NERA
ECONOMIC CONSULTING

Project TransmiT: Ofgem's Assessment of Options for Change

A Review Prepared for RWE npower

14 February 2012

Project Team

Sean Gammons
Richard Druce

NERA Economic Consulting
15 Stratford Place
London W1C 1BE
United Kingdom
Tel: +44 20 7659 8500
Fax: +44 20 7659 8501
www.nera.com

Disclaimer

All opinions, advice and materials provided by NERA are included, reflected or summarized herein as the “NERA Content”. There are no third party beneficiaries with respect to the NERA Content, and NERA disclaims any and all liability to any third party. In particular, NERA shall not have any liability to any third party in respect of the NERA Content or any actions taken or decisions made as a consequence of the results, advice or recommendations set forth herein.

The NERA Content does not represent investment advice or provide an opinion regarding the fairness of any transaction to any and all parties. The opinions expressed in the NERA Content are valid only for the purpose stated herein and as of the date hereof. Information furnished by others, upon which all or portions of the NERA Content are based, is believed to be reliable but has not been verified. No warranty is given as to the accuracy of such information. Public information and industry and statistical data are from sources NERA deems to be reliable; however, NERA makes no representation as to the accuracy or completeness of such information and has accepted the information without further verification. No responsibility is taken for changes in market conditions or laws or regulations and no obligation is assumed to revise NERA Content to reflect changes, events or conditions, which occur subsequent to the date hereof.

Contents

Executive Summary i

1. Introduction 1

2. Appraisal of Ofgem's Proposals 2
2.1. Key Appraisal Criteria 2
2.2. Ofgem's Rejection of Socialised Charging 3
2.3. Ofgem's Proposal to Pursue "Improved ICRP" 5
2.4. Conclusion 9

3. Assessment of the "Improved ICRP" Model 10
3.1. SQSS Transmission Investment Requirements 10
3.2. Link Between "Improved ICRP" Tariffs and Investment Costs 13
3.3. Scaling by Load Factor to Proxy Investment Costs 19
3.4. Conclusions 25

4. Other Considerations 27
4.1. Potential for Undue Discrimination 27
4.2. Impact on Regulatory Risk 28
4.3. Conclusion 29

5. Conclusions 30

Appendix A. Review of Redpoint's Modelling Framework 31
A.1. Overview of Redpoint's Approach 31
A.2. Modelling Investment Decisions 31
A.3. Modelling the Power Market 37
A.4. Adjustments to Subsidy Levels in "Stage 2" Modelling 40
A.5. The Need for Sensitivity Analysis 41
A.6. Consistency of CBA with Model Results 41
A.7. Conclusions 42

Executive Summary

Background

RWE npower has commissioned NERA Economic Consulting ("NERA") to conduct an independent review of the latest proposals for reform of GB transmission charging put forward by Ofgem in the context of Project TransmiT. Ofgem's latest Project TransmiT consultation document considers three charging options for charges to generators:

- The "status quo" charging model, which would retain the existing Transmission Network Use of System (TNUoS) charging methodology, but with some small incremental changes;
- The "improved ICRP" charging model, which would change the current approach by splitting the locational "wider" element of TNUoS charges into a charge intended to reflect the costs of providing "peak security", and a "year round" tariff that is intended to allocate transmission costs to those users who drive the need for investment at other times of the year. This charging model, put forward by National Grid, stems from recent reforms of the SQSS implemented through GSR009; and
- The "socialised" charging model, which would recover transmission costs through a uniform £/MWh tariff applied to all generators, whatever their type and location.

Ofgem has proposed to rule out the "socialised" charging model, and that the "improved ICRP" model is the "right direction" for British electricity transmission charging.

Assessment of Ofgem's Case Against Socialised Charging

- **There is strong evidence to support Ofgem's proposal to reject socialised charging**

The evidence examined by Ofgem in its consultation provides a strong case for rejecting the "socialised" charging model on the grounds that it materially reduces social welfare and increases costs to consumers compared to the "status quo" model. This result corroborates similar findings by NERA/Imperial in earlier work in the Project TransmiT process. Together, this provides assurance that the finding of a large negative impact on social welfare from socialised TNUoS is robust.

- **Socialised charging would not increase the risk of missing the 2020 targets**

Ofgem's conclusion that the "socialised" charging model reduces the risk of missing the government's 2020 renewables targets is not robust, as it is based on evidence (Redpoint's "stage 1" modelling) that ignores the response of government subsidies to changes in the costs faced by renewables developers. Moreover, because the 2020 renewables targets are achieved under all three charging models, Redpoint's modelling shows that none of them creates a barrier to achieving the 2020 targets.

Even if it were necessary to increase subsidy levels to wind farms in order to meet government targets, and the modelling provides no evidence that this is the case, it would be more efficient for the government to offer increased subsidies to developers through the RO or CFD FITs than through transmission charges, if necessary by offering different levels of support to generators in different parts of the country. Such policies are less likely to lead to distortionary effects on the entire electricity market that would ultimately be detrimental to social welfare, than providing implicit subsidies to low carbon generation through the transmission charging regime.

Assessment of Ofgem's Case for "Improved ICRP"

§ There is no quantitative evidence supporting the introduction of "improved ICRP"

The evidence prepared by Redpoint suggests that the "improved ICRP" model would have a negative impact on social welfare as compared to the "status quo" over the whole period to 2030. However, Ofgem overlooks this finding when assessing the merits of the "improved ICRP" scheme as compared to the "status quo", focussing only on its impact to 2020 when the NPV impact on social welfare is small but positive, and ignoring the period to 2030, when the NPV impact on social welfare is relatively large and negative. Ofgem also seems to place no weight on Redpoint's low gas price sensitivity, which suggests "improved ICRP" reduces social welfare by £3.7 billion throughout the period to 2030.

If the "improved ICRP" model did improve the efficiency of network usage by targeting the costs of investment on those users that drive the need for them, we would expect total power sector costs to fall as a result, which increases social welfare. Because the modelling finds the opposite result, we examined the extent to which the "improved ICRP" model reflects the impact of generation users on the need for transmission investment.

§ Generation charges under "improved ICRP" do not reflect the costs faced by TOs to comply with the SQSS

The "improved ICRP" charging model stems from the reforms to the SQSS implemented through the GSR009 modification. These reforms change the amount of transmission capacity that TOs are required to provide in order to accommodate the installed portfolio of generation capacity.

By analysing schematic electricity transmission systems, we illustrate that the charges generators face under "improved ICRP" are not reflective of the costs incurred by the TOs to accommodate their presence. Specifically, the cost TOs face to comply with the SQSS is determined by connected capacity, scaled as described in the SQSS, and not by generators' load factors, which determine "improved ICRP" tariffs.

§ Generation charges under "improved ICRP" do not reflect the economic trade-off TOs make between reinforcement and constraints

We find that the statistical evidence put forward by National Grid to support the link between load factor and constraint costs is not robust. We have identified statistical evidence that shows the relationship between load factor and constraint cost is not constant across technologies, and that the relationship between constraint costs and load factor[1] is not "one-for-one", as the "improved ICRP" model implicitly assumes. In particular, we find using

---

[1] Where both are defined in percentage terms.

National Grid's data, that wind plants impose a higher cost on the system than other technologies in most zones. Our analysis therefore suggests that the charges users face under "improved ICRP" do not reflect the economic trade-offs TO make between transmission reinforcement and constraint costs.

§ "Improved ICRP" appears to charge intermittent generators less than the cost they impose on the system

The "improved ICRP" model appears to significantly discount the TNUoS charges faced by intermittent generators compared to the costs they impose on the system. This will lead wind generators to locate in more remote locations than would be economically efficient, based on a trade-off between wind speeds and transmission costs. As a result, costs to the consumer will rise, and social welfare will fall (i.e. power sector costs will rise), because reinforcement and constraint costs will increase.

Other Considerations

§ "Improved ICRP" may unduly discriminate between generators

The "improved ICRP" charging model might also materially increase the potential for undue discrimination between network users. Undue discrimination can arise where people in similar situations are treated differently, or people in different situations are treated similarly, without objective justification. "Improved ICRP" gives different treatment to producers who impose similar costs on the system, and who receive the same access rights in return, by requiring them to pay different charges, for no obvious economic reason.

Moreover, the argument that the "improved ICRP" discriminates less than the "status quo" because it better reflects the costs users impose on the system is not valid. As we demonstrate in this report, the "improved ICRP" model may materially under- or overstate the costs that users impose on the transmission system, and in particular our analysis suggests it understates the costs intermittent generation in the north imposes on the system.

§ Changes to TNUoS charges may have substantial distributional effects, which will contribute to investors' perception of regulatory risk

Changes to the TNUoS regime can have material distributional effects that influence investors' perception that similar changes will occur in future, and hence increase the perceived riskiness of future investments. The resulting increase in the required rate of return on investments tends to increase power sector costs, and the costs faced by consumers.

While there may be a cost of increased regulatory risk associated with any change to market arrangements, changes to the transmission charging regime have a particularly material effect due to the potential for large distributional effects amongst network users. Hence, because there is no strong case for the introduction of the "improved ICRP" model on the grounds that it improves social welfare, there appears to be no justification for incurring the additional costs associated with creating large re-distributions of producer surplus.

1. Introduction

This report provides an independent review of Ofgem's latest Project TransmiT consultation document,[2] which contains Ofgem's initial assessment of three charging models for the British electricity transmission network:

- The "status quo" charging model, which would retain the existing Transmission Network Use of System (TNUoS) charging methodology based on the Investment Cost Related Pricing (ICRP) principle, but with some small incremental changes to reflect issues that were previously unanticipated, such as the need for the High Voltage Direct Current (HVDC) bootstraps;
- The "improved ICRP" charging model, which would change the current approach by splitting the locational "wider" element of TNUoS charges into a charge intended to reflect the costs of providing "peak security", and a "year round" tariff that is intended to allocate transmission costs to those users who drive the need for investment at other times of the year; and
- The "socialised" charging model, which would recover transmission costs through a uniform £/MWh tariff applied to all generators, whatever their type and location.

As described in more detail below, Ofgem has proposed to rule out the "socialised" charging model, and concludes that the "improved ICRP" model is the "right direction" for British electricity transmission charging.

The remainder of this report is structured as follows:

- In Chapter 2 we appraise Ofgem's proposals to rule out socialised transmission charging, and its suggestion that the "improved ICRP" model is the "right direction" for the TNUoS charging regime;
- In Chapter 3 we conduct a detailed appraisal of the "improved ICRP" charging regime;
- In Chapter 4 we examine other considerations regarding the case for changing the transmission charging regime, such as the potential for undue discrimination, and the impact on regulatory risk; and
- Chapter 5 concludes.

---

[2] Project TransmiT: Electricity transmission charging: assessment of options for change, Ofgem (188/11), 20 December 2011. Unless otherwise specified, all other citations of Ofgem in this report refer to this document.

2. Appraisal of Ofgem's Proposals

In this chapter we appraise the proposals put forward by Ofgem in its recent "options for change" consultation document. As described further below, Ofgem has proposed to rule out socialised transmission charging, and proposes to "reaffirm the principle of cost reflectivity in transmission charging".[3] Ofgem suggests that the "improved ICRP" model is the "right direction for transmission charges", though as we describe below, Ofgem has not provided any objective economic evidence that justifies this proposal.

2.1. Key Appraisal Criteria

When assessing the case for changing the transmission charging regime, it is necessary to estimate the expected impact on social welfare, which is defined in the economics literature as the change in consumer surplus (a measure of consumer welfare, defined by the difference between the price consumers would be willing to pay, and the price they actually pay), plus the change in producer surplus (defined as profits earned by firms). The sum of consumer surplus and producer surplus defines the total benefit captured by a society. Changes in this amount capture the net benefits of a project, or a change in policy.

In certain conditions,[4] a proxy for the change in social welfare due to a reform of transmission charges is the change in power sector costs, which Ofgem has commissioned Redpoint to estimate in this case.[5] In line with Ofgem's statutory duties to protect the interests of current and future consumers, Ofgem has also considered changes in costs to the consumer (i.e. changes in consumer surplus) in its appraisal of the three transmission charging options.

Ofgem also has responsibilities to follow guidance issued by the Secretary of State with regard to environmental policies. The government's Guidance to the Authority states that "Within its statutory remit, the Authority should identify any aspects of the regulatory framework which could act as an undue barrier to meeting the 2020 EU renewable energy targets and pursue the necessary changes to that framework".[6] The Energy Act 2008 also enshrines in law the Authority's obligation to consider "sustainable development".[7] Hence, Ofgem's assessment of the case for change also needs to examine whether the current regime creates an "undue barrier" to meeting the 2020 target for renewable generation, and whether it promotes sustainable development.

---

[3] Ofgem, page 5.

[4] This result requires that demand for electricity does not change as a result of the reforms.

[5] We provide a review of the methods and assumptions underpinning the Redpoint modelling work in Appendix A.

[6] Revised Social and Environmental Guidance to the Gas and Electricity Markets Authority issued by the Secretary of State under section 4AB(1) of the Gas Act 1986 and section 3B(1) of the Electricity Act 1989, paragraph 11.

[7] Energy Act 2008, Article 1(c).

2.2. Ofgem’s Rejection of Socialised Charging

2.2.1. Redpoint’s analysis shows socialised TNUoS reduces social welfare and is costly to consumers

As compared to the “status quo” charging model, Redpoint’s analysis suggests that the “socialised” TNUoS charging model increases costs to consumers in net present value terms by £19.7bn and increases power sector costs by £7.6bn in the period to 2030. Given that the modelling demonstrates the government’s environmental targets are achieved in both cases, there is therefore no justification for implementing the “socialised” model. Ofgem’s proposal to rule out the “socialised” TNUoS model is therefore consistent with its regulatory obligations to consider costs and benefits to society, the impact on consumers and the implications for sustainable development.

2.2.2. Ofgem is wrong to suggest that socialised charging reduces the risk of missing the 2020 renewables target

The modelling conducted by Redpoint suggests that, holding the subsidies to renewables constant across the three charging models, the deployment of renewables is higher in the “socialised” model than the “status quo” or “improved ICRP” models:

§ Holding subsidies constant at current levels, the “socialised” charging model results in 36.8% of generation from renewables in 2020,[8] slightly higher than the 29.9% and 31.0% achieved under the “status quo” and “improved ICRP” models respectively; and

§ Fixing subsidies across all three charging models at the level required to provide 30% of renewable generation by 2020 in the “status quo” scenario (Redpoint’s “Stage 1” modelling), renewable generation increases by 6.2 percentage points in the “socialised” case relative to the “status quo”.[9]

Ofgem concludes that the introduction of socialised charging “[reduces] the risk of missing the 2020 target if the levels of low carbon support do not deliver”,[10] and that “For any given level of government support the socialised approach reduces the risk of not meeting the UK government’s 2020 renewable generation target”.[11]

The suggestion that the “socialised” charging model reduces the risk of missing the 2020 renewables targets is misleading, because the government has stated that it will adjust renewables subsidy levels in light of changes to TNUoS charges, as noted in Ofgem’s consultation:[12]

---

[8] See the Redpoint’s Figure 33, and its Excel file containing detailed modelling results (Cell N591, Worksheet “Socialised (RO banding)”).

[9] Ofgem, para 4.25.

[10] Ibid.

[11] Ofgem, page 5.

[12] Ofgem, para 1.30.

> *"Government has indicated that it will take into account the effect on low carbon deployment of the result of the TransmiT project in setting subsidy levels. We therefore expect such subsidies to be "flexed" in the light of adoption of any of the options so that the target is met in 2020 but not before."*

All Redpoint's modelling shows is that, given its assumptions on the costs and the constraints on the deployment of renewable generation, and keeping subsidy payments constant, a larger number of projects can be profitably developed with a socialised TNUoS charge than under the alternative models.[13] But, as Ofgem points out, the government has the ability to change subsidy levels in light of changes to TNUoS charges, and in practice has indicated that it will do so.[14]

It is therefore misleading to suggest socialised charging reduces the risk of missing 2020 targets, as this statement is conditional on the premise that subsidies remain constant, no matter what changes take place to the TNUoS regime. This premise is not credible. When comparing the three charging models, a consistent approach would require that Ofgem discounts any benefit it attributes to the "socialised" charging model on the basis that it increases the probability of meeting the renewables target.

2.2.3. Ofgem understates the cost at which socialised charging "reduces the risk" of missing environmental targets

As described further in Appendix A, Redpoint's modelling was conducted in two "stages". In "stage 1", Redpoint set subsidy levels in order to achieve 30% of renewables in power generation by 2020 in the "status quo". Holding subsidy levels constant at this level, it then ran the "improved ICRP" and "socialised" scenarios, and recorded the change in renewables deployment. As mentioned above, the deployment of renewables was somewhat higher in the "socialised" model, and similar under "improved ICRP".

In its "stage 2" runs, it adjusted renewables subsidy levels to achieve 30% of renewables in power generation by 2020 across all three charging models. It used this run to calculate the change in power sector costs across the three models.

Ofgem states that:[15]

> *"For any given level of government support the socialised approach reduces the risk of not meeting the UK government's 2020 renewable generation target. However in order to meet these targets, it does so at disproportionate cost (to 2020 power sector costs would increase by £2.8bn, pushing up consumer bills by £6.9bn)."*

---

[13] Recent work by Oxera for Scottish Power also suggests that a socialised charge increases the profitability of the portfolio of renewable generation projects in the pipeline, taken as given the level of subsidies paid. Specifically, it would increase project IRRs by an average of 46-53 basis points.

Source: Principles and priorities for transmission charging reform, Oxera, November 2010.

[14] Ofgem, para 1.30.

[15] Ofgem, page 5.

However, the impact on social welfare of £2.8bn and the impact on consumers of £6.8bn are calculated from Redpoint's "stage 2" modelling,[16] in which the level of renewable generation in 2020 is 30% under all three charging models. It is therefore misleading to present the costs of increasing renewables deployment from the "stage 2" modelling, when the "stage 2" runs show no increase in the deployment of renewables.

Although neither Redpoint nor Ofgem presents the welfare and cost impacts of the "stage 1" modelling, it is likely that the "stage 1" run of the "socialised" scenario would be more costly to society than the "stage 2" run of the "socialised" scenario, as it includes more renewable generation, which is generally more expensive than other forms of generation on a levelised (per MWh) basis. Hence, Ofgem is understating the cost of increasing renewables deployment under the "socialised" model. And in any case, Ofgem recognises that this downwardly biased cost estimate is already "disproportionately" high.

2.3. Ofgem's Proposal to Pursue "Improved ICRP"

As described above, Ofgem has proposed that the "improved ICRP" model is the "right direction" for transmission charging. The supposed justifications it offers for this proposal are that, compared to the "status quo", it would slightly reduce power sector costs in the period to 2020, it better reflects the costs that TOs incur to accommodate generators on the system, and that it would be more consistent with the direction of European policy.[17] As described below, all of these claims are without foundation.

2.3.1. Redpoint's modelling results indicate that "improved ICRP" negatively impacts social welfare

As Table 2.1 illustrates, Redpoint's modelling results clearly show that the "improved ICRP" model has a negative impact on social welfare in net present value terms over the period to 2030. Specifically, "improved ICRP" increases costs to consumers by £1.4bn, and reduces social welfare by £400Mn.

Table 2.1
Estimated Impact of the "Improved ICRP" Model

Real 2011 £Mn	**2011-2020**	**2021-2030**	**Total**
Impact on Consumers	-897	-512	-1,409
Impact on Power Sector Costs	122	-543	-421

Source: Redpoint, Table 5

---

[16] Redpoint Table 6.

[17] Ofgem, page 5.

Despite these results, Ofgem's consultation proposes that "improved ICRP is the right direction for transmission charges".[18] In justifying this stance, Ofgem states that:[19]

> *"Under improved ICRP society would benefit from a small reduction in power sector costs (£120m savings to 2020) compared to the status quo. Customer bills would be largely unaffected in the early years and whilst they rise after 2017 (£0.9bn rise to 2020) the effects are small as measured against total costs."*

However, this analysis of the impact of "improved ICRP" on power sector costs (and hence social welfare) is incomplete. Ofgem focuses solely on the impact to 2020, which, assuming the revised charges are implemented on 1 April 2013, only covers the first 8 years or so of the scheme's operation. Indeed, from Figure 8 in Ofgem's consultation, significant positive benefits of "improved ICRP" appear to arise only in 2018 and 2020.

Given that changes to TNUoS charges affect investment decisions in long-lived assets, and Ofgem has at its disposal evidence on the impact of "improved ICRP" over the whole period to 2030, there is no reason why it should ignore the longer-term impacts that suggest the reform would *reduce* social welfare by over £400Mn.[20] Moreover, focusing only on the short-term impacts appears inconsistent with Ofgem's statutory obligation to protect the interests of current *and future* consumers, and its own interpretation of its sustainability objectives.

Ofgem states in paragraph 5.1, which sets out its interpretation of its duties to "have regard to the need to contribute to sustainable development", that it has "taken a long-term view and taken account of the potential impacts on depletable assets by modelling to 2030". In light of this statement, it is not clear why it ignores the impact of "improved ICRP" on power sector costs (or "depletable assets") between 2021 and 2030, and thus contradicts its own interpretation of its sustainability objective.

Moreover, the only sensitivity conducted by Redpoint to examine the welfare implications of the "improved ICRP" against the "status quo", the low gas price sensitivity, indicates that the NPV impact on social welfare of "improved ICRP" is negative throughout the whole modelling horizon. Specifically, social welfare falls by £316Mn in the period to 2020, and by £3,433Mn in the period to 2030.[21]

2.3.2. Ofgem's belief that "improved ICRP" is more cost reflective requires further investigation

The role of locational TNUoS charges is to promote the efficient use of the transmission system. In general, this goal is most likely to be achieved by targeting the costs of providing transmission network infrastructure on those users that drive the need for it. If changes to the

---

[18] Ofgem, page 5.

[19] Ofgem, page 5.

[20] Although this paragraph appears in Ofgem's Executive Summary, Ofgem also appears to focus on the short-term

[21] Redpoint, Table 10.

transmission charging regime improve the efficiency of network usage, we would expect total power sector costs to fall as a result, and thus increase social welfare.

Ofgem states in its consultation document that:

> *"improved ICRP better reflects the costs variable generators impose on the need for transmission investment and more accurately reflects the economic trade-off each Transmission Owner makes between expected constraint costs and the cost of new transmission reinforcements when planning investment activity".*[22]

However, as described above, Redpoint's modelling finds that the "improved ICRP" model *reduces* social welfare as compared to the "status quo". Hence, Ofgem's claim that "improved ICRP" better reflects the costs that generators impose on the system, which we would expect to improve the efficiency of network usage and so reduce power sector costs, is not supported by Redpoint's modelling.

Because Ofgem provides no further evidence or argumentation to support the statement quoted above, in Chapter 3 we therefore provide our own assessment of whether the charges generators face under the "improved ICRP" model are likely to reflect the costs they impose on the system.

2.3.3. The "status quo" and "improved ICRP" models do not create barriers to meeting 2020 targets

Ofgem suggests that the "improved ICRP" model increases the probability of meeting 2020 renewables targets:[23]

> *"The modelling suggests that, for the same level of low carbon support, improved ICRP could somewhat increase the probability of hitting the 2020 renewables target, relative to the status quo, by increasing the deployment of onshore wind in Scotland. For the same level of support, renewables output hits 30% of total demand in mid to late 2019 and is 0.6 percentage points higher than the status quo by 2020."*

Despite this statement, which appears to refer to Redpoint's "stage 1" modelling results, Ofgem's Figure 5 (on the same page as this statement) shows that "improved ICRP" achieves a lower penetration of renewables than the "status quo" in 2020 on the assumption that current subsidy levels remain in place. The quantitative modelling therefore does not support the suggestion that the "improved ICRP" model better meets the government's sustainability objectives.

Moreover, even if the "status quo" model did result in a lower expected penetration of renewables than the "improved ICRP" model in Redpoint's "stage 1" modelling, this result would not imply that "improved ICRP" increases the probability of achieving government

---

[22] Ofgem, page 5.

[23] Ofgem, para 4.23.

targets, for the same reasons as apply to Ofgem's claims about socialised charging (see Section 2.2.2).

From the evidence presented in Ofgem's report, we therefore see no basis for the suggestion that the "improved ICRP" model would improve the chances of meeting the 2020 renewables target.

2.3.4. Ofgem has not demonstrated that "improved ICRP" is more consistent with EU policy than the "status quo"

Ofgem's consultation also suggests that "improved ICRP would appear to be more consistent with the direction of travel of European policy".[24] Ofgem goes on to say that: [25]

> *"it is important to avoid locking transmission charging into an approach which is inconsistent with the direction of travel of the European Target Model and the potential requirement for market splitting. The full implications of market splitting are unclear, but it will result in locational charging for energy and/or transmission in some form. Arguably the status quo and improved ICRP approaches are more consistent with this direction of travel than socialised charging, which would result in completely non-locational charging for energy and transmission."*

As the above statement indicates, both the "improved ICRP" and the "status quo" align with "the direction of travel of European policy" by providing locational signals. Hence "the direction of travel of European policy" does not justify introducing "improved ICRP" in place of the "status quo". Statements in the Ofgem consultation suggesting that the "improved ICRP" model is more consistent with "the direction of travel of European policy" than the "status quo" are therefore incorrect.

Also, the EU Target Model is likely to introduce zonal energy pricing in some form, which will materially affect the locational incentives placed on all market participants in GB. It would therefore appear prudent to consider a sensitivity to this key change in trading arrangements before reforming the TNUoS charging regime. Ofgem's failure to consider the implications of "market splitting" therefore reduces the robustness of its conclusions, and runs contrary to its recent decision to reject BSC Modification Proposal P229, in part on the grounds that changes in EU policy be introduced before the supposed benefits of the proposal could be realised:[26]

> *"the P229 proposals are being decided in the context of a changing external environment, in which an approved transmission losses proposal may be superseded before the full benefits have been realised. In particular, at a European level, there is an active debate for greater integration of electricity markets focused on market splitting approaches that create*

---

[24] Ofgem, para 5.3.

[25] Ofgem, para 5.12.

[26] Decision on "Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)", Ofgem, 28 September 2011, page 6.

> *multiple price areas within a national system and implies “locational” energy prices. This could be implemented as early as 2015”*

2.4. Conclusion

Ofgem’s recent “options for change” consultation document proposes to rule out socialised transmission charging, and that the “improved ICRP” model is the “right direction for transmission charges”.

As described above, the evidence examined by Ofgem in its consultation provides a strong case for rejecting the “socialised” charging model on the grounds that it materially reduces social welfare and increases costs to consumers compared to the “status quo” model. This result corroborates similar findings by NERA/Imperial in earlier work in the Project TransmiT process.

Despite its rejection of “socialised” TNUoS, Ofgem states that the “socialised” charging model may reduce the risk of missing the government’s 2020 renewables targets. As described above, this conclusion is based on Redpoint’s “stage 1” modelling which shows increased deployment in the “socialised” model compared to the “status quo” model. However, the finding that renewables deployment increases is based on the incorrect premise that government will ignore changes in the network costs faced by renewables developers when setting subsidy levels.

The evidence prepared by Redpoint also suggests that the “improved ICRP” would have a negative impact on social welfare as compared to the “status quo”. However, Ofgem overlooks this finding when assessing the merits of the “improved ICRP” scheme, focussing only on its impact to 2020.

The mechanism through which locational TNUoS charges can improve social welfare is by targeting the costs of providing transmission network infrastructure on those users that drive the need for it, thus encouraging a more efficient use of the transmission system. If the “improved ICRP” model is likely to improve the efficiency of network usage, we would expect total power sector costs estimated in Redpoint’s model to fall as a result. But as described above, Redpoint’s modelling suggests that “improved ICRP” would *increase* power sector costs, and therefore reduce social welfare, compared to the “status quo”.

Because Ofgem has not provided evidence or argumentation to supports its claim that “improved ICRP” would better reflect the costs generators impose on the transmission system, in the next chapter we provide our own assessment of whether the charges users would face under “improved ICRP” model reflect the costs they impose on the system.

3. Assessment of the "Improved ICRP" Model

In this chapter, we describe the relationship between the "improved ICRP" charging model and the reforms to the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) implemented through the "GSR009" modification.[27] GSR009 implemented planning standards that were intended to require that the TOs provide the quantity of transmission boundary capacity that makes a least-cost trade-off between constraint and reinforcement costs.

Hence, taking as given that GSR009 prescribes the "efficient" level of boundary investment, we assess whether the "improved ICRP" charges reflect the investment costs TOs incur to provide the investment capacity prescribed by the SQSS when accommodating generators on the GB transmission system. In practice, it is likely to be a necessary condition for improving the efficiency with which the transmission system is used, and hence improving social welfare, that "improved ICRP" reflects the transmission investment costs that each user imposes on the grid.[28]

As noted in the previous chapter, Ofgem suggests a key justification for the "improved ICRP" model is that it better reflects the costs that intermittent generators impose on the system. Therefore, a number of the examples presented in this chapter focus on assessing whether "improved ICRP" tariffs meet this criterion.

3.1. SQSS Transmission Investment Requirements

3.1.1. Reforms implemented through GSR009

Section 4 of the NETS SQSS on the "Design of the Main Interconnected Transmission System" describes criteria that the TOs must adhere to when planning the development of the transmission system. In particular, it determines the amount of transmission boundary capacity that TOs are required to provide, given the profile of installed capacity on the system. Until recently, the investment criteria in the SQSS required TOs to provide sufficient transmission capacity to operate the system in Average Cold Spell (ACS) peak demand conditions, where the output from all capacity on the system is scaled uniformly to meet demand.

In November 2011,[29] Ofgem approved SQSS modification proposal GSR009, which followed from a consultation on the appropriate transmission planning standards in a system dominated

---

[27] Amendment Report GSR009: Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, Prepared by the SQSS Review Group for submission to the Authority, Consultation Reference: GSR009 and GSR009-1, Version: 1.0, 1 April 2011.

[28] We focus primarily on investment costs, rather than constraint costs, as TNUoS charges are intended to recover network infrastructure costs, while constraint costs are recovered through other arrangements.

[29] Decision on proposal to amend the minimum transmission capacity requirements in the System Security and Quality of Supply Standard (SQSS) - GSR009, Ofgem, 1 November 2011.

by significant volumes of intermittent generation.[30] Following GSR009, the SQSS now obliges TOs to provide sufficient boundary capacity to fulfil two criteria:[31]

1. a "demand security criterion", that requires sufficient boundary capacity to ensure continued system operation in ACS peak demand conditions, on the assumption that intermittent generation and interconnectors are unavailable, and with all other generation "variably scaled" uniformly to match generation to demand; and
2. an "economic criterion", that requires sufficient boundary capacity to ensure continued system operation in ACS peak demand conditions, on the assumption that output from intermittent, nuclear, Carbon Capture and Storage (CCS), pumped storage and interconnectors are scaled by specific factors, and the remainder of generation is variably scaled to meet demand.

The scaling factors underlying the two generation backgrounds, which are now written into the SQSS, are shown below in Table 3.1.

Table 3.1
Scaling Factors Specified in SQSS Planning Criteria

Technology	Demand Security Criterion	Economic Criterion
Peaking plant (e.g. OCGTs)	Variably Scaled	0%
Wind, wave and tidal	0%	70%
Nuclear and CCS	Variably Scaled	85%
Pumped storage	Variably Scaled	50%
Interconnectors	0%	100%
Other	Variably Scaled	Variably Scaled

Source: SQSS Version 2.02, Appendices C and E.

In principle, it is most efficient for TOs to build boundary capacity to make a least-cost trade-off between the costs of investment and the costs of constraints. In the documentation surrounding the GRS009 modification, this approach is known as conducting a full cost benefit analysis (CBA) of transmission reinforcements.

In developing the reforms proposed under GSR009, the SQSS Review Group conducted analysis to compare the quantity of boundary reinforcement that a number of alternative security standards, like those listed in Table 3.1, would prescribe, as against the optimal quantity of boundary capacity that a full CBA suggests is required. According to the Review Group's analysis, the approach adopted in GSR009 prescribes the boundary reinforcements

---

[30] Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, SQSS Review Group Consultation GSR009, 11 June 2010.

[31] National Electricity Transmission System Security and Quality of Supply Standard Amendment Report GSR009, Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, Prepared by the SQSS Review Group for submission to the Authority by NGET, SHETL and SPT, 1 April 2011.

that were closest to those prescribed by a full CBA.[32] Hence, the selected methodology is sometimes referred to as a "pseudo CBA" approach, as it intends to mimic the outcomes of a full CBA, i.e. identify capacity provision that reflects an optimal trade-off between investment costs and congestion costs, taking account of the running patterns of different generation.

3.1.2. Calculation of "Improved ICRP" Tariffs

As described in detail in several key documents published through the Project TransmiT process,[33] the "improved ICRP" charging model comprises two "wider" locational tariffs.

The generation backgrounds underlying these two charges stem from the generation backgrounds specified in the "demand security" and "economic" criteria in the new SQSS. Each of these charges is based on an estimated cost of accommodating generation in a particular zone, which, under the "improved ICRP" proposal, would be estimated as follows:

§ The first step is to run a load flow model of the GB transmission system for a single hour with generation scaled to serve ACS peak demand. The load flow models underlying the "peak security" and "year round" charges use respectively the backgrounds specified in the SQSS for the "demand security" and "economic" criteria;

§ The next step is to compare the modelled flows on every circuit in the system in the two runs of the load flow model. Circuits with the highest flows in the "economic criterion" background are flagged as being required to fulfil this criterion, and all others are flagged as being required to meet the "peak security" criterion;

§ Under each generation background, an incremental MW of generation is then added sequentially to every node on the system[34] to identify the additional load flows over the network measured in MWkm. This calculation is performed separately for the circuits allocated to each of the "demand security" and "economic" criteria backgrounds. The results are averaged across all nodes within each zone on the network, weighted in proportion to scaled generation; and

§ For each zone, the final step is to multiply the incremental network flows (in MWkm) on those circuits flagged as required by the "demand security" and "economic" criteria by an "expansion constant" (in £/MWkm)[35] to set the "peak security" and "year round" charges respectively.

Generators' liability to pay the "peak security" component of the "improved ICRP" charge is determined by their TEC. Hence, this component is a capacity-based charge. Their liability to pay the "year round" charge is determined by their TEC, multiplied by their annual load

---

[32] Amendment Report GSR009 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, Prepared by the SQSS Review Group for submission to the Authority, 1 April 2011, Appendix 4.

[33] See, for example, Project TransmiT: Electricity Transmission Charging Significant Code Review: Initial Report of the Technical Working Group, Ofgem, 23 September 2011, Annex 3.

[34] NGET subtracts a corresponding MW of generation from a reference node to equate generation and load.

[35] In practice, this figure would also be multiplied by a security factor, and scaled according to the "G:D split", which determines the share of network costs recovered from generation and load.

factor. For this calculation, each generator’s annual load factor[36] is set equal to its average load factor over the preceding five years, excluding the two years in which its load factor was highest and lowest over this period. Hence, this charge is effectively levied on a trailing average of each plant’s energy production.

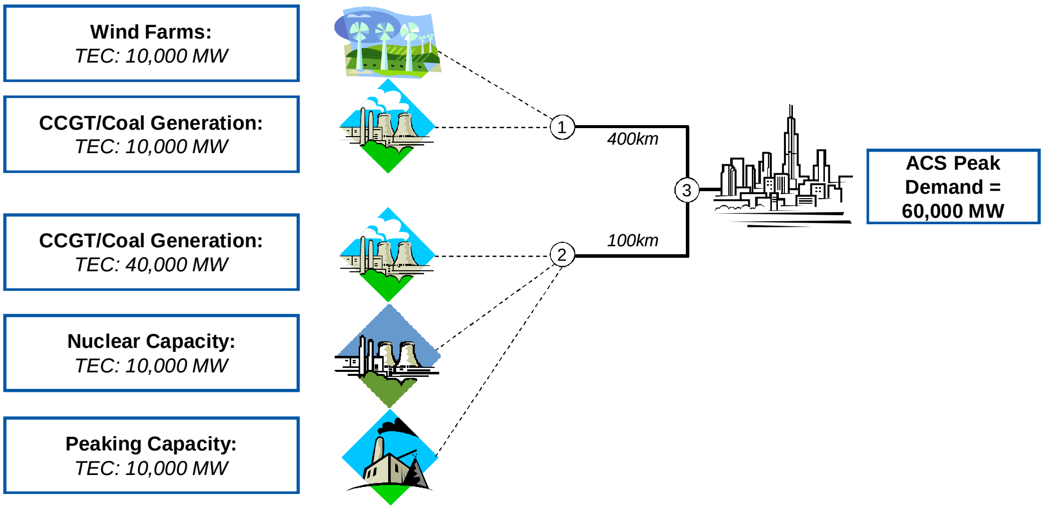
3.2. Link Between “Improved ICRP” Tariffs and Investment Costs

3.2.1. A schematic transmission system

We use the schematic transmission system presented in the figures below to illustrate the investment costs that TOs incur to accommodate different types of generation on their networks in order to comply with the new SQSS.

Figure 3.1 shows a transmission system containing three nodes. At the first node, 10,000MW of wind generation capacity, and 10,000MW of coal/CCGT capacity connects to the system. At a second node 40,000MWof coal/CCGT capacity connects, alongside 10,000MW of nuclear and 10,000MW of peaking plant. Demand is located at the third node, with ACS peak assumed to be 60,000MW. Node (1) is located 400 kilometres from demand, and node (2) is located 100 kilometres from demand.

Figure 3.1
Schematic Transmission System



In the “peak security criterion” background specified in the SQSS, as Figure 3.2 shows, the wind capacity at node (1) is assumed not to run at all. All other plants on the system are “variably scaled” to meet demand. Under this pattern of dispatch, flows across the transmission line (1)-(3) would be 8,571MW, and flows across the line (2)-(3) would be 51,429MW.

In the “economic criterion” background specified in the SQSS, as Figure 3.3 shows, the wind capacity runs at 70% of capacity, the nuclear capacity runs at 85% of capacity, and the peaking capacity does not run at all. The coal and CCGT plants on the system are “variably

---

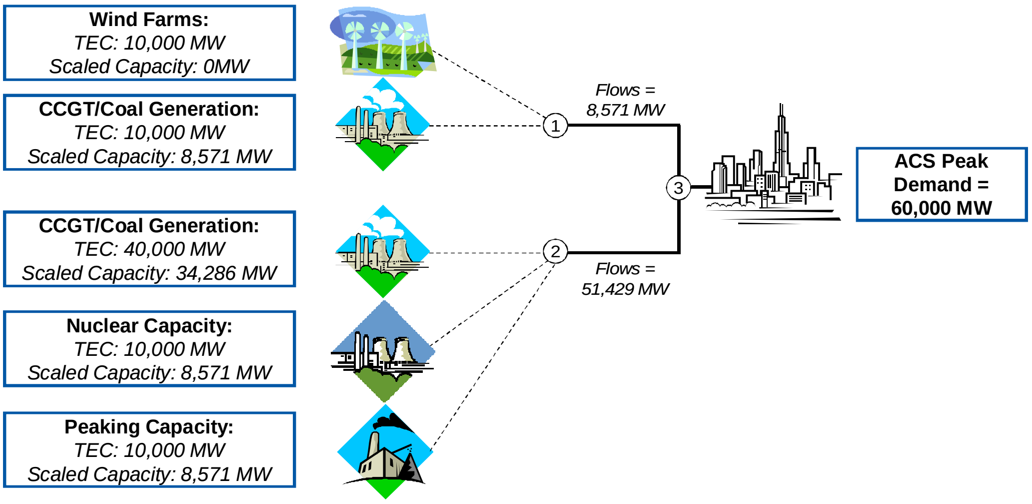
[36] Assuming it has been online for five years or more.

scaled" to meet demand. Under this assumed pattern of dispatch, flows across the transmission line (1)-(3) would be 15,900MW, and flows across the line (2)-(3) would be 44,100MW.

Comparing the two scenarios shows that flows are highest on the (1)-(3) line in the "economic criterion" background, whereas flows are highest on the (2)-(3) line in the "peak security criterion" background. Hence, under the "improved ICRP" model, the costs of the (1)-(3) line would be allocated to the "year round" charge, and the costs of the (2)-(3) line would be allocated to the "peak security" charge.

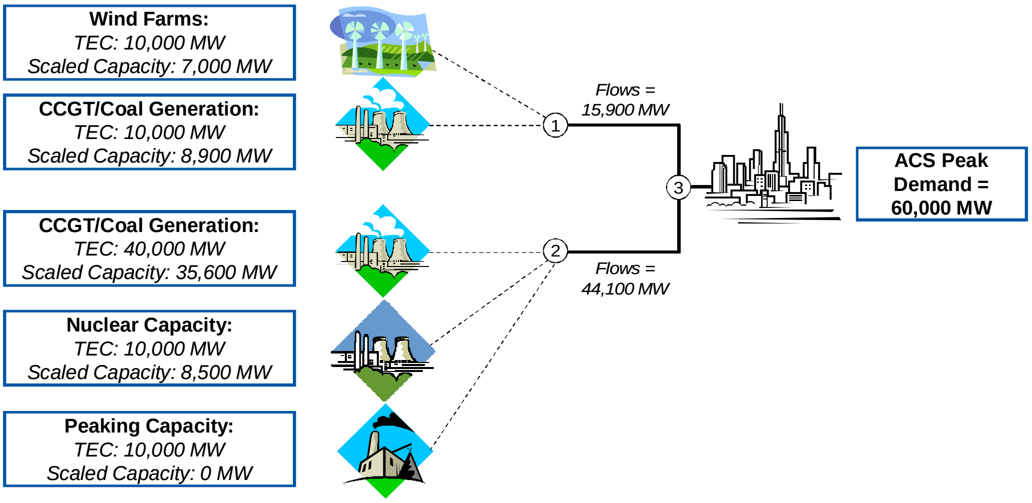
Moreover, the example shows that, if the TO builds precisely enough capacity to comply with the SQSS planning criteria, it would need to provide 15,900MW of transmission capacity along route (1)-(3), and 51,429MW of transmission capacity along route (2)-(3). Assuming the investment cost of providing network capacity is £10/MWkm, the cost of providing an incremental MW of transmission capacity along the (1)-(3) route is £4/kW, and the cost of providing an incremental MW of transmission capacity along the (2)-(3) route is £1/kW. The difference between these reinforcement costs is due to the assumed distances from nodes (1) and (2) to load, as shown in Figure 3.1.

Figure 3.2:
Peak Security Criterion Background: Illustrative Load Flow



Source: NERA analysis and illustrative assumptions.

Figure 3.3:
Economic Criterion Background: Illustrative Load Flow



Source: NERA analysis and illustrative assumptions.

3.2.2. The incremental cost of accommodating new generation capacity does not depend on plant load factors

To illustrate the costs the TO incurs to connect generators in this schematic transmission system, suppose that a new 1MW wind turbine connects at node (1). This change in capacity would not affect the "peak security criterion" background, as wind capacity is assumed not to run in this background. However, it will affect patterns of output in the "economic criterion" background. In this case, the "scaled" output from wind will rise by 0.7 MW, as the incremental MW of capacity is assumed to run at 70%. Assuming demand does not change, the output from all the "variably scaled" generators will fall slightly to compensate. The net effect is that flows on the (1)-(3) transmission line rise by 0.56MW, as wind output is 0.7MW higher, but output from the conventional generators at node (1) falls by 0.14MW to ensure that supply matches ACS peak demand. Hence, to accommodate an incremental MW of wind at node (1), the TO incurs a cost of £2.24/kW of TEC (= 0.56 x £4/kW).

Similarly, an incremental MW of CCGT or coal generation capacity technology at node (1) increases "variably scaled" generation in the "economic criterion" background, and increases the amount of capacity required on the (1)-(3) route by 0.71MW. This extra capacity requirement imposes a cost of £2.848/kW. No extra capacity is required on the line (2)-(3).

As noted above, the route (2)-(3) is allocated to the "peak security criterion" background. Hence, an incremental MW of generation capacity at node (2) has no effect on the costs of complying with the "economic criterion" background. An incremental MW of any generation capacity at node (2), which is all "variably scaled" in the "peak security criterion" background, increases flows from (2) to (3) by 0.12MW, and therefore imposes a cost of £0.12/kW on the TO in order to comply with the SQSS (= 0.12 x £1/kW).

Table 3.2
The Incremental Cost of 1MW of TEC

Node	Technology	Incremental Reinforcement Triggered (MW)			Reinforcement Cost (£/MW/km)	Distance (km)	Incremental Cost (£/kW of TEC)		
		Peak	*Economic*	*Total*			*Peak*	*Economic*	*Total*
(1)	Wind Farm	0.00	0.56	0.56	10.00	400	0.00	2.24	2.24
(1)	Conventional	0.00	0.71	0.71	10.00	400	0.00	2.85	2.85
(2)	Conventional	0.12	0.00	0.12	10.00	100	0.12	0.00	0.12
(2)	Peaking	0.12	0.00	0.12	10.00	100	0.12	0.00	0.12
(2)	Nuclear	0.12	0.00	0.12	10.00	100	0.12	0.00	0.12

Source: NERA analysis and illustrative assumptions.

This analysis illustrates that the incremental investment cost of reinforcement to accommodate an incremental MW of TEC while complying with the SQSS, as summarised in Table 3.2, depends on the scaling factors in the SQSS, as well as the type of installed capacity and its location. The actual energy produced by any generator over the year has no influence on the costs of complying with the SQSS criteria. This feature is as we would expect, given the SQSS triggers an obligation for TOs to make investments and incur investment costs when generators connect, independent of generators' actual running once connected. The mere fact that the "improved ICRP" model calculates charges as a function of load factor therefore demonstrates that this charging model will not reflect the costs that a generator's presence imposes on the TOs.

3.2.3. Reinforcement costs incurred to comply with the SQSS differ systematically from "improved ICRP" tariffs

Table 3.3 shows a derivation of the TNUoS charges that the five groups of generators would face under "improved ICRP". In this example, we make a series of simplifying assumptions. We assume that the G:D split is 100:0, that the security factor is 1.0, and we assume an expansion constant (i.e. the incremental cost of adding transmission capacity) of £10/MWkm. We also use node (3) as a "reference node", where we add a MW of demand when examining the impact of increasing generation by a MW at nodes (1) and (2) in order to maintain a balanced system.

Adding a MW of generation at node (1) and a MW of demand at node (3) increases flows across the line (1)-(3) by 400MWkm in both backgrounds. Because the costs of this line are allocated to the "year round" background, the "year round" charge is set at £4/kW, which for each generator is multiplied by their annual load factor. Hence, the wind generators pay £1/kW (= £4/kW x 25%) and the conventional generators pay £2.80/kW (= £4 x 70%). The "peak security" charge for generators at node (1) would be £0/kW, as only line (2)-(3) is allocated to the "peak security" background, and flows on this line do not change by adding a MW of generation to node (1) and a unit of demand to node (3).

Similarly, adding a MW of generation at node (2) and a MW of demand at node (3) increases flows across the line (2)-(3) by 100MWkm in both backgrounds, leaving flows on the line (1)-(3) unaffected. Because the costs of this line are allocated to the "peak security" background, the "peak security" charge is set at £1/kW, and the "year round" charge for generators at node (1) would be £0/kW.

Table 3.3
Derivation of "Improved ICRP" TNUoS Charges

Node	Technology	Load Factor	TEC (MW)	"Improved ICRP" TNUoS Charges (£/kW of TEC)		"Improved ICRP" TNUoS Charges with Load Factor Scaling (£/kW of TEC)		
				Peak	*Economic*	*Peak*	*Economic*	*Total*
(1)	Wind Farm	25%	10,000	0.00	4.00	0.00	1.00	1.00
(1)	Conventional	70%	10,000	0.00	4.00	0.00	2.80	2.80
(2)	Conventional	70%	40,000	1.00	0.00	1.00	0.00	1.00
(2)	Peaking	5%	10,000	1.00	0.00	1.00	0.00	1.00
(2)	Nuclear	85%	10,000	1.00	0.00	1.00	0.00	1.00

Source: NERA analysis and illustrative assumptions.

Table 3.4 compares these illustrative "improved ICRP" tariffs to the incremental cost imposed by each generator when they obtain an incremental MW of TEC, which arises from the TO's need to comply with the "peak security" and "economic" criteria in the SQSS, as shown in Table 3.2.

Table 3.4
Incremental Reinforcement Costs vs. "Improved ICRP" TNUoS Charges

Node	Technology	Incremental Cost (£/kW of TEC)	"Improved ICRP" TNUoS Charges (£/kW of TEC)	Difference (£/kW of TEC)
		Total	*Total*	*Total*
(1)	Wind Farm	2.24	1.00	-1.24
(1)	Conventional	2.85	2.80	-0.05
(2)	Conventional	0.12	1.00	0.88
(2)	Peaking	0.12	1.00	0.88
(2)	Nuclear	0.12	1.00	0.88

Source: NERA analysis and illustrative assumptions.

Table 3.4 shows that, as compared to the incremental cost of accommodating an additional MW of wind generation capacity at node (1) of £2.24/kW, wind generators at node (1) only face a TNUoS charge of £1/kW. This difference arises because the incremental cost of reinforcement on line (1)-(3) of £4/kW is multiplied by a 25% load factor to calculate the "year round" charge, and not by the 56% factor that actually drives the incremental reinforcement cost on the affected transmission line.

In fact, if we had assumed that the wind generator runs at 30% instead of 25% (see Table 3.3), it would have made no difference to the investment cost incurred to comply with the SQSS, but its TNUoS charge would have increased. This demonstrates that in this example, the "year round" charge faced by wind generators under "improved ICRP" tends to understate the costs they impose on TOs.

The CCGT/coal plants located at node (1) pay a TNUoS charge under "improved ICRP" that is close to the costs they impose on the TO in order to comply with the SQSS. This arises because its assumed load factor (70%) approximately reflects 71% factor that actually drives the incremental reinforcement cost on the affected line from (1) to (3), although as noted above, this similarity arises coincidentally, because the load factor does not cause TOs to incur investment costs. For example, if we had assumed a 50% load factor, the conventional generator would pay a charge below the costs it imposes on the TO, and if we had assumed a 90% load factor, it would pay more than the costs it imposes.

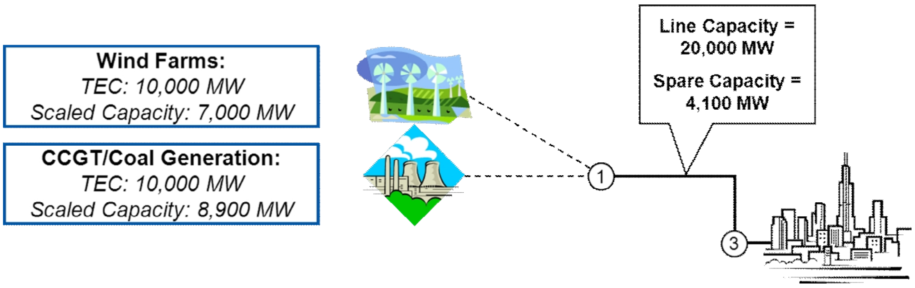
All technologies at node (2) pay a charge higher than the costs of accommodating an incremental MW of generation, because the “peak security” charge does not reflect the scaling back of generation that would take place in the “peak security criterion” background under the SQSS after an incremental MW of TEC connects to the system.

3.2.4. “Improved ICRP”, like the “status quo”, does not link tariffs to incremental reinforcement costs

Another reason that the “improved ICRP” model will not reflect the cost TOs incur to accommodate an incremental MW of generation capacity is that, like the current TNUoS methodology, charges are not directly linked to the incremental cost of reinforcement. Rather, both the “status quo” and “improved ICRP” models link TNUoS charges to the average cost (in £/MWkm) of capacity on those transmission lines that see an increase in flows following an increase in generation capacity at a particular node.

For example, suppose that capacity on line (1)-(3) in the schematic transmission system we introduced above is 20,000MW, as Figure 3.4 illustrates. In the “economic criterion” background, when flows on the line are the higher of the two investment planning backgrounds at 15,900MW, there is therefore spare capacity of 4,100MW (assuming a security standard of 1.0). In this case, the incremental cost of accommodating an incremental MW of either conventional or wind generation is zero, as there is already spare capacity on the line.

Figure 3.4:
Economic Criterion Background: Illustrative Load Flow



Source: NERA analysis and illustrative assumptions.

However, accommodating an extra MW of generation at node (1) and increasing demand at node (3) by a corresponding MW still increases flows on (1)-(3) by 400MWkm. As a result, generators under both the “status quo” and “improved ICRP” models would face a charge based on the average cost of providing capacity on the line (1)-(3) of £4/kW, even though the cost their presence imposes on the system is zero.

While we recognise that the above analysis uses a simplistic representation of the transmission system, and more work would be required to assess the cost reflectivity of the "improved ICRP" model using data on the actual transmission system, it enables us to draw some general conclusions regarding the "improved ICRP" model as it currently stands.

It shows that it is relatively easy to define plausible situations in which the "year-round" and "peak security" charges under "improved ICRP" can differ materially from the reinforcement costs imposed on the TO by the need to comply with the SQSS. The example shown above therefore undermines any suggestion that "improved ICRP" reflects the investment costs TOs now incur to adhere to the recent reforms to the SQSS implemented through GSR009.

A major cause of this problem is the use of load factor to scale the "year round" tariff. The cost of reinforcements required to comply with the "economic" and "peak security" criteria in the SQSS depends solely on decisions to connect generation capacity to the network. Annual load factors have no bearing on the costs TOs incur to comply with the SQSS.

3.3. Scaling by Load Factor to Proxy Investment Costs

We have also reviewed the statistical analysis National Grid presented to justify the use of a load factor adjustment, which it presents in annex 3 to the technical working group's initial report.

3.3.1. There is not necessarily a "logical" link between load factor and the constraint costs imposed by a generator

Firstly, the premise that a generator running at a high load factor imposes a "larger impact" on the transmission system is misleading. National Grid states that:[37]

> *"a generator with a high load factor, who generates at a higher level, or more often, than a lower load factor generator will have a larger impact on the transmission system. This is because, during periods of system constraint, it is more likely to be operating and potentially adding to the constraint. Whilst logically a relationship can be appreciated, it does not mean that the relationship is of a linear nature, nor indeed that it is a significant factor in constraint costs at all."*

The costs generators impose on the transmission system depends on the extent to which their running causes, worsens or resolves a constraint on the network. If running a generator does not create, worsen or resolve any constraint, its "impact" on the transmission system, as measured by the costs of constraints, is zero. This is true no matter how many hours the generator runs during the year. Hence, it is far from "logical" to presuppose that a relationship exists (linear or otherwise) between load factor and investment costs.

National Grid actually recognises this point itself, as demonstrated by the last sentence in the quote above: *"Whilst logically a relationship can be appreciated, it does not mean that the*

---

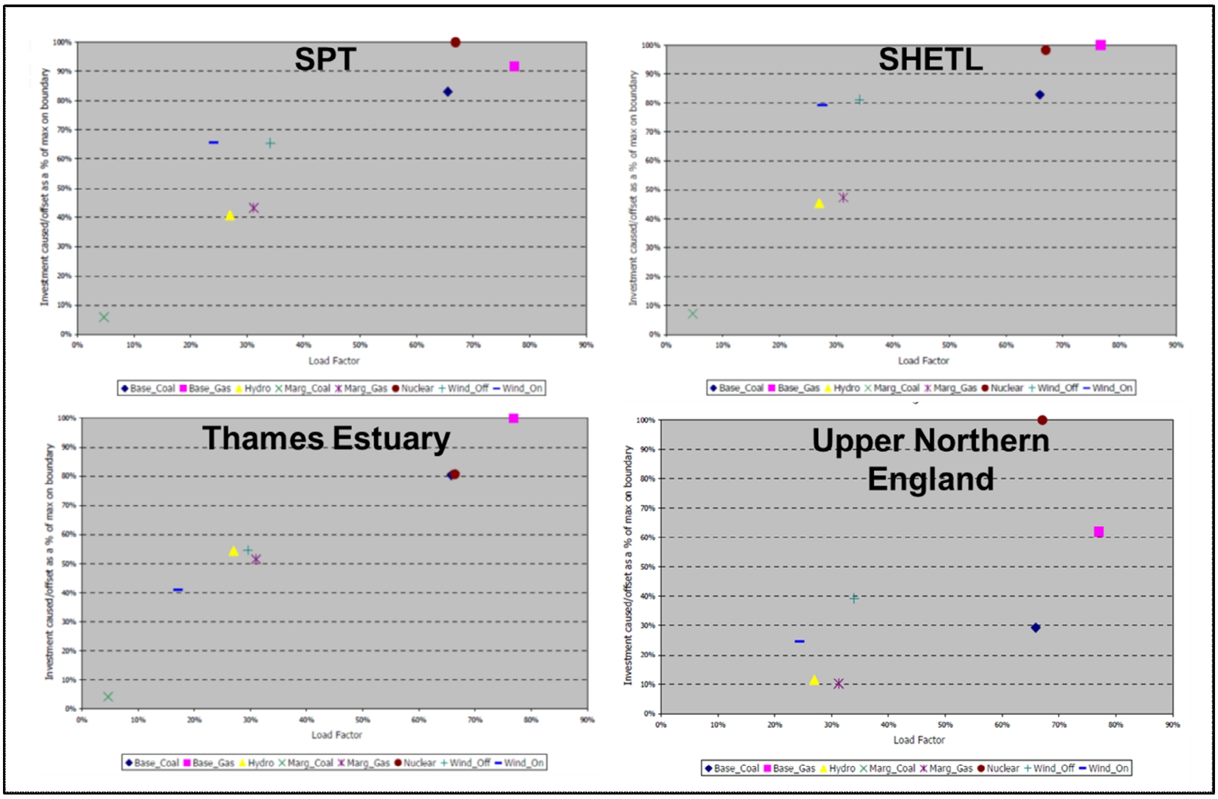
[37] Technical Working Group Report, page 71.

relationship is of a linear nature, nor indeed that it is a significant factor in constraint costs at all".[38]

3.3.2. National Grid's statistical analysis is not robust, so does not support the hypothesised link between cost and load factor

In the technical working group's initial report, National Grid presents a number of scatter plots that appear to show an upward sloping relationship between load factor and the cost that generators impose on the system. Figure 3.5 illustrates four of these zonal scatter plots. Each point on the scatter plot shows the estimated cost that a series of generation technologies impose on the system on a year-round basis, across eight zones on the network.

Figure 3.5
Illustration of NERA Statistical Test



Source: Technical Working Group Report, Annex 3.

It is not entirely clear from the report whether National Grid uses a measure of constraint or investment cost as the measure of cost for this analysis, as the annex containing this analysis uses the terms interchangeably. However, National Grid mostly refers to constraint costs in the text of its report, so below we assume that this is the measure it uses.

---

[38] Technical Working Group Report, page 71.

On the basis of this analysis, National Grid concludes that there is a strong correlation between load factor and constraint costs, and that this observed link is linear and independent of technology:[39]

> *"National Grid believes that generally there is a good correlation as to the relationship between generation load factor and constraint costs, and in the majority of cases this relationship is found to be broadly linear in nature. This suggests that the relationship is maintained, regardless of a generator's specific fuel type."*

We have conducted some tests on National Grid's data to assess the robustness of this conclusion. Specifically, we started by reading data points from the charts in A.3.2.1 of the technical working group report into an Excel spreadsheet. For each of the zones analysed, we then ran a "least squares" regression to estimate the parameters "a0", "a1" and "b" in the following equation. We defined the "wind dummy" term as equal to one for those data points corresponding to onshore or offshore wind, and zero for all other technologies to identify the specific effects attributable to the pattern of output typical of a wind farm.

$$\text{Investment Caused/Offset as a \% of Max on Boundary} = a0 + b \times \text{Load Factor (\%)} + a1 \times \text{Wind Dummy}$$

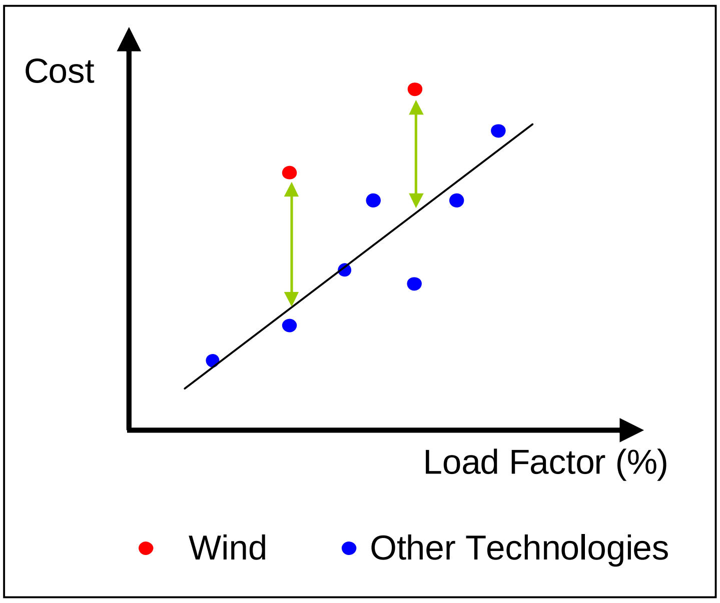
For each zone, we then tested the hypothesis that the constraint costs imposed by onshore and offshore wind plants are significantly different from the constraint costs imposed by other technologies, after accounting for the load factor of wind generation. In other words, we estimated whether the linear relationship hypothesised by National Grid is the same for wind generators as for all other generation technologies. To test this hypothesis, we ran a t-test to determine whether the "a1" coefficient is significantly different from zero. If the value of "a1" is significantly different from zero, the data implies that wind farms have a different impact on investment from other generators.

This procedure is illustrated in Figure 3.6 below. We essentially tested whether wind plants (the red dots) impose a different constraint cost on the system than other technologies (the blue dots), when running at the same load factor. We test this by estimating the probability that the parameter "a1" (the average length of the two green lines) is different from zero.

---

[39] Technical Working Group Report, page 72.

Figure 3.6
Illustration of NERA Statistical Test



Source: NERA

The results shown below in Table 3.5 report the estimated regression coefficients, and their associated t-statistics and p-values. The p-values represent the probability that we would be wrong to reject the "null hypothesis" that each coefficient is equal to zero.[40] For example, the coefficient on the wind dummy in zone 0 has a p-value of 0.001. This shows that, there is a 0.1% chance of us being wrong if we conclude that wind farms do not have the same impact on constraint costs from other generators. That is a very strict standard of proof (or rather, a very strict standard for rejecting a hypothesis). In practice, statisticians often use a standard of 1%, 5% or 10%, which is usually known as the "significance level".

Across five out of the eight zones, we find we can reject the null hypothesis that wind generators have the same impact on constraint costs as other technologies with the same load factor at the 5% significance level. In seven of the eight zones, the coefficient on the dummy variable is positive. This means that wind generators have a higher impact on constraint costs than their load factor alone suggests. These zones include NW SHETL, SHETL and SPT, where the majority of onshore wind is likely to connect to the system. Only in one case (southern England) do we find a negative coefficient on the dummy variable. Hence, only in southern England do we find that a wind plant's load factor understates its impact on transmission system costs.[41]

---

[40] In statistical terms, this is known as the probability of a "type one" error.

[41] We recognise that the choice between the 10%, 5% and 1% significance levels is somewhat subjective, as statistical theory does not provide a comprehensive guide as to the appropriate significance level to use. However, in this case, we consider that the 5% significance level is sufficient to provide a high-level indication that wind farms impose different costs on the system compared to the level of costs predicted by their load factor alone. As a cross-check, when we pool this data and run all zones together, we find a similar result, i.e. that wind plants impose a significantly higher impact on constraint costs than other technologies. However, as described in this paragraph, the relationship appears to differ by zone.

This analysis suggests that wind farms in Scotland and parts of Northern England impose higher costs on the system than a simple scaling by their load factor suggests, whereas wind farms in Sothern England impose lower costs on the system than a simple scaling by their load factor suggests. Hence, the “year round” tariffs they face under the “improved ICRP” model would tend to undercharge wind farms in the North, and overcharge wind farms in the South.

Assuming that wind farms respond to TNUoS charges, and that efficient location requires charges that differ by the difference in costs, then “improved ICRP” would tend to result in more wind capacity in Scotland and less in southern England than is economically efficient.

Table 3.5
Results of NERA Statistical Analysis

	Zone	**Zone 0**	**Zone 1**	**Zone 2**	**Zone 3**	**Zone 4**	**Zone 5**	**Zone 6**	**Zone 7**	**All Zones**
	Name	*NW SHETL*	*SHETL*	*SPT*	*Upper North England*	*North England*	*Midlands*	*Thames Estuary*	*Southern England*	
Constant (a)	*Coefficient*	0.063	0.051	0.039	0.139	0.133	0.134	0.115	0.503	0.147
	t-statistic	1.346	1.404	0.580	0.637	2.502	2.270	1.517	6.606	3.320
	p-value	0.236	0.219	0.587	0.552	0.054	0.072	0.190	0.001	0.002
Coefficient on Wind Dummy (a1)	*Coefficient*	0.357	0.228	0.245	0.000	0.153	0.068	0.113	-0.223	0.121
	t-statistic	7.375	6.047	3.530	0.000	2.723	1.047	1.364	-2.677	2.558
	p-value	0.001	0.002	0.017	1.000	0.042	0.343	0.231	0.044	0.013
Coefficient on Load Factor (b)	*Coefficient*	1.278	1.199	1.286	0.636	1.169	1.143	1.148	0.579	1.055
	t-statistic	14.070	17.090	9.873	1.533	11.360	10.040	7.755	3.960	12.350
	p-value	0.000	0.000	0.000	0.186	0.000	0.000	0.001	0.011	0.000
Observations		8	8	8	8	8	8	8	8	64
R-Squared		0.977	0.983	0.951	0.337	0.963	0.957	0.927	0.881	0.717

Source: NERA Analysis

Finally, the scaling of generators’ “year round” TNUoS charges in proportion to load factor implicitly assumes a one-for-one relationship between investment cost and load factor. In other words, compared to the general linear model outlined above, National Grid assumes that a0 and a1 are equal to zero, and that the slope of the regression line (“b”) is equal to one.

General Relationship:

Investment Caused/Offset as a % of Max on Boundary =
a0 + b x Load Factor (%) + a1 x Wind Dummy

National Grid’s Assumed Proportional Relationship:

Investment Caused/Offset as a % of Max on Boundary =
0 + 1 x Load Factor (%)

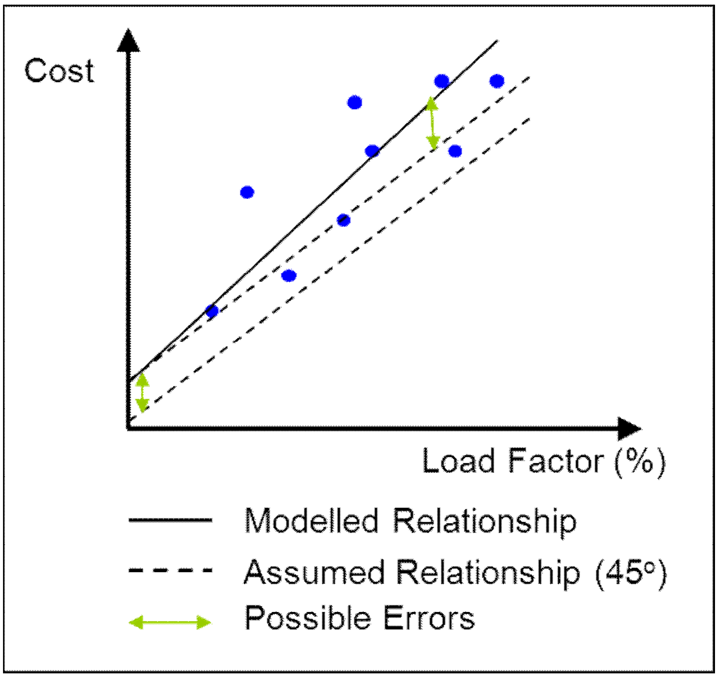
As the chart below illustrates, if National Grid assumes the linear relationship goes through the origin by assuming a one-for-one relationship between TNUoS and load factor, and these assumptions do not hold in reality, its approach may over or understate the costs users impose on the system (by the errors shown as the green arrows in Figure 3.7).

To test whether this is the case in practice, the data in Table 3.5 also shows the coefficients and p-values on the constant term (the parameter “a”). The p-values shows that, at a 5%

significance level, the constant term is significantly different from zero in three of the nine regressions (North England, Southern England and in the "pooled" regression covering all zones). In all cases the intercept is positive. This evidence suggests that that ignoring the intercept in this supposed linear relationship may be biasing downwards the tariffs calculated under the "improved ICRP" method. In other words, the "improved ICRP" model systematically underestimates the costs users imposes on the system.

The data also shows that the slope coefficients are greater than one in most zones. This also suggests that assuming a one-for-one relationship between investment cost and load factor might understate the costs all generators impose on the system. For each zone, we therefore tested the null hypothesis that the "b" coefficients are equal to one, and for three of the eight zones (NW SHETL, SHETL and Southern England), we were able to conclude at the 5% significance level that "b" was different from one. This provides further evidence that the one-for-one relationship assumed by National Grid is not appropriate.

Figure 3.7
Illustration of NERA Statistical Test



Source: NERA

3.3.3. Implications for the use of load factor to scale TNUoS charges

The analysis above is simplistic, and uses only the data that National Grid has published through the technical working group report. Each regression therefore uses a small sample, and the data underlying it examines only one generation background, in one year, and using one set of cost assumptions. It would therefore be prudent to conduct (and publish) further analysis to investigate the link between load factor and cost before drawing conclusions about the link between load factor and the costs generators impose on the system.

However, based on the available data, the analysis shown above indicates that wind generators impose a higher cost on the transmission system than other technologies after adjusting for load factor. It also shows that, even if a linear relationship between constraint costs and load factor did exist, then it is not a one-for-one relationship, as assumed in the "improved ICRP" model.

Overall however, a proportional adjustment to tariffs to reflect a plant's load factor appears to provide a poor reflection of the costs generators impose on the transmission system. Our analysis also undermines National Grid's assertion that the linear relationship between load factor and cost does not depend on technology. This evidence also contradicts Ofgem's belief that:[42]

> *"improved ICRP better reflects the costs variable generators impose on the need for transmission investment and more accurately reflects the economic trade-off each Transmission Owner makes between expected constraint costs and the cost of new transmission reinforcements when planning investment activity."*

In addition, National Grid's analysis seems to focus on the relationship between load factor and constraint costs, without recognising that TOs invest to minimise the joint costs of investment and constraint costs. Given TNUoS are designed to recover investment costs, the relationship National Grid should study is the one between load factor and optimised investment costs, which is what was done for the SQSS. There is therefore no justification for looking at the narrow trade-off between load factor and constraint costs in a second step, as the basis for the "improved ICRP" model.

3.4. Conclusions

In this chapter, we describe the origin of the "improved ICRP" charging methodology in modification GSR009 to the SQSS, and the procedures for calculating TNUoS charges under this model. We also assess the extent to which these TNUoS charges reflect the costs generators impose on the system, as derived from the SQSS.

On the assumption that TOs provide network infrastructure to comply with the SQSS planning criteria introduced under GSR009, we find using some simple illustrative transmission systems that the "improved ICRP" TNUoS charges imposed on generators can differ materially from the incremental investment costs imposed on the TO by their presence. In particular, the charges levied on wind generators appear systematically lower than the costs they impose on the TO.

Ofgem and National Grid have both suggested that "improved ICRP" tariffs reflect the least-cost trade-off TOs make between constraints and reinforcement when planning their network. The main evidence cited for this conclusion is a positive correlation between the costs generators impose on the system and load factor, which is used to scale "improved ICRP" tariffs. Contrary to National Grid's assumed relationship, we find evidence that the relationship between cost and load factor does not apply equally to all technologies. We also find that the relationship between load factor and cost is not "one-for-one" as the "improved ICRP" model assumes, i.e. a 1% increase in load factor does not necessarily increase costs by

---

[42] Ofgem, page 5.

1%. In addition, it is not clear that the load factor analysis conducted by National Grid uses the right metric of costs, which undermines its usefulness.

We therefore conclude that the "improved ICRP" model does not reflect the economic trade-off TOs make between constraint and reinforcement costs, i.e. it fails to reflect the costs imposed on the TOs by the SQSS planning criteria. A key reason for this finding is the use of load factor to scale tariffs under the "improved ICRP" model. The cost a generator imposes on the TOs is determined solely by the capacity of the connecting generator, its location, its technology and the associated SQSS scaling factors. The amount of energy it generates is irrelevant in estimating the boundary capacity that TOs are required to provide, and the statistical evidence presented by National Grid provides no evidence to the contrary.

4. Other Considerations

In this chapter, we consider other implications of Ofgem's proposal to reject socialised TNUoS, and its suggestion that the "improved ICRP" model is the right direction for British TNUoS charges.

4.1. Potential for Undue Discrimination

4.1.1. Ofgem is wrong to suggest "improved ICRP" reduces the potential for discrimination

Ofgem notes in its consultation document that "various elements of the proposals under consideration might be argued to result in discrimination, whether through treating like cases differently or treating different cases alike, in either case without objective justification". [43] Ofgem goes on to argue that:[44]

> *"to the extent that proposals promote or further cost reflectivity, they can be said to reduce the risk of an element of possibly discriminatory treatment in the current system by increasing the extent to which a relevant difference between customers – the costs that they impose on the network – results in differential treatment as between those customers. It could be argued, for instance, that the current charging methodology results in discrimination to the extent that it fails to reflect, by not taking into account load factors , the lower costs imposed by intermittent generation"*

For the reasons set out in Chapter 3, the evidence presented by National Grid to support a link between load factor and cost is not robust. Hence, the view that the "improved ICRP" model is less discriminatory than the "status quo" because it reflects the lower costs imposed by intermittent generation is unfounded.

If undue discrimination includes "treating different cases alike", it may follow that it is discriminatory to charge generators that impose different costs on the system the same TNUoS charge. However, to conclude that "improved ICRP" reduces the potential for undue discrimination, Ofgem would need to demonstrate that it results in tariffs to users that are more cost-reflective than the "status quo". So far, it has not done so.

Given the increasing role of intermittent generation on the system, it may be possible to devise a more cost-reflective, and hence less discriminatory, charging mechanism than the "status quo" that charges generators for the costs they impose in off-peak conditions. However, as described in Chapter 3, the "improved ICRP" model as it stands does not achieve this aim.

---

[43] Ofgem, Appendix 3, para 1.17

[44] Ofgem, Appendix 3, para 1.18

4.1.2. The "socialised" model may be the most discriminatory model, as it does not reflect cost at all

To the extent that it is discriminatory to charge different users the same tariff to access the network, even though they impose different costs on the system, there may be a case to argue that the "socialised" model is the most discriminatory of all the three charging models considered, as it makes no differentiation whatsoever between the costs users impose on the system in the charges they face.

4.1.3. The "improved" ICRP model charges different tariffs to users who obtain the same transmission access rights

Both the "socialised" and "improved ICRP" models impose different tariffs on users per unit of connected capacity. Under BETTA, all users have a firm option to export power to the grid up to the value of their TEC at any time when they choose to generate, for whatever reason, or be compensated for the opportunity cost of doing so if they are constrained off.[45] Hence, both these models might be seen as discriminatory as in some conditions they impose different charges to generators in the same location with the same TEC, who ultimately receive the same product from the transmission company.

4.2. Impact on Regulatory Risk

Changes to the transmission charging arrangements may have substantial distributional effects. Large redistributions of profits (i.e. producer surplus) amongst industry participants will affect the extent of regulatory risk perceived by all current and potential future participants in the generation market. Perceptions of regulatory risk will influence the rate of return that investors will require when developing new electricity industry assets, where future Ofgem decisions have the potential to influence value. The resulting increase in the costs of developing new generation assets will tend to increase power sector costs, and the costs faced by consumers.[46]

Ofgem has not published any analysis of the distributional effects of its proposals amongst participants in the supply and generation markets. If the distributional effects of introducing "improved ICRP" are material, then whatever benefit Ofgem attributes to the introduction of "improved ICRP", if any (see Chapter 2.3), may not be justified by the cost of increased regulatory risk.

---

[45] This statement applies to the vast majority of generators on the GB system who have a firm TEC specified in their bilateral agreement. However, we are aware that there some "Transmission Related Agreements" that restrict output of power stations under certain outage conditions, e.g. where connections are not SQSS-compliant under these outage conditions. However, the quantity and terms of these agreements are not transparent, since in essence they are bilateral agreements between individual generators and National Grid.

[46] The cost of increasing regulatory risk may be material. For example, suppose the UK energy industry requires £200bn of investment over the period to 2020, as Ofgem has previously suggested. Suppose the £200bn of investment is spread evenly over each year, and that by changing the TNUoS regime Ofgem adds as little as 0.01% (1 basis point) to the real WACC. In this case, the increase in power sector costs to 2020 would be around £200 million in NPV terms, using a 3.5% real discount rate. If the WACC increased by 0.1% (10 basis points), the impact would be around £2 billion.

This situation is analogous to the recent decision on BSC Modification P229, in which Ofgem cited a low NPV benefit, combined with a large distributional effect as a reason not to approve the modification:[47]

> *"We note, however, to the detriment of the achievement of objective (c), that the redistributional impacts of both P229 proposals are relatively high and certain and the NPV is relatively low and subject to a degree of uncertainty, at least in the shorter term."*

Moreover, by implementing changes to the current transmission charging regime, Ofgem may increase investors' perception that the new regime will have a limited lifespan. And given the approximations within this tariff model, it may need to change again when problems arise. Generators cannot predict these changes and they cannot protect themselves against the effects of such changes, except by maintaining a diversified portfolio of generation. Another effect of regulatory risk is therefore to undermine the incentives provided by the transmission charging regime.

4.3. Conclusion

As described above, the "improved ICRP" might materially increase the potential for discrimination between network users, as it introduces charges that differentiate between network users, all of whom receive the same access rights. Moreover, the argument that the "improved ICRP" discriminates less than the "status quo" because it better reflects the costs users impose on the system may not be valid, because as we demonstrated in the previous chapter, the "improved ICRP" model may materially under- or overstate the costs that users impose on the transmission system.

Finally, changes to the TNUoS regime can have material distributional effects that affect investors' perception that similar changes will occur in future, and hence increase the perceived riskiness of future investments, and so raise the required rate of return for future investments.

---

[47] Decision on "Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)", Ofgem, 28 September 2011, page 5.

5. Conclusions

From the arguments and evidence emerging from the Project TransmiT process, including the Redpoint modelling report, there appears to be strong evidence that the “socialised” TNUoS model would materially increase costs to consumers, while bringing no material benefit in terms of improved performance against the government’s environmental targets.

However, we see no justification for Ofgem’s conclusion that the “improved ICRP” model, as currently proposed, is the “right direction of travel” for transmission charging. It provides no discernible benefit by improving social welfare. It also has no impact on performance against environmental targets. The fact that it does not improve the efficiency of market outcomes suggests it is no more reflective of the costs users impose on the transmission system than the “status quo”. Indeed, we have conducted analysis to show that generation charges under “improved ICRP” do not reflect the investment costs TOs incur to comply with the SQSS, which following the adoption of GSR009, are designed to reflect the economic trade-off TOs make between reinforcement and constraints.

Specifically, the “improved ICRP” model appears to significantly discount the TNUoS charges faced by intermittent generators compared to the costs they impose on the system. This will lead wind generators to locate in more remote locations than would be economically efficient, based on a trade-off between wind speeds and transmission costs. As a result, costs to the consumer will rise, and social welfare will fall (i.e. power sector costs will rise), because reinforcement and constraint costs will increase.

If it were necessary to increase subsidy levels to wind farms in order to meet government targets, it would be more efficient for the government to offer increased subsidies to developers through the RO, CFD FITs, and if necessary, offer different levels of support to generators in different parts of the country. Such policies are likely to lead to fewer distortionary effects that would ultimately be detrimental to social welfare, than providing implicit subsidies through the transmission charging regime.

The comparison of the “socialised” and “status quo” charging models illustrates the potential benefits that locational transmission charging can deliver by improving the efficiency of investment decisions. At the same time, we recognise that it may be possible to devise a more cost-reflective charging model than the “status quo”, which may improve the efficiency of network use by targeting the costs of constraints and investment more precisely on the parties that are driving those costs. However, the analysis presented to date suggests that the “improved ICRP” model as it stands would not achieve this aim, because the resulting tariffs provide a poor proxy for the costs users impose on the system.

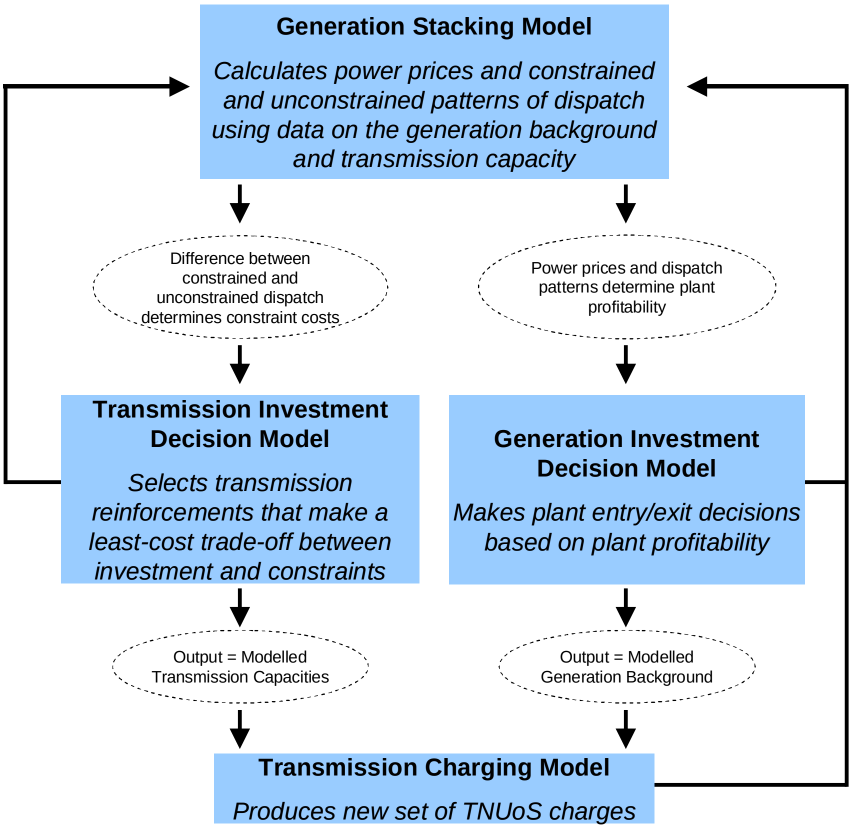
Appendix A. Review of Redpoint's Modelling Framework

A.1. Overview of Redpoint's Approach

From Figure 3 in Redpoint's report, its modelling framework appears to centre around an iterative mechanism, which we have represented below in Figure A.1. This framework combines a market dispatch model, transmission and generation investment decision models, and a model to recalculate TNUoS charges, taking modelled transmission and generation investment decisions as given.

As described below, we have identified fundamental problems with this framework relating to the modelling of the constrained and unconstrained dispatch, and the procedures used to generate the power prices that inform generation investment decisions.

Figure A.1
NERA Overview of Redpoint's Modelling Framework



A.2. Modelling Investment Decisions

Redpoint uses this modelling framework to perform two runs for each of the three charging models. It characterises the two approaches as assuming "imperferct foresight" and "perfect foresight" respectively. As described further below, the CBA in Ofgem's consultation only uses the results from the "imperfect foresight" runs.

A.2.1. Redpoint's "imperfect foresight" modelling does not constitute a coherent economic framework

As described below, Redpoint's "imperfect foresight" approach does not reflect how rational investors make decisions in power generation assets, and its characterisation of its two modelling approaches as assuming "perfect foresight" and "imperfect foresight" is misleading.

Firstly, when considering whether to invest in an asset, such as a power generator with an economic life of several decades, it would not be rational for investors to ignore known or expected changes in market conditions that occur after the arbitrarily defined planning horizon of five years, which Redpoint assumes in its "imperfect foresight" scenario. Hence, Redpoint's framework does not reflect the way rational investors would take decisions.

By assuming short planning horizons, an implicit assumption is that conditions today (commodity prices, low carbon subsidy levels, TNUoS charges etc) are the most reliable reflection of conditions that will prevail over the life of an asset. In many cases, evidence that is already available to investors today, suggests that current conditions may not be a reliable guide to conditions prevailing in the future. For example:

- Commodity prices are often said to follow mean reverting processes.[48] Hence, it is likely that prices today are either above or below a long-term mean, to which investors will expect them to converge over time. As well as commodity prices prevailing today, investors will therefore consider the expected evolution in commodity prices over the long-term when committing capital to investments in particular generation technologies;
- Redpoint's modelling shows that TNUoS charges are expected to change materially over time. For example, Redpoint's scenarios with "locational" TNUoS charges show that TNUoS charges north of the Cheviot boundary increase substantially following the development of the HVDC bootstraps. Investors in generation located in affected zones would anticipate this change in TNUoS charges (by reading Redpoint's report, if for no other reason) and account for the resulting increase in their costs when making investment decisions. However, Redpoint assumes that investors make investment decisions based only on the tariff applying during the five years after the generation capacity starts producing output, despite Redpoint forecasting further changes; and
- The patterns of power prices prevailing over the first five years of the modelling horizon are likely to be materially different from those resulting from a generation mix that includes 20-30GW of intermittent renewable generation, as a result of government policies that have already been announced.[49] Hence, for example, Redpoint's approach may lead investors in thermal plants to overestimate the energy they will produce, and underestimate the volatility in power prices that they will face, over the expected lifetime of their assets.

---

[48] See, for example, Dixit, A.K., and Pindyck, R.S., Investment Under Uncertainty, Princeton University Press, 1994, page 74.

[49] Redpoint, figure 31.

Orthodox investment theory says that a firm will invest in an asset whenever the NPV of expected future revenues exceeds the NPV of expected future costs. However, more recent and sophisticated models of investor decision making allow theoretical predictions of investor behaviour in an industry of many firms, each facing similar irreversible investment decisions, but in the face of uncertainty over future industry demand and their own costs. The impact of both these sources of uncertainty is to make investors apply a premium to the hurdle rate they apply to investment appraisal:[50]

- All firms know that an unexpected increase in demand will increase prices, but any positive effect on profits will be dampened by the symmetric response of firms to invest and thus compete away the increase in profitability. Conversely, a reduction in industry demand will reduce profits to all firms. The effect of uncertainty about the future is therefore asymmetric, and this asymmetry incentivises investors to apply a premium to the hurdle rates they apply when taking investment decisions; and
- Uncertainty regarding an individual firm's costs relative to others in the market creates a "value from waiting" associated with the potential for information revelation over time. To compensate for foregoing this value of waiting, firms also apply a hurdle rate when considering whether to invest.[51]

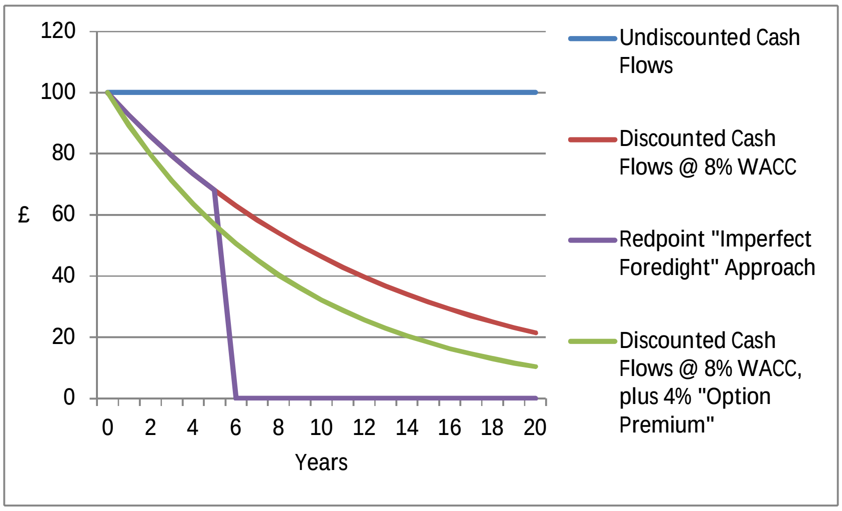
The application of a higher hurdle rate means investors will effectively discount cash flows more heavily than they would by simply applying a WACC estimated using a Capital Asset Pricing Model (CAPM) framework. This is illustrated by the difference between the red and the green lines below in Figure A.2. However, by ignoring all cash flows that arise after five years (or one year, in the case of generation retirements), Redpoint is discounting cash flows at a standard WACC for five years, then effectively discounting all cash flows that occur after this time at 100%, as shown by the purple line in Figure A.2. This approach is neither consistent with a standard NPV investment decision rule, nor the alternative "real options" approach of modelling uncertainty described briefly above.

---

[50] See, for example, Dixit, A.K., and Pindyck, R.S., Investment Under Uncertainty, Princeton University Press, 1994, pages 17-19.

[51] In normal conditions, WACCs derived from market data using methods such as the CAPM provide the best estimates of the hurdle rates applied by investors for decision-making. However, as has been discussed in the literature on "real options", there are conditions in which investors may require a higher hurdle rate incorporating a premium over the WACC before they will invest. For this to be the case, investors must be considering an investment that is irreversible, and that they expect some of the investment risks to fall over time, for example because uncertainties regarding future government policy or the cost/performance of new technologies are removed. This expectation of information revelation regarding the future value of investments creates an incentive for investors to delay investments and wait for information about future uncertainties to emerge, thus creating a "value to waiting" or "option premium" that increases the hurdle rate required by investors today. Of course, once the uncertainties are removed, there would be no "option premium" and the hurdle rate will fall to reflect the WACC.

Figure A.2
Illustration of Alternative Discount Rates



Source: NERA

Investors cannot have perfect knowledge of the future. However, assuming a short planning horizon as Redpoint did is not an objective method for reflecting uncertainty about future outcomes. Where the future is uncertain, investors will still take decisions that reflect how they *expect* the future to evolve over the whole life of an investment, but they may apply premiums to the hurdle rates they expect to obtain before investing in conditions of uncertainty, as described above. Attempting to factor in option premiums, e.g. through sensitivities, would provide a more robust economic framework.

Therefore, because its framework does not reflect how rational investors would take decisions in the face of uncertainty about the future, Redpoint's results do not constitute a reliable basis for Ofgem's decision making in the context of Project TransmiT. Moreover, by only allowing generators to consider changes in TNUoS charges over the following five years when taking investment decisions, its approach may distort the impacts of any cost signals conveyed through the charging models.

A.2.2. Ofgem's characterisation of the "imperfect foresight" approach appears incorrect

Ofgem's characterisation of the "imperfect foresight" approach is also misleading. It states that the "imperfect foresight" approach "simulates expected player behaviour under uncertain conditions and models how players react to various policy options assuming imperfect information about how other parties will react and a limited view of how future prices will develop".[52]

As described above, Redpoint's approach does not coherently "simulate expected player behaviour under uncertain conditions", or how agents take investment decisions with "a limited view of how future prices will develop".

---

[52] Ofgem, para. 3.9.

Moreover, as we understand it, Redpoint's approach does not make any explicit assumptions in either the "perfect foresight" or "imperfect foresight" runs about the information each investor has about the decisions taken by other investors. "Imperfect information" can have a range of definitions in game theoretic models applied in microeconomics. However, typically this concept is not used to refer to a situation where one party cannot observe the actions taken by another party (in this case, investors in power stations). It usually refers to underlying uncertainty about the conditions prevailing in a market (e.g. future demand), or the specific conditions (e.g. costs) facing other agents.

In fact, our interpretation of Redpoint's model is that investors cannot explicitly observe the decisions that each other are taking in either the "perfect foresight" or "imperfect foresight" runs. Instead, because the model iterates, it allows individual investors to react to the decisions taken by other parties at earlier iterations, because those decisions affect prices in a way that all parties can observe, albeit only five years ahead in the "imperfect foresight" case. Hence, even if the model does not explicitly link one investor's decision to those taken by other "agents", the knock-on effects of each investment decision will show up in the prices seen by other investors during the iterative process.

A.2.3. Redpoint's "perfect foresight" modelling provides a more coherent conceptual framework, but it did not converge

Redpoint's "perfect foresight" modelling framework, combined with assumptions regarding the option premiums required to invest in conditions of uncertainty, should therefore constitute a materially more reliable basis for decision making. Rather than assuming perfect foresight, this approach assumes that market participants make the best use of information available when making investment decisions, i.e. they do not engage in systematically irrational behaviour.

Redpoint's "perfect foresight" modelling framework did not produce stable results for all scenarios and therefore was not available for use in Ofgem's assessment of the three charging methodologies. This suggests the modelling tools Redpoint applied are inadequate for comparing the costs of benefits of the alternative charging models. It does not justify the use of the "imperfect foresight" results, which as described above, are based on an incoherent set of assumptions regarding agents' appraisal of investments.

A.2.4. Ofgem's characterisation of the "perfect foresight" approach is also misleading

Also, as with the "imperfect foresight" approach, Ofgem's description of the "perfect foresight" approach also appears misleading. Ofgem describes it as a:

> *"least cost optimisation"* that *"simulates full (or perfect) information about future outcomes, economically rational behaviour and ability to react instantly to signals on transmission charges and generator locations. Under this approach generation and transmission investors react to each other's*

> *investment plans every year until the globally optimal combination of investments is determined".*[53]

Like the "imperfect foresight" approach, Redpoint's "perfect foresight" approach does not apply a cost minimisation algorithm. Rather, it uses the same "agent simulation" framework as the "imperfect foresight" approach, but assuming that investors account for expected changes in conditions over the whole modelling horizon when taking investment decisions. It is not necessarily true that this will result in a least-cost outcome.

Ofgem is correct to note that this approach does appear to assume more "economically rational behaviour" than the "imperfect foresight" approach because it does not assume investors use an arbitrary planning horizon when considering investments. However, suggesting that investors have the "ability to react instantly to signals on transmission charges and generator locations" appears misleading. Our understanding of the modelling approach is that investors' *anticipate* future changes in transmission charges, and plan to invest optimally in response to those expected changes. They do not need to react instantly if they anticipate changes in advance, and plan their investments accordingly.

A.2.5. The "perfect foresight" runs do not support Ofgem's conclusions on the welfare implications of the alternative charging models

Ofgem suggests that the "perfect foresight" results, where the model did converge, are similar to the results from the "imperfect foresight" modelling:

> *"This approach was discussed at WG 7 where it was explained that the Perfect Foresight analysis showed that where convergence occurred the results were similar to the Imperfect Foresight results."*[54]

However, the analysis presented in Appendix D of the Redpoint report shows that this is not in fact the case, and therefore that Ofgem has made an incorrect interpretation of the modelling results.

In particular, the only evidence on costs from the "perfect foresight" runs relates to constraint costs. It shows that constraint costs are somewhat higher in the "perfect foresight" runs of both the "improved ICRP" and "socialised" scenarios than in the corresponding "imperfect foresight" runs, but that constraint costs in the "status quo" *diverge* over iterations one to five.[55] Hence, the "perfect foresight" modelling does not provide evidence to support Ofgem's conclusions regarding the relative costs and welfare implications of the alternative charging models.

The results in Redpoint's Appendix D do show that across the "perfect foresight" runs of the three charging methodologies, the share of renewable generation approximately meets the

---

[53] Ofgem, para. 3.9.

[54] Ofgem, footnote 23.

[55] Redpoint, figures 48, 50 and 53.

level required to meet the government's target of 30% by 2020. This evidence would support a conclusion that none of the three charging models constitute a barrier to meeting the 2020 renewables targets.[56]

A.3. Modelling the Power Market

A.3.1. The Electricity Scenario Illustrator (ELSI) model is not a reliable tool for forecasting the evolution of the GB power market

Redpoint uses National Grid's ELSI model to determine constrained and unconstrained patterns of dispatch for installed generation on the GB transmission system. This model has a number of limitations that may undermine its reliability as a guide to the expected impact of changes to the TNUoS regime, and limit its reliability as a tool for cost-benefit analysis.[57]

Firstly, the ELSI model does not account for the impact of generator dynamic constraints, such as ramp rates and minimum stable load, on prices and dispatch. This means that the model does not reflect the capability of generators to provide flexibility to the power system to compensate for sudden changes in the supply-demand balance, which is an especially important driver of market outcomes where there is an increasing share of intermittent generation capacity on the system. This has several implications for Repoint's modelling:

- It is likely to understate the value of flexible generation technologies, such as gas-fired OCGTs, and overstate the value of less flexible generation technologies; and
- Because prices do not reflect the impact of generators' dynamic constraints, it is likely that Redpoint's model materially understates the likely volatility of power prices in a wind-dominated system, which will affect the value of all transmission and generation investments considered by the model.

Moreover, the model includes a range of other simplifications such as the lack of "time step linkage" and consideration of energy constraints in its treatment of pumped storage. This means that the model will tend to overestimate the flexibility of pumped storage. ELSI also uses a "fixed price" treatment of interconnected markets.[58] This means that the operation of interconnectors is likely to be unrealistic on an hour-by-hour basis. Both these simplifications will cause the model to misrepresent the characteristics of potential sources of flexibility to the power system, which makes the ELSI model unsuitable for use in modelling a system dominated by intermittent generation.

Redpoint mentions PLEXOS as an alternative to the ELSI model, and we know from previous experience that PLEXOS does not suffer from many of the shortcomings of ELSI. In particular, unlike ELSI, it conducts a full chronological dispatch, accounting for dynamic constraints and unit commitment costs, thus accounting more robustly for the impact of intermittency on the power system. Redpoint states that PLEXOS "models the market at a

---

[56] Redpoint, figures 47, 49 and 52.

[57] See also: Electricity Scenario Illustrator, National Grid, 23 March 2011, slides 13-14: http://www.nationalgrid.com/NR/rdonlyres/CBB795B4-EFB6-48C0-95E7-51136C48F66D/46096/ElectricityScenarioIllustrator.pdf

[58] Ibid.

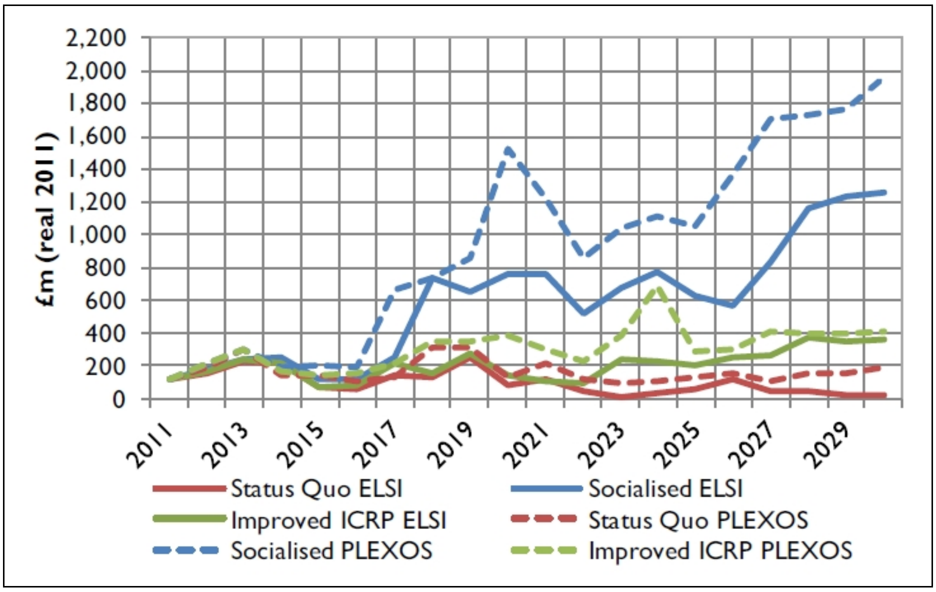
greater level of detail than ELSI", but "the run time made it unsuitable for incorporation within the TransmiT Decision Model".[59] It is not clear that this decision is justified given the shortcomings of ELSI.

A.3.2. Redpoint's calibration exercise indicates significant differences between ELSI and the more detailed PLEXOS model

Redpoint notes that it benchmarked the constraint costs resulting from its modelling using ELSI to the constraint costs emerging from PLEXOS using the same input assumptions on generation and transmission capacities. This analysis shows that, across all three charging scenarios, PLEXOS produces higher constraint costs than ELSI in most years of the modelling horizon. Redpoint describes this result, illustrated in the figure below, as follows:[60]

> *"Figure 39 shows a comparison of the ELSI and PLEXOS constraint costs. The results show that there is a very good match between constraint cost estimates in the near term. Over the longer term the levels of constraint costs diverge somewhat but there is consistency in relativity and direction."*

Figure A.3
Redpoint's Comparison of PLEXOS and ELSI Constraint Costs



Source: Redpoint, Figure 39.

This evidence does not support the conclusion that ELSI provides a reasonable approximation to the functioning of the GB power market:

- The fact that the absolute level of constraint costs is higher across all scenarios suggests the value of transmission reinforcements may be higher, which indicates a different

---

[59] Redpoint, page 78

[60] Ibid.

pattern of reinforcement investment may have been selected if Redpoint had modelled the market using a more realistic framework. This difference may materially affect TNUoS costs, and hence generation investment decisions. As a result the comparison of costs and benefits associated with the three charging models may also be affected; and

§ The significant difference between the absolute levels of constraint costs arising from the ELSI and PLEXOS models suggests that the power prices and dispatch patterns resulting from the two models might be substantially different. This indicates that the generator entry/exit decisions these results influence may also be unreliable.

A.3.3. Redpoint's "uplift" function is not transparent, as well as potentially arbitrary and unreliable

Redpoint's modelling includes "a calibrated 'uplift' function, which adds a margin to the system short run marginal cost depending on the tightness (capacity margin) in each period". "The uplift function within the model was calibrated using 2009/2010 data".[61] However, Redpoint's report does not explain either the theoretical rationale for this uplift function, or the detailed methodology used to calculate it. The only further description of the role of the uplift we see in Redpoint's report is as follows:[62]

> *"Changes in power sector costs and changes in consumer bills may diverge in some years, particularly through variations in wholesale costs. Wholesale prices are set by the marginal costs of generation plus and* [sic] *additional 'uplift' element which is related to capacity tightness. Capacity payments may also be higher in years of capacity tightness. These two factors result in consumers paying more in years of capacity tightness, and less in years with higher capacity margins."*

The assumed link between the capacity margin and the uplift to power prices suggests that the role of this uplift function might be to reflect the effect of scarcity on energy prices, and thus allow thermal generators to recover their capital costs. However, the use of an uplift function would not be a robust method for ensuring capital cost recovery.

In a competitive energy-only market, the power price should be set in every hour by the system marginal cost of generation, determined by either the marginal cost of dispatching the most expensive plant required to meet demand, or the marginal cost of load shedding in periods of scarcity. In an efficient market, a combination of inframarginal rents earned by generators, plus the revenue earned from price spikes to the value of lost load (VOLL) in periods of scarcity, provides sufficient revenue to generators to allow the efficient (i.e. least cost) portfolio of generation to recover its costs. Hence an uplift function should not be necessary in long-run equilibrium.

In markets with capacity mechanisms, generators receive side-payments that are intended to substitute for spikes in energy prices. Hence, less scarcity will appear in energy pricing, and reflecting this, Redpoint's modelling work undertaken in the EMR process assumes no uplift

---

[61] Redpoint, page 82 and footnote 50.

[62] Redpoint, page 85.

is required with a "market wide" capacity mechanism, similar to the one Redpoint assumed for its TransmiT modelling.[63] It is therefore unclear what role the "uplift" function plays in Redpoint's modelling of the GB power market with an assumed capacity payment.

Finally, the calibration of Redpoint's uplift function to 2009/10 data may lead to misleading results. The year 2009/10 was characterised by particularly low demand, resulting in low clean spark spreads, suggesting energy prices provided limited remuneration of capital costs. Hence, any uplift calibrated to 2009/10 data is unlikely to provide a guide to how generators' fixed costs are remunerated in a power market in a long-run equilibrium. Secondly, over Redpoint's modelling horizon to 2030, the generation mix is likely to change materially due to the increasing penetration of intermittent generation. Hence, assuming that the structure of any uplift from 2009/10 remains constant to 2030 is unlikely to be a robust assumption.

This uplift function affects power price formation in Redpoint's modelling. Hence, if the conceptual basis for applying it is unsound, or its calibration is not reliable, then Redpoint's modelling of generation investment decisions, as well as transmission reinforcements and constraint costs, may be unreliable.

A.4. Adjustments to Subsidy Levels in "Stage 2" Modelling

As well as assuming irrational behaviour on the part of investors in both generation and transmission infrastructure, in its "stage 2" modelling, Redpoint has also assumed an irrational method by which government adjusts subsidy levels. Redpoint's report indicates that in its "stage 2" modelling it scales "support under Improved ICRP and Socialised charging uniformly to achieve the same renewable share (in 2020) and approximately the same carbon intensity (in 2030) as under Status Quo".[64]

A more coherent method would have been for Redpoint to assume that government sets subsidies at a level that achieve the assumed targets (100g/kWh emissions intensity in 2030, and 30% of renewables generation in 2020), but at lowest total cost to consumer.[65] This would have mimicked the approach government has taken previously when setting subsidy levels, such as through the RO banding review:[66]

> *"By setting support for the cheapest technologies at a level that ensures high deployment, we are able to minimise the amount of generation needed from*

---

[63] Redpoint's modelling report describing its modelling for the EMR consultation states that "The principle of Capacity Payments for All is that this new revenue stream will cover the capital and fixed costs of low load factor plant, such that these plant are economic without the need for significant price 'uplift' above the system SRMC." It states elsewhere in the same report that "Under Capacity Payments for All (introduced in 2018) this variable 'uplift' in prices is replaced by a steady stream of capacity payments."

Source: Electricity Market Reform: Analysis of policy options, A report by Redpoint Energy in association with Trilemma UK, December 2010, pages 89 and 103.

[64] Redpoint, page 40.

[65] For example, an alternative approach would have been for Redpoint to optimise support levels using a simple linear program that minimises total costs to consumers, subject to constraints that require the government environmental targets to be achieved, as well as constraints on the achievable build rates and resource potential for specific technologies, e.g. nuclear or wind.

[66] Consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012, DECC (URN 11D/876), October 2011, page 9.

> *our most expensive technologies. By bringing down support for the most expensive technologies in line with the reducing costs of offshore wind, we ensure that we are not paying more than is necessary to get the deployment we need to meet our legally binding target."*

A.5. The Need for Sensitivity Analysis

Given the potentially significant distributional and welfare effects of reforming TNUoS charging regime, we consider that it would have been prudent for Ofgem to ask Redpoint to conduct further sensitivity analyses. Without such sensitivity analyses, it is not possible for Ofgem to reach an informed decision regarding the relative merits of alternative TNUoS charging regimes.

The only sensitivity Redpoint examined that compared the impacts of the "improved ICRP" and "status quo" models was a low gas price case, that suggested "improved ICRP" would be substantially worse for social welfare than the results presented in Ofgem's main CBA suggest. Amongst others, it would be prudent to run scenarios on the following:

- Scenarios on the development of arrangements for energy pricing, e.g. by considering a scenario where the UK introduces zonal pricing to comply with the EU Target Model;
- Demand growth, e.g. due to the extent of electrification of heat and transport;
- Long-term decarbonisation targets (e.g. 100g/kWh by 2030, vs. 50g/kWh);
- The costs of developing HVDC bootstrap links;
- The constraints on renewables build rates; and
- The development of new interconnectors with neighbouring markets.

A.6. Consistency of CBA with Model Results

Although it is not possible from the figures presented in Redpoint's report to conduct a full independent check of its methods and calculations, from the figures presented in the report we have identified possible inconsistencies in its results.

In particular, Redpoint's Figure 18 shows that under the "improved ICRP" model cumulative transmission reinforcement costs on the Main Interconnected Transmission System (MITS) increase by around £2.5 billion between 2020 and 2030 as compared to the "status quo". However, Table 5 in Redpoint's report suggests that "improved ICRP" increases transmission costs by only £418 million in the period 2020-2030 in net present value terms. Given a real discount rate of 3.5%,[67] costs incurred between 10 and 20 years into the future should be discounted by between 29% and 50%.[68] Even if the upfront construction costs of transmission investments have themselves been annuitised over their assumed useful lives for

---

[67] Redpoint, page 52.

[68] Calculated as follows: $1 - (1 + 3.5\%)^{-10} = 0.29$; $1 - (1 + 3.5\%)^{-20} = 0.50$

Redpoint's CBA, this figure is surprisingly low given the impact on investment costs in the period to 2030, and therefore merits further scrutiny by Ofgem.[69]

Moreover, Redpoint's Table 5 estimates that demand TNUoS falls under "improved ICRP" by £98 million in NPV terms during the period to 2020, and by a further £62 million in the period between 2020 and 2030, as compared to the "status quo". Hence, despite a substantial increase in transmission investment costs, 85% of which should be recovered through demand TNUoS charges, Redpoint's cost benefit analysis indicates no corresponding increase in demand TNUoS. This result also appears inconsistent, and so also merits further scrutiny by Ofgem.

A.7. Conclusions

A.7.1.Shortcomings in Redpoint's modelling framework

We have identified a series of shortcomings in Redpoint's modelling framework, as summarised below.

Firstly, the use of an "imperfect foresight" framework does not reflect how rational investors in generation and transmission infrastructure take investment decisions. This approach is not justified on the grounds that investors have short planning horizons, or that current conditions in the power market always constitute the most reliable guide to future conditions. Redpoint's "perfect foresight" approach would have provided a more objective basis for quantifying the impact of alternative TNUoS regimes, but it did not converge correctly.

Secondly, the ELSI modelling tool Redpoint used to dispatch generation and calculate power prices significantly simplifies the operation of the power market, and ignores generation dynamic constraints and unit commitment costs. These factors will become increasingly important drivers of power price formation, and hence generation and transmission investment decisions, and hence the costs and benefits of adopting different approaches, as the generation mix becomes increasingly dominated by intermittent renewables.

Furthermore, Redpoint's method of "uplifting" power prices using an approach calibrated to 2009/10 data is not transparently described in Redpoint's report. Also, by calibrating to historic data will not produce a good estimate of future costs and benefits, given the significant changes to the generation mix in the coming years.

These problems with Redpoint's framework mean the modelled (constrained and unconstrained) prices that emerge from Redpoint's modelling will not reflect the expected changes in the GB generation mix, and so will not provide a reliable basis for modelling generation and transmission investment decisions.

Finally, the approach Redpoint has taken to adjusting subsidy levels in its "stage 2" modelling is not consistent with the approach that it would be rational for the government to

---

[69] Redpoint's Figure 19 shows that offshore reinforcement costs are virtually identical under the "improved ICRP" and "status quo" models. Hence, the explanation for this anomaly is not associated with differences in offshore infrastructure investment costs.

take, and that the government has taken in the past, to setting subsidies for low carbon generation.

In practice, a possible cross-check as to whether these problems are affecting modelling results would be to compare the profitability of transmission and generation investments made in Redpoint's model, but using prices emerging from a run of the PLEXOS model. For example, comparing modelled internal rates of return (IRR) achieved on new investments[70] with the assumed weighted average cost of capital (WACC) for new investments would identify whether Redpoint's simplified modelling approach systematically over or understates the value of particular technologies, or transmission investments in certain locations.[71]

A.7.2. Implications for Project TransmiT

The theoretical shortcomings of Redpoint's modelling framework we have identified undermine its robustness as a tool for forecasting the evolution of the GB power market, and hence quantifying the impact of changes to the TNUoS charging regime. These shortcomings mean that Redpoint's results do not constitute a robust basis for Ofgem's decision making in the context of Project TransmiT.

In terms of the charging models Ofgem is considering, the problems we have identified may be especially important for comparing the "status quo" and "improved ICRP" models, as the net benefits of reforming the current system estimated by Redpoint's model are relatively small. Redpoint's modelling is therefore not sufficiently robust to support Ofgem's conclusion that "improved ICRP" would provide a small societal benefit through a reduction in power sector costs compared to the "status quo", when the difference between the models appears so finely balanced in terms of the impact on social welfare.[72] If the true impact of the "improved ICRP" is slightly different, the societal benefit to 2020 could become negative.

In contrast, the conclusion that the "socialised" model would impose significant societal costs compared to the "status quo" appears more robust. Firstly, the quantum of the impact is much larger in absolute terms. Hence, it is less likely that changes to the modelling framework would reverse this conclusion. Secondly, although not entirely comparable,[73] the estimated impact of socialised charging estimated by Redpoint is relatively close to those NERA and Imperial College London estimated earlier in the Project TransmiT process, as Table A.1 shows. Moreover, the NERA/Imperial model does not suffer from all the shortcomings that we have identified in the Redpoint framework:

---

[70] In the case of generation investments, the modelled IRR could be calculated by comparing the upfront construction costs of new entrants to the net revenues they earn from the market (including capacity payments, ancillary service revenues, etc), less ongoing O&M costs. In the case of transmission investments, the upfront construction and ongoing O&M costs should be compared to the value of congestion rents captured by the capacity provided, e.g. as measured by the difference between the marginal costs of production between zones.

[71] Redpoint committed to publish outturn IRRs at the Project TransmiT event in Glasgow on 17 November 2011, but as far as we are aware, has not yet done so.

[72] Ofgem, page 5.

[73] The NERA/Imperial and Redpoint reports consider slightly different models for the "socialised" and "status quo" charging models. In particular, NERA/Imperial analyse a capacity-based (£/kW) charge in the "socialised" scenario, whereas Redpoint's report assumes an energy-based (£/MWh) charge.

- NERA/Imperial's model simultaneously models generation investment decisions and conducts a full chronological dispatch, taking into account unit committment. Hence, power prices are fully consistent with generation investment decisions, and fully account for the impact of increasing intermittency on market outcomes; and
- Unlike Redpoint's "imperfect foresight" approach, NERA/Imperial's model uses a "rational expectations" framework, in which investors base their decisions on expected profitability over the whole life of assets, not an arbitrarily defined planning period that assumes investors adopt systematically irrational behaviour.

Table A.1
NERA/Imperial vs. Redpoint: Estimated Impact of Socialised Charging

Real 2011 £Mn	**Impact on Consumers**	**Impact on Power Sector Costs**
NERA/Imperial	-20,074	-7,681
Redpoint	-19,749	-13,592

Source: Redpoint and NERA/Imperial analysis[74]

---

[74] Redpoint (Table 6), NERA/Imperial (Tables 6.1 and 6.2). Note, NERA/Imperial figures converted into 2011 £ for consistency with the Redpoint figures.

NERA
ECONOMIC CONSULTING

NERA Economic Consulting
15 Stratford Place
London W1C 1BE
United Kingdom
Tel: +44 20 7659 8500
Fax: +44 20 7659 8501
www.nera.com

NERA UK Limited, registered in England and Wales, No 3974527
Registered Office: 15 Stratford Place, London W1C 1BE