Review of selected issues relating to Ofgem's Project TransmiT

Note prepared for ScottishPower

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1 Summary

This note reviews some of the arguments presented in the report prepared for RWE npower by NERA and Imperial College London (the 'NERA/ICL 2013 report'), as well as those contained in Ofgem's Further consultation on Project Transmit (the 'Ofgem 2014 consultation document').[1] The note is structured as follows.

- Section 2 considers estimates of the effect of implementation of WACM2 on the cost of the GB capacity mechanism. It reviews the key parameters of the auction mechanism and the determinants of the auction clearing prices, concluding that the impact of WACM 2 charges on consumer welfare could be significantly different from that estimated in the NERA/ICL 2013 report.
- Section 3 considers whether clearer direction of policy lead to delivery of renewables targets at lower cost. It considers related evidence from reports by Oxera and NERA. The main finding from this section is that continued commitment by Ofgem to the current targets would avoid introducing more policy risk which could, in turn, help protect against an increase in the costs of delivering these targets.
- Section 4 sets out the benefits of a diverse portfolio of renewable generation. It concludes that reflecting the benefits of a more diverse generation mix in the WACM2 charging methodology helps to internalise the associated external benefits. Hence WACM2 would be expected to improve the economic incentives on generators to target the optimal level of generation diversity.

[1] NERA and Imperial College London (2013), 'Assessing the Cost Reflectivity of Alternative TNUoS Methodologies', prepared for RWE npower, February; Ofgem (2014), 'Project TransmiT: Further consultation on proposals to change the electricity transmission charging methodology', April.

- Finally, section 5 explains how WACM2 could reduce the cost of delivering the UK's renewable energy targets. It sets out the mechanisms by which lower transmission charges for renewable generators in Scotland would translate into greater renewable new build with support levels remaining constant, or with support levels declining while achieving the same level of renewable investment.

2 The effect of WACM2 on the cost of the capacity mechanism

The Ofgem 2014 consultation document reviews additional evidence provided by NERA/ICL among others with regard to Ofgem's minded-to decision on WACM2. The document questions the usefulness of quantitative analysis in estimating the impact of the change in the TNUoS charging methodology on consumers. Paragraph 2.41 of the Ofgem 2014 consultation document states:

> We think that the modelling of power sector costs is likely to be a more accurate illustration of the impact of WACM 2 on the sector as a whole than the results for consumer benefit. Modelling consumer benefit relies on the interaction with the capacity mechanism and it is uncertain how the introduction of this mechanism will drive behaviour. The modelling of power sector costs does not rely on assumptions about this.

Further, paragraph 2.42 of the Ofgem 2014 consultation document states:

> Higher wholesale prices combined with lower costs shown in the modelling of power sector costs suggests that generators experience higher profits under WACM 2 but the modelling does not consider how generators might respond to this. We consider higher profits will in the long term lead to existing generators choosing to stay open and/or new entrants to the market. This is likely to lead to lower wholesale prices through efficiency gains and greater competition in the capacity auction, resulting in lower capacity payments. We therefore consider in the long term that the differential in consumer's bills between WACM 2 and the status quo is likely to be reversed or reduced.

With regard to the methodology employed to estimate the effect of changing the TNUoS charging methodology to WACM2, the NERA/ICL 2013 report states:

> Our approach to estimating the price effect is therefore to (1) identify which generation technologies are the 'marginal' source of new entry into the market in each scenario using the results from our market model, (2) estimate the change in TNUoS costs faced by the marginal new entrant in each case, and (3) calculate the change in prices required to ensure that in both cases prices cover the long-run marginal cost of entry.[2]

As we stated in our previous report prepared for SSE,[3] the modelling results obtained by NERA/Imperial suggest that changing the transmission charging arrangements to WACM 2 from the status quo would significantly increase the price of electricity paid by consumers. However, there is considerable uncertainty around these estimates because of the uncertainty and complexity of how changes to the costs of marginal generators could be expected to feed through to wholesale prices. NERA/Imperial provides no detailed evidence in this regard, particularly with respect to which generators would be marginal should the WACM 2 charging methodology be adopted.

[2] See p. 13 of the NERA/ICL report.

[3] Oxera (2014), 'Review of the NERA/Imperial College London report on the impact of the WACM 2 charging model', note prepared for SSE, February.

Given that, in the period to 2020, the average cost of new entry in the modelling carried out by NERA/ICL is higher under WACM2 than under the status quo[4], it is likely that new flexible plant built in GB is assumed by NERA/ICL to be built primarily in the zones where TNUoS charges increase as a result of WACM2.

Outcomes in the capacity mechanism will determine the nature of new entry by thermal plant in the GB market going forward. Our understanding of the key parameters of the GB capacity mechanism is as follows.

The government will set a reliability standard and a demand curve for capacity auctions. This will provide flexibility to procure less capacity if the price is high. The capacity auction will be 'pay as clear', where all participants will receive the clearing price set by the marginal bidder. The auction will be run as an open descending-clock auction.

To mitigate market power, bidders will be classified as price-takers (who can bid freely up to a predetermined threshold) and price-makers (who can bid up to the overall auction price cap). Existing plant will be price-takers; new plant and DSR can participate as price-makers.

Existing plant will have access to one-year contracts; existing plants requiring major refurbishment up to three years, and new plant will have access to contracts with longer duration. Although the GB capacity market will be operated as a single zone, zonal auctions may be needed depending on the decision to split the market with the implementation of the EU Target Model.

Whether the capacity auction clears at new or existing capacity will be determined by a number of factors, including the forecast capacity margin. The factor that is likely to play a crucial role in the effect of WACM2 on the cost of the capacity mechanism is the location of the plant that are marginal in the capacity auction. Only changes to the costs of marginal generators could be expected to feed through into capacity mechanism prices. For generators that are not marginal, cost changes could be expected to feed into changes in their infra-marginal rent.

New capacity

With regard to new capacity, in its 2011 report NERA/ICL already recognised the anomalies in the siting decisions, in which there was an over-reliance of siting decisions on TNUoS charges and gas NTS exit charges, with the absence of consideration of other siting drivers.[5] This led to a substantial amount of new investment being modelled to take place in northern transmission zones under the uniform charging approach. In the 2012 and 2013 reports, NERA/Imperial revised its modelling approach by placing constraints on zonal deployment potential. These factors provide a proxy of the availability of land and cooling water, both of which have impacts on siting decisions.

However, NERA/Imperial's modelling for its 2013 report still does not take into account other siting drivers, such as the impact of the planning process. Moreover, it is not clear whether differences in potential revenue from the provision of ancillary services, which can vary significantly depending on a plant's location, play any role in investment decision-making.

[4] See section 3.2.4 of the NERA/ICL report.

[5] NERA and Imperial College (2011), 'Project TransmiT: Impact of uniform generation TNUoS', report prepared for RWE npower, 31 March.

In reality, it is not clear that sites will be developed in strict order of profitability, as modelled by NERA/Imperial. There is evidence that investors do consider building plant at a mix of locations, with new CCGT developments being considered in locations where existing infrastructure (eg, cooling water and transmission assets) can be redeveloped and re-used, despite transmission charges being higher than in other TNUoS zones.

As new investment could take place in a number of locations with differing transmission charges, it is difficult to determine with great precision which transmission charging zone is truly ‘marginal’. This would imply that the scale of the impact of WACM2 charges on the long-run marginal costs of new entrants, and consequently on power prices, could be smaller than that envisaged in the NERA/Imperial modelling.

Existing capacity

With regard to existing plant bidding into the capacity mechanism, it is not clear how corresponding auction outcomes are reflected in the modelling undertaken by NERA/ICL. As for new capacity, the auction clearing price—and thus the ultimate impact on the cost of the capacity mechanism and consumer welfare—will be determined by the marginal bidder. Likewise, the impact of changing the TNUoS charging methodology from the status quo to WACM2 on the cost of the capacity mechanism is likely to be driven by the impact of that change on the costs of plant that are marginal in the capacity auction.

It is difficult to predict which existing plant may be marginal in the capacity auction in any given year, and we have not undertaken any quantitative analysis in this regard. However, some important factors can be highlighted in the context of the relative likelihood of existing CCGTs—particularly those in Northern TNUoS zones—being marginal in the capacity auctions.

Since 2012, a number of CCGT plant in GB have been mothballed or closed. These include Kirkby, Grain, Teeside, Shotton, Derwent, Peterhead, King’s Lynn and Roosecote.[6] These closures have been as the result of low spark spreads in the GB market for CCGTs in general, as well as other factors specific to each of these plants. In light of this, the economic rationale for keeping CCGT capacity open can be considered to be marginal in the current market environment. This may make it more likely that CCGTs are marginal in the auctions for existing thermal generation capacity.

All other factors remaining equal, higher transmission charges for generation in Northern TNUoS zones would make CCGTs in that region more likely to be marginal in the capacity auction, and, by implication, CCGTs south of the Scotland–England boundary would be more likely to be infra-marginal. However, we acknowledge that many factors determine the economics of keeping a CCGT plant in operation, and the level of transmission charges is unlikely to be the most important factor in this regard.

Overall, the factors highlighted above would imply that the impact of WACM 2 charges on consumer welfare could be significantly different from that envisaged in the NERA/Imperial modelling.

[6] Source: Reuters.

3 Could clearer direction of policy lead to delivery of renewables targets at lower cost?

Project TransmiT has been ongoing for nearly 4 years, and the CMP213 modification was raised by NGET in June 2012. Ofgem's position of being 'minded to' adopt WACM2 has been known to market participants since August 2013. Specifically with regard to the date of implementation, in its August 2013 consultation Ofgem had indicated that it is minded to approve implementation in April 2014. A significant delay to this signalled position could increase the perception of risk around the transmission charging regime.

While the change to TNUoS charges may not in itself be a significant factor in some of potential investment decisions, the proposals are part of a broader set of policy measures to support the delivery of renewable targets (as the new methodology would reward diversity of the generation mix). Therefore, a change in Ofgem's position could increase uncertainty over the broader policy stance towards renewables. This would in turn increase perceptions of policy risk, and could increase the cost of delivering renewable targets. This is because policy risk would be expected to affect investors' risk perceptions associated with investing in renewables, and therefore also the hurdle rates investors require in order to commit capital to these investments.

Several studies have recently considered the evidence on the investment hurdle rates for renewable technologies, including the evidence on the impact of policy risk on hurdle rates.[7]

Oxera's work on discount rates for low-carbon technologies concludes that all low-carbon technologies are exposed to policy risk and that this is a significant factor affecting investors' risk perceptions. According to the survey underpinning the report, the impact of removing policy risk is at least as important as the actual risks that could be mitigated by a particular government support policy. The report also estimated the scale of possible reductions in investment hurdle rates over time—these reductions were partially driven by an assumption of increased policy clarity over time.

Similarly, a recent report by NERA suggests that a 'novelty' premium is likely to be incorporated into investment hurdle rates when a significant change to policy is introduced. Over time, the premium may reduce as market participants become more familiar and comfortable with the new policy in place.

In other words, both Oxera and NERA reports suggest that: i) policy risk is a significant factor affecting investment hurdle rates, and hence also the cost of delivering renewable targets; and ii) greater policy clarity may be associated with the reduction in investment hurdle rates.

In the context of Project TransmiT, this suggests that a continued commitment by Ofgem to the current proposals (which have been extensively consulted on and well signalled to the market) is likely to help ensure that the policy environment remains stable and predictable from investors' perspective. This could avoid introducing more policy risk, and in turn, help to protect against an increase in the costs of delivering renewable targets. Specifically with regard to the date of implementation, in its August 2013 consultation Ofgem had indicated

[7] See, for example, Oxera (2011), 'Discount rates for low-carbon and renewable generation technologies', report for Committee on Climate Change, April; and NERA (2013), 'Changes in hurdle rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to Contracts for Difference Regime', report for DECC, December.

that it is minded to approve implementation in April 2014. A significant delay to this signalled position could increase the perception of risk around the transmission charging regime.

4 Benefits of a diverse portfolio of renewable generation

There are at least two arguments for why greater diversity in renewable generation could be beneficial:

- a more diverse mix of intermittent renewable technologies would bring security of supply benefits through the ‘portfolio’ effect of imperfectly correlated output from different technologies summing to a more stable overall output level;
- a more stable overall output level would be expected to reduce the cost of system balancing. Since balancing costs in the GB market are effectively socialised across all generators and consumers, this would result in higher overall social welfare.

These diversity benefits are reflected in the UK government’s policies towards supporting investment in renewable generation, both under Electricity Market Reform and under the Renewables Obligation. Under these policies, higher levels of support are offered to more innovative and higher cost renewable generation technologies to ensure a diverse mix of new renewable capacity.

Paragraph 2.48 of the Ofgem 2014 consultation document states:

> The broader range of renewables technologies that might be developed under WACM2 contributes to benefits in terms of energy mix.

We elaborate on Ofgem’s argument below.

The majority of renewable generation technologies that are currently being built in GB are non-dispatchable, meaning that their output is driven by factors that are outside of direct operator control. Such technologies include wind, solar, run-of-river hydro, wave and tidal. The variation in the output of these technologies can be predictable to a certain degree when driven by factors such as change of season or the time of day, but can also have a significant element of random variation.

One of the key benefits of a diverse mix of renewable generation is that imperfectly correlated shocks from a variety of sources, both predictable and random, add up to a less variable overall output level than output from a narrower or less diverse mix of renewable generation.

In the context of renewable generation, diversification can be achieved both by increasing the mix of technologies being deployed and by diversifying the locations of the same type of intermittent generation technology. This is because different technologies are subject to different output shocks that are not perfectly correlated. Random output shocks in different locations also tend to be imperfectly correlated, with correlations decreasing with distance.

A more stable overall electricity output level would be expected to bring about three main benefits. The first such benefit is a reduction in the cost of system balancing. This benefit would mainly be accrued through:

- lower cost of procuring reserve and frequency response; and

- lower balancing mechanism costs—including lower constraint costs due to a reduction in deviations of transmission requirements from the fixed capacity of the grid.

The second expected benefit is a reduction in the cost of the transmission system. At a technical level, greater efficiency would be achieved because, with a more stable aggregate output level, overall transmission capacity, especially on the major boundaries, could be matched more closely with transmission requirements when averaged over time. The economic equivalent of this argument is that optimal transmission capacity is found at the point where the marginal cost of the transmission system is equal to the marginal cost of constraints. Hence, if the cost of constraints is expected to decrease with a more stable output level, the cost of the economically optimal transmission grid is also expected to decrease.

The third expected benefit of a more stable output level is improvement in security of supply. This could be expected to materialise through more stable output levels reducing the probability that actions by the system operator are insufficient to prevent a supply shortage at a local or system level.

As a general economic principle, an efficient allocation of resources is expected to be achieved when economic agents face the full costs and benefits of their decisions. The benefits of a more diverse mix of renewable generation highlighted above, including improved security of supply and lower transmission and balancing costs, could be very significant and may be largely external to the economic decisions of generators. This is due to the following factors:

- the costs of the balancing system in GB are effectively socialised through BSUoS charges, and individual generators do not face the full economic impact of their actions on the cost of the balancing system;
- electricity prices may not be allowed to rise to the full value of lost load (VoLL) in the event of electricity shortages. This means that the opportunity cost faced by generators that are not operating at times of shortage is below the benefit that would be accrued to consumers had that generator been operating; and
- transmission charges under the status quo do not reflect the full benefits of diversifying generation sources for the cost of the transmission system.

In conclusion, reflecting the benefits of a more diverse generation mix in the WACM2 charging methodology helps to internalise some of what would otherwise be an external benefit for the generators that influence the level of diversity of generation sources. This means that the economic incentives on generators to target the optimal level of generation diversity are likely to be improved under WACM2.

5 Could WACM2 reduce the cost of delivering the UK's renewable energy targets

Paragraph 2.47 of the Ofgem 2014 consultation document states:

> The modelling demonstrates that implementing WACM 2 increases the likelihood of meeting renewables targets for a given low carbon support budget. This can be seen in the lower CfD strike prices under WACM 2. Tariffs are lower under WACM 2 in Scotland, where the potential for renewable generation is high. As these sites generally have higher yields, less overall development should be needed to achieve targets. This could

support the long term government policy to deliver increasing amounts of energy from renewable sources and to achieve carbon targets.

Ofgem’s statement suggests two alternative ways in which the interaction between changes to the transmission charging methodology under WACM2 and the UK’s renewable energy targets could be expected to play out: either as a fixed subsidy or as a fixed renewable target.

Fixed subsidy

One way to look at this issue is by assuming that the overall subsidy amount provided to incentivise renewable generation investment, which is managed by government through the Levy Control Framework (LCF), is fixed. In this case, lower transmission charges for renewables in Scotland, where a large proportion of new renewable capacity is expected to be built, would mean that more renewable capacity is built overall.

A higher penetration of renewable generation carries an associated social benefit. Renewable generation in GB has in the past required substantial levels of support to incentivise investment in new capacity, and this is expected to remain the case. The economic justification for such support is that renewable energy has intrinsic economic value to society over and above the economic value of equivalent amounts of energy produced from non-renewable sources. This economic value is implicit in the renewable energy targets, which were agreed on an EU-wide basis.

An indication of the intrinsic social value of renewable energy can be obtained under the assumption that the social economic value of 1MWh of renewable electricity that is over and above the economic value of 1MWh of electricity generated by conventional means is equal to the corresponding subsidy provided under the Renewables Obligation. This could give an indication of the social value created by greater renewable investment being brought about through lower transmission charges in Scotland.

As pointed out elsewhere in this document, many factors determine whether a particular generation investment project is economically viable. The level of transmission charges applied is just one of those factors, and is by no means the greatest. However, all other factors remaining equal, lower transmission charges make it more likely that a given project is economically viable and gets built.

A helpful theoretical framework for thinking about this issue is to consider all of the potential renewable projects that could be built as a supply curve. Each project will have its own characteristics, including costs, revenue generation potential and associated risks. These characteristics, considered together, would imply a risk-adjusted expected rate of return for each project. A supply curve would represent a ranking of projects, or, more specifically, of their capacity to generate renewable electricity, in order of decreasing risk-adjusted expected rates of return.

The expected amount of renewables new build would be determined by the intersection of the supply curve described above with a line representing the risk-adjusted rate of return demanded by investors in renewable generation. A decrease in transmission charges would increase the expected risk-adjusted rates of return for the affected projects. This would mean that the point of intersection, assuming sufficient granularity of projects that form the supply curve, would be expected to correspond to a higher amount of renewable new build.

Fixed renewables target

Another way to look at the interaction between transmission charging and renewables new build is by starting from the premise that the total amount of renewable generation capacity built in GB is fixed. Since a significant proportion of that capacity will be built in Scotland in light of its abundant renewable resources, in theory, lower transmission charges in Scotland are likely to mean that the burden of the cost of the transmission system would be reduced for renewables overall. The benefit of this is that lower subsidy levels would be required to achieve the same quantity of new renewable generation capacity under WACM2.

The above argument could also most usefully be presented within the theoretical supply curve framework introduced in the previous section. However, since the quantity target would be fixed in this case, the shift in the supply curve of renewables as a result of a reduction in transmission charges would have to be exactly offset by a reduction in the level of support provided to renewables. This saving in support payments would give an indication of the additional value created by lower transmission charges in Scotland under WACM2.

In reality, given that changes in renewables support have to be announced with sufficient notice to allow investors and developers to adjust their plans efficiently, as well as to avoid increasing investors' perception of risk around the renewable support regime, any savings in renewable support payments resulting from lower transmission charges are likely to be realised through an earlier reduction in renewable support levels than that which would otherwise take place.