Department of Energy & Climate Change

Annex F: EMR Panel of Technical Experts Final Report for DECC

July 2013

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Contents

Executive Summary

The Government appointed a Panel of Technical Experts in February 2013 to review analytic work that it had commissioned to inform the first Electricity Market Reform (EMR) delivery plan. The scope of the Panel's assessment is to review whether the analysis is fit for the purposes for which it has been designed, including the likely response of the investor community. This assessment is provided in this report. The Panel has no remit to comment on policy concerning the EMR or deliverability of the EMR programme. The Panel's Terms of Reference mean that the Panel cannot comment on affordability, value for money or achieving least cost for consumers. These matters are excluded from the Panel's scope and therefore from this report.

Commentary on Analysis and Key Findings

The Panel's approach to this work has been pragmatic, concentrating on gaining an understanding of the methodologies and analytical techniques available to National Grid (NG) to conduct analysis commissioned by the Government for the EMR delivery plan to 2020. This is not a comprehensive review or due diligence exercise. Much of our work was done in parallel with the production of the analysis with inevitably limited time to probe in depth. As a result of this timing, we developed our own summary of the results of NG's analysis to clarify our understanding and to test the utility of NG's results. Our comments are confined to the material provided to early July 2013. The Panel's key findings are given below.

Modelling impacts of EMR

Overall, our view is that National Grid's analytical approach, as commissioned by the Government, and its reliance on the Dynamic Dispatch Model (DDM) is a valid one for assessing the impacts of different technology cost assumptions and market scenarios on different policy parameters (e.g. a percentage of renewable generation, a Reliability Standard, emission intensities and the Levy Control Framework). This is largely assured by specifying build-rate limits and ensuring that strike prices are sufficient to induce investors profitably to invest, given their assumed hurdle rates.

The approach is relevant for the purposes of establishing the first stages of the Electricity Market Reform programme. This should enable the Government to collect the information to facilitate the transition to a more cost-reflective and ultimately market-driven solution. A more competitive market should address the many risks (investor appetite, hurdle rates, pace and cost of technology learning curves, fuel price uncertainty) inherent in this complex market which no model can realistically fully portray.

There are other modelling approaches – such as traditional utility least cost expansion models, but we suspect the differences would not be material and DDM has some advantages versus these models (e.g. stochastic capabilities). If we have a concern with this area of the analysis it is the limited amount of stress testing of the policy variables that have been conducted to date under a wider range of market scenarios. This is something DECC and National Grid may wish to develop further before publishing the final EMR Delivery Plan.

Electricity Generation costs

DECC and National Grid have undertaken an extensive review and analysis of costs of electricity generation in the UK, which has confirmed there is considerable variation within technology bands reflecting the range of site conditions, design and plant configurations, etc. When considering levelised cost estimates, it should be recognized that they are derived from a number of separate cost items, which need to be separately evaluated if they are to be considered plausible. The key components are the cost of the equipment and of its operation and maintenance (which are likely to be standard), the site and construction costs together with the connection assets and annual transmission charges, which are site-specific, the capacity factor (which is also site-specific for wind), and the weighted average cost of capital (WACC), which will depend on the debt:equity ratio and hence on the risk exposure. DECC and National Grid commissioned a range of consultants to review these cost assumptions, which have been published alongside the draft Delivery Plan. Due to time and commercial sensitivity, we have reviewed the aggregated assumptions but not the underlying primary data. We have reservations about the hurdle rate and Weighted Average Cost of Capital used in this analysis, which we detail in the body of the report. The review also indicates much uncertainty regarding future cost trends - and even near term cost outturns - especially for the less mature technologies. This includes the big three low carbon technologies of third generation nuclear, CCS and offshore wind. Of these, only offshore wind support levels are set through the EMR Delivery Plan.

The numbers generated are largely plausible given the assumed hurdle rates and build constraints, subject to the caveats mentioned above, although we believe that the risk that the construction and operating costs will remain high (or may even increase) for a few technologies[1] has not been fully explored. We also consider that the hurdle rates may prove excessive once investors gain familiarity with the contracts and market environment, and that the post 2016 levels assumed in modelling may therefore prove too high. DECC should therefore collect evidence on financing costs and plan to revisit the assumptions on which strike prices are periodically set in the light of new evidence as it is gained.

[1] Cost of low-carbon generation technologies, Mott MacDonald, Published by Committee on Climate Change, May 2011

De-rated plant availabilities

We believe that National Grid (NG) is using an overly conservative assumption for peak power plant availabilities for assessing future system capacity margins and hence amount of new capacity which would need to be procured through the Capacity Market, although this analysis is yet to begin. NG is using numbers based on plant availability when demand is above the 50th percentile during the winter months over recent years as a guide to availability at peak demand periods. NG's 2013/14 winter outlook consultation[2] gives availabilities close to those observed at last winter's Triad peak. However, these availability figures are low by international standards, and in comparison to what Great Britain (GB) achieved prior to 2001. The low values reflect the lack of strong incentive to make capacity available in GB. The Panel believes the correct metric is unplanned availability (one minus the expected unplanned outage rate), since generators should not be taking service outages during peak times. This would lead to higher plant availability than is assumed by NG. There is time to adjust this position ahead of the implementation of the Capacity Market. The incentive to make capacity available will of course be reinforced once the mechanism is implemented. NG has (at the Panel's request) tested this as a sensitivity case and it is shown to lower the gross value of capacity mechanism payments significantly, by over £200m a year from when capacity payments start[3].

Commentary on the Realism of Investor Modelled Behaviour

The Dynamic Dispatch Model assumes that investors are driven (subject to exogenous constraints) by the rate of return on an investment determined by a calculation of projected generation costs vs. revenues. There is inevitably a gap between the abstractions needed for modelling and the complexity and diversity of real world investor behaviour as investors may employ different methodologies in allocating their resources; operate as a disparate rather than cohesive group; have different perspectives on risk; and value aspects of investments which are not included in the models.

The model has two levers with which to consider investor appetite; the hurdle rate and the build rate. The build rate is also affected by other factors such as supply chain constraints, planning consents etc. Accordingly, considerable effort and thought needs to be devoted to understanding elements outside the model to guide the values of these key variables.

DECC recognises the need to augment the model by significant effort to build up the critical insights and body of evidence necessary to make these key inputs as

[2] http://www.nationalgrid.com/uk/Gas/TYS/outlook/

[3] Note that gross value is not the net costs that electricity customers face; net costs are significantly lower, reflect the true costs, as they take into account the offsetting effect of a decrease in the wholesale electricity price. A full analysis of the potential costs of the capacity market to consumers is done and published, by DECC, in its Cost Benefit Analysis published in the EMR Impact Assessments.

realistic as possible and have devoted considerable energies to this task. Clearly, there is more to do in this area as the EMR Delivery Plan is developed.

Recommendations

As a result of these findings, the Panel's key recommendations are:

- There are inevitable gaps in cost information because of the immaturity of technology, the evolving nature of many of the relevant markets (for the reference price and for balancing) and lack of experience in the cost of financing these new instruments. DECC should use all its opportunities to access data and understand cost drivers, to inform future strike prices.
- Industry owns the cost data for the more mature technologies and DECC's requests for this information need to be specific and defined, ideally in clear data catalogues. DECC should work with industry to develop "should" cost (i.e. benchmarked) and "could" cost (i.e. collaboration to further reduce costs) models to improve the evidence base for future strike prices.
- DECC should commission an independent technical advisor to re-examine the question of appropriate availability levels for technologies during periods when operating plant margin is low including other jurisdictions where there is an incentive to be available at such times. This work should be done before the capacity market is implemented.
- There should be a stronger and more visible link between DDM modelling and the feed through to consumer prices.
- The DDM should be run stochastically to improve the reliability of outputs (e.g. to test the risk of missing targets, the Levy Control Framework and capacity mechanism costs)
- DECC should consider adopting best practice from the private sector by employing light-touch Scenario Planning methodologies to inform their assumptions concerning investor appetites.
- DECC should continue to monitor evolving market conditions (the spot and balancing markets) and the actual financing cost for these and similar investments to assess the extent to which changes alter risk and hence the hurdle rate to inform the setting of future strike prices.
- DECC should continue to monitor support conditions in other EU countries to learn what knowledge and evidence can be transferred to understand how they achieve more capacity at lower cost.

Caveats

Certain aspects associated with the EMR are outside of the remit of the Panel and are not included in this report:

- EMR costs beyond 2020,
- The risk of a “capacity crunch” in 2014/15 due to the risk of plants “retiring” earlier than expected,
- The treatment and impact of Interconnectors on the strategic intent of the EMR,
- Locational issues in relation to transmission pricing and constraints,
- Reviewing the Carbon Price Floor,
- Demand side forecasting and management,
- Value for money, costs to consumers and affordability.

This report has been prepared from information provided by DECC, National Grid and the collective judgement and information of its authors. Whilst this report has been prepared in good faith and with reasonable care, the authors expressly advise that no reliance should be placed on this report for the purpose of any investment decision and accordingly, no representation or warranty, expressed or implied, is or will be made in relation to it by its authors and nor will the authors accept any liability whatsoever for such reliance on any statement made herein. Each person considering investment must make their own independent assessment having made whatever investigation that person deems necessary.

Introduction

Role of the Panel of Technical Experts

1. The Government has commissioned a Panel of Technical Experts (PTE) to review a series of analysis from National Grid (NG), DECC and others which will provide an evidence base for Ministerial decisions prior to consultation on the EMR Delivery Plan in July 2013 and production of a final Delivery Plan thereafter.

2. The Panel of Technical Experts is an advisory group of independent consultants who have been appointed by Government to provide impartial quality assurance of technical analysis. The background of the members and terms of reference of the Panel were published upon appointment[4]. This report has been prepared for DECC by:

   Andris Bankovskis
   Dr. Guy Doyle
   Professor David Newbery CBE FBA
   Dr. Norma Wood

Scope

3. The Government appointed a Panel of Technical Experts in February 2013 to review analytical work that it had commissioned to inform the first EMR Delivery Plan. The scope of the Panel's assessment is to review whether the analysis is fit for the purposes for which they have been designed, including the likely response of the investor community. Our assessment is provided in this report. The Panel has no remit to comment on EMR policy, Government's objectives, or the deliverability of the EMR programme. The Panel's Terms of Reference mean the Panel cannot comment on affordability, value for money or achieving least cost for consumers. These matters are excluded from the Panel's scope and therefore from this report.

[4] https://www.gov.uk/government/policy-advisory-groups/141

Timing

4. The timeline is critical: the draft Delivery Plan needs to be ready to go out to consultation in July 2013 if the Final Delivery Plan is to be available for publication by the end of 2013, subject to Royal Assent of the 2012 Energy Bill. The consultation process will pose well-defined questions and will provide strong signals to the market: for example, draft strike prices are available for consultation. There is significant pressure on DECC and NG team to deliver key elements of the EMR for July and consequently, some of the Panel's recommendations may need to be considered post July.

Approach

5. This is not a comprehensive review. The approach to this work has been pragmatic, concentrating on gaining deeper understanding of the methodologies and analytic techniques available to NG and to DECC for the EMR Delivery Plan. In this process, the Panel noted several aspects of the modelling and analysis and the way it is being used which may have material impacts on the results, their interpretation and the conclusions drawn. These need to be recognised in the decision-making process.

6. Using this approach to develop the working relationship between the Panel and DECC and NG, the Panel provided two informal reports with interim recommendations. These recommendations were welcomed by the Analytical Steering Group[5] as being constructive and material. The Panel appreciate the way in which their recommendations have been adopted and incorporated where possible into DECC's and NG's thinking and subsequent analysis:
   - National Grid used their Plexos model to enhance analysis of constraint costs,
   - National Grid used alternative assumptions for de-rated plant availabilities to model their sensitivity and impact,
   - DECC explained their engagement with investors and developers to date,
   - National Grid developed preliminary conclusions on sensitivities run through the DDM together with tornado charts, block diagrams etc. to improve confidence in and understanding of the model and analysis, especially for those less familiar with EMR

[5] The Analytical Steering Group is co-chaired between DECC and National Grid for the purposes of the analysis for the EMR delivery plan, with Ofgem as an independent advisor.

7. The Panel’s report focuses on key aspects of DECC and NG’s work providing our commentary on:

    - The analysis and major findings
    - The realism of Investor modelled behaviour

Caveats

8. Certain aspects associated with EMR are outside of the remit of the Panel and are not included in this report:

- EMR costs beyond 2020,
- The risk of a “capacity crunch” in 2014/15 due to the risk of plant “retiring” earlier than expected,
- The treatment and impact of Interconnectors on the strategic intent of EMR,
- Locational issues in relation to transmission pricing and constraints,
- Reviewing the Carbon Price Floor,
- Demand side forecasting and management, and;
- Value for money, costs to consumers and affordability.

9. This report has been prepared from information provided by DECC, National Grid and the collective judgement and information of its authors. Whilst this report has been prepared in good faith and with reasonable care, the authors expressly advise that no reliance should be placed on this report for the purpose of any investment decision and accordingly, no representation or warranty, expressed or implied, is or will be made in relation to it by its authors and nor will the authors accept any liability whatsoever for such reliance on any statement made herein. Each person considering investment must make their own independent assessment having made whatever investigation that person deems necessary.

Commentary on analysis and findings

The analytical approach and key assumptions

10. On behalf of the Government, National Grid has carried out an extensive analysis of the impact of key EMR policy choices such as the level of strike prices for renewable technologies and the level of the reliability standard. A major part of this has been the modelling of the future cost impacts using DECC's Dynamic Dispatch Model (DDM). At the time of writing, some of this work is still underway, with National Grid testing a range of scenarios and sensitivities. The Panel has been involved in commenting on the inputs and outputs of modelling, though the extent of this scrutiny has been at a high level. To aid the interpretation of our scrutiny, we have provided a short assessment of the conclusions that could be reasonably drawn from the modelling analysis that we have seen to date.

11. The DDM provides a projection of generation capacity requirements and associated dispatching levels which meets projected demand with a given Reliability Standard (Loss of Load Expectation), power sector carbon intensity and other constraints e.g. the Levy Control Framework (LCF). For new low carbon generation, plant investment and dispatch decisions are made on the basis of projected investor returns versus strike prices or (for non-CfD backed generation) are based on projected market prices and rewards in the capacity mechanism.

12. In most cases, the carbon intensity of the sector is constrained to a modelling assumption of 100g/kWh in 2030 although this makes little difference to the choice of strike prices to 2020, which is primarily driven by the desire a level of renewables generation in 2020 consistent with electricity system contributing to the UK's economy-wide renewables target. The renewable energy share in total generation achieves between 30% and 35% in 2020.

13. Strike prices are constant over the life of a contract. However, in the scenarios included in the analysis there is some degression over time in the strike prices offered for future investment. This reflects the expectation that levelised costs of generation of all technologies are projected to fall, through a process of learning both of construction and financing. We note that this

approach mirrors, although less aggressively, the degression profiles published by the German Government[6].

14. Fuel and carbon prices are taken from DECC's fossil fuel price projections[7]. This sees NBP gas at a plateau of about 70p/therm from 2015 while the carbon price floor increases steadily reaching £32/t in 2020 and £75/t in 2030.[8]

15. Demand (or generation requirement on the GB system) is sourced from DECC's Updated Energy and Emissions Projections[9]. Demand is projected to fall in the medium term as a result of announced efficiency measures. Under those central assumptions, demand is projected to increase to over 380 TWh in 2030 versus 340 TWh in 2012.

Headline findings

LCF costs

16. The main headline finding is that under most cases the EMR instruments should be able to enable the electricity system to contribute appropriately to meeting 2020 renewables energy ambition within the current LCF cap of £7.6bn, compared with costs of £3bn in 2013/14. Up to 2020 these costs are dominated by Renewables Obligation (RO) and small scale Feed-in Tariff (FIT) support costs, but with an increasing wedge of CfD difference payments from 2017, such that these comprise about 35% by 2020. Beyond 2020, although we note there is not yet an agreed LCF envelope beyond 2020/21, assuming a carbon intensity of 100g in 2030, those payments may increase to become proportionally more of the spend from 2025. RO and CfD costs then step down as support for biomass conversions ceases in 2027.

Capacity

17. These LCF costs exclude the costs of payments to generators for providing capacity. These capacity payments only start in winter 2018/19, the first delivery year of a capacity market as currently outlined. From this date on, capacity payments become significant and after an initial period these costs stabilise at between £2bn and £3bn a year from the mid-2020s. However,

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[6] http://www.eeg-aktuell.de/wp-content/uploads/2010/09/Verguetungsuebersicht_Windenergie_nach_EEG_2009.pdf
[7] https://www.gov.uk/government/publications/fossil-fuel-price-projections
[8] All prices in this report are at 2012 prices
9 www.gov.uk/government/uploads/system/uploads/attachment_data/file/65717/6660-updated-emissions-projections-october-2012.pdf

these figures represent the gross value of the capacity market, not net costs to customers. Net costs, which are significantly lower, reflect the true costs of the Capacity Market for customers as they take into account the offsetting effect of a decrease in the wholesale electricity price. A full analysis of the potential costs to customers from EMR is available in DECC's published Impact Assessments[10].

18. In the initial years the modelling suggests participation in the Capacity Market will be dominated by payments to legacy gas, coal and nuclear plants. We would expect that as new capacity builds up the payments for these new plants would exceed those for the legacy plants.

19. The new CfD support mechanism (and the RO up until 2017) are projected to attract a further 15 GW of new grid connected capacity (or conversions) on to the system by 2020. This is likely to be dominated by nuclear and wind, both onshore and offshore, with smaller contributions from CCS (mainly gas), solar and other renewables.

Network costs

20. This increase in generation capacity and associated investment costs will be broadly matched by an increase in network and system operation costs, which will be required to manage a more diverse mix of generation assets, responsive load and storage facilities. Overall GB network costs are projected to increase from £2.8bn a year in 2012/13 to £4bn in 2020/21. Most of this increase is due to the higher transmission use of system costs, due largely to deep grid reinforcements which are required to handle connection of dispersed renewables.

Price outlook and spark spreads

21. The core scenarios projects the base load power price will increase from around £45/MWh today to around £65/MWh in 2021 and around £70/MWh in 2027, after which there is a slight decline to 2030. The price increase reflects the increase in carbon price, which feeds through to the marginal cost of unabated gas plants, which are expected to be the main price setting plant until 2030. The softening in prices in the late 2020s is due to the displacement of unabated gas in the merit order by low variable cost low carbon generation. This is likely to happen only in periods of high renewable availability versus demand, so would not be expected to bring a major

[10] https://www.gov.uk/government/publications/energy-bill-impact-assessments

reduction in average annual prices, although this is a possibility beyond 2030.

22. It is clear that the increasing carbon price floor will make low carbon generation more attractive, but CfD support will be required to make these technologies viable under DECCs central and low gas price cases. Were gas prices to be higher, the CfDs would not be required for some technologies in the 2020s, other than to provide investor reassurance. If gas prices outturn at these higher levels, many of the CfDs would provide payments to government, so reducing the LCF costs.

23. Spark spreads (the margin that generators earn over their fuel and carbon costs from electricity sales at market prices) for gas fired CCGTs is projected to be about £5/MWh up to 2020 and around £6.5/MWh between 2021-2028, before declining sharply thereafter. This is based on the standard 49.13% HHV (high heating value) efficiency standard, but this is still low compared with what developers of new plant would require in order to justifying investing in new capacity. The expectation is that higher efficiency plant would make a higher margin and all plant would gain a further uplift from payments for capacity. However, with capacity payments expected to be triggered only from 2018/19 this suggests the squeeze on gas generation spreads will continue in the medium term unless capacity margins tighten.

Impact on electricity customers

24. DECC's energy prices and bills team takes the analysis of impacts of EMR on the top level electricity sector metrics - wholesale prices, LCF costs and other costs associated with the capacity mechanism and network and balancing services – and then estimates the impact on final customers. This analysis compares the projected outturn versus a counterfactual of achieving the same renewable energy and decarbonisation ambitions through reliance on existing policy instruments (RO and carbon prices). A comparison is also made against a counterfactual with renewable energy but without decarbonisation ambitions. In all comparisons the impact of energy efficiency measures is included in both the EMR and counterfactual scenarios. Whilst this analysis is helpful to assess the potential impacts of EMR on customers, we recommend there should be a stronger and more visible link between DDM modelling and the feed through to consumer prices.

Sensitivities

25. Numerous sensitivity cases have been run, considering variations in cost and strike price assumptions, security and emission intensity standards, increased reliance on particular technologies, etc.

26. The notable feature about these sensitivity cases is that there is comparatively little impact on the outcomes to 2020, with the projected LCF costs rarely exceeding the £7.6bn cap and even when they do exceed the cap; it is only by a relatively small amount.

27. National Grid has also tested sensitivities of other variables, most notably fuel prices and electricity demand, which are more influenced by external market and macroeconomic drivers, which would clearly also impact on the costs of achieving GB's renewable electricity, decarbonisation and security of supply ambitions. However, National Grid have not tested the impact of adjusting the carbon price support level, which is a major policy variable, for which the trajectory set out in the Government's response to the Consultation on the Carbon Price Floor is used.[11]

Outlook for technologies beyond 2020

28. The majority of the analysis to support the draft EMR Delivery Plan focuses on the period to 2020/21, and particularly to 2018/19, which is the last year for which strike prices will be set in this Delivery Plan. DECC has included analysis of scenarios-based deployment beyond 2020[12]. These scenarios all project a significant role for renewables, nuclear and CCS from 2020 onwards. Biomass conversions (of existing coal stations) are projected to play a critical role in delivering overall lower costs and comparatively prompt savings and enabling a high renewable electricity share to be achieved. This biomass generation continues into the 2020s, only ending in 2027, when the RO and CfD support is scheduled to finish.

29. Assuming carbon intensity of 100g by 2030, nuclear generation is projected to be broadly maintained and indeed shows a modest increase in the 2020s as new capacity is assumed to come on from 2020 and replace the legacy plant. By 2030 nuclear is projected to meet over 25% of GB's total generation requirement.

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[11] https://www.gov.uk/government/consultations/carbon-price-floor-support-and-certainty-for-low-carbon-investment
[12] See Chapter 5 of the draft EMR Delivery Plan consultation document

30. Similarly, wind generation is projected to account for a steadily increasing share of generation such that by 2030, it meets more than 20% of requirements, with offshore potentially overtaking onshore in the mid-2020s. The expected rate of build on on-shore wind is low compared to that achieved in Germany over the last decade which has poorer wind resources. Nuclear is projected to run up against its build limit constraints and onshore wind gets close, signalling that if these constraints were relaxed these could have contributed more and reduced overall costs.

31. A number of generation types, most notably CCS and several of the less mature renewable technologies such as wave and tidal stream, are assumed to be developed through the 2010s. We note that this requires higher support levels for these technologies during this period, in order to provide the required optionality for longer term when costs may be more comparable with more established technologies. Solar PV is projected to play a significant role but much less than Germany is anticipating for their market, given the less sunny conditions and lower end user tariffs in GB. The core scenarios have 6TWh of net imports from interconnectors in 2020, which is less than 15% of their potential capacity.

The Panel's view of the analytical approach

32. Overall, our view is that National Grid's analytical approach and its reliance on the DDM is a valid one for assessing the impacts of different technology costs and market scenarios on different policy parameters (e.g. a percentage of renewable generation, a Reliability Standard and emissions intensities and the Levy Control Framework). This is largely assured by specifying build-rate limits and ensuring strike prices are sufficient to induce investors to invest profitably, given their assumed hurdle rates.

33. We are, however, concerned that the hurdle rates used in the modelling (and published by DECC alongside the draft Delivery Plan) may prove higher than necessary to induce the required supply of investment once the EMR has bedded down and investors gained familiarity with the new contracts. There are other modelling approaches – such as traditional utility least cost expansion models, but we suspect the differences would not be material and DDM has some advantages versus these models (e.g. stochastic capabilities). A further concern with this area of the analysis is the limited

amount of stress testing of the policy variables under a wider range of market scenarios to date.

34. Note that the main advantage of the modelling is to test the extent to which different strike prices for renewables and reliability standards for the Capacity Market will viably meet a set of policy parameters such as a percentage of renewable electricity generation, the LCF and assumptions about investor behaviour, critically the hurdle rates they adopt. While the model can indicate whether the strike prices are sufficient to induce the desired level of low-carbon investment (given the correctness of the assumed investor behaviour) much depends on the accuracy with which the cost and build constraints of these technologies are measured. The attractiveness of these investments would need to be better informed by the details of location, cost build-up, marketing and balancing risk as well as investor appetite, for which even as sophisticated a model as the DDM is not well suited to validate. Indeed, the DDM does not model the spatial elements that determine wind capacity factors and grid changes that affect location decisions for all plants.

Analysis to inform the reliability standard

35. The analysis of EMR impacts has adopted a supply reliability standard based on a Loss of Load Expectation (LOLE) of 3 hours a year. This can be seen as the sum of the areas of overlap between two probability distributions of demand and available supply for each hour and is a standard approach applied by system operators. Based on a high level screening of this analysis, the Panel is comfortable with the approach and most of the assumptions. The standard of 3 hours was set based on an economic valuation of the appropriate security margin using an initial estimate of the value of lost load (Voll) of £17,000/MWh, and the cost of new entry of £47/kW per year.

Plant availability factors

36. The above analysis all appears reasonable, however, there is an issue which relates to plant availability factors that we believe National Grid and DECC need to consider, preferably ahead of implementing the capacity mechanism.

37. Plant availability factors applied to the modelling calculating metrics based on peak demand periods are extremely conservative (low) by industry standards. National Grid is using the average plant availabilities when demand is over the 50th percentile in recent years' winter (Dec-Feb) outturns[13]. These give availability expressed as a percentage of maximum export limit (MEL) of 88% and 85% for coal and gas (CCGT) plants, respectively. Our view is that this not the appropriate metric for analysing plant availabilities at peak demand periods, and the appropriate one is the peak period availability, which is derived plants' forced outage rates over a narrow time window, rather than total outage rate over a wide time period. This is because generators would not normally take scheduled (service) outages in periods of high demand for commercial reasons (loss of high energy and reserve payments). Typically in other jurisdictions and where there is a strong incentive to make capacity available "good practice" annual forced outage rates are 2-4% for coal and gas plant, implying availability rates of 96-98%, excluding service outages. Peak availability rates are even higher, given there is often scope to postpone shutdowns.

38. National Grid has informed the Panel, that the actual outturn availabilities for the recent winter peak – on 12 December 2012 – were close to those it as assumed for its DDM analysis. This showed that for CCGTs the availability increase from 85% to 86%, nuclear 81% to 83% and coal 88% to 92%. These figures are low by international standards, and low compared to what was achieved under the Pool. The main reason for the low availabilities is the lack of strong reward for making plant available and generating in peak periods in the current UK market. Accordingly, plant has been less well maintained and so forced outage rates and service outages are much higher. As the market moves towards a tighter balance over the next two to three years we would expect that peak prices will rise and so generators will be incentivised to make more capacity available. This may add a percentage point or two to availabilities. However, the real shift would come once the capacity mechanism is implemented, especially if there are significant penalties for non-availability at times of low operating reserve margins.

39. There are however two reasons why GB may not rapidly achieve best practice availabilities. Firstly, there may still be significant rump of legacy

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[13] National Grid also considered plant availabilities when demand is over the 80th percentile; however their analysis showed little difference.

plant in operation in 2018/19, when it is anticipated the capacity mechanism will be required, so plant reliability may be impaired. Secondly, as we move towards a system with high amounts of wind then periods with low operating reserve margins will not be so well correlated with overall peak demand. This is because wind output may be low in periods of moderately high demand, perhaps when a significant amount of fossil and nuclear plant is taking service outages. This suggests that de-rated availabilities are likely to be significantly less than at times of system demand peak. However, by deploying a more sophisticated approach to scheduling service outages and by providing strong incentives to make capacity available, our view is that de-rated availabilities of CCGT, coal and nuclear plant would be in the 91-94% band, in the shoulder periods[14]. In the low demand summer months, availabilities could be well below 90%, while in peak winter periods 95% should be achievable.

40. In the light of this we believe that NG's assumption of continued low availabilities once the capacity mechanism is introduced is overly conservative. The implication is that NG's current analysis may be underestimating future plant margins and hence overestimate the amount of future capacity payments. Also, since projected wholesale prices in the DDM are partly driven by the capacity margin, wholesale power prices are also uplifted, albeit a second order impact.

41. National Grid has, following the Panel's initial comments, run a sensitivity case with a higher peak availability level for CCGTs and coal plant, which indicates a saving of over £200m a year in the gross value of capacity market payments[15] from 2020. The Panel is recommending that the measurement of plant availabilities issue is further explored and that an independent assessment is undertaken of plant availabilities in the future, based on appropriate international experience.

Cost assumptions

42. DECC and NG have undertaken an extensive review and analysis of costs of electricity generation in the UK, which has confirmed there is considerable

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[14] Mott MacDonald

[15] However, note that this figure is only the gross value of the Capacity Market, not net costs to the customer. Net costs, which are significantly lower, reflect the true costs they take into account the offsetting effect of a decrease in the wholesale electricity price. A full analysis of the potential costs of the capacity market to customers is available and published in DECC's Impact Assessments.

variation within technology bands reflecting the range of site conditions, design and plant configurations, etc. The review also indicates much uncertainty regarding future cost trends - and even near term cost outturns - especially for the less mature technologies. This includes the big three low carbon technologies of third generation nuclear, CCS and offshore wind.

43. Most of the low carbon technologies are hugely capital intensive so the main drivers of levelised costs are the initial capital cost, the weighted average cost of capital (WACC) and the life time full load equivalent running hours. Operations and maintenance is typically a small component and tends to be linked to capex. Transmission charges (and more fundamentally, the incremental cost of transmission) vary widely across the country and are also site-specific.

44. The general view is that for most technologies both capex and WACC will reduce over time as all parties benefit from industry learning through increased deployment and economies of scale. This assumes that supply chains are uprated. WACC falls as investors and lenders become more comfortable with construction, operation and market risks.

45. Our view is that the central cost estimates are reasonable given the assumed hurdle rates. However, we consider that the hurdle rates could fall significantly once financiers become comfortable with the credibility of these CfDs and their counterparty. The hurdle rate for on-shore wind is assumed to fall slightly to 8% real from 2016 and to remain at that level until 2030, before gradually declining to 5% in 2040, although only the hurdle rate to 2018/19 has been used to inform the strike prices published in the draft Delivery Plan. In contrast, the most natural comparator, the WACC revealed in the auction for the contracts to operate and maintain the offshore transmission assets connecting offshore wind farms to the grid, were reportedly[16] as low as 4-5% real. These 20 year Offshore Transmission Owner (OFTO) contracts are also indexed but the revenue earned depends critically on availability, which in a hostile sub-sea environment is probably riskier than that of easy to access on-shore wind farms.

[16] KPMG (2013) *Assessment of Synergies and Conflicts of Interest,* report to Ofgem (22 April) gives an estimate of 7.84% real return on equity with an equity share of 16%. If the remaining 84% is real indexed debt at 3%, the WACC would be less than 4%.

46. Beyond 2020 there is considerable uncertainty about future costs. The draft EMR Delivery Plan does not set strike prices beyond this period. We consider that there is a significant chance that several technologies will face major challenges in achieving deep construction cost reductions; the main hurdles include more demanding sites (for offshore wind), intrinsic complexity of the technology combined with extreme levels of scrutiny during construction and commissioning (for nuclear and to a lesser extent CCS) and supply constraints on some critical components that can create bottlenecks in supply chains. The evidence from long-run cost studies is that it may take a decade or more from the demonstration stage before construction costs begin to fall. Nuclear generation has failed to see a cost reduction trend after several decades of commercial deployment, largely as technology changes have been matched by continually evolving and tightening regulatory scrutiny, and a loss of experience in building plants.

47. Notwithstanding this history, our view is that there should be scope for capex cost reduction to be deployed in nuclear plant in the late 2020s assuming regulatory oversight is reasonably stable. Some other technologies may also reasonably expect significant cost reductions over the same time frame. If not, then the portfolio needed for decarbonisation will presumably have to adapt to revealed costs.

48. Clearly, the quicker that the CfD allocation can move towards a more competitive process, the less important the task of future cost assessment becomes. In the meantime, there would considerable value in DECC collecting data on costs, site and performance metrics across all low carbon projects benefiting from RO, FIT and CfD support mechanisms to inform future Delivery Plans – although we note that this does not inform the scope of the first EMR Delivery Plan, which is the focus of this report. This data disclosure could presumably be part of a knowledge transfer obligation in the CfD.

49. At a detailed level there are some questions regarding all the costs, but this is to be expected given the complexity of drivers and the range of site conditions and particular circumstance. This is evidenced by the Panel's deliberations on onshore wind costs. While we have some confidence that construction costs have been fairly well surveyed, further analysis could be undertaken of how transmission charges and capacity factors vary across

space and time, and whether they are consistent with the presumed evolution of the industry as modelled in the DDM.

50. The degradation in output of wind turbines is a complex factor which will require ongoing monitoring. For example, one recent report by Green and Staffell (2013) "Turbines are found to lose 1.4% of their output per year, with average load factors declining from 28.5% when new to 21.1% at age 19."[17] In light of this report, it would be useful for DECC to undertake further analysis of onshore wind load factors for the final delivery plan[18]. More generally, continued monitoring of wind performance closely (and its variation across sites) will improve the future evidence base on costs.

51. We are unclear how much wind will connect to the grid and pay transmission charges. We are unclear what these charges would be for wind for transmission-connected plant, especially in the regions affected by the western "bootstrap" (sub-sea HVDC link between Scotland and England. There is also an issue of how much capacity will connect to the distribution networks (DNO) and what in that case this would pay (unlike grid connections, DNO connected generation pay deep connection charges that are highly site-specific) but escape the locational transmission charges.

52. The focus on levelised technology cost assumptions is reasonable when gaining some sense of the required strike prices, although it is important to be aware that the cost estimates are station gate (or beach-head for marine technologies) so exclude costs associated with reinforcement of the network, balancing or the reserve needs in handling and delivering the energy. The energy is also treated as homogenous in terms of its time value in the market, which is valid if comparisons are for baseload energy but is not appropriate for comparisons between baseload and mid merit and/or peaking generators. This does not present a problem in the DDM analysis of EMR impacts because the network and balancing costs and time value of energy aspects are all taken into account in addressing the impacts of different technology deployments. However, there would be value in flagging the need for continued caution to be noted on the use of levelised costs in DECC's electricity generation cost publications.

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[17] Iain Staffell and Richard Green (2013) "How Does Wind Farm Performance Decline with Age?" mimeo, Imperial College Business School

[18] German feed-in tariffs are set for a period that depends on the achieved output per MW capacity measured in the first three years and the period is reduced for achieved above average capacity factors

The Hurdle Rate and the Weighted Average Cost of Capital

53. The key metric for effective delivery is the cost of the CfDs, as these impact directly on the LCF and the final consumer prices (and hence the Impact Assessment and Social Cost Benefit Analysis). The costs of the CfDs depend on the strike prices and the volumes of each technology that the strike prices bring forward. One of our main concerns is that there is very considerable uncertainty about the hurdle rate of return required to motivate adequate volumes of finance.

54. We are impressed that DECC is actively consulting with the financial and utility community both here and abroad, and is also actively promoting the UK and the EMR framework as an attractive destination for footloose funds. We also understand that there is considerable doubt in those communities about how that framework will play out. The unfortunate starting point of EMR is in the middle of the longest and deepest recession for at least 80 years, in which banks and other financial institutions are under pressure to rebuild their balance sheets and eschew risky investments. This combination has the rather perverse consequence that the cost of capital (for government debt and even financially solid companies, both debt and equity) is at an all-time low in the UK (and the US and the sounder EU countries such as Germany). Long-term government debt has a near zero real interest rate, while Price/Earnings ratios for solid companies are so high that expected rates of return to holders of such equities are very depressed. At present, the US cyclically adjusted price/earnings ratio (measured over a decade) is at an almost all–time high of 23.6, compared with past lows of 5.2-9.6. More to the point, on past performance this implies an annual return of less than 1% over the next 10 years[19]. Consequently the real weighted average cost of capital, or the WACC, which is the average of the cost of debt and equity given the relevant gearing, is apparently at an almost all-time low. This can be seen in the WACC allowed to regulated utilities, the rising Market to Regulatory Asset Value of these utilities, and the enthusiasm with which foreign wealth funds are taking over UK regulated utilities. As noted above, it can also be seen in the WACC used to win the recent Offshore Transmission Owner (OFTO) auctions, where financiers quote the price needed to provide under-sea connections to off-shore wind farms, and these contracts are not

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[19] From John Author's Long View, *Financial Times* 8 June 2013.

dissimilar in their risk characteristics to the proposed CfDs (except they are not written on a reference price).

55. On the other hand, and as a consequence of risk aversion and the need to restore balance sheets, banks and financial institutions are reluctant to lend except for short tenors and for very secure assets. In addition, electricity utilities, and generating companies in particular, lack the balance sheet strength to finance at the scale needed. These companies, most of which are foreign-owned, feel that in many Continental countries the value of their existing fossil and nuclear assets are being seriously undermined, either by forced early nuclear retirements or support to renewables that is weakening wholesale prices and causing a collapse of the clean spark spread.[20]

56. The consequences of the difference between the real WACC and the assumed hurdle rates used in the setting of strike prices and running the DDM to forecast the key metrics are that there is likely to be a period of learning as uncertainties are reduced and investor perceptions are aligned with the eventual revealed cost of finance.

57. Once the planning situation has been clarified, sites and grid connections secured, contracts signed, plant built and commissioned, and the contract payments start arriving in a timely and convincing way, developers, whose skills lie in securing sites and delivering projects, will look for a timely exit, to realise what is now a secure revenue stream that in many ways is more appealing than that of a periodically price-controlled regulated utility. With the substantial uplift they may secure (sales value of the asset with CfD less development cost) hurdle rates may be higher than necessary to induce the required supply of investment. Investors can either reinvest and repeat the cycle, or crystallise their profits.

58. There is a trade-off in setting strike prices between protecting costs to consumer and mobilising sufficient investment for security of supply. It will be an iterative process to establish the precise balance between these factors that will ultimately be tested by market reaction.

[20] The price of wholesale electricity less the cost of gas and the required EUAs in a standard efficiency CCGT.

Commentary on Realism of Investor Modelled Behaviour

59. A key consideration in predicting investor behaviour using the Dynamic Dispatch Model is the plausibility that investors will behave as predicted taking account of exogenous factors that may be non-technical at their root, such as confidence in policy consistency and comprehension of the complexity of the UK system of electricity market and design.

60. The degree to which it is believed that investors will come forward with investment must be reflected in build rate constraints to account for any shortfall in investment appetite that would be calculated using hurdle rates alone. Conversely, if the strike prices are shown to be over-generous, then actual build rates may exceed those predicted by the DDM, threatening the Levy Control limits (or prompting a move to allocation processes). Build rate assumptions therefore involve complex judgements. It is beyond the remit of the Panel to substitute our judgements for DECC's, but it is our remit to scrutinise the assumptions, therefore we have examined whether DECC has sufficiently informed itself about investor appetite in order to arrive at its assumptions.

61. Being aware of the importance of build constraints from the start of its review work, we explored what factors, other than costs and other explicit model variables, are accounted for and validated in producing investor behaviour forecasts. We are encouraged that DECC takes independent advice from consultants, monitors project developments, takes sounding from potential investors, gathers commercial intelligence and that these and other considerations are factored into the build rate assumptions by DECC.

62. For example, DECC pointed us to the fact that the build rates for renewable technologies used in the Draft EMR Delivery Plan analysis are consistent with those used in the ROBR Government Response, which are based on the maximum build rates published by Arup (2011). The ROBR Government Response IA sets out which level of maximum build rates have been chosen: i.e. 'The high version of the annual maximum build rates was used for these, reflecting the high level of ambition the Government has to tackle non-

financial barriers to renewables deployment, as detailed in the Renewables Roadmap'[21].

63. Also, DECC confirmed that pipeline plant information for renewable electricity technologies is based on two primary sources: the UK's Renewable Energy Planning Database[22], which lists all projects that are operational, under construction and in planning; and (for projects not yet in planning) information gained through discussions with key developers, some of which is provided under commercial confidentiality. DECC acknowledges that it is likely that this full dataset is not 100% accurate, but collects information as thoroughly as they believe to be feasible given the diversity of the market. Information on the pipeline was combined by DECC with the economic modelling to take into account the financial constraint that is not reflected in the pipeline data.

64. DECC's approach to understanding investors is evolving rapidly to meet the challenge of EMR deployment, whereby intelligence, analysis and dissemination of information is planned to become more systematic to allow improved validation of methods and judgements.

Simplifying assumptions of the modelled investor

65. It is clear that efforts are made on an on-going basis to ensure the precision of input data (such as those that inform the costs, plant availability and many other factors and has been a large part of the focus of this Panel's work) and output in modelling investor behaviour. Considerable effort has been focussed on "bottom-up" validation of data and confirmation that inputs give rise to similar outputs using models whose designs are based on very similar principles: prioritising the allocation of financial resources in order of levelised costs with availability constraints and rate of return adjustments.

66. Exogenously imposed build rates are particularly strong carriers of judgements about investor appetite and response. Although different models are used to cross-reference and validate outputs, the use of a common methodology and most significantly, common data in areas of behavioural judgements, introduces a risk of common mode error in the outputs. We

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[21] Para 123: www.gov.uk/government/uploads/system/uploads/attachment_data/file/42847/5945-renewables-obligation-government-response-impact-a.pdf

[22] https://restats.decc.gov.uk/cms/planning-database

think it is reasonable therefore, in assessing the ability of the modelling to predict investor behaviour that we should consider not only the *precision* of modelling inputs, but also their *accuracy* and therefore we have particularly sought evidence for DECC's methods in assessing and reflecting investor appetite.

Use of modelling to predict realistic investor behaviour

67. We recognise that the explicit modelling assumptions reflect a simplified version of real investment and that judgement is then applied through build rates to reflect real behaviour more closely. Table 1 shows how convergence with realism can be achieved and some of the additional factors we would suggest that must be taken into account by DECC in making their judgement on build rates.

Table 1: Summary of investor behaviours

Endogenous Modelling Assumptions and Simplifications	Exogenous Modelling Adjustments (implicit in Build Rates and Hurdle Rates)	Examples of Convergence with Investor Realism
Economically rational	Rationality bounded	Investors biased towards "easier" rather than "harder" investments. For example, smaller, complex projects require much more due diligence (whose costs are rarely, if ever, explicitly modelled) and which may present too great a risk in relation to "easy" investments such as PV or onshore wind. Investors also motivated by other forces such as "momentum", as where good performance of investments inspires a preference for that class of investment. Investors consider matters other than levelised costs and rate of return. Free from cognitive bias (such as over-confidence or loss-avoiding)
Financially risk neutral	Highly asymmetrical	In reality, investors are not prepared to accept and manage any risk

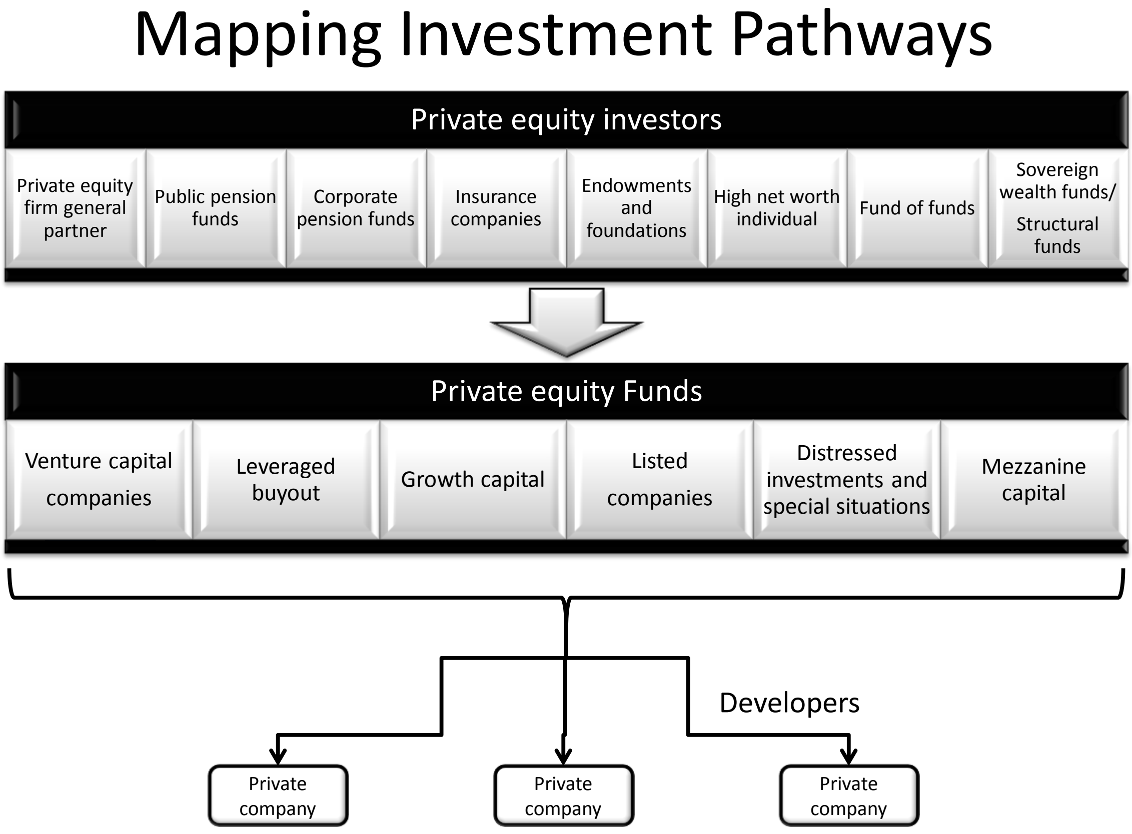
	attitude to risk	simply because it is theoretically incorporated into the rate of return. Cash flows, loss-aversion, the influence of Government underwriting liabilities (such as the nuclear back-end risks), all play a significant role in skewing attitude to risk. Technology and development risks present serious barriers to commercial development which are potentially better addressed by grant finance rather than market revenue support.
Homogenous	Highly diverse and fragmented	Whilst in modelling terms, the investor is akin to a “central” investor, in reality, the community is a highly uncoordinated and fragmented set comprising, e.g.: utilities financing long term, self-managed assets on-balance sheet; project promoters seeking simultaneous investment from private equity seeking an exit strategy and project finance secured on assets; grant financed pre-commercial projects; highly targeted investment funds; a multitude of other investment sources. The investment motivations and behaviours of each differ significantly.
Financially unconstrained	Investors focus on specific investment ranges with an overall cap.	Lack of funding for specific classes of small or large investments such as AD at the low end and CCS at the high end. Credit status may significantly affect investment choices.
Globally constrained to build rate and resource availability	Locally constrained to build rate and resource availability	This modelling approach appears to be a reasonable means by which local variation can be reflected provided it is a richly informed explicit and exogenous calculation.
Located at a notional geographical average point in the transmission	Highly sensitive to geographical location for economic and planning	Although wholesale price outcomes for electricity should be modelled on a geographically blind basis in the single GB market, investment decisions must incorporate not only geographical cost variations, but

system	reasons in particular.	also economic uncertainty in connected markets (e.g. supply chain, availability of skill such as for off-shore wind development in Scotland), non-economic constraints such as planning consent probabilities, Due Diligence costs and technology uncertainties.
Pursues a technology-blind investment policy	Highly sensitive to technology for non-economic reasons	In reality, investors have strong technology bias, moving in herds in relation to some (such as PV) and virtually ignoring others (such as wave).
Has limited foresight	Perception of little or no foresight due to (sometimes exaggerated) concerns over regulatory risk.	Through fear of loss, investors hold back while the next piece of major legislative or regulatory uncertainty is resolved. Regulatory risks ranging from fear of EU legislation, reorganisation of the UK energy markets, sustainability regulations are relevant examples.
Non-strategic investment	Highly strategic investment	Portfolios, corporate strategy, exit strategies, competition from international investment opportunities and many other factors influence investor behaviour and appetite.
Does not engage in gaming	Pursuing profit can lead to actions that may be entirely rational from an investment perspective but perceived as gaming from a regulatory perspective.	Deferment of investment with the intention of capturing a higher point of reward in a capacity or generation market at points in time which are subject to more acute strain and in the process, ‘contributing’ to increased strain and therefore reward to the investor.

68. Moreover, the pathways from the very large sources of finance required for EMR’s success down to individual investments are reasonably complex and span a huge range of quanta, durations and investment stages as much of the investment required must be sourced from beyond the balance sheets of the current UK power incumbents. A highly simplified illustration of the

complexity of the investment pathways (which ignores the debt side of finance which is yet another complexity) is illustrated in Figure 1 below.

Figure 1: Mapping Investment Pathways



This figure is for limited illustrative purposes only and is not intended to represent the EMR Investment Map

69.Figure 1 illustrates a very complex and rich investment landscape compared to the necessarily simplified concept of the investor modelled in the DDM. This by no means invalidates the use of such models as the bottom-up modelling can be readily complimented with exogenous input.

70.It might be helpful if DECC considered best practice from the private sector by adopting a light-touch Scenario Planning methodology. In this, the models play an important but more limited role compared with exogenous guidance. We believe that this could lead to greater realism and enhance plausibility. Most importantly, we believe this or a similar methodology could promote deeper discussion and broader consensus on the key market drivers, provide detailed adjustment to default model calculations and crucially, lead to a detailed and intelligible narrative in relation to each scenario with the following benefits to the process:

- Less reliance on pure, bottom-up quantitative modelling coupled with a stronger reflection of real investor behaviour,
- Allows the cross-cutting connections with, as well as trade-offs between, other Government policies to be explored and exposed explicitly. These might include cost to the consumer, employment, international competitiveness etc.,
- Allows discussion of deep levels of practicality, such as potential barriers to investment arising from market complexity,
- Provides an environment where the barrier to full utilisation of the knowledge and views of National Grid arising from potential conflicts of interest can be overcome,
- Convergence on a very limited number of accepted scenarios allowing more time to enhance the richness of output by using stochastic representation of input parameters,
- Mitigating costs of revisions to scenarios by having a coherent record of the sources of information reviewed, selected and rejected in building scenarios,
- Provides a record of the top-down reasoning used to pull together each self-consistent and plausible view of the future, and;
- Highly communicable narrative to transmit outcomes to other stakeholders such as ministers and the public

Observations on DECC's process to elicit investor appetite through market engagement

71. We received encouraging responses from DECC to our probing regarding investor realism as well as evidence that EMR is being shaped in a manner that could be conducive to investment. The responses included:

- DECC arranged and ran an investor simulation workshop which appears to have served in part as a means for conveying and sharing the thinking and approach of EMR to new investors as well as allowing an opportunity to test proposals with over 50 people representing potential investors over a range of technologies.
- We were invited to observe an industry expert group facilitated by DECC which is dealing with Contracts for Difference allocations and the Baseload Reference Price and in which practicalities of importance to investment decisions are being worked through in an open, robust and forthright fashion. We were particularly impressed with the commitment of

the representatives to engage and complete what appears to be an extremely significant amount of detailed work in a relatively short time.

- DECC's commercial team, who are responsible for promoting EMR for investment across the world, met with us to describe the work they are involved in. By their own account, they have been extraordinarily proactive in informing and stimulating large, potential investors across the world about the opportunities for UK energy infrastructure and generation capacity investment, including approaches to sovereign wealth funds, infrastructure funds and other private capital institutions such as pension funds which collectively represent an enormous magnitude of capital in relation to UK energy investment requirements. At this meeting, we suggested that greater consideration should be given to mapping investors and the routes for specific funds to investments in as much detail as possible taking account of known attitudes to contract design and other market issues.
- At present, investment decisions in the model are based on hurdle rates and build constraints. These appear to be the appropriate input controls that are necessary as a minimum to achieve a balance between realism and modelling simplicity.

Investor appetite

72.The Panel recognises the following potential merits of EMR in relation to attracting investors:

- The intended initial, orderly congruence between the RO and the CfD, thereby avoiding serious systemic shocks as well as apparently reducing risks for investors (through income certainty) coupled to a reduction in cost for consumers (through the "RO-X" principle). For example, Drax which is critical for 2020 renewable targets, has secured investment for Biomass conversion under the RO scheme without hiatus,
- The flexibility to adapt the CfD to the competitive markets in due course whilst grandfathering or protecting historic investments from regulatory change,
- The long-term track record of the UK's protection of support schemes for primary energy asset development as evidenced by Ernst and Young's high rating, and;

- DECC's efforts to ensure broad and timely involvement with industry in the process of development of the EMR.

Sufficiency of finance

73. We sought some assurance that funds exist in sufficient quantity for the very large scale development and build envisaged in the modelling. We are also aware of the insightful comments of European Committee of the House of Lords[23] in relation to the need for energy investments in Europe as a whole. We would comment on their findings in relation to the UK as follows:

    - We note the evidence in the report of the existence of very substantial investment finance under the management of Life Insurance companies, pension funds, mutual funds and endowments, which amount to some €13.5 trillion. In addition, we note that sovereign wealth funds add even further to this capital figure as the top 20 sovereign wealth funds hold some US $4.5 trillion, which puts some perspective on the €1 trillion needs to be invested in the EU's energy system in the period to 2020.
    - We note the Committee recommends to Member States to "work urgently with investors, including pension funds, to ensure their awareness of the opportunities, to identify obstacles and to propose solutions, such as the development of instruments to allow the pooling of resources in order to mitigate risk and encourage investment." The Green Investment Bank is a signal of what the Government is doing to attract investors in this regard as is DECC's efforts to engage with investors, globally.

74. We have encountered a mix of views in the investor community which vary depending on their views of the market, the terms of the CfD and their individual risk appetites. There appears to be some confidence that, in principle, the CfD can be an appropriate and investible instrument, subject to final terms and the strike price. The only valid test for financiability is, of course, the appetite for actual investment.

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[23] http://www.parliament.uk/business/committees/committees-a-z/lords-select/eu-environment-and-agriculture-sub-committee-d/news/eu-energy-report-publication/

Conflicts of Interest

75. The Panel notes that there are potential conflicts within National Grid that need to be carefully managed:

- Access to cost assumptions which might inform other parts of National Grid's business, and;
- Building demand/supply relationships in the model which benefit transmission costs.

76. However, the Panel also observed that concern over perceived conflict of interests were inhibiting National Grid's behaviour and limiting their appetite for innovative solutions that would be beneficial to the EMR and consumers.

77. Given that National Grid as System Operator and as advisor on CFDs has much of the relevant information they ought to be able to undertake more detailed modelling referred to earlier but this does not seem to be happening. A large part of this could be because of concerns over perceived Conflicts of Interest, where NG feels only able to stick to a very narrow interpretation of its remit. NG has the best knowledge of detailed operational problems of an electricity system and of the potential for much smarter solutions (to contracting for and managing wind, for example, and for condition-responsive transmission management) but they will be overcautious about exploiting this knowledge to the best advantage for the EMR without raising fears that they are trying to exploit asymmetries of information (which are inherent in the problem). There may be solutions which address perceived and actual conflicts of interest that preserve the information and skill base. We note DECC and Ofgem's recent publication on this issue[24].

[24] https://www.gov.uk/government/consultations/synergies-and-conflicts-of-interest-arising-from-the-system-operator-delivering-electricity-market-reform-emr

Preliminary Conclusions

78. Overall, our view is that National Grid's analytical approach, as commissioned by DECC, and its reliance on the Dynamic Dispatch Model (DDM) is a valid one for assessing the impacts of different technology cost assumptions and market scenarios on different policy parameters (e.g. a percentage of renewable generation, a Reliability Standard, Emission Intensities and the Levy Control Framework). This is largely assured by specifying build-rate limits and ensuring that strike prices are sufficient to induce investors profitably to invest, given their assumed hurdle rates.

79. The approach is relevant for the purposes of establishing the first stages of the Electricity Market Reform programme. This should enable DECC to collect the information to facilitate the transition to a more cost-reflective and ultimately market-driven solution. A more competitive market revealing itself in future strike prices determined at any auction should address the many risks (investor appetite, hurdle rates, pace and cost of technology learning curves, fuel price uncertainty) inherent in this complex market which no model can realistically fully portray.

Next Steps

80. We will continue to work with DECC and National Grid through the period of the consultation process, up to the publication of the final EMR Delivery Plan, scheduled for December 2013, subject to Royal Assent of the 2012 Energy Bill.