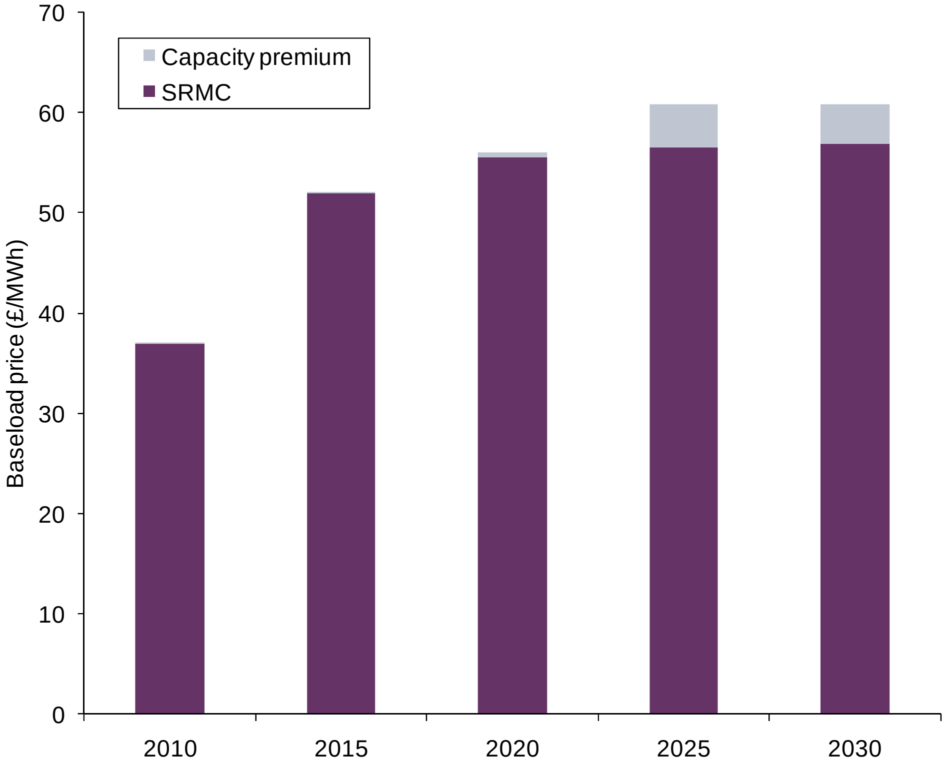
Figure 4.7 below sets out the modelled short-run marginal costs and capacity premium components of average baseload prices, showing that:

– the short-run marginal costs component of prices increases over time as the carbon price increases;

– the capacity premium component is driven by the capacity margin, which takes account of the intermittency of wind. The capacity credit given to wind is lower the higher the wind capacity on the system. Therefore, as wind capacity grows, the capacity credit to wind declines. Combined with closures of existing nuclear and thermal plant, this would result in a decline in the 'reliable' capacity margin and an increase in the capacity premium component of prices.

The increasing importance of the capacity premium as a component of prices would imply that policies that distort the capacity premium might result in a reduction in returns to thermal plant.

Figure 4.7 Baseload prices, real 2010 prices

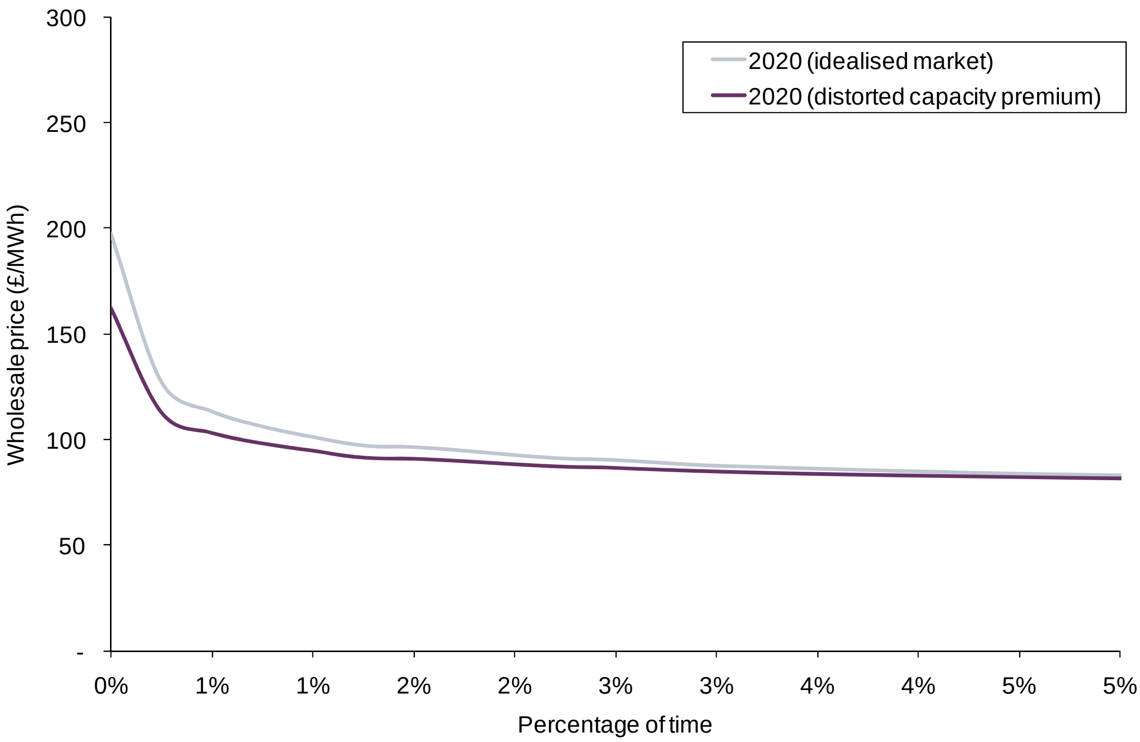


Note: SRMC, short-run marginal costs.
Source: Oxera analysis.

The capacity premium forms a greater proportion of peak prices than baseload prices. As existing thermal plant increasingly relies on revenues from periods of system tightness, the average prices realised by these plant is likely to increase.

However, this may serve to magnify the impact of price distortions. This is highlighted in Figure 4.8 below, which shows the illustrative impact of a 30% reduction in prices on the price duration curve in winter 2020. It shows that this reduction has a greater impact on prices in peak periods than off-peak periods.

Figure 4.8 Price duration curve, winter 2020



Source: Oxera analysis.

4.2.5 Impact on plant economics

Greater variability in plant operations due to increased wind capacity might be expected to have the following effect on plant operations.

– Realisation of higher average prices as plant shift from operating baseload to operating in a declining number of peak periods.

– Despite higher realised prices due to shifting of operations towards peak periods, total returns to existing thermal plant could decrease over time as a result of a decline in load factors.

– Reduced 'price capture' (or the ability of plant to foresee and operate in high price periods) due to greater demand and price variability, a reduction in operational hours, increased requirements for plant to ramp up frequently to take advantage of peak prices, and risk of plant operating in negative price periods given high start-up costs.

– Reduction in efficiency due to low load factor operation.

– Increased O&M costs as a result of low load factor operations.

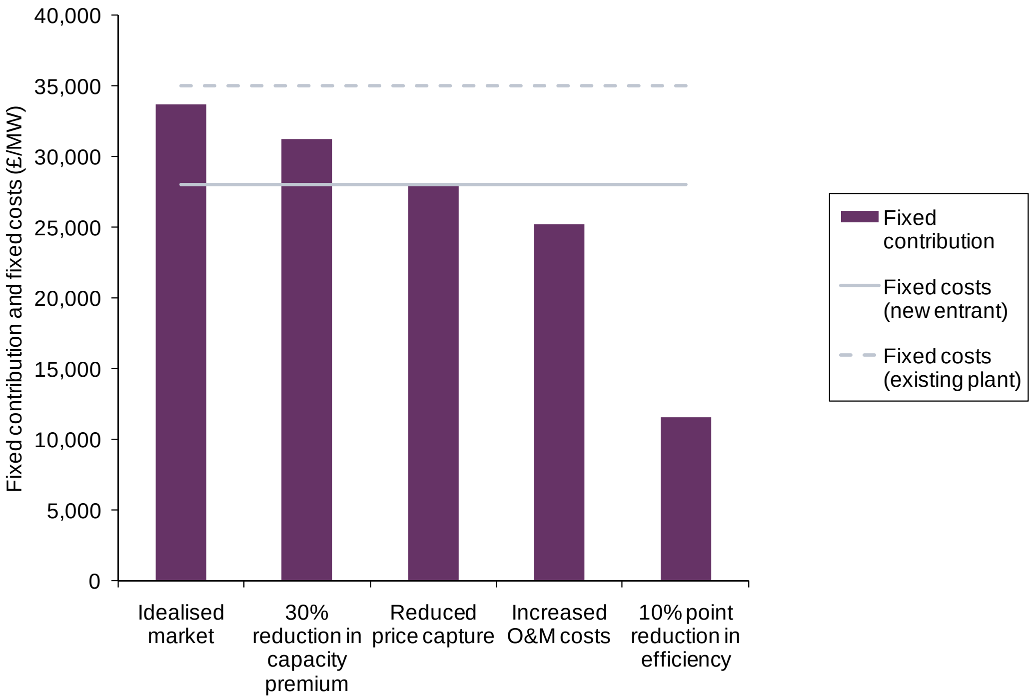
The TCM proposed in the EMR could exacerbate the impact of wind variability on thermal plant economics through the following routes.

– Dampening of peak prices received by thermal plant through the potential distortions described in section 3.

– Reduced 'price capture' ability of plant outside the mechanism if some of the targeted reserve capacity is used in out-of-market actions.

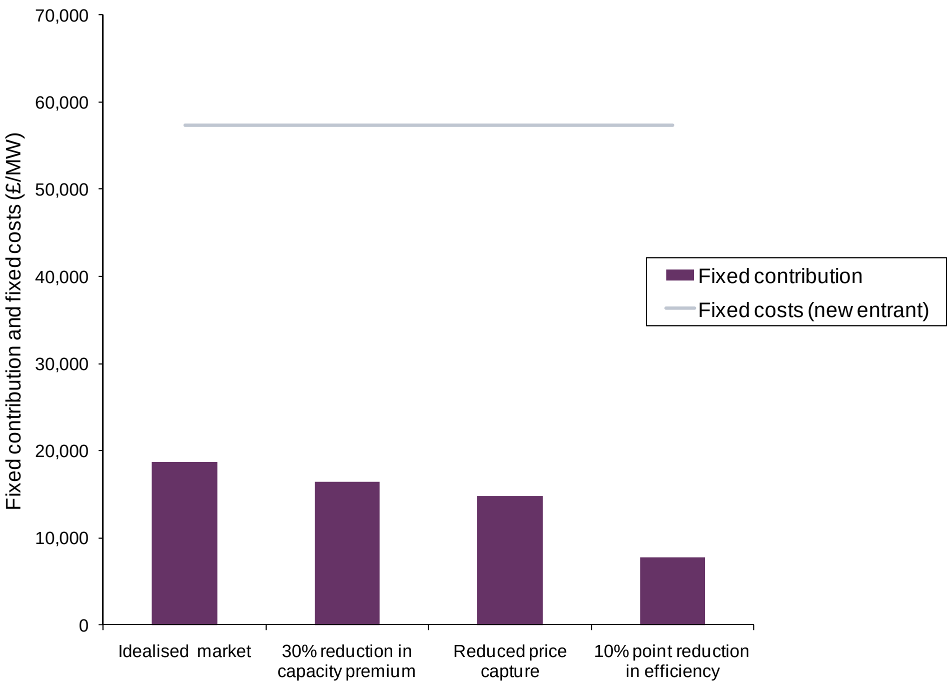
The remainder of this section considers the effects of these distortions on existing thermal plant. The impact of these effects on fixed cost recovery for existing CCGTs and coal plant is illustrated in Figures 4.9 and 4.10.

Figure 4.9 Impact of market distortions, existing CCGT, 2020



Note: Data is in real 2010 prices.
Source: IEML, and Oxera analysis.

Figure 4.10 Impact of market distortions, existing coal plant, 2020



Note: Data is in real 2010 prices.
Source: IEML, and Oxera analysis.

The figures show the returns (pre-tax real IRR) to plant under an ‘idealised market’—where market participants have perfect foresight, there is efficient dispatch and there are no additional costs associated with increased output variability. The impact of relaxing each of these assumptions is assessed to determine the viability of existing thermal plant remaining open.

The approach to assessing the impact of relaxing the idealised market modelling assumptions is as follows.

– Distortion of peak prices—the scarcity component of prices is reduced by 30% consistent with the illustrative impact of an additional 5GW on capacity margins (as described in section 3).

– Price capture effects—the price capture effects have been tested by assessing the impact of a 10 percentage-point reduction in plant load factor.

– O&M costs—to determine the effects of an increase in O&M costs, the variable O&M costs of a CCGT are assumed to increase three-fold (consistent with a 30% increase in total variable costs).

– Efficiency—in assessing the impact of lower load factor operations on plant efficiency, the efficiency of existing CCGTs is assumed to fall by 10 percentage points based on analysis by IEML. The effects of low load factor operations on coal plant are smaller (2–3 percentage points reduction).

The analysis highlights that by 2020 the existing CCGT may be unable to meet its fixed costs even under idealised market conditions. On relaxing the typical idealised market modelling assumptions and considering the likely costs of increased output variability, and distortions created by a mechanism similar to the TCM, the shortfall in the fixed cost recovery of plant increases substantially (see Figure 4.9). Existing CCGTs would, therefore, require additional support mechanisms to enable them to remain open.

Although coal plant economics looks unattractive under idealised market conditions (due to the commodity price assumptions used), their economics worsen further on considering market distortions arising due to the TCM (see Figure 4.10). Coal plant are therefore likely to require further support in addition to returns from the energy-only market to enable them to remain open.

An area of further analysis would be to test these results under a range of commodity price scenarios.

4.3 Summary

The analysis in this section suggests the following.

– Thermal plant is likely to operate for fewer hours over time with increasing deployment of wind.

– Thermal plant is likely to be required to ramp up and down more frequently, given variations in wind output, to enable price capture. However, technical constraints could prevent frequent variations in output, thus affecting plant’s ability for price capture and risks of receiving low or even negative prices.

– The shift from operating baseload to operating in a proportion of peak periods could increase dependence on peak prices to enable recovery of fixed costs. Mechanisms like the TCM that distort peak prices could therefore worsen plant economics.

- Although average prices realised by existing thermal plant may be expected to increase as they operate in peak periods instead of operating baseload, declining load factors could result in lower returns.
- Low load factor operations are also likely to result in a reduction in plant efficiency and an increase in O&M costs, further worsening plant economics.
- Under the current forward curve for gas and coal prices, power prices in an energy-only market are unlikely to be high enough to enable existing thermal plant to recover their fixed costs and remain open. In addition to revenues earned through the energy-only market, additional support mechanisms are likely to be required.

5 A possible GB flexibility mechanism

The sections above have set out that there may be a need for a mechanism to encourage the retention of existing flexible capacity, and construction of additional flexible capacity.

The analysis has highlighted that the proposed TCM, which is narrowly focused by design, may find it difficult to attract sufficient market-wide investment in flexible capacity, and may further create distortions that could deter investment in capacity outside the proposed mechanism.

This section presents an alternative, broader-based solution that attempts to achieve a balance between simplicity and transparency, while sending appropriate signals to encourage investment in flexible generation rather than focus on peak demand requirements.

Further analysis would be required to produce a full cost–benefit analysis to compare the outcomes under alternative models.

The key messages are highlighted in Box 5.1.

Box 5.1 Key messages

A possible GB flexibility mechanism

– Sufficient flexible capacity may not be incentivised under DECC's preferred capacity mechanism.

– Desirable elements of any new mechanism are to provide transparent, market-wide signals.

– A stable, fixed revenue mechanism based on system requirements could be used to provide additional incentives that increase as the penetration of wind capacity increases.

5.1 Priorities for mechanism design

DECC set out in the EMR consultation that it would assess the effectiveness of the market reform options along four broad principles.

– **Cost-effectiveness**—options for reform should preserve competitive pressures where possible, and be affordable to consumers.

– **Durability and flexibility**—proposals should be robust to a number of unlikely outcomes (regarding prices and technology costs).

– **Practicality**—new mechanisms should be able to work in practice and achieve a manageable transition.

– **Coherence**—policies must combine with other existing and proposed mechanisms in a complementary manner.

From the discussion of potential distortions of the proposed TCM in section 3, it would appear that in order to achieve long-run cost-effectiveness, any mechanism should look to:

– mitigate the increased risks faced by flexible plant as wind penetration increases;

– minimise entry barriers that could accompany a non-market-based and discretionary mechanism.

On durability, flexibility and practicality, it would seem appropriate that any new mechanism should:

– provide greatest signals to invest as the flexibility requirements from intermittency increase;
– accommodate increased DSR, and spur innovation and increasing participation from the demand side.

International experience of capacity mechanism design can also provide a useful guide to possible design features for a GB flexibility mechanism, even though the capacity mechanisms implemented to date (eg, in the USA and Ireland) have been designed to meet demand peaks and not flexibility requirements.

Two key lessons from international experience (as highlighted from the Swedish experience as described in section 3, and from US markets as described in the appendix) are as follows.

1. Selective tendering and discretionary use of reserve capacity can create price distortions, and this prospect can reduce generators' revenue expectations and subsequently deter investment.

2. Schemes that rely on decentralised pricing, ex post rebate schemes, or additional regulations to limit total revenues can become administratively complex and open to the risk of gaming.

This suggests that, given uncertainty over whether market-driven investment may be sufficient to provide the required GB system flexibility, as highlighted in section 2, two central features of a possible flexibility mechanism for the GB market could include:

– being transparent and providing market-wide investment signals to flexible generation and flexible demand;
– providing revenues from a centrally determined pot, the value of which is reflective of system requirements.

5.2 Alternative market design: a possible flexibility mechanism

Figure 5.1 and Table 5.1 below set out the steps by which a possible fixed revenue flexibility mechanism could be implemented.

A key design aspect would be to define the system flexibility requirement, including the timescale over which that flexibility is measured—eg, hourly or daily variations—and the generation and demand participants that are able to meet that requirement.

– An annual flexibility requirement (GW) could be calculated based on wind penetration and expected hourly variations in output, inflexible demand variations, and a security standard (eg, a requirement to meet three standard deviations (or 99.7%) or expected hourly variations in demand net wind).

  – Alternative mechanism designs could consider other flexibility timescales—eg, variations in the daily range of demand net wind (ie, peak-to-trough variations).

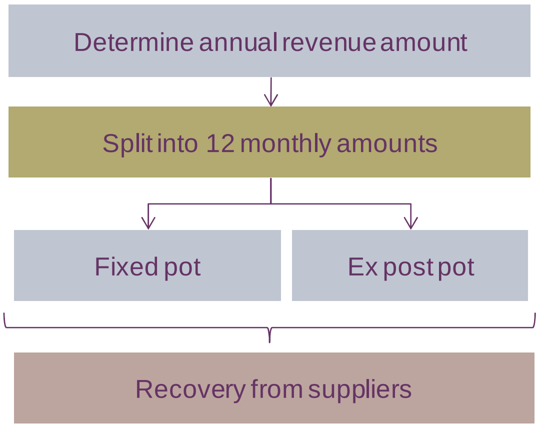
– A total annual revenue amount could be determined based on system flexibility requirements and the costs of the marginal provider of flexibility.

– The revenue pot could be split between different time periods, based on a combination of anticipated flexibility requirements and ex post demand and wind outturn (so that greatest revenues are available when flexibility requirements are highest).

– All flexible generation and demand participants available within a given period could be eligible to receive a share of the revenue available in that period.

A worked example of what this would mean for consumers and generators is set out in Box 5.2 below.

Figure 5.1 Allocation and recovery of flexibility payments



Source: Oxera.

The key design elements are summarised in Table 5.1 below.

Table 5.1 Key design elements

Design element	Operational details
Annual revenue amount	Annual flexibility requirement calculated based on expected half-hourly wind variations and inflexible demand variations throughout the year (in MW) to meet a reliability standard.[1] Annual revenue amount calculated by multiplying the flexibility requirement by the fixed costs of the marginal flexibility provider *minus* the expected energy and ancillary revenues of the marginal flexibility provider.[2]
Monthly amounts	Monthly payments to generators/demand participants could be profiled within sub-periods (daily or half-hourly) according to a pre-determined ex ante fixed element in each period and an ex post variable element. Allocations could be based on the difference in supply and system demand for flexibility: **Flexibility margin** = {supply of flexible capacity and demand} minus {changes in demand net wind*} *excluding flexible demand
Eligibility	The eligibility of plant to receive payments could be based on their ability to provide flexible capacity/demand.
Recovery from suppliers	A pro-rated levy could be introduced based on the level of inflexible demand.
Data requirements	Wind penetration and typical half-hourly variations. Inflexible demand levels and typical variations. Unit capacities obtained from generators. Outturn wind and demand changes and flexible generation and demand availability.

Note: [1] A reliability standard could be equal to the flexibility required to meet, for example, three standard deviations (99.7%) of expected hourly variations in demand net wind.
[2] This approach has been adopted in the Irish Single Electricity Market (SEM) but in the context of a Best New Entrant Peaker. In a possible flexibility mechanism, these revenues could be based on a rolling average of output of flexible plant—a technique adopted in PJM in the USA.
Source: Oxera.

Eligibility

The proposed mechanism could help to promote investment and participation from a wider range of flexibility providers than under DECC's preferred TCM.

Eligible generators could be required to demonstrate a minimum flexibility standard, and generators who receive a FIT (or other incentive) under the proposed reforms could be excluded.

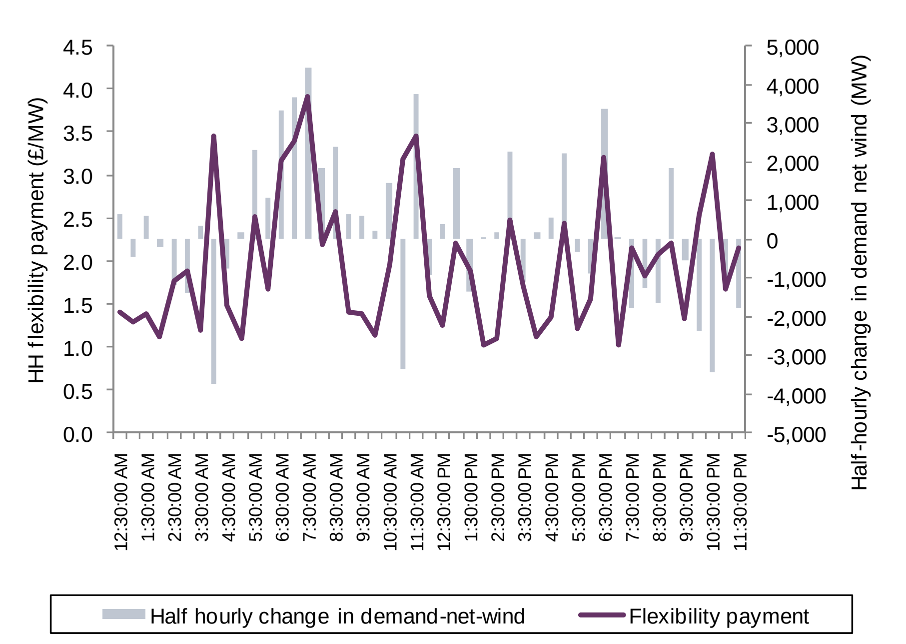
If appropriate, an additional complexity for plant which have some ability to provide flexibility and a low-carbon inflexible element such as CHP, nuclear or some biomass plant could declare part of their plant low-carbon inflexible and part flexible. Such a plant could then have a proportion of its capacity rewarded in the FIT mechanism and part in the Flexible Capacity Mechanism. DSR and storage projects could also be eligible for the capacity payment.

Box 5.2 Possible flexibility mechanism—illustrative example

The table below presents illustrative calculations for the possible flexibility mechanism.

Calculation step	Comments
Annual revenue amount	
Annual flexibility requirement	Maximum expected hourly demand-net-wind variations based on wind and demand distributions: 17GW (2020); 25GW (2030) Flexibility standard: requirement to cater for 99.7% (three standard deviations) of all simulated hourly demand-net-wind variations. Range of expected hourly demand-net-wind variations that encompass 99.9% of expected distribution: 15GW (2020); 17GW (2030)
Annual revenue amount	Marginal source of flexibility: OCGT Fixed and capital costs: £100/kW Load Factor (LF): 0% Wholesale contribution = LF x (realised price-variable costs): 0 <u>Annual revenue amount</u> = (fixed & capital costs – contribution)* flexibility requirement £1.5 billion (2020): (100-0)*15 £1.7 billion (2030): (100-0)*17
Daily profile of payments	
	Assumed ratio of fixed and ex post revenue: 50:50 The figure below shows the variation in demand net wind for an illustrative day in 2020 and the associated flexibility payments, paid in proportion to the absolute half-hourly change in required flexibility. Total payments (fixed and ex post) range from £3–£10/MW in each half-hour.

Source: Oxera.



Source: Oxera.

5.3 Assessment

Table 5.2 below provides a qualitative assessment of the Flexibility Payment Mechanism against DECC's performance principles.

Table 5.2 Assessment of Flexibility Payment Mechanism against DECC criteria

Criteria	Assessment
Cost-effectiveness	The relatively wide-based flexibility mechanism could explicitly include DSR, as well as promote investment in new flexible plant, and life extensions to existing plant, promoting competition in the wholesale market. A flexibility revenue stream separate from imbalance risks and wholesale energy transaction costs may be more likely to promote entry from non-integrated or portfolio generators. Any potential over-subsidy would be likely to be eliminated through competition and liquidity improvements as recognised by DECC, and through a mechanistic calculation of expected energy revenues in determining the revenue pot.
Durability and flexibility	The mechanism could include DSR and therefore accommodate technological changes on system requirements. A broader-based mechanism that could avoid the risk of the slippery slope would also be likely to improve durability. Annual calculations of the revenue pot could reflect changes in technology costs, expected wholesale revenues (and commodity price movements), as well as wind deployment.
Practicality	Flexibility requirements are likely to be small in the near term and to grow over time. The proposed mechanism would therefore entail a relatively small revenue pot at low wind penetration, and increase as the system flexibility requirements increase.
Coherence	Eligibility criteria could be used to ensure that flexibility payments are awarded to plant that do not receive the proposed FITs. Alternatively, generators could opt to declare a proportion of their capacity that is inflexible and eligible for FITs and the remaining proportion that is eligible for flexibility payments.

Source: Oxera.

The advantages of such a fixed revenue mechanism could be that:

– a degree of stability could be introduced into the flexibility payments through tailoring the revenue split between the fixed pot and ex post pot;
– the mechanistic calculation of annual revenues based on wind penetration, demand growth and known statistical distributions could help promote longer-term investment signals;
– short-term signals could be generated to create the incentive for flexible generation and demand to be available through the ex post revenue allocation.

The potential drawbacks of such an approach are the administrative costs of annual forecasting and operation of the scheme. This would be likely to be a feature of any broad-based mechanism, but could be smaller for mechanisms that are relatively less complex.

5.4 Summary

This section has examined the features of a possible mechanism that may be required in order to promote the retention of existing flexible capacity and construction of additional capacity.

Consistent with the principles put forward by DECC to assess alternative policy proposals, any appropriate flexibility mechanism might be expected to:

– mitigate the increased risks faced by flexible plant as wind penetration increases;
– minimise entry barriers that could accompany non-market-based and discretionary mechanism;

- provide the greatest signals to invest as the flexibility requirements from intermittency increase;
- accommodate increased DSR, and spur innovation and increasing participation from the demand side.

A fixed revenue mechanism may be able to strike an appropriate balance between creating the right investment signals for providers of flexibility while minimising complexity and the risk of gaming. The advantages of such a mechanism are that:

- a degree of stability could be introduced into the flexibility payments through tailoring the revenue split between the a fixed element and one related to ex post system conditions;
- the mechanistic calculation of annual revenues based on wind penetration, demand growth and known statistical distributions can help to promote longer-term investment signals;
- short-term signals can be generated to create the incentive for flexible generation and demand to be available through the ex post revenue allocation.

A useful area of further work would be to assess how this mechanism would work under a range of possible supply and demand conditions.

6 Conclusions

This report has provided an assessment of the change in system conditions, and the accompanying risks that may be caused by increased wind generation alongside the expansion of nuclear and CCS projects in the GB electricity market.

It has provided an assessment of whether DECC's preferred TCM may alleviate or exacerbate these risks and the impact that this could have on meeting the UK's energy policy objectives. It has also suggested an alternative mechanism that may be better equipped to address the challenge posed by the possibility of early retirement of existing flexible plant, and weakened investment incentives that may otherwise deter sufficient investment in new flexible capacity required to complement wind power and deliver longer-term security of supply.

The key findings of the analysis are as follows.

- Changes in the generation mix could increase GB flexibility requirements, which are governed by short-term variations in demand net wind, and different to the traditional need to meet system peak demand.
- Flexibility can be provided from flexible generation and DSR, with short-term responsiveness on the generation side governed by the difference in plant's maximum and stable export limits, with further constraints determined by plant ramp rates and whether the plant is already part- or fully-loaded.
- System flexibility could become tight from around 2015.
- A flexibility gap could emerge in which flexible capacity could be insufficient to meet demand variations by 2020 regardless of whether system capacity is sufficient to meet peak demand.
- Absent intervention, there might be insufficient incentive to invest in adequate flexibility since thermal plant is required to increasingly rely on short-term revenues that encompass increased risks that may not be hedged, and is subject to the threat of distortions from out-of-market actions.
  - Specific risks include the ability to capture short-term price spikes caused by wind variations, and the increased risk to plant performance from more frequent output variations.
  - These risks are likely to be larger for non-integrated and non-portfolio players.
- DECC's preferred TCM does not attempt to mitigate these risks, and may exacerbate the risk of price distortions.
- The report has set out a flexibility mechanism that, with careful design, could:
  - mitigate the increased risks faced by flexible plant as wind penetration increases;
  - minimise entry barriers that could accompany non-market-based and discretionary mechanisms;
  - provide greatest signals to invest as the flexibility requirements from intermittency increase;

- accommodate increased DSR, and spur innovation and increasing participation from the demand side.

- A fixed revenue mechanism may be able to strike an appropriate balance between creating the right investment signals for providers of flexibility while minimising complexity and the risk of gaming. The advantages of such a mechanism could be that:

  - a degree of stability can be introduced into the flexibility payments through tailoring the revenue split between the a fixed element and one related to ex post system conditions;
  - the mechanistic calculation of annual revenues based on wind penetration, demand growth and known statistical distributions can help promote longer-term investment signals;
  - short-term signals can be generated to create the incentive for flexible generation and demand to be available through the ex post revenue allocation.

The analysis in this report provides an initial examination of the potential flexibility gap facing the GB electricity system, and the risks that are likely to be faced by owners of existing flexible capacity and developers of new plant. The provision of future flexibility has been assessed based on existing price dynamics.

Useful further work would be to refine the estimates of future GB flexibility requirements, based on a more detailed analysis of flexible plant operating capabilities, and the manner in which prices may respond to a potential flexibility shortfall and the implications of this for plant returns. This would also facilitate a full cost–benefit analysis of alternative flexibility mechanisms.

A1 Features of the New England capacity mechanism

Box A1.1 describes the rationale for the introduction of a capacity mechanism as commonly used in US markets, and the method in which ‘inframarginal’ rents earned in the energy market are deducted from capacity payments in the New England mechanism.

Box A1.1 Rationale and features of the US capacity mechanism design

In a well functioning ‘energy-only’ electricity market, peak prices would be high enough to cover the fixed cost of providing the capacity needed to meet the peak demand (including reserve).

These peak prices would often be set by the demand side, as consumers with appropriate (hourly) meters show their willingness to reduce consumption as the price rises. In practice, many consumers do not have these meters, or do not receive the price signals.

Furthermore, system operators frequently take actions which have the effect of reducing market prices at times of system stress (Joskow, 2008). For example, system operators may be able to take “out of market” actions from stations with which they have contracts, thus avoiding the need to buy higher-priced power in the day-ahead or real-time market, and suppressing prices in those markets.

If prices do not rise sufficiently above plant’s variable costs in the energy market, generators will not be able to recover their full costs from the energy prices alone.

The remedy adopted in north-eastern US markets is to have a separate market for capacity, operating on a much longer timescale than the day-ahead markets. The New England capacity market runs three years in advance, so that entrants can effectively compete with incumbents, giving them time to build a peaking generator if they succeed in the capacity auctions. They can also opt to receive the resulting price for five consecutive years, reducing their revenue risk.

In the New England model, the system operator determines the demand for capacity, which is price-responsive and location-specific. This reflects the fact that the value of capacity, just like that of energy, depends on where it is sited. The price of capacity can therefore be higher in regions that are transmission-constrained and short of generating capacity.

Market design has evolved, and the capacity mechanism has been reformed to introduce price-responsive demand curves which are set so that if there is just sufficient capacity to meet the standard administratively-set capacity margin (typically 15% on top of expected peak demand), then the price will just equal the expected cost of new entry, net of energy and ancillary service revenues. With more capacity, the price will be lower, while the demand curve slopes up towards a capped level (1.5 times the cost of new entry) if less capacity is offered.

The market design takes account of the fact that peaking generators may be able to make a surplus from peak energy and ancillary services prices that exceed their fuel costs.

In PJM, the net cost of new entry is calculated (and fixed in cash terms) after subtracting an estimate of this surplus, based on the market prices of the previous three years. In New England’s capacity market, however, the out-turn energy and ancillary services prices (net of fuel costs) are used to reduce the eventual payments to a successful seller. This makes the payments from the capacity market more variable, but this should be exactly offset by the rents received in the energy market, providing a more stable income stream overall.

It also provides a hedge for consumers, and reduces the incentives for generators to exercise market power at peak times, since changes in peak prices are offset by changes in capacity payments.

Source: Stoft, S. (2002), 'Power System Economics: Designing Markets for Electricity'. Joskow, P. (2008), 'Capacity payments in imperfect electricity markets: Need and design', *Utilities Policy*, September, pp. 159–170.

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