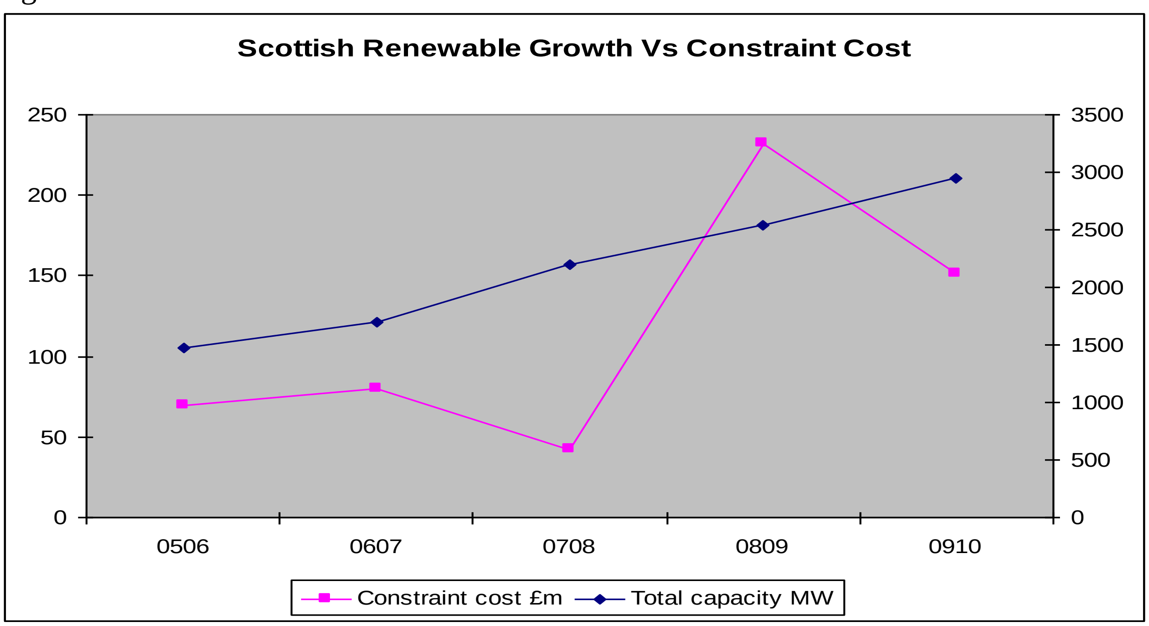
CHAPTER: Three

Question 1. Do respondents have any comments on NGET's analysis?
Yes, we have significant concerns with the underlying constraint cost forecasts that the proposal is justified on. It is clear looking at the forecast outturn costs for this year that NGET's forecasting is flawed. NGET's first forecast of GB constraint costs for 2009/10 was £307m, made in December 2008. They are now forecasting £198m and we believe that this will be much lower, given we are through the summer outage period of high constraints. NGET are incentivised to overstate constraint costs and disincentivised to contract for constraint management services (that would lower the costs) before their SO Incentive scheme is set at the end of March.

Contrary to what is stated in the RIA (attributed to NGET), that the increase in constraint costs is due to increased generation in Scotland, there is no correlation between the jump in constraint costs in 2008/09 and increased wind generation. This can be seen in the graph in Figure 1 below.

Figure1



Instead, the current level of constraints is primarily due to circuits being taken out of service that will allow upgrading of the network, allow new generation to connect and reduce constraint costs. It can be seen from the constraints data in Table 1 below, that whilst in the first year of BETTA, the Cheviot constraint costs are higher than that in E&W, they settle down at a lower level in 06/07 and 07/08, before the Cheviot "Interconnector" upgrade works started in 08/09.

Constraint Cost	05/06 Actual (£m)	06/07 Actual (£m)	07/08 Actual (£m)	08/09 Actual (£m)	09/10 Latest Forecast (£m)
E&W	13	28	29	31	55
Cheviot	44	25	22	178	106

Without the upgrade works, the underlying constraint cost in Scotland would be of the order of £40m to £50m. It should also be noted that the consequence of upgrade works increasing constraint costs was recognised, though not quantified, in the analysis carried out for the introduction of BETTA, the constraint costs forecasts were based on *"the assumption of an intact network and that this is optimistic, particularly in light of the significant construction outages required to accommodate additional windfarm generation."* .

There is a great deal of focus in the RIA on the reduction of constraint costs through the implementation of Locational BSUoS. It is presented that there will be a decrease in constraint costs, saving hundreds of millions of pounds. However, there has been little detailed analysis provided on the wider impact that Locational BSUoS will have on wholesale market prices and indeed Balancing Mechanism prices. Ofgem simply conclude that it appears that "*the wholesale price does not have a large impact on the case for introducing the proposed modification"*. However, both the Redpoint and Frontier Economics analysis (for DECC and Ofgem respectively) have shown that the benefits of increased generation entry on the wholesale price can be significant and can outweigh the cost of constraints under a Connect & Manage regime.

Further, Redpoint's recent analysis of Locational BSUoS for DECC, and its impact on constraint costs and wholesale price shows that in their Central Case over the period to 2020, implementing Locational BSUoS is broadly neutral, compared to a fully socialised model (a £7m NPV on NPVs of around £1.6bn). It should be noted that the analysis takes no account of the change on BM prices, and that given DECC's minded to statement of 14th January 2010, any Locational BSUoS proposal implemented by Ofgem will be short-lived and therefore any savings will, if any, be negligible. It is therefore clear that a) there has not been sufficient analysis of this carried out either by NGET or Ofgem as part of the RIA and b) that the implementation of Locational BSUoS will at best result in little if any overall savings, rather than the savings put forward in the RIA for constraints in isolation. In short, Locational BSUoS will not produce the anticipated cost savings and could in fact increase costs overall.

NGET's analysis and a "key input" to Ofgem's is based on data from 2008/09. Not only does this not take account of the most recent summer outage programme in 2009, the year 2008 has already been recognised and quoted by both Ofgem and NGET as "atypical"[1].

The analysis by NGET is based on there being an *"instantaneous feedback loop"* between generators getting and acting on information on Locational BSUoS costs.

[1] Recognised in Ofgem's letter on TAR, issued on 27 February 2008, where, in NGET's commentary on Project Rationale, it is stated that *"data in respect of the current year is atypical and is influenced by unusual conditions which are not believed to be representative of the long term outlook"*.

However that will not be the case. Generators will not have sufficient information on other generators' behaviour ex-ante and will only have outturn BSUoS data two working days later. It is clear that there will be no instantaneous feedback loop and therefore it puts NGET's analysis in doubt.

The RIA is also deficient in assessing the impact the proposal would have on companies' IT systems and the time it will take to put new systems in place. In our case we have estimated that the changes required to our Front office, Back office and financial reporting systems will take some 6 months to put in place.

This is a complex change. NGET have found it difficult to predict how generators will behave and therefore how to model the outcome of the change. This raises doubts about the analysis but also raises concerns with regard to any unintended consequences, which there are certain to be.

Question 2. Do respondents wish to present any additional quantitative analysis that they consider to be relevant to assessing the proposal?
We would refer to the analysis completed by Redpoint and Frontier Economics in relation to the impact on wholesale market prices and our comments in response to Question 1 above.

Question 3. Do respondents consider that there are any aspects of the proposal that have not been fully assessed?
The most significant failing has been the analysis of the wider impact on wholesale and Balancing Mechanism prices, that when these are taken account of, there is no net gain from the implementation of Locational BSUoS.

Question 4. Do respondents consider that the key features of the proposal strike an appropriate balance between cost reflectivity, transparency, complexity and stability?
No. We do not believe that the proposal is cost reflective. We do not believe that the imposition of short-run cost has been appropriately justified. Justification is given for its implementation at the derogated Cheviot boundary because the short run costs of access (i.e. constraint costs) are diverging from the long-run cost (i.e. TNUoS). However, the cost of constraints in E&W of £100m for the Thames Estuary constraint clearly highlights that constraint costs can be high, and that the short-run costs can diverge from the long-run costs <u>without</u> there being a derogated boundary. The specific targeting of such short-run constraint costs at Scotland can be seen as wholly unjustified and discriminatory.

In addition, the derogated boundary is used as a justification for the imposition of a short-run cost of access charge. However, this is based on a statement in the RIA that the long-run TNUoS charge assumes a compliant system. We believe that there is a question mark over the way that the derogated boundary and the Security Factor are treated in the

TNUoS model[2]. We believe that the TNUoS model already makes allowances for the derogated boundary meeting the security standards. That being the case, it would be inappropriate to then apply a "short-run" Locational BSUoS cost to Scottish generators in addition to the cost already being paid under TNUoS.

It is also stated that in a non compliant system, locational behaviour of generators can have a high impact on short-run costs. However, it is not just Scottish generators that have an impact on these costs, E&W generators have an impact on both costs and volumes, through their Offer prices and plant disposition. It is also commented that the costs have increased beyond what would be considered efficient. However, this level of cost is within the range of constraint cost anticipated at BETTA. It is not clear why this would now be considered inefficient. It is also commented in the RIA that the level of constraints could remain high given the long queue of generators waiting to gain access. But as shown above, there is no correlation between the jump in constraint costs in 2008/09 and new renewable connections. The level of constraints is dependant on infrastructure upgrade works to ultimately reduce constraints and provide renewable generation access in the long term. We therefore do not believe that the imposition of a short-run Locational BSUoS signal is cost-reflective.

The Locational BSUoS proposals are complex, the costs will be unknown ex-ante and will be extremely volatile as they depend on many factors including circuit configuration, circuit outages, generation operation in Scotland and E&W and generator Bids in Scotland and Offers in E&W. The whole process will be dynamic and iterative. If, as proposed, Locational BSUoS is applied at multiple "nested" derogated boundaries, this will increase the complexity even further. There is also a risk of a feedback effect to the extent that certain generators take into account anticipated future BSUoS costs in Scotland in their balancing market Bids and Offers. As such the Locational BSUoS costs will be unknown and therefore there can be no meaningful signal given to generators on how they should operate nor, importantly, to those planning to invest in Scotland.

We also believe that the proposal lacks the degree of transparency that will allow generators to be able to take any meaningful action. The analysis by NGC is based on there being an *"instantaneous feedback loop"* between generators getting and acting on information on Locational BSUoS costs. However that will not be the case. Generators will not have sufficient information on other generators' behaviour ex-ante and will only have outturn BSUoS data two days later.

As the costs of constraints are simply recycled back into Scotland, the proposals also mean that there can be no meaningful signal given to the Transmission Companies on when to reinforce the transmission network or to incentivise the SO in managing the system.

[2] In calculating the Security Factor, NGET state that they run a secure DCLF ICRP transport study, and that this calculates the nodal marginal costs where peak demand can be met despite the Security and Quality of Supply Standard contingencies. This suggests that, in contrast to the statement in the RIA, the TNUoS model makes allowances for the derogated boundary meeting the security standards.

Given the whole process will be dynamic and iterative, it provides no stable signal to generators. Overall, the proposal does not strike an appropriate balance between cost reflectivity, transparency, complexity and stability.

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

No we do not believe the proposal promotes more effective competition. Targeting constraint costs at Scottish generators reduces competition in the wholesale market and the Balancing Mechanism. The impact on the wholesale market needs to be taken account of in the assessment of the proposals. Only Redpoint's analysis tackles this. We do not believe that the proposal promotes a more economically efficient use of the transmission system, given the difficulties participants will have in working out what the short-run costs of Locational BSUoS will be and that most parties will have little control of the costs being imposed nor have any alternative but to absorb the costs.

We also have significant concerns with respect to discrimination. The proposal clearly discriminates against Scottish generators. The forecast Cheviot constraint cost of £180m for 2010/11, largely associated with outages on the Cheviot circuits, is to be targeted through Locational BSUoS at Scottish generators. However, the forecast cost of £100m associated with the Thames Estuary circuit outages in E&W in 2010/11 is not being targeted at the generators behind that constraint and will continue to be socialised. It is also clear that whilst E&W constraints costs are forecast to go up by more than three times in 2010/11, Scottish constraint costs will go up by a much lower degree, yet no form of targeting is proposed for E&W constraints.

As well as Locational BSUoS being introduced because of the increase in constraint costs in Scotland, further justification is given for its implementation at the derogated Cheviot boundary on the grounds that the short run costs of access (i.e. constraint costs) are diverging from the long-run cost (i.e. TNUoS). However the cost of constraints in E&W clearly highlights that constraint costs can be high, and that the short-run costs can diverge from the long-run costs without there being a derogated boundary. The specific targeting of such short-run constraint costs at Scotland can be seen as wholly unjustified and discriminatory.

Further justification given for Scottish generators being targeted is that only they have control over the level of constraints and costs. However, this is flawed, as these constraint cost are determined from a number of factors in relation to the Cheviot boundary: generation in Scotland; generation in E&W; demand in Scotland; demand in E&W; the infrastructure that is taken out for routine maintenance; the infrastructure that is taken out whilst reinforcement work is undertaken; the infrastructure build that is delayed and indeed NGET's strategy for managing constraint costs. More particularly, not only do E&W generators influence costs at the Cheviot boundary through their Offers in E&W into the Balancing Mechanism, they also influence volumes as the transfers at the Cheviot boundary are dependant on the disposition of plant in E&W, especially generation in the North of England. This has always been the case and was a feature of the operation of the Interconnector prior to BETTA (transfer levels were referenced to E&W generation in Appendix K of the Interconnector Agreement). It is also noted in NGET's report on access options in the run up to BETTA, that *"generation close to the SP-NGET interconnector (particularly North West England) will have an impact on the capability of the interconnector"*. Given the level of influence E&W generators can have on the constraint costs and volumes at the Cheviot boundary, targeting the costs at only Scottish generators is wholly discriminatory.

The introduction of Locational BSUoS will increase costs and risks to new renewable investments having a particularly detrimental effect on the financing of independent development. It is also clear that existing renewables, through their inherent inflexibility to dispatch, will not be able to react to the additional costs, having simply to absorb the cost.

The proposal also clearly discriminates against Scottish non-portfolio generators, particularly those that are inflexible. These generators have no influence on the economic level of constraints. They also do not benefit from any upside in the reduction in BSUoS in E&W. Such outcomes are highly unsatisfactory and clearly discriminate against renewable generators as a class, and in particular independent non-portfolio developers.

The Derogated Boundary

The derogated boundary is used as a justification for the imposition of a short-run cost of access charge. This is based on a statement in the RIA that the long-run TNUoS charge assumes a compliant system. However, we believe that there is a question mark over the way that the derogated boundary and the Security Factor are treated in the TNUoS model[2]. We believe that the TNUoS model already makes allowances for the derogated boundary meeting the security standards. That being the case, it would be inappropriate to then apply a "short-run" Locational BSUoS cost to Scottish generators in addition to the cost already being paid under TNUoS.

We also question Ofgem's rational in picking out the derogated boundary at BETTA for special treatment when there are many derogations applied across the market and have been since privatisation. For example, generators that do not meet the requirements for Reactive capability or Frequency Response capability. These increase costs to customers and disadvantage those generators that do not have derogations and provide the services, sometimes under scrutiny from Ofgem, because they are the only ones that actually provide a service to NGET. Ofgem's focus on only one derogation, the derogated Cheviot boundary is inconsistent and discriminatory.

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. We do not believe that there is an underlying problem. The level of constraints is overstated, is the result of outages on the system to allow reinforcement that will reduce constraints and allow more renewables to connect and is within the levels envisaged at BETTA. The proposal discriminates against certain generators, mainly those in Scotland when it is clear that E&W generators influence both the level of constraint and the volume of constraints at the Cheviot boundary. The proposal is complex and as such will provide no meaningful signal for generators to react to. It also removes any signal for network investment and SO incentivisation. The proposal does not guarantee a reduction in constraint costs only that they will be targeted at Scottish generators. Any reduction in constraint costs cannot be seen in isolation. The work by Redpoint highlights that there is likely to be no benefit from the proposal overall. The level of constraint costs in the Thames Estuary highlights that this level of constraint cost is not unique to the Cheviot boundary. The nature of the transmission network is changing because of new renewables connecting in Scotland. This proposal with its inherent complexity and costs for renewables can only deter investment essentially bringing the *"changing nature of the transmission network"* to a halt.

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

No.

In relation to moving part of the locational signal from long run to short run, we would refer to our comments above, where justification is given for its implementation at the derogated Cheviot boundary because the short run costs of access, i.e. constraint costs are diverging from the long-run cost, i.e. TNUoS. The cost of constraints in E&W of £100m for the Thames Estuary constraint clearly highlights that constraint costs can be high, and that the short-run costs can diverge from the long-run costs <u>without</u> there being a derogated boundary. The specific targeting of such short-run constraint costs at Scotland can be seen as wholly unjustified and discriminatory.

In addition, the derogated boundary is used as a justification for the imposition of a short-run cost of access charge. However, this is based on a statement in the RIA that the long-run TNUoS charge assumes a compliant system. We believe that there is a question mark over the way that the derogated boundary and the Security Factor are treated in the TNUoS model[2]. We believe that the TNUoS model already makes allowances for the derogated boundary meeting the security standards. That being the case, it would be inappropriate to then apply a "short-run" Locational BSUoS cost to Scottish generators in addition to the cost already being paid under TNUoS.

It is also stated that in a non compliant system, locational behaviour of generators can have a high impact on short-run costs. However, it is not just Scottish generators that have an impact on these costs, E&W generators have an impact on both costs and volumes, through their Offer prices and plant disposition. It is also commented that the costs have increased beyond what would be considered efficient. However, this level of cost is within the range of constraint cost anticipated at BETTA. It is not clear why this would now be considered inefficient. It is also commented in the RIA that the level of constraints could remain high given the long queue of generators waiting to gain access.

But as shown above, there is no correlation between the jump in constraint costs in 2008/09 and new renewable connections. The level of constraints is dependant on infrastructure upgrade works to ultimately reduce constraints and provide renewable generation access in the long term. We therefore do not believe that a short-term Locational BSUoS signal is warranted.

On targeting costs at only Scottish generators, we have the same comments as above, in relation to costs being higher on a non-compliant system and that they will persist given the long queue of generation waiting to connect. With regard to the level of constraints caused by a capacity shortfall on the Cheviot boundary, we would note that the current level of constraints is primarily due to circuits being taken out of service that will allow upgrading of the network, allow new generation to connect and reduce constraint costs. It can be seen from the constraints data in Table 1 below that whilst in the first year of BETTA the Cheviot constraint costs are higher than that in E&W, they settle down at a lower level in 06/07 and 07/08, before the Cheviot "Interconnector" upgrade works started in 08/09.

Table 1

Constraint Cost	05/06 Actual (£m)	06/07 Actual (£m)	07/08 Actual (£m)	08/09 Actual (£m)	09/10 Latest Forecast (£m)
E&W	13	28	29	31	55
Cheviot	44	25	22	178	106

We do not agree with the statements attributed to NGET that the costs are primarily due to the over selling of access capacity to Scottish generators. The costs are due to the interconnector circuits being taken out of service for upgrade works. Without this, the level would be significantly lower, some £40m to £50m. We also do not agree with the statement that the costs arise directly from actions taken by these (Scottish) generators. As noted above, the costs and volumes are influenced by the Offers and plant disposition of generators in England.

On including generation margin in the costs, we continue to believe that it is inappropriate for margin costs to be passed back to Scottish generators. There is no obligation to provide margin. Indeed the Cheviot constraint limits the ability of Scottish generators to provide Offers into the GB Balancing Mechanism. So Scottish generators lose out on providing Offers, then get charged for not being able to offer what would be free headroom to NGET, at prices that are solely related to E&W generation. This is both absurd and unreasonable.

In addition to the above we would also make the following points on the methodology used by NGET. The calculation and attribution of Locational BSUoS costs remain complex and non-transparent. NGET's constraint cost attribution is not sufficiently transparent, robust, developed or consulted upon to provide the basis of attribution of costs to market participants in Scotland.

The treatment of intertrips and constrained-on generation lacks development and clarity. It is not clear how generators that provide an intertrip service or other network services e.g. for voltage support, running under instruction from NGET, will be treated with respect to the allocation of Locational BSUoS costs.

We also continue to seek clarification on NGET's logic in relation to the level of constraints to be attributed to Locational BSUoS, that *"if the volume of constraints taken to manage the B6 boundary is less than or equal to 1813MW, the cost of this volume will be allocated to the Locational BSUoS charge.*" This ignores the fact that even a compliant boundary can have constraints that would be allocated to non-locational BSUoS, and therefore that a non-compliant boundary can also have constraints that should be allocated to non-locational BSUoS. NGET recognise this in section 4.4 of the consultation. However, having recognised this, allocating the first tranche of constraint costs to Locational BSUoS ignores this logic. For example, during the summer, circuits will be taken out for upgrade works. Whether or not the Cheviot circuits (Interconnector) is compliant, the removal of these circuits will cause constraints, and the cost of the constraints associated with the removal of these circuits should be allocated to non-locational BSUoS regardless. It means that the first tranche of volume cannot automatically be allocated to Locational BSUoS. Indeed, there would appear to be a contradiction with the graphic representation given in Figure 4 in the Constraint Costing Methodology paper.

Finally, we would question whether it is appropriate to use long term planning values to calculate the level of costs that would go towards Locational BSUoS. In operational timescales, there is scope to increase the level of the Interconnector transfer. On an intact network, the transfer would at times be greater than 2,200MW, the transfer level being dependent on the varying generation pattern in Scotland and the North of England. We believe therefore that it is inappropriate to cap the transfer level at 2,200MW when calculating the cost attributable to Locational BSUoS.

CHAPTER: Four

Question 1. Do respondents wish to present any additional quantitative or qualitative analysis that they consider would be relevant to assessing this proposal?
Please refer to our answers to Questions 1 and 2 in Chapter Three above.

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 noted above, the most significant failing has been the analysis of the wider impact on wholesale and Balancing Mechanism prices, that when these are taken account of, there is no net gain from the implementation of Locational BSUoS.

Question 3. Do respondents consider that there is discrimination between transmission system users as a result of this proposal?
Yes. As noted above in response to Question 5, we believe that the proposal is discriminatory on a number of levels.

Question 4. We welcome further views on whether the proposal could have an adverse impact on security of supply.
It is clear that during the recent cold spell this winter, with a prolonged high pressure across the UK, little generation output came from wind. It has been put forward in the RIA that there will be little impact on security of supply from the proposal, that even if a coal set shut in Scotland, there would be little impact on security of supply. Even if that were the case in GB, given the fact that the Cheviot boundary transfer going North into Scotland is actually lower than the transfer limit going South, and with increasing wind generation in Scotland, if existing thermal plant in Scotland closes, even if the rest of GB is secure, there could be negative implications for Scotland's security of electricity supply.

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.
We do not believe that this proposal does anything for the transition to a low carbon economy. The additional risk and costs of the proposal will make financing of independent projects more difficult and deter investment in renewables in Scotland. This increased risk is not balanced by a complementary lessening of risk in E&W. Therefore the overall impact will be negative. This increased risk and cost is likely to materialise in two ways, some marginal projects not going ahead (which some would put down as not being material at present), but more importantly that individual projects will be developed at a smaller scale as the marginal wind turbines on a specific site become uneconomic to develop sooner.

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?
As noted in our response to Question 1 Chapter 3, we do not believe that the proposal will result in an overall benefit to customers. Analysis of the wider impacts of increased renewable generation connecting to the system shows that this lowers wholesale prices. Analysis of this in respect to Locational BSUoS has been carried out by Redpoint for DECC. Without taking account of Balancing Mechanism prices, Redpoint's analysis shows that over the period to 2020 (it should be noted that given DECC's minded to statement of 14th January 2010, any Locational BSUoS proposal implemented by Ofgem will be short-lived), the scheme is broadly neutral.

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

Ofgem continue to take forward the proposal despite the clear intention of DECC to introduce Connect & Manage with a fully socialised BSUoS charge as noted in their "minded to" statement of 14th January 2010. No matter what Ofgem decide, given DECC's powers under the Energy Act 2009, Ofgem's decision is going to be overwritten. Any decision by Ofgem can only be very short-lived, indeed it is unlikely that changes to systems could be made in time for implementation before DECC's implementation of Connect & Manage on or before June 2010. It makes the ongoing pursuit of this proposal by Ofgem inefficient and costly to all market participants.