Review of the NERA/Imperial College London report on assessing the cost reflectivity of alternative TNUoS methodologies

Note prepared for SSE

27 May 2014

1 Summary

This note reviews the latest report prepared for RWE npower by NERA and Imperial College London (the '2014 NERA/ICL report')[1] and assesses the methodologies employed in it. This note also assesses claims that earlier implementation of WACM2 would materially increase costs to consumers in the long term.

The NERA/ICL model aims to assess whether the WACM2 charging methodology is cost-reflective, by comparing projected WACM2 charges to its own estimation of costs (LRMCs).

We have undertaken a review of the modelling methodology and assumptions employed by NERA/ICL. We believe that the approach taken is conceptually correct overall, although we believe that omitting generation capacity and some additional benefits of network reinforcement from the optimisation model may lead to some anomalies and influence some of the key results reported by NERA/ICL. Importantly, we found a number of points where we believe that the NERA/ICL model may not reflect the real costs of network reinforcement. This may cast doubt on NERA/ICLs key conclusion that the WACM2 charging methodology is less 'cost-reflective' for wind plant in Scotland than the status quo.

[1] NERA and Imperial College London (2014), 'Assessing the Cost Reflectivity of Alternative TNUoS Methodologies', prepared for RWE npower, February.

More specifically, we found that:

- the LRMC cost concept with regard to transmission access charging is reasonable in light of precedents from other sectors;
- the general set-up of the model omits the effect that higher transmission charges could have on generation location decisions, and does not account for some cost-reducing effects of transmission investments, such as improvements in security of supply, the renewable portfolio effect and more competition in the balancing market. These omissions could potentially lead to overestimation of 'cost-reflective' transmission access charges in the NERA/ICLs model;
- some of the key results of the NERA/ICL reports hinge on a small set of assumptions about the availability and costs of different reinforcement options, which may underestimate the cost of onshore network reinforcement. These assumptions may lead to an understatement of LRMC-based transmission access charges for generation units south of the North–South constraint;
- given the strong conclusions that NEAR/ICL derives on transmission access charges for Scottish wind generation capacities, we believe that there is a risk that wind infeeds have not been modelled in sufficient detail.

We have also undertaken a review of the conclusions reached by NERA/ICL, which is that WACM2 charges are less 'cost-reflective' than charges under the status quo. Overall, we do not believe that the logical conclusion from the modelling results derived by NERA/ICL is that WACM2 charges are less 'cost-reflective' than charges under the status quo.

Finally, on the question of whether earlier implementation of WACM2 would materially increase the costs to consumers in the long term, we conclude that the arguments put forward by Ofgem for why early implementation is not desirable may have merit in some cases. However, given the current context, the factors highlighted by Ofgem are unlikely to have material long-run cost implications for consumers. In addition, Ofgem does not appear to consider factors suggesting that delayed implementation may also have undesirable implications; namely, by increasing risk perception through a break with a previously signalled position on the timing of implementation. It is possible that, on balance, the overall impact of delayed implementation is negative.

2 Is WACM2 less cost-reflective than the status quo?

2.1 Overview of NERA/ICL methodology and results

Our understanding of the methodology employed by NERA/Imperial to calculate 'cost-reflective' charges for incremental increases in generation capacity can be summarised as follows.

Two model runs are carried out. Given an exogenously determined generation capacity mix, the first model run determines optimal transmission capacity across the modelled boundaries. For every boundary, this is done on the principle of equality of marginal transmission constraint (re-dispatch) costs and the marginal cost of reinforcing that boundary.

The second model run calculates the shadow price of an incremental increase in a given generation technology in a given location. Since this is calculated in the region of the optimal transmission capacity as defined above, this should be approximately equal to the resulting increase in total system cost, which consists of total constraint costs and the total cost of the transmission infrastructure.

The key results derived in the NERA/ICL paper are that:

- for wind generation in Scotland, TNUoS charges under WACM2 are less ‘cost-reflective’ than TNUoS charges under the status quo;
- for peaking generation in Scotland, TNUoS charges under WACM2 are more ‘cost-reflective’ than TNUoS charges under the status quo; and
- for baseload gas and nuclear plants, the difference between the two charging methodologies in terms of how ‘cost-reflective’ they are is negligible.

2.2 Assessment of NERA/ICL methodology

Although we think that the basic Idea of the NERA/ICL model to assess the shadow prices of an incremental increase in generation technology is conceptually correct, we do have several points of critique in relation to:

- the LRMC cost concept used;
- the general set-up of the model;
- the input assumptions on HVDC and overhead transmission lines;
- the modelling of wind infeeds; and
- some other possible shortcomings of the model.

The following section explains these points in detail, and concludes with a summary.

2.2.1 LRMC cost concept

The standard definition of an efficient economic allocation in a given market is for the market price to be equal to the marginal cost of the relevant product. This means that fixed costs would not form part of the market price in efficient market equilibrium. This condition is the fundamental reason why natural monopolies such as networks almost always operate under strict regulatory regimes and their prices are capped.

The NERA/ICL report states that the marginal electricity transmission technology on the Scotland–England boundary is undersea HVDC cable. HVDC cables are a relatively ‘lumpy’ transmission technology, which means that the smallest increment of investment could be in the region of 350MW.

Investment and maintenance costs of HVDC bootstraps are fixed at the level of the smallest increment. Hence, unless a given generation investment changes the optimal transmission capacity on the Scotland–England border by a similar increment or more, the marginal cost of that investment on the transmission system is very low.

The concept applied to the pricing of transmission access by NERA/ICL is LRMC, which includes fixed and investment costs. The LRMC of transmission on the Scotland–England border used by NERA/ICL is for the marginal transmission technology represented by HVDC bootstraps. Hence, the LRMC approach represents something of a hybrid of average and marginal cost concepts.

We have studied relevant precedent for regulated network access pricing in other industries. Our overall finding is that the LRMC concept adopted by NERA/ICL is broadly in line with methodologies adopted in other sectors. For example, paragraphs 29 and 30 of the European Commission recommendation on consistent non-discrimination obligations and costing methodologies to promote competition and enhance the broadband investment environment state the following:[2]

> The bottom-up long-run incremental costs plus (BU LRIC+) costing methodology best meets these objectives for setting prices of the regulated wholesale access services. This methodology models the incremental capital (including sunk) and operating costs borne by a hypothetically efficient operator in providing all access services and adds a mark-up for strict recovery of common costs. Therefore, the BU LRIC+ methodology allows for recovery of the total efficiently incurred costs.
>
> The BU LRIC+ methodology calculates the current costs on a forward-looking basis (i.e. based on up-to-date technologies, expected demand, etc.) that an efficient network operator would incur to build a modern network today, one able to provide all required services. Therefore, BU LRIC+ provides correct and efficient signals for entry.

Overall, while the concept applied to the pricing of transmission access by NERA/ICL does not meet the strict definition of an economic optimum in a competitive market, nevertheless similar approaches are used to price network access in the context of network expansion in other industries. Hence we believe that the LRMC approach adopted by NERA/ICL is reasonable subject to the use of appropriate assumptions and modelling techniques, Potential concerns around the key assumptions used are set out in section 2.2.3 of this note.

2.2.2 General setup of the model

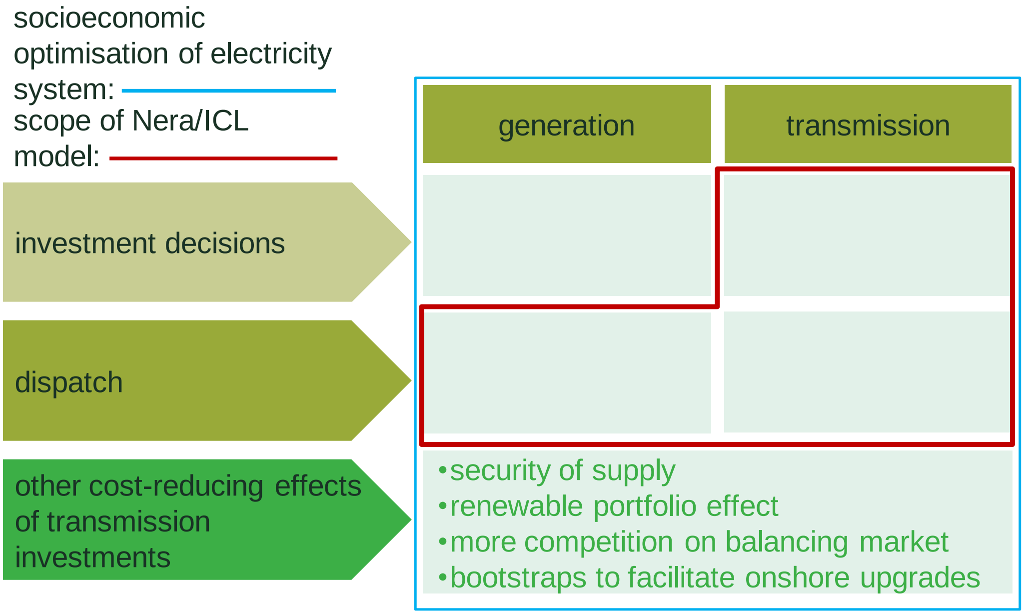
Compared with what would be needed for a complete socioeconomic optimisation of an electricity system, the NERA/ICL model does not account for

- investment decisions on the generation side; and
- other cost-reducing effects of transmission investments.

Figure 2.1 compares the scope of the NERA/ICL Model with the scope of a model that would take all potentially relevant factors into account.

[2] European Commission (2013), 'Commission recommendation of 11.9.2013 on consistent non-discrimination obligations and costing methodologies to promote competition and enhance the broadband investment environment', September.

Figure 2.1 Scope of NERA/ICL model vs a full socioeconomic optimisation of electricity system



Source: Oxera.

Generation investment decisions

The NERA/ICL report starts with a description of locational marginal pricing, which is a widely held 'textbook' ideal for the locational pricing of electricity. In theory, this concept would lead to optimal investment decisions in generation and transmission and to an optimal dispatch. The report then explains why such a system is not used in practice and that a similarly efficient result can be achieved by the correct pricing of transmission investments. The idea behind this is simply that if generating units have to pay a cost-reflective price for being connected to the grid, they would tend to be built where transmission tariffs are lower, and hence the investment costs needed for generation and transmission infrastructure would be jointly optimised.[3]

However, this is not what the NERA/ICL model actually does. Investment decisions on the generation side are not modelled explicitly. Rather, the model takes a fixed projection of the future development of generating plants and then optimises the transmission investments around that. This means that the potentially important steering mechanism of transmission charges is not explicitly modelled.

Without detailed knowledge of the model and further analysis, the effect of this omission cannot be assessed fully. However, it seems plausible that it could lead to an overstatement of future LRMCs of transmission reinforcement in areas where transmission charges tend to be higher. This is because, in reality, if plant investors expect high transmission charges in an area, they may change their investment plans and invest in an area with lower transmission charges. This in turn could mean that LRMCs in an area with high transmission charges do not actually turn out as high as projected by the model.

[3] Apart from transmission tariffs, other factors such as fuel availability, labour costs, etc, influence the location decision of a generator as well.

Other positive effects of transmission investments

The model optimises the trade-off between transmission investment costs and the costs of system constraints.

Although we broadly agree with this approach, we believe that four other important cost factors that are positively influenced by transmission investments should be accounted for as well (see Figure 2.1).

The first factor is that better interconnectivity in an electricity system is most likely to enhance the security of supply of the system as a whole. A larger interconnected area means that failures of individual generation units or sudden load surges can be absorbed more easily. It also means that it may be easier to deal with the failure of a power line.

The second factor is the ‘renewable portfolio effect’. Intermittent generation sources that are spread over a larger area have the advantage that low renewable generation in one part of that area could be offset by higher renewable infeeds in another part.

The third factor is that a larger market area (that is not separated by constraints) means that there will be more bidders in the balancing market (or a geographically larger balancing market). As is the case with any market, more bidders mean that there will be more downward pressure on the price of balancing services because of greater competition intensity.

The fourth factor is that, once completed, the bootstraps may allow further reinforcements such as voltage upgrades on the North–South onshore lines. Such upgrades are not possible now because these lines are so highly utilised that significant upgrade operations would be prohibitively costly.

In sum, all four factors partly offset transmission investment costs because they reduce the cost of the whole electricity system. So, although they are hard to quantify, they would reduce the ‘effective’ LRMC of marginal transmission investments after those factors are taken into account.

2.2.3 Assumptions on HVDC and overhead transmission lines

Some of the results of the NERA/ICL report—especially the very high LRMCs of transmission reinforcements associated with additional wind generation capacity in the North—seem to depend strongly on a small set of assumptions around HVDC and overhead transmission lines:

- on the **availability or transmission reinforcement options**, NERA/ICL assumes that the North–South capacity of conventional overhead transmission lines cannot exceed 4.4GW.[4] The report also assumes that the only way to increase transmission capacity is to build new lines;[5]
- on the **cost of conventional vs HVDC network reinforcements,** NERA/ICL assumes that HVDC connections are almost three times as expensive as conventional overhead transmission lines.[6]

[4] NERA and Imperial College London (2014), ‘Assessing the Cost Reflectivity of Alternative TNUoS Methodologies’, February, p. 13.

[5] NERA and Imperial College London (2014), ‘Assessing the Cost Reflectivity of Alternative TNUoS Methodologies’, February, p. 17.

[6] NERA and Imperial College London (2014), ‘Assessing the Cost Reflectivity of Alternative TNUoS Methodologies’, February, p. 18.

The first two of these assumptions ensure that whenever new capacities North of the North–South constraint are built in the model, the relevant marginal transmission technology that the model uses to expand the network is HVDC. The third assumption puts a relatively high price on that technology. In the light of the strong conclusions that NERA/ICL draws from its modelling—especially on the cost reflectivity of transmission charges in the North—we suggest that the sensitivity of results to these assumptions should be explored.

Availability of transmission reinforcement options

For example, it may be possible to expand the capacity of conventional North–South overhead transmission lines beyond 4.4 GW, including the use of smart solutions to increase the transmission capacities of the existing lines. This may lower the estimated LRMCs of transmission reinforcements arising from the connection of generation units north of the North–South constraint.

In this context, it is interesting that NERA, in a report in 2004, criticised the use of fixed expansion cost factors, as follows:[7]

> ‘expansion constant’ and ‘expansion factors’, which define the cost of these power flows in £ per MW km, overstate costs by ignoring the potential for low-cost methods of adding transmission capacity that NGC has used extensively in the past.

Cost of conventional vs HVDC network reinforcements

NERA/ICL used 60 £/MW/km/year as the cost estimate for conventional overhead lines and 160 £/MW/km/year for HVDC lines. In light of the numbers that were the source for the NERA/ICL figures, these assumptions are open to question.

Table 2.1 shows the National Grid numbers from which NERA/ICL derived its cost estimate. Four different kinds of estimate considered. The first, which NERA/ICL uses as a reference for its costs for conventional overhead lines, is based on a bottom-up estimate of an idealised reinforcement project. The second is simply an average cost number based on the allowed revenues of the entire networks of the three UK TSOs. NERA/ICL does not use these estimates. We believe that this is reasonable because these figures are backward-looking and include assets that are already depreciated.

The third estimate is based on the projected costs of actual future network expansion projects. Given that these figures are based on actual projects (not idealised figures) and that they are forward-looking, we believe that they could be a reasonable estimate of network expansion costs. It is notable that the cost estimate for the only HVDC-based project (100 £/MW/km/year for the Scotland to England HVDC link) is actually one of the cheapest projects in this list on a £/MW/km/year basis. Compared with this, conventional expansion projects appear relatively more expensive, and range from 100 £/MW/km/year to 240 £/MW/km/year.

The fourth estimate of £113/MW/km/year has been taken from the transport tariff model of National Grid and used as a reference for NERA/ICLs ‘own estimation’ of HVDC costs, which is 160 £/MW/km/year.[8]

[7] NERA (2004), ‘Review of GB-Wide Transmission Pricing: A Report for ScottishPower UK Division’, p. ii.

[8] NERA and Imperial College London (2014), ‘Assessing the Cost Reflectivity of Alternative TNUoS Methodologies’, February, p. 18.

Table 2.1 National Grid estimates of network reinforcement costs

Bottom-up estimate	**Cost (£/MW/km/year)**
Ideal pricing based on idealised reinforcements of overhead lines	58
Average TSO costs (allowed revenues divided by line length)	
NGET	41
SHETL	58
SPT	32
Actual future network expansion plans	
Scotland to England 'Incremental'	240
Scotland to England HVDC links	100
Beauly-Denny	200
North Wales	100
Assumption by National Grid in transport and tariff model	
Western HVDC link	113

Source: National Grid (2011), 'NETS SQSS Amendment Report GSR009 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation', Appendix 5, April, pp. 58–59; and NERA and Imperial College London (2014), 'Assessing the Cost Reflectivity of Alternative TNUoS Methodologies', February, p. 18.

If higher-than-'ideal' cost estimates are used for reinforcements to boundaries other than the Scotland–England boundary, the gap between NERA/ICL's estimates of LRMC-based transmission charges for wind in Scotland and its estimates of equivalent transmission charges under WACM2 and the status quo could narrow. The reason for this could be that the average of actual future network expansion plans for reinforcements of boundaries within England and Wales and within Scotland is higher than the 'ideal' cost, and much closer to the cost of HVDC bootstraps.

Our conclusion is that a more thorough investigation of these assumptions and cost figures would be needed. Given the strong conclusions that NERA/ICL draws from its modelling, and the fact that these results seem to rely on these assumptions and cost figures, we think that further analysis appears justified.

2.2.4 Modelling of wind infeeds

Wind is an intermittent source of generation that requires a probability distribution in modelling to describe the uncertainty of wind infeeds. Especially in this case, where the need to reinforce networks is strongly driven by peak wind infeeds, the way in which wind is modelled is likely to have a large impact on results.

To be more specific, three aspects have to be modelled correctly:

- the statistical distribution of wind;
- the correlation of wind infeeds in different regions; and
- the correlation of wind infeeds with demand.

As we do not have access to the model, we cannot say whether NERA/ICL models these parameters appropriately. However, the description of the model[9] states that for each 4–5-year period only ten different wind output levels are considered. There is no information on any correlations that were used.

Given the strong conclusions NERA/ICL derives for the LRMC of Scottish wind, it is perhaps surprising that this aspect of modelling has not received more attention and that a distribution of wind output with such apparently low level of granularity is used.

2.2.5 Other possible shortcomings

There are two more potential shortcomings of the NERA/ICL model that we identified:

- the modelling has been done under the assumption of certainty, whereas actual grid investment decisions have to be made under considerable uncertainty;
- the underlying network model is a radial network, which means that loop flows are not considered.

Although we cannot assess whether these two simplifications in the NERA/ICL model have any material effect on the ability of the model to come up with correct LRMC estimates, it is conceivable that this could be the case.

2.2.6 Summary

The NERA/ICL model seeks to assess whether the WACM2 charging methodology is cost-reflective by comparing projected WACM2 charges with its own estimation of transmission reinforcement costs based on LRMCs.

We have undertaken a review of the modelling methodology and assumptions employed by NERA/ICL. We believe that the approach taken is conceptually correct, although we also consider that omitting the impact of generation investment and other benefits of network reinforcement from the optimisation model may have a material impact on the results reported by NERA/ICL. Importantly, we found a number of points where we believe that the NERA/ICL model may not reflect the real costs of network reinforcement. This may cast doubt on NERA/ICLs key conclusion that the WACM2 charging methodology is less ‘cost-reflective’ for wind plant in Scotland than the status quo.

More specifically, we found that:

- the LRMC cost concept with regard to transmission access charging is reasonable in light of precedents from other sectors;
- the estimated LRMC of transmission access in Scotland is a key assumption that is likely to have a significant impact on the cost reflectivity comparison between WACM2 and status quo for wind generation in the Scottish zones. Hence the concerns highlighted in section 2.2.3 of this note may have the implication that WACM2 charges for wind in Scotland are more cost-reflective than estimated by NERA/ICL;

[9] NERA and Imperial College London (2014), ‘Assessing the Cost Reflectivity of Alternative TNUoS Methodologies’, February, p. 13.

- the general set-up of the model omits the effect that higher transmission charges could have on generation location decisions and does not account for some cost-reducing effects of transmission investments such as improvements in security of supply, the renewable portfolio effect, and more competition in the balancing market. These omissions could potentially lead to overestimation of ‘cost-reflective’ transmission access charges in the NERA/ICL model;

- some of the key results of the NERA/ICL reports hinge on a small set of assumptions about the availability and costs of different reinforcement options, which may underestimate the cost of onshore network reinforcement. These assumptions may lead to an understatement of LRMC-based transmission access charges for generation units south of the North–South constraint;

- given the strong conclusions that NEAR/ICL derives on transmission access charges for Scottish wind generation capacities, we believe that there is a risk that wind infeeds have not been modelled in sufficient detail.

2.3 Assessment of NERA/ICL conclusions

NERA/ICL concludes that the WACM2 charging methodology is less ‘cost-reflective’ overall than the status quo. The key results highlighted by NERA/ICL and described in section 2.1 of this document, show that WACM2 charges are more cost-reflective than charges under the status quo for peaking plant in Scotland, but less cost-reflective for wind plant in Scotland. A more detailed examination of figures 5.3 and 5.4 of the NERA/ICL report appears to show that WACM2 charges are more ‘cost-reflective’, as defined by NERA/ICL, for all types of generation plant and all years modelled, with the exception of wind in 2020 and 2030. In this light, the conclusion that WACM2 is less ‘cost-reflective’ overall does not appear to be backed up by the results obtained by NERA/ICL.

Apart from the modelling inputs and the key results described above, the basis for the conclusion reached by NERA/ICL appears to be the observation that TNUoS charges for peaking plant are lower in the south than they are in the north, regardless of the charging regime, and the assumption that the level of TNUoS charges is the most important determinant of the location decisions of peaking plant. Given this, NERA/ICL argues that changes to TNUoS charges faced by peaking plant are unlikely to change their location decisions.

As argued in a previous Oxera report,[10] many factors other than locational transmission charges play an important role in the location decisions of flexible generators, not least the potential to generate revenue from the provision of balancing services. The 2014 NERA/ICL report provides no new counterarguments in this regard. In light of this, we conclude that the optimal location for a given peaking plant, and how economically marginal an investment decision to build a peaking plant is, are likely to be determined by a multitude of factors. Hence it is not possible to say that more cost-reflective transmission access charges for peaking plant will make no difference to their location.

Overall, even if the modelling results derived by NERA/ICL are taken at their face value and the concerns about the NERA/ICL methodology raised in section 2.2 are disregarded, we do not believe it is correct to conclude that WACM2 is less ‘cost-reflective’ than the status quo.

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

3 Would earlier implementation of WACM2 materially increase costs to consumers in the long term?

In the most recent consultation regarding Project TransmiT, Ofgem made the following comment about the possibility of implementing WACM2, if approved, earlier than the planned implementation date of April 2016:[11]

> If we approve earlier, parties would not be able to adjust their agreed capacity in response without incurring penalties. Therefore we do not consider that there is any benefit in an earlier implementation date. In addition, we consider there to be a cost associated with an earlier implementation date. If we do not allow parties to respond to the changes ahead of implementation, they could increase hurdle rates for future generation investment if they have greater uncertainty about their ability to respond to future changes. This could adversely affect competition in the generation market and harm consumers. Earlier implementation could lead to suppliers including greater risk premia in their fixed tariff offers to consumers if they are not given sufficient lead time ahead of significant changes. This could increase costs to consumers.

Ofgem essentially puts forward three arguments why earlier implementation could be detrimental to consumers. The Ofgem consultation does not provide specific analysis to support these statements.

- generators would not be able to adjust their capacity in response to early implementation without incurring penalties;
- hurdle rates for future investment may increase, as early implementation may increase policy uncertainty and reduce generators' ability to plan effectively for policy changes;
- suppliers may increase the risk premia built into their fixed tariffs if they do not have sufficient time to plan for changes in transmission charges.

3.1 Direct additional costs to generators

Given that TNUoS is a fixed charge faced by generators that is invariant in their load factor, an earlier-than-anticipated change in the fixed cost of running a power plant is unlikely to have any material impact on the running regime of the plant. It is possible, as suggested by Ofgem, that the change in TNUoS charges could make it economic for some generators to adjust their capacity and incur penalties in the process. One remedy that could mitigate the impact of penalty charges could be to reduce the notice period required for generators to adjust their capacity without incurring a penalty.

We note that generators already face uncertainty on changes to TNUoS charges on an annual basis. In order to avoid penalties, the commitment to TEC is made on Initial TNUoS tariff information provided by NG at the year-ahead stage. Information provided to Oxera by SSE suggests that revisions in TNUoS charges in certain zones between the initial forecast and the time that the charges are finalised can be of the same order of magnitude as the changes to TNUoS charges for baseload and peaking gas plant under WACM2 as estimated by NERA/ICL. Hence the risk of changes to TNUoS charges as a result of tariff reform does not appear to be substantially higher for these types of plant than the risk faced by some plant within the context of the current TNUoS charging arrangements.

[11] Ofgem (2014), 'Project TransmiT: Further consultation on proposals to change the electricity transmission charging methodology', April, para 2.54.

Finally, we also note that any penalties do not represent a fundamental loss of social welfare, but a transfer from generators who choose to adjust their capacity at short notice to other market participants, including consumers.

The change in the transmission access charging regime may, in principle, have some effect on the existing investment plans of some generators, as it will have some impact on the attractiveness of building certain types of power plants in different locations. As a result of earlier implementation, plant in Southern GB are likely to see higher transmission access costs, but intermittent and low load factor plant in Northern GB are likely to experience the opposite effect. For GB as a whole, the impact of earlier implementation is uncertain and there does not appear to be any reason to believe that the impact of an increase in costs would be greater than the impact of a decrease in costs. In practice, the effect is likely to be negligible since Project TransmiT has been ongoing for nearly four years, and the CMP213 modification was raised by NGET in June 2012. The position that Ofgem is 'minded to' adopt WACM2 has been known to market participants since August 2013. Investment plans are formulated from a long-term perspective. The pre-development phase of power plant construction alone can be two years for a gas plant and between four and six years for a wind plant.[12] Minor changes to implementation timing of certain policy measures, which have been well-signalled and extensively consulted upon, are, in practice, unlikely to lead to a material impact on generators' investment plans. For this reason, we do not think the impact on generators affected provides a robust reason for delay.

3.2 Impact on hurdle rates for future investment

The link between hurdle rates and policy risk, and in particular, policy uncertainty, is widely recognised by various market participants. For example, in the context of investment cases for new low-carbon generation, a number of recent studies have provided evidence that policy risk is an important factor affecting hurdle rates.[13] Specifically, policy uncertainty would be expected to increase the required hurdle rate for a given investment.

However, for reasons similar to those outlined in section 3.1, it is questionable to what extent early implementation of WACM2 would be seen by the market as a material increase in policy uncertainty. The policy itself, assuming no further changes to the methodology, has been known to market participants for some time, and would have been factored into investors' expectations of the financial attractiveness of future investments. When set against other risks that affect the business case for future generation, such as wholesale market price risk, construction cost risk, a revision in the timing of a change to a relatively small part of the overall cost base of new power plant would seem unlikely to have a material impact on investors' required returns.

It can also be argued that continued commitment by Ofgem to the current proposals (that 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 the investors' perspective. This could help to lower investment hurdle rates for new generation. 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

[12] See DECC (2013), 'Electricity generation costs', July, Table 19.

[13] See, for example, the survey evidence presented in Oxera (2011), 'Discount rates for low-carbon and renewable generation technologies', April.

signalled position could increase the perception of risk around the transmission charging regime.

3.3 Impact on suppliers' pricing behaviour

When offering fixed-price contracts to customers, it is reasonable for suppliers to include a risk premium in the price to reflect the considerable degree of uncertainty over the future costs of actually procuring and delivering energy to customers. The risk premium can be thought of as an insurance premium that is built into the price to minimise the risk of not recovering the costs of supply.

The size of the risk premium is likely to be driven mainly by expected volatility in the wholesale power price, which is by far the largest component of the final energy bill. Transmission charges, by contrast, account for a very small proportion of the bill.[14] Even if a change in the implementation timetable of WACM2 induces suppliers to increase the risk premium, the effect on final customer bills is likely to be small.

We have not undertaken a specific evaluation of the potential pass-through of changes in TNUoS charges on generators into wholesale prices. We note that the effects will be different depending on the type of generator, and hence the overall pass-through of tariff changes is difficult to predict. However, we consider it unlikely that changes in generator TNUoS charges that are passed through into wholesale prices will be material relative to the expected overall volatility of wholesale prices when viewed from the perspective of suppliers offering fixed tariffs.

The argument that the proposed tariff reform does not appear to pose substantially greater risk than that which currently exists between the publication of Initial and Final TNUoS tariffs for certain types of plant and in certain zones also applies in relation to generator tariffs feeding through to wholesale prices and the consequent impact on suppliers.

Finally, the argument that the proposed changes have been known for a while also applies in the case of suppliers. It is possible that suppliers have already put plans in place to deal with a step change in the transmission charge, and that there are ways to adjust these plans to reflect changes in the implementation timetable without a long-term impact on consumers.

3.4 Summary

In summary, whilst all of the arguments put forward by Ofgem as to why early implementation is not desirable may be based on sound principles and may have merit in some cases, they do not appear to have been supported by any quantitative analysis, and could be structured to support sticking with the original implementation timetable as closely as is feasible.

The underlying drivers of the increase in risk suggested by Ofgem do not appear to be substantially greater than those that some parties currently face in the context of differences between Initial and Final TNUoS Tariffs. Overall, we believe that the factors highlighted by Ofgem are unlikely to have material long-run cost implications for consumers.

Ofgem does not appear to consider factors suggesting that delayed implementation may also have undesirable implications; namely, by increasing

[14] See, for example, Ofgem (2013), 'Updated Household energy bills explained', February. As at December 2012, transmission charges represented around 4% of the average consumer's electricity bill.

risk perception through a break with a previously signalled position on the timing of implementation. Hence, on balance of arguments, it is possible that the overall impact of delayed implementation is negative.