Title: Extending competitive tendering in the GB electricity transmission network **IA No: DECC 3088(1)** **Lead department or agency:** DECC **Other departments or agencies:** Ofgem	Impact Assessment (IA) **Date**: 21 January 2016 **Stage**: Final **Source of intervention**: Domestic **Type of measure**: Other **Contact**: Richard Tilley and Birgit Wosnitza
Summary: Intervention and Options	**RPC Opinion:** GREEN

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, Two-Out?**	**Measure qualifies as**
n/a	n/a/	n/a	Yes	Zero net cost (pro-competition)

What is the problem under consideration? Why is government intervention necessary?

Significant investment is needed to ensure that Great Britain's electricity networks support a secure, sustainable and affordable energy supply, whilst also delivering value for money for consumers. In 2014, nearly a quarter (24%) of the average household electricity bill was made up of the cost of transporting electricity from the place that it was generated to the customer.[1] It is imperative that Government looks for opportunities to bear down on these costs and reduce those being passed through to consumers.

In 2009, Government introduced legislation that enables the Office of the Gas and Electricity Market Authority (Ofgem) to run a competitive process to identify the party that owns and operates electricity transmission infrastructure that connects offshore generators like windfarms to the mainland. The regime has proved a success, and has brought significant savings for consumers.[2]

The Government is planning to extend this competitive regime to the onshore electricity transmission network. This would mean that the right to develop and operate certain onshore electricity transmission assets would no longer automatically be given to the regional monopoly operator, but would instead be awarded to a successful participant in a competitive tender process. Introducing a competitive tender process would enable new parties to enter the market, address the information asymmetry that exists between Ofgem and the network companies it regulates and introduce for the first time direct, in-the-market competitive pressure on capital and operational expenditure on large electricity transmission infrastructure. Government intervention is necessary because the establishment of this regime requires primary legislation.

What are the policy objectives and the intended effects?

The primary policy objective is to extend competitive tendering to areas of the onshore transmission network where it is efficient and cost-effective to do so, thereby helping to bear down on the cost of network investment in order to limit the costs being passed through to consumers. Based on the experience of the offshore competition regime and taking into account tender costs incurred by Ofgem, Government estimates that the introduction of this system could, in a medium scenario, provide overall net estimated savings of £380m (PV over 30 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset). In addition, competition will help bring on new technological solutions and more investment in research and development. It should also encourage new players into the market and drive up performance.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

Two options were considered in this IA:

Do Nothing: The status quo remains in place: all onshore transmission network assets continue to be built by the 'incumbent' or 'monopoly' owners of the networks in their respective regions.

Policy Option: Government introduces changes to primary legislation that enable Ofgem to tender competitively those onshore electricity transmission assets where there would be a demonstrable consumer benefit from doing so. The initial intent is to extend competition to large, high value and separable onshore transmission network assets, but Government will look to ensure sufficient flexibility within the legislation to extend competition further in the future if this is in the interest of consumers. This is the preferred option.

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384404/Prices__Bills_report_2014.pdf, p.72. These costs are divided between transmission and distribution networks in the ratio of approximately one-quarter to three-quarters, respectively.
[2] https://www.ofgem.gov.uk/publications-and-updates/consultation-cepabdo-evaluation-offshore-transmission-tender-round-1-benefits

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** Five years from introduction	
Does implementation go beyond minimum EU requirements?	NA

Are any of these organisations in scope?	**Micro** Yes	**<20** Yes	**Small** Yes	**Medium** Yes	**Large** Yes

What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)	**Traded:** NA	**Non-traded:** NA

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the relevant Minister: Date: 18/01/2016

Summary: Analysis & Evidence Policy Option

Description: Provide enabling powers to extend competitive tendering to the onshore transmission network and thereby lower the cost of network investment in order to limit the costs passed through to consumer bills.

FULL ECONOMIC ASSESSMENT

Price Base Year 2013/2014	PV Base Year 2014	Time Period Years 30	Net Benefit (Present Value (PV)) (£m)		
			Low: n/a	**High:** n/a	**Best Estimate:** n/a

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low	n/a		n/a	n/a
High	n/a		n/a	n/a
Best Estimate	n/a		n/a	n/a

Description and scale of key monetised costs by 'main affected groups'

The proposed changes to primary legislation would enable secondary legislation that would, in turn, enable Ofgem to determine competitively the party that would own and operate certain onshore electricity transmission assets. The primary legislation in itself would therefore not create any immediate costs: these will only take effect once the subsequent secondary legislation is in place. It is estimated that there will be costs associated with setting up the scheme and running additional tenders. While these costs are likely to be higher than the cost of regulation under 'Do Nothing', they are estimated to be outweighed by the benefits realised through competitive tendering. Ofgem incurs setup costs, which it passes through to National Grid Electricity Transmission (as the Transmission Owner (TO) with the System Operator (SO) function): these are estimated to be £3m. In future some of these costs might be recouped through tender costs. The cost of running tenders is incurred by Ofgem and passed through to the successful bidder. In the first instance, this cost is estimated to be between £0-£55m (PV of costs over 30 years). Successful incumbent TOs or new entrants incur bid costs, which Government estimates to be between £0-£115m (PV of costs over 30 years). Based on the offshore experience, set-up, tender and bid costs (of successful bidders) are assumed to be passed through to generators / suppliers and ultimately end-consumers. The bid costs of unsuccessful bidders are assumed to remain with them; these have not been quantified. Additionally, the System Operator - that calculates Transmission Network Use of System (TNUoS) charges - will have to deal with more parties in the market. However, as the SO already deals with a number of parties involved in transmission networks (three onshore TOs and a number of other operators), additional interface costs are assumed to be £0m.

Other key non-monetised costs by 'main affected groups'

Competitive tendering would enable any party to deliver the construction or operation of selected assets, which may lead to new parties entering the market should they be appointed as successful bidder. In this scenario, the incumbent TO would no longer deliver that asset and would forego return on this investment; instead, the new entrant would incur the asset costs, which would ultimately be a gain as they will earn a return on this investment. These effects have not been separately quantified for the incumbent TOs and new entrants as they depend on the success rates of either group during a competitive tender (potential upper bounds are set out in the supporting evidence).

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	n/a		n/a	n/a
High	n/a		n/a	n/a
Best Estimate	n/a		n/a	n/a

Description and scale of key monetised benefits by 'main affected groups'

The proposed changes to primary legislation would enable secondary legislation that would in turn enable the competitive tendering of onshore transmission licences. The primary legislation in itself would, therefore, not create any immediate benefits; these can only be realised once the relevant secondary legislation is in place. The overall monetised benefit to society associated with extending competitive tendering is the cost saving associated with increased competition, which is likely to be more effective in some circumstances in revealing the true and more efficient costs of TOs than through the price control process. In terms of any benefits to the group of incumbent TOs and new entrants, this IA assumes, for simplicity, that returns on investment are unchanged between 'Do Nothing' and the 'Policy Option'. Caveats around this assumption are set out in the supporting evidence. The ultimate quantified benefits of cost savings are felt by consumers. Based on the operating cost savings from the offshore experience these savings have been estimated to be between £0-£940m (PV over 30 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset) across scenarios. This figure does not include savings in construction costs, which Government would also expect the regime to bring about.

Other key non-monetised benefits by 'main affected groups'

Introducing competition can bring many wider non-monetised long term innovation benefits to society beyond the monetised reduced cost of investment in assets over time. These include new technological solutions being brought forward and more investment in research and development. These will in turn drive costs down in the long run for the industry overall. Reduced barriers to entry will mean that new parties may enter the market, while incumbent TOs will incur lower transmission asset costs (either due to not being appointed as the successful bidder or due to experiencing more efficient costs through competitive pressures). These effects have not been separately quantified for incumbents and new entrants as they depend on the success rates of either group during competitive tendering. Furthermore, there are also benefits due to reduced costs of price control regulation for Ofgem and incumbent TOs. However, Ofgem has advised that it is not possible to estimate these costs in isolation.

Key assumptions/sensitivities/risks	**Discount rate**	3.5%

A full list and detailed explanation of assumptions underpinning the monetised costs and benefits, risks and sensitivity analysis is included in the main body of this IA in the 'Assumptions and Risks' section.

Key assumptions for quantifications include:

- 3.5% discount rate, 2013/14 price base, discounted to 2014.
- There is no end date to the proposed 'Policy Option'. Therefore, the IA assumes that assets are tendered over the next 10 years, with benefits considered over 20 years for each asset.
- Pipeline scenarios of eligible projects in the future are approximated by considering historic information on Transmission Investment for Renewable Generation (TIRG), the Transmission Investment Incentives (TII) framework and Strategic Wider Works (SWW) investments over the Transmission Price Control Review 4 (TPCR4) from 2007/08 to 2012/13.
- The pipeline scenarios assume that a set of criteria will be adopted that will identify the assets suitable for tendering. The best available information at the time of writing this IA, in line with Ofgem's Integrated Transmission Planning and Regulation (ITPR) final conclusions[3], is that these assets will be new, high-value, and separable.
- Tender costs are based on a 1% of asset value, which is an Ofgem estimate based on the offshore experience.
- Bid costs of successful bidders (which include preparing bids for evaluation, reaching the licence grant and acquiring the asset) are assumed to be 2% of asset value and are based on the 'Evaluation of OFTO Tender Round 1 Benefits' report by Cambridge Economic Policy Associates (CEPA) and BDO. Bid costs of unsuccessful bidders (which only refer to the preparing of bids for evaluation) have not been quantified.
- In terms of benefits, the operating cost percentage savings experienced in the offshore regime and the price control counterfactual, as set out in the CEPA/BDO report, have been applied to asset values in this IA.
- The CEPA/BDO report points out that there are limits to the extent to which lessons for the onshore network can be drawn from results in the offshore network. Results in the offshore network, for example, are context and time-specific: construction was not subject to competitive tender; financing cost savings were very low, while onshore they may be higher; and there are real-world, technological differences between on- and offshore transmission assets. However, while savings in the onshore network are likely to be driven by different factors, Government believes that it is reasonable to assume that the overall levels of saving in operational expenditure under competition will be comparable across the onshore and offshore regimes.

BUSINESS ASSESSMENT (Option 1) (2009 Prices, 2010 NPV base year)

Direct impact on business (Equivalent Annual) £m:			**In scope of OITO?**	**Measure qualifies as**
Costs: 7.8m	**Benefits: £0m**	**Net: - £7.8m**	Yes	Zero net cost (pro-competition)

[3] https://www.ofgem.gov.uk/publications-and-updates/integrated-transmission-planning-and-regulation-itpr-project-final-conclusions

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Background and problem under consideration

1. The National Electricity Transmission System (NETS)[4] is the high-voltage infrastructure that conveys electricity through Great Britain, her territorial seas, and the wider Renewable Energy Zone[5]. The NETS consists of three integrated transmission networks, each owned by one of three transmission operators (TOs). Each of the TOs is responsible for maintaining, reinforcing and extending their network, the extent of which is geographically limited in scope (see figure 1). Licences granted to the TOs by Ofgem set out their responsibilities, obligations and, ultimately, their allowed revenues. The System Operator (SO) is responsible for directing and coordinating the flow of electricity across the NETS, and works with the three TOs to ensure this happens.

Figure 1: Transmission owners in the GB mainland

Onshore transmission – regional monopoly regime

2. There are three TOs in mainland GB: National Grid Electricity Transmission (NGET) in England and Wales, Scottish Power Transmission (SPT) in the south of Scotland, and Scottish Hydro Electric Transmission (SHE-T) in the north of Scotland. A separate arm of National Grid (within NGET) provides the role of SO across the NETS. The TOs operate as monopolies in their geographically-defined network regions. Because they are monopolies, Ofgem[6], as the network regulator, seeks to ensure value for money for consumers through price control regulation, which serves to limit the amount of allowed revenue that a network company can take over the length of a price control period. The TOs recover their allowed revenues through charges to generators and suppliers who in turn pass them through to customers. Allowed revenues are set at a level which covers the companies' costs and allows them to earn a reasonable return, subject to them delivering value for consumers, behaving efficiently and achieving their targets.

[4] "National Electricity Transmission System" is defined in Standard Condition A1 of the Transmission Licence as "...the system consisting (wholly or mainly) of high-voltage electric lines owned or operated by transmission licensees within Great Britain, in the territorial sea adjacent to Great Britain and in any Renewable Energy Zone and used for the transmission of electricity from one generating station to another generating station or between sub-stations or to or from any interconnector..."
[5] A visual representation of GB territorial seas and the Renewable Energy Zone can be found at https://www.ukho.gov.uk/ProductsandServices/Services/Documents/Renewable_Energy_Web%20Page_Jan06_v2.pdf
[6] https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf

3. Ofgem agrees the price control for a particular TO by setting a revenue cap for the business, based on the size of its asset base and its projected investment over the period of the price control. The revenue cap will take account of the operating cost of the asset base, depreciation, tax, the development work and investment the TO intends to take forward, and the cost of capital of maintaining and developing the network. Once the revenue cap has been set, the TO is responsible for running its business and meeting its licence and statutory obligations (which include maintaining an efficient, coordinated and economic system)[7] within the limits of that cap. They can also benefit (or suffer) from over-performing (or underperforming) against Ofgem's cost estimates.

4. The current price control for onshore electricity transmission networks, 'RIIO-T1'[8], runs from 2013-2021. In some cases, investment in the transmission system need only be taken forward if certain generation projects are undertaken. Because there was uncertainty at the time of finalising RIIO-T1 about the timing of and need for these projects, TOs are able to bring forward certain high-value[9] transmission projects for regulatory approval through the so-called 'Strategic Wider Works' process. This helps to ensure that transmission assets are in place to connect new, large generation projects, while also ensuring that investments are in the interest of existing and future consumers.

Offshore transmission – competitive delivery

5. Offshore transmission concerns the transmission of electricity from an offshore generating station such as a wind farm to the mainland grid[10]. Increasing levels of offshore wind generation in the past decade created a need for a process to identify the party that would be responsible for owning and operating these connections. The Energy Acts of 2004 and 2008 amended the Electricity Act 1989 to enable Ofgem to run a competitive process to identify the party to be awarded a licence for this purpose. Such licensees – offshore transmission operators – are known as 'OFTOs'.

6. The first competitive tender for an offshore connection was launched in June 2009. Interested parties submit bids to purchase, maintain, operate, and receive a regulated return from an offshore transmission asset for 20 years. To date, the competitive tender regime has granted 13 licences to transmission assets worth £2.5 billion[11]. A further two projects, worth approximately £350 million, are also in the pipeline[12].

7. In August 2014, an independent report commissioned by Ofgem[13] found that in the first tender round, which consisted of nine projects and £1.1 billion worth of investment, the competitive offshore transmission regime generated savings of £200-£400 million against any other plausible counterfactual regime. The report considers five counterfactual cases, and identifies, for example, £205 million of NPV savings (excluding tax) against a counterfactual where construction and operation of the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime (Counterfactual 3). The vast majority of these savings were associated with the operation of the assets. The report notes that competitive tendering led to savings through innovation and different contracting approaches. The report concludes that greater savings in the future are likely.

The problem under consideration

8. Government believes that there would be benefit in introducing a competitive process for the allocation of licences for onshore electricity transmission. However, because the current legislative framework only allows for the competitive allocation of transmission licences for offshore transmission, primary legislative change is needed.

[7] Section 9(2) (a) of the Electricity Act 1989 states that transmission licensees have a duty to "develop and maintain an efficient, co-ordinated and economical system of electricity transmission".
[8] The RIIO price control (Revenues = Incentives + Innovation + Outputs) runs from 1 April 2013 to 31 March 2021.
[9] The onshore TOs each have a different threshold value level for Strategic Wider Works: NGET=£500m; SPT=£100m; SHE-T=£50m.
[10] Note that offshore transmission is distinct from cross-border transmission. The latter relates to the four high-voltage lines that link the NETS with transmission systems in other countries. These 'interconnectors' are regulated through a separate interconnector licence. Ofgem has recently adopted a new method of regulating interconnectors that involves setting a cap (maximum) and a floor (minimum) on the level of revenue an interconnector owner can earn. In future, it may also be possible for direct connections to be built between generating stations in other countries and the NETS. At this time, there are no such projects in development.
[11] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders
[12] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders
[13] CEPA/BDO, 'Evaluation of OFTO Tender Round 1 Benefits', published May 2014 https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf

Rationale for intervention

9. In the coming years, significant investment will be needed in the electricity network to ensure it delivers a secure, sustainable and affordable energy supply, as emphasised by the agreed RIIO price controls for transmission[14]. Nearly a quarter (24%) of the average household electricity bill in 2014 was made up of the cost of transporting electricity from the place that it was generated to the customer. Around a quarter of this cost in 2014 was due to onshore transmission[15]. Government is committed to looking for opportunities to bear down on these costs and reduce those being passed through to consumers. The experience of competitive delivery of offshore licences shows that significant savings can be made through a competitive approach to asset delivery.
10. Competition can drive companies to rationalise costs, increase efficiency and improve productivity. Competition can also encourage access to a wider and more diverse pool of labour across different organisations, as well as promoting innovation. Access to more sources of capital can provide timely investment, and natural competitive drivers can lead to lower pricing for goods and services.
11. Government has in the past sought to promote competition in other parts of the energy market. The outcomes of the first round of the Contracts for Difference auction, in which renewable energy projects compete for a fixed-term contract to provide electricity, were announced in early 2015. Awarding the contracts on a competitive basis has ensured that annual costs are £110m lower than they would have been without competition[16]. Further, and as outlined above, competitive tendering for offshore transmission connections has provided savings of £200m-£400m across the first nine projects.
12. Whilst elements of the RIIO framework serve as a proxy for natural competition, such as Ofgem's process of comparing and benchmarking network company costs against each other, a number of market failures persist:
    a. **Market power and barriers to entry**: The three incumbent TOs currently have monopoly rights over the planning, construction and operation of all transmission assets in their respective regions. While TOs already competitively tender certain aspects of their projects, it is limited and the TO retains overall control. This prohibits the ability of other parties to take part in the market, regardless of the fact that they may be able to deliver assets more efficiently. Limiting the size of the market also limits innovation, approaches to procurement, price-reflectivity, financing and construction.
    b. **Imperfect information**: Ofgem does not currently have access to the same level of information as the companies it regulates. While incumbent TOs engage with the supply chain by, for example, running tenders for construction of transmission assets, Ofgem is only presented with a single source of information and no choice over which party owns and operates a particular asset. This information asymmetry reduces the size of the Authority's evidence base and in turn weakens its ability bear down on costs. Competition can bring increased diversity in the industry, which will increase the sources of information that Ofgem can use to assess cost submissions. This should provide a more effective means of revealing the true costs incurred by TOs and reveal efficient prices more quickly than negotiations and benchmarking[17] process alone. This will strengthen Ofgem's ability to bear down on costs for those assets that continue to be regulated through the price control process.
    c. **Foregone positive externalities**: Restricting competitive tendering to offshore transmission restricts in turn the positive externalities associated with increased competition. This is because increased competition brings long term innovation benefits beyond the reduced costs of those firms that take part in a tender. Firms, in their drive to gain market share, are more likely to draw on innovative technologies and to increase their investment in research and development. This will in turn drive costs down in the long run for the industry overall.

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[14] https://www.ofgem.gov.uk/ofgem-publications/76230/riio-controls-come-effect.pdf
[15] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384404/Prices__Bills_report_2014.pdf
[16] https://www.gov.uk/government/news/world-leading-auctions-to-provide-major-green-electricity-boost
[17] 'Benchmarking', is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.

Policy objectives

13. The principal policy objective of this measure is to push the costs of developing and operating certain onshore transmission assets to the efficiency frontier by putting in place a legislative framework that allows Ofgem to run a competitive process for identifying the operator that will build and operate such an asset. Government recognises that it is not cost-effective for Ofgem, business, or the consumer to run a competitive tender for all onshore transmission assets. The societal costs of running a tender for a small project, for instance, would likely be higher than any savings achieved by running it. As such, only those assets which meet a certain set of technical criteria will be eligible for competitive tender. These criteria will likely evolve over time to ensure that increasing efficiency and future technological developments can be reflected in the decision as to whether or not to run a tender. Government will look to ensure sufficient flexibility within the legislation to extend competition further in the future if this is in the interest of consumers. The impact of doing so would be considered in future impact assessments at the appropriate time.

14. Ofgem and Government are considering the type of transmission assets suitable for competitive tender, and final details on the relevant criteria will be set out following further industry engagement. However, at the time of writing (September 2015) it is anticipated that they would be as follows:

    a. The asset must be **new**. This is a readily-comprehensible criterion which has the benefit of making it easy for industry to identify which assets may be tendered. Transfers of pre-existing assets from a regulated party to a newly-appointed operator are not insurmountably complex, but costly.

    b. The asset should be '**high value**'. The cost savings from competitive tendering are at least partly proportional to the value of the asset being tendered; the greater the value of the asset, the greater the cost savings. There is a certain level of cost associated with running a tender that cannot be escaped, and additional costs may be incurred depending on the value and complexity of the asset that is being tendered. In order to realise benefits from competition, the value of the asset needs to be significant enough that the cost savings outweigh the costs.

    c. The asset should be '**separable**' from the rest of the network. This means that projects should be easily identifiable as discrete projects. Separable projects are more easily scoped and defined, giving greater clarity on the opportunity presented by the tender.

15. For the purposes of this IA, it has been assumed that incumbent TOs will be able bid for licences to own and operate onshore transmission assets. Government and Ofgem will undertake further work to understand how best to manage and prevent any conflicts of interest that may arise as a result of the fact that market incumbents necessarily possess more information about the nature of the network in their region than new market entrants.

16. A number of ancillary changes to legislation will ensure that the competitive tendering of onshore assets is enabled within a robust and streamlined framework. They ensure that interested parties can be confident that the tender framework will be timely, efficient, have safeguards to investment, and be well-communicated. This confidence will indirectly increase the number or range of sustainable suppliers and thus competitive pressure within the marketplace. These changes, which do not have economic impacts separate to those already under discussion here, are:

Cost recovery

17. Ofgem currently recovers the cost of running competitive tenders for offshore transmission assets from the bidders in the process[18]. This serves to incentivise appropriate bidding activity. The extension of competitive bidding for certain onshore transmission assets will in turn require Ofgem to be enabled to recoup costs from a slightly broader range of parties.

Property Transfer Scheme

[18] Costs arise from staff and resource costs needed to design the tender process, evaluate bids, and ensure successful bidders meet their licence obligations. Bidders in the tender process also incur costs in preparing bids for evaluation.

18. If competition is introduced, it may be the case that in certain instances property will need to be transferred from one party to another during the lifetime of an asset. This could arise, for example, if the planning and consenting work for a project is taken forward by the system operator, but it is the competitively-awarded party that should be the ultimate beneficiary of that work. In such instances, Government believes that a failsafe legislative route to require property to be transferred from one party to another serves as an important reassurance to all parties that they will be able to benefit from the property to which the regulatory regime says they are entitled. This power would only ever be used as a failsafe, and in the first instance, commercial negotiation would always be expected to achieve the desired outcome. A similar power exists in the offshore regime, and has never been called upon.[19]

Generator Commissioning

19. In the offshore transmission regime, it is typically offshore generators who build the transmission assets that connect their generation to the mainland. The assets are then transferred to an offshore transmission owner following a competitive tender run by the Authority to identify a licensee. When the offshore generator builds a transmission system, there is a period following the construction of the assets during which it also has to operate them for the purposes of commissioning them to ensure they are functioning correctly. With certain important exceptions, it is not legal under EU law for electricity generators to engage in electricity transmission, so offshore generators benefit from a special 'commissioning period' exemption which enables them to transmit electricity (for 18 months following the completion of a transmission asset) for the purposes of commissioning it.

20. There could be benefits in allowing onshore generators to build – and commission – their own transmission assets. For instance, it would allow greater control by the generator of all aspects of their project pipeline and the date that they would eventually connect to the grid. This could also enable more flexible project financing and potentially cost savings. As such, Government is proposing to allow onshore generators to build and commission transmission assets. These assets would then be the subject of the tender process described at length above. Because the asset would eventually be tendered in the same way as any other asset, this IA does not consider these assets to be a special case that needs to be analysed separately here.

Governance and administrative functions

21. Extending the use of competition will have a significant impact on the codes and standards under which parties in the transmission sector are expected to operate. To ensure the efficient running of the transmission system, Ofgem will need to be given powers to modify certain parts of these agreements in a timely fashion and only for the purpose of enabling the competitive regime. Again, the Authority already has a similar power under the offshore regime.[20]

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[19] See Schedule 2A to the Electricity Act 1989.

[20] See section 6H of the Electricity Act 1989.

Policy options considered, including alternatives to regulation

22. Two options have been considered in this IA. While costs and benefits are only expected at secondary legislation stage, for transparency the two options have been appraised qualitatively and, where possible, quantitatively (based on the competitive tendering experience in offshore transmission):

    - **Do Nothing:** The status quo continues. Offshore transmission assets can be competitively tendered, but all onshore transmission network assets continue to be built, owned and operated by the incumbent, monopoly owners of the networks in their respective areas.

    - **Policy Option:** Government introduces legislation that enables Ofgem to award licences for the operation of certain transmission licences on a competitive basis. <u>This is the preferred option.</u>

23. There are two alternative options to legislative change of the kind described here, neither of which Government believes are desirable.

    - Ofgem could award licences for the operation of onshore transmission assets without corresponding primary legislation. This carries significant legal risk. There is primary legislation in place that enables the operation of competition for offshore networks, and an asymmetry between the offshore and onshore regimes could invite legal challenge. Without a clear legal framework in place, investors may be less willing to come forward, weakening the level of competition and reducing the potential savings for consumers.

    - Government could introduce legislation that enables Ofgem to award licences for the operation of certain transmission licences on a competitive basis, but mandate competition for *all* transmission assets, regardless of size, newness or other criteria. Government believes this would be disproportionate and that, competitive tendering of transmission assets will only lead to cost savings in certain circumstances.

24. These options will not be considered further in this IA.

Monetised and non-monetised costs and benefits of each option

25. As set out above, costs and benefits are only expected at secondary legislation stage and the two options have been appraised qualitatively and quantitatively, where possible, for transparency.

1. Do Nothing

26. There is no change to primary or secondary legislation in 'Do Nothing' and, therefore, there is no cost. The sections below set out the costs of the status quo for baseline purposes only to be able to enable a comparison with the costs associated with the 'Policy Option' where the costs are non-zero.

1.1 Cost of transmission assets assumed eligible

27. In order to estimate the savings under the 'Policy Option' resulting from improved cost discovery and more efficient prices, it is necessary to set out which transmission assets would be eligible and what their costs are under 'Do Nothing'.

28. There is a high degree of uncertainty around the scale and timing of the pipeline of projects that would be potentially eligible. There is also a high degree of commercial sensitivity around using information from the actual project pipeline. To account for this uncertainty, five stylised pipeline scenarios of investment over the next 10 years that abstract data from specific projects are considered (see Table 1). There is no end date to the proposed Policy Option, so the 10 year cut-off for new assets coming forward has been assumed for the purposes of this IA.

29. These scenarios use historic capital expenditure information over the Transmission Price Control Review 4 (TPCR4) period from 2007/08 to 2012/13 (as estimated by Ofgem) under schemes such as Transmission Investment for Renewable Generation (TIRG)[21], the Transmission Investment Incentives (TII)[22] framework and Strategic Wider Works (SWW)[23].

30. Table 1: 'Do Nothing' Assumed Asset Costs across Pipeline Scenarios (2013/14 prices)

	Annual	Total investment over next 10 years (undiscounted)
Scenario 1	£0bn per year	£0bn
Scenario 2	£0.5bn every other year	£2bn
Scenario 3	£0.5bn per year	£3.5bn
Scenario 4	£1bn every other year	£4bn
Scenario 5	£1bn per year	£7bn

31. Scenario 1 represents an extreme lower bound where no project is deemed eligible under the chosen criteria over the next 10 years, hence there being no investment. Scenario 5 represents an extreme upper bound with £1bn worth of assets per year being deemed eligible there and therefore £1bn per year of investment (an undiscounted total of £7bn investment over the next 10 years given that the first three years are used for scheme set up and the first tender round). These extremes are based on high value transmission assets being brought forward in particular years over the TPCR4 period, but are unlikely to be a permanent phenomenon.

[21] www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview
www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-sp-transmission-ltd-and-scottish-hydro-electric-transmission-ltd
[22] Ibid.
[23] www.ofgem.gov.uk/ofgem-publications/52669/jul12whvdcdecisionfinal.pdf; www.ofgem.gov.uk/ofgem-publications/84439/finaldecisionletter-kintyrehunterston.pdf; www.ofgem.gov.uk/ofgem-publications/87262/decisiononthe proposedbeaulymossfordreinforcementunderriio-t1strategicwiderworksarrangements.pdf; www.ofgem.gov.uk/ofgem-publications/91977/decisiononourassessmentofthecaithnessmoraytransmissionproject.pdf

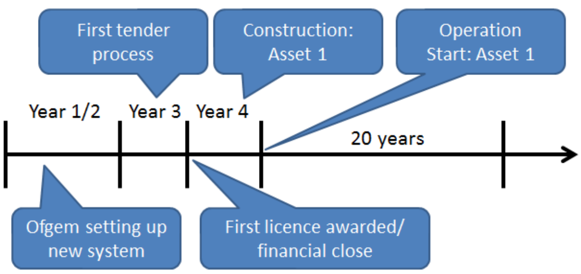
32. Scenario 2 includes an annual investment of £0.5bn (an undiscounted total of £3.5bn investment over the next 10 years) represents the average annual investment over TPCR4. It is possible that projects eligible for competition are brought forward on a less frequent basis, rather than, for instance, every year. To account for this intermittency, Government has included two further scenarios, i.e. £0.5bn every other year (Scenario 3) (an undiscounted total of £2bn investment over the next 10 years) and £1bn (Scenario 4) every other year (an undiscounted total of £4bn investment over the next 10 years). Annex A summarises the investment and operation assumptions.

33. These investment averages can cover one or several projects (depending on the 'high value' criterion). Cost implications related to the number of projects are set out under the costs and benefits of the 'Policy Option'.

34. This IA considers the impact of the measure under the 'Do Nothing' and 'Policy Option' scenarios over the same timescale. Ofgem, and therefore this IA, assumes a two year period to set up the scheme and, for the purpose of this IA, each tender process is assumed to take one year. Our assumption is based on independent analysis[24] of the offshore tendering regime, which sets out that the time between submitting the tender and licence award or financial close for the first four licences awarded has been between 350 and 600 days. The proposed policy does not have an end date. Therefore, this IA assumes assets being built over the next 10 years, i.e. from Year 4 up to Year 10, with savings occurring over a 20 year time period for each of these assets (based on the offshore experience). This is set out in further detail in Annex A. Furthermore, for simplicity, it is assumed that construction costs are incurred in the year following the tender, and operation starting two years following the tender. It is assumed that under 'Do Nothing', the timing of the financial close of assets is the same as under the 'Policy Option'. Figure 2 sets out the assumed timings.

35. Ofgem's Integrated Transmission Planning & Regulation (ITPR) Final Conclusions[25] set out that the earliest Ofgem would be in a position to run a tender would be either 2016 or 2017. This IA assumes 2015 as a conservative start year for scheme set-up (Year 0), with the first potential financial close in 2018. Note that a later start date for the stylised scenario analysis in this IA would only alter the degree of discounting assumed in the NPV of the proposed 'Policy Option'. Undiscounted costs and benefits would remain unchanged.

Figure 2: Assumed Timings in this IA



<u>1.2 Cost of regulation (8 year price controls) for transmission assets assumed eligible</u>

36. Under the 'Do nothing' option there are costs associated with regulating large transmission such as those falling under TIRG, TII or SWW. These include costs associated with eligibility, needs case and project assessment stages, as well as a consultation phase. Costs are incurred by both Ofgem and the TOs. Ofgem estimates that this process takes approximately 12-15 months from the start of the assessment process to a funding decision for well-evidenced proposals[26] but is unable to provide an estimate for these costs in isolation. The costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial.

37. Costs of regulation faced by Ofgem are passed on to the network businesses that hold licences for gas transportation, electricity transmission with system operator conditions (National Grid Electricity Transmission), and electricity distribution. Costs are currently passed through to licensees proportionate to the number of customers they serve. These costs are treated as 'pass-through costs', which means that licence holders, in turn, recover the costs from generators and suppliers,

[24] https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf
[25] https://www.ofgem.gov.uk/publications-and-updates/integrated-transmission-planning-and-regulation-itpr-project-final-conclusions
[26] https://www.ofgem.gov.uk/ofgem-publications/85263/strategicwiderworksfactsheet.pdf

which ultimately pass costs onto consumers. In addition, licensees also face costs of regulation. Costs of regulation faced by licensees directly, in addition to those passed through to them by Ofgem, are also assumed to be ultimately passed through to consumers in this IA. This principle is integral for assessment of these costs (and their reduction) in the IA, which shall be demonstrated through the costs and benefits under the 'Policy Option' below.

1.3 Interface costs of the System Operator (SO)

38. Currently, the System Operator (National Grid Electricity Transmission) already interacts with a range of industry actors, including three onshore TOs, a number of OFTOs, 14 different DNO regions and interconnector operators. For the purposes of this IA, these interface costs have not been quantified for use as a counterfactual under 'Do Nothing', because additional new entrants under the 'Policy Option' are expected to cause only marginal changes for the SO (costs are assumed to be zero). Therefore there is no change in costs between 'Do Nothing' and the 'Policy Option'.

2. Policy Option (compared to 'Do Nothing')

39. This section provides a qualitative and, where possible, quantitative assessment of these costs and benefits of the Policy Option. These costs and benefits are classified as direct impacts at the secondary legislation stage as they are expected to result directly from the implementation of secondary legislation.

40. The quantifications represent approximations and ranges of potential costs and benefits. They are intended to provide a sense of scale rather than precise costs and benefits which Government expects from competition. It is inherently difficult to predict with any accuracy the potential efficiency benefits that introducing a competitive process might bring, given the many uncertainties around the project pipeline, and the fact that examples of the use of competition in transmission delivery are context specific. It is also difficult to quantify meaningfully the dynamic benefits of competition, such as the scope for increased innovation and the introduction of new products, services and technologies.

2.1 Additional costs (monetised / non-monetised) as compared to 'Do Nothing'

41. Table 2 below sets out the additional categories of costs and benefits identified with regards to the 'Policy Option' as compared to 'Do Nothing'.

Table 2: Costs and Benefits

	Costs	Benefits

Generators/ Suppliers and ultimately end-consumers (“Consumers”)	• Set-up/Tender/Bid costs (of successful bidders) (TO pass through)[3]
	• Costs due to delay risk
	• Costs due to delay risk (TO pass through)
		• Cost savings through more competition
		  ○ Better information for Ofgem benchmarking
		  ○ Innovation (technical, commercial, financial)
		  ○ More efficient and innovative procurement practices
		  ○ New sources of labour and capital
		  ○ Increased diversity in the industry
		  ○ Improved timescales
		  ○ Widening of expertise in different areas of the network and potential widening of investment activity in other areas of the industry
		• Lower cost of regulation under the price control (TO pass-through)[3]

Incumbent Transmission Operators (“Producers”)	• Bid costs • Potentially foregone returns on assets (transfer within the producer group) • Costs due to delay risk • Tender costs (Ofgem pass through)	• Lower cost of regulation under the price control • Lower cost of regulation under the price control (Ofgem pass-through) • Reduced expenditure on transmission assets due to not being appointed successful bidder (transfer within the producer group) or due to revealing a more efficient cost
NGET (in their function as Transmission System Operator)	• Set up costs (Ofgem pass through) • Additional interface costs	
New entrants (“Producers”)	• Bid costs • Potentially higher expenditure on transmission assets (transfer within the producer group) • Costs due to delay risk • Tender costs (Ofgem pass through)	• Potential for market entry • Potential gain of returns on assets (transfer within the producer group)
Ofgem	• Tender costs (directly passed through)[1] • Set-up costs (directly passed through)[1]	• Lower cost of regulation under the price control (directly passed through)[2] • Reputation and confidence

Note:
1 The set-up costs that Ofgem incurs are directly passed through to NGET and Ofgem’s tender costs are directly passed through to incumbent TOs or new entrants. These are considered to be direct costs to NGET, incumbent TOs and new entrants. Note that in future some set-up costs may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender rather than from NGET (this would also be a direct cost to business).
2 The lower cost of regulation under the price control for Ofgem is directly passed on to incumbent TOs. This is considered to be a direct benefit to incumbent TOs.
3 Based on the offshore experience, set-up, tender and bid costs (of successful bidders) passed through to generators/suppliers and ultimately end-consumers. The same holds for lower cost of regulation under the price control (benefit). These costs/benefits are considered indirect impacts of the ‘Policy Option’ through incumbent TO or new entrant recovery/pass through.

42. For the purposes of this IA:
    a. <u>'Set-up costs'</u> are the one-off costs associated with creating the competitive regime;
    b. <u>'Tender costs'</u> are the costs associated with running a particular competitive tender; and
    c. <u>'Bid costs'</u> are the costs of bidding in to a particular tender round.

43. In order to estimate the additional costs associated with extending competitive tendering to some transmission assets, this IA relies on the findings from the offshore transmission asset experience, assessed in the CEPA/BDO report on OFTO Tender Round 1[27]. For the purposes of the quantifications in this IA, cost savings are estimated against a price control counterfactual from the CEPA/BDO report where construction and operation of the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime. In the CEPA/BDO report, this is outlined as "Counterfactual 3", and is the most comparable counterfactual to the 'Do Nothing' option, as well as being the conservative counterfactual.

44. The CEPA/BDO report sets out that, against the price control counterfactual (Counterfactual 3) as set out above, the cost to society in the first OFTO tender round of bid costs was £35m (NPV). Expressed as a percentage of the total NPV lifetime revenues for OFTOs in that round (£1.5bn[28]), bid costs total 2% of the asset value.

45. Costs incurred by Ofgem from running the tender process are assumed to be 1% of the asset value. In reality this will vary by project and tender round. For example, in place of one large project, several smaller projects could be tendered in a given year, which may either increase Ofgem's administration costs (because they are running several projects) or decrease them (because they are running several projects at once). Consequently, 1% represents an appropriate long-run average and is based on Ofgem's experience to date.

46. The 'Assumptions and Risks' section below gives the full list of appropriate caveats associated with using the CEPA/BDO report for this IA. The list below, however, summarises the key points:
    a. Tenders in offshore networks have so far only been run for the right to operate an asset. Using the evidence on operating cost savings from the OFTO regime, this IA has quantitatively assessed the likely savings in operational costs that the policy option could bring about. Tenders for onshore network assets would however almost certainly be run for the right to operate *and* construct an asset. In principle, it is most likely that competition for construction would bear down on costs, which could represent a further saving for consumers. Given the lack of evidence, this IA has not attempted to quantify the impact of the 'Policy Option' on construction costs, though Government recognises that there could be such an impact.
    b. While new entrants are likely to incur a lower capital expenditure than incumbent TOs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. However, as is the case with large investments in other sectors, refinancing is likely to take place post-construction which would almost certainly lower the cost of capital substantially (from its pre-construction level).
    c. Savings in the offshore regime were realised in part by offshore generators quoting very low prices for maintenance costs in an attempt to maintain control over their own assets. It is arguable that because there is less likely to be a corresponding generation asset to attempt to control in an onshore competition, onshore bidders will not be incentivised to bid in this way, and that overall savings may be lower. However, savings could be seen in construction delivery, and there have been genuinely innovative approaches to asset maintenance in the offshore regime, which have brought about savings.
    d. Government recognises, as indicated in the CEPA/BDO report, that there are limits to the extent to which lessons can be drawn from the CEPA/BDO report conclusions for the onshore electricity transmission network, given that the outcomes demonstrated in the report are context - and time - specific. However, Government believes that the onshore projects expected to be captured by competitive tendering share similarities with offshore projects – being new, high-value, and separable – therefore comparisons are reasonable. It is also the

[27] http://www.cepa.co.uk/publication-oftotr1eval?flBack=PB&selYear=2014
[28] https://www.ofgem.gov.uk/ofgem-publications/90352/draftletteronoutcomeofconsultationontheevaluationofoftotenderround1benefits20140919.pdf

case that this report, which estimates the savings realised by introducing competition into the offshore electricity transmission network, is the best indication of the savings likely to be realised by introducing competition into the onshore electricity transmission network.

2.1.1 Additional costs to generators, suppliers and ultimately end-consumers under the Policy Option

47. **Set-up/Tender/Bid costs (of successful bidders) (TO pass through):** In the offshore competitive regime:

    a. Set-up costs are incurred by Ofgem. They are directly passed onto NGET as part of NGET's licence condition (direct cost for NGET, see 'NGET' section below). The terms of this licence also allow NGET to consider this cost a 'pass-through' cost for the purposes of the price control: in other words, the costs are recovered from generators and suppliers, who in turn are assumed to pass these costs on to end-consumers.

    b. Tender costs are incurred by Ofgem. These costs are directly passed onto the successful bidder in a tender round (direct cost for successful bidder). Bidders will build that cost into their proposed revenue stream, which means that the tender costs are ultimately passed on to generators, suppliers, and ultimately end-consumers.

    c. Bid costs are in the first instance incurred by incumbent TOs and new entrants (direct cost) (see relevant sections below). If a bidder is successful, this cost will be passed through to generators, suppliers and ultimately end-consumers through the revenue stream. If the bidder is unsuccessful, the costs will formally remain with them, though some informal pass-through to end-consumers may occur if the bidder is already operational in the transmission market.

    For this IA Government has assumed that the same will hold for onshore assets. The bid costs of unsuccessful bidders will remain with the bidder. Generators recoup the passed-through set-up, tender and bid costs from end-consumers either in the form of higher wholesale prices (if price setting plants are affected) or in the case of low carbon plant, in the form of higher clearing prices in CfD allocation rounds and therefore potentially less low-carbon generation uptake within the Levy Control Framework (LCF), which would lead to higher emissions (a cost for society). Suppliers pass the set-up, tender and bid costs to end-consumers through higher network charges on customer bills. Therefore, end-consumers ultimately bear these costs. This IA assumes that all set-up, tender and bid costs are fully passed through to consumers, either informally or formally through the licence. This is based on the offshore experience.

48. In order to estimate the likely scale of the set-up, tender and bid costs borne by end-consumers, this IA applies cost assumptions as supplied by Ofgem and experienced in the offshore competitive tendering process. The set-up cost is assumed to be £3m. The costs for Ofgem of running the tender process are assumed to be 1% of the asset value, while bid costs for incumbent TOs and new entrants are assumed to be 2% of the asset value. These assumptions, combined with the pipeline scenarios, results in set-up, tender and bid costs of £3m-£175m across scenarios as set out in Table 3 below.

Table 3: Estimated Set-up/Tender/Bid Costs (2013/14 prices)

	Annual*	30 Year Period (PV)
Scenario 1	£0m per year	£3m**
Scenario 2	£15m every other year	£55m
Scenario 3	£15m per year	£90m
Scenario 4	£30m every other year	£100m
Scenario 5	£30m per year	£175m

* The annual figures exclude Ofgem's set-up costs of £3m as these are transitional, one-off costs.
** In Scenario 1, Ofgem's set-up costs are fully recovered through the licence fee (paid by NGET, direct cost). NGET passes these costs through to generators/suppliers, which ultimately pass them through to end-consumers. In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder

(direct cost), who will also pass these costs on to generators/ suppliers and ultimately to end-consumers.
Note: All estimates are rounded.

49. **Costs due to delay risk**: There is a risk that generation new build could be delayed due to the time taken to run a tender. A delay in network asset delivery implies direct costs for developers of new generation assets (if they depend on the tendered network asset) as it implies a delay to their timetables. Generators are assumed to pass these costs on to end-consumers. As explained in the paragraph below, the quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

50. **Costs due to delay risk (TO pass through):** In addition to the direct cost on generation new build, a delay also implies a direct cost to incumbent TOs and new entrants (set out in the relevant sections below). Incumbent TOs and new entrants are assumed to pass on their higher costs to generators and suppliers, in the form of higher charges, which will ultimately be borne by end-consumers. To address the delay risk, Ofgem is expected to develop a tender process that fits with project timings and does not cause undue delays for projects where some early development work has already been completed. Ofgem's general framework is likely to include incentives on the competitively appointed party to encourage timely delivery. Additionally, the robustness of the bidders' delivery plans is likely to be a key aspect of Ofgem's tender evaluation process. These measures are likely to help ensure competitively tendered projects are delivered within the appropriate time frame. The quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

<u>2.1.2 Additional costs to incumbent TOs under the Policy Option</u>

51. **Bid costs**: If incumbent TOs bid in the tender process they incur costs in preparing bids for evaluation, reaching the licence grant and acquiring the asset. Based on the offshore experience, bid costs of successful bidders are estimated to be 2% of the asset value. It is not possible to isolate the bid costs falling onto incumbent TOs, should they decide to bid, as it is dependent on the TO success rate in the tender process. For illustration, as an extreme upper bound, it can be assumed that incumbent TOs are the successful bidder in all tenders and therefore face the 2% bid costs on all tenders (see Table 4). As set out in the 'Set-up/Tender/Bid costs (of successful bidder) (TO pass through)' section above, this IA assumes that all set-up, tender and bid costs are fully passed through to consumers.

52. The bid costs of unsuccessful bidders are not taken into account due to lack of evidence and commercial sensitivity of this information. They do however present a cost to society. The bid costs of unsuccessful bidders remains with them and cannot be passed on. It is important to note that bid costs for incumbent TOs are partially offset by cost savings under the price control process. Ofgem does not have a separate estimate of these cost savings and they are, therefore, not quantified in this IA.

Table 4: Estimated Bid Costs (2013/14 prices)

	Annual	30 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£10m every other year	£35m
Scenario 3	£10m per year	£60m
Scenario 4	£20m every other year	£65m
Scenario 5	£20m per year	£115m

Note: All estimates are rounded and these costs and those in Table 6 are mutually exclusive.

53. **Tender costs (Ofgem pass through)**: Under the 'Policy Option', the proposed cost recovery provisions given in primary legislation, would allow Ofgem to recover the costs of any tender it conducts (also captured under the 'Ofgem' section below). This is a direct cost to the successful bidder. Ofgem estimates that its tender costs are 1% of the asset value. In reality this will vary by project and tender round, but 1% represents an appropriate long run average and is based on

Ofgem's experience to date. It is not possible to indicate what proportion of tender costs Ofgem will recover from incumbent TOs, as it is dependent on the TO submitting a bid and, if they bid, their success rate in the tender process (the successful bidder of any given tender bears those costs alone). For illustration, as an extreme upper bound, it can be assumed that incumbent TOs are successful bidders in all tender rounds and therefore Ofgem's 1% tender cost is fully passed on to incumbent TOs (Table 5). Incumbent TOs then recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above. If they are not the successful bidder in any tenders, Ofgem would not recover any costs from them and they would only face their own bid costs, which have not been quantified due to lack of evidence.

Table 5: Estimated Tender Costs (Ofgem recovery) (2013/14 prices)

	Annual	30 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£5m every other year	£15m
Scenario 3	£5m per year	£30m
Scenario 4	£10m every other year	£35m
Scenario 5	£10m per year	£55m

Note: All estimates are rounded and these costs and those in Table 7 are mutually exclusive.

54. **Potentially foregone return on assets (transfer)**: In the scenario that an incumbent TO does not bid or fails to be appointed as successful bidder for a specific project that previously would have fallen under their regional monopoly, they will lose the right to deliver and operate a project which they otherwise would have retained. The incumbent TO would forego the revenue stream for the investment, but would also not incur the asset costs (set out in the benefits section below). The unsuccessful incumbent TO therefore foregoes the return on the investment.

55. The potential reduction in return for incumbent TOs represents a **transfer within the 'producer' group** (incumbent TOs and new entrants) as a new entrant would instead earn the return (given they would receive the revenue stream and incur the asset cost). For simplicity, for the purpose of this IA it has been assumed that the gain in return for new entrants offsets the loss in return for incumbent TOs. Therefore, the return to the 'producer' group is assumed to be unchanged. While new entrants incur a lower capital expenditure than incumbent TOs, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption on returns being unchanged is a fair one.

56. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how exactly revenue streams will be set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

57. There might also be transfers *amongst* incumbent TOs, where a TO is the successful bidder for an asset in another incumbent TO's previous regional monopoly area. This IA does not estimate impacts for each individual incumbent TO. Both these types of transfers have not been quantified as they depend on the incumbent TOs (or an individual incumbent TO) submitting a bid and, if they bid, their success rate in the tender process.

58. In addition, incumbent TOs may lose economies of scale, which could push up overall costs in other areas of non-competed business. Given the size of the incumbent TOs current transmission portfolios and the relative scale of the assets likely to be selected for tendering, this is highly unlikely. Further, by applying suitable criteria in regulation as discussed above, Government will ensure that competitive tendering of select projects provides additional cost efficiencies and wider benefits. This

IA does not quantify the value of the potential loss of assets or return on these investments as this depends on the incumbent TOs submitting a bid and, if they bid, their success rates.

59. **Costs due to delay risk**: There is a risk that projects could be delayed due to the time taken to run a tender. This would have implications for asset costs. As set out in the 'generators/suppliers and ultimately end-consumers' section above, the quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

2.1.3 Additional costs to NGET under the Policy Option

60. **Set-up costs (Ofgem pass through):** As explained above, National Grid Electricity Transmission (NGET) comprises both Transmission Operator for England and Wales, and also System Operator for the whole of the electricity transmission network (NETS) across Great Britain. Therefore, NGET performs a number of additional functions associated with their System Operator role which the other transmission operators in GB do not have. Ofgem incurs set-up costs in creating the competitive regime. In general, Ofgem costs are funded by payments made to the Authority by parties who are licenced by it. With regards the creation of a competitive regime for electricity transmission assets, set-up costs will be recovered from the electricity transmission owner that has the 'System Operator Standard Functions' condition in its licence. NGET is the only such licensee, so the costs of creating a competitive regime are passed to it alone. These costs therefore constitute a direct cost to business. In future, some costs associated with the setting up of the scheme may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender. This has not been separately quantified as it depends on who would be successful during a competitive tender.

61. **Interface costs**: Under the Policy Option, NGET in exercise of its role as System Operator (SO) could bear an additional administrative burden arising from the requirement to interact with a broader group of industry parties. However, these costs are likely to be negligible (and have here been assumed to be zero) as, under 'Do Nothing', the SO is already interacting with three onshore TOs and a number of OFTOs, DNOs and interconnector operators. This means that the addition of new parties to the market would have only a marginal effect. The incremental interface cost associated with adding new parties to the network cannot be determined.

62. The 'Assumptions and Risks' section below discusses the treatment of preliminary works in the analysis.

2.1.4 Additional costs to new entrants under the Policy Option

63. **Bid costs:** New parties, as bidders in the tender process, incur costs in preparing bids for evaluation. Based on the offshore experience, the bid costs of successful bidders are estimated to be 2% of the asset value. It is not possible to isolate the bid costs falling onto new parties as it is dependent on the new entrants' success rate in the tender process. For illustration, as an extreme upper bound, it can be assumed that new parties are the successful bidder in all tenders and therefore face the 2% bid costs on all tenders (see Table 6). As set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above, this IA assumes that all tender and bid costs are fully passed through to consumers, either informally or formally through the licence. This is based on the offshore experience.

64. Note that bid costs of unsuccessful bidders are not taken into account due to lack of evidence and commercial sensitivity of this information. They do however present a cost to society. The bid costs of unsuccessful bidders remain with them and cannot be passed on. Unlike for incumbent TOs, bid costs relating to preparing the bid are not partially offset by cost savings under the price control process.

Table 6: Estimated Bid Costs (2013/14 prices)

	Annual	30 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£10m every other year	£35m
Scenario 3	£10m per year	£60m
Scenario 4	£20m every other year	£65m
Scenario 5	£20m per year	£115m

Note: All estimates are rounded and these costs and those in Table 4 are mutually exclusive.

65. **Tender costs (Ofgem pass through)**: Following the cost recovery provisions in primary legislation, Ofgem will recover the costs to it of conducting a tender (also captured under the 'Ofgem' section). This is a direct cost to the successful bidder. Ofgem estimates that their tender costs are 1% of the asset value. It is not possible to indicate how much of their tender costs Ofgem will recover from new parties as it depends on the success rate of the latter in the tender process (bearing in mind that it is the successful bidder only of a given tender which bears the costs associated with running it). For illustration, as an extreme upper bound, it can be assumed that new entrants are successful bidders in all tender rounds and, therefore, Ofgem's 1% tender cost is fully passed on to new entrants (Table 7). Based on the offshore experience, new entrants are then assumed to recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above. Any bidder that is not successful would not be subject to the recovery of tender costs from Ofgem: only individual party bid costs would be incurred, which have not been quantified due to lack of evidence.

Table 7: Estimated Tender Costs (Ofgem pass through) (2013/14 prices)

	Annual	30 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£5m every other year	£15m
Scenario 3	£5m per year	£30m
Scenario 4	£10m every other year	£35m
Scenario 5	£10m per year	£55m

Note: All estimates are rounded and these costs and those in Table 5 are mutually exclusive.

66. **Potential increased expenditure on transmission assets (transfer)**: If a new entrant is appointed as successful bidder, that new entrant will incur the costs of that asset (although those costs will be more efficient as a result of the new competitive pressures on them). At the same time, the new entrant would receive the revenue stream on the asset and therefore would gain overall by earning the return on the asset.

67. The increased expenditure on assets represents a **transfer within the 'producer' group** (incumbent TOs and new entrants), because any increased expenditure by new entrants under the 'Policy Option' (with more efficient costs) is more than offset by a reduction in status-quo expenditure from incumbent TOs (set out in the benefits section). At the same time that incumbent TOs benefit from less expenditure on assets, they would not receive the revenue stream on the asset and therefore will overall be worse off by losing the return on the asset (set out in the 'generators/suppliers and ultimately end-consumers' section above). This transfer of asset costs (and returns) has not been quantified as it depends on the success rate of new entrants in the tender process.

68. **Costs due to delay risk**: There is a risk that projects could be delayed due to the time taken to run a tender. For new entrants this is a delay compared to the timings of an asset built by incumbent TOs under 'Do Nothing'. This would have implications for asset costs. As set out in the

‘generators/suppliers and ultimately end-consumers’ section above, the quantifications in this IA assume that Ofgem’s framework will prevent any delays from occurring.

2.1.5 Additional costs to Ofgem under the Policy Option

69. **Set-up costs**: Ofgem incurs costs setting up the competitive process, including on the development of policy, legal and operational frameworks (including the modification of codes and standards) and structures needed to run tenders. Ofgem estimates these costs to be between £2m-£3m (2013/14 prices). For the purpose of this IA, a high / conservative estimate of £3m has been chosen. As set out above, these costs are assumed to be directly recovered from NGET. It therefore constitutes a direct cost to business. In future some costs associated with the setting up of the scheme may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender.

70. **Tender costs**: Ofgem incurs costs when running an individual tender, on items such as the staff and resources required to design the tender process, to evaluate bids, and to ensure that appointed licensees meet their obligations. The costs to Ofgem of running a tender are assumed to be 1% of the asset value. In reality, this will vary by project and tender round, but 1% represents an appropriate long run average and is based on Ofgem’s experience to date. There may be some efficiency savings gained by grouping projects together, but in this IA an upper bound cost estimate has been assumed. Table 8 sets out the tender costs across scenarios. These costs are partially offset by a reduction in regulatory costs for Ofgem. However, as set out above, Ofgem does not have a separate estimate for these costs. Therefore, the estimates of net cost to Ofgem are high/ conservative.

71. It is important to note that a ‘high value’ criterion minimises the relative costs of tendering. A ‘new’ and a ‘separable’ criterion minimises interfaces and therefore the ongoing tender costs associated with more parties.

72. Ofgem recovers its tender costs from successful TOs, which in turn are assumed (based on the offshore experience) to recover these costs from generators and suppliers as set out in the ‘Set-up/Tender/Bid costs (of successful bidders) (TO pass through)’ section above.

Table 8: Estimated Set-up/Tender Costs (2013/14 prices)

	Annual*	30 Year Period (PV)
Scenario 1	£0m per year	£3m**
Scenario 2	£5m every other year	£20m
Scenario 3	£5m per year	£30m
Scenario 4	£10m every other year	£35m
Scenario 5	£10m per year	£60m

* The annual figures exclude Ofgem’s set-up costs of £3m as these are transitional, one-off costs.
** In Scenario 1, Ofgem’s set-up costs are fully recovered through the licence fee (paid by NGET) (direct cost). NGET passes these costs through to generators/suppliers, which ultimately pass them through to end-consumers. In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost), who will also pass these costs on to generators/ suppliers and ultimately to end-consumers.
Note: All estimates are rounded.

2.2 Additional benefits (monetised / non-monetised) as compared to the ‘Do Nothing’ option

2.2.1 Additional benefits to generators, suppliers and ultimately end-consumers under the Policy Option

73. **Cost savings through competition**: Extending competitive tendering to some onshore transmission assets significantly benefits generators and suppliers (and ultimately end-consumers) by addressing various market failures present under ‘Do Nothing’.

74. Firstly, generators, suppliers and consumers benefit because new parties are able to enter the market (barriers to entry that exist under 'Do Nothing' are removed) and there is increased competitive pressure on all operators. This drives:

- **Innovation**. New parties are invited to present designs, manage the supply chain and operate the transmission assets. Current incumbents are encouraged to seek savings and produce innovative approaches to delivering and maintaining assets. Innovation may also occur in the technical, commercial and financial space.
- **More efficient and innovative procurement practices** and, therefore, more efficient pricing.
- **Access to new and more diversified sources of labour and capital** as competition widens the pool of transmission owners and investors. This has the benefit of increasing the exposure of financing costs to competitive pressure, and in driving innovation.
- **Increased diversity in the industry** which increases the sources of information that Ofgem can use to benchmark[29] cost submissions. This helps to improve the regulation of all transmission projects, not only those that are subject to competition.
- **More timely delivery** of transmission assets through the deepened incentives on construction.
- **Widening of expertise** in different areas of the network and **potential widening of investment activity** in other areas of the industry.

75. Secondly, generators, suppliers and consumers benefit because competitive pressures in the market allow better cost discovery and therefore a reduction in imperfect information. Under 'Do Nothing', Ofgem does not have access to the same level of information as the companies it regulates, an information asymmetry which can impede Ofgem's evidence base and ability to act in the interest of consumers. Although price controls represent an effective method of controlling costs, competitive pressures under the 'Policy Option' are likely to be more effective in some circumstances through revealing the true and more efficient costs of TOs which will, therefore, address the information asymmetry between the regulated company and Ofgem. This is likely to improve Ofgem's assessment of the efficiency of companies' total costs.

76. It is very likely that competitive tendering will bring about efficient prices more quickly than negotiations and price reviews as part of a price control. While incumbent TOs do engage with the supply chain by running tenders for construction of transmission assets, Ofgem is only presented with a single source of information and no choice over which party owns and operates a particular asset. Competitive pressure will bring increased diversity in the industry, which will increase the sources of information that Ofgem can use to benchmark cost submissions, thus helping to improve the regulation of all transmission projects, not only those that are subject to competitive tendering.

77. There are three ways in which cost savings filter through to consumers. First, savings in the form of lower TNUoS charges are passed through to generators (73%) and suppliers (27%). Second, the cost savings felt by generators can be passed to end-consumers in the form of lower wholesale prices (if it affects price setting plants). Third, in the case of low carbon generators, cost savings can be passed to consumers through lower clearing prices in CfD allocation rounds and therefore potentially more low carbon generation uptake within the Levy Control Framework (LCF), which would lead to lower emissions (a benefit for society). The cost savings that fall to suppliers are assumed to be passed to end-consumers through lower network charges on customer bills. In the first instance any cost savings are experienced by the incumbent TOs and new parties (set out in the relevant sections below).

2.2.2 Level of savings to generators, suppliers and ultimately end-consumers under the Policy Option

78. In order to estimate approximate additional cost savings from extending competitive tendering to some onshore transmission assets, this IA relies on the findings from the offshore transmission asset experience, as assessed in the CEPA/BDO report on OFTO Tender Round 1[30]. For the purposes of this IA, cost savings are estimated against a price control counterfactual where construction and operation of the transmission asset is onshore TO-led (Counterfactual 3). This counterfactual is the most comparable to the 'Do Nothing' option, as well as being the conservative counterfactual.

[29] 'Benchmarking', is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.
[30] http://www.cepa.co.uk/publication-oftotr1eval?flBack=PB&selYear=2014

79. The analysis in the CEPA/BDO report focuses on cost savings in NPV terms, i.e. savings over the economic life of the asset. The report argues that due to competitive pressures the costs borne by consumers will be driven down as the true cost of the asset is revealed and pricing becomes more efficient. The report assumes that this happens faster than might have taken place under the price control review process.[31]

80. Note that for the purpose of this IA, potential tax savings have not been considered due to lack of a suitable counterfactual, because in the CEPA/BDO report as they were derived using a simplified approach devised for OFTOs which is unlikely to be applicable for onshore assets.

81. The CEPA/BDO report sets out that against Counterfactual 3 the benefits to society for the first tender round of the OFTO regime are estimated to be £240m (NPV excluding tax), broken down into operating (£232m, NPV) and financing (£8m, NPV) cost savings. The report also sets out the operating cost assumptions, from which these figures are derived. Table 9 sets out the low and high operating cost assumptions for Counterfactual 3, as well as the assumed preferred and average bidder operating costs under the OFTO regime. Operating costs are expressed as percentage of the final transfer value. This IA assumes that the final transfer value is equivalent to the capex of the project.

Table 9: Operating cost assumptions (% of final transfer value)

	Low	High
Counterfactual 3	3.4% (Years 1-5) 3.0% (Years 5-10) 2.5% (Years 10-15) 2.1% (Years 15-20)	4.5% (Years 1-5) 4.0% (Years 5-10) 3.6% (Years 10-15) 3.2% (Years 15-20)
OFTO regime	**High - Average bidder**	**Low - Preferred bidder**
	2.1% (Years 1-20)	1.8% (Years 1-20)

82. Using these operating cost assumptions, a high and a low cost saving scenario can be established. The high scenario combines the ‘high’ Counterfactual 3 operating costs with the ‘low’ (preferred bidder) operating costs. The low scenario combines the ‘low’ Counterfactual 3 operating costs with the ‘high’ (average bidder) operating costs. The average of these represents the average savings from each asset over an assumed 20 year period of operation.

83. In addition to operational savings, there could be further savings with regards financing costs. The OFTO regime saw limited financing cost savings (£8m, NPV). It is difficult to estimate potential financing cost savings for onshore competition, given that the fact that bidders will be taking on construction risk of the asset means that the risk profile is very different. It is also hard to predict a likely cost on capital for onshore projects for new entrants because financiers have never funded them to engage in these types of projects before. However, as is the case with large investments in other sectors, refinancing is likely to take place post-construction which would almost certainly lower the cost of capital substantially (from its pre-construction level). Given these uncertainties, the margin for error for calculating the potential financing cost savings, which have been quite small in the OFTO regime, is large; therefore this IA does not attempt to quantify it.

84. Under the policy option there might also be savings in capital expenditure, which would come about as a result of competitive pressure on all aspects of the asset delivery process. Because bidders in the offshore regime have only bid for the right to operate – not construct – an asset, it is not possible to estimate the level of savings that might be realised here. While competitive pressures might result in more innovation, it is possible that opportunities for innovation and construction efficiencies are fewer for onshore assets. The ‘Assumptions and Risks’ section sets out several caveats that need to be borne in mind in this regard.

[31] http://www.cepa.co.uk/publication-oftotr1eval?flBack=PB&selYear=2014

85. This IA assumes that all cost savings are passed on to consumers (Table 10). These represent stylised ranges of cost savings, which are mainly aimed at providing a sense of scale rather than a precise assessment of what benefits from competition would be.

Table 10: Estimated Cost Savings through Competition over 30 years (2013/14 prices)

	Annual	30 Year Period (PV)
Scenario 1	£0m per year	£0bn
Scenario 2	£15m per year	£270m
Scenario 3	£25m per year	£470m
Scenario 4	£30m per year	£540m
Scenario 5	£50m per year	£940m

Note: All estimates are rounded.

86. **Lower cost of regulation under the price control (TO pass-through):** Set-up, tender and bid costs will be partially offset by lower costs of price control regulation. These lower costs arise from the fact that there would no longer be a need for the TO to conduct an eligibility, needs case and project assessment under the terms of the price control[32]. This will ultimately benefit consumers (indirect benefit). The benefit is initially felt by Ofgem and incumbent TOs (captured in the sections below). Ofgem passes any reduced cost of regulation under the price control mechanism on to NGET, which is considered a direct benefit. NGET will pass these savings on to generators (27%) and suppliers (73%) through lower TNUoS charges (indirect benefit). Generators pass these savings through to end-consumers either in the form of lower wholesale prices (if price setting plants are affected) or in the case of low carbon plant in the form of lower clearing prices in CfD allocation rounds and therefore potentially more low carbon generation uptake within the Levy Control Framework (LCF), which if it materialised would lead to lower emissions (a benefit for society). This IA assumes that suppliers pass these savings through to end-consumers through lower network charges on customer bills.

87. As set out under 'Do Nothing', Ofgem does not have a separate estimate of these reduced costs under the price control mechanism. The costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial. Therefore, because these costs cannot be quantified, the net costs estimated in this IA under the 'Policy Option' might represent a conservative estimate.

2.2.3 Additional benefits to incumbent TOs under the Policy Option

88. **Lower cost of regulation under the price control**: Incumbent TOs benefit from lower costs of price control regulation, as they will not have to submit a business plan under the price control for a project which will be competitively tendered. As set out under 'Do Nothing', Ofgem does not have a separate estimate for the reduced costs of regulation under the price control mechanism. Therefore, the net costs estimated in this IA represent high estimates. Incumbent TOs pass any cost reductions through to end-consumers as set out in the 'Lower cost of regulation (TO pass-through)' section above.

89. **Lower cost of regulation under the price control (Ofgem pass-through):** Ofgem benefits from a reduced cost of regulation under the price control, because it no longer needs to undertake an eligibility, needs case assessment, and consultation under the price control. It passes these savings on to the respective incumbent TO. As set out under 'Do Nothing', Ofgem does not have a separate estimate for the reduced costs of regulation under the price control mechanism. Therefore, the net costs estimated in this IA represent high estimates. Incumbent TOs pass any cost reductions through to end-consumers as set out in the 'Lower cost of regulation (TO pass-through)' section above.

90. **Lower expenditure on transmission assets**: Reduced barriers to entry in the transmission market, and an increased number of parties in the market, will create competitive pressure and better cost discovery. Incumbent TOs will consequently spend less on assets due to either:

[32] Under 'Policy Option', Ofgem determine the needs case.

a. not being appointed as the successful bidder in situations where the asset would otherwise have fallen into their region (case 1, transfer); or

b. being appointed as successful bidder but at a more efficient asset cost (case 2).

91. The lower expenditure under case 1 represents a **transfer within the 'producer' group** (incumbent TOs and new entrants) as any reduced expenditure by incumbent TOs is partially offset by an increase in expenditure from new entrants (who would anyway have more efficient costs due to competitive pressures, as set out in the cost section). In this case, the incumbent TO would not receive the revenue stream and, therefore, the return for the asset (as set out in the cost section). In turn, the potential increase in expenditure for new entrants is offset by their receipt of a revenue stream. These transfers have not been quantified as they depend on the incumbent TOs submitting a bid and, if they bid, their success rate in the tender process.

92. Expenditure under case 2 is reduced because the incumbent TO has been appointed as successful bidder, but competitive pressures mean that their costs are more efficient.

93. The 'Assumptions and Risks' section below discusses the treatment of preliminary works in the analysis.

2.2.4 Additional benefits to NGET under the Policy Option

94. There are no additional benefits for NGET under the 'Policy Option'.

2.2.5 Additional benefits to new entrants under the Policy Option

95. **Market entry**: New players will benefit from the policy option because it creates a route to market.

96. **Potential gain of returns on assets (transfer)**: An increased market share for new entrants means that they should benefit from a return on any assets they own in the form of a revenue stream, provided that actual asset delivery costs are not eroding the returns.

97. The potential return for new entrants represents a **transfer within the 'producer' group** (incumbent TOs and new entrants), because it can only occur when an incumbent TO loses the return (given they would not receive the revenue stream, though not incur the asset cost). For simplicity, this IA assumes that the loss in return for incumbent TOs is offset by the gain in return for new entrants. Therefore, the return to the 'producer' group is assumed to be unchanged. While new entrants incur a lower capital expenditure, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption on returns being unchanged is a fair one.

98. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how revenue streams are set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

99. Note that these transfers have not been quantified as they depend on the new entrants' success rate in the tender process.

2.2.6 Additional benefits to Ofgem under the Policy Option

100. **Lower cost of regulation under the price control (directly passed through)**: Tender costs will be offset by reduced costs of regulation under the price control. The reduced cost of regulation relates to the reduced costs of undertaking an eligibility, needs case and project assessment, as well as a consultation for projects covered by the price control mechanism under 'Do Nothing', but deemed eligible for competitive tendering in the 'Policy Option'. Ofgem will pass any reduced cost of regulation directly on to NGET (as the TO with the SO function) (direct benefit), which will then pass these savings on to generators/ suppliers, and ultimately end-consumers, as set out in the 'Lower cost of regulation (TO pass-through)' section above. Ofgem does not have a separate estimate for these

reduced costs. However, as the costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial, it is likely to offset the additional tender costs to a certain degree. Therefore, the net costs estimated in this IA represent high/conservative estimates.

101. **Reputation and confidence benefit**: Ofgem is likely to experience a reputational benefit from being better able to protect existing and future consumers. Furthermore, introducing competition would mitigate the current information asymmetry that exists between Ofgem and the TOs, the existence of which suggests that Ofgem is currently inhibited from ensuring consumers are provided the best value for money. Confidence in the regulator is, therefore, increased when competition is applied.

2.3 Net Cost / Benefit Estimates

102. Table 11 below summarises the estimated direct net monetised benefit to business in NPV terms across the five scenarios. The scenarios demonstrate the likely scale of potential costs and benefits. Note that not all costs and benefits could be quantified (as set out in the detailed sections above).

103. The quantified direct net cost to business is in the range of £3m to £175m (PV) over the appraisal period of 30 years, with a central estimate of £90m (PV). Note that while some businesses, namely TOs and new entrants, incur the direct expenditure, they will pass these costs onto other businesses, namely generators and suppliers (indirect cost), which ultimately pass them on to end-consumers, which includes business consumers (indirect cost).

104. The net benefit to society is in the range of -£3m to £760m (NPV over 30 years) (Table 12). All of these costs and benefits will be incurred as a consequence of secondary legislation. None of these costs or benefits relate directly to the primary legislation associated with this IA.

Table 11: Quantified Net Direct Cost/Benefit to Business, NPV over 30 years, £m, 2013/14 prices (discounted to 2014)

NPV (£2013/14m, discounted to 2014)		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Benefits	**Total quantified benefits**	**-***	**-***	**-***	**-***	**-***
Costs	Bid costs of appointed incumbent TOs or new entrants	£0m	£35m	£60m	£65m	£115m
	Set-up and tender costs (Ofgem pass through)	£3m**	£20m	£30m	£35m	£60m
	Additional interface costs for the SO	£0m	£0m	£0m	£0m	£0m
	Costs due to delay risk	£0m	£0m	£0m	£0m	£0m
	Total quantified costs	**£3m**	**£55m**	**£90m**	**£100m**	**£175m**
Total cost/benefit to business		**-£3m**	**-£55m**	**-£90m**	**-£100m**	**-£175m**

* Benefits for businesses are zero as the analysis assumes that reduced asset costs imply reduced revenue streams, therefore keeping the return on assets for business (all incumbent TOs and new entrants) the same as under 'Do Nothing'. Should the competitive tender regime provide better or more stable returns or should businesses outperform anticipated cost structures as set at the time of the tender by more than under 'Do Nothing', businesses would experience a benefit. In addition, businesses experience a benefit through lower cost of regulation under the RIIO price control (their own and Ofgem's costs decrease); however these could not be quantified in this IA.
** In Scenario 1, Ofgem's set-up costs are fully recovered through the licence fee (paid by NGET, as TO with the SO function) (direct cost). In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost).
Note: All estimates are rounded.

Table 12: Quantified Net Direct Cost/Benefit to Society, NPV over 30 years, £m, 2013/14 prices (discounted to 2014)

NPV (£2013/14m, discounted to 2014)		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Benefits	Consumer cost savings	£0m	£270m	£470m	£540m	£940m
	Total quantified benefits	**£0m**	**£270m**	**£470m**	**£540m**	**£940m**
Costs	Bid costs of appointed incumbent TOs or new entrants	£0m	£35m	£60m	£65m	£115m
	Set-up and tender costs	£3m	£20m	£30m	£35m	£60m
	Costs due to delay risk	£0m	£0m	£0m	£0m	£0m
	Additional interface costs for the SO	£0m	£0m	£0m	£0m	£0m
	Total quantified costs	**£3m**	**£55m**	**£90m**	**£100m**	**£175m**
Total cost/benefit to society		**-£3m**	**£215m**	**£380m**	**£435m**	**£760m**

Note: All estimates are rounded.

Assumptions and Risks

105. For the quantifications in this IA, various assumptions have been made. These are set out below. Most importantly, the monetised impacts estimated in this IA aim to provide a sense of scale of benefits and costs, rather than to provide definite predictions of likely costs and benefits.

106. **Cost savings due to competition:** The benefits section above sets out how Government has derived cost savings in this IA. Much of this analysis relies on a comparison with an independent evaluation of the results of the first round of offshore tenders carried out for Ofgem by CEPA/BDO. Several caveats need to be borne in mind:

a. Tenders in offshore networks have so far only been run for the right to operate an asset. Using the evidence on operating cost savings from the OFTO regime, this IA has quantitatively assessed the likely savings in operational costs that the policy option could bring about. Tenders for onshore network assets would however almost certainly be run for the right to operate *and* construct an asset. In principle, it is most likely that competition for construction would bear down on costs, which could represent a further saving for consumers. Given the lack of evidence, this IA has not attempted to quantify the impact of the 'Policy Option' on construction costs, though Government recognises that there could be such an impact. By not including estimates for the savings in design and construction costs that might be realised under the policy option (because there is a lack of conclusive evidence suggesting what the size of these savings might be), this IA risks being too conservative in the size of the savings that the policy option may realise.

b. While new entrants are likely to incur a lower capital expenditure than incumbent TOs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. However, as is the case with big investments in other sectors, refinancing is likely to take place post-construction, which would almost certainly lower the cost of capital substantially (from its pre-construction level).

c. Savings in the offshore regime were realised in part by offshore generators bidding for very low maintenance costs in an attempt to maintain control over their own assets. Arguably, because there is no corresponding generation asset to attempt to control in an onshore competition, onshore bidders will not be incentivised to bid for such low maintenance costs, and overall savings may be lower. However, as set out above, savings could be seen in construction delivery, and there have been genuinely innovative approaches to asset maintenance in the offshore regime which has brought about savings.

d. The report analysed the level of savings realised in delivering the first nine offshore licences. A further four licences have been awarded, since the CEPA/BDO report was published. Given that these have not yet been analysed in a report similar to the CEPA/BDO report, the analysis in this IA does not factor in any changes that these four licences would make to achievable operating cost savings. Anecdotal evidence is that these projects have continued to deliver innovative solutions and savings compared to expectations.

e. Government recognises, as indicated in the CEPA/BDO report, that there are limits to the extent to which lessons can be drawn from the CEPA/BDO report conclusions for the onshore electricity transmission network, given that the outcomes demonstrated in the report are context- and time-specific. However, Government believes that the onshore projects expected to be captured by competitive tendering share similarities with offshore projects – being new, high-value, and separable – therefore comparisons are reasonable. It is also the case that this report, which estimates the savings realised by introducing competition into the offshore electricity transmission network, is the best indication of the savings likely to be realised by introducing competition into the onshore electricity transmission network.

107. **Pipeline scenarios:** The IA proposes a future pipeline of eligible projects by analysing historic information on TIRG[33], TII[34] and SWW[35] investments over TPCR4 from 2007/08 to 2012/13. The IA

[33] www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview

emphasises the uncertainty surrounding this pipeline and the likelihood that assets will eventually be constructed through competitive tendering in the future. Whilst Ofgem does possess a forecast of projects to be constructed, this forecast is commercially sensitive, and there is no certainty over which of the projects in it would be competitively tendered. To mitigate this uncertainty, this IA considers five investment scenarios over the next 10 years of £0bn per year, £0.5bn every other year (an undiscounted total of £2bn investment over the next 10 years), £0.5bn per year (an undiscounted total of £3.5bn investment over the next 10 years), £1bn every other year (an undiscounted total of £4bn investment over the next 10 years) and £1bn per year (an undiscounted total of £7bn investment over the next 10 years). Note that all undiscounted totals account for the first three years being used for scheme set up and the first tender round. £0bn per year is considered an extreme lower bound, while £1bn per year represents an extreme upper bound. However, if more than £1bn per year were to be realised, the additional benefits from competition would outweigh the associated costs. Therefore, in this respect, the IA risks being too conservative in terms of benefits from competition.

108. The IA assumes that a set of criteria (new, high-value, separable) will be applied to the pipeline scenarios to select the assets that will be tendered. This represents the best available information at the time of writing this IA. However, the final criteria will be set following further engagement with stakeholders. Therefore, there is a risk in the level of precision of the final criteria, which reflects the possibility that the investments captured by competitive tendering will change. The fact that the scenarios encompass a wide range of possible outcomes mitigates against this risk.

109. If a tender fails, no bidder is appointed, and a third party who agrees to manage the asset cannot be found, Ofgem intends to enable a 'last resort' mechanism. Under this mechanism, a transmission owner will be required to manage the relevant assets for a period of time. This mechanism exists in the offshore regime, but has never been used, because competitions have never failed in this way. This IA assumes that assets would be built by a competitively appointed TO, or eventually transferred to a competitively appointed TO through commercial negotiations, a reasonable assumption given that the offshore scheme has to date always been successful in appointing an owner.

110. **Size of projects:** The investment averages are assumed to cover one or several projects (depending on the 'high value' criterion). Because tender and bid costs are expressed in percentage terms, this IA assumes that costs increase in tandem with higher asset values or more projects. The impacts of size or number of projects on tender costs are set out in the tender cost section under the 'Policy Option'.

111. **Preliminary works**: The SO may complete early development work and some preliminary works prior to a tender. The nature and extent of these works will depend on the tender model that is used. While this may involve a small amount of additional cost for the SO, these costs will be offset by the work no longer undertaken by TOs (transfer within the "Producer" group). These arrangements will be further considered as part of secondary legislation when a detailed framework is developed. This has not been quantified in this IA.

112. **Cost of regulation of projects assumed eligible**: In order to estimate the cost of regulation for potentially eligible projects, it is worthwhile considering the costs faced by other large projects, such as those falling under TIRG, TII or SWW. These include costs associated with eligibility, needs case and project assessment stages, as well as a consultation phase. Ofgem estimates that this process takes approximately 12-15 months from the start of the assessment process to a funding decision for well-evidenced proposals.[36] Costs are incurred by both Ofgem and the TOs. As advised by Ofgem, it is not possible to provide an estimate for these costs in isolation. However, the costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial.

113. **Chosen assessment timeframe:** Extending competitive tendering to all transmission assets is considered to be a permanent policy change i.e. there is no end-date. Therefore, for the purpose of the quantifications in this IA, pipeline scenarios of network assets coming forward over the next 10 years and their respective savings over a 20 year period have been used. This is in line with the evidence provided by the offshore regime. The appraisal timeframe in this IA in full is therefore 30

www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-sp-transmission-ltd-and-scottish-hydro-electric-transmission-ltd

[34] Ibid.

[35] www.ofgem.gov.uk/ofgem-publications/52669/jul12whvdcdecisionfinal.pdf; www.ofgem.gov.uk/ofgem-publications/84439/finaldecisionletter-kintyrehunterston.pdf; www.ofgem.gov.uk/ofgem-publications/87262/decisionontheproposedbeaulymossfordreinforcementunderriio-t1strategicwiderworksarrangements.pdf; www.ofgem.gov.uk/ofgem-publications/91977/decisiononourassessmentofthecaithnessmoraytransmissionproject.pdf

[36] https://www.ofgem.gov.uk/ofgem-publications/85263/strategicwiderworksfactsheet.pdf

years. Choosing a longer time frame magnifies the scale of the costs and benefits; however, the overall conclusion that more competition is beneficial for society is unchanged.

114. **Return on Investment for incumbent TOs and new entrants**: For simplicity, it is assumed that the group of incumbent TOs and new entrants as a whole has unchanged returns between ‘Do Nothing’ and the ‘Policy Option’. While, under the Policy Option, new entrants incur a lower capital expenditure, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption that returns are the same across ‘Do Nothing’ and the ‘Policy Option’ is a fair one.

115. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how revenue streams are set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able to deliver projects according to anticipated cost structures as well as incumbent TOs under ‘Do Nothing’; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under ‘Do Nothing’.

116. **Bid costs for incumbent TOs and new entrants:** Bid costs include the costs incurred in preparing bids for evaluation, reaching the licence grant and acquiring the asset. Actual bid costs from the offshore regime are commercially sensitive and cannot be used for the purposes of this IA. Instead, this IA uses the findings from the CEPA/BDO report, which sets out that successful bidder costs are £35m, or 2% of total cost and revenues, over nine projects. 2% of asset value is likely to be a conservative estimate. Offshore, because generators build the assets that are eventually transferred to the winning bidder, time and resources are spent on due diligence, which can substantially add to bid costs. This will not be the case onshore (because the competitively-appointed party will build their own asset), which means that bid costs may be lower. Further, there will be other avoided onshore costs (such as not having to prepare SWW project submissions), which may reduce the overall size of the bid costs. There is no separate estimate of these avoided costs and they are therefore not quantified in this IA.

117. The cost to each unsuccessful bidder of preparing bids for evaluation has not been quantified because this information is commercially confidential. The total costs of unsuccessful bids in each tender round would also rely on the total number of bidders, which varies across tenders.

118. **Additional interface costs for the SO:** This IA assumes that there are no additional interface costs for the SO. There may be an incremental interface cost associated with adding new parties to the network; however, because the SO already interacts with a broad group of industry parties, additional parties would only lead to a marginal increase in cost, which Government estimates to be zero. Industry codes and standards are already in place to manage the relationships between parties and, where necessary, they can be amended to accommodate competitively-appointed TOs and to ensure that industry relationships are managed in a constructive and efficient manner.

119. **Tender costs for Ofgem:** Ofgem estimates that scheme set-up costs are between £2m-£3m (2013/14 prices). For the purpose of this IA, a conservative estimate of £3m spread over two years has been assumed. These costs will occur prior to launching the first tender, regardless of the subsequent volume or frequency of tenders. Costs of running an individual tender, associated broadly with staffing, technology and external advice on legal technical and financial matters, are assumed to be 1% of the asset value. This is based on the offshore experience. In reality, these costs will vary by project and tender round, given that there are some fixed costs associated with running tenders. However, it is expected that these costs will balance out over time and 1%, therefore, represents an appropriate long run average.

120. In place of one large project, several smaller projects could be tendered in a given year, which may either increase Ofgem’s administration costs (because they are running several projects) or decrease them (because they are running several projects at once). Consequently, 1% represents an appropriate long-run average and is based on Ofgem’s experience to date. For the purpose of this IA, an upper-bound cost estimate has been assumed. It is important to note that these costs would be partially offset by other avoided costs (e.g. Ofgem assessment and processing of SWW project submissions). However, these costs have not been quantified.

An early assessment of likely OITO status of the 'Policy Option'

121. Amending primary legislation to enable the extension of competitive tendering to onshore transmission assets, has no direct impact on business at the primary legislation stage and is, therefore, out of scope of the one-in, two-out (OITO) framework. Costs to businesses are expected at the secondary legislation stage, but have been included in this IA for the purposes of transparency.

122. Cost to businesses at the secondary legislation stage will be in scope of OITO, as it concerns the regulation of business and involves direct impacts on businesses. For OITO purposes, the present values have been converted into a 2009 price base and have been discounted to 2010 (using a 3.5% social discount rate). Costs are considered for network assets coming forward over the next ten years, though it should be noted that the proposed policy change does not have an end date. Using the same assumptions as above, the direct costs and benefits to businesses of a medium scenario (Scenario 3) are:

a) The **direct cost impact** of the policy change on businesses (the group of incumbent TOs and new entrants) is associated with bid costs and Ofgem's pass through of its set-up[37] and tender costs. It is important to note that these businesses pass the costs on to suppliers and generators, which in turn pass them on to end-consumers. The total direct cost impact is calculated to have a present value of £67m (2009 prices, discounted to 2010).[38]

b) There is not assumed to be a **direct benefits impact** of the policy change on businesses as it is assumed that assets move between producers, such that returns on investment overall remain unchanged. Therefore, the total direct benefit is estimated to have a present value of £0m (2009 prices, discounted to 2010).[39] However, there are indirect benefits for generators and suppliers as they will benefit from lower network charges brought about by increased competition which drives down costs and fosters innovation. This IA assumes that generators and suppliers pass these benefits on to end-consumers (including businesses), who will benefit from lower wholesale prices and lower network charges.

123. The total present value of net costs to business (PVNCB) is equal to £67m (2009 prices, discounted to 2010). Using this value, the equivalent annual net cost to business (EANCB), calculated with reference to 'Do Nothing', is £7.8m (2009 prices).

Pro-Competition Measure

124. All impacts of the proposed 'Policy Option' at the secondary legislation stage specifically relate to the introduction of competition. The 'Policy Option' of introducing competition for certain onshore electricity transmission assets can therefore be defined as a 'pro-competition' measure and be scored as 'zero net costs' at secondary legislation stage for the purpose of OITO.

125. Government believes that the measure can be classified as pro-competition because it has positive responses to all of the questions set out in the *Better Regulation Framework Manual*[40]. These are:

Is the measure expected to promote competition?

a. The measure is directly aimed at enabling competition in the appointment of operators of certain electricity transmission assets. Increased competitive pressure on transmission operators is expected to result in more efficient development and operation of these assets. While under 'Do Nothing' all onshore transmission network assets continue to be constructed, owned and operated by the incumbent, monopoly owners of the networks in their respective areas, the 'Policy Option' introduces changes to primary legislation that enables Ofgem to

[37] In Scenario 1, Ofgem's set-up costs are fully recovered through the licence fee (paid by NGET, as TO with the SO function). In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee and the successful bidder (direct cost). Set-up costs are considered a direct cost to business.

[38] Note, that this IA has only quantified the bid costs of successful bidders. While the costs to unsuccessful bidders also constitute costs to businesses, they have not been quantified as this information is commercially confidential. Costs due to delay risk and SO interface costs are assumed to be zero (as set out earlier in this IA).

[39] Reduced costs of regulation under the price control mechanism are also a direct benefit. However Ofgem does not have a separate estimate for these reduced costs, therefore this benefit to businesses has not been quantified in this IA.

[40] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/211981/bis-13-1038-better-regulation-framework-manual-guidance-for-officials.pdf

provide a robust competitive framework for tendering transmission assets that meet specified criteria across the network. The accompanying ancillary changes to cost recovery, property transfer, generator commissioning and governance and administrative functions, as explained in the 'Policy Objectives' section above, are crucial to the success of a competitive regime. They ensure that interested parties can be confident that the tender framework will be timely, efficient, have safeguards to investment, and be well-communicated. This confidence will indirectly increase the number or range of sustainable suppliers and thus competitive pressure within the marketplace.

Is the net impact expected to be an increase in competition?

b. As the primary aim of the 'Policy Option' is to create competition in the identification of operators of certain transmission operators and therefore push the costs of developing and operating assets to the efficiency frontier, the expected net impact is increased competition. The accompanying ancillary changes to cost recovery, property transfer, generator commissioning and governance and administrative functions aim to ensure the stability of a competitive regime, providing confidence to interested parties that the tender framework will be timely, efficient, have safeguards to investment, and be well communicated. Therefore, the net impact of these ancillary changes is increased competition.

Is promoting competition the primary expected impact of the policy?

c. The primary expected impact of the 'Policy Option' is to create competition for the identification of the operators of certain electricity transmission assets. Increased competition will push the costs of developing and operating certain onshore transmission assets to the efficiency frontier and benefit consumers. The same holds for the accompanying ancillary changes to cost recovery, property transfer, generator commissioning and governance and administrative functions, as these provide stability to a competitive regime and confidence to interested parties, thereby indirectly increasing the number or range of sustainable suppliers.

Would it be reasonable to expect a net social benefit from the policy, even where all the impacts may not be monetised?

d. The cost and benefit assessment across various scenarios in this IA has shown it is reasonable to expect a net social benefit from the policy. While some costs could not be quantified, such as the bid costs of unsuccessful bidders, these are more than likely outweighed by the several unquantified benefits, such as the reduced cost of construction, the reduced cost of regulation, innovation, efficient delivery, and widening of expertise. Therefore, even though not all the impacts could be monetised, it is reasonable to expect a net social benefit from the policy. The qualitative assessment of the accompanying ancillary changes to cost recovery, property transfer, generator commissioning and governance and administrative functions finds that these changes will provide stability to the competitive regime and confidence to interested parties; it is therefore reasonable to expect a net social benefit from these changes.

126. As described above, the four changes to primary legislation concerning cost recovery, property transfer, generator commissioning and governance and administrative functions will ensure that the competitive regime is robust and commands investor and public confidence. As crucial underpinnings to the competitive regime, both they and the core of the policy option itself should be considered pro-competition.

Wider impacts

Economic and financial impacts

127. The estimated quantified and non-quantified impacts on consumers and businesses of extending the use of competitive tendering in the GB transmission network are covered in the monetised costs and benefits assessment above. This also addresses the expected impacts on Ofgem. Impacts on small and start-up businesses are captured in the Small and Microbusiness Assessment below.

128. Particular attention should be given to the ways in which the policy will diversify the sources of labour and capital and incentivise innovation. Opening up investment opportunities to new parties allows different sources of labour and capital to enter the industry. Competitive pressure and the involvement of new parties in the market will likely lead to preferential financing costs and drive innovation. On an individual project basis, innovation can result in lower costs and better value for consumers.[41]

129. Increased diversity in the industry also increases the sources of information Ofgem can use to benchmark[42] cost submissions, thus helping to improve the regulation of all transmission projects, and not only those that are subject to competition.

130. More investment in electricity networks may also prompt stronger investment appetite from newer investors.

Social impacts

131. There are no social impacts expected to arise under the ‘Policy Option’.

132. Government does not expect any additional impacts of the ‘Policy Option’ on vulnerable consumers as a subset of GB consumers. However, consumers who have lower incomes will generally see greater relative improvements in the affordability of their electricity compared to ‘Do Nothing’.

Environmental impacts

133. The proposed ‘Policy Option’ is unlikely to have any significant environmental impacts. Innovative approaches to delivering and maintaining transmission assets may lead to lower embedded carbon levels. In addition, lower network costs may serve to encourage investment in the energy sector more generally, and this may focus on low carbon generation.

[41] For example, in financing, Greater Gabbard OFTO was the first UK and second EU project to use the innovative EIB Project Bond Credit Enhancement (PBCE) product (https://www.ofgem.gov.uk/press-releases/ofgem-grants-offshore-transmission-licence-greater-gabbard-wind-farm), reducing the cost of capital and giving value to consumers. In technology development, TC Ormonde OFTO Ltd has been awarded funding through the 2014 Network Innovation Competition to develop an offshore cable repair vessel and universal cable joint (https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-competition/transmission-capital-partners). This is intended to reduce the cost of offshore maintenance, and produce benefits for consumers.

[42] ‘Benchmarking’, is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.

Rationale and evidence that justify the level of analysis used in the IA

134. Where possible, impacts of the proposed measure have been quantified and monetised, mainly to provide a sense of scale of the likely impacts. The quantification of pipeline scenarios is stylised due to the uncertainty and market sensitivity around potentially eligible projects in the pipeline. Monetisation draws heavily on the competitive tendering experience for offshore transmission assets (because it is the best available source of data). Sensitivity analysis has been used to demonstrate the uncertainties associated with the assumptions made in this IA.

Small and Microbusiness Assessment (SMBA)

135. There are no small or microbusinesses currently operating in the transmission sector. The current incumbent TOs – National Grid Electricity Transmission, SP Transmission and SHE-Transmission– are large businesses. Operators of offshore transmission assets who secured their licences through the competitive process introduced in 2009 are all Special Purpose Vehicles consisting of consortia of large businesses, such as construction companies or financial institution investors.

136. The policy option proposed here does not introduce any additional burdens on small or micro-businesses. Instead, the policy option lifts a barrier to small- and microbusiness-involvement in the transmission market by opening up the market to new entrants.

137. Small and micro-businesses may see greater relative improvements in the affordability of their electricity compared to ‘Do Nothing’ than other businesses.

Summary and preferred option with description of implementation plan

138. Nearly a quarter (24%) of the average consumer electricity bill is made up of the cost of transmitting electricity from the place where it is generated to the customer. Bearing down on the costs of developing, improving and maintaining the infrastructure through which electricity is transmitted ensures that customer bills are kept as low as possible.

139. In 2009, Government introduced legislation that enables Ofgem to determine through a competitive process the party that owns and operates offshore transmission infrastructure. It is estimated that between 2009 and 2014, this approach created savings of £200m-£400m.

140. In light of this, Government proposes to enable competitive tendering in other areas of the transmission network, where it and Ofgem judge that a competitive tender could be socially beneficial.

141. Government is proposing to publish for pre-legislative scrutiny draft primary legislation that would enable Ofgem to implement this competitive process through secondary legislation.

142. At both the stage where Government intends to publish proposals for pre-legislative scrutiny, and the primary legislative stage, there are no immediate monetised costs or benefits. The costs and benefits at the secondary legislation stage have been assessed as far as possible. This assessment is based on stylised assumptions about eligible projects, and estimated costs and savings are based on the offshore experience of competitive tendering. This analysis suggests that the proposal should result in a net benefit to society as a whole of between -£3 to £760m (NPV over 30 years, 2013/14 prices) with a medium scenario of £380m. The estimated impacts will be further analysed at the secondary legislation stage.

Annex A

1. The table below lays out the assumed investment and operational timings for the purposes of this IA. Year 1 and 2 are needed to set up the scheme; the first tender takes place in Year 3; and construction of the first asset begins in Year 4. There are 5 investment scenarios assumed in this IA:

    a. No investment
    b. £0.5bn per year (an undiscounted total of £3.5bn investment over the next 10 years)
    c. £0.5bn every other year (an undiscounted total of £2bn investment over the next 10 years)
    d. £1bn every other year (an undiscounted total of £4bn investment over the next 10 years)
    e. £1bn per year (an undiscounted total of £7bn investment over the next 10 years)

2. The savings generated by the policy option from each asset are considered over a 20 year time period from start of operation. This is based on the time period used in the offshore regime. This results in an overall assessment period of 30 years.

	Year 4	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**
Construction ► Operation▼	Asset 1 built	(Asset 2 built)	Asset 3 built	(Asset 4 built)	Asset 5 built	(Asset 6 built)	Asset 7 built
Year 5	x						
Year 6	x	x					
Year 7	x	x	X				
Year 8	x	x	X	x			
Year 9	x	x	X	x	x		
Year 10	x	x	X	x	x	x	
Year 11	x	x	X	x	x	x	x
Year 12	x	x	X	x	x	x	x
Year 13	x	x	X	x	x	x	x
Year 14	x	x	X	x	x	x	x
Year 15	x	x	X	x	x	x	x
Year 16	x	x	X	x	x	x	x
Year 17	x	x	X	x	x	x	x
Year 18	x	x	X	x	x	x	x
Year 19	x	x	X	x	x	x	x
Year 20	x	x	X	x	x	x	x
Year 21	x	x	X	x	x	x	x
Year 22	x	x	X	x	x	x	x
Year 23	x	x	X	x	x	x	x
Year 24	x	x	X	x	x	x	x
Year 25		x	X	x	x	x	x
Year 26			X	x	x	x	x
Year 27				x	x	x	x
Year 28					x	x	x
Year 29						x	x
Year 30							x

Annex B

Index of terms

CATO: Competitively appointed transmission owner

CEPA: Cambridge Economic Policy Associates

CF: Counterfactual

DECC: Department of Energy and Climate Change

DNO: Distribution Network Operators

ITPR: Integrated Transmission Planning Regulation

NETS: National Electricity Transmission System

NPV: Net Present Value

Ofgem: Office for Gas and Electricity Markets

OFTO: Offshore transmission owner

PV: Present Value

SO: System Operator

SWW: Strategic Wider Works

TII: Transmission Investment Incentives

TIRG: Transmission Investment for Renewable Generation

TO: Transmission Owner