SCOTTISHPOWER
Energy Wholesale

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Ofgem
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21 January 2010

Dear Dena,

Response to Impact Assessment on locational BSUoS charging methodology – GB ECM-18

Thank you for the opportunity to respond to this Impact Assessment and consultation. This response is submitted on behalf of ScottishPower Energy Management Ltd, ScottishPower Generation Ltd and ScottishPower Renewable Energy Ltd.

Summary

The first and best response to the issue of constraint costs anywhere within the GB market is to redouble efforts to upgrade the transmission infrastructure to eliminate the problem at source. By contrast, the proposed locational charges would undermine the fundamental principles of a single GB market and would adversely impact investment in generation in locations affected by constraints in the transmission network.

Locational BSUoS would initially impact Scottish generators, who are already significantly disadvantaged by high transmission charges, but would also increasingly affect generators at other GB locations. The vast majority of the generation that would be impacted is seeking to use its location to reduce carbon emissions and thus the proposal works directly against UK energy policy objectives – in particular the target to achieve 15% of energy from renewables by 2020 and the UK's aspirations for clean coal and Carbon Capture & Storage (CCS).

Our concerns about the proposal – both in terms of the substantive effects that we can foresee and also because of the insufficient analysis and information contained in the Impact Assessment – can be grouped in three broad categories:

(a) Negative and discriminatory impact on renewable generation

The proposal would disproportionately impact renewable generators behind constraints because they are the type of plant least likely to be able to react to the proposed charges and their generation is most likely to be concentrated in periods when an export constraint is active. Not only is this contrary to the requirements of the Directive on Electricity Production from

Renewable Energy Sources 2001/77/EC (RES Directive), but also it could significantly impact delivery of the Government's renewables targets[1].

(b) Ineffectiveness in reducing constraint costs

There are two key factors. First, the proposal would be unlikely to reduce the scheduling of flexible plant behind the constraint at times when the constraint is active. The BSUoS charges would be highly volatile and unpredictable, and generators will not know the likely behaviour of competitors. Our analysis suggests that a "run regardless" strategy is best even at low values of the spark/dark spread. And second, the hope that locational BSUoS will reduce the need for constraint management services would reduce the amount of low cost long term services bought by NGET, thus increasing the use of the more expensive bid/offer solutions procured at the last minute.

(c) Distorted and reduced competition in the GB power market, to the detriment of consumers

The "overselling" of access rights between Scotland and England has allowed a significant strengthening of competition in the GB power market by allowing the Scottish generators to compete in the market on equal terms. Locational BSUoS would limit access for Scottish plants, leading to less keen competition and therefore higher prices for consumers. Indeed, it could cause Scottish plant to close prematurely rather than undertake capital investment, with existing coal and nuclear plant potentially at risk. This could set back the Government's low carbon agenda, especially given the CCS project proposed for Longannet. The benefits from Scottish plant participating in the GB market are considered to be significantly greater than the cost of constraints.

Overlaid on these issues are important questions of discrimination and the framework for investment. We do not consider that a case has been made that Scottish generation is the cause of the continuing shortfall in grid capacity, as opposed to planning and financial approval issues. And given that about 76% of the value added by bid/offer activity accrues on the offer side (ie plants in England and Wales increasing output to compensate for a Scottish turn-down), we do not think it is appropriate to treat the Scottish generators as the sole beneficiaries from constraints payments. Changing the terms of trading for plant in Scotland after the event, including for recent renewable investments, will not give a positive signal to future investors.

None of these issues are adequately addressed in the Impact Assessment. For these reasons, and also those set out in our response of 20 April 2009[2] to NGET's pre-consultation (which we reiterate), we believe that implementing the locational BSUoS proposal would be both contrary to the public interest and unlawful.

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[1] Whilst we consider the report by Redpoint published by DECC on January 14th January 2010 to be fundamentally robust, we have not had sufficient time to fully analyse it and it appears that their conclusion that there would be little or no impact on the target is predicated on an optimistic view of the underlying finances of renewable investments. On other reasonable assumptions, analysis prepared for us by Oxera shows a pronounced negative effect.

[2] ScottishPower (2009), 'Response to pre-consultation on GB ECM-18 Locational BSUoS Charging Methodology', April 20th.

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In our view, the conclusions of the recent grid access consultation undertaken by DECC indicate the right way forward on these issues – namely to proceed with a fully socialised connect and manage option, assisted by a moderate increase in user commitment. This is not consistent with locational BSUoS. The analysis prepared by Redpoint of the costs and benefits of the socialised access model represents a balanced and realistic overview of the likely constraint costs that this would entail.

The following pages set out our thinking and evidence on these points in more detail together with Annexes as follows:

- Annex 1 contains the legal analysis that shows why the proposed locational BSUoS charges would be unlawful.

- Our responses to the specific consultation questions posed by Ofgem are provided in Annex 2.

- Details of the analysis undertaken to assess the impact on renewable investment are provided in Annex 3.

I hope you find these comments useful. Should you have any queries on the points raised, we would welcome the opportunity to discuss the matter.

Yours sincerely,

James Anderson
Commercial and Regulation Manager

DETAILED COMMENTS AND EVIDENCE

1. **Negative and discriminatory impact on renewable generation**

Given the 'important' nature of the proposal for locational BSUoS within the meaning of the Utilities Act, Ofgem's Impact Assessment is deficient as it fails to include a proper assessment of the likely effects on the environment.[3]

Insufficient attention has been given to the following issues:

- **the negative impact of the proposals on investment incentives in renewable generation;**
- **the results of recent work commissioned by DECC, showing that the benefits of increased renewables under a socialised cost model exceed the costs of constraints; and**
- **the discriminatory and disproportionate impact of the proposal on renewables on the basis of their location and the economics governing their operating decisions.**

Investment incentives

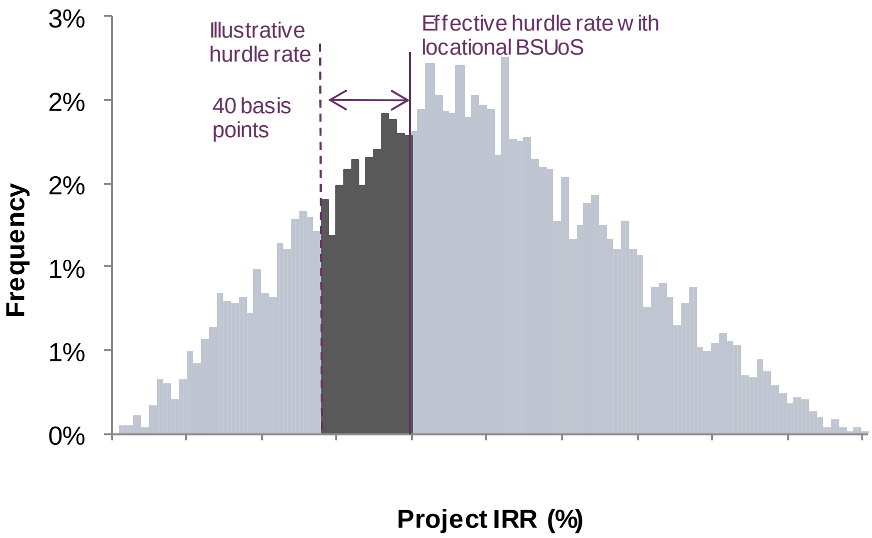
Ofgem's statement that the proposed charges 'will only prevent renewable investment if it would make such investment uneconomic' is no more than a statement that investors tend to behave in an economically rational manner. It highlights that Ofgem has yet to examine in any meaningful manner the impacts on expected returns to renewable generation projects.[4] Even in its own terms, the statement omits the importance of balance sheet constraints; in current conditions, many projects have to compete with other investment opportunities in the UK and overseas. Meeting the hurdle rate – being "economic" – may not be enough.

Our assessments show that the economics of all renewables subject to locational BSUoS would be expected to be adversely affected, given the likely evolution of future power prices and support under the Renewables Obligation.

Figure 1 shows the distribution of project returns based on the possible distribution of relatively favourable project costs. This shows that if a locational BSUoS charge of £4.6/MWh were to be incurred by a Scottish wind development for around a quarter of its expected operating hours,[5] project economics would be severely affected; the IRR of a typical onshore wind development would fall by around 40 basis points. Even with favourable economics, Figure 1 highlights that a number of projects would be at risk under the proposed charges given the competition for capital from other projects and in other markets, especially under equally probable scenarios with higher project costs or with greater locational charges.

[3] As set out in Ofgem (2009), 'Guidance on Impact Assessments', December 15th.
[4] Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 4.20.
[5] This figure is used by Ofgem in Appendix 6 of its Impact Assessment within the '350MW scenario'.

Figure 1 **Illustrative impact of Locational BSUoS on onshore wind economics**



Note: Simulation results shown for a range of typical 'medium onshore wind' developments, based on cost data used in analysis for DECC's Low Carbon Transition Plan: capital costs £1,200/kW (triangular distribution +/- 10%), fixed costs £40/kW/yr (normal distribution, 10% standard deviation) , TNUoS based on 2009/10 tariffs for Central Highlands £16.9/kW. Electricity and ROC revenues based on Oxera modelling. Indicative locational BSUoS of £4.6/MWh, consistent with Appendix 6 in Ofgem's Impact Assessment.
Source: Oxera

The proposed changes represent a significant and retrospective reduction of expected returns to existing generation, and would therefore affect future investment, not only through the direct impact of increased costs, but also through higher returns demanded by investors due to the regulatory risk of future intervention.

Given the Government's efforts to reduce the risks faced by renewable generators within the Renewables Obligation, locational BSUoS would appear to significantly negate those efforts and would be detrimental to meeting the Government's environmental targets.[6]

Evidence of this is provided in the analysis described in Annex 3, which examines the impact on renewable investment under a range of scenarios for the level of the proposed charge, and the number of investment decisions affected.

The analysis, which is summarised in Table 1 and Figure 2 highlights the following key results (all results expressed as changes from a base case without locational BSUoS).

- the impact of locational BSUoS would be detrimental to meeting the Government's renewable targets in all scenarios
- marginal onshore wind developments would be deterred across all scenarios, with a loss in output from onshore wind between 2.4 to 3.8TWh, equivalent to around 10% of anticipated onshore investment;
- if all offshore wind investment decisions were to be affected, the loss in total renewable output could be as high as 17 TWh in 2020, and reduce the ability of the UK to meet its renewable electricity target by some 5 percentage points;

[6] See examples in DECC (2009), 'Consultation on Renewable Electricity Financial Incentives 2009', such as proposals to include a wholesale price link within the RO.

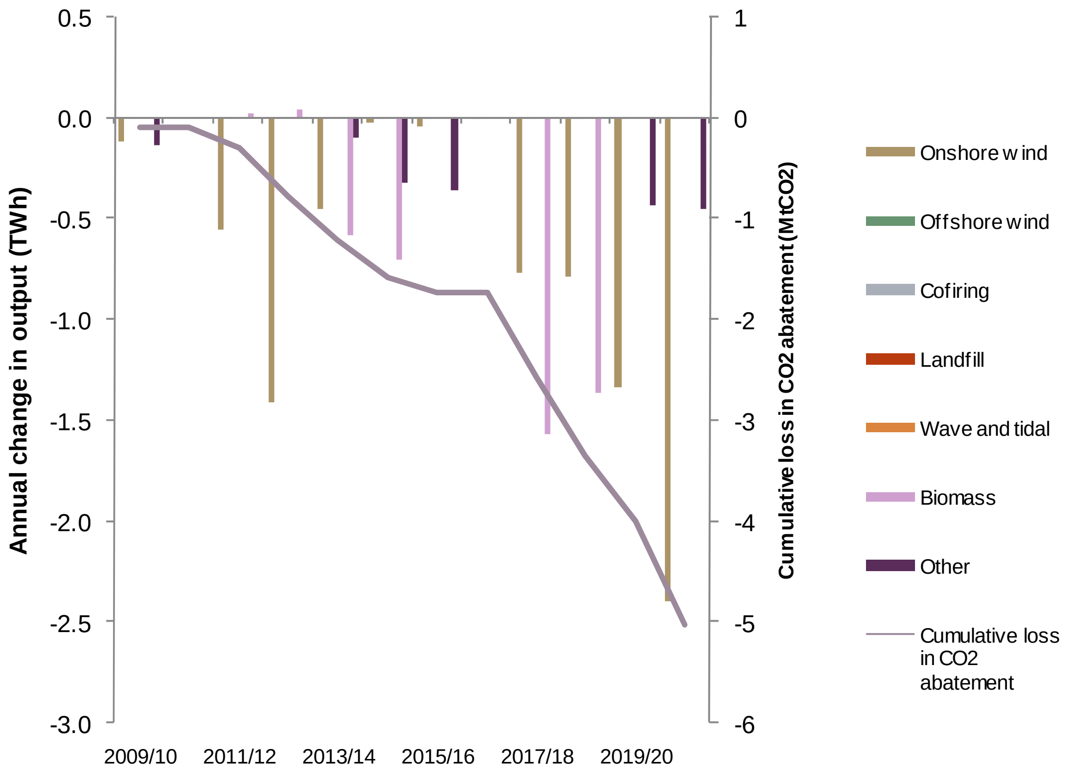
- the cumulative effect of lost output over time is to increase power sector emissions, which could be in the range 5-42 $MtCO_2$ in the period up to 2020, with an associated cost of unabated emissions of £89m-749m in present value terms.

Table 1 Summary of locational BSUoS impacts

	2020 output	2020 renewable generation	NPV of cumulative emissions avoided
Base case	100 TWh	28.7%	230 $MtCO_2$; £4,127m
Change with locational BSUoS			
locational charge (£4.6/MWh) in all investment decisions	-17 TWh	-4.9%	-42 $MtCO_2$; -£749m
locational charge (£4.6/MWh) in half of investment decisions	-3 TWh	-0.8%	-5 $MtCO_2$; -£89m
locational charge (£10/MWh) in half of investment decisions	-4 TWh	-1.1%	-11 $MtCO_2$; -£190m

Note: Emissions avoided are calculated based on displacement of CCGT emissions of 0.34tCO_2/MWh. Present values of emissions avoided are calculated using a discount rate of 3.5% based on HM Treasury Green Book and traded carbon prices in DECC guidance on measuring the carbon impacts of policy.
Source: Oxera

Figure 2 Impact of locational BSUoS (locational BSUoS of £4.6/MWh within half of investment decisions)



Source: Oxera

It is recognised that this is one area where our opinion differs from Redpoint's analysis of the impacts of locational BSUoS, which concluded that there may be a limited impact on renewable generation.[7]

We believe that this conclusion is only possible because of the favourable technology cost and power price assumptions employed by Redpoint (basesd on DECC price outlooks), which have the effect of increasing the profitability of renewable generation investments to such an extent that the proposed charges are prevented from having a significant effect on investment decisions.

Using other, equally plausible assumptions, including commodity and power prices more closely aligned with industry expectations, shows that there could be a significant number of projects at risk from the proposals, and the analysis above highlights the risks to the attainment of the Government's targets. Details of the modelling methodology and results are provided in Annex 3.

The analysis above is based on indicative values of the locational charge. However, as discussed further below, the wide variation in forecast constraint costs means that the ultimate impact of the proposed amendment on the level of future charges remains in doubt. This additional uncertainty means that the impact on the economics of renewable generation projects and their overall deployment could be greatly affected.

As set out below, we consider that the use of an unpredictable short-run price signal to incentivise generation location decisions is inappropriate, lacks transparency and would be inefficient. Moreover, we are concerned that Ofgem's reference to the potential for locational BSUoS to play such a role constitutes acknowledgement that there is likely to be an un-quantified deterrent to investment.[8]

Cost–benefit analysis of increased renewables

Accelerating the deployment of renewables and other low carbon technologies is at the heart of the Government's consultation on Improving Grid Access.[9] Table 2 highlights the results of analysis commissioned by DECC to assess the various options being considered adjusted for the impact of avoided carbon emissions[10] to which we have added adjustments (calculated by Oxera). The following messages are clear from this analysis:

- only when constraint costs are socialised are renewable investment incentives sufficient to reach the Government's desired level of deployment;
- the benefits of increased renewables through lower wholesale prices outweigh the increase in system balancing costs; and
- the net benefit of more renewables is further increased if the cost of avoided carbon emissions is included.

[7] Redpoint Energy (2010), 'Improving Grid Access: Modelling the Impacts of the Consultation Options', January 14th, p98.
[8] Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 4.19.
[9] DECC (2009), 'Improving Grid Access. Consultation Document', August 25th.
[10] Redpoint Energy (2009), 'Improving grid access: modelling the impacts of the consultation options', December.

Table 2 Costs and benefits of increased renewables under alternative models

	Socialised constraint costs (ie, 'connect and manage')	Reduced constraint costs (ie, 'invest and connect')	Benefit of socialised constraint costs[1]
Renewable output in 2020 as a share of total electricity generation	30.5%	23.2%	7.3%
NPV of wholesale electricity prices	NR	NR	£1,600m
NPV of system balancing costs…	NR	NR	-£650m
…of which constraint costs	£999m	£804m	-£195m
NPV of cost of carbon emissions[2]	-£30,183m	-£30,991m	£808m
NPV of benefits of socialised constraint costs			**£1,758m**

Note: [1]Positive values indicate benefits of socialised constraint costs. [2]Oxera estimate of benefits from carbon emissions avoided from increased renewables not included in published report, based on DECC valuation methodology (DECC (2009), 'Carbon Appraisal in UK Policy Appraisal: A revised Approach'). NR denotes 'not reported'. NPVs are net present values of costs and benefits between 2010 and 2020 using a discount rate of 3.5%.
Source: DECC (2009), 'Carbon Appraisal in UK Policy Appraisal: A revised Approach'; Redpoint and Oxera analysis.

Locational BSUoS would act to increase the costs borne by renewable generators behind a derogated boundary, weaken both grid and generation investment incentives, and reduce the price and carbon benefits of their deployment. Under the proposed amendment, renewable investment is likely to fall, thereby putting the attainment of the Government's renewables targets at risk.

In our opinion, Ofgem has failed to undertake a complete assessment of the wider impacts of locational BSUoS on renewables, including the implications for emissions, price levels, and the volume of constraints. This goes against the principles of Better Regulation and Ofgem's own guidance on Impact Assessments.[11]

Disproportionate effect on renewables

Intermittent renewable generators are disproportionately affected by the proposals due to their economic characteristics, as set out below.

- **The output of intermittent generators is correlated**. Intermittent sources of renewable generation are likely to operate when wind resource and total output behind a derogated boundary are high, and thereby incur relatively high targeted constraint costs. In contrast, thermal generators also face an incentive to generate when intermittent (ie, renewable) generation output is low and wholesale prices are high, and would subsequently incur a greater proportion of relatively low targeted constraint costs. Accordingly, the weighted average targeted constraint costs for intermittent generators would be higher than for thermal generators.
- **Renewables developments tend to be located at the extremities of the transmission network**. A key benefit of overselling access through Connect and Manage is to accelerate the deployment of renewable generation. Given this, and the fact that intermittent renewables will be located where their resource is most abundant,

[11] Ofgem (2009), 'Guidance on Impact Assessments', December 15th.

it is to be expected that new developments will have a much greater propensity to be located behind existing and future derogated boundaries than is the case for other new generation. As such, the investment incentives faced by new renewables are likely to be disproportionately affected. As discussed further below, this is discriminatory.

- **The ratio of variable to fixed and capital costs is small**. As NGET suggests, the dispatch decisions taken by renewable generation operators are unlikely to be affected by a targeted cost of the kind proposed, due to their low marginal costs.[12] The effects of the proposals on renewables would be to increase costs with no prospect of any reduction in variable costs from changes in output, and reduce the incentives for investment in renewable generation.
- **There is less scope for renewables to provide Offers into the Balancing Mechanism (BM)**. There is limited scope for renewable generators such as wind to increase output to provide certain balancing services, such as BM Offers. As discussed further below, unpredictable costs that are realised ex post are effectively fixed costs that might reasonably be reflected in Offer prices submitted by other generators. This increases the net costs borne by renewables relative to other generators.

We believe that the proposed amendment would unduly discriminate against renewable generators and that it would therefore be unlawful. Relevant legal issues are set out in greater detail in Annex 1.

2. Ineffectiveness in reducing constraint costs

At a time when reform of the existing access arrangements is needed to provide a more transparent signal to improve grid access, the proposed charges will add considerable uncertainty to the costs faced by new and existing generators.[13] This is because the level of the locational BSUoS charge is retrospective by design, and is impossible to estimate with the required degree of accuracy.

We believe that this poses a significant challenge to the proposals in that it would restrict the ability of the proposed charges to alter generators' operating decisions. Importantly, and as discussed below, absent any change in operating behaviour on the part of generators, the suggested benefits of the proposed amendment would not be realised.

If plant operating and pricing decisions are based on anticipated levels of the BSUoS charge that, after the event, turn out to be wrong, generators will face higher costs or lower revenues than they would have achieved with a transparent price signal. Both of these unexpected additional costs effectively increase generators' fixed costs. However, unlike other risks faced by generators (eg, price risk), the uncertainties embodied within the proposed charges cannot be managed through the market due to the lack of counterparties with which to trade to effectively hedge forecasting errors.

As discussed in section 1, this would be expected to adversely impact on investment in all types of generation in Scotland.

There are serious deficiencies within the proposal in providing an adequate signal to generation for the following reasons:

[12] Wind is treated as a 'must run' technology in NGET's analysis. See NGET (2009), 'Addendum to GB ECM-18 Report to the Authority', November 26th, p17.
[13] Ofgem acknowledges that the proposals depart materially from the existing arrangements, whereby TNUoS serves aims to provide the 'total cost signal' (ie, reflecting both short and long-run costs) for a compliant network. See Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 3.48.

- **NGET and Ofgem's assumption that there will be 'instant feedback', and that companies will be able to forecast locational BSUoS charges, based on a highly unpredictable signal is unrealistic; and**
- **the analysis omits a rigorous assessment of the interactions between different generators, and the extent to which output decisions will be based on the expectations of other generators' behaviour.**

Generators' ability to anticipate and respond to the level of the charge

NGET's analysis assumes that it will be in a position to determine the impact of the interaction between demand and generator behaviour on either side of the derogated boundary and the transmission capability of the boundary on constraint volumes, as well as the cost of balancing actions, and be able to signal these to generators sufficiently far in advance for it to be factored into output and pricing decisions.

Ofgem has also assumed that generators' behaviour reflects 'instant feedback' to the proposed charges, implying that generators would be able to accurately predict locational BSUoS charges such that these charges could be taken into account by generators.

However, the ability of NGET to forecast constraint costs is limited due to the volatile nature of demand, supply, transmission capacity and the increased variability from renewable generation and we do not believe it will be able to forecast accurately the level of the locational BSUoS charge sufficiently far in advance to allow generators to incorporate this forecast charge into their commercial decisions. This is because, as NGET has recognised, there must also be sufficient market liquidity for generators to trade to meet their contractual commitments, something that has not been adequately addressed in the analyses undertaken by NGET and Ofgem.[14]

Moreover, given the significantly lower level of constraint costs forecast by the analysis prepared by Redpoint Energy for DECC, it would appear that the level of the price signal and the extent of behavioural change implied by NGET's results are highly questionable. In light of Ofgem's concern over the level of future constraint costs, additional analysis is clearly needed to determine more accurately what the level of those costs would be.

We believe that the proposed amendment would breach the requirement of transparency applicable to transmission charges and that it would therefore be unlawful. Relevant legal issues are set out in greater detail in Annex 1.

Incentives of generators to respond

We believe that NGET and the Impact Assessment fail to analyse a further defect in the ability of the charge to alter behaviour, since understanding generator behaviour requires an assessment of how individual plant will react to the output decisions of other generators, which is completely absent from NGET's analysis.

NGET's 'cycling' result provides evidence that generators' output decisions are influenced by the expectation of the behaviour of other generators.[15] That is, in iterations of NGET's modelling where generation is expected to be low (in expectation of high locational charges), subsequent iterations in fact show an increase in generators' output (since locational charges would then be low). The cycling behaviour highlights the flaw in NGET's modelling in which expectations are inconsistent with outturn events.

Figure 3 illustrates these effects which arise from the strategic behaviour of generators in a competitive market - that is, the operating decision of a particular generator is conditional on the anticipated operating decisions of other generators. If output from one or more generators is

[14] NGET (2009), 'Addendum to GB ECM-18 Report to the Authority', November 26th, p4.
[15] NGET (2009), 'Addendum to GB ECM-18 Report to the Authority', November 26th, p21.

reduced, there will be a profitable opportunity for another generator to increase output. The only equilibrium consistent with a competitive market is one in which there is no behavioural change (ie, all generators continue to generate), and each generator expects high costs. It is only in this situation that there is no incentive to deviate from the competitive equilibrium.

Figure 3 Dominant operating strategies with marginal spreads

Fossil generator 1		Fossil generator 2: Continue running	Fossil generator 2: Don't run
	Continue running	fossil 1: 5-4.6 = 0.4 fossil 2: 5-4.6 = 0.4	fossil 1: 5-1 = 4 fossil 2: 0
	Don't run	fossil 1: 0 fossil 2: 5-1 = 4	fossil 1: 0 fossil 2: 0

Note: The spread available to fossil plant is shown as £5/MWh. BSUoS costs are shown equal to £1/MWh when one generator reduces output, and £4.6/MWh when both plant generate.
Source: Oxera.

NGET and Ofgem have also failed to assess the impact of the proposals on the prices paid to resolve constraints.

The proposed charges are likely to increase the prices paid by the system operator to resolve constraints for two reasons:

- uncertainty caused by the locational charge is likely to lead to more short-term, expensive contracting for ancillary services and increased dependence on the BM; and
- competition for ancillary services may be less effective and innovation may decrease.

The first reason why the prices paid by the System Operator to resolve constraints are likely to increase is that the uncertainty over the extent to which the locational BSUoS charge changes generators' behaviour will increase the propensity for short-term balancing actions to be used to resolve constraints.

With the proposed charges in place, the system operator will either continue to contract for the same level of longer term constraint solutions (such as commercial constraint contracts and commercial intertrip) anticipating that the proposed charges will have no behavioural effect, or will have no option but to resort to more short-term actions such as using the BM if it waits to see if there will be any behavioural change from the proposed charge. Clearly the former highlights the ineffective and redundant nature of the proposals, while the latter acts to increase total costs, as short-term actions within the BM are based on prices reflecting increased risks on the Offer side of Bid-Offer acceptances.

Secondly, the cost of resolving constraints is likely to increase with the introduction of locational BSUoS due to distortions in competition and reduced innovation in the provision of constraint management solutions. Insufficient attention has also been given to the potential distortions of the proposal on competition for ancillary services, and its interaction with the wholesale market. Increased reliance on short-term measures may act to dampen innovation and demand for longer-term constraint management services, such as capped Physical Notification (PN) contracts and commercial intertrip. NGET's intention to signal when constraint action is likely to be greatest may also signal to generators on the other side of a derogated boundary that more profitable opportunities may arise to sell power in the BM rather than the forward market, which may act to distort their operating decisions and increase costs to consumers.

These factors suggest that there is a considerable risk that locational BSUoS would fail to reduce constraint costs and could in fact exacerbate the issue. It is essential that further analysis is undertaken and consulted on in this area before a decision to implement locational BSUoS could be taken.

3. Distorted and reduced competition in the GB power market, to the detriment of consumers – including issues of discrimination

This section addresses adverse impacts on competition and questions of discrimination and proportion. The key points include:

- **the benefits of overselling access rights fall mainly to consumers through enhanced competition in the generation market – it has not been justified that generators behind a derogated boundary should pay for the cost of resolving constraints;**
- **it has not been justified that the constraint costs from non-compliant boundaries, which are driven to a significant extent by outage programmes and network reliability, should be targeted on a subset of generators;**
- **given the likelihood of no behavioural change being realised by the proposal, Ofgem has not justified why it believes that its assessment that Scottish charges could increase by around 1000–2000% is proportionate;**
- **it has not been justified that the effects of potential future exploitation of market power should be borne by only a subset of those generators who are not undertaking that (hypothetical) exploitation.**

Benefits of 'overselling' access rights

We disagree fundamentally with Ofgem's initial view that the proposed charges are non-discriminatory and reduce the undue discrimination between generators benefiting from the over-allocation of access and those that do not.[16]

The benefits of what Ofgem describes as 'overselling' transmission access are primarily system-wide. Indeed, DECC's consultation on Improving Grid Access states its preference for a Connect and Manage model (and the associated over-allocation of access) over other models in order to meet public energy policy goals that, by definition, are system-wide societal benefits.[17]

These system-wide benefits fall into two broad categories.

- **Competition benefits**. The desired benefits that led to the creation of BETTA were to increase competition, leading to lower system-wide prices, which were believed to outweigh the costs of constraints.[18]
- **Renewable energy benefits**. The analysis provided by Redpoint Energy for DECC shows that the increase in new renewables under a Connect and Manage model will enable the attainment of Government's renewable policy goals, as well as lead to reductions in wholesale prices that exceed the associated increase in constraint costs.[19]

The competition benefits of BETTA achieved through the creation of a GB-wide market will continue to allow the development of relatively low cost renewable generation (e.g. onshore

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[16] Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 3.89.
[17] DECC (2009), 'Improving Grid Access. Consultation Document', August 25th.
[18] See Ofgem (2009), 'Addressing market power concerns in the electricity wholesale sector – initial policy proposals' para 1.4.
[19] Redpoint Energy (2009), 'Improving grid access: modelling the impacts of the consultation options', December, p6.

wind), as well as providing a reasonable framework for the investments needed to maintain existing generation in Scotland (in particular, pollution control requirements and nuclear life extension involve significant capital spending). Maintaining this framework would encourage competition for CCS demonstration and the prospects for early delivery of the demonstration. It would also provide a competitive constraint on generators in England and Wales.

Our analysis of the benefits of a single 2GW coal plant in Scotland within the GB market show that baseload prices are some £0.8/MWh lower with the additional plant based on historic conditions. This brings a net benefit to consumers of over £250m per year.

In addition to the price effects associated with increased renewables presented in the Redpoint analysis, overselling access rights will generate additional social benefits through carbon abatement as thermal generation is displaced, and make possible the prospect for the Government to meet binding EU targets.

Table 2 (in the above section on renewables), which quantifies the additional costs and benefits of adopting a socialised cost model, highlights that the net (social) benefit (£1,758m) of the price effects and carbon savings from overselling access exceeds any sums paid to resolve constraints (ie, -£195m, see Table 2). The costs associated with policies to achieve these benefits should therefore be socialised, reflective of the system-wide benefits.

Based on the information presented, we believe that Ofgem has not justified the proposed differential treatment between generators on the basis of whether they have been sold 'over-allocated' access rights. Under the existing access arrangements, once connected, access rights are effectively 'evergreen'.[20] As such, the access rights bought by generators reflect the conditions at the time of their connection. It is therefore discriminatory to alter the charges to a subset of generators that have invested in plant and obtained access rights prior to the establishment of a derogated boundary.

Drivers of constraint costs

Constraints at transmission boundaries arise from the power flows at those boundaries, which result from the net effect of generation and demand on both sides of the boundary, as well as the actions of NGET. It is therefore discriminatory to propose an amendment which only considers the generation element of the flows on one side of the boundary.

As recognised by Ofgem and NGET, the probability with which a constraint will be active will depend on a number of factors:[21]

- the level of demand which is forecast on either side of the transmission boundary;
- the indicated output of generation each side of the boundary; and
- the capability of the boundary (determined in part by the level of outages).

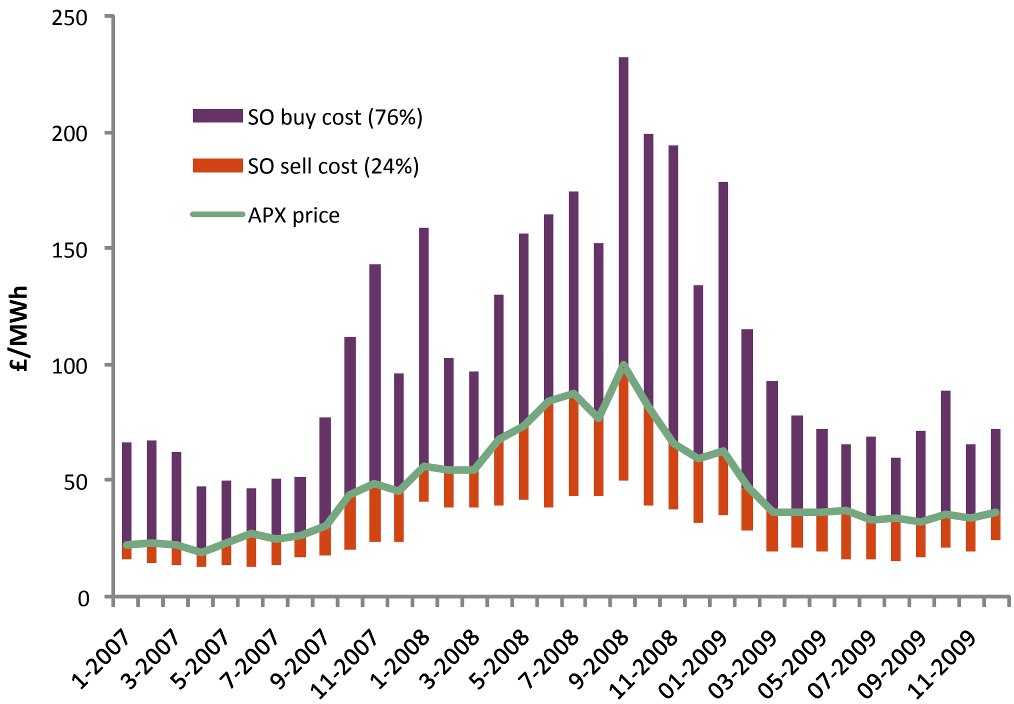
Contrary to NGET's assertion, whether a contributing factor, such as demand, has been constant over time does not preclude it as a determinant of constraint volumes or costs.[22] Changes in the level of demand have the same impact on constraint costs and provide the same contribution to resolving constraints as changes in generation. There is therefore no basis on which demand should face a different level of BSUoS charges than generation.

[20] Access rights have evolved from connection arrangements at the time of privatisation. Given the long lives and sunk costs of generation assets, if access rights were not 'evergreen' different contracting arrangements would be observed by generators to manage the associated risks.
[21] Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 3.81.
[22] Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 3.66.

The role of demand in contributing to constraint costs could have been demonstrated by modelling the implications on constraint costs if demand on either side of a derogated boundary were to change (although to our knowledge this has not been done by Ofgem or NGET).

As highlighted in our response to National Grid's consultation document, and updated in Figure 4, the majority of costs incurred through the BM to resolve constraints, reflective of the Bid-Offer spread, relate to Offers accepted by plant on the other side of a derogated boundary. Between 2007-2009, around 76% of BM costs are attributable to Offer acceptances. This is supported further by the downward revisions National Grid has made to its constraint cost projections for 2009/10, in light of significant innovation in the provision of ancillary services including commercial intertrip and capped PN contracts that reduce the reliance on the BM.[23] This evidence as to where the benefits of BM actions to resolve constraints fall (i.e. mainly in England and Wales), clearly indicates that it is inappropriate and disproportionate to target them on Scottish generators.

Figure 4 **Decomposition of BM costs**



Note: SO buy cost represents the proportion of BM costs that relate to Offer acceptances, calculated as the volume weighted average Offer price minus the APX spot price. SO sell cost represents the costs that relate to Bid acceptances, calculated as the APX prices minus the volume weighted average Bid price. Source: BMRA database, Argus, and Oxera analysis.

We believe that the proposed amendment would breach the requirement of proportionality applicable to transmission charges (derived from Articles 11(7) and 23(4) of the Internal Market Directive, Articles 4 and 6(1) of the Access Regulation and Standard Condition C5 of National Grid's transmission licence) and that it would therefore be unlawful. Relevant legal issues are set out in greater detail in Annex 1.

[23] Ofgem (2009), 'Further consultation on CAP170: updated analysis on potential cost savings for 2009/10', July 28th.

Proportionality of charges

It is particularly important to understand the implications of the proposals under a scenario with no behavioural change given the serious deficiency in Ofgem's and NGET's analysis of generator behaviour.

We note the omission of analysis by NGET of the implications of the proposal with no behavioural change, despite Ofgem's request in its open letter of June 17th 2009.[24] Given the likelihood of no behavioural change being realised, we are concerned that this has led to a more simplified assessment by Ofgem, which uses detailed data for May 2008 only.

Furthermore, if the main effect of the proposal is to act as a deterrent to investment (in conflict with the overriding policy objectives) to influence siting decisions (rather than to alter short-run output decisions), it would appear inappropriate to rely on such an unpredictable short-run signal.

Market power concerns

Under the powers of the Competition Act 1998, Ofgem has previously investigated whether there had been an abuse of dominance arising from constraints. In light of Ofgem's closure of the investigation without an adverse finding,[25] we strongly reject Ofgem's suggestion that past market outcomes reflect the exploitation of market power.[26]

Even if it is assumed that market power were to be exploited, we believe that Ofgem's view that the proposals would target the quantum of constraint costs that are due to the exercise of market power at the parties behind a derogated boundary would be discriminatory.[27] The Impact Assessment provides no justification why Ofgem believes that a subset of generators comprising generators that do not abuse any market power operating behind a derogated boundary should be more exposed to the effects of the potential exploitation of market power than generators on the other side of a derogated boundary.

If such an effect were likely, given the tendency of new renewable generation to locate behind potential derogated boundaries, as set out above, we would expect this to further deter investment.

We believe that the discriminatory nature of the proposals is unlawful, and the legal basis for this position is set out in more detail in Annex 1 of this letter.

4. Lawfulness of Proposed Amendment

In addition to the responses to the Impact Assessment set out above (and our responses to Ofgem's specific questions set out in Annex 2), it is our belief, as mentioned above, that adoption and implementation of the proposed amendment would be unlawful for the reasons noted in Annex 1.

ScottishPower
21 January 2010

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[24] Ofgem (2009c), 'GB ECM-18 – locational BSUoS', June 17th.
[25] Ofgem (2009), 'Competition Act investigation into Scottish Power and Scottish & Southern Energy', January 19th.
[26] Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 1.22.
[27] Ofgem (2009), 'Locational BSUoS Charging Methodology – GB ECM-18'', December 3rd, para 3.84.

ANNEX 1 – LAWFULNESS OF PROPOSED AMENDMENT

This annex sets out, in high-level summary terms, the reasons why Scottish Power considers that the adoption and implementation of the proposed amendment would be unlawful. The summary is not designed to be exhaustive and we reserve the right to expand upon, or to supplement, the reasons specified below at a future stage.

We refer at various points in this annex to our detailed comments and evidence submitted with our covering letter dated 21 January 2010 setting out our response to the impact assessment.

1. DISCRIMINATION: IMPOSITION OF CHARGES ON ONE CLASS OF GB GENERATORS

1.1 All generators located behind a derogating non-compliant boundary (**DNCB**) have the right, as users of the GB transmission system and participants in the GB generation market, to be treated in a non-discriminatory manner as regards the charges which they pay for access to and use of the GB transmission system. The sources of this right include Article 3 of the Internal Market in Electricity Directive (the **Internal Market Directive**).

1.2 The adoption and implementation of the proposed amendment would violate this right in the following manner:-

1.2.1 The generators who are the object of the proposed amendment participate in a GB-wide competitive market for the sale of electricity at wholesale level.

1.2.2 The proposed amendment treats the class of generators who are to be subjected to increased BSUoS charges as a consequence of their location (the **Relevant Class**) differently (and adversely as regards ability to earn a commercial margin) in comparison to other existing participants in this market.

1.2.3 This differential treatment has not been (and, we consider, cannot be) objectively justified by National Grid or the Authority as required by law.

1.2.4 Neither National Grid nor the Authority has demonstrated the existence of an objective need for action of the nature or extent proposed nor has it advanced a logical justification for requiring members of the Relevant Class to shoulder a substantially larger share of the increased burden of managing constraints arising at derogated non-compliant boundaries than any other users of the GB system.

1.2.5 Paragraph 3.63 of the Impact Assessment states that the excess generation which causes constraints is as a result of 'overselling' of capacity. There is no robust basis upon which to conclude that there is an objective justification for treating so-called beneficiaries of 'overselling' any differently than other generators. In particular:-

(i) Constraints arise due to power flows at boundaries from both a generation and demand perspective. Neither the proposal nor the Impact Assessment has sought satisfactorily to demonstrate the extent to which constraint costs associated with a particular DNCB are caused by the actions of GB market participants (such as, in the case of the Cheviot Boundary, those in England & Wales) other than generators located behind the DNCB. See, in this respect, the points made in section 3 of our detailed comments and evidence under the heading 'Drivers of constraint costs'.

(ii) The concept of 'overselling' is not an objectively justifiable one: neither the proposal nor the Impact Assessment demonstrate why the benefits resulting from the allocation of access rights to affected generators should be regarded as accruing to them as opposed to other parties. See the points made in section 3 of our detailed comments and evidence under the heading 'Benefits of 'overselling' access rights'.

(iii) The proposal takes no account of the contribution to elevated constraint costs made by delays in obtaining approval from the Authority and others for necessary upgrades to the relevant transmission infrastructure and also National Grid's own failure to invest sufficiently in the infrastructure at DNCBs and to adequately manage the constraint costs arising at those boundaries, such as the failure pointed out by the Authority to National Grid in its letter of 16 February 2009. See the points made in section 1 of our response to National Grid's consultation dated 20 April 2009 under the heading 'Investment in Transmission Infrastructure'.

1.2.6 The discriminatory treatment of this particular class of generators in this way will result in the distortion of competition within the GB market mentioned above.

2. DISCRIMINATION: FAILURE TO TAKE INTO ACCOUNT RELEVANT DIFFERENCES BETWEEN AFFECTED GENERATORS

2.1 Even if it is the case (which Scottish Power disputes) that it would be objectively justifiable to treat generators located behind a DNCB differently, for the purposes of locational BSUoS charges, from all other GB generators on the basis that they are the beneficiaries of 'oversold' capacity on that side of the relevant boundary, the imposition of such charges on all generators located behind the relevant DNCB would also constitute unlawful discrimination for the reasons set out below.

2.2 First, by imposing charges on generators located behind the relevant DNCB without reference to their date of connection to the GB system, the proposed amendment will result in unlawful discrimination as follows:-

2.2.1 The proposed amendment will have the effect of treating all generators located behind a DNCB similarly, irrespective of whether they were connected to the GB system before the date on which it acquired derogated status (the **Relevant Date**) or were only subsequently connected to the system.

2.2.2 Discrimination may occur when those in a comparable situation are treated differently, or when those in different situations are treated in a similar fashion, in each case without objective justification.

2.2.3 In the present situation, generators who connected to a particular part of the GB system before the Relevant Date (**Pre-Existing Generators**) cannot reasonably be viewed as having benefited from the 'overselling' of capacity in that location on or after the Relevant Date. Generators who decide to locate behind a boundary before it becomes a DNCB (sometimes years beforehand) are differently situated to those who do so after it becomes so: the access rights which they bought (and the long-term investment decisions which they made) reflect the conditions at the time of their connection. See, in this respect, the points made in section 3 of our detailed comments and evidence under the heading 'Benefits of 'overselling' access rights'.

2.2.4 We note that the Impact Assessment states (at paragraph 3.63) that, "*Under the current access arrangements all access rights, once allocated, are treated in the same way in terms of ongoing commitment to the use of the system and charges they face*". This fails to address the fact that Pre-Existing Generators are differently situated from other generators behind a DNCB for the reasons given at paragraph 2.2.3 above.

2.3 Second, Ofgem acknowledges that the proposed amendment fails to differentiate between generators located behind a relevant DNCB in terms of the market power which they may or may not possess as follows:-

2.3.1 Ofgem acknowledges in its Impact Assessment (paragraph 3.83) the risk that an unintended consequence of the proposed amendment, "*might be to increase the incentive on parties not currently wielding market power to use it, as well as the potential for different gaming strategies and indeed possible tacit collusion to be used*".

2.3.2 Ofgem suggests (paragraph 3.84) that this risk would be addressed by the proposed amendment in that it, "*would target the quantum of constraint costs that are due to the exercise of market power, at parties behind the derogated boundary. Therefore, the effect of GB ECM-18 would be to remove the impact of market power from all generators and concentrate it on a few behind the derogated boundary*".

2.3.3 In other words, Ofgem acknowledges (a) that there exists a class of generators within the GB market who do not possess market power but who are impacted by it, (b) that the proposed amendment may increase incentives to exercise such power, but (c) that the effect of the proposed amendment will be to expose only part of such class (i.e. those behind the relevant DNCB) to that increased risk.

2.3.4 Ofgem seek to argue that this discriminatory treatment should somehow be 'balanced' against the way in which the proposed amendment is likely to increase cost reflectivity by targeting the cost of constraints on generators behind the derogated boundary and away from generators whose actions did not contribute to the cost of the constraints. However, this does not amount to an objective justification for imposing additional costs (resulting from the exercise of market power) on this sub-class of generators.

2.4 Again, the discriminatory treatment of particular generators in these ways will result in the distortion of competition within the GB market mentioned above.

3. DISCRIMINATION: IMPACT ON RENEWABLE GENERATORS

3.1 The generators targeted by the proposed amendment include those producing electricity from renewable sources, notably wind. National Grid has a duty to ensure that, in charging for access to or use of the GB transmission system, it does not discriminate against electricity produced from renewable sources, in particular in peripheral regions. This duty arises under Article 7(6) of the Directive 2001/77/EC (the **RES Directive**).

3.2 The adoption and implementation of the proposed amendment would violate this duty in the following manner:-

3.2.1 Electricity generated from renewable sources in Scotland is electricity which is protected from discrimination in terms of Article 7(6).

3.2.2 The proposed amendment specifically targets generation located in Scotland by virtue of its location to the north of the only currently derogated non-compliant boundary on the GB transmission system. Similarly, given that renewables developments tend to be located at the extremities of the transmission network, the proposed amendment will have the effect of targeting renewable generators in future. See, in this respect, the points made in section 1 of our detailed comments and evidence under the heading 'Disproportionate effect on renewables'.

3.2.3 Thus, the proposed amendment will have the direct result of increasing the cost of generating electricity from renewable sources in Scotland as compared to that of generating electricity (including from renewable sources) elsewhere in Great Britain. The Impact Assessment fails properly to take these increased costs into account by asserting (at paragraphs 4.20 – 4.22) without justification (and without having examined the impacts of the proposed amendment on expected returns to renewable generation projects) that such costs are only relevant to the extent that they render investment in renewable generation 'uneconomic'. See further, in this respect, section 1 of our detailed comments and evidence under the heading 'Investment incentives'.

3.2.4 In addition, those increased costs will produce a materially different, and adverse, effect on renewable generators as compared to other generators located behind a DNCB. See further, in this respect, section 1 of our detailed comments and evidence under the heading 'Disproportionate effect on renewables'. The Impact Assessment fails to address this disparate effect.

3.2.5 This discrimination has not been (and, we consider, cannot be) objectively justified by National Grid or Ofgem as required by law.

4. TRANSPARENCY

4.1 The generators targeted by the proposed amendment have the right, as users of the GB transmission system and participants in the GB generation market, to expect that the rules according to which National Grid imposes charges for access to and use of the GB transmission system will operate in a transparent manner. The sources of this right include Recital (6) Articles 11(7) and 23(2) of the Internal Market Directive and Recital (14) and Articles 4(1) and 6(1) of the Regulation on Conditions for Access to the Network for Cross-Border Exchanges in Electricity (the **Access Regulation**).

4.2 In this context, the European Court of Justice has ruled[28] that the objective of the Internal Market Directive, "*can be achieved only by the establishment of precise tariffs or of elements of a methodology of tariff calculation of a level of precision such as to allow economic operators to estimate their cost of access to the transmission and distribution networks*".

4.3 The adoption and implementation of the proposed amendment would violate this right in the following manner:-

4.3.1 In order to satisfy the requirement of transparency, affected generators ought to be in a position where they can reliably estimate their exposure to locational BSUoS charges.

4.3.2 It is evident, however, that liability to pay such charges may arise, cease or be increased or decreased as a consequence of factors which are beyond the control of the charge payer and may, indeed, relate to the output decisions of other generators. The Impact Assessment acknowledges that, "*NGET aims to signal* […] *likely constraint volume* [for the purposes of estimating charges] *to the market based on its evolving forecasts of the variables and evolving information provided by the market. However, NGET states that the accuracy of these forecasts is significantly impacted by the accuracy with which it can predict generator behaviour*" (paragraph 3.82). It also notes that, "*the unpredictability of the BSUoS charges would primarily arise due to the behaviour of the generators, not the way the charges are calculated*" (paragraph 3.95).

4.3.3 While the BSUoS charges that are presently collected from system users vary from trading period to trading period, they apply equally to all generators and therefore do not change the question as to which plants would be most economic to run. Furthermore, by being spread over the whole market, the quantum of the charges for each plant is reduced. Thus, variations in these charges cannot presently have a material impact on decisions by generators as to whether and to what extent to exercise access rights from trading period to trading period. By contrast, the proposed amendment would expose affected generators to variations in BSUoS charges which would have a material impact on such trading decisions, but without providing sufficient means of estimating (or, for that matter, of mitigating) their exposure to those charges in time to influence those decisions.

4.3.4 As a consequence, it is not possible for affected generators to produce reliable estimates of their exposure to such charges.

4.4 See further, in this respect, section 2 of our detailed comments and evidence under the heading 'Generators' ability to anticipate and respond to the level of the charge'.

5. PROPORTIONALITY

5.1 The generators targeted by the proposed amendment have the right, as users of the GB transmission system and participants in the GB generation market, to expect that the rules according to which National Grid imposes charges for access to and use of the

[28] Case C-274/08, Commission v. Sweden, Judgement of 29 October 2009 at paragraph 40.

GB transmission system will operate in a proportionate manner. The sources of this right include Articles 11(7) and 23(4) of the Internal Market Directive, Articles 4 and 6(1) of the Access Regulation and Standard Condition C5 of National Grid's transmission licence.

5.2 The adoption and implementation of the proposed amendment would violate this right in the following manner:-

5.2.1 The stated aim of the proposed amendment is to target the short run cost of providing access to the non-compliant portion of the GB system towards the generators who require such access and, thus, enable them to make economically informed decisions as to the efficiency of their generation output decisions.

5.2.2 However, there is no robust evidence to justify the proposition that the elevated constraint costs arising on DNCBs (the extent of which appears to be doubted by the analysis recently prepared for DECC) result from economically uninformed decisions on the part of generators as opposed to the actions of other market participants or inefficient behaviour on the part of National Grid. See, in this respect, the points made at paragraphs 1.2.5(i) and (iii) above.

5.2.3 On the assumption (which Scottish Power disputes) that pursuit of the stated aim is objectively justifiable, the proposed amendment must represent a suitable means of achieving that aim and enable individual generators to make informed and efficient output decisions. The proposed amendment falls short of this requirement in three separate respects:

(i) First, the liability of each such generator to pay locational BSUoS charges ought reasonably to relate to the output decisions which it takes and not to factors beyond its control. It is evident, however, that liability to pay such charges may arise, cease or be increased or decreased as a consequence of factors which are beyond the control of the charge payer and may, indeed, relate to the output decisions of other generators. See, in this respect, the various points made in paragraph 4 above.

(ii) Second, as discussed more fully in section 2 of our detailed comments and evidence, the Impact Assessment fails properly to assess whether, and to what extent, the potential liability for charges under the proposed amendment would result in the desired (or, for that matter, any) change in the behaviour of affected generators. Indeed, the Impact Assessment appears to suggest that it would be appropriate to approve the proposed amendment on the premise that generator behaviour would be unchanged.

(iii) Third, the Impact Assessment notes the Authority's consultation (and the Secretary of State's own plans) as regards the introduction of a 'Market Power Licence Condition' (paragraph 1.23) and the other work being undertaken by the Authority to tackle the issue of undue exploitation of market power in the wholesale electricity sector (paragraph 3.85). However, no attempt is made to explain or justify the need for the proposed amendment in addressing that perceived issue in addition to those other initiatives or why the proposed amendment is better suited than them to achieving that goal.

5.2.4 In addition, the proposed amendment should not result in the imposition of an excessive individual burden on those generators who are subject to the locational BSUoS charges, having regard to the net increase in use of system charges faced by such generators under the proposal (after taking into account the rebate proposed in respect of their TNUoS charges). However, the proposed amendment falls short of this requirement in three separate respects:

(i) First, it is apparent (for the reasons mentioned at paragraph 1.2.5(iii) above) that the level of charges which would be imposed on individual generators under the proposed amendment is substantially greater than that which ought reasonably to result from efficient constraint management action on the part of National Grid.

(ii) Second, the existence of discrimination within the class of affected generators, as noted in paragraphs 2 and 3 above, means that the group discriminated against would be shouldering a disproportionate share of the liability for the proposed charges.

(iii) Third, as discussed at section 1 of our detailed comments and evidence (under the heading, 'Drivers of constraint costs') it is likely that the effect of the proposed amendment will be to increase National Grid's costs of managing the relevant constraints (and thus the charges borne by affected generators).

5.3 To this extent the charging rules introduced under the proposed amendment are manifestly inappropriate having regard to the stated aim, would result in the imposition of an excessive burden on affected generators and would amount to a disproportionate interference with the rights set out above.

ANNEX 2 – Responses to the specific consultation questions

This annex provides answers to the specific questions posed by Ofgem in chapters 3 and 4 of the Impact Assessment and consultation.

Chapter 3

Question 1. Do respondents have any comments on NGET's analysis?

While NGET has undertaken a detailed analysis, it is not complete. Our main response above sets out a number of reasons why the proposal would be ineffective in reducing the volume of constraints or their cost. These have not been adequately considered by Ofgem or NGET to date.

In addition, NGET did not take into account the potential impact of locational BSUoS if there were no change in the behaviour of generators located behind a derogated boundary. We note this omission despite Ofgem's request in its open letter of June 17th 2009 for NGET to investigate the impacts of the proposal assuming that no significant change in output is achieved.

As discussed in our response, this poses a significant challenge to the GB ECM-18 proposals since absent any change in operating behaviour on the part of generators, the assumed benefits of the proposals will not be realised.

This deficiency is especially significant since NGET has recognised that because the level of the locational BSUoS charge is retrospective, incentivising behavioural change is partly dependent on forecasting constraint costs which are driven by several volatile parameters. As a result, neither NGET nor the generators would be expected to be able to forecast the level of the locational BSUoS charge sufficiently far in advance to allow generators to incorporate this forecast charge into their commercial decisions.

Question 2. Do respondents wish to present any additional quantitative analysis that they consider to be relevant to assessing the proposal?

We have provided in our main response evidence which shows that the principal gains (about 76%) from providing constraint management services through the BM accrue on the Offer not the Bid side. This demonstrates, together with other evidence in our response, that the proposal would be discriminatory.

Further quantitative and qualitative analysis is referred to in our answer to Chapter 4, Question 1 below and in Annexe 3.

Question 3. Do respondents consider that there are any aspects of the proposal that have not been fully assessed?

The analyses undertaken by Ofgem and NGET fail to assess the impact of the proposal on generators' operating decisions and their response to the incentives provided by locational BSUoS. For example, NGET's 'cycling' result provides evidence that generators' output decisions are influenced by the expectation of the behaviour of other generators. That is, in iterations of NGET's modelling where generation is expected to be low (in expectation of high locational charges), subsequent iterations in fact show an increase in generators' output (since locational charges would then be low). The cycling behaviour highlights the flaw in NGET's modelling in which expectations are inconsistent with outturn events. As shown in Figure 3 of our response, the only equilibrium consistent with a competitive market is one in which there is no behavioural change (ie, all generators continue to generate), which raises doubts over the effectiveness and efficiency of the proposal.

NGET and Ofgem have also failed to assess the impact of the proposals on the prices paid to resolve constraints. As set out in section 2 of our response, the proposed charges are likely to increase the prices paid by the system operator to resolve constraints for three reasons: the Bid-Offer spread is likely to widen within the BM; uncertainty caused by the locational charge is likely to lead to more short-term contracting for constraint management services and increased dependence on the BM; and competition for ancillary services may be less effective and innovation may decrease.

As set out in sections 1 and 3 of our response, there are further impacts on renewable generation and on the competitiveness of the GB market which have not been explored.

Taken together, the above considerations would suggest that the existing impact assessment is deficient and that further analysis of the full range of impacts of GB ECM-18 is required.

Question 4. Do respondents consider that the key features of the proposal strike an appropriate balance between cost reflectivity, transparency, complexity and stability?

GB ECM-18 does not strike an appropriate balance between these features of the proposal.

As described in our answer to question 5 (chapter 3) below and as discussed in our response, the proposal is discriminatory and does not provide for cost-reflective charges.

In addition, the proposal lacks transparency. Generators targeted by the proposed amendment have the right, as users of the GB transmission system and participants in the GB generation market, to expect that the rules according to which National Grid imposes charges for access to and use of the GB transmission system will operate in a transparent manner. However, transmission system users under this proposal would be unable to control or forecast their exposures to liabilities arising from locational BSUoS due to its retrospective nature.

Furthermore, the proposals are complex, as highlighted by the analysis recently undertaken by NGET. From the perspective of a transmission system user, several parameters and their interactions would need to be modelled in order to forecast locational BSUoS charge levels. Notwithstanding these challenges, the fact that the level of the proposed charges are sensitive to the strategic interactions of multiple generators suggests that any forecasting exercise is not practicable.

Finally, the proposed charges that would be levied on generators would be unstable, something that is reinforced by the disparate constraint cost estimates available from Ofgem, NGET and Redpoint Energy (the latter of which is most closely aligned with our own views).

Question 5. Do respondents consider that this modification promotes more effective competition? Conversely, do respondents wish to provide further detail of any discrimination concerns?

ScottishPower believes that the proposed modification raises a number of concerns relating to the promotion of effective competition.

First, the proposed modification undermines the fundamental principles of a single GB market and will adversely impact investment in generation in locations affected by constraints in the transmission network. That Ofgem should support this proposal is surprising given that one of the key desired benefits that motivated the creation of BETTA was increased competition in the generation market, which leads to lower system-wide prices and these were believed to outweigh the costs of constraints at the time when BETTA was introduced.

For example, our analysis of the benefits of a single 2GW coal plant in Scotland within the GB market shows that baseload prices are around £0.8/MWh lower with this additional plant, based on historic conditions. This brings a net benefit to consumers of over £250m per year.

By undermining a GB-wide market the implementation of locational BSUoS would serve to impede the development of relatively low cost renewable generation, as well as put at risk the investments needed to maintain existing generation in Scotland (both coal emissions reduction projects and nuclear life extension require significant capital spending). This could reduce competition for CCS demonstration and the prospects for early delivery of the demonstration. These effects would reduce the competitive constraint on generators in England and Wales. Indeed, the analysis provided by Redpoint Energy for DECC shows that the increase in new renewables under a Connect and Manage model will lead to reductions in wholesale prices that exceed the associated increase in balancing costs.

Second, the proposed modification would reduce competition and innovation in balancing services. Locational BSUoS has the potential to distort competition between different constraint management services due to the greater propensity for short-term balancing actions to be used to resolve constraints. In turn, increased reliance on short-term measures may act to dampen innovation and demand for longer-term constraint management services, such as capped PN contracts and commercial intertrip. NGET's intention to signal when constraint action is likely to be greatest may also signal to generators on the other side of a derogated boundary that more profitable opportunities may arise to sell power in the BM rather than the forward market, which may act to distort their operating decisions.

Third, the proposal is discriminatory in a number of respects including that it targets constraint costs on a subset of generators located behind a derogated boundary, and this would distort competition in the generation market. Even if it is assumed that market power were to be exploited, the proposals have the effect of targeting constraint costs that are due to the exercise of market power at all parties behind a derogated boundary. This would imply that generators that are not dominant and those that do not abuse their dominance operating behind a derogated boundary should be more exposed to the effects of the potential exploitation of market power than generators on the other side of a derogated boundary. If such an effect were likely, given the tendency of new renewable generation to locate behind potential derogated boundaries, as set out above, we would expect this to further distort competition and deter investment.

Question 6. Do respondents consider that the proposal complements the changing nature of the transmission network and assists the development of an economic and efficient transmission system?

No. Locational BSUoS would seem intended to disguise the effect of insufficient grid capacity by seeking to make it the problem of generators behind the derogated boundary. This does not seem best calculated to maintain the necessary focus on improving the infrastructure. Nor, for the reasons given in the main response, does it complement the changing nature of the transmission network, especially the growth of renewables in Scotland and behind other potentially derogated boundaries.

In many respects the timely authorisation of investment in new grid infrastructure will be the primary method of resolving transmission constraints and, as noted above, we believe that locational BSUoS could act to mask the urgent requirement to make the GB transmission network able to support the delivery of the government's renewables policy objectives.

Question 7. Do respondents consider that the different methodologies used in the proposal are appropriate?

No, for the reasons given in our main response and in our response on April 29th 2009 to NGET on this subject. In particular, including replacement offers in the cost of resolution includes the "profit" element obtained by replacement generation in England and Wales and has a re-distributional effect on electricity market participants.
In determining the constraint costs to be assigned to the non-compliance of the transmission boundary, there has been no justification of why the most expensive balancing actions should be allocated to the derogated boundary. As the derogation, and potential non-compliance are

known well in advance, the System Operator should be able to take long-term actions to mitigate the effects of constraints in the most economic and efficient manner. The most expensive actions are more likely to have been taken at short notice in response to much shorter-term issues on the transmission system and therefore it would not be appropriate to allocate these costs against the derogated boundary.

Chapter 4

Question 1. Do respondents wish to present any additional quantitative or qualitative analysis that they consider would be relevant to assessing this proposal?

ScottishPower would like to highlight two pieces of quantitative analysis that are relevant to the assessment of the merits of this proposal discussed in chapter 4 of Ofgem's consultation.

First, the analysis presented in Annex 3 of our response shows that, on reasonable assumptions about renewable generation costs and the future development of the electricity market, the impact of locational BSUoS would be detrimental to meeting the Government's renewable targets. Depending on the level of the charge and the scope of renewable technologies that would be affected (which would depend on the number and location of derogated boundaries during the anticipated life of the Renewables Obligation), the loss in total renewable output could be as high as 17%, and reduce the ability of the UK to meet its renewable target by around 5% of total electricity generation. In turn, the cumulative effect of lost renewable generation output over time could be to increase power sector emissions with an associated cost, in present value terms, of £89m-749m.

Second, Figure 1 in our response shows that if a locational BSUoS charge of 4.6 £/MWh were to be incurred by a Scottish wind development for around a quarter of its expected operating hours, the economics of renewable generation would be severely affected. This could lead to a decrease in the IRR of a potential project by some 40 basis projects, which, given future cost and power price uncertainty as well as the competition for capital from other projects and in other markets, could put a significant number of potential projects as risk.

Given that GEMA is required to have regard to the need to contribute to the achievement of sustainable development, the above evidence would suggest that the existing impact assessment is deficient and that further analysis of the impacts on renewable generation investment and deployment is required.

In addition, we would draw attention to our analysis showing that approximately 76% of the cost to NGET of balancing activity undertaken through the Balancing Mechanism arises on the Offer and not the Bid side, and that it would therefore be unfair and discriminatory to target the costs on generators behind derogated boundaries.

We also draw attention to all the qualitative analysis presented in our response.

Question 2. Do respondents consider that there are any aspects of the proposal that have not been fully assessed against the factors set out in this chapter?

As mentioned in our response to question 1 (chapter 4) above, a key aspect of the proposal that has not been fully addressed is the impact on renewable investment and deployment.

Another aspect that has not been taken into account of in the development of the proposed charges is the discriminatory treatment of generators. Specifically, the proposed amendment will have the effect of treating all generators located behind a derogated boundary similarly, irrespective of whether they were connected to the GB system before the date on which the derogated boundary acquired derogated status. This discriminatory treatment remains to be objectively justified by National Grid or GEMA as required by law.

Question 3. Do respondents consider that there is discrimination between transmission system users as a result of this proposal?

The generators targeted by the proposed amendment include those producing electricity from renewable sources, notably wind. National Grid has a duty to ensure that, in charging for access to or use of the GB transmission system, it does not discriminate against electricity produced from renewable sources, in particular in peripheral regions.

The adoption and implementation of the proposed amendment would violate this duty by specifically targeting generation located in Scotland by virtue of its location to the north of the only currently derogated boundary on the GB transmission system. Similarly, given that renewables developments tend to be located at the extremities of the transmission network the proposed amendment will have the effect of targeting renewable generators in future.

In addition, those increased costs will produce a materially different, and adverse, effect on renewable generators as compared to other generators located behind a derogated boundary, as set out in section 1 of our response.

Question 4. We welcome further views on whether the proposal could have an adverse impact on security of supply.

The proposal could prejudice both investment in renewables and life extension investment on existing, especially coal and nuclear, plant. This could have a negative impact on security of supply both in GB as a whole and (depending on progress in upgrading the interconnector with England) Scotland in particular.

Question 5. We welcome further views on whether the proposal could have an adverse impact on sustainability in particular the transition to a low carbon economy.

As discussed in our replies above, our analysis shows that on reasonable assumptions, the proposed charges would be detrimental to meeting the Government's renewable targets and could also be prejudicial to the early demonstration of CCS and the life extension of nuclear plant in Scotland.

Question 6. Do respondents wish to present any further analysis on the wider implications of the benefit that may ultimately be expected to be passed through to consumers?

The analysis in our main response indicates that no such benefit is likely to arise and therefore there is likely to be no benefit to consumers. In a competitive market, all cost movements, up or down, will eventually be passed to consumers.

Question 7. Do respondents have any views on the interaction of NGET's charging proposal with TAR as set out in this chapter?

The Government has just announced its proposal to implement a socialised connect and manage regime as the surest way to maximise the deployment of renewables by 2020. It has published analysis by Redpoint which shows that, without locational BSUoS, the additional cost of constraints is low and more than compensated for by the competitive pressure from the additional generation. We welcome those conclusions.

In our view, it would be taking a huge risk with the progress thus made if the simple and effective model was complicated with locational BSUoS. We believe that any suggestion that renewables deployment would not be significantly prejudiced by locational BSUoS is dependent on optimistic assumptions about the costs of renewable generators and competing electricity.

In the event that these optimistic circumstances do not prevail – quite likely in our view – then Oxera's work for us demonstrates that there would be a significant problem. In our view, it is not worth the risk.

SCOTTISHPOWER
Energy Wholesale

ANNEX 3 – Impact of locational BSUoS on renewable deployment

This annex provides a summary of the methodology, assumptions, and results of analysis to assess the potential impact of locational BSUoS on renewable investment.

Investment in renewable generation and output has been determined using Oxera's independent Renewables model. This simulates investment decisions based on expected revenues from electricity prices and Renewable Obligation Certificates (ROCs), technology specific costs, and returns demanded by investors. The model is run iteratively with Oxera's GB power model to generate power prices consistent with the modelled level of renewable generation.

Policy assumptions and build rate constraints are based on those used recently to inform DECC's Low Carbon Transition plan as well as more recent developments, and are as follows:

- the level of headroom increases from 8% to 10% in 2011, and the obligation size is extended in 2010/11 in line with DECC's recent announcements;[29]
- Re-banding occurs in 2013, which changes the number of ROCs eligible per unit of output for each technology such that offshore wind receives 2 ROCs/MWh and wave and tidal stream receive 3 ROCs/MWh; and
- maximum potential build rates of new installations are capped at the 'high' build rates suggested by the report commissioned from SKM by DECC.[30]

Redpoint's analysis is a substantial and important piece of work. We believe it contributes significantly to the debate around grid access and the UK's ability to achieve policy goals. We agree with the very large majority of their analysis and the main variances tend to be in relation to differing views on commodity pricing assumptions.

The evolution of electricity demand, and generation inputs such as gas, coal and carbon prices, and generation costs are based on Oxera estimates.

As discussed below, differences between these and Redpoint's assumptions are also highlighted:

- average annual gas prices are assumed to be 43 p/therm in 2010, rising to 88 p/therm by 2030. In comparison, Redpoint assumes a gas price that is over 60 p/therm in 2010, and that this will rise to 80 p/therm by 2030. It is notable that the spot gas price is currently 30 p/therm. These assumptions will in part be dependent on the evolution of gas to oil price indexation.
- average annual coal prices are assumed to be 80 $/tonne in 2010, to rise to 87 $/tonne in 2014, and then to settle once again to 80 $/tonne by 2030. Redpoint assumes a coal price of 120 $/tonne in 2010, which appears high in the short term but falls to around 85 $/tonne by 2015. Coal is currently trading at $80-$100/tonne.
- average annual carbon prices are assumed to be 15 €/tonne in 2010, rising to 35 €/tonne in 2030. Redpoint assumes carbon prices of around 25 €/tonne between 2010 and 2020, rising to over €80/tonne by 2030. Carbon is currently trading at just over €13/tonne. The Oxera (and independent ScottishPower view) of carbon

[29] Headroom is used to determine the obligation size if expected generation is sufficiently close or exceeds the obligation size set out in legislation. Details of recent changes are taken from DECC (2009), 'Government response to the 2009 consultation on the Renewables Obligation'.
[30] SKM and AEA (2008) 'Quantification of constraints on the growth of UK renewable generating capacity', June.

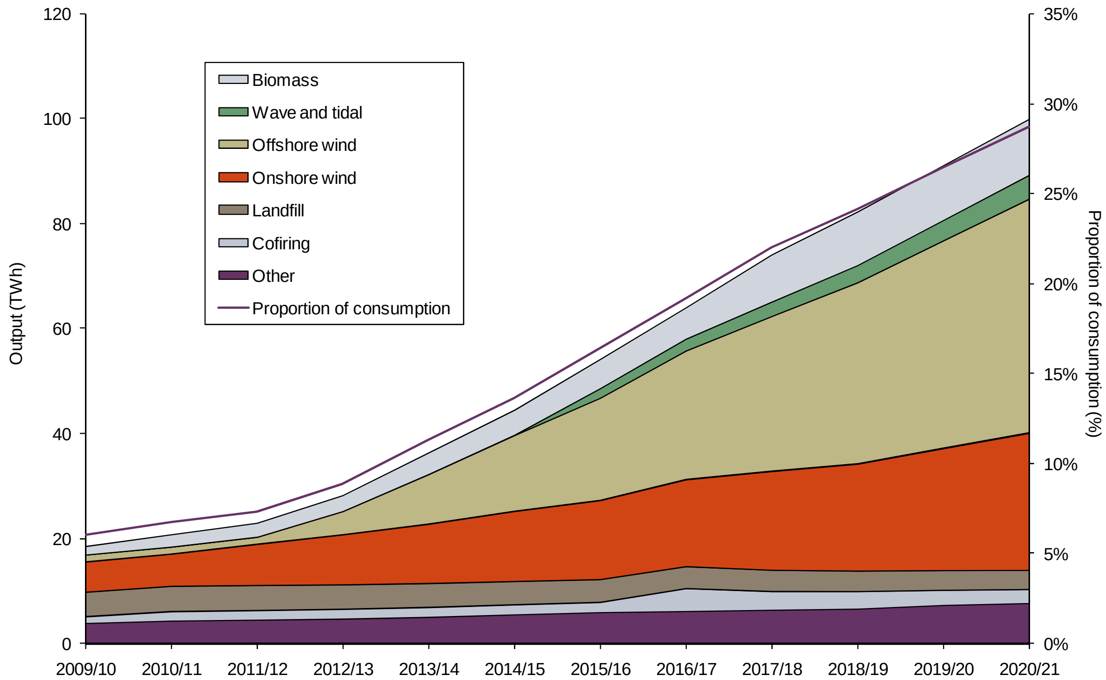
reflects concerns over the sustainability of high CO2 prices absent a global market developing due to the adverse impacts on EU international competitiveness.

- current onshore wind generation capital costs are assumed to lie within the range 1,500–1,600 £/kW, depending on the size and location of particular developments and the scale of grid costs. Offshore wind generation capital costs are assumed to lie within the range 2,667–3,334 £/kW. Redpoint's assumptions are significantly lower, at £1,200/kW and £2,300/kW for onshore and offshore wind, respectively.

The results of modelling under the Oxera base case are shown in Figure A3.1, which shows the following:

- renewable generation is equal to 28.7% of consumption in 2020;
- headroom sets the level of the obligation size in 2010/11 and then from 2013;
- there is a significant dependence on the deployment of onshore and offshore wind to meet the Government's target, which represents around 26% and 45% of renewable output respectively in 2020.[31]

Figure A3.1 Base case renewable output (no locational BSUoS)



Note: Other includes regular and energy crop biomass, Energy from Waste (EFW), hydro, sewage gas, solar, gasification and CHP.
Source: Oxera

Three scenarios of the potential impact of locational BSUoS on deployment are set out below to investigate an increase in the costs borne by the following key technologies: onshore and offshore wind, biomass, hydro, and wave and tidal. The increase in costs modelled includes a variable charge equal to the illustrative targeted constraint cost, and an increase in the hurdle rate demanded by investors.[32]

[31] This proportion differs to the proportion of new capacity represented by wind due to differences in capacity factors across technologies.
[32] Changes in the hurdle rate are constant across scenarios and equal to a one-percentage point increase, consistent with the change in IRR of an onshore wind project with an additional

A range of impacts have been assessed within the following scenarios.

- a potential locational charge of £4.6/MWh included in the investment decisions of all of the key technologies
- a potential locational charge of £4.6/MWh included in half the investment decisions of the key technologies
- a potential locational charge of £10/MWh is included in half the investment decisions of the key technologies

Table A3.1 captures the aggregate differences between the scenarios in 2020.

Table A3.1 Summary of locational BSUoS impacts

	2020 output	2020 renewable generation	NPV of cumulative emissions avoided
Base case	100 TWh	28.7%	230 MtCO2; £4,127m
Change with locational BSUoS			
locational charge (£4.6/MWh) in all investment decisions	-17 TWh	-4.9%	-42 MtCO2; -£749m
locational charge (£4.6/MWh) in half of investment decisions	-3 TWh	-0.8%	-5 MtCO2; -£89m
locational charge (£10/MWh) in half of investment decisions	-4 TWh	-1.1%	-11 MtCO2; -£190m

Note: Emissions avoided are calculated based on displacement of CCGT emissions of 0.34tCO2/MWh. Present values of emissions avoided are calculated using a discount rate of 3.5% based on HM Treasury Green Book and traded carbon prices in DECC guidance on measuring the carbon impacts of policy.
Source: Oxera

Further analysis by technology is shown in Figure A3.2, A3.3 and A3.4.

The analysis highlights the following key results.

- the impact of locational BSUoS would be detrimental to meeting the Government's renewable targets in all scenarios
- marginal onshore wind developments would be deterred across all scenarios, with a loss in output from onshore wind between 2.4 to 3.8TWh, equivalent to around 10% of anticipated onshore investment;
- if all offshore wind investment decisions were to be affected, the loss in total renewable output could be as high as 17 TWh in 2020, and reduce the ability of the UK to meet its renewable target by some 5 percentage points;
- the cumulative effect of lost output over time is to increase power sector emissions, which could be in the range 5-42 MtCO2 in the period up to 2020, with an associated cost of unabated emission of £89m-749m in present value terms.

Whilst we view the Repoint analysis as a valuable contribution to the debate on constraints, it is important to note that the results above differ from Redpoint's analysis of the impacts of

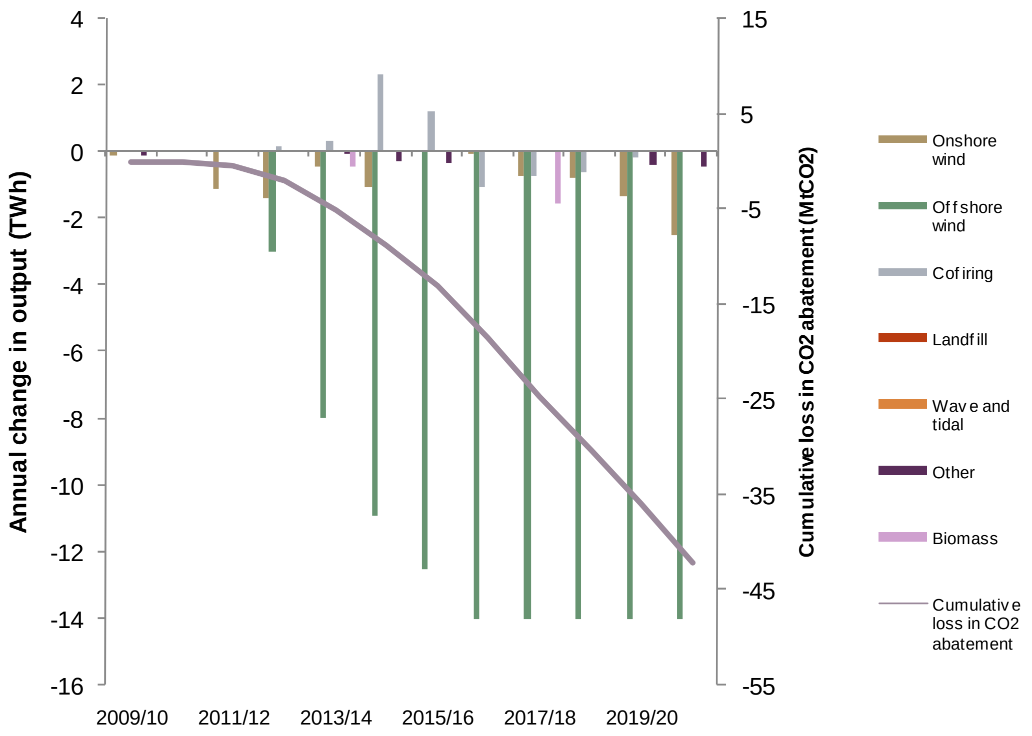
locational charge of £4.6/MWh. This can be thought to represent the increased risk faced by investor's of future regulatory change.

locational BSUoS, which concluded that there may be a limited impact on renewable generation.[33]

We believe that the underlying reason for Redpoint's conclusion is because of the favourable technology cost and power price assumptions employed by Redpoint, which have the effect of increasing the profitability of renewable generation investments to such an extent that the proposed Locational BSUoS charges are prevented from having much effect on investment decisions.

Using other, equally plausible assumptions, including Oxera commodity and power prices more closely aligned with outturn levels, shows that there are a significant number of projects at risk from the proposals, and the analysis above highlights the risks to the attainment of the Government's renewable energy targets.

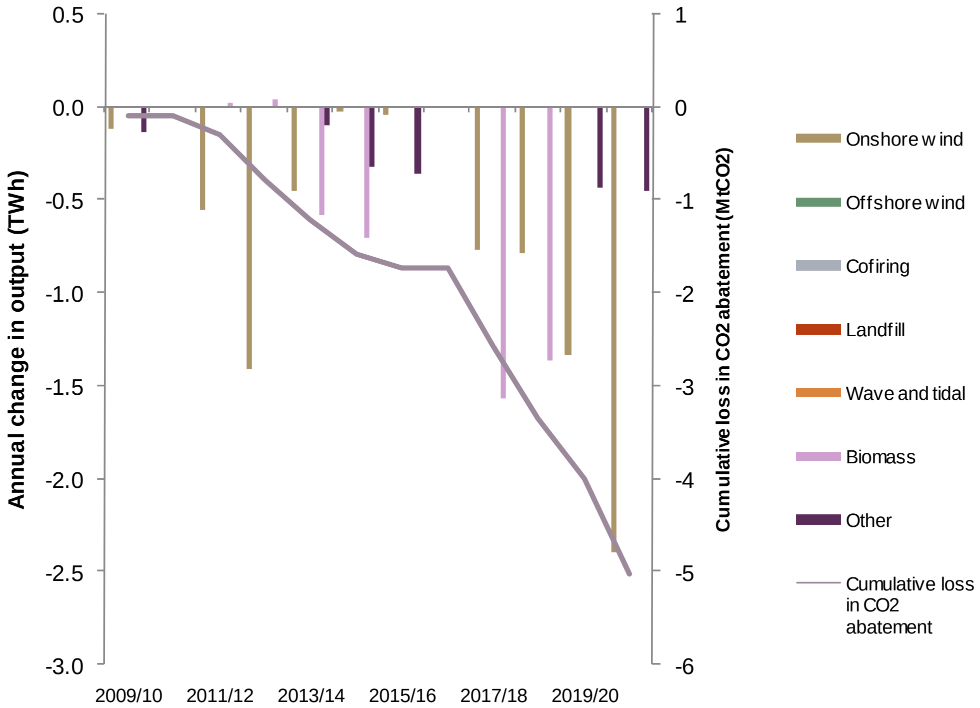
Figure A3.2 Impact of locational BSUoS (£4.6/MWh in all investment decisions)



Source: Oxera

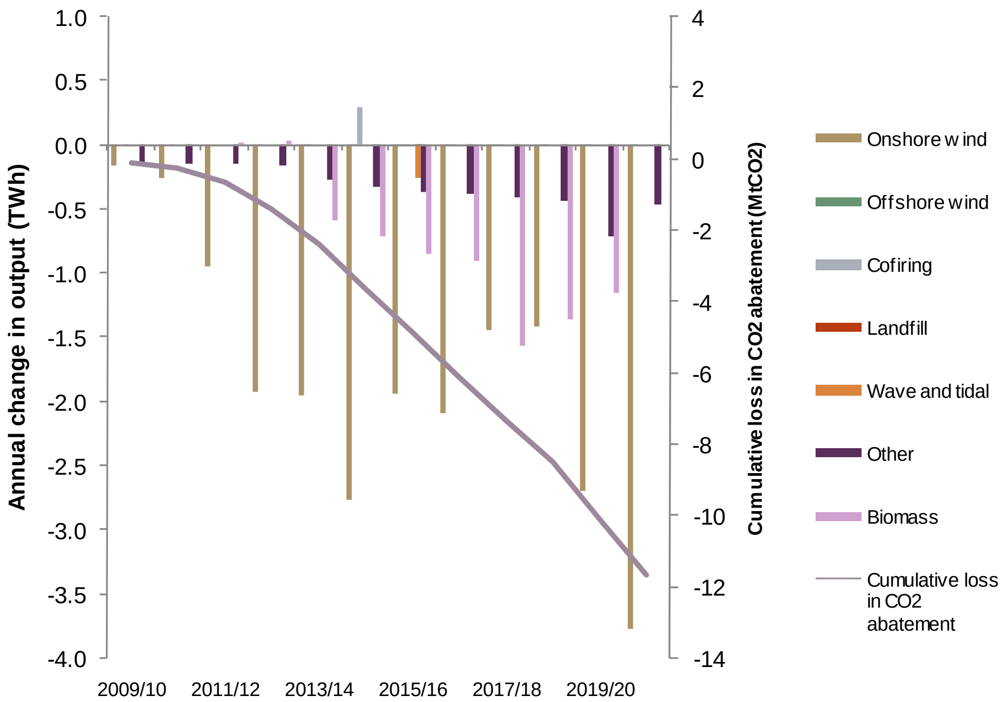
[33] Redpoint Energy (2010), 'Improving Grid Access: Modelling the Impacts of the Consultation Options', January.

Figure A3.3 Impact of locational BSUoS (£4.6/MWh within half of investment decisions)



Source: Oxera

Figure A3.4 Impact of locational BSUoS (£10/MWh within half of investment decisions)



Source: Oxera