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Electricity Capacity Assessment: Measuring and modelling the risk of supply shortfalls

ConocoPhillips welcomes the opportunity to respond to this consultation.

We are an international energy company operating in over thirty countries and, in addition to our upstream oil and gas and downstream refining interests in the UK, we own and operate the UK's largest CHP plant at Immingham with a capacity of 1,218MW. We also have Section 36 consent for an 800MW CHP facility at Seal Sands in Teesside, which would provide steam to the Teesside Oil Terminal and other local industrial customers.

Headline comments

In this cover letter we summarise our views, the headline points are:

- we welcome the new requirement on the Secretary of State to produce an annual indication of the required level of capacity on the GB system;
- we also support the placing of the new obligation on Ofgem to report to the Secretary of State annually setting out plausible forecasts of the necessary capacity margins with supporting scenarios;
- these arrangements will be key drivers of the capacity mechanism proposed under the Electricity Market Reform (EMR) package, which we believe should be established on an open market wide basis;
- establishing plausible forecasts is a complex requirement that could create very perverse investment signals and costs/risks for consumers if the assessment is not conducted appropriately or over sufficient time horizons;
- the design of the mechanism and the supporting assessments to be carried out by Ofgem needs to have appropriate regard to the growing Flexibility Gap on the GB electricity system, as well as the capacity requirement;
- crucially, the time horizon of the assessment and the derived capacity margin needs to be at least seven years and not four as proposed;
- any measure of supply security needs to thoroughly assess the capability of the GB market to meet demand in a scenario of low wind occurring at the same time as high demand (our analysis shows this has occurred frequently in the last few years);
- the analysis needs to establish the flexibility of the plant that will be required to meet demand; this is likely to be heavily weighted towards gas plant. Interactions between the gas and power markets during periods of system stress need to be much better understood than at present[1], as does the scope for interventions by National Grid in its role as both gas and electricity system operator;
- proposed changes to the gas emergency arrangements and possible changes to electricity cash-out through the pending Significant Code Reviews could well result in significant changes to existing rules and alter incentives and behaviours;

[1] Related questions here include the following. Do they have the required technical capability? Can they take gas off the system (NEXA) when needed? Will the gas infrastructure be able to cope with large fluctuations in demand? What is the scope for fuel substitution at power stations and on industrial sites?

- where possible, bespoke, auditable models should be developed rather than relying on historical studies;
- considerable further investigation is required to establish how Demand Side Response can best be assimilated into the analysis;
- the scope of the proposed stress testing needs to be significantly broadened beyond loss of the gas interconnector; and
- once adopted by the regulator the methodology should constitute a formal guideline that is only changed following due process and consultation.

Our reasoning on some of these points is set out in more detail below.

Need for a market-wide capacity mechanism

We – indeed most prospective generation investors – are convinced that a capacity mechanism is required in the GB electricity market and that this should be a market-wide mechanism, not a targeted one. The reasons behind this view have been fully set out in our response to the Government's recent EMR "Appendix C: Capacity Mechanism Consultation". The capacity mechanism needs to provide a level playing field for both generation plant and "despatchable" demand-side response and be open to all providers of firm capacity. A mechanism needs to be open to new and existing plants if it is not to result in perverse economic outcomes. It should also be technology and location neutral.

The Government has set out at a high level a Strategic Reserve option and one formulation of a capacity mechanism based on a Reliability Market. We think Ofgem's task with regard to providing robust advice on the capacity margin will be unexecute-able if the Strategic Reserve option were adopted. The regulator would be permanently second guessing the system operator and updating its modelling and scenarios in the light of commercial actions by National Grid. It is also highly likely that interventions into the market by the system operator will distort market prices, compound illiquidity in traded markets and accelerate the "slippery slope" effect whereby only successful tenderers have the surety to remain on the system. In turn, all these effects could invalidate or undermine the modelling approach Ofgem is proposing.

It is vital that the market has an early understanding of the Government's proposal for a Capacity Mechanism to remove the uncertainty that currently exists on the way forward and to allow proper evaluation of new generation investment. This imperative is brought into clear focus by:

- DECC's own assessment of the changing capacity margin, which appears to tighten noticeably as early as 2015-16;
- the absence of any major new firm projects currently proceeding;
- typical timescales for new plant development at around seven years, which is longer than seems to be officially acknowledged (see Appendix 1);
- the increasing operational problems already being experienced on the GB system. In this context high demand peaks have historically been concurrent with low wind levels highlighting the need for not just replacement but firming capacity that can be used to cover a range of operational challenges. Conversely, in April and September noticeable amounts of wind capacity had to be constrained off the system during low demand periods at considerable cost to consumers requiring the constraining of flexible coal in low demand periods (see Appendix 2); and
- operational problems also being experienced by continental operators. In this context the Dutch system operator Tennet recently took the unprecedented step of calling for

a slow-down in the rate of connection of new offshore wind schemes in neighbouring markets, while it gets to grips with its own flexibility and capacity issues.

Delivering flexibility

We note that the capacity mechanism as presently contemplated is intended by DECC to specifically address a potential lack of capacity to meet demand during periods of high demand and low wind generation and not a potential lack of short-term flexibility. However, we believe Ofgem's analysis will also need to take a view on system flexibility and reflect this in the capacity requirement and how this is defined. A lack of appropriate flexibility within the electricity system could have just as severe consequences for security of supply as a lack of capacity, and capacity adequacy and flexibility are also closely linked.

In this context the formal requirements placed on Ofgem should require it to consider capacity needs in a range of situations. It needs to have regard to the number of peaking plants required to meet short-term spikes in demand as well as the requirement for plant that can be brought on at three to four days' notice. It needs to consider not just 1-in-20 cold spells but also credible operational challenges in anti-cyclonic conditions across the year. It is also relevant that anti-cyclonic conditions tend to be common across much of Northern Europe at the same time, so regional effects and interactions also need to be taken into account in an environment where market-to market power flows could increase dramatically. These differing operational conditions are likely to be increasingly impacted by the effects of the Government's connect-and manage decision on transmission access, which will inevitably lead to significantly increased transmission constraints across the system, further complicating Ofgem's task.

Producing the assessment

Ofgem should delegate a significant tranche of the work to National Grid Electricity Transmission (NGET) as, in its role of system operator, it has the appropriate experience and access to data to enable it to compile the Electricity Capacity Assessment (ECA) in the GB market. In effect Ofgem acknowledges this by proposing to make extensive use of NETS SYS data.

The system operator should not be the sole source of information used to arrive at the assessment of the desired levels of capacity. Independent assessments should supplement the ECA to offset the risk of bias given in participants' views. There are also risks that National Grid will be over-reliant on contracted commitments, which can and do inflate expectations of new connections and which fail to take into account actual project timescales and also plant withdrawals from the system.

These third party providers and their relationships with Ofgem should be set out unambiguously in the guidelines we have proposed.

The assessment process should include comprehensive pre-defined stress tests (such as high demand, low wind, exacerbated by high levels of transmission constraints see Appendix 3). These stress tests should take into account the skewed nature of the risks surrounding capacity, in that capacity can disappear overnight due to unplanned outages, fleet problems, abandonment and shut down decisions while, conversely, new plant cannot suddenly come on to the system, with investors experiencing project cancellations and construction problems.

Time horizons

The time horizon for the ECA is not currently being consulted on (as this is determined by the Secretary of State). However, we would strongly urge Ofgem to seek from the Secretary of State an extension of this timeframe covered by its remit.

Our analysis (see Appendix1) concludes that four years as proposed is far too short to provide meaningful information to operators or investors. Even if a plant is already consented, many factors (including planning issues, air permits, bidding and receiving quotes for gas turbines and other equipment, as well as engaging a contractor to build and then construct the facility) will mean the project will not be completed in this time-frame even for the most simple types of plants. Industry practice suggests an average timeframe of around seven years. Indeed the seven year figure in itself could be conservative as this figure ignores any delays between stages in the process from planning to commissioning.

For these reasons we believe a seven year timeframe for the assessment is the minimum credible approach if the capacity margin assessment is to be robust and drive appropriate targetted margins. It may be wise to also look out 10 years, although we acknowledge there is much less certainty over this period.

Answers to consultation questions

More detailed responses on the questions raised in the consultation are attached.

Please let me know if you have any questions on this response or would like any further comment on these key issues.

Please contact Maureen McCaffrey (Maureen.mccaffrey@conocophillips.com) for any further information.

Electricity capacity assessment: measuring and modelling the risk of supply shortfalls

Answers by ConocoPhillips to Ofgem consultation questions

1. Do you agree that the de-rated capacity margin is a good indicator of future capacity adequacy?

We think Ofgem should consider both the de-rated annual capacity margin profile, as well as the de-rated capacity margin at peak demand, rather than measures of the simple capacity margin. However, we note that historic de-rated capacity margins will over-estimate future availability as increased number of starts will accelerate planned outages and will also over time increase unplanned outages. Plant degradation should also be taken into account.

Consideration should be given to analysing what could be termed the "Flexibility Gap". This gap accounts for the balance between the amount of peaking plants, compared to plants that can be brought on at 3 or 4 days' notice (rather than in very short timescales). If the ECA model fails to do this it may incorrectly estimate the requirement for fast response peaking plant requirements. If, as a result, too much fast response OCGT plant is incentivised this may result in this low efficiency plant running more than would be necessary had additional slower response but more efficient CCGT been incentivised. Conversely, if there is too little fast response plant there may be sufficient capacity in the system but it may be unable to react to sudden changes in net demand (demand net of wind generation).

In this context the formal requirements on Ofgem should be made to explicitly require it to consider capacity needs in a range of operational circumstances.

2. Are there any measures of risk other than LOLE and EEU that we should report and what are their comparative advantages?

No, these should be sufficient. This answer is subject to the caveats below about extending the range of the assessment to at least seven years and also carrying out a range of appropriate stress tests.

3. Are there any additional key input assumptions that we should consider in the modelling?

The listing looks complete (save for the limited stress testing).

We do not consider there needs to be a distinction between type 1 and 2 assumptions. In particular it is questionable that some of the 'Type 1' inputs identified in chapter 4 will not experience a fundamental change over time. For example:

- forced outages: as noted these are likely to increase on existing plants as more flexibility is required from them. Also, forced outage rates at current, mature, plants cannot be applied to new plants because these would be expected to have an initial 'bedding in' period with a higher forced outage rate;
- planned outages are a function of Fuelled Hours Fired, this calculation takes into account the number of starts and ramping a plant has been required to do. By behaving in a more flexible way a plant will bring forward its next planned outage. Hence we would expect to see planned outage rates increase for CCGT plant as it becomes more flexible in response to wind intermittency;
- cross-correlation between increasing volumes of wind generation and demand (See Appendix 2);

- constraints on gas plant ramping and gas system flexibility;
- wind availability: classifying this as 'type 1' implies that option 1 is selected for wind availability even though Ofgem are minded to use option 2 (see question 5); and
- demand profile: electrification of heating and transport combined with increasing energy efficiency but also increasing use of appliances and gadgets has the potential to change the demand profile both within-day and between seasons. These changes bring into question the methodology for deriving the demand profile.

For these reasons, it may not be sufficient to rely on historical data to assess future demand profiles or growth. We note that the Government recently announced the creation an Energy Efficiency Deployment Office within DECC. The model should seek input from this office on the impact the policies may have on future electricity demand.

We consider that all inputs should therefore be classified as Type 2, requiring clear, explicitly stated and justified assumptions that operators and investors can test and understand.

Further consideration should be given to include specific stress tests within the model beyond the impacts of a shortage of gas supplies. The effect of the recession was a substantial reduction in demand (the largest in 30 years) that has arguably not yet been factored into policy and market development considerations, and as we discuss below there are a range of other eventualities that could stress the GB electricity system (see Appendix 3).

4. Do you agree that the use of stochastic (probability distributions) to model short-term variation of key input variables is the best available method? Do you agree with the use of scenarios and stress tests for capturing long-term uncertainty in key input variables?

Given our answer to the previous question, we do not consider that stochastics are an appropriate method for sole variation. The example given, of weather impacting the demand profile, could be used to create scenarios once assumptions are made of the long-term trends.

For the type 2 inputs, the combination of forward-looking assumptions and scenarios, with additional stress tests as we recommend, is appropriate.

5. Do you agree with the proposed approach to modelling wind availability?

We do not support Option 1, which would look at the correlation of wind speed and wind generation based on data from existing wind farms. As Ofgem acknowledges, wind technology has developed significantly in recent years, and historic correlation of wind speed and wind generation availability may no longer be valid.

Option 2, which would convert wind speeds to wind generation by looking at the technical specifications of wind turbines, seems a more appropriate approach. However, rather than using seasonal/ monthly averages of wind availability, Ofgem should create a half-hourly wind profile based on historic data and use this to forecast wind output. Its assumption on the availability of wind speed data at the level of granularity required should be tested.

We support the other elements of the proposed approach to modelling wind in respect of using the same approach for transmission-connected and embedded generation, recognising geographic variation and running different scenarios for wind-build rates going forwards.

Stress tests on low-wind events should be included in the scenarios. We would like to draw your attention to two pieces of analysis in this context:

- first, we have conducted our own in-house analysis of historical wind intermittency. We have included some of the results at Appendix 2. The analysis provides ample evidence that the GB is *already* showing signs of additional stress during periods of high demand/low wind. Five of the top ten highest daily demand figures of all time were recorded during December 2010 and were associated with low wind load factors (4.72%, 5.51%, 2.59% and 2.51% respectively). More generally, Illustration 1 shows that there is a high correlation between high demand/low wind output both in 2009 and 2010; Illustration 2 shows this correlation already has an impact on wholesale prices, resulting in more extreme prices during high demand periods coincident with low wind outputs. We also expect stress on the system and strain on prices to increase as the wind contribution increases (See Appendix 2). It is also relevant in this context that the value to the system of this low wind output will decrease further as network losses increase over HVDC "bootstraps" and at onshore connections as power passes over long distances in cold temperatures; and
- second, analysis by Stuart Young published by the John Muir Trust[2] has showed that a low-wind event of 20MW or less occurred on average once every 6.38 days for a period of 4.93 hours between November 2008 and December 2010.

We also note that Ofgem will correlate wind availability and demand in its modelling, and embedded wind will be treated as negative demand. We assume that demand data will include all intermittent generation, particularly with the increase of PV deployment (now almost 0.5GW) since the introduction of feed-in tariffs for small-scale generation.

We agree with the proposal to run different scenarios for wind build rates going forward.

6. Do you agree with the proposed use of NGET's existing data and assumptions regarding, in particular, commissioning and decommissioning dates and embedded generation?

We fully agree with Ofgem's views on the limitations of using National Grid's TEC register as a guide for determining a plant's operational maximum export limit (MEL). There are a number of reasons why a plant may wish to hold excess TEC, such as for a potential upgrade or for rare times when perfect weather conditions allow output to be maximised. Consequently there is a need to make adjustments to reflect maximum historical availabilities. Additionally it should never be assumed a plant is going to be built until a contractor has been engaged and is under contract.

Plant degrades over time but changes in output and efficiencies will rarely reduce TEC as once given up this cannot necessarily be regained. Furthermore, commercial output start-up dates do slip as these dates are normally based on the first possible date without unforeseen delays or delivery problems, and often vary significantly from the contract date. Use of NETS SYS data may help to a degree, but the risks are effectively skewed. Plant will not come on earlier than anticipated but are often later. Historic analysis is also required with regard to when a plant first said its commercial operation date would be and what actually occurred.

With regard to decommissioning and retirements, the method should again be aligned with NETS SYS, subject to suitable sensitivity analysis. Care will be needed as and when CMP192 is codified, as there are risks that commercial user commitment may not actually reflect on the ground circumstances of plant being withdrawn.

Turning to embedded generation, this is clearly a material variable and it should be modelled. We think it would benefit the model to require from DNOs all information they hold regarding the installed generation at the local level. This should also help refine how

[2] http://www.jmt.org/assets/pdf/Report_Analysis%20UK%20Wind_SYoung.pdf

constraints are dealt with. We think these information flows should be subject to formal reporting requirements on the DNOs.

7. Do you believe that Ofgem should require industry stakeholders to submit up-to-date data with regard to commissioning and decommissioning dates and embedded generation? Which industry process will ensure the confidentiality of information provided?

Yes. Such requirements should be administered under the relevant licences subject to appropriate confidentiality requirements and limitations on how Ofgem (or its consultants) can use the information.

It is unclear exactly how National Grid proposes to make "informed decisions" to determine the commissioning and decommissioning dates. Currently plants don't have to notify NGET until relatively near to the closure date (under the current connect and manage arrangements a user can relinquish TEC by providing a minimum of one year and five days notice), using the NGET approach may, we believe, lead to capacity being overstated. It should also be noted that CUSC modification proposal CMP192 is currently under review, but if this is implemented there will be a minimum of either two or four years notice of plant closures depending on the version of the change proposal approved. As we have already noted, care will be needed as and when CMP192 is codified as there are risks that commercial user commitment may not actually reflect on the ground circumstances of plant being withdrawn.

It is also not clear that requiring generators to provide commissioning and decommissioning information will of itself be an effective means of determining future capacity, since judgements on when to close capacity will be affected by emerging market conditions and decisions on market frameworks and renewable subsidies etc. Assuming this route is chosen, then it must be clear that any information is confidential, provided as the best view at the time, and not used for any purposes than informing the development of the capacity report.

We propose that the view of forward generation capacity should be validated by an independent party as a formal input to the annual process.

8. What are your views on how best to model LCPD opt-out plants' restricted running regimes?

Due to the significant impact of the Carbon Price Support (CPS) on generation costs at LCPD plant, they should first be assumed to run as much as possible in periods prior to 2013. However, the number of hours they run in any year should not be greater than their annual average in the years since the introduction of the LCPD (particularly due to the high price environment of 2008 encouraging maximising output of available plant).

It is known how many hours the plants have remaining to operate so Ofgem could run their model without the LCPD plants running and then, plant-by-plant, set them to run in the tightest hours such that they use up the full quota of remaining hours (provided this does not give a greater number of running hours on average per year than seen since the LCPD commenced). This is a reasonable commercial approach as they are likely to be the highest priced periods and so maximising the value of the remaining plant. This is a similar approach (but the mirror image) to the optimisation of maintenance outages approach suggested in the first option of paragraph 4.42.

It is important that the methodology considers the impact of the Industrial Emissions Directive. This will need to be done ordinarily over time as the impacts begin to bite, but these can be expected to be already impacting over the ECA timeframe especially if it is extended out to a minimum of seven years (as it should be).

9. Which of the two approaches for modelling electricity interconnection flows will provide the most realistic flows? If you favour a scenario-based approach, what are you views on reasonable scenarios to run?

Appropriately modelling interconnector flows (gas as well as electricity) is crucial given the increasingly interconnected nature of the GB energy system.

Option 1 is our preferred choice as it has the benefit of simplicity and removes reliance on commercial decisions. An additional stress test could then examine whether the interconnectors were fully importing (i.e. stress in the UK pushes up prices sufficiently high) and whether the interconnectors were fully exporting (i.e. stress in the UK happens at the same time as stress elsewhere giving rise to higher continental power prices, e.g. cold weather with low wind across Europe).

In Appendix 3 we examine what happened on one day of high demand and low wind, it was interesting to note than on this occasion the UK exports to Northern Ireland via the Moyle Interconnector were at near maximum capacity whilst imports from Continental Europe were limited to less than half the interconnector capacity despite very high prices in the UK of 326 £/MWh.

Additional stress tests should model the impact of introducing the CPS mechanism over time at different levels of CPS rates, as significant price differentials between GB and continental prices may affect flows. When the price of EUAs falls, and therefore the value of CPS rises, this effect becomes increasingly important.

We do not support Option 2. This option requires modelling of prices both in the UK and across Europe. Using a pricing model to help set inputs into the capacity model would introduce a feedback loop, as price and capacity are not independent variables.

Clearly a range of different scenarios need to be considered on future interconnector build outside of the NETS SYS assumptions.

10. Under what conditions would users respond by curtailing their demand and how would you go about modelling this? Is it worth Ofgem requesting data from DNOs on self-interruption and interruptible contracts?

Demand elasticity and demand-side response (DSR) is a difficult area but should not be ignored. The approach to modelling it should be flexible to development of a market-wide reliability market. Other likely developments such as demonstration and roll-out of storage technologies, and not just smart meters, also need to be taken into account.

DSR also needs to be looked at in the context of demand growth. In high demand growth scenarios where there is electrification of transportation on a significant level then there may be significant DSR, but this is unlikely to be the case where demand is flat.

In principle, the more information that can be gathered, the better. This information should include information from DNOs on interruption contracts. This should be backed up with a formal reporting requirement (but probably subject to the same qualifications noted on generator reporting above).

We are aware of various literature commissioned by DECC (Global Insight and Mott MacDonald studies) and Ofgem (under the Electricity Demand Reduction Programme (EDRP)) that need to be assimilated in determining the approach. The electricity systems policy being developed by DECC may well be relevant here as well.

The model should be future proofed to account for the introduction of time of use tariffs should they emerge into the market at significant volumes. EDRP assessments may be helpful in testing potential impacts.

11. Is historical data of scheduled outages a good indicator of future patterns of scheduled maintenance timings?

No. The optimisation of maintenance outages approach (first option) is a better approach than simply using historical data, as historical outage information does not take into account changing market conditions. Rather than delaying the building of the model until later it should be designed from the beginning of capacity assessments so that a) it is in place and does not get de-prioritised once a simple method has been accepted and b) the earlier periods provide time to test and refine the model.

Another important consideration is that, as we mentioned in the response to Q3, forced outages are likely to increase on existing plant as more flexibility is required from them. Current mature plant forced outage rates cannot be applied to new plants and new operational paradigms are likely to apply, and Ofgem itself notes that there is likely to be wider shifts in maintenance patterns in an energy market with significantly more wind.

Any measure of capacity needs to take account of possible or probable constraints in the GB transmission system, which are set to increase significantly.

12. Will treating half-hour periods independently have significant effects on our estimates of the de-rated capacity margin and risk of supply shortfalls and how should the model take into account half-hourly cross-correlations?

Provided that Ofgem use the Option 2 approach detailed for wind availability on the basis discussed in response to Q5 and ensure that they correlate demand with wind availability, it should not be necessary to correlate the wind availability between half hours.

Ofgem should use known technical limitations to correlate half hours, particularly the amount of time a storage site can be used in extended periods of high demand and low wind.

13. Are there any boundaries other than Cheviot that may significantly affect the risk of supply shortfalls?

Probably, but this is an issue for the transmission companies. As we have seen from recent statements by the Dutch TSO Tennet, there are likely to be increasing capacity limitations arising from rapid offshore development. Furthermore, the implementation of "connect-and-manage" means there is a systematic bias towards increasing constraints within the system over time, and the pattern of development under Round 3 is likely to lead complex binding constraints in a variety of locations sooner rather than later.

Appendix 1

Observed development timescales

Development type	Extension	Extenstion	Extenstion	New Site	New Site	New Site	New Site	New Site	New Site
Power Stations	Immingham P2	Barking	Spalding	ICHP Phase 1	Marchwood	Carrington	Langage	Gateway Energy Centre	Abernedd Power
Owner	Conoco Phillips	Thames Power /SSE/EDF	Intergen	Conoco Phillips	ESBI and SSE	ESBI (85%)	Centrica	intergen	SSE
Plant size (MW)	450	470	900	760	842	860	895	900	450
Location	Humberside	Barking	South Lincolnshire	N-E Lincolnshire	Southampton	Manchester	Plymouth	Essex	Port Talbot, Wales
Initial Developer	ConocoPhillips		Intergen	ConocoPhillips			Wainstones power sub. of NRG	Intergen	BP
s.36 Application	11-Nov-05	23-Aug-06	31-Mar-09	15-Nov-00	18-Oct-01	15-Aug-07	01-Jun-98	26-Feb-10	04-Sep-08
s.36 granted	01-Aug-06	19-Dec-07	11-Nov-10	11-Jul-01	28-Nov-02	30-Jul-08	15-Nov-00	04-Aug-11	23-Feb-11
Start of construction	15-Mar-07		01-Jan-12	01-Mar-02	01-Feb-07	01-Feb-12	01-Sep-06	01-Jan-12	
End of construction	01-Dec-09		01-Oct-14					01-Oct-14	
C.O.D	01-Jan-10		01-Jan-15	04-Oct-04	10-Dec-09	01-Aug-14	01-Mar-10	01-Jan-15	
Status	Completed	OH	OH	Completed	Completed	Site works	Completed	OH	OH
Design and internal development (Assumed)	24	24	24	24	24	24	24	25	24
Planning duration (months)	8.6	15.9	19.4	7.8	13.3	11.5	29.5	17.2	29.7
Project Construction (months)	33.6		36.0	31.2	34.3	30.0	42.0	36.0	
Total (months)	73.7		93.1	70.7	121.8	107.6	165.1	83.2	
plus development period	6.1		7.8	5.9	10.2	9.0	13.8	6.9	

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Development Time Scales Summary

	Average	Min	Max
Design and internal development (Assumed)	24.1	24.0	25.0
Planning duration (months)	19.3	7.8	49.0
Project Construction (months)	38.0	30.0	50.8
Total Development time (months) inc. pre-application estimated	81.3	61.8	124.8
Total (years)	6.8	5.2	10.4

- Average development time is 7 years
  - All data from third party sources
  - Totals ignore any delays between stages
  - The shortest real project took nearly a year longer than this but this is the shortest possible fast-track timeline
  - There is assumed to be no substantial difference between development timeline for a peaking/OCGT plant and a CCGT
- Project by project detail in Appendix

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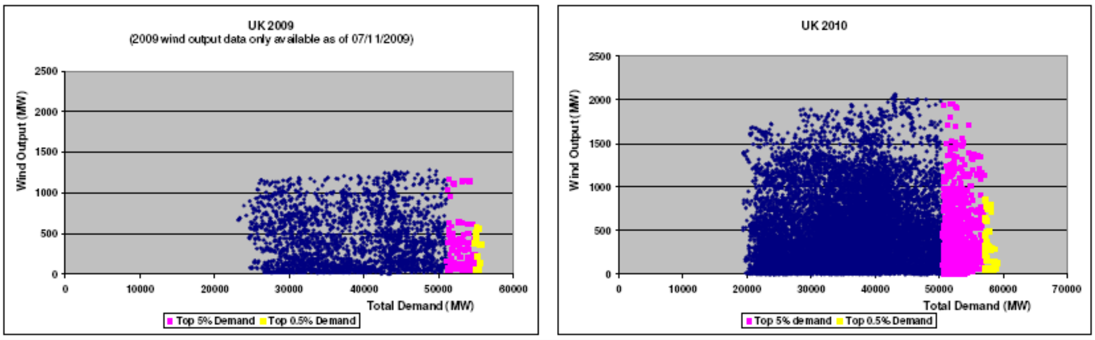
Appendix 2

Impact of wind intermittency

- Analysis involves classifying wind output into 3 different categories of low/medium/high

- Classification based on the output relative to the maximum output recorded (not max. generation capacity)
  - High wind: top 10% (10% of time wind output is higher than threshold)
  - Medium wind: between 10—70% (between 10-70 % of time wind output are between two thresholds)
  - Low wind: low 30% (30% of time wind output less than threshold)

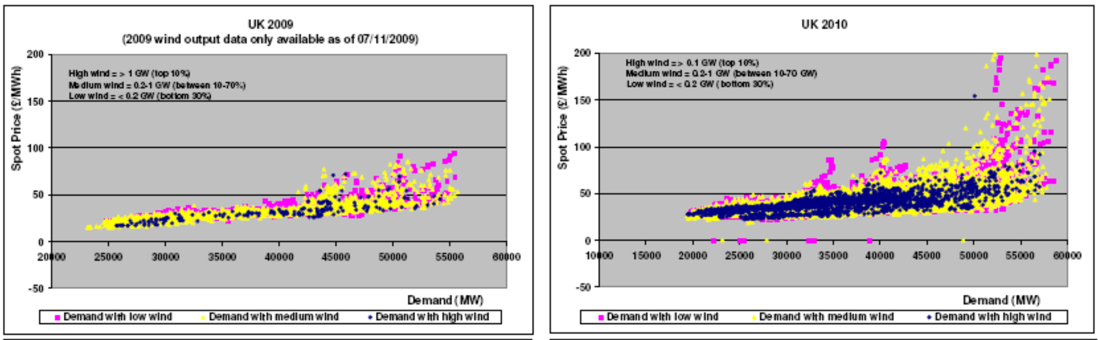
Illustration 1 – Hourly wind output vs. half-hourly demand 2009/10 in GB



- Top 5% demand points (high demand) 2009: high demand is predominantly coinciding with low wind outputs
- Top 0.5% demand points (very high demand) 2009: very high demands are coinciding even more with low wind outputs
- Top 5% demand points (high demand) 2010: significant tendency to low wind outputs
- Top 0.5% demand points (very high demand) 2010: very high demands are coinciding even more with low wind outputs
- 2010 on average a low wind year
- Overall higher concentration of low wind outputs

Data source: BM Reports

Illustration 2 – Half-hourly intraday spot price vs. half-hourly demand 2009/10 in GB



UK 2009:

- Positive gradient = higher demand leads to higher prices
- Layering formation: high wind data points tend to be associated with lower prices and vice versa
- At higher demand there is a significant concentration of data points with low wind output
- Majority of high prices achieved under medium or low wind conditions although some exceptions can be seen
- Of top 10% half hourly Intraday spot prices
  - 43% low wind output
  - 51% medium wind output
  - 6% high wind output

UK 2010:

- Positive gradient = higher demand leads to higher prices
- Layering formation: high wind data points tend to be associated with lower prices and vice versa
- Highest prices occur mainly during high demand periods under medium/low wind conditions
- Less high wind data points during high demand periods
- Of top 10% half hourly Intraday spot prices
  - 35% low wind output
  - 56% medium wind output
  - 9% high wind output

Data source: BM reports

Appendix 3

UK 7th December 2010 Cold Spell

Afternoon at 17.30 on 7th December prices spiked to 326 £/MWh.

Prices remained high for a few days during the December cold spell.

- Circumstances:
  - Weekday
  - Peak demand = 59.7 GW
  - Anti-cyclonic climatic conditions
  - Extremely low wind speeds

- Reasons:
  - “snow effect” = peoples inability to travel to work leading to high domestic consumption
  - No major thermal supply losses
  - Wind output = 132 MW of 5000 MW available (approx. 2.5% load factor)
  - Limited French imports = 986 MW import vs 2000 MW capacity
  - Nearly full exports on Moyle interconnector (NI) = 400 MW vs 500 MW capacity

Source: National Grid Winter Consultation 2011/12