

# Integrated Transmission Planning and Regulation (ITPR) Project: Emerging Thinking

## Consultation

**Reference:** 83/13  
**Publication date:** 5 June 2013  
**Response deadline:** 2 August 2013

**Contact:** Charlotte Ramsay, Head of European Electricity Transmission  
**Team:** ITPR  
**Tel:** 020 7901 0512  
**Email:** [ITPRMailbox@ofgem.gov.uk](mailto:ITPRMailbox@ofgem.gov.uk)

### Overview:

The Integrated Transmission Planning and Regulation (ITPR) project is a review of the Great Britain (GB) electricity transmission arrangements for system planning and delivery that currently apply to onshore, offshore and interconnector assets. Our focus is on whether these separate regimes can continue to ensure the efficient, coordinated and economic development of the overall network over the longer-term.

This document sets out our initial analysis of options to facilitate efficient and coordinated planning and delivery, both within and across regimes, including those which may combine multiple purposes such as onshore reinforcement, connection of offshore generation and interconnection with other countries. We seek views on our emerging thinking and on whether any other options should be considered. We plan to set out further analysis in an impact assessment alongside our initial proposals around early 2014.

## Context

---

The ITPR project is considering the existing GB electricity transmission arrangements for planning and delivery and is assessing whether any changes are appropriate to facilitate a future integrated system for onshore and offshore transmission and interconnection. This is in response to the longer-term challenges arising from the move to a decarbonised energy system.

We launched ITPR with an open letter in March 2012, setting out the drivers for the project and seeking views. We published a second open letter in November 2012 seeking further views on the potential issues that stakeholders had identified may pose a barrier to facilitating an integrated network. This document sets out our emerging thinking in light of our initial analysis of the potential options. It also discusses the broader policy context and interactions with related policy areas through which some issues relevant to ITPR are being considered in the nearer term. These policy areas include Strategic Wider Works, offshore coordination, interconnector regulation and Electricity Market Reform (EMR).

## Associated documents

---

Associated documents: ITPR

[Open Letter: Planning for an integrated electricity transmission system – request for views, 23 March 2012](#)

[Open Letter: Update on the Integrated Transmission Planning and Regulation Project – request for further views and evidence, 6 November 2012](#)

[Imperial College London and Cambridge University: Review of System Planning and Regulation, report on approaches and international experience on system planning and delivery, May 2013](#)

[Sinclair Knight Merz \(SKM\) review of worldwide experiences of voltage source converters \(VSC\) technology for High Voltage Direct Current \(HVDC\) installations, March 2013](#)

Associated documents: Other

[Cap and Floor Regime for Regulated Electricity Interconnector Investment for application to project NEMO, 7 March 2013](#)

[Consultation on a proposed framework to enable coordination of offshore transmission, 7 December 2012](#)

[Implementing competition in onshore electricity transmission: update, 23 April 2012](#)

---

## Contents

---

<b>Executive Summary</b>	<b>i</b>
<b>1. Introduction</b>	<b>1</b>
The Integrated Transmission Planning & Regulation project	1
This document	2
<b>2. Current arrangements and future developments</b>	<b>4</b>
Current arrangements	4
Future developments	5
Areas for review under ITPR	7
<b>3. Initial analysis of options for system planning</b>	<b>8</b>
Introduction	8
Overview of options for system planning	10
Options for depth of the system planning coordination function	13
Planning an integrated electricity transmission system	13
Options for institutions, separation and transparency	18
Analysis of synergies, potential conflicts and institutional options	18
Approaches for identifying cross-border capacity needs	21
Background	21
Alternative approaches	23
<b>4. Initial analysis of options for delivery of transmission assets</b>	<b>27</b>
Introduction	27
Delivery options considered	30
Option 1: No flexibility in use of delivery routes	30
Option 2: Limited flexibility in use of delivery routes	32
Option 3: Full flexibility in use of delivery routes	33
Discussion on additional flexibility in use of delivery route	33
<b>5. Emerging thinking and next steps</b>	<b>37</b>
Emerging thinking	37
Case for change	37
System planning	38
Framework for delivery of transmission assets	39
Next steps	40

---

<b>Appendices</b>	<b>42</b>
<b>Appendix 1 - Consultation Response and Questions</b>	<b>43</b>
<b>Appendix 2 – 2<sup>nd</sup> ITPR workshop – further details</b>	<b>46</b>
<b>Appendix 3 – Comparison of the current regimes</b>	<b>47</b>
<b>Appendix 4 – Summary of responses to November 2012 open letter</b>	<b>51</b>
<b>Appendix 5 – Other initiatives</b>	<b>53</b>
<b>Appendix 6 – Glossary</b>	<b>56</b>
<b>Appendix 7 - Feedback Questionnaire</b>	<b>61</b>

---

## Executive Summary

---

The UK energy system is on a trajectory towards decarbonisation, with stretching targets to 2020 and beyond. These policy objectives are driving significant development of the electricity system to accommodate changes in use and support integration of new forms of generation. The full impact of these drivers is uncertain, but could be significant.

In GB, separate regimes currently apply to investment in transmission onshore, offshore and cross-border. To date, these have delivered considerable levels of investment. This has been achieved by different bodies having a role in system planning and a combination of monopoly regulation, competitive and developer-led approaches to delivery. However, given the increasing scale and technical complexity of the network it is timely to consider whether the current arrangements continue to provide the right framework. For example, planning across GB electricity networks may not be sufficiently coordinated to enable realisation of future integrated assets and the boundaries of the current regimes may unnecessarily limit delivery options. This could create perverse incentives or inhibit integration. The ITPR project is considering the system planning and delivery arrangements with a view to enabling a more integrated and efficient approach to development of the transmission system.

### **System planning**

At present, system planning onshore is led by the Transmission Owners (TOs) responding to requests for connection from grid users, by generators offshore and by developers in relation to interconnection. The System Operator (SO) plays a limited role. Potential alternative approaches to the planning of investments include: improving and formalising coordination among the parties involved in system planning; increasing the role for a single coordinating body; or separating the planning functions from other transmission activities.

Improving coordination between all transmission parties could offer some improvement to planning, but may not go far enough to support complex, integrated projects. Increasing the role of a single coordinating body may improve the outcome for such projects, but could increase concerns as to conflicts of interest if that body were National Grid plc (NGET). Separation of the planning function to form an independent body (either as an Independent System Operator (ISO) or Independent Design Authority (IDA)) could mitigate this, but could create significant disruption and reduce existing synergies within NGET between the TO and SO.

### **Delivery of transmission assets**

Currently, there are three distinct delivery mechanisms applied according to the legal classification of the asset: onshore; offshore; and interconnection. Potential alternative approaches include: setting out a process for how a new licence will be awarded if the asset classification changes; adapting the regimes on a limited basis to allow the original licensee to continue to operate the asset even if its classification

changes; or adding flexibility to the use of different delivery routes to allow for either a competitive approach or incumbent delivery, regardless of classification.

Clarifying the process for change of asset classification could minimise uncertainty for projects already under development but may create perverse incentives to design the network to avoid competitive tender. Limited adaptation of regimes could remove these perverse incentives, but does not provide an obvious solution for all potential multiple purpose projects (MPPs). Adding flexibility to the use of delivery routes could provide greater certainty of delivery route for MPPs and could also allow for alternative delivery approaches where this is in the interests of consumers. However, the time taken to effect such reform may mean it could be too late for some projects already facing challenges and the scale of reform may not be justified if some investment fails to materialise.

### **Our emerging thinking**

Our emerging thinking is that an evolutionary approach is needed given the current level of uncertainty over the scale, timing, cost and technical complexity of network development required. This approach builds upon the policy development already undertaken on anticipatory investment and improved coordination within existing regimes and would help Ofgem evaluate the increasingly complex mix of factors involved in projects that come to us for funding approval. It would also minimise investor uncertainty to continue to facilitate the significant investment needed.

For system planning, our emerging thinking is that there may be merit in enhancing NGET's current role as SO to include new responsibilities for coordination of system planning. This could include: identifying strategic system needs; working with relevant parties to identify potential coordination opportunities and preferred solutions at a GB level; and reviewing the needs case for critical investments at key decision points. It could also provide advice to support Ofgem decisions on the appropriateness of particular investments. Any changes to NGET's role would be subject to consideration of whether the change supports identification of robust planning solutions and of whether any additional mitigation measures would be required to address potential or perceived conflicts of interest.

For delivery of transmission assets, we consider adding flexibility to application of delivery regimes has potential to provide for the delivery of assets in the interests of consumers. This could be particularly valuable if technology develops to allow for new types of investment in an integrated network. We envisage that the development of criteria to determine whether a new asset should be delivered by incumbent TOs or through a competitive process would, in most cases, lead to assets being developed under the same delivery route as they are currently. With regard to interconnection, the options for an enduring approach remain open and are focused on whether to retain the developer-led approach or move towards centralised identification of opportunities.

We are undertaking further work including assessment of the evidence for any changes to the current arrangements for planning and delivery and, if changes are needed, whether legislative change would be required. To make progress, we seek views on the case for change and our analysis of options and emerging thinking.

# 1. Introduction

---

## Chapter Summary

Provides background to this consultation, identifying its purpose and context and sets out the structure of the rest of the document. There are no questions on this chapter.

## The Integrated Transmission Planning & Regulation project

1.1. The ITPR project is a review of the GB electricity transmission system planning and delivery arrangements. This includes transmission infrastructure that is located onshore and offshore and that connects GB to other Member States of the European Union (interconnection). The project builds on the work that has already been undertaken to develop the individual regimes onshore, offshore and cross-border and to address particular issues associated with the development of nearer-term transmission projects, namely:

- Competition in transmission, following our RIIO conclusions, which confirmed there would be further consideration of the use of third party delivery for onshore electricity transmission;
- Strategic Wider Works, which builds upon the policy development already undertaken around anticipatory investment within the existing onshore regime and allows the incumbent TOs to propose, during the price control period, the delivery of large network developments.
- The Offshore Coordination project, which is seeking to enhance the existing arrangements (including around the roles of transmission parties) to enable greater coordination among offshore projects in the shorter-term. We will be publishing an update on our proposals in this area shortly; and
- The development of a regulatory approach for interconnectors, as currently being developed as a Cap and Floor approach for the GB-Belgium interconnector (project NEMO).

1.2. Against this background, the ITPR project is an opportunity to proactively consider a range of longer-term options. It will help us to ensure that the way in which investment is identified and delivered in the future can meet the longer-term challenges of ensuring the network is economic, efficient and coordinated and has the ability to facilitate integrated networks. This includes supporting the longer-term transition to decarbonisation of the energy system.

1.3. The ITPR project was launched in March 2012 with an open letter that set out the drivers for the project and sought views. Another open letter was published in November 2012 around the potential issues (set out in Chapter 2) that stakeholders

identified as a potential barrier to facilitating an integrated network. We have also engaged with stakeholders both individually and through workshops.

### This document

1.4. Following on from our November 2012 open letter, this document sets out our further analysis on potential options to facilitate efficient and coordinated planning and delivery of assets, in response to the future challenges set out in Chapter 2. While we set out emerging thinking on the options, we note that at this stage all options, including that of no change, remain open.

1.5. The remainder of this document is structured as follows:

- Chapter 2 discusses the current arrangements and potential future developments.
- Chapter 3 sets out our initial analysis on potential options for system planning.
- Chapter 4 sets out our initial analysis on potential options for delivery (in terms of development, regulation and potential ownership) of transmission assets, including around how projects serving multiple purposes might be delivered.
- Chapter 5 sets out our emerging thinking on the approach to system planning and delivery. It also discusses the way forward, next steps and interactions with related work.

1.6. Our analysis has been informed by work we have commissioned from Imperial College London and Cambridge University (on the principles of and international approaches to system planning and delivery) and by SKM on worldwide experiences of VSC technology for HVDC installations. Both of these papers are published alongside this document.<sup>1</sup>

1.7. Responses to this consultation are invited by **Friday 2 August 2013**. Details of how to submit a response are set out in Appendix 1 which includes a summary of the specific questions on which we invite views. We also welcome views on any of the issues raised in this consultation and any other issues that are considered relevant.

---

<sup>1</sup>See here:

[http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/itpr/Documents1/Imperial\\_Cambri dge\\_ITPR\\_report.pdf](http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/itpr/Documents1/Imperial_Cambri dge_ITPR_report.pdf)

[http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/itpr/Documents1/SKM\\_Review\\_of\\_VSC\\_HVDC.pdf](http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/itpr/Documents1/SKM_Review_of_VSC_HVDC.pdf)

Note that while both of these reports have been commissioned by Ofgem, they are independent works and the views expressed are those of the authors.



1.8. Respondents' views will inform our assessment of whether there is sufficient evidence to make changes to the current arrangements for both system planning and delivery and the basis upon which to make any change. Our focus at this stage is therefore on an exploration of a range of potential initial options to identify those which merit a more detailed consideration in our impact assessment. To inform this work, we seek views on the analysis set out in this document. As part of this, we are hosting a workshop on **Wednesday 26 June 2013**. Please see Appendix 2 for further details.

## 2. Current arrangements and future developments

---

### Chapter Summary

Outlines the current arrangements for electricity transmission and the future challenges created by the increase in scale and complexity of network development. We have been making improvements to the regulatory regimes in response to these challenges and now consider the case for change towards further integration and coordination across regimes.

### Question box

**Question 1:** Do you think we have appropriately characterised the future challenges to network development? Where do you see the main challenges? What are the long-term strategic and sustainability implications of these challenges?

**Question 2:** Are any of the review areas under ITPR more relevant than others?

### Current arrangements

2.1. There are different regulatory approaches for the different parts of the electricity transmission system onshore, offshore and for interconnection. Table 1 outlines key features of the current arrangements that are relevant to how investment in the network is planned and delivered.

2.2. The existing arrangements have been developed to facilitate efficient investment. The majority of investment is shaped by market signals and driven by requests from users seeking connection at a given location. This optimises the planning of the network according to need and reduces the risk of stranded assets. The arrangements to deliver network investment onshore, offshore and for interconnection drive efficiencies by allowing alternatives to financing, construction, ownership, and operation that are suitable for the differing characteristics of the infrastructure.

2.3. A more detailed summary of the key differences between the regimes under the current regulatory arrangements is set out in Appendix 3. The arrangements in respect of system planning and delivery are also explored in Chapters 3 and 4.

**Table 1: Current arrangements for system planning and delivery**

	<b>System planning</b>	<b>Asset delivery</b>
<b>Onshore</b>	TOs make plans for regional areas based on grid users' needs and some strategic planning with some coordination by NGET as the SO	Monopoly regulated TOs deliver assets through their price controls
<b>Offshore</b>	Generators drive planning of offshore assets, with onshore elements required to support the connection. SO facilitates coordination through managing interactive offers and the Connection Infrastructure Options Note (CION) process	Competitive tender for an Offshore Transmission Owner (OFTO) licence. The offshore generators may either chose to require an OFTO to construct the assets, or to build the assets itself and transfer them to an OFTO
<b>Interconnection</b>	Discrete projects developed where there is a market opportunity to interconnect systems, with a limited role for NGET as the SO around the design of the connection offer	Developer led merchant or Cap and Floor regulated (under development)

### Future developments

2.4. For GB to meet its sustainable energy targets, the national electricity transmission system will need to respond to new challenges. Significant change is underway in the whole energy system to meet renewable energy targets, decarbonise the energy mix, maintain secure and affordable electricity supplies, and promote the internal European energy market. To meet these objectives, substantial investment is required for replacement and expansion of the electricity transmission networks, on a scale not seen since the construction of the high voltage transmission network. It is likely that expansion will be accompanied by added technical complexity in network design and system operation. This is driven by the increasing penetration of intermittent and remotely located renewable generation as well as greater levels of interconnection to other markets.

2.5. In response to these challenges, new developments in the way that electricity transmission is regulated have been implemented. Onshore, the RIIO price control (Revenue = Incentives + Innovation + Outputs) has created a framework where network companies are incentivised and resourced to deliver the major network investment. Offshore, the regime to award OFTO licenses through competitive tenders has delivered infrastructure in a timely manner with savings for consumers. GB's interconnector regime has also enabled merchant investment that minimised the risk for consumers.

2.6. We continue to seek to ensure that these regimes can facilitate investment in a cost effective way for existing and future consumers: onshore, in implementation of the Strategic Wider Works process under RIIO and through considering the

potential role of third party delivery; offshore, through the development of an enduring regime and frameworks for coordination; and in interconnection, where recent developments have recognised the need for a regulated alternative to ensure delivery of new investment where it is economic and efficient.

2.7. However, the scale of developments in network investment, timings, technical complexity, and overall build specification is uncertain. This will depend on the extent to which government will support future renewable projects, their capacity and their location; the overall fuel mix; the extent to which interconnection meets security of supply concerns and integrates with other markets; and benefits and risks from potential technological innovation in network components. With respect to technological innovations, this is particularly relevant to the feasibility of projects that would combine more than one purpose, so-called MPPs.

2.8. Work undertaken for us by SKM has provided an in depth view of the challenges associated with the potential development of new HVDC technologies, and is published alongside this report. This builds on work TNEI/PPA Energy and Redpoint Energy undertook for us as part of the offshore coordination project.<sup>2</sup> Taken together, the reports suggest that there are potential benefits from integration in the form of MPPs but that there are significant technical hurdles to be overcome before such projects can be delivered. This means that the overall quantity, cost, design, capacity, and timing of these major projects cannot be easily identified.

2.9. Despite this uncertainty, we consider that, as a minimum, there is a need to consider whether the approaches under the three separate regimes will be sufficient to provide an efficient outcome in foreseeable cases, in a manner that is appropriate for existing and future consumers.

2.10. In considering whether the planning and delivery arrangements can accommodate future network development, there is a need to consider the potential for MPPs. As set out in further detail in Appendix 3, there are differences in the structure and function of the existing transmission regimes. These regimes have been developed with single purpose transmission assets in mind and so there is a need to consider whether changes may be needed for MPPs, including whether and how the commercial arrangements that sit beneath these regimes (eg access rules, charging, user commitment etc) are applicable.

2.11. Under the ITPR project, we are therefore considering whether the current arrangements for system planning and delivery across multiple regimes can meet these long-term challenges of ensuring the efficient, coordinated and economic development of the network in the future. In doing so we are looking across the three regimes to consider whether a more integrated approach to transmission planning and regulation may be needed for the network.

---

<sup>2</sup> See here:  
<http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/reports/Pages/reports.aspx>.

## Areas for review under ITPR

2.12. We engaged with stakeholders through open letters in March and November 2012 in an effort to understand which features of the current arrangements should be reviewed if more integration across the GB network as a whole is needed.<sup>3</sup>

2.13. In our open letter of November 2012, we identified four broad areas for consideration:

- 1 – The obligations and incentives on the multiple parties involved in transmission network planning and delivery may not align to ensure that individual networks or assets develop in line with the overall needs of the system;
- 2 – The framework for GB transmission entities to engage in European transmission activities may not provide an effective means for all relevant parties to contribute, giving rise to a risk that the GB transmission system is insufficiently represented at the European level;
- 3 – There is a potential for conflicts of interest to arise for parties undertaking transmission planning and delivery; and
- 4 – The regime interfaces for transmission related projects that could be developed over one or more of the three investment regimes – MPPs – are potentially unclear, giving rise to a lack of clarity around the regulatory treatment of these assets.

2.14. Responses to our November open letter indicated that each of these four broad characteristics of the current arrangements is relevant. See Appendix 4 for a brief summary of responses to the November 2012 open letter. Non-confidential responses are available on our website.<sup>4</sup>

2.15. Since our November open letter consultation we have undertaken further analysis of these features of the current arrangements, focusing on the specific areas of system planning and delivery of transmission assets. This analysis is set out in Chapters 3 and 4 of this document, alongside possible options to facilitate efficient and coordinated planning, both within and across each regime and efficient delivery of transmission assets. We set out our emerging thinking in light of this analysis in Chapter 5.

---

<sup>3</sup> See here: <http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/itpr/Pages/index.aspx>.

<sup>4</sup> See here: <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/ElecTransPolicy/itpr>.

## 3. Initial analysis of options for system planning

---

### Chapter Summary

Sets out some potential options to facilitate efficient and coordinated system planning, both within and across each regime. It focuses on the roles and responsibilities of relevant parties and the institutional and transparency arrangements that underpin those roles.

### Question box

**Question 3:** What are your views on the options for system planning discussed in this chapter? Are there other approaches to system planning that you think we should be considering within the ITPR project?

**Question 4:** Do you think that it would be beneficial to strengthen the role of a coordinating body working with relevant parties to facilitate efficient decision-making? In what areas could this coordinating body add most value to the process?

**Question 5:** What are your views on the (real or perceived) conflicts of interest that could occur from parties holding dual responsibility in system planning and asset delivery and ownership? What are your views on potential options for institutional arrangements, separation and transparency measures to mitigate this?

**Question 6:** What are your views on potential future approaches to planning interconnection? Should there be increased central identification of potential interconnection that could benefit GB consumers?

### Introduction

3.1. Onshore, transmission system planning is based on TOs responding to (and in some cases planning for) users' requirements, which in turn are shaped by market signals (such as transmission charges and user commitment requirements). These arrangements have helped to encourage efficient generation location decisions, minimise the risk of stranded assets and deliver set security standards.

3.2. Offshore, generator developers receive connection offers based on the onshore TO's analysis of options and then, upon signing a connection agreement, take over the lead role in design (assets can then be delivered by generator build or potentially OFTO build).<sup>5</sup> For cross-border capacity, interconnector developers

---

<sup>5</sup> The terms Generator build and OFTO build are defined in the glossary.

identify opportunities for projects based on their assessment of potential revenues available from congestion rents which arise from opportunities to engage in arbitrage between markets.<sup>6</sup>

3.3. Market signals are central to driving investment decisions and we are considering the future role of these as part of the Future Trading Arrangements forum work.<sup>7</sup> We also recognise the need to investigate alternative approaches in relation to the roles, responsibilities and institutional arrangements of parties that might facilitate economic, efficient and coordinated planning of the network.

3.4. This is an area where we have already done some work to encourage improvements. In RIIO-T1 for example, we introduced the requirement for a Network Access Policy (NAP) to improve the coordination and communication between the TOs and NGET as the SO. Further developments in this regard will also be considered under the ITPR project.

3.5. In the November 2012 open letter, we identified a number of features with the current arrangements for planning and delivery of the system which may create long-term challenges going forwards, given the potential scale and complexity of the new investment required. These features are set out in Chapter 2 of this consultation. We consider these broad challenges may relate to the following characteristics of the current system planning arrangements:

- There is a separate system planning framework under each regime, leading to regional or asset-specific TO-led planning and a shallow<sup>8</sup> SO role for NGET onshore and offshore which is focused around coordinating the connections process;
- The presence of large, technically complex projects. These projects are driven by uncertain future requirements and are often dependent on/interactive with other projects and/or may evolve to become MPPs in the future;
- Parties currently leading on detailed local network planning of these projects (including interconnection) may lack the incentives and information to consider the GB-wide investment needs; and
- The regulatory framework requires case by case consideration by the Authority of whether particular (often complex and interdependent) investments are in

---

<sup>6</sup> The term Congestion rent is defined in the glossary.

<sup>7</sup> See here for further information:

[http://www.ofgem.gov.uk/MARKETS/WHLMKTS/COMPANDEFF/Documents1/FTA%20Forum%20Launch%20Letter%20\(24%2005%2013\).pdf](http://www.ofgem.gov.uk/MARKETS/WHLMKTS/COMPANDEFF/Documents1/FTA%20Forum%20Launch%20Letter%20(24%2005%2013).pdf).

<sup>8</sup> We define a "shallow" role as one where the SO responsibilities are limited to providing the commercial interface between users and the TOs, provision of high level market information and development of background scenarios. The "shallow" SO would not undertake asset design or detailed assessment of the viability of different technology options. The "shallow" role describes the current function performed by National Grid as the SO in GB.

consumers' interests. The frequency and magnitude of the Authority's decisions in this capacity is likely to increase, for example, in the context of Strategic Wider Works, offshore coordination and the determination of regulated revenue (as appropriate) for new interconnectors.

3.6. We consider these characteristics of the current system planning arrangements may not be fully aligned to support the potential scale, timing and technical complexity of investment required in the longer-term. This may lead to the potential risk of some future investment in the network being undertaken on a piecemeal, uncoordinated basis which could potentially unnecessarily increase costs to consumers and delay integration of renewable generation.

3.7. In developing potential options to address these risks we are considering potential changes to the roles and responsibilities of the parties involved in the system planning process, including where holistic knowledge of the network could usefully be applied in decision-making and where decisions in system planning should be agreed and potentially led by the delivery party.

### Overview of options for system planning

3.8. In our initial analysis, we have identified a number of alternatives to the current system planning framework. These have been identified through an examination of international examples and analysis of their applicability to GB. For example, in Europe the dominant model is the fully-integrated Transmission System Operator (TSO) model. In the US and Latin America, the ISO model is common. Further detail of these models can be found in the Imperial College London and Cambridge University report published alongside this consultation document.<sup>9</sup>

3.9. As we have well established institutional arrangements, whereby transmission ownership is largely unbundled from the SO function, returning to full vertical integration would be a significant and highly disruptive departure from the existing arrangements. Given this, we have not considered the TSO model further and have focussed our options on models that we consider have the capacity to facilitate coordination between parties and across regimes within GB (including interconnection).

3.10. The first consideration in developing these options is whether to maintain the existing 'shallow' SO framework or whether to introduce a more extensive or 'deeper' role for a single party to coordinate the development of the system – this is **the 'depth' question**. We have considered 'shallow', 'enhanced' and 'directive' models as follows:

---

<sup>9</sup> See here: [http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/itpr/Documents1/Imperial\\_Cambridge\\_ITPR\\_report.pdf](http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/itpr/Documents1/Imperial_Cambridge_ITPR_report.pdf)

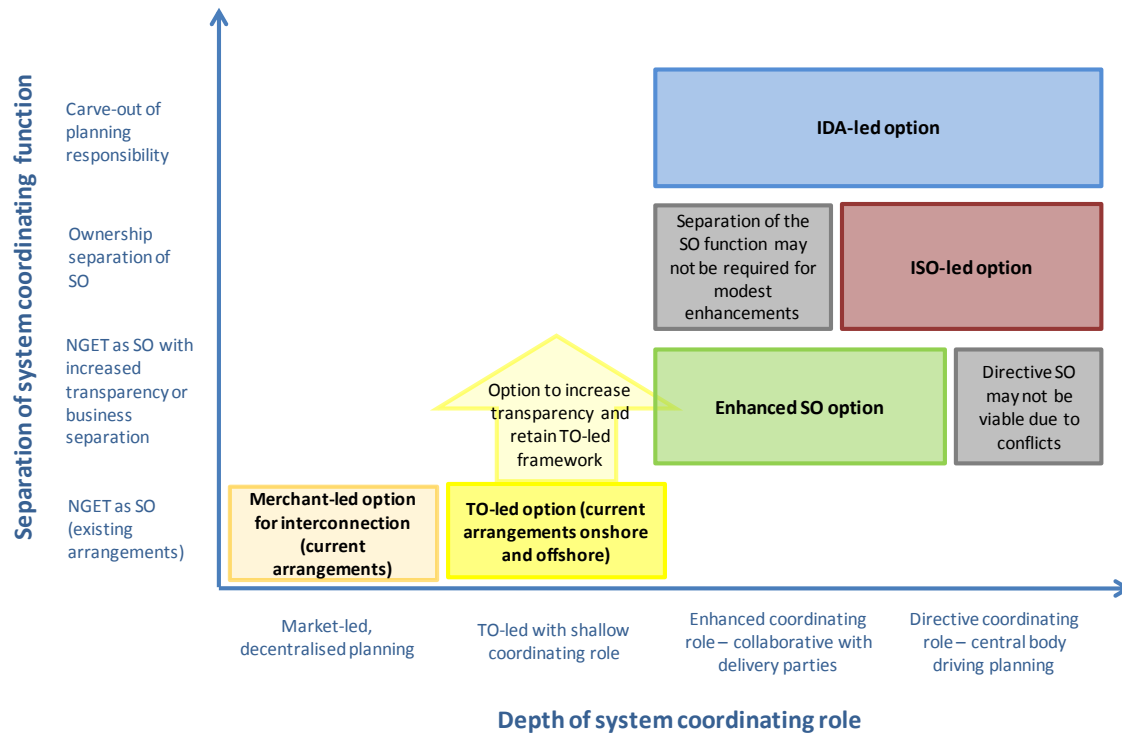


- **Shallow coordinating body ('TO-led')**: this model broadly describes the current framework whereby NGET as SO has a limited coordinating role. For example, NGET provides scenarios and market information and acts as the contracting party for connections, but development of the system is led by the TOs and other transmission asset developers;
- **Enhanced coordinating body**: Under this model, a body with a view of the whole system would take an active role in strategic system planning, working closely with the delivery parties to support their decision-making in development of the local networks. This could be through, for example, a more formalised and collaborative role in the strategic planning stage such as in identifying system needs and coordinating the preferred solution at a system level; and
- **Directive coordinating body**: Under this model, a body with a view of the whole system would take on a directing role in system planning. Depending on the scope and practical application of this model, this could significantly change the roles of the TOs in planning developments in their local network compared to current arrangements by passing a number of roles and responsibilities on to the coordinating body.

3.11. The second consideration is the issue of which institutional arrangements should under-pin that role – this is **the 'separation' question**. Should the SO role be fulfilled by NGET as SO or another party? And if the former, then should there be strengthened transparency or separation measures? We have identified a number of potential institutional models for this planning /coordinating role. In particular we have analysed the following options in detail:

- **Existing SO framework**. Under this model, NGET is TO in England and Wales and SO across the GB system (onshore and offshore). In its SO capacity it acts as the coordinating body in development of the networks;
- **NGET as SO with increased transparency or business separation**. Under this model, NGET would retain the SO function, but with additional steps taken to improve transparency in the decision making process to reflect its increased responsibilities around development of the system. This option could also include business separation measures such as the regulation of information flows and/or functional separation between NGET's SO function and its delivery activities, if required;
- **Ownership separation of the SO and planning functions**. Under this model, system operation and system planning would be independent of asset ownership. This would likely be implemented through separation of the SO function from NGET; and
- **Carve-out of planning responsibility**. Under this model, system planning would be independent of both asset ownership *and* system operation. NGET as SO would retain its role in system balancing. It is likely that this model would be implemented through the establishment of an IDA.

Figure 1: System planning options



3.12. Combining these considerations on depth and separation allows identification of the following options for coordination / planning of network development in GB:

- **TO-led system planning** with a shallow SO role undertaken by NGET;
- **Enhanced SO role in system planning** undertaken by NGET (this option is referred to hereafter as "Enhanced SO option");
- **Independent System Operator (ISO)-led system planning;** an ISO is a body responsible only for system operation and related operational functions. An ISO will not own any transmission assets, and will typically be a not-for-profit entity<sup>10</sup>; and
- **Independent Design Authority (IDA)-led system planning.** An IDA is a body responsible only for system planning and design. An IDA will not own any transmission assets or have any responsibility for system operation. The exact role and functions of the IDA and its standing in relation to other bodies involved in transmission system operation, delivery and regulation will vary.

<sup>10</sup> Note that where the term 'ISO' is used in the context of ITPR it is not equivalent to the meaning of an ISO in the context of Article 13 of Directive 2009/72, which relates to unbundling arrangements of a TSO from generation, production and/or supply interests.

3.13. These options, in relation to the depth and separation considerations are illustrated in Figure 1 above. Analysis of the depth and separation considerations is set out in the following sections of this chapter.

3.14. Additionally, for the identification and planning of cross-border capacity, we are considering approaches that capture the developer-led approach (the status quo for interconnection) and more 'centralised' approaches (centralised within the potential coordinating body outlined above or an alternative institution, such as Ofgem or Government). This analysis is presented in the final section of this chapter.

### Options for depth of the system planning coordination function

#### Planning an integrated electricity transmission system

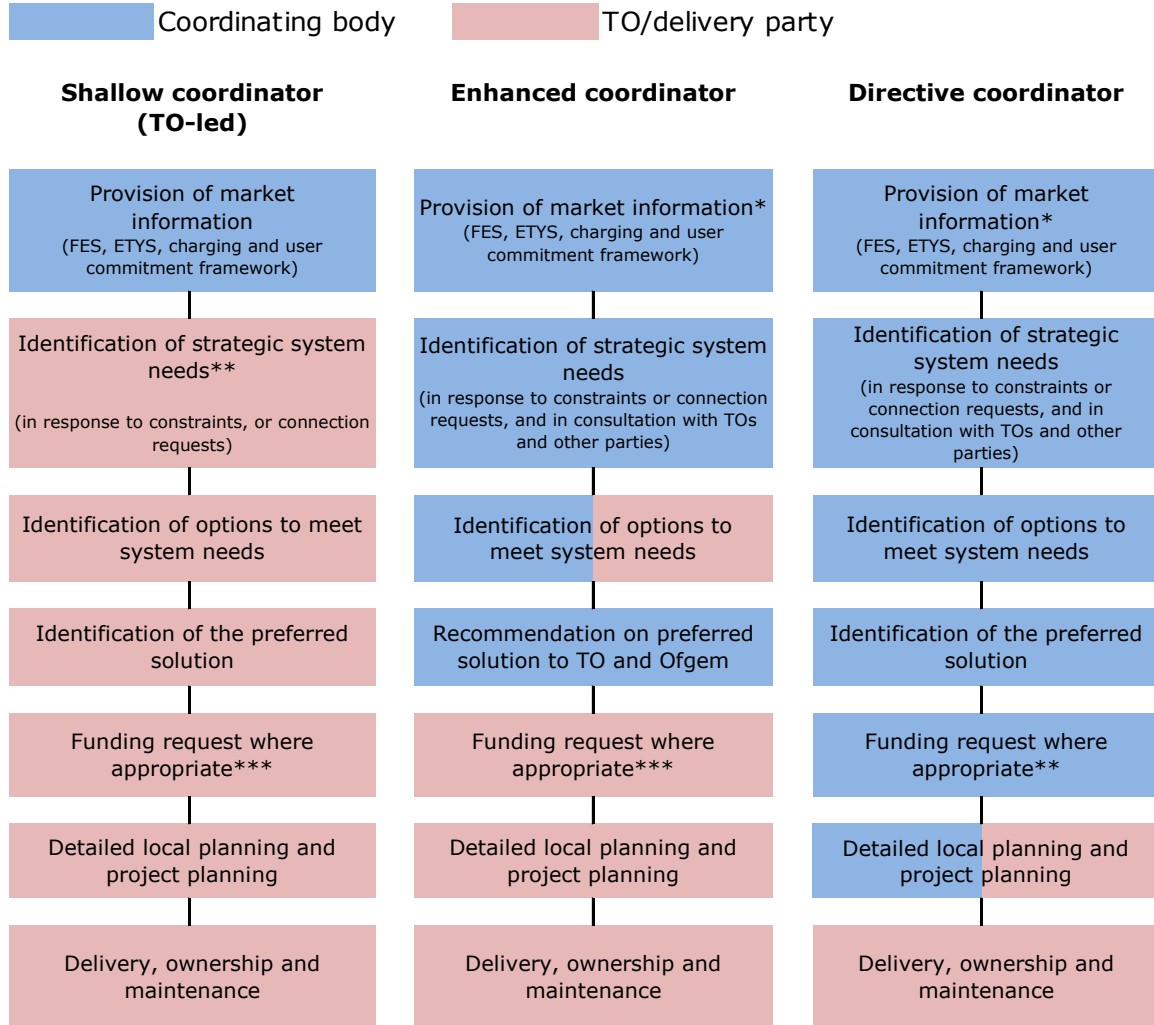
3.15. We have developed three illustrative models for a shallow, enhanced and directive coordinating body, acting across the GB transmission system. These are outlined in Figure 2 below, which explores potential roles of parties in the planning of strategic investment for the GB network. Options for, and analysis of, possible approaches to the identification of interconnector capacity needs are discussed separately in the following section.

3.16. In considering the relative merits of the different approaches (shallow, enhanced and directive coordinating body), it is worth considering the benefits each party can bring to the different stages in network development outlined in Figure 2. For example, NGET as the SO benefits from having a system-wide view and knowledge of existing and future users through its system balancing role and its role as the contracting party (and thus relationship manager) for potential new generation. The TOs benefit from detailed knowledge of their networks, local conditions and consenting risks that are highly relevant to system planning.

3.17. Under the **shallow coordinating body (TO-led)** model TOs and other transmission developers lead the development of the network. This includes the identification of local network needs and options to resolve network capacity requirements and the preferred solution. At times, parties coordinate to undertake planning that covers development of the whole system. For example, the SO and the TOs meet as the Joint Planning Committee (JPC). This is rooted in requirements of the SO-TO Code (the STC) and is the main forum in which the SO and TOs should work together on network development. The SO and TOs are also members of the Electricity Networks Strategy Group (ENSG). This is a high-level forum through which members can offer advice on whole system planning, although it has no formal role in commissioning new network investments.

**Figure 2: Comparison of potential shallow, enhanced and directive coordinating models in system planning of strategic investments**

**KEY** - colour indicates lead party



\* Under an IDA-led option, some of these roles may be distributed between the IDA and the SO.

\*\* In providing connection offers to individual projects, the SO may consider wider strategic network needs.

\*\*\* For offshore generator build a cost assessment process is used. Additionally, offshore, some subsequent stages are led by the relevant generator.

3.18. There is also evidence of coordination on a project basis through discussions with NGET, as the SO (around, for example, network design for interactive projects that could benefit from a coordinated network solution). In its role as SO, NGET's

contribution to system planning is shallow; it provides the market information such as the Electricity Ten Year Statement (ETYS)<sup>11</sup> and maintains the charging framework.

3.19. With its SO role, NGET also acts as the contracting party in development of the system and undertakes Security and Quality of Supply Standards (SQSS) compliance checks on network development proposals. To ensure that future network investment is delivered efficiently, the arrangements could potentially be better facilitated by providing mechanisms for other network developers (such as interconnector developers and generator builders) to input to network fora, potentially through reviewing membership of the STC.

3.20. Making improvements to the shallow coordinating body model has potential benefits. In particular, making less change is likely to minimise the risk of regulatory uncertainty and impact on investor confidence. The emphasis on user led developments also provides generators with a significant level of control over delivery of assets to meet their individual needs, which reduces risk.

3.21. However, the transmission parties that could have increased input to network fora (eg STC and ENSG) are still subject to diverse requirements, incentives and commercial confidentiality barriers which this option does little to address. Additionally, the shallow coordinating body model does not have a strong emphasis on consideration of whole system benefits in developing local assets. Furthermore it does not provide a clear framework for representation of GB at the European Network of Transmission System Operators for Electricity (ENTSO-E), as it fails to identify a body (or bodies) with a comprehensive mandate to undertake this activity.

3.22. Under an **enhanced coordinating body** model, NGET as the SO, or an alternative body such as an ISO or IDA, could undertake a more proactive role in the planning of the system through working with TOs and other transmission developers. This role could include identifying strategic system needs and coordinating the preferred solution at a system level. This could include working with parties to facilitate solutions which are anticipatory or multiple-purpose in nature.

3.23. We would anticipate that the detail of defining options for the local network and providing the engineering input to the local planning process would remain a TO role under this model. However, the coordinating body would also be reviewing options put forward by the TOs and recommending further options to be considered if necessary. These recommendations to consider further options could reflect opportunities the coordinating body may identify based on its whole system view and reflect both network and non-network solutions (such as use of operational solutions, instead of new assets, to resolve network capacity constraints).

---

<sup>11</sup> The ETYS replaced the Seven Year Statement (SYS) and the Offshore Development Information Statements (ODIS) in 2012.

3.24. For the onshore network, the decision to invest and submission of the funding request to Ofgem would continue to be the responsibility of the TOs. Within this process however, both Ofgem and the TOs would receive greater input from the coordinating body on the needs case for investment. For this model, detailed local asset planning may not be an area that would need significant inputs from a coordinating body and therefore we would envisage this would remain a broadly TO-led activity. However, it could be an area that is subject to additional information-sharing provisions to allow the coordinating body to have sufficient information to conduct its own system-wide planning activities and to support the subsequent delivery of assets.

3.25. Offshore, similar arrangements could apply whereby the offshore generator would retain decision-making responsibility in connection design, with the coordinating body providing advice to the generator(s) and Ofgem on the needs case for coordinated, or perhaps multiple-purpose, investment. The relevant delivery party (such as a generator builder or OFTO) would lead local asset planning.

3.26. Under an enhanced coordinating body model, one option would be for the coordinating body to take on a role in representing the GB view at ENTSO-E where appropriate. Additionally, the coordinating body (or the SO if they are not the same entity) could take on an increased role in undertaking system studies for network design options, such as harmonics analysis, detailed stability analysis and overall system operation considerations.<sup>12</sup> This could include a role in coordinating system studies undertaken by the delivery parties to ensure overall system operability or could include taking more of a role in undertaking the studies (in place of the delivery parties).

3.27. The introduction of the British Electricity Trading and Transmission Arrangements (BETTA) resulted in provision of more comprehensive sets of network and generator data to the TOs to facilitate their network planning. However, with an increased number of parties involved in the planning and delivery of network assets there may be a case for the coordinating body or SO to do more in this area. We note changes in this area may be driven by other factors separate from ITPR; for example, in order to achieve compliance with the new European Network Codes.<sup>13</sup>

3.28. The coordinating body may also be in a position to play a role in identifying innovative solutions to address identified network capacity needs (including non-network solutions and coordinated solutions that might rely on technically complex or more innovative technologies). However, it would be important to ensure that the coordinating body was appropriately incentivised/directed to produce alternative solutions that were robust and well justified and would not put forward solutions that would create excessive risks for generators.

---

<sup>12</sup> This could include considering cross-system stability/dynamics, sub-synchronous resonance and power system stabiliser tuning/grading.

<sup>13</sup> See here for further information on European Network Codes: <http://www.ofgem.gov.uk/Europe/EEM/Pages/EEM.aspx>.

3.29. Depending on the further development and practical application of this model, there is the possibility that further consideration of duties on all parties would be needed.<sup>14</sup> Any legislative change that may be required will be considered carefully alongside other options should we develop this approach further.

3.30. This option may have the potential to address the issues identified under the ITPR project and may align roles in the system planning process with the capabilities and expertise of parties. In particular, it could leverage the benefits of the whole-system view in identifying transmission capacity requirements and in determining the needs case for investment at key decision points. This option also utilises the expertise of the TOs in identifying options based on knowledge of their networks, providing the engineering input to system planning and in taking decisions to invest (and submitting a funding request to Ofgem where appropriate).

3.31. There are potential risks arising from this model however, including uncertainty during the implementation of changed roles and responsibilities. There are also potential or perceived conflicts of interest should NGET as SO take on this role; this is discussed in more detail in the next section.

3.32. A **directive coordinating body** model represents a more significant change in the roles of TOs in system planning and other delivery parties in the planning of the network. Under this model, a single body would take on a directive role, identifying system needs, options and the preferred solution for resolving an identified network capacity need. Depending on the practical implementation of this model, it could also undertake elements of detailed local asset planning and pre-construction works. Throughout this process, the roles of the TOs could be substantially changed in favour of a single body with a mandate over the whole network. Legislative change may be required to implement this model and we will consider all of the options for implementation carefully should we develop this approach further.

3.33. Like the enhanced coordinating body model, this model has potential benefits including creating a clear framework that would enable the needs of the network as a whole to be taken into account in the system planning process. However, this option may not fully align responsibilities with capabilities in system planning. For example, it may not maximise the use of TOs' expertise in system planning (such as in drawing on knowledge of their networks and providing the local knowledge and engineering input).

3.34. Additionally, this option could entail significant change in the roles of parties in system planning with the potential to create uncertainty and disruption. It may also have the potential to cause conflicts of interest should the directive coordinating role be provided to NGET in its capacity as SO. On this basis, it may be appropriate for a

---

<sup>14</sup> Electricity transmission licence holder duties include the section 9 duty in the Electricity Act 1989 to develop and maintain an efficient, coordinated and economical system of electricity transmission and to facilitate competition in the supply and generation of electricity.

directive role to be underpinned by more significant institutional reform. On the other hand, significant change would have a greater potential to cause disruption and uncertainty.

### Options for institutions, separation and transparency

3.35. The ITPR project is considering potential risks of (real or perceived) conflicts of interest that may arise if parties have responsibilities for both system planning and system delivery. Dual responsibility could lead to perverse incentives in decision making or opportunities for a party to have unfair influence on one of its functions by virtue of its other functions (see Figure 3). Conversely, there may be useful synergies between the functions of planning, delivery and balancing which, where possible, we would seek to maintain were we to adopt a potential new framework. This section of the consultation document explores options for institutional arrangements, separation and transparency to underpin potential changes to the depth of the coordinating role.

3.36. There are clear links between this analysis and the conflicts and synergies analysis undertaken for the EMR project which is discussed further below.

### Analysis of synergies, potential conflicts and institutional options

3.37. As discussed earlier in this chapter, we have identified four illustrative institutional frameworks which could underpin the potential changes to the coordinating body role outlined above: **TO-led** (with NGET as a shallow SO), **Enhanced SO** (within NGET), **ISO-led** and **IDA-led**. In considering the relative merits of these options, we have analysed the synergies and potential conflicts between different functions within transmission. We have also considered the potential governance arrangements for new institutions, the role of incentives and implementation requirements (such as the potential for non-legislative or legislative change for some options).

3.38. Figure 3 illustrates our analysis of the synergies and potential conflicts between the functions of system planning, balancing and delivery through the incumbent TO role or competed projects. The figure identifies a number of synergies between different functions, with notable potential for conflicts to arise between the system planning (coordinating) function and delivery. There is also potential for conflict and synergy between incumbent and competitive delivery<sup>15</sup>.

3.39. For the **TO-led** approach, the institutional arrangements and responsibilities are broadly in line with our current arrangements. So any synergies, or conflicts of interest (actual or perceived) are those which already exist in our current

---

<sup>15</sup> Note that Figure 3 indicates where synergies and potential conflicts may exist, but does not indicate the relative magnitude of such synergies or conflicts.

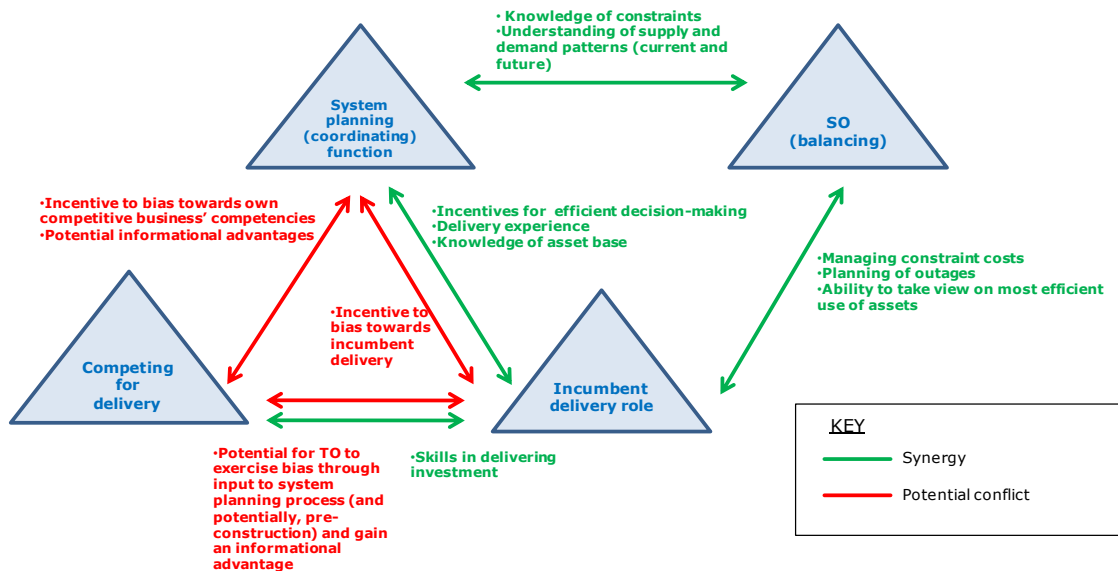


arrangements, this option does not add substantially to any existing concerns or positive attributes.

3.40. With regard to the **IDA**, this option poses minimal concern regarding conflicts of interest. However, it may have notable disadvantages (from loss of synergies) due to the separation of system planning from the balancing role. We also consider there could be significant challenges in successfully allocating roles between the IDA and NGET as the SO (which would remain to undertake the system balancing role). Because this option involves creation of a new entity (the IDA), it could also increase the administrative burden on industry parties through creating an additional party with which to engage.

3.41. Legislative change may be required to implement the IDA option; primary legislative change could only be taken forward by Government and would be subject to the Parliamentary legislative timetable.

**Figure 3: Illustration of conflicts and synergies**



3.42. The ISO option has the capacity to address potential conflicts of interest whilst maintaining the synergies between planning and balancing. However, we also need to consider the impact of the institutional nature of a new independent body, including matters of ownership and for-profit versus not-for-profit models. Depending on its form, the **ISO** option may potentially require legislative change. We would consider options for change and implications for implementation carefully at the appropriate time.

3.43. The benefits of the *current* (for profit, privately owned) institutional arrangements include the ability to apply financial regulatory incentives, such as the current SO incentives on balancing and the ability to consider taking enforcement

action through financial penalties in certain circumstances.<sup>16, 17</sup> In applying these considerations to an ISO model, we consider it may be problematic to expose an ISO to similar financial risk (eg through incentives and fines) given its asset-light nature.

3.44. Indeed, through our review of international models with Imperial College London and Cambridge University, we have not found any examples of a pure for-profit ISO (or an IDA). Based on international experiences, it appears that the ISO option may be more suited to the not-for-profit, possibly publically-owned model. Regulatory incentives may be difficult to apply to the not-for-profit model, meaning this option may entail the loss of the opportunity for SO incentives on balancing.

3.45. For the **enhanced SO** option, we consider there are potential synergies with delivery that could be captured, including the management of constraint costs. However, careful consideration would need to be given to the potential for conflicts of interest that could arise, including the potential for NGET to use its influence over the whole system to confer a commercial advantage on its own delivery business (whether these be its monopoly-regulated or competitive businesses). These risks may be real or perceived; the perception of conflicts of interest may be heightened if the SO's functions as coordinating body are carried out with insufficient transparency.

3.46. DECC and Ofgem recently published a joint report covering synergies and conflicts of interests arising from NGET undertaking the EMR delivery functions.<sup>18</sup> The report concludes that DECC and Ofgem will need to ensure that regulation provides for adequate managerial, information, physical, employee, and legal separation of certain 'competitive businesses' (for example, in offshore transmission, interconnectors and carbon capture and storage) from NGET, which present potential conflicts of interest with the addition of the EMR delivery role.

3.47. The report recognises that the situation may change, therefore these measures and the other measures to address EMR conflicts set out in that report will be kept under review. DECC and Ofgem are exploring how best to achieve the necessary separation, whether by modifications to NGET's licence conditions or other means. This may also be relevant to some of the potential conflicts that we have identified under ITPR.

---

<sup>16</sup> For further details on SO incentives, see here:

<http://www.ofgem.gov.uk/Markets/WhIMkts/EffSystemOps/SystOpIncent/Pages/SystOptIncent.aspx>.

<sup>17</sup> The circumstances in which we may take enforcement action are set out in Chapter 3 of our Enforcement Guidelines on Complaints and Investigations. See here:

<http://www.ofgem.gov.uk/About%20us/enforcement/Documents1/Enforcement%20Guidelines%20post%20consultation.pdf>.

<sup>18</sup> See here:

<http://www.ofgem.gov.uk/Markets/WhIMkts/EffSystemOps/Documents1/EMR%20COI%20consultation%20report.pdf>.

3.48. Further to this, under ITPR the enhanced SO option could include the extension of business separation measures within NGET to provide for increased functional separation of the SO (and system coordinating) role from the TO role, should that be found to be necessary.

3.49. Alongside this and across all options, we have considered the potential role of regulatory incentives in driving effective long-term system planning, that is, the extent to which regulatory incentives could be utilised to encourage parties to take action and decisions that are in the interest of existing and future consumers. Such regulatory incentives could potentially be applied across different parties depending on whether a shallow, enhanced or directive coordinating body model is adopted. However, due to the long term nature of planning decisions and the number of factors that affect transmission costs that are beyond system planners' control, we consider that the introduction of an effective regulatory incentive on the results of system planning decisions could be problematic (though it may be possible).

3.50. We consider there may be merit in considering the role of published planning methodologies. These are utilised in other transmission networks (eg in the US), and can provide a framework for system planning as well as providing stakeholders with increased clarity of process and the reasons for decisions. This approach therefore has the ability to increase transparency in decision making and thus further mitigate the risk of conflict of interest.

3.51. In GB, the implementation of this approach could include building on or adapting NGET's existing Network Development Policy (NDP) and CION processes. It could also include building on the RIIO-T1 onshore arrangements where the existing NAP provides NGET as the SO with information on what it can expect from the TO (including joint communication and coordination of plans).

## **Approaches for identifying cross-border capacity needs**

### **Background**

3.52. The frameworks for transmission system planning outlined in the previous section could all be extended to include consideration of interconnection and cross-border capacity needs. Alternatively, interconnection could be left as a separate, entirely developer-led regime. Both models exist in other jurisdictions. For example, elsewhere in Europe, almost all TSOs will consider cross-border capacity needs as part of their overall assessment of system developments. However, in the US, the "seams" between neighbouring ISO areas are typically left to merchant interconnector developers.

3.53. Existing interconnectors in GB were developed under different regimes. The England-France link ('IFA') was built pre-privatisation, as part of the state owned transmission system. More recently, the BritNed interconnector was developed as a 'merchant', stand-alone project outside the price-controlled transmission business. The interconnector developers planned the investment based on price signals and

market opportunity and are fully exposed to the upside and downside of market demand for the capacity.<sup>19</sup>

3.54. Under this current model, the merchant developer typically seeks some protection against the possibility that regulatory intervention to cap profits or change the basis on which capacity can be sold. Such protection has been provided through 'exemptions' from certain licence requirements and European legislation.

3.55. Following the introduction of the Third Energy Package and assessment of its implications for interconnection, Ofgem undertook to consider whether the current regulatory arrangements continue to provide sufficient incentives for investment in new interconnection capacity.<sup>20</sup> Numerous factors, including the risks inherent in the exemptions process and a lack of compatibility between the merchant approach and the regulated regimes of neighbouring systems, led us to consider developing an alternative, regulated approach.

3.56. The result is the proposed Cap and Floor regime, under development for project NEMO. This approach limits the developer's exposure to downside risk (through the floor) whilst protecting consumers from excessive returns (through the cap).<sup>21</sup>

3.57. Currently, the merchant-exempt route remains open. However, given the scale of potential investment (including interconnector related MPPs) and the need to unlock new sources of finance there is also a strong driver to build upon our work on NEMO and consider our enduring approach to regulation of interconnection.

3.58. This could include considering how Ofgem or potentially another party can appraise competing projects, or determine when sufficient interconnection capacity may be reached. It could also include considering whether it would be in the interest of GB consumers to change how investment opportunities are identified, with potential implications for how projects are delivered.

3.59. To that end and in the context of the general principles for system planning presented in the previous section, the following section provides some initial analysis on an enduring approach to planning and delivery of potential new interconnector investments.

---

<sup>19</sup> The EastWest interconnector was initiated by the Irish TSO, EirGrid and is wholly supported by Irish consumers. The Moyle interconnector is a mutualised company, wholly owned by Northern Irish consumers.

<sup>20</sup> The term "Third Package" refers to a package of EU legislation on European electricity and gas markets. To view the Third Package legislation, see here: [http://ec.europa.eu/energy/gas\\_electricity/legislation/third\\_legislative\\_package\\_en.htm](http://ec.europa.eu/energy/gas_electricity/legislation/third_legislative_package_en.htm).

<sup>21</sup> Information on the different transmission regimes, including the cap and floor regime, is provided in Appendix 3.

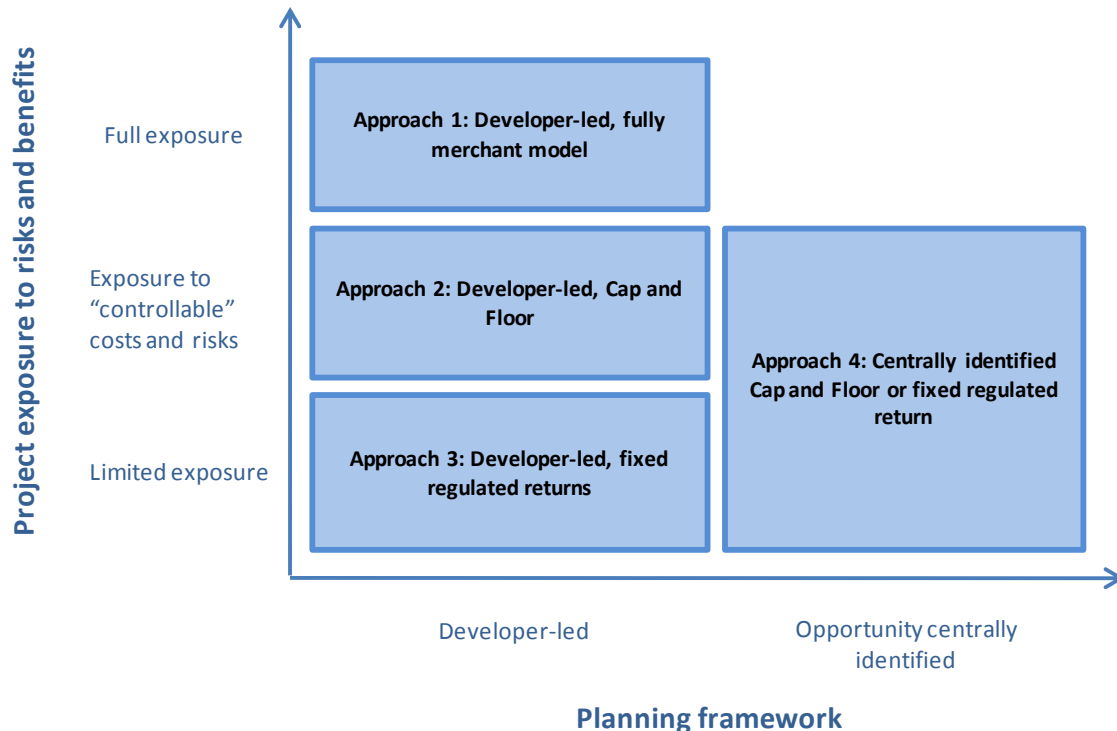
### Alternative approaches

3.60. We have identified two factors in developing an enduring interconnector investment regime. The first is the method for the **identification** of the investment opportunity, for instance, developer-led (driven by market signals) versus central identification based on market and social welfare studies. The second is the **allocation of risks** between project developers and consumers in delivering these projects. We note there are strong interdependencies between both of these factors.

3.61. We have developed a range of possible approaches for the identification and delivery of future interconnection. These approaches are illustrated in Figure 4 and described below.

3.62. It is important to note that these approaches represent a spectrum and are not comprehensive. They seek to illustrate that the key questions on the planning side are: to what extent there could continue to be a developer-led role through exposure to market signals; and whether there should potentially be a greater role for central planning (with the two not necessarily entirely mutually exclusive).

**Figure 4: Approaches for identification and delivery of future interconnection**



*Approach 1: Developer-led, merchant model*

3.63. This approach represents the status quo for interconnection projects delivered to date. Developers bring projects forward with no underwriting from consumers, ie all risks are allocated to project developers. They identify opportunities on the basis of price signals in the wholesale markets of interconnected countries.

3.64. This approach removes the risk of stranded assets and limits the cost burden to consumers as long as the commercial arrangements surrounding the interconnector are fully cost reflective. However, it has proven increasingly difficult to realise investment under this framework, mainly due to: the complexities of the exemption process; and the fact that many other countries that GB can interconnect with (including Belgium) have regimes that do not accept merchant interconnection.

3.65. In addition, although there are arbitrage opportunities between GB and the rest of Europe, these opportunities will diminish with each new interconnector. Furthermore, price signals sent through the wholesale market price may not capture all of the benefits and costs of interconnection. Therefore, depending on the quality of the price signals, a pure merchant model may not lead to an efficient level of interconnection. Further work is needed to assess whether current market design and related policy interventions (that may dilute price signals) can still justify reliance on market signals alone to stimulate new investment.

3.66. Finally, because interconnector operators do not pay any Transmission Network Use of System (TNUoS) charge (or equivalent), it is not clear whether the existing price signals allow developers to make the appropriate trade-offs in the location of new interconnectors. This is potentially a downside of all approaches with market-exposure, although further analysis is needed to understand whether this is actually a material concern and to explore proportionate solutions to improve cost reflectivity as necessary.

*Approach 2: Developer-led, cap and floor on returns*

3.67. This approach represents the model we are developing alongside the Belgian regulator for project NEMO. Developers identify opportunities based on wholesale market price signals. The Authority evaluates the proposal to provide a cap and floor on returns, where returns are based on interconnector congestion revenues. Market exposure is maximised through maintaining some distance between the cap and floor.

3.68. While consumers are potentially exposed to additional costs if interconnector revenues are consistently below the floor, the proposed cap and floor distance as well as the introduction of incentives, such as an interconnector availability incentive, will help to ensure their interests are protected. In addition, consumers have an upside benefit if revenues are above the cap, as excess revenues are returned to consumers.

3.69. This approach retains the market's valuation of new interconnection projects, which is important in a system where no central body has a responsibility for determining the efficient level of interconnection. This regime is designed to be compliant with Article 16(6) of the Electricity Regulation<sup>22</sup> relating to use of revenue requirements which we expect would remove the need for an exemption from the use of revenues.

3.70. However, as with the merchant approach, this model is dependent on the sharpness and accuracy of market signals to bring forward new and efficient investments and the same issues apply regarding a lack of TNUoS-type charge.

3.71. Furthermore, evaluation of proposals becomes challenging as new interconnector projects are brought forward simultaneously. Maintaining strong market exposure should limit the need for independent evaluation of proposals, but in practice this may not always be possible. This puts additional emphasis on the Ofgem-led cap and floor setting process, particularly for evaluating competing proposals.

*Approach 3: Developer-led, fixed regulated return*

3.72. This approach represents a model whereby we maintain the developer-led approach to interconnector identification but provide a fixed regulated return independent of congestion income. Compared to the developer-led Cap and Floor regime, this removes the benefit of market testing of new projects, since there will be no private commercial incentive to focus investment in new capacity on places where that capacity will be heavily used. Instead, it would require Ofgem or another party to evaluate the social and economic benefits of new projects. It would also require Ofgem or another party to take a view on the efficient level of interconnection for GB to allow comparison of competing projects and prevent overinvestment.

3.73. A fixed regulated return is likely to further reduce the project risks as expected returns would not vary based on asset use. We would therefore need to consider introducing sharper incentives, particularly on cable availability and cost efficiency, in order to ensure consumers' interests are protected and appropriate risks are allocated to project developers.

*Approach 4: Centrally identified opportunity, cap and floor on returns or fixed regulated return*

3.74. This approach represents a model where a central body (such as NGET acting in its role as the SO, Ofgem or Government) identifies and evaluates potential new interconnection capacity that would be beneficial to GB. This could entail

---

<sup>22</sup> Regulation 714/2009 of the European Parliament and Council.

identification of opportunities to invest in a set amount of capacity connecting to other markets within a time period, based on market and social studies. Or, it could involve planning of projects including, for example, specifying capacity, connection location and technology. In either case the opportunity could be for a fixed regulated return or for a cap and floor on returns.

3.75. This approach removes the reliance on market signals alone to deliver the efficient level of interconnection but places new responsibilities on a particular party to take a holistic view of network needs. This is an activity often associated with TSOs and is common practice elsewhere in Europe.

3.76. This centrally planned approach removes the risk of identifying cross-border opportunities for project developers and, depending on the regime that is applied, could also remove the risk associated with volume and revenue volatility. Appropriate risk allocation would need to be ensured through the use of sharper incentives to protect consumer interests. Moving towards central identification of opportunities has knock-on impacts for the appropriate delivery mechanism and return for investors. This is discussed in more detail in Chapter 4.

*Implications for options for system planning*

3.77. The system planning frameworks described in the previous section could play an important part in facilitating some of these approaches to interconnection. In particular, the role of a coordinating body could be important where additional oversight and analysis of proposals is needed, or where centralised identification of opportunities to interconnect is deemed necessary. This may then raise further questions about the institutional arrangements currently in place, particularly where the conflicts could arise between planning and regulated or competitive activities. This would be particularly relevant to the enhanced SO model, given NGET's commercial interest in owning and operating interconnection.



## 4. Initial analysis of options for delivery of transmission assets

---

### Chapter Summary

Examines options to facilitate efficient delivery of transmission assets. The chapter's focus is on how projects serving multiple purposes might be delivered and the approach to determining whether assets are delivered by an incumbent TO or via competitive selection.

### Question box

**Question 7:** What are your views on the options for delivery of transmission assets discussed in this chapter? Are there other options that you think we should be considering within the ITPR project to address the delivery drivers and challenges identified?

**Question 8:** Do you think that it would be beneficial to introduce some flexibility in the existing regimes to provide for alternative delivery routes, where this is in the interests of consumers? If so, what criteria could be used to determine the delivery route for an investment?

**Question 9:** If we pursued additional flexibility in application of the regimes, what role should discretion play in identifying the delivery route for a particular investment?

### Introduction

4.1. Together with DECC, stakeholders and industry participants, Ofgem has been developing the electricity transmission delivery regimes (onshore, offshore and cross-border) to help them meet the needs of users and consumers. As discussed in Chapter 2, our analysis and stakeholder feedback has highlighted a number of potential future challenges which suggest that we should consider how these regimes interface and operate across the GB network.

4.2. In this chapter we set out three options to address these challenges. In doing this, two factors are considered:

- Proposed transmission projects are increasingly likely **to be more integrated** across onshore, offshore and cross-border transmission. The underlying characteristics of these projects, such as their use for **multiple purposes**, their technical complexity, uncertain costs, and overall timing mean that it is not clear how some of these projects would fit within the existing regimes; and

- The forthcoming large investment needs lead us to consider where **different approaches to delivery (by the incumbent TO or through a competitive process) could bring value to consumers.**

### **Integrated transmission developments**

4.3. For new and more integrated transmission projects such as MPPs that straddle onshore, offshore and cross-border transmission there could be some regulatory uncertainty around which regime applies in the first instance, or may apply if the asset becomes multi-purpose over time. Such integrated projects may also carry technology uncertainties as they often involve the use of innovative technologies.<sup>23</sup> However, where these projects are in the interests of consumers, regulation should not be a barrier to their development.

4.4. Figure 5 discusses some of the challenges of integrated projects under the existing regulatory framework. These scenarios illustrate asset designs that could blur the boundaries between the existing regulatory regimes, particularly because the regulatory regime applying to it may not fully reflect how the asset will be used. There may also be a question as to whether an asset's classification could change in the future and, if so, whether the regulatory regime under which that asset or activity is currently regulated would also need to change and a new licence would be needed.

### **Reviewing existing delivery routes for value to consumers**

4.5. The likely large scale of investment in electricity transmission required in the coming years means that it is important to consider whether the regulatory approach will enable delivery of that investment efficiently and cost effectively. While the existing onshore, offshore and interconnector regimes provide a good basis for delivering investment, it may be beneficial to introduce some flexibility in their use to provide for alternative delivery routes. The ITPR project builds on our intention as noted under RIIO to consider the use of so-called "third party delivery" (ie opening up delivery to parties other than just the incumbent TO) for onshore electricity transmission where it might be in the interest of consumers.<sup>24</sup> We are also considering whether there are some areas where incumbent TO delivery might be extended in the interest of consumers.

4.6. Competitive delivery could have clear benefits in some circumstances, including the potential to bring new innovation, cost savings and timely delivery. However, there are other circumstances where incumbent TO delivery might be appropriate. Taken as a whole, in reviewing these delivery routes we would need to

---

<sup>23</sup> For further detail, see the SKM report referenced earlier in this document.

<sup>24</sup> See the decision on strategy for the next transmission price control - RIIO-T1 here: <http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf>.

establish what elements or characteristics of a particular investment make it a good candidate for one delivery route or another. These would need to reflect the requirements of network operation and stability for investors alongside the potential benefits to consumers.

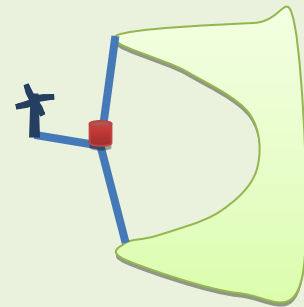
**Figure 5: Challenges of Integrated Projects**

**Scenario 1: Asset providing wider reinforcements to the network, while transmitting offshore generation**

These are projects that relieve onshore network constraints by means of a shore-to-shore subsea cable, or 'bootstrap'. Subject to available technology, it may be possible to integrate the development of these cables with the connection of offshore generation, either at the outset of the project's development or at a later stage.

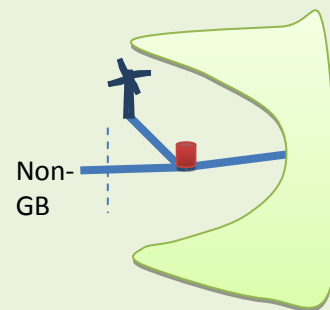
In the scenario depicted here, if offshore generation is connected to the 'bootstrap', an offshore transmission licence would be needed to operate both the bootstrap and the connection to the offshore generating station. This would be the case regardless of the timing of the commissioning of the various assets in question.

Consequently, if offshore generation is connected to an existing bootstrap, current legislation requires that the bootstrap is covered by an OFTO licence that is awarded via competitive tender. Therefore, such a licence would not be awarded to the developer or operator of the 'bootstrap' (typically the onshore TO) as a matter of course. Such potential ownership and licence changes may present uncertainty for project developers, and may lead to perverse incentives in planning.



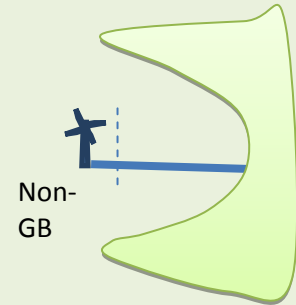
**Scenario 2: Asset used for transmitting offshore generation and interconnection**

Offshore transmission could also integrate with interconnection. Currently, the regulatory regimes do not specify how revenue and access arrangements might work in this circumstance, acting as a disincentive for parties to cooperate or oversize their asset to allow integration. There is also a lack of clarity in legislation as to which parts of the assets would require an OFTO licence and which an interconnector licence, presenting uncertainty for project developers. The market arrangements highlighted by this sort of asset configuration are also being considered through the North Seas Countries Offshore Grid Initiative (NSCOGI).



### Scenario 3: Asset used to directly connect generators located outside GB

Opportunities for renewables trading with other Member States present the possibility of renewable generation, located in another Member State, connecting to the GB transmission system directly. The operator of the links would, under domestic legislation, require an interconnector licence because part of its line or plant would be situated in GB and would convey electricity between GB and another country or territory.<sup>25</sup> Since the asset is not (initially) connecting two markets, it would not use price arbitrage as a revenue mechanism. This means that the commercial considerations for this asset may differ from those set out in the existing interconnector regime.



### Delivery options considered

4.7. We examine these delivery challenges in the context of three potential options that might be used to facilitate efficient delivery of transmission assets. Currently, the delivery method is strictly based upon whether the asset is classified as onshore, offshore or interconnection. This leads to: incumbent TO delivery onshore; competitive tendering for offshore transmission licences; and merchant or Cap and Floor approaches for interconnectors.

4.8. The options we have developed consider the level of flexibility where the current regimes are applied. We consider three options: no provision of flexibility between or within the current regimes (but with new processes set out in the delivery routes used); introduction of a limited level of flexibility to which delivery route is used while largely maintaining the current regime boundaries; and establishing full flexibility in the application of the existing delivery methods for all transmission investments. These are aimed at providing key options across the spectrum of possible approaches and are not intended to be comprehensive.

### Option 1: No flexibility in use of delivery routes

4.9. Under this approach all delivery routes would continue to be determined by how the asset is currently classified. This would determine whether they are delivered by incumbent TOs (under the onshore regime), licensed following a

---

<sup>25</sup> There are different definitions of 'interconnector' in EU legislation. For the purposes of this consultation we are focusing on the domestic definition and will address other definitions as necessary as the development of options take place.

competitive tender (under the offshore regime), or delivered through a merchant or cap and floor interconnector licence (through the interconnector regime).

4.10. MPPs would need to fit within one of the existing delivery regimes and, as a result. Therefore, if pursued, a key aspect of this option would be to provide clarity to industry participants on how particular assets would be treated under the regulatory framework.

4.11. Scenario 1 in Figure 5 provides one illustrative example of the application of this option. The owner of this 'bootstrap' asset would need to be licensed as an OFTO once offshore generation connects to it. A licence wouldn't be awarded as a matter of course and would, under the no flexibility option, require a competitive tender process. Following the award of a licence, the asset would pass on to the successful bidder, who may not be the incumbent owner.

4.12. In this example, clarification of the process and principles by which such assets would transfer to an OFTO would require consideration of issues including: how ownership transfer might take place (including timing of the process); how the transfer value would be determined; and what it would mean for the onshore TOs' regulated asset base. Careful consideration would need to be given as to whether the option would be possible under the current legislative framework or whether legislative change would be required.

4.13. Likewise, for other types of MPPs, such as an asset used simultaneously for transmitting offshore generation and interconnecting two markets (Scenario 2), we would need to carefully consider the current legislative framework in order to determine its application in particular circumstances. Such consideration would need to take account of whether the asset is multi-purpose from the start, or if there is incremental development of an interconnector from an offshore transmission line (or vice versa).

4.14. The 'no-flexibility' option could increase regulatory clarity while maintaining current delivery expectations. Therefore, it could build on the existing investor certainty in the onshore and offshore regimes and help to maintain confidence in a steady pipeline of projects.

4.15. However, this option may give perverse incentives which stop coordinated designs from being brought forward. For example, a party designing a particular asset could make choices in relation to technology or design on the basis of their effect on the regulatory status of the asset, rather than on the basis of what will serve the interests of an economic and efficient network. Another potential drawback of this option is that it could create ongoing ownership uncertainty if assets were subject to re-licensing and ownership change at an unspecified future date.

4.16. Furthermore, a lack of flexibility implies that either competitive or incumbent TO delivery might not be able to be used in some cases, even if it could bring benefits to consumers. Finally, the changes required to clarify existing regimes, for example to put in place clear routes for change of asset classification, extend asset

transfer capabilities etc, are significant and could be time consuming to implement. This is a risk present in all options explored which will require further analysis in the next phase of our work.

## **Option 2: Limited flexibility in use of delivery routes**

4.17. A second approach could be to introduce some flexibility to which delivery route is used for certain types of project while largely maintaining the current regime boundaries. This implies that some projects could be “carved out” of any of the existing regimes to be delivered via a different route. For example, identifying a project in the onshore network that could be delivered by a competitively selected third party, or allowing an incumbent TO to be licensed for an offshore transmission asset without it being awarded via competitive tender. In both cases, we would also need to look at the criteria that could be applied to determine the assets appropriate for a carve out from a regime.

4.18. Applying this option to Scenario 1 in Figure 5 could mean establishing a process to carve out certain assets from the need to be covered by a competitively tendered offshore transmission licence. For example, for a ‘bootstrap’ that was initially developed purely as an onshore reinforcement by an onshore TO, a carve out could allow it to continue to be covered by their licence. This would require changes to the offshore tender regulations and may require changes to primary legislation as well. The same principles could also be applied to carve out projects from incumbent TO delivery and award licenses to deliver through a competitive tender process.

4.19. The ‘limited flexibility’ option could help to enable MPPs since it could encourage efficient development by the incumbent developer. It could also provide a clear route for some MPPs to be delivered. However, if flexibility were only applied on a limited basis, it could maintain a level of uncertainty for some MPPs. In addition, even with this ‘limited flexibility’ option, there are some potential projects where it may not be possible to provide a clear delivery route from the outset.

4.20. Furthermore, and as with Option 1, this option would require significant development of the existing regimes, for example in identification of criteria, building a robust framework to allow carve outs from the existing regime for certain projects etc. Again, this would be time consuming to implement and so may not address the concerns of near-term projects.

4.21. Finally, because this option opens up the possibility of competitive delivery to deliver projects onshore and incumbent TO delivery offshore, there is a risk that this could undermine investor confidence in the pipeline of projects in either case. This is a concern, however it could potentially be mitigated to the extent that this option offers a ‘two-way’ carve out, offering new opportunities for investment. In addition, development of robust criteria to identify projects suitable for carve out would also help to manage expectations and provide clarity on the pipeline of projects. Development of criteria is discussed later in this section.

### **Option 3: Full flexibility in use of delivery routes**

4.22. A third option would be to establish full flexibility in application of the delivery route used for all transmission investments. Under this approach, all new projects would be assessed for their suitability for being delivered by an incumbent TO or through a competitive approach.

4.23. As with Option 2, full flexibility would also require a set of criteria to be developed and applied to all assets to determine whether delivery through the incumbent TO or a competitive process would be economic and efficient for a particular investment. For example, the criteria could include the purpose, value, and degree of separability from the rest of the network to determine what delivery route should be used.

4.24. It is also important to reiterate that we consider the current regimes are generally working well for the delivery of most assets. Given this, we envisage that the criteria that would generate greatest value for consumers would be such that there would only be a limited number of assets, which might be developed under a different route.

4.25. This approach would allow for some change in the use in competitive or incumbent delivery at the margin of regimes if this could be demonstrated to create more value for consumers. In addition to this, this approach would establish a route for delivery of projects that blur the existing regime boundaries and that currently have no clear route to delivery.

4.26. However, again, there is a risk that the changes required are significant, disruptive and time consuming to implement, which would need to be weighed against the possible benefits that may come from this option. We will be undertaking further work to consider how full flexibility might be implemented, but note that this option may require changes to primary legislation which could only be taken forward by Government.

4.27. The proposals also have the risk of a potential impact on investor confidence in a similar way to Option 2. Although, again, the same mitigating factors apply, in that new opportunities for both competitive and incumbent delivery will be created and robust criteria would help to manage expectations and bring clarity.

### **Discussion on additional flexibility in use of delivery route**

*What criteria might be used to identify the delivery route*

4.28. If additional flexibility is pursued, either on a limited or broader basis, we would need to consider possible criteria that could help decide which types of transmission network investments or activities are suitable for the competitive delivery route and which are suitable for delivery by incumbents. These criteria

would need to reflect the extent to which competitive delivery could benefit consumers as well as the practicalities of one path over another.

4.29. The criteria could vary based on the level of flexibility being introduced. Potential criteria could include:

- The level to which outputs and services can be appropriately specified for a particular asset;
- The extent to which the investment is separable from the rest of the network, including on both ownership and operational grounds;
- The cost of the project;
- The likely timeliness of delivering the investment through one model or another; and
- Location of the asset.

*How criteria might be applied to reach delivery decisions*

4.30. We would also need to consider how and when the criteria would be applied to designate an asset's delivery path. The criteria could be used to develop clear and comprehensive upfront rules (a "rules-based approach") or high-level principles by which a decision maker (possibly Ofgem) could take a case-by-case approach to evaluating the most appropriate route (a "discretionary approach").

4.31. Under a rules-based approach, it would be necessary to specify clear boundaries and thresholds that determine whether specific transmission projects fall under different delivery models. This mechanistic approach would provide greater clarity on the likely delivery route for specific projects which could improve investor confidence and avoid unnecessary resource costs, disputes and delays as the delivery route could be determined from the outset. However, with this strict framework comes the consequence that rigid rules-based criteria could be less flexible to specific project circumstances.

4.32. Alternatively, Ofgem (or another decision-making body) could take a discretionary approach and use of the criteria to make case-by-case decisions on whether specific transmission network projects or activities should be carried out by an incumbent or competitive delivery. Criteria for a discretionary approach are likely to be framed as high level principles for selection, and less mechanistic and comprehensive than the rules-based criteria.

4.33. This approach allows greater account to be taken of case-specific evaluation criteria, such as timeliness which cannot be captured well under the rules-based approach. It also creates opportunities for learning-by-doing on suitability of different types of transmission activities for competitive or incumbent TO delivery. However,



the discretionary nature of this approach, if used without clear guiding principles, may undermine investor confidence.

4.34. Given this, a combination of the rules-based and discretionary approaches may be the best outcome for any new criteria. Further analysis and development of options is required, along with an assessment of the options for implementation of any approach requiring the development of new criteria.

*Key considerations for flexible application of the existing delivery routes*

4.35. We would also need to consider some of the practicalities of applying different delivery routes where they currently do not exist. There would be some considerations to address how to extend incumbent TO delivery to new types of assets, including potential licence modifications and revenue impacts. There are also additional considerations to be made in extending competitive delivery to new areas beyond the current offshore remit (eg onshore or interconnection).

4.36. With reference to competitive delivery, consideration of the timing for introduction of the competitive process (and how this interacts with any criteria) is also needed. There could also be a role for criteria to determine the approach within a particular delivery route. For example, where competitive delivery is applied, additional criteria could be developed to determine when the generator build option is available. The current offshore delivery model of using competitive tender exercises to identify OFTO licensees is a useful starting point for this.

4.37. The offshore regime has previously examined three broad development options. Under 'early OFTO build', a delivery party would be identified at the outset of the project development and would be responsible for the design, consenting, procurement, construction and ownership of the transmission asset. Under 'late OFTO build', the preliminary works such as high level design would be completed by the offshore generator before the OFTO licensee takes it forward from procurement and construction onwards. Under "generator build", the offshore generator undertakes the preliminary works as well as construction before an OFTO is granted a licence to own and maintain the assets.

4.38. There are risks and benefits to each of these models that need further consideration. For example, using a model where a development party is identified early in the process is advantageous because it could lead to innovation in proposed solutions. However, there are additional challenges in determining an efficient outcome from a competitive approach during the early stages of a project's development. This is due to the fact that significant uncertainty still remains around the project at that point, with a number of major variables that could still change.

4.39. Instead, preliminary works could potentially be completed by an incumbent party prior to the eventual construction and ownership by a third party. This model raises its own challenges such as ensuring that the development and procurement activities sit with the right parties but are also completed in a timely manner.

4.40. Another key consideration is potential conflict of interest concerns where incumbent TOs or their associated businesses are also taking part in a competitive process. This is discussed in Chapter 3 with respect to system planning but also relates to any delivery options that increase flexibility. An area for further consideration is if information such as asset or system risks were available to one party (and not to other bidders) that gave it a competitive advantage.

### **Implications for interconnectors and non-GB generation connections**

4.41. Interconnectors are delivered via developers identifying opportunities for price arbitrage between markets, driven entirely by wholesale market price signals. This is the current mechanism for delivery of merchant interconnection and the proposed Cap and Floor regime (for NEMO) also supports this developer-led delivery route.

4.42. If the project identification approach moves away from this and towards more centralised identification of opportunities as identified in Chapter 3, there may be cause for the delivery approach to evolve to reflect this change. For example, if there were to be a regulated return for the owner of a new interconnector then alternative approaches may be needed to select the party most appropriate to bring forward that investment.

4.43. In relation to non-GB generation seeking an exclusive connection to GB, as noted in Figure 5, price differentials do not exist to drive interconnector investment for transmission links connecting non-GB generation to the GB network. One option would be to treat these links more akin to the treatment of transmission connections for GB generation. This would imply that the owner of the links would receive a fully regulated revenue stream, with cost recovery from the non-GB generators in line with user commitment and transmission charging principles.

4.44. Under this approach, a licence to deliver new interconnection could be awarded via a competitive approach or to the incumbent TO to build out. However, the existing regulatory framework does not currently support the application of either delivery route. Further work is needed to consider any potential regulatory and legislative changes needed to make either approach work. We will consider all such options carefully at the appropriate stage. Primary legislative change could only be taken forward by Government and would be subject to the Parliamentary legislative timetable.

4.45. An alternative to these routes could be to consider appropriate adaptation of the developer-led interconnector regimes (as detailed in Chapter 3 and elaborated in Figure 4), ranging from merchant through to Cap and Floor, or a regulated revenue stream. Further analysis is needed for all of these options to ascertain whether any can be adapted to offer a shorter-term solution that will allow projects to come forward where it is in the interests of consumers.

## 5. Emerging thinking and next steps

---

### Chapter Summary

Sets out our emerging thinking on options for transmission system planning and delivery in the light of the initial analysis set out in the preceding chapters and discusses the next steps for the ITPR project.

### Question box

**Question 10:** Do you think that the case for change to current arrangements to enable more integration and coordination is material now, or may become so in the future? If the latter, when?

**Question 11:** What are your views on our emerging thinking to consider further an enhancement of NGET's role as the SO in system planning to provide for a more coordinated and holistic approach across the GB system?

**Question 12:** What are your views on the emerging thinking that introducing further flexibility and applying criteria to designate whether an investment should be delivered by incumbent delivery or competitive selection could address many of the challenges and drivers identified?

**Question 13:** What other options should we take forward for consideration in the next stage of our work on ITPR?

**Question 14:** Do you have any views on our approach and timetable for our work on ITPR, or on interactions with related areas?

**Question 15:** Do you have any other views on the ITPR project not covered by these questions?

### Emerging thinking

#### Case for change

5.1. When considering the case for change across existing arrangements, it is important to consider how material the future challenges could be. Any case for change should be based on an assessment of the costs and benefits of both action and retaining the status quo.

5.2. We have identified a number of potential drivers for change in both transmission system planning and delivery. However, there is significant uncertainty surrounding all these drivers around the materiality of their impact, and what changes, if any, they should prompt.

5.3. Although there is uncertainty in the extent and timescales with which these factors will affect system development, we consider that the benefits of greater integration and coordination across the system have the potential to be significant. We therefore see merit in progressing further analysis of the current arrangements and options for change, while keeping these drivers under review. Our focus is on exploring a proportionate response, based on potential benefits and risks. We welcome views on whether the case for change under ITPR is established now, or may become so in the future.

### **System planning**

5.4. We are interested in views on the respective merits of each option identified in Chapter 3 and any other options. This includes the so-called 'depth' of the potential coordinating role acting across the system and the institutional arrangements and transparency frameworks required underpinning that role.

5.5. At this stage we see merit in developing further the enhanced SO model, based on the 'enhanced coordinating body' model and underpinned by increased transparency measures within the existing institutional framework, such as building on the existing NDP and CION processes to alleviate potential concerns regarding conflicts of interest. This could compliment NGET's proactive approach to the development of a more holistic planning document through the ETYS. If required, this could also entail strengthened business separation measures from NGET's delivery businesses (taking account of the business separation arrangements being considered as part of EMR delivery).

5.6. We consider that enhancing the role of NGET as SO in the areas outlined could leverage the benefits that could come from a single party having a mandate to take a 'whole-system view' at key decision points whilst continuing to utilise the TOs', OFTOs', generator-builders' and interconnector developers' expertise. It could also smooth the boundaries in system planning across the different delivery regimes and potentially enable greater clarity in system planning decisions/processes for stakeholders.

5.7. NGET with an enhanced SO function could support Ofgem decision-making, including on anticipatory, coordinated and strategic investment proposals, through acting in an advisory capacity to Ofgem and transmission developers. This may in turn alleviate risks of piecemeal, uncoordinated or underutilised investments in the network that could unnecessarily increase costs to consumers. Further work would be needed to determine what form this support from the SO would take. For example, would NGET as the SO provide guidance or recommendations on technology choices for particular network designs? And what additional powers, if any, would the SO need to undertake this new role?

5.8. Depending on the further development and practical application of this model, there is the possibility that this option may require legislative change as outlined in Chapter 3 of this document. Any such changes would need to be carefully considered.

5.9. Our preliminary analysis of the risks and benefits of different institutional options (including the potential for disruption during implementation) is that full separation of the SO function may not be needed with this approach. However, under this model, some steps may be needed to improve transparency of decision-making. Additionally, there may be merit in considering nearer-term options to improve transparency in regards to the role and responsibilities of interconnectors under the system planning arrangements.

5.10. In the near term, we will continue to work with industry to progress targeted measures which will support any future option with respect to system planning. These measures include:

- Exploring options for, and possible benefits of, involvement of interconnectors in the STC;
- Making improvements to the Connections Infrastructure Options Note (CION) process, and to facilitate the potential developments to user commitment and charging regimes to better accommodate an integrated, coordinated or interconnected offshore – onshore network;
- Exploring options for potential changes to the process, and roles, for undertaking system studies, such as harmonics analysis;
- Possible updates to clarify and improve the relationship between onshore TOs and NGET as the SO under the NAP; and
- Setting out further details in our offshore coordination policy work on the potential role of the SO in supporting the needs case for wider network benefit investment for submission to Ofgem gateway assessments.

### **Framework for delivery of transmission assets**

5.11. With regard to transmission asset delivery our emerging thinking is that additional flexibility in the application of the existing delivery routes is likely to provide benefit and that full flexibility may provide the greatest scope to achieve benefits for consumers and clarity for industry.

5.12. The addition of clear criteria to help determine which route delivers most benefits for consumers would provide a regime for delivery of projects that blur the existing regime boundaries and that currently have no clear route to delivery. Clear criteria would also help to ensure certainty for investors, although further work would be needed to develop the right balance between rules-based and discretionary criteria to continue to promote investor confidence.

5.13. We envisage that the criteria able to generate greatest value for consumers would not change the delivery route for most assets. However, the criteria would allow for some change in the use in competitive or incumbent delivery at the margin of regimes if this could be demonstrated to create more value for consumers.

5.14. Additional flexibility between regimes fits well with the emerging thinking for system planning. Where an enhanced coordinating body has identified investment needs, including MPPs, additional flexibility would enable a method to then determine the appropriate delivery route for that identified investment. The level of flexibility that may be preferable is subject to several considerations. First, many of the drivers that could point towards additional flexibility remain uncertain, as described in Chapter 2.

5.15. In addition, we are considering all options with respect to the planning and delivery of interconnection. We are looking at the relative merits of developer-led versus centrally identified projects and considering the links between planning options and choosing an appropriate delivery route, whether it is developer-led, a competitive tender or incumbent TO delivery.

5.16. We recognise that both moving towards an enhanced coordinating body and introducing additional flexibility to the delivery regimes may require legislative change, though we will first explore whether options are consistent with the current legislative framework. Furthermore, we recognise the need to provide certainty for projects that are already under development and will consider further whether any transitional measures may be appropriate. Examining these areas and further implementation questions will remain important aspects of our work following this consultation.

### **Next steps**

5.17. Figure 6 sets out the timescales currently proposed across the stages of ITPR and the purpose and content of each stage. We are also progressing a number of related initiatives alongside policy development for the ITPR project, set out in Appendix 5. This includes further details of the work that is currently underway to consider the connection of Irish renewable projects to the GB transmission system.

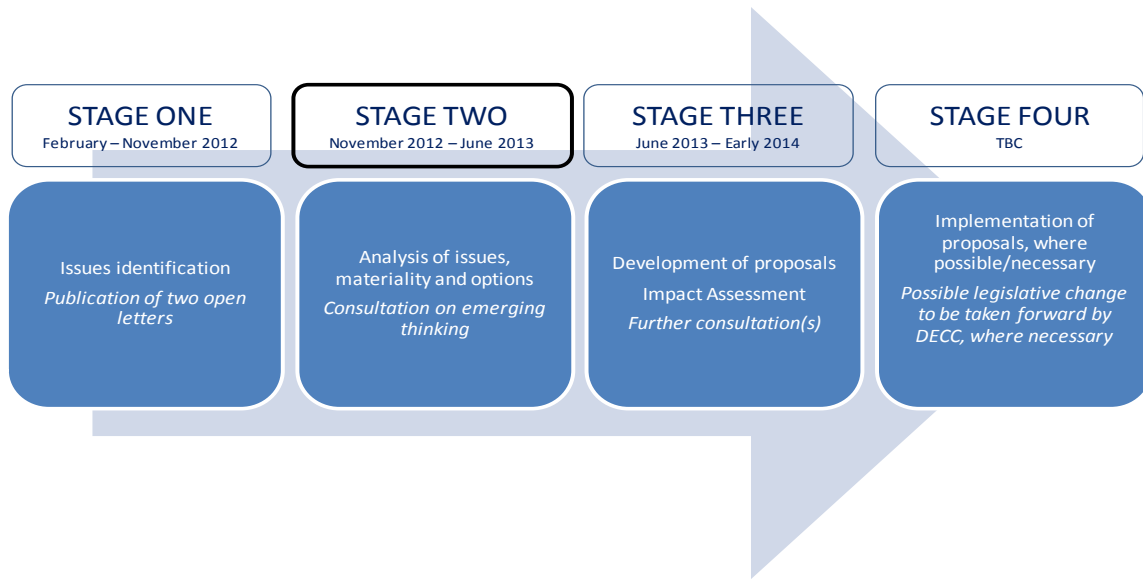
5.18. Stage One of the ITPR project focused on the exploration of issues with the system planning and delivery arrangements for electricity transmission networks. This consultation outlines our emerging thinking on options to address these issues and concludes Stage Two of the project, following further analysis and an assessment of the materiality of the drivers behind the project.

5.19. Over the course of 2013 and into 2014, we will undertake further policy development as part of Stage Three. This will be achieved through stakeholder engagement (including analysis of responses to this consultation), industry workshops and ongoing analysis. We will look to produce an impact assessment alongside initial policy proposals which we intend to consult on in early 2014.

5.20. Stakeholder engagement in the early part of Stage Three will be critical in developing the preferred options from the detail in this consultation. As such we welcome feedback on whether we are focusing on the appropriate options. We do not consider it manageable or appropriate to give detailed consideration to the large number of planning and delivery frameworks that could be derived from all possible

permutations of the options set out in this document. In our ongoing policy development we therefore intend to narrow our focus to combinations which represent a coherent overall framework, and which could potentially represent a proportionate response to the issues set out in Chapter 2.

**Figure 6: ITPR project stages**



5.21. In doing so we will seek to identify interdependencies between options for system planning and delivery. When considering changes in planning alongside changes in delivery, we will further review our analysis of potential conflicts and synergies between the SO and TO functions and the extent to which those conflicts may be mitigated and synergies may be maximised. We note it may also be appropriate to consider further these issues in the context of any future decisions on the allocation of roles under EMR.

5.22. Stage Three will also consider potential implementation routes and the lead times for these. Some of the options set out in this document may require legislative change. We will consider all such options carefully at the appropriate stage. Primary legislative change would be a matter for Government to consider and, if taken forward, would be subject to Parliamentary legislative timetable. In Stage Three we will also continue to progress policy options for developing the Cap and Floor regime for interconnection into an enduring regime.

5.23. Stage Four will build on the initial proposals formed in Stage Three, subject to feedback from consultation and will move towards implementation. The timing of this stage will be dependent on the issues arising from Stage Three.

## Appendices

---

### Index

Appendix	Name of Appendix	Page Number
1	Consultation Response and Questions	43
2	ITPR workshop, 26 June 2013 – further details	46
3	Key differences between the current regimes	47
4	Summary of responses to November open letter	51
5	Other initiatives	53
6	Glossary	56
7	Feedback Questionnaire	61



## Appendix 1 - Consultation Response and Questions

---

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by Friday 2 August 2013 and should be sent to:

Charlotte Ramsay, Head of European Electricity Transmission  
ITPR team  
Ofgem  
9 Millbank  
London  
SW1P 3GE

Tel: 020 7901 0512

Email: [ITPRMailbox@ofgem.gov.uk](mailto:ITPRMailbox@ofgem.gov.uk)

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website [www.ofgem.gov.uk](http://www.ofgem.gov.uk). Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the documents to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

### **CHAPTER: One**

There are no questions in this chapter.

### **CHAPTER: Two**

**Question 1:** Do you think we have appropriately characterised the future challenges to network development? Where do you see the main challenges? What are the long-term strategic and sustainability implications of these challenges?

**Question 2:** Are any of the review areas under ITPR more relevant than others?

### **CHAPTER: Three**

**Question 3:** What are your views on the options for system planning discussed in this chapter? Are there other approaches to system planning that you think we should be considering within the ITPR project?

**Question 4:** Do you think that it would be beneficial to strengthen the role of a coordinating body working with relevant parties to facilitate efficient decision-making? In what areas could this coordinating body add most value to the process?

**Question 5:** What are your views on the (real or perceived) conflicts of interest that could occur from parties holding dual responsibility in system planning and asset delivery and ownership? What are your views on potential options for institutional arrangements, separation and transparency measures to mitigate this?

**Question 6:** What are your views on potential future approaches to planning interconnection? Should there be increased central identification of potential interconnection that could benefit GB consumers?

### **CHAPTER: Four**

**Question 7:** What are your views on the options for delivery of transmission assets discussed in this chapter? Are there other options that you think we should be considering within the ITPR project to address the delivery drivers and challenges identified?

**Question 8:** Do you think that it would be beneficial to introduce some flexibility in the existing regimes to provide for alternative delivery routes, where this is in the interests of consumers? If so, what criteria could be used to determine the delivery route for an investment?

**Question 9:** If we pursued additional flexibility in application of the regimes, what role should discretion play in identifying the delivery route for a particular investment?

**CHAPTER: Five**

**Question 10:** Do you think that the case for change to current arrangements to enable more integration and coordination is material now, or may become so in the future? If the latter, when?

**Question 11:** What are your views on our emerging thinking to consider further an enhancement of NGET's role as the SO in system planning to provide for a more coordinated and holistic approach across the GB system?

**Question 12:** What are your views on the emerging thinking that introducing further flexibility and applying criteria to designate whether an investment should be delivered by incumbent delivery or competitive selection could address many of the challenges and drivers identified?

**Question 13:** What other options should we take forward for consideration in the next stage of our work on ITPR?

**Question 14:** Do you have any views on our approach and timetable for our work on ITPR, or on interactions with related areas?

**Question 15:** Do you have any other views on the ITPR project not covered by these questions?

## Appendix 2 – 2<sup>nd</sup> ITPR workshop – further details

---

1.1. As part of our stakeholder engagement on our initial analysis of issues and options, we are hosting our 2<sup>nd</sup> ITPR workshop on **26 June 2013**. The event will take place from 10.30 to 16.00, at Mary Ward House Conference & Exhibition Centre, 5-7 Tavistock Place, London WC1H 9SN. We welcome organisations and individuals with an interest in electricity transmission to take part in the workshop.

1.2. The workshop will be an opportunity to learn more about our analysis around system planning and delivery, including the work undertaken by Imperial College London and Cambridge University around the principles and international approaches to system planning and delivery. The workshop will also be an important opportunity for us to hear your views around our initial analysis of options.

1.3. If you wish to attend, please register your interest, or that of your organisation, by reply to this e-mail [ITPRMailbox@ofgem.gov.uk](mailto:ITPRMailbox@ofgem.gov.uk) as soon as possible. In the coming weeks we will ask for confirmation of attendance and release a full agenda.

## Appendix 3 – Comparison of the current regimes

1.1. This appendix summarises some key differences between the three regimes currently applying to onshore transmission, offshore transmission and interconnectors, in relation to the aspects of those regimes that are most relevant to the areas under review in ITPR.

**Table 2: Summary of current delivery regimes**

Onshore	Offshore	Interconnector
<ul style="list-style-type: none"> <li>▪ Three licensed TOs based on geographic natural monopolies</li> <li>▪ 8-year price control set for TOs with periodic reviews of prices and 4-year interim review of outputs</li> <li>▪ The price control is carried out under the RIIO model, setting the primary outputs the TOs are expected to deliver and the revenue for their efficient delivery</li> <li>▪ TOs submit business plans which are assessed by Ofgem against delivering sustainable energy sector and long-term value for money</li> <li>▪ Continuous stakeholder engagement around how TOs perform is designed to enable changes in views around policies and processes to be taken account of</li> </ul>	<ul style="list-style-type: none"> <li>▪ OFTO licences are, and can only be, awarded through a competitive tender process</li> <li>▪ Generator Build and OFTO Build options for design and construction</li> <li>▪ OFTO receives a fixed 20-year revenue stream</li> <li>▪ Effective competition creates incentives to bid an economic and efficient revenue stream</li> <li>▪ Balance of regulatory obligations and performance incentives drive outcomes</li> </ul>	<ul style="list-style-type: none"> <li>▪ Cross-border transmission capacity connecting GB to another Country</li> <li>▪ Interconnector owners earn revenues by auctioning interconnector capacity. These revenues are dependent on the existence of price differentials between markets at either end of the interconnector that create opportunities for cross-border trades</li> <li>▪ An individual developer proceeds with a project based on understanding of market conditions. That developer cannot also hold any generation, transmission, distribution or supply licence<sup>26</sup></li> <li>▪ Merchant and regulated approaches are available</li> </ul>

<sup>26</sup> Section 145(1), (6) of the Energy Act 2004 inserted section 6(2A) into the Electricity Act.

**Table 3: Funding**

Onshore	Offshore	Interconnector
<ul style="list-style-type: none"> <li>▪ Base revenue through RIIO to cover expected efficient costs of delivering outputs and long-term value for money</li> <li>▪ Adjustments to reflect company performance in delivering outputs efficiently; innovating to expose efficiencies during the control period; and adjustments during the control period for specific uncertainties</li> <li>▪ Allowed revenue is recovered through Transmission Network Use of System (TNUoS) charges from generation and demand users. NGET as the SO has responsibility to ensure charging methodologies are up to date and modifications better achieve the objectives of each methodology<sup>27</sup></li> <li>▪ 45-year asset life for investment cost recovery</li> </ul>	<ul style="list-style-type: none"> <li>▪ A fixed 20-year revenue stream determined in the tender process and subject to certain pass-through items and incentives, including an availability incentive</li> <li>▪ Under OFTO Build, OFTO bears capex and opex risk.<sup>28</sup> Under Generator Build, capex evaluated through a cost assessment process by the Authority<sup>29</sup></li> <li>▪ More highly geared financial structures than onshore</li> <li>▪ The OFTO recovers revenue from NGET as the SO who correspondingly recovers it according to the TNUoS charging methodology applying to onshore and offshore assets</li> </ul>	<ul style="list-style-type: none"> <li>▪ Interconnectors generate revenue through the sale of capacity in auctions</li> <li>▪ Under a merchant-exempt approach, interconnector operators seek an exemption from the European requirements in order to hold on to the revenue generated, while bearing the full upside and downside risks of rising and falling volumes and prices</li> <li>▪ Under a regulated approach proposed for initial application to Project NEMO, revenues above a cap are paid back to consumers while revenue below a floor triggers payment from consumers, collected through TNUoS<sup>30</sup></li> <li>▪ Cap and floor levels for a regulated approach are set ex-ante on the basis of cost using a Regulatory Asset Value (RAV) based model. These are fixed for the length of the regime (20 or 25 years). An availability incentive is also tied to the cap</li> </ul>

<sup>27</sup> Open governance arrangements allow industry parties to propose modifications. Ofgem makes the final decision on whether to implement any change but does not set or approve the level of individual charges.

<sup>28</sup> Subject to certain risk sharing mechanisms eg related to weather.

<sup>29</sup> The Authority determines the asset transfer value (from developer to OFTO) based on whether costs are economic and efficient.

<sup>30</sup> See here for further information:

<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=168&refer=Europe>.

**Table 4: Drivers of investment**

Onshore	Offshore	Interconnector
<ul style="list-style-type: none"> <li>▪ Users of the network (demand and generation) influence network planning through their connection and use of system requirements. Network develops according to projected demand and generation scenarios</li> <li>▪ There are automatic revenue drivers for small scale investments. A Strategic Wider Works mechanism is in place for large investments, whereby TOs propose works that are subject to the Authority’s assessment of the technical economic needs case</li> </ul>	<ul style="list-style-type: none"> <li>▪ Generators drive transmission investment need. Network design specified through the connection agreement</li> <li>▪ We are continuing to explore potential processes to provide greater clarity on how assets including anticipatory or wider network benefit investment will be treated through the tender process, where there is a technical and economic case for doing so</li> </ul>	<ul style="list-style-type: none"> <li>▪ Market driven. Project developer identifies, proposes and delivers investment. Assessment of future cash flows forms basis of private investment decision</li> <li>▪ No specific mechanism in place for anticipatory investment. Anticipatory investment would form part of the consideration in the business case to determine constructed interconnector capacity</li> </ul>

**Table 5: Generator / user access arrangements**

Onshore	Offshore	Interconnector
<ul style="list-style-type: none"> <li>▪ Each generator has a contracted level of Transmission Entry Capacity (TEC)</li> <li>▪ Generators have a firm right to export energy onto the transmission system</li> <li>▪ Connect and Manage allows generators to connect to the grid immediately after local 'enabling' works have been completed, rather than waiting for the TOs to carry out the deep reinforcements necessary to support additional generation</li> </ul>	<ul style="list-style-type: none"> <li>▪ Each generator has a contracted level of Transmission Entry Capacity (TEC)</li> <li>▪ Generators have a firm right to export energy on to the transmission system</li> </ul>	<ul style="list-style-type: none"> <li>▪ Market-based congestion management by means of explicit and implicit auctions. Both methods may coexist on the same interconnector</li> <li>▪ Auctions are mostly explicit, where capacity is allocated to users on the basis of their value preferences</li> <li>▪ Implicit auctions do not allocate capacity to individual market participants. Rather, transmission flows are internalised in the market-based mechanisms for clearing the energy markets and setting the geographically differentiated energy prices</li> <li>▪ Interconnectors seek connection offer via the CUSC. Capacity contractual framework agreement as per generators</li> </ul>



## Appendix 4 – Summary of responses to November 2012 open letter

---

1.1. Our open letter in November 2012 sought views around four potential issues associated with system planning and delivery that stakeholders said may pose a barrier to facilitating an integrated network. Below, we set out a summary of stakeholders' views with respect to each of them.

**Issue 1 – The obligations and incentives on the multiple parties involved in transmission network planning and delivery may not align to ensure that individual networks or assets develop in line with the overall needs of the system.**

1.2. There was broad agreement among stakeholders that features of the system planning process, such as access to technical information and the regulatory treatment of interconnectors, should be addressed under ITPR.

1.3. Stakeholders commented on the connections process. Some said that it worked reasonably well, while others said that timelines around a connection offer and a lack of clarity around decision making gave rise to problems and uncertainty. Some stakeholders argued that interconnectors should be treated as transmission and that they should be similar financial incentives and reporting requirements as other transmission parties.

1.4. On parties' roles and responsibilities in system planning, some stakeholders indicated that a lack of clarity and a lack of coordination among TOs and/or instruction from an over-arching body could hinder the development of an efficient and economic system. Some stakeholders suggested that system planning could benefit from more coordination among existing bodies, with some pointing to the existing joint planning committee under the TSC and the ENSG arrangements as a "starting point". While some stakeholders said that an instructive framework was not appropriate, others suggested that the creation of a centralised system planning body could help to promote a holistic perspective of long term system planning. With respect to having an enhanced NETSO, there was recognition that while it would represent less disruption to the current arrangements, it would give rise to concerns around independence compared with the creation of a new, independent body.

**Issue 2 – The framework for GB transmission entities to engage in European transmission activities may not provide an effective means for all relevant parties to contribute, giving rise to a risk that the GB transmission system is insufficiently represented at the European level.**

1.5. Some parties say that the current arrangement for representation of GB transmission entities is working broadly well, pointing out that where a party is

certified as a TSO it is eligible to participate in ENTSO-E. Others, including those who are not party to the ENTSO-E, argue that there is a need to ensure there is a sufficient GB-wide representation at a European level and that there is scope for discrimination as they are not represented and lack the resources to do it effectively. Furthermore, some stakeholders argue there are conflicts of interest with NGET representing other GB parties.

1.6. To address this issue, some stakeholders suggested having one independent party representing all GB transmission parties. Of those who suggest changes to the current arrangements, they say it is material in the development of the Ten Year Network Development Plan (TYNDP) and the selection of Projects of Common Interest (PCI). Some stakeholders say that the impact of the arrangement may become more material over time as European considerations become increasingly important.

**Issue 3 – There is a potential for conflicts of interest to arise for parties undertaking transmission planning and delivery.**

1.7. Stakeholders' views around the potential for real or perceived conflicts of interest in parties that undertake transmission system planning and delivery appear mixed. Some say that the current arrangements are effective, while others argue that they have the potential to give rise to conflicts.

1.8. Of those who suggest there is a potential for conflicts, some suggest greater transparency and clarity around decision making.

**Issue 4 – The regime interfaces for transmission related multiple-purpose projects (MPPs) are potentially unclear, giving rise to a lack of clarity around the regulatory treatment of these assets.**

1.9. The delivery framework for MPPs was a significant issue among a number of stakeholders, who argued that the current regimes are unclear and inappropriate which, in turn, could undermine investor confidence. They suggest that there is a potential risk of assets moving from one regulatory regime to another as the project develops, that there is uncertainty around charging and access arrangements for such projects and there is a lack of clarity with respect to oversizing.

1.10. In general, stakeholders appeared to favour an overarching, long-term approach to address all such projects in order to provide most clarity rather than a bespoke approach for one or two projects.

## Appendix 5 – Other initiatives

---

1.1. This appendix identifies a number of related initiatives being progressed alongside policy development for the ITPR project. These include:

- **European System Operation Network Codes** - the three European Network Codes on Operational Security, Operational Planning and Scheduling and Load Frequency Control and Reserves set out roles and responsibilities for TSOs to coordinate and manage their responsibilities for operating the interconnected Transmission Systems across Europe. These codes are still under development they become legally binding following comitology and will be directly applicable in GB. The implications and interactions with the ITPR project will be considered going forward.
- **Electricity Market Reform (EMR)** - the Government has indicated that NGET, in its role as the SO, is the preferred delivery body for EMR. DECC and Ofgem have considered the potential synergies and conflicts of interest that may arise from the proposed EMR role.<sup>31</sup> Although the ITPR project will focus on the system planning role undertaken by NGET as the SO and not the EMR delivery role specifically, where relevant we will consider the published responses to the EMR consultation that preceded the final report and the implications for options we may explore under ITPR.
- **Future Trading Arrangements Design** - Ofgem's Future Trading Arrangements Forum will create and build consensus on a coherent and consistent approach to wholesale electricity trading arrangements in the context of EMR, European Target Model and market and technological developments.
- **Interconnector Cap and Floor** - this project proposes a new Cap and Floor regime for regulation of new interconnector investment under project NEMO, a proposed interconnector between GB and Belgium, as a pilot project.<sup>32</sup>
- **Offshore Coordination** - Ofgem's coordination policy work focuses on enhancing the existing offshore regulatory framework to enable greater coordination in offshore transmission. This will look to be able to support coordination in nearer term offshore projects, whereas the ITPR project is looking at potential additional changes in the longer term to support an integrated GB system as a whole. We will continue to develop proposals to support coordination of offshore transmission, including considering

---

<sup>31</sup> See here for further information:

<http://www.ofgem.gov.uk/Markets/WhIMkts/EffSystemOps/Documents1/EMR%20Conflicts%20of%20interest%20consultation.pdf>.

<sup>32</sup> See here for further information:

<http://www.ofgem.gov.uk/Europe/Documents1/Cap%20and%20floor%20regime%20for%20regulation%20of%20new%20subsea%20interconnector%20investment5.pdf>.

implementation of the potential gateway assessments for developer-led wider network benefit investment.

- **North Seas Countries' Offshore Grid Initiative (NSCOGI)** – this initiative looks to facilitate strategic, coordinated development of offshore grids (among ten European Member States including the UK) to ensure more cost-effective investment and identify and tackle barriers to grid development. The ITPR project is contributing to the wider NSCOGI work.
- **Renewable Trading/Non-GB generation** - the Renewables Directive provides a mechanism whereby renewable energy produced in one EU member state can be counted towards the target of another, although this cannot be to the detriment of the producing country not achieving its own target. Under the Directive, a formal agreement between two or more member states is required whereby the Governments agree that a certain proportion of renewable energy produced in one country is counted or shared with the other and both countries notify the European Commission of this. More information about a possible renewables trading agreement between the UK and Ireland is given in Box 1.

### **Box 1: Renewables trading between the UK and Ireland**

#### UK and Ireland – Memorandum of Understanding on renewable trading

In January 2013 the UK and Irish governments signed a Memorandum of Understanding (MoU) to consider how Irish renewable energy resources, onshore and offshore, might be developed to the mutual benefit of Ireland and the UK.

The EU Renewables Directive (Directive 2009/28/EC) sets legally binding targets for individual Member States for the development of renewable energy by 2020. The Directive provides a mechanism whereby renewable energy can be traded between Member States and count towards the target of the non-producing state.

The MoU Steering Group, which comprises governments and regulators, centres on analysis of the costs and benefits of energy trading, the renewable support mechanisms, the transmission connections, licensing arrangements, and details of what an Inter-Governmental Agreement might cover. Ofgem is a member of this steering group. We are focused on the treatment of potential transmission links between onshore and offshore renewable sources in Ireland and the GB transmission system.

To date, Ofgem has engaged with potential project developers as part of our analysis on ITPR. Subject to Government decisions regarding the support available for generation outside of GB and the timing implications set out under the MoU, parallel work will take place to consider the treatment of transmission assets for these projects. This could require proposals ahead of the wider ITPR project final conclusions in order to ensure progress in time for any future agreement between the UK and Irish governments.

- **Review of Strategic Wider Works proposals submitted under RIIO** - Strategic Wider Works (SWW) will be particularly relevant as we look at the application of competition in transmission onshore. In RIIO-T1, we gave some funding to the incumbent onshore TOs to undertake pre-engineering works for a number of large network developments. We also put in place the SWW arrangements to allow the incumbent TOs to propose, during the price control period, the delivery of large network developments. Under these arrangements, the incumbent TO is able to initiate a regulatory assessment and approval of its proposal by the Authority. However, as noted in our RIIO-T1 Final Proposals, we consider that some of these projects, where these have not yet been through the SWW regulatory approval process, may in the future be suitable for third party delivery and therefore also open to competition.
- **SO Incentives** - we will monitor progress on ITPR in our work on SO incentives to ensure that these incentives are fit for purpose, sitting alongside our approach to RIIO and the way we envisage the role of the SO going forwards. We plan to publish final proposals on a new scheme covering the period from 1 April 2013 to 31 March 2015 shortly.

## Appendix 6 – Glossary

---

### A

#### Anticipatory investment

Capital expenditure that supports anticipated future network requirements, rather than investment driven by user commitment alone

#### The Authority

Means the Gas and Electricity Markets Authority (GEMA), established by section 1 of the Utilities Act 2000

### B

#### BETTA

The British Electricity Trading and Transmission Arrangements

### C

#### Cap and Floor

Developer (market) led approach whereby interconnector owner profits cannot exceed a “cap” and are guaranteed not to fall below the “floor”. Developer returns commensurate with level of risk they are exposed to

#### CCS

Carbon Capture and Storage

#### CION

Connections Infrastructure Options Note

#### Congestion rent

The revenue derived by interconnector owners from sale of the interconnector capacity through auctions. In general, the value of the congestion rent is equal to the price differential between the two connected markets, multiplied by the capacity of the interconnector

#### Coordinated network (design)

In the context of the ITPR project, coordinated networks arise when interactions between two or more generation projects mean that a common network solution (rather than separate radial links) offers a more cost effective network solution. Coordinated network can also arise where the need for reinforcements in a different part of the network interact with generation connections. In this case, oversizing of the generation connection may be a more cost effective solution when considering the whole system benefits, including the reinforcement needs elsewhere in the network

## CUSC

Connection and Use of System Code

## D

### Developer-led

See 'Merchant'

## E

### Electricity transmission system

The system of high voltage electric lines providing for the bulk transfer of electricity across GB.

### EMR

Electricity Market Reform

### ENSG

Electricity Networks Strategy Group

### ENTSO-E

European Network of Transmission System Operators, the body responsible for representing European Transmission System Operators

### ETYS

Electricity Ten Year Statement, which is produced by NGET as the SO in order to provide clarity and transparency around the potential development of the national electricity transmission system

### The EU Renewables Directive (Directive 2009/28/EC)

A Directive which mandates levels of renewable energy use within the European Union

## G

### Gateway Assessments

Subject to final decision, this will be an Ofgem assessment of the rationale for developer-led or non developer-led Wider Network Benefit Investment in offshore transmission assets being taken forward at the preliminary and construction works stages. The assessment would be voluntary and would require a needs case supported by the SO.

### Generator build

Where a generator would design and construct the transmission assets, with a transfer of ownership to an OFTO after the generator had completed

## I

### Independent Design Authority (IDA)

An Independent Design Authority is a body responsible only for system planning and design. An IDA does not own any transmission assets or have any responsibility for

system operation. The exact role and functions of the IDA and its standing in relation to other bodies involved in transmission system operation, delivery and regulation will vary

#### Independent System Operator (ISO)

An Independent System Operator is a body responsible only for system operation and related operational functions. An ISO will not own any transmission assets, and will typically be a not-for-profit entity. Note that where the term 'ISO' is used in ITPR that this is not equivalent to the meaning of an Independent System Operator in the context of Article 13 of Directive 2009/72, which relates to unbundling arrangements of a TSO from generation, production and/or supply interests

#### Interconnector

Equipment used to link electricity systems, in particular between two EU Member States

#### Inter-Governmental Agreement

A contractual agreement for cooperation between 2 or more governments

#### Integrated (network)

In the context of the ITPR project, this term is used to describe the principle of considering a whole system view in transmission planning and delivery of assets, recognising the interactions between the networks onshore, offshore and cross-border. Rather than just considering network developments in any one of the three general locations as a separate system without interactions. An integrated network is one which includes onshore, offshore and cross-border transmission. Integration is needed in such projects to ensure an economic and efficient outcome for consumers

## L

#### Local planning

Planning activities leading to the design and delivery of physical assets at a given location to meet a given investment need. Including, but not exclusively, options identification, route planning, detailed design and consenting

## M

#### Merchant (interconnection)

This is a developer (market) led approach to building new interconnection. Private interconnector developers identify the need for new capacity and build, own and operate the assets themselves. They receive no regulated return for their investment, bear full costs and keep all profits. Revenues are derived from sale of capacity on the interconnector. The return will be based on the arbitrage opportunity between markets. Merchant developers will typically apply for an exemption from requirements in the EU Third Package regarding, for example, use of revenues and third party access

#### Multiple Purpose Project (MPP)

A project that features a combination of onshore, offshore and cross-border transmission network. For example, a project that combines connection of offshore generation with interconnection to a different market, or a project that uses



oversizing of a generation connection offshore to accommodate network reinforcements to relieve constraints in the onshore network

## **N**

### [National Grid Electricity Transmission plc \(NGET\)](#)

The electricity transmission licensee in England & Wales

### [NDP](#)

Network Development Plan

### [Non-Network Solution](#)

An operational solution to an identified network capacity problem or requirement. For example, the use of a demand side response programme to reduce demand at peak times can be a cost effective alternative to actual network reinforcements to meet a network capacity need

## **O**

### [OFTO](#)

Offshore Transmission Owner

### [OFTO build option](#)

Under this option in the GB offshore transmission regime, the generator would obtain the connection offer and undertake high level design and preliminary works. A prospective OFTO would bid their approach to the procurement, financing, construction, operation, maintenance and decommissioning of transmission assets, and the costs associated with carrying out these activities

## **R**

### [Renewables Trading](#)

The export and import of renewable energy under the flexibility mechanisms in the Renewable Energy Directive 2009/28/EC.

### [RIIO-Transmission Price Control Review 1 \(RIIO-T1\)](#)

The current price control of the electricity and gas transmission network operators, following the TPCR4 rollover. This price control runs from 1 April 2013 to 31 March 2021 and is the first transmission price control review to reflect the new regulatory framework, RIIO (Revenues = Incentives + Innovation + Outputs), resulting from the RPI-X@20 review

## **S**

### [Strategic investment](#)

Investment in transmission capacity to meet uncertain future requirements

### [STC Joint Planning Committee \(JPC\)](#)

System Operator Transmission Owner Code's Joint Planning Committee, which is intended to facilitate coordination around investment planning among parties to the STC

### SWW

Strategic Wider Works

### System Operator (SO)

NGET is the System Operator for GB, a role which covers on and offshore networks. Key activities undertaken by the System Operator are real time system operation and system balancing.

### SQSS

System Security and Quality of Supply Standards

### T

### TEC

Transmission Entry Capacity

### Third Package

The term 'Third Package' refers to Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC; Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003; and Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators

### Third party developers

Potential transmission developers / owners / operators that are not existing operators of an onshore monopoly regulated transmission network (ie one of the Scottish TO companies or NGET as TO for England and Wales). This term could apply to developers looking to build / own / operate transmission lines onshore and offshore, or interconnection

### TNUoS

Transmission Network Use of System (charge)

### Transmission Owner (TO)

In the context of the ITPR project, the term Transmission Owner is used to describe the onshore transmission companies, NGET, Scottish Power Transmission and Scottish Hydro Electric Transmission. The use of the term TO in this document only describes the transmission ownership function, NGET also has a system operator function

### TO-led

The term used to describe the current approach to system planning, whereby a relevant TO would identify the need and location for system planning

## Appendix 7 - Feedback Questionnaire

---

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

**Andrew MacFaul**  
Consultation Co-ordinator  
Ofgem  
9 Millbank  
London  
SW1P 3GE  
[andrew.macfaul@ofgem.gov.uk](mailto:andrew.macfaul@ofgem.gov.uk)