Review of Ofgem's Proposals on Transmission Investment for Renewable Generation

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

Europe Economics has reviewed the cost-benefit analysis of proposed transmission reinforcements for renewable generation undertaken by Sinclair Knight Merz (SKM), along with Ofgem's initial proposals for funding investment.

The major conclusions to emerge from the review are that:

(a) the valuation of constraints should be based on market prices;

(b) a market valuation suggests that the stage one interconnector reinforcement is justified and hence could be treated as baseline investment by Ofgem;

(c) there are arguments for treating the Kendoon line as incremental investment, although further analysis is needed of likely levels of future generation connections in this area, and the incremental benefits and costs of over-sizing this investment.

SKM Analysis

SKM's cost-benefit analysis compares the present value of reductions in transmission constraints and losses once reinforcements are complete with the capital cost of reinforcement and the cost of constraints during the construction period.

The review carried out by Europe Economics suggests that SKM has used inappropriate valuation assumptions and that there are weaknesses in its treatment of timing issues.

Valuation assumptions

SKM's valuation of constraints affecting conventional generation is based on the additional fuel costs associated with resolving constraints by switching to less efficient generation plant. SKM disregards the higher costs that a system operator would incur in the market on the grounds that market prices include a mark-up to recover fixed costs, and that these are not relevant since constraints will not require additional generation capacity to be built.

The review found that SKM's decision not to value constraints at market prices is incorrect. This is because:

(a) Market prices reflect underlying opportunity costs provided the market is competitive. The existence of fixed costs in the generation sector does not in itself imply that prices are not competitive, and SKM has provided no further evidence to suggest that wholesale or balancing markets under NETA are not competitive.

(b) The cost-benefit analysis should include the fixed costs associated with *maintaining* a sufficient margin of flexible generation capacity, over the 40 year timeframe of the analysis, in order to resolve the constraints that would occur if reinforcement proposals were not to proceed.

Europe Economics notes that this conclusion is in line with Ofgem's initial view that constraint costs should be valued at market prices.

Europe Economics understands that a system operator would incur a net cost of around £25/MWh resolving a constraint affecting conventional generation, based on a price of £40/MWh paid to the generator that is constrained on less a price of £15/MWh received from the generator that is constrained off.

In the case of constrained renewable generation, the valuation should take account of the full market value of Renewable Obligation Certificates (ROCs) and exemption from the Climate Change Levy (CCL). This will tend to promote economic efficiency, by ensuring that all investments that facilitate renewable generation (whether network reinforcements or investment in plant) are evaluated on the same basis. The analysis will need to reflect the fact that ROC prices may fall in the future, and that the RO ends in 2027.

SKM is incorrect to interpret the original Renewables Obligation (RO) buy-out price as a proxy for the carbon-saving benefits of renewable generation. Therefore, the application of this figure to large hydro generation (which is not eligible for ROCs) and to loss reductions over-values these impacts.

Europe Economics suggests using a figure of £32.5/MWh to value loss savings, based on Ofgem analysis of the cost of distribution losses, but adjusted to exclude impacts which are not relevant at transmission level. Ofgem's figures are based on the market price of electricity, with additional allowances for environmental benefits and savings in network capacity costs.

Where the majority of CAPEX for a project is incurred by one of the Scottish transmission licensees, it seems appropriate to use the cost of capital and asset life of the relevant Scottish company to capitalise benefits, rather than NGC's price control parameters.

Indicative calculations

Europe Economics has undertaken indicative calculations of the impact of revising SKM's valuation assumptions for projects involving SP Transmission.

The calculations drew on the information available in SKM's report and some further data provided by SKM. However, the firm did not receive the complete dataset it requested, and hence some of the calculations are based on assumptions.

The calculations suggest that the Kendoon line would be justified if connected wind capacity in the area reaches 320 MW to 335 MW. This would require around 55 per cent of connections currently under quote to go ahead. A lower cost alternative would allow the investment to go ahead at an even lower threshold level of wind capacity. However, once the benefits of a third interconnector are valued at market prices, there appears to be a potential case for over-sizing the Kendoon line to allow for this future development. Europe Economics recommends that further analysis is undertaken on these issues.

In line with SKM's own results, the Scotland-England interconnector upgrade appears to be justified once its benefits are valued at market prices. Europe Economics has adjusted SKM's market valuation to take full account of the benefits of loss reductions, but also to value constraints during construction at the higher market rate.

The recommended valuation assumptions make little difference to the existing case for the Beauly-Denny reinforcement, because the various adjustments offset each other.

The calculations appear to strengthen further the case for the Sloy reinforcement, although the result depends on what proportion of constraints in the area affect large hydro as opposed to wind generation.

Timing issues

SKM's analysis of optimal timing is weak, because it implicitly assumes that the same level of generation would be connected to the network throughout the lifetime of reinforcements.

Further quantitative analysis would be needed to assess whether reinforcements are justified at an earlier state date than suggested by SKM's approach. This analysis would need to take account of the marginal benefits and costs of bringing forward investment, as well as the greater uncertainty associated with investing sooner.

Ofgem Proposals

The concept of classifying projects according to whether or not they are justified on a cost-benefit basis would appear appropriate.

However, Europe Economics suggests that it may be appropriate to reclassify the interconnector upgrade and possibly the Kendoon line, as shown in Table 1 below. With regard to the Kendoon line, the appropriate classification depends on the proportion of connection enquiries which are likely to become firm. However, SKM concluded that reinforcement circuits were required and that initial design and engineering works were justified, which would suggest classification as incremental investment.

Classification of Projects Involving SP Transmission

Reinforcement	Ofgem initial classification	Europe Economics classification	Comments
Beauly-Denny	Baseline	Baseline	-
England/Scotland interconnectors upgrade	Incremental	Baseline	Upgrade justified, using market valuation of constraints
Kendoon area connection infrastructure	Additional	Incremental or additional	Issue of oversizing still needs to be addressed
Sloy area reinforcements	Baseline	Baseline	-

The proposal to fund baseline investment through revenue allowances is appropriate. However, the suggestion that only the cost of debt should be funded during construction rather than the full cost of capital would mean that efficient financing costs would not be covered. There is a case for, Ofgem, at a minimum, providing lump-sum compensation for the lower revenues implied by this approach (thus preserving the penalty on delays at the margin).

Any adjustment to the revenues allowed for baseline investment to reflect actual outputs delivered should be based on output measures which are fully within the control of transmission licences. Pro-rata scaling of revenues is unlikely to provide the correct economic incentives.

The proposal to fund initial design and engineering for incremental investment is appropriate, as this preserves the option of an early go-ahead for projects which may prove to be worthwhile.

It is also appropriate not to fund projects which are not justified on a cost-benefit basis. However, the review reached the following conclusions on the mechanisms put forward by Ofgem for allowing transmission companies to proceed with these projects if they believed them to be justified:

(a) *revenue driver* — this could distort incentives for renewable businesses which are affiliated to transmission licensees. Furthermore, it seems likely that very high returns would need to be available to induce investment under this mechanism, in order to cover the cost of capital and the foregone option value associated with investment under uncertainty, and to offset the possibility that the project might prove a failure.

(b) *longer-term contractual arrangements* — it is very unclear how this mechanism could work in practice. The review identified potential problems with the various options for determining transmission charges and deciding whether investment was justified under this mechanism.

Hence Europe Economics concludes that these mechanisms are at the least not sufficiently developed to be regarded as a substitute for reclassifying projects where sufficient new evidence emerges.

1 INTRODUCTION

1.1 This report by Europe Economics, commissioned by SP Transmission, reviews Ofgem's initial proposals on transmission investment for renewable generation[1] and the cost-benefit analysis by SKM on which Ofgem's proposals are based.[2] The report is drafted on the assumption that the reader is familiar with the background issues involved.

1.2 SKM's report evaluates the network reinforcements proposed by the three transmission licencees (NGC, SP Transmission and SHETL) by comparing the cost of the each project with the estimated value of reductions in losses and constrained energy. Additionally, SKM considers the benefits of early asset replacement and the cost of constraints during the construction phase.

1.3 Ofgem's document sets out initial proposals for funding investment in transmission networks before the next transmission price controls take effect. Ofgem suggests that proposed reinforcements should be placed into three categories:

(a) *baseline investment* — projects for which estimated benefits exceed costs, and which will be funded through an adjustment to the existing transmission price controls;

(b) *incremental investment* — projects where there is greater uncertainty as to whether benefits will outweigh costs, or where there may be significant delays before construction should commence. Ofgem suggests that initial development and pre-construction costs should be funded, and that these projects could proceed once the uncertainties are resolved;

(c) *additional investment* — projects where estimated benefits are below 50 per cent of forecast investment costs, and which will not be funded as above. However, Ofgem states that transmission companies could still proceed with these projects in one of the following ways:

- by providing further information which allows the project to be reclassified as baseline or incremental investment;
- by Ofgem specifying a revenue driver, perhaps based on the volume of additional generation connections, to provide the licensee with revenue while protecting customers from the risk of stranded assets;
- by transmission companies agreeing long-term access agreements with generators, thus guaranteeing an appropriate level of funding.

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1 Ofgem (2004), "Transmission Investment for Renewable Generation; Initial Proposals", August.

2 Sinclair Knight Merz (2004), "Technical Evaluation of Transmission Network Reinforcement Expenditure Proposals by Licensees in Great Britain", August.

1.4 SKM and Ofgem's initial conclusions with regard to the four reinforcement proposals which involve capital expenditure by SP Transmission are summarised in Table 1.1.

Table 1.1: SKM and Ofgem's initial conclusions for projects involving SP Transmission

Reinforcement	SKM initial views	Ofgem initial classification
Beauly-Denny	Justified on the basis of savings in constraint costs and losses	Baseline
England/Scotland interconnectors upgrade	Further assessment required before the project could be deemed justified at this stage; proceed with initial design and engineering works. Easier to be justified on a cost-benefit basis if staged. Should follow Beauly-Denny project.	Incremental
Kendoon area connection infrastructure	Lower cost alternative should be investigated but in any case reinforcement circuits required. Justified initial design and engineering works.	Additional
Sloy area reinforcements	Justified on the basis of accepted connection offers and associated savings in constraint costs.	Baseline

1.5 SKM's analysis is based on technical engineering modelling of the effect of proposed reinforcements, followed by estimation of the value of changes in the level of losses and constrained generation. This report does not attempt to review the engineering aspects of SKM's work.

1.6 Section 2 of the report reviews the assumptions used by SKM to value losses and constrained generation, and sets out indicative calculations illustrating how the conclusions of SKM's work might change if more appropriate assumptions are employed. Section 3 comments on the classification of projects by Ofgem and the proposed mechanisms for funding each category of projects.

2 SKM ANALYSIS

2.1 From an economic perspective, Europe Economics has identified two main areas where SKM's work is open to criticism. These two areas are:

(a) the assumptions used to value constrained energy and losses; and

(b) the analysis of the optimal timing of reinforcements.

2.2 This analysis in this section focuses primarily on the valuation assumptions used by SKM. As agreed with SP Transmission, the discussion of timing issues has been limited to brief qualitative analysis.

Valuation of Constrained Energy and Losses

2.3 The connection of large volumes of renewable generation in Scotland and the north of England may lead to constraints in the existing transmission system. Reinforcing the network could provide benefits by reducing the extent of such constraints. In addition, reinforcements may reduce the level of transmission losses.

2.4 In order to estimate the value of these benefits, engineering analysis must first be undertaken to quantify the physical volumes of any reduction in constraints or losses. These volumes must then be converted into monetary terms, using assumptions about the value of reductions in constraints or losses. Finally, the projected stream of benefits must be capitalised in order to be compared with upfront capital expenditure.

2.5 Where a network constraint requires generation to be constrained off, the relevant cost comprises two components:

(a) the cost of constraining off affected generation within the constrained part of the network. In some cases generators might be willing to pay to be constrained off since they would save on fuel costs; and

(b) the cost of constraining on an equivalent volume of generation outside the constrained area of the network.

2.6 The cost of resolving network constraints will depend on the type of generation affected. Constraining off conventional generation will generally be cheaper than constraining off renewable generation, and would therefore be expected to happen first wherever possible. However, for some of the proposed reinforcements there is no conventional generation in the relevant part of the network. In such circumstances, there would be no option but to constrain off renewable generation in the event of constraints.

2.7 The following sub-sections analyse how constraints affecting different types of generation should be valued. Consideration is then given to the valuation of losses and to the assumptions used to capitalise benefits. Finally, Table 2.4 summarises all of the proposed revisions to SKM's assumptions.

Conventional generation

2.8 In its valuation of constraints affecting conventional generation, SKM distinguished between what it termed a "market" valuation and what it termed an "economic" valuation, as discussed below.

Market valuation

2.9 SKM's market valuation places a value of £10/MWh on constrained conventional generation, based on the difference between the System Buy Price (SBP) and the System Sell Price (SSP) under NETA. SKM states that in 2003 the average SBP was £23.5/MWh, the average SSP was £14.38/MWh and the average difference between the two was £9.2/MWh.

2.10 Effectively, SKM's approach assumes that conventional generators in the constrained part of the network would be willing to pay the SSP to not have to generate (since they would save on fuel costs), and that the system operator would have to pay the (higher) SBP in order to increase generation in the rest of the system. On these assumptions, the difference between the two prices would represent the net cost incurred by the system operator in resolving the constraint.

2.11 SKM also undertakes some calculations using the value of £25/MWh for constrained energy which was previously used by the transmission licensees in the RETS study.[3] This figure represents the difference between a price of £40/MWh for purchasing replacement energy and a price of £15/MWh which the generators being constrained off would be willing to pay not to burn fuel. Europe Economics understands that the value of £40/MWh for replacement energy is based on the level of offers in the Balancing Mechanism.

2.12 Ofgem's consultation document sets out its initial view that market prices represent the most appropriate way to value constraints:

> Ofgem's initial view is that the value of constraint costs would be most appropriately based on the costs that consumers are exposed to and the willingness of generators to pay for firm access to the transmission network.

Economic valuation

2.13 SKM's "economic" valuation is based on the difference in plant efficiencies (and therefore fuel costs) between the plant which is constrained off and the plant constrained on. SKM states that these differences will typically be quite low. The cost-benefit analysis uses a value of £1/MWh for constraints affecting coal plant (based on the additional fuel cost of replacing old coal plant with old coal plant). Constraints affecting the Peterhead CCGT

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3 Renewables Energy Transmission Study (RETS), contained as annex in DTI (2003), "The Transmission Issues Working Group Final Report", June.

plant are valued at £5/MWh (based on the additional fuel cost of replacing CCGT with old coal plant).

2.14 SKM used its "economic" valuation as the basis for its cost-benefit analysis and hence its conclusions on whether reinforcement proposals were justified.

2.15 Europe Economics notes that SKM's "economic" valuation does not take into account other short-run marginal costs that may be associated with flexible operation. Furthermore, the report does not discuss the gas and coal price assumptions behind the estimated cost of replacing CCGT with old coal plant (despite the current debate about the level of wholesale gas prices), nor does it mention the environmental costs associated with such fuel switching. However, there are more fundamental problems with SKM's approach which are discussed below.

Market versus economic valuation — a false dichotomy?

2.16 The starting point for discussing this issue is to recognise that, in a competitive market, market prices would be expected to reflect underlying opportunity costs and should therefore be used as the basis for any cost-benefit assessment. This is reflected in Treasury guidance on appraisal and evaluation:[4]

> Costs and benefits should normally be based on market prices as they usually reflect the best alternative uses that the goods or services could be put to (the opportunity cost).

2.17 The Treasury mentions markets dominated by monopoly suppliers or distorted by taxes or subsidies as cases where the use of market values might not be appropriate. Neither of these characteristics would appear to apply to the generation sector.

2.18 SKM itself acknowledges that market prices reflect underlying economic costs in a competitive market:

> Under a competitive generation scenario on both sides of a given network constraint, the market prices will tend towards the economic prices that represent the underlying generation production costs. (p.7)

2.19 To defend its distinction between "economic" value and "market" value, SKM would have to demonstrate that electricity markets under NETA are not competitive (discussed further below). However, there is no analysis to support this in the report — indeed, SKM concludes that:

> The behaviour of prices (Buy and Sell) under NETA seems to follow a logical economic pattern linked to variations in the demand. (p.66)

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[4] HM Treasury (2003), "The Green Book; Appraisal and Evaluation in Central Government".

2.20 Given the *primae facae* case in favour of using market prices, the following two sections explain in more detail where SKM has gone wrong in concluding that market prices differ from economic cost. In particular, the discussion shows that:

(a) SKM's suggestion that market prices do not reflect the underlying economic cost of generation is based on a misunderstanding of how fixed costs might be recovered in a competitive electricity market;

(b) furthermore, to exclude fixed costs from the valuation exercise ignores the dynamic issues associated with maintaining sufficient capacity on the system for constraint management purposes and is therefore incorrect.

Mechanisms for fixed cost recovery

2.21 What lies behind SKM's approach is the idea that electricity prices are bid up above the competitive level (i.e. the marginal cost of generation) in order to recover fixed costs. SKM's report states the following:

> In setting its price in the market the generator will, in simple terms, add to the variable costs per unit generated a fixed amount based on its estimate of its utilisation so that when multiplied by the expected number of units generated it will equal its fixed costs including profit. (p.63)

2.22 It can easily be demonstrated that pursuing such a pricing strategy in the spot market would be unsustainable if the market were competitive. Suppose in a particular time period the marginal generator were to mark its price up above the marginal cost of the next most expensive generator. In such circumstances, the second generator would find it profitable to begin generating electricity and to undercut the price of the first generator, thus driving the first generator out of the market.

2.23 Therefore, the pricing strategy described by SKM would only be sustainable in the spot market if generators had market power. As mentioned earlier, the SKM report contains no evidence to suggest that this is the case. Indeed, the price mechanism described by SKM is inconsistent with the evidence of recent years, which have seen some generators exposed to spot prices come into financial difficulties (i.e. unable to recover all of their costs) due to movements in wholesale prices.

2.24 Nonetheless, a competitive market is not automatically inconsistent with fixed cost recovery. There are three ways in which generators might recover their fixed costs in a pure competitive market:

(a) *Infra-marginal plant* — the price in a competitive spot market would be set by the marginal plant. Infra-marginal plant would therefore be able to earn more than their marginal generation cost, thus contributing to fixed cost recovery.

(b) *Periods of constraint* — the most expensive plant would receive more than their marginal fuel cost during periods of constraint when market prices would rise further to choke off demand. During such periods, spot prices would reflect the economic scarcity value of electricity. In the long run, entry and exit would occur until in equilibrium the frequency of such constraints was sufficient to allow the most expensive generator to just recover its total costs (including profit).

(c) *Forward contracts* — the marginal cost relevant when pricing forward contracts may include fixed costs, if the marginal plant has to incur these costs in order to be available for generation. This suggests that forward prices in a competitive market would be sufficient to allow the marginal plant to recover expected operational and maintenance costs. Furthermore, where the projected level of demand requires new plant build, the price of forward contracts would reflect the full cost of new entry.

2.25 This discussion has centred on the wholesale electricity market. Additional issues may arise when considering the market for residual energy and system balancing (covering both bilateral contracts agreed by the system operator and trading in the Balancing Mechanism).

(a) First, prices for the provision of balancing services may reflect additional short-run marginal costs associated with flexible operation.

(b) Second, generators placing bids or offers in the Balancing Mechanism will not know in advance what the marginal bid or offer will be (since the direction and volume of balancing actions that the system operator will undertake is unknown). However, generators might be expected to set their bids and offers in line with some central expectation of what the marginal bid or offer will be in time periods when their own bid or offer is accepted.

(c) Third, prices for balancing services would arguably be expected to reflect the opportunity cost associated with plant foregoing the opportunity to earn revenue in other markets in order to offer flexibility services to the system operator. In equilibrium, prices for offering generation into the balancing market may have to be higher than prices in the wholesale market in order to compensate plant for lost opportunities, since generators face uncertainty as to whether their bids and offers into the balancing mechanism will be accepted. Providing that prices in the wholesale market reflect underlying economic costs, then the opportunity cost associated with the provision of balancing services is an economic cost and should be taken into account. On this issue, the Treasury guidance on appraisal and evaluation states:

> What matters are costs about which decisions can still be made. However, this includes the opportunity cost of continuing to tie up resources that have already been paid for.

2.26 Europe Economics has not undertaken any analysis of whether pricing in either the wholesale electricity market or the Balancing Mechanism is competitive.

2.27 The analysis demonstrates, however, that the existence of significant fixed costs in the generation sector does not in itself mean (as SKM's report appears to imply) that market prices in either the wholesale market or the balancing market must be different from underlying economic costs.

Importance of fixed cost recovery

2.28 Europe Economics has argued that market prices can permit fixed cost recovery without moving away from the marginal economic cost of generation. This section further argues that adopting a valuation approach which explicitly ignores fixed costs will lead to incorrect conclusions regarding the efficient level of network investment.

2.29 SKM argues that fixed costs should only be taken into account "if the constraints affect the capacity margin and it becomes necessary to add additional capacity". In the case of the Scotland-England interconnectors, it concludes this would not happen until 6 GW of wind generation is connected in Scotland, given the capacity value assigned to wind output.[5]

2.30 SKM's approach ignores the dynamic issues associated with *maintaining* a sufficient capacity margin and hence security of supply. In particular:

(a) existing plant will have to recover ongoing fixed operational and maintenance costs in order to induce them to remain on the system;

(b) as existing plant retire and electricity demand grows, new plant build will eventually be required to maintain the existing capacity margin (particularly over the 40-year lifetime of the transmission investments under consideration). These plant will not be built unless prices allow recovery of construction costs.

2.31 Furthermore, when discussing constraint management the focus should be on whether sufficient flexible generation capacity is available, rather than on the overall capacity margin. The growth of wind generation may increase the need for generation able to offer flexibility services to the system operator.

2.32 Essentially, the cost-benefit analysis should be seeking to make the long-run choice between managing the growth of renewables in Scotland and the north of England by:

(a) reinforcing the transmission network to avoid constraints; or alternatively

(b) keeping sufficient flexible generation capacity available on the system and thus managing constraints through system operator actions.

2.33 Failure to take into account the fixed costs associated with the latter option will distort comparison between the two choices. Excluding long-run generation capacity costs

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5 The capacity value refers to the proportion of installed generation capacity that can reasonably be relied on to secure demand. SKM assign a capacity value of 20% to wind, based on analysis of the correlation between electricity demand and wind output.

seems especially inappropriate when the time frame for the analysis is 40 years (i.e. the lifetime of transmission assets).

2.34 Exclusion of fixed costs also runs counter to the Treasury's guidance on appraisal and evaluation:

> For substantial proposals, the relevant costs are likely to equate to the full economic costs of providing the associated goods and services… The full cost includes direct and indirect costs, and attributable overheads. The full cost … as built up in this way, should also equal the total of the analysis of costs into their fixed, variable, semi-variable and stepped elements.

2.35 SKM suggests that if generators are unable to fund capacity costs through the prices paid for constraint management costs, they would be able to recover them through increasing their prices in other electricity markets. However:

(a) as discussed earlier, this suggests a misunderstanding of the way that fixed costs may be recovered in a competitive market, and implicitly assumes that generators have market power;

(b) furthermore, in such a scenario the rewards for providing flexibility services would be below those available from trading in other markets. Generators would be unwilling to provide flexibility services if the rewards available were not sufficient to cover the opportunity cost. As mentioned earlier and as set out in the Treasury's guidance on appraisal and evaluation, such opportunity costs should be taken into account in a cost-benefit analysis.

2.36 Based on this analysis, Europe Economics concludes that the distinction made by SKM between "market" and "economic" valuation is spurious. Unless it can be demonstrated that pricing in the balancing market is not competitive, it remains appropriate to use market prices to value the cost of transmission constraints.

Parameters of market valuation

2.37 Having demonstrated that a market valuation is likely to represent best the true economic cost of managing constraints, a further issue to be addressed is whether replacement generation should be valued at the SBP or using the higher figure of £40/MWh implicitly assumed in the earlier RETS study.

2.38 Since the implementation of Modification Proposal P78 to the Balancing and Settlement Code in February 2003, cash-out prices under NETA (i.e. the SBP and SSP) for imbalances in the opposite direction to the overall system imbalance have been determined on the basis of a neutral reference price linked to trading in spot and forward markets prior to Gate Closure. Consequently, the SBP only represents the cost of NGC's balancing actions in periods when the overall system is short (i.e. demand exceeds generation).

2.39 While Europe Economics has not undertaken any analysis of Balancing Mechanism data, it would seem possible that the methodology now used to calculate cash-out prices is responsible for the difference between the figure of £40/MWh quoted for offers in the Balancing Mechanism and the average SBP of around £24 which SKM calculated for 2003. To the extent that this is the case, then the figure of £40/MWh would appear a more appropriate value to use in the cost-benefit analysis.

2.40 In addition to the above consideration, a quick check against Balancing Mechanism data for 2003 also confirms that SKM has calculated a simple time-weighted average of half-hourly cash-out prices during the year. However, it might be expected that in half-hour periods when NGC has to accept a large volume of offers the SBP might be higher than on average, whereas the SSP might be lower than on average in half-hour periods when NGC has to accept a large volume of bids. If this is the case, then a volume-weighted average across half-hour periods would better reflect the true cost to NGC of resolving constraints, and would imply a larger difference between the SBP and SSP than suggested by SKM's calculations.

2.41 Another factor concerns the way in which the costs of different types of balancing action are distinguished. Europe Economics understands that it is normally difficult to determine which trades in the Balancing Mechanism relate to energy balancing (i.e. matching overall demand and supply), establishment of reserve/response and constraint management. However, the firm understands that NETA convention is that the cheapest trades are assumed to be energy balancing, and that NGC convention regards reserve/response as the next cheapest trades. This implies that trades to manage constraints are the highest cost trades.

2.42 Europe Economics is not able to comment on the validity of the above conventions. However, if they are correct, this would again suggest that the figure of £40/MWh might be a more appropriate value to assume for replacement generation than the SBP.

2.43 In conclusion, there are reasons why £40/MWh may better represent the cost of constraining on replacement generation. However, in the absence of more detailed analysis on the issue, Europe Economics has carried out separate indicative calculations using both values.

Renewable generation

2.44 SKM used a figure of £45/MWh for the economic value of constrained wind generation. This was calculated as the foregone environmental value of wind generation, which SKM assumed to be the original RO buy-out price of £30/MWh,[6] plus an average variable cost of £15/MWh associated with replacement conventional generation.

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6 The buy-out price is increased annually in line with inflation.

2.45 As discussed earlier, when valuing replacement generation it seems inappropriate to ignore market data and to adopt a valuation approach which explicitly excludes the fixed costs of providing flexible generation capacity. Europe Economics has therefore used figures of £40/MWh and £25/MWh for the cost of purchasing replacement generation in its own indicative calculations.

2.46 The remainder of this section discusses the cost of constraining off renewable generation, and argues that:

(a) it is incorrect to interpret the £30/MWh buy-out price as a proxy for the direct carbon-saving value of renewable generation, and therefore the application of this figure to large hydro generation (which is not eligible for ROCs) and to reductions in losses is inappropriate;

(b) for renewable generation which is eligible for ROCs, the valuation should be based on the full premium market value of renewable generation, in order to ensure that an efficient choice is made between different options for meeting the government's renewables target.

Interpretation of buy-out price

2.47 SKM has interpreted the RO buy-out price as a proxy for the environmental value of renewable generation. Based on this interpretation, it has made use of the same figure in valuing large hydro generation (which is not eligible for ROCs) and electricity losses, both of which give rise to the same carbon benefits.

2.48 However, the level of support provided to renewables under the Renewable Obligation would appear to be significantly higher than could be justified by reference to the direct carbon-reducing benefits of renewable output. Consequently, current policy has partly been justified by reference to the fact that policy may stimulate cost reductions for renewable technologies through "learning" effects.

2.49 The fact that the buy-out price of £30/MWh over-estimates the direct carbon benefits of renewable generation can be illustrated by reference to a recent Ofgem document which mentioned the carbon cost associated with electricity generation:[7]

> The government has proposed a range for valuing the cost of carbon – the bottom end of which is £35/tC. Using this figure produces an environmental cost ... of around £3.60/MWh.

2.50 Extrapolating from the above, the high end of the government's range for the cost of carbon (£140/tC) would therefore imply a maximum carbon cost of £14.40/MWh.

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[7] Ofgem (2004), "Electricity Distribution Price Control Review; Initial Proposals", June, p.17.

2.51 These figures imply that SKM has over-valued large hydro generation and reductions in electricity losses. A more appropriate valuation of loss reductions is discussed later.

2.52 SKM has not provided any details of assumed volumes of hydro generation, and therefore the only adjustment made in this area in the indicative calculations presented later is a sensitivity check for the Sloy project. For this sensitivity check, constraints affecting hydro generation were assumed to cost either £25/MWh or £40/MWh, based on the cost of constraining on replacement generation and assuming that hydro generators would neither be willing to pay to be constrained off (since they would not save on fuel costs) nor would require compensation for the foregone value provided by renewable support mechanisms (since these do not apply to large hydro). More detailed analysis of the cost of constraining off hydro generation might include consideration of:

(a) whether an additional premium might be appropriate to reflect the external environmental benefits of large hydro; and

(b) whether hydro generators would be willing to pay to be constrained off to reflect the expected value of being able to use the water retained behind the dam to generate electricity in the future.

Cost of constraining off renewable generation

2.53 The market price of a ROC is currently greater than the RO buy-out price, because the RO includes a recycling mechanism under which buy-out payments are recycled to those suppliers who meet their obligation by surrendering ROCs. This is likely to continue to be the case until such time as eligible renewable output matches or exceeds the obligation on suppliers (in which circumstances there would be no buy-out payments to recycle).

2.54 Renewable generation can also earn revenue worth £4.30/MWh as a result of the fact that renewable energy is exempt from the Climate Change Levy (CCL).

2.55 Currently, therefore, the market value of renewable generation is significantly higher than the premium value of £30/MWh assumed by SKM. In a market for balancing services, renewable generators would wish to be compensated for the foregone opportunity to earn this revenue if they were constrained off. Therefore, the full ROC price and the value of the CCL exemption would form the basis of a market valuation of the cost incurred by a system operator to constrain off renewable generation.

2.56 Further in the future, the premium market value of ROCs may fall towards or below the value assumed by SKM. This is because ROC prices are likely to fall as renewable output comes closer to fulfilling the obligation on suppliers. Indeed, ROC prices could fall below the buy-out price if the market were to provide sufficient renewable generation at lower cost. Furthermore, the RO itself is due to end in 2027.

2.57 There are strong economic reasons for using a market valuation to assess the value of constraining off renewable generation. Taking the government's targets for renewable energy as given, it is important from the perspective of economic efficiency that the target should be met at the lowest cost possible. In order to ensure that the choice between different options for meeting the target is not distorted, all potential investments relevant to this sector must be assessed on the same basis. Since private developers evaluating projects will take account of the full market value of renewable generation, network investments should also be assessed on this basis.

2.58 This can be illustrated by reference to a hypothetical example. Consider the comparison between two options for increasing renewable generation:

(a) a private developer incurring capital expenditure to upgrade the capacity of its wind turbines in order to increase renewable output;

(b) a transmission company incurring capital expenditure to reinforce its transmission system, reducing the level of constraints and allowing renewable output to be increased.

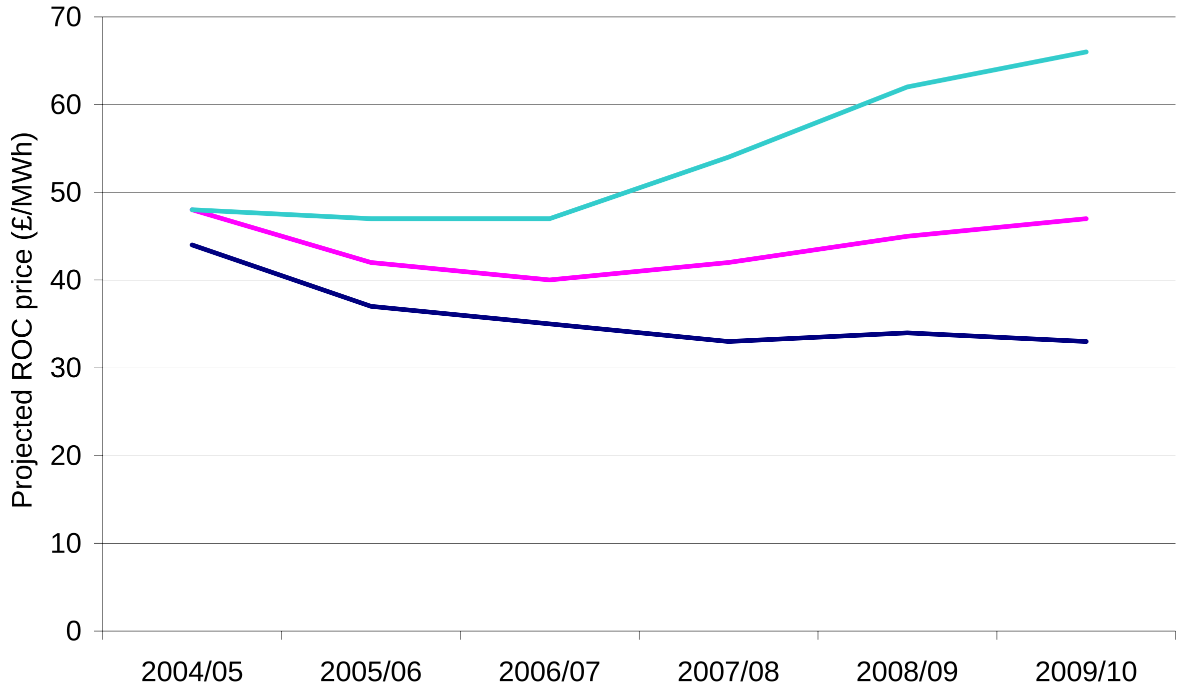
2.59 If the private developer takes account of the full market value resulting from government policy but the transmission company places a different value on renewable generation in its cost-benefit analysis, then the cheapest investment option might not be selected.

2.60 These conclusions are in line with Ofgem's own initial view that that the value of constraint costs would be most appropriately based on the costs that consumers are exposed to and the willingness of generators to pay for firm access to the transmission network. Ofgem states the following with regard to renewable generation:

> In the case of wind generation that has firm access to the transmission network the costs of the constraint payments made by the system operator and ultimately passed on to consumers may be relatively high. In part this is because the operation of the arrangements for ROCs that will tend to push up the costs of constraining wind generation that has firm access to the transmission network. Wind generators may bid into the electricity balancing mechanism in a way that reflects their opportunity cost of not generating. Bids may reflect the revenue lost from energy sales and the market price of ROCs (which is significantly above the £30 MWh buyout value for ROCs, although the market price may fall over time). This would give a higher value than most estimates of the economic value of savings in greenhouse gas emissions associated with renewable generation. Nevertheless, constraint costs will reflect actual costs to consumers and give a broad indication of the willingness of generators to pay to avoid being constrained off the transmission network.

2.61 In its own indicative calculations, Europe Economics has therefore adopted a market valuation for the cost a system operator might incur constraining off renewable generators. Chart 2.1, which shows Platts ROC price projections, illustrates that there is considerable uncertainty over future ROC prices. Europe Economics has made use of the medium-build Platts scenario up to 2009/10.

Chart 2.1: Platts ROC price projections



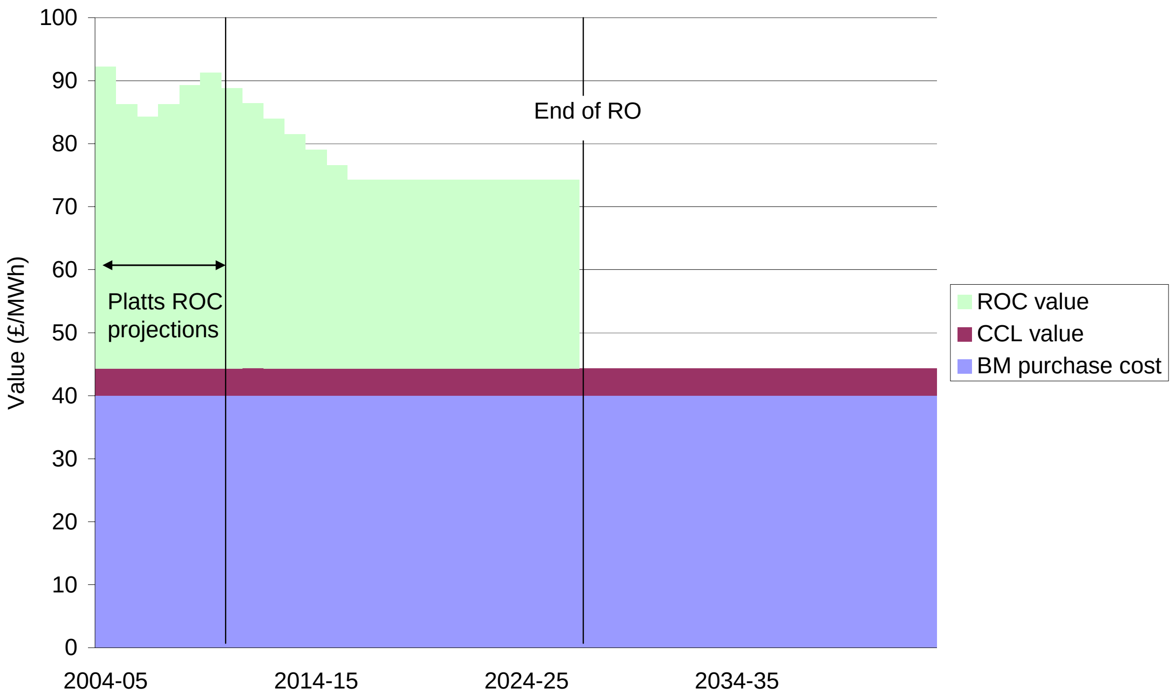
Source: Power UK

2.62 Charts 2.2 and 2.3 show the assumptions used to place a value on the cost of constraining off renewable generation and constraining on replacement generation, over the period of the cost-benefit analysis. (The separate charts reflect the use of the alternative figures of £40/MWh and £25/MWh for the cost of replacement generation.)

2.63 The government has announced annual increases in the obligation on suppliers up to 2015/16. The charts assume that the ROC price will trend down to the buy-out price by this date and remain at this level in subsequent years, until the end of the RO. The CCL value is assumed to be available throughout the period.

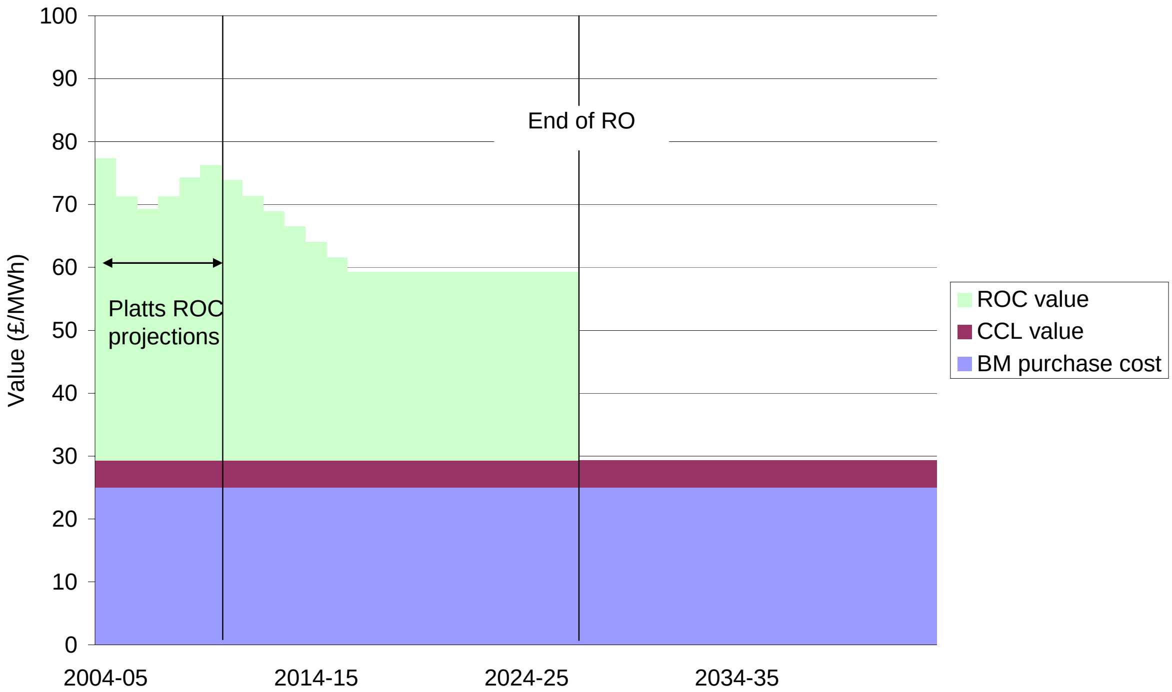
2.64 It must be emphasised that many alternative scenarios are possible. As well as market risks, there is also uncertainty over the future direction of policy. For example, the government might in the future raise the supplier obligation for years after 2015/16 or move the end-date of the RO further into the future. On the other hand, future governments might be reluctant to provide further support within the current policy framework, or the CCL might be altered or removed at some stage in the future.

Chart 2.2: Cost of constraining renewable generation (high value)



Source: Europe Economics

Chart 2.3: Cost of constraining renewable generation (low value)



Source: Europe Economics

Losses

2.65 SKM has used a figure of £45/MWh to value reductions in losses, on the grounds that a reduction in losses has the same effect as wind generation in terms of displacing conventional generation and achieving environmental benefits. SKM states that this figure is consistent with the value of £48/MWh proposed by Ofgem to incentivise reductions in distribution losses.

2.66 As discussed above, the interpretation of the RO buy-out price as a proxy for the carbon-reducing benefit of renewable generation is highly questionable. Therefore, valuing the carbon-reducing benefit of losses at £30/MWh (as implied by SKM's approach) appears inappropriate.

2.67 The apparent consistency of SKM's figure with the incentive rate for distribution losses proposed by Ofgem is spurious. As set out in table 2.1, the two figures are derived on a very different basis. For example, whereas SKM's figure does not take account of the impact of losses on network capacity requirements, Ofgem's figure implicitly values these network effects at £18/MWh.

Table 2.1: Comparison of value placed on losses by SKM and Ofgem (£/MWh)

	SKM value	Ofgem value
Cost of electricity generation	15	27
	(excludes fixed costs)	(full wholesale price)
Environmental premium	30	3 (1)
Reduction in required transmission capacity	Not taken into account	1–4
Reduction in required distribution capacity	Not taken into account	10–21
Total	45	41–55 (mid-point 48)

Note: (1) This is the figure added to the forward wholesale price. However, Ofgem discusses the fact that forward prices may partly capture environmental costs already as a result of the EU emissions trading scheme.

Source: SKM, Ofgem

2.68 The proposed reinforcements to the transmission network would give rise to reductions in transmission losses rather than distribution losses. Using the mid-point of Ofgem's figures but excluding the benefits that are specific to distribution networks would suggest a figure of £32.5/MWh for the value of transmission loss reductions.

Capitalisation assumptions

2.69 In its analysis, SKM has capitalised the value of annual reductions in constrained energy and losses assuming a 40-year asset life and using a discount rate of 6.25%. These are consistent with the assumptions used in NGC's last transmission price control.

2.70 Europe Economics notes that the assumptions Ofgem used for the cost of capital and depreciation period at the last transmission price reviews varied between the three transmission licensees, as set out in table 2.2 below.

Table 2.2: Price control parameters used for each transmission company

	Cost of capital	Depreciation period for new CAPEX
NGC	6.25	40
SP Transmission	6.5	40
SHETL	6.5	48

Source: Ofgem

2.71 To the extent that these differences reflect genuine variations in financing costs and asset lives, it would seem appropriate to move away from use of the NGC price control parameters for projects which primarily involve investment by the Scottish companies.

2.72 Table 2.3 summarises the breakdown of CAPEX between the three transmission licences for the three projects which involve investment by SP Transmission. The table also presents revised capitalisation assumptions for each project based on the price control parameters of the transmission licensee which would incur the highest proportion of the CAPEX associated with that project.

Table 2.3: Suggested revisions to capitalisation assumptions

	Percentage of CAPEX			Suggested capitalisation assumptions	
Reinforcement	SHETL	SPTL	NGC	Discount rate	Asset life
Beauly-Denny	77	23	0	6.5	48
England/Scotland interconnectors	0	29	71	6.25	40
Kendoon area connection infrastructure	0	100	0	6.5	40
Sloy area reinforcements (Stage 2)	34	66	0	6.5	40

Source: Europe Economics

Summary

2.73 Table 2.4 summarises the revised assumptions suggested by Europe Economics, and compares them with the original assumptions used by SKM. Some of the proposed adjustments (e.g. using market prices to value constraints) will tend to increase the estimated benefit of network reinforcements, whereas others (e.g. placing a lower value of losses) will tend to reduce estimated benefits. The next section presents indicative calculations showing how the revised assumptions taken overall might affect the results of SKM's analysis.

Table 2.4: Summary of adjustments to SKM assumptions

	SKM assumption	Europe Economics assumption	
		Low constraint management cost	**High constraint management cost**
Valuation of impacts			
Constrained renewable generation eligible for ROCs	£45/MWh	**Until 2026/27** Projected ROC price plus £4.30/MWh plus £25/MWh **After 2027/28** £4.30/MWh plus £25/MWh	**Until 2026/27** Projected ROC price plus £4.30/MWh plus £40/MWh **After 2027/28** £4.30/MWh plus £40/MWh
Constrained large hydro generation (not eligible for ROCs)	£45/MWh	£25/MWh	£40/MWh
Conventional generation	Economic valuation of £1/MWh to £5/MWh depending on plant affected Market valuation of £10/MWh Calculations also undertaken using RETS assumption of £25/MWh	£10/MWh	£25/MWh
Losses	£45/MWh	£32.5/MWh	
Capitalisation assumptions			
Discount rate	6.25	6.25 or 6.50 depending on project (see table 2.3)	
Lifetime of benefits	40	40 or 48 depending on project (see table 2.3)	

Indicative Calculations

2.74 This section presents some indicative results showing the impact of modifying SKM's calculations by changing the valuation assumptions. The effect of other potential improvements is also highlighted.

Data and methodology

2.75 For the purpose of this analysis, SP Transmission requested data from SKM on the results of its engineering analysis, where not explicitly tabulated in SKM's report. The data request covered the volumes of reductions in constrained energy and losses for each of the projects involving capital expenditure in SP Transmission's region, as well as volumes of constrained energy during construction.

2.76 SKM provided SP Transmission with additional data in relation to the Kendoon project and the interconnector reinforcement scenarios in which Cockenzie and Longannet are closed. However, the requested dataset was not provided in full. The receipt of the complete dataset would have allowed more robust benefit calculations to be carried out for each reinforcement project, enabling all relevant impacts to be re-valued using the preferred assumptions. The data would also have enabled further examination of the details of the methodology used by SKM in its cost-benefit analysis.

2.77 In carrying out indicative calculations, Europe Economics was therefore restricted to use of the information given in the SKM report and the partial dataset provided by SKM. For some of the reinforcement projects, the analysis could proceed directly from data on volumes of constrained energy and loss savings. For other projects, the information available consisted of SKM's final estimates of costs and benefits (mostly presented in graphical form). In these instances, our analysis began by working backwards from SKM's results to compute implied volumes of constrained energy and losses, which were then re-valued using the revised assumptions. This gave rise to a number of complications which are discussed below as they become relevant.

2.78 While in the absence of the underlying data one cannot be sure, overall the methodology employed by SKM in its cost-benefit analysis seems at times to be rather inconsistent between projects. These inconsistencies, discussed below, make the analysis in Chapter 9 of the SKM report much less transparent than might be expected.

2.79 One caveat associated with the calculations for Beauly-Denny and the interconnector is that Europe Economics could not ascertain from the report whether SKM had discounted the value of increased volumes of constrained energy during construction. It was assumed that they had not been discounted, in line with the apparent treatment of capital construction costs for some projects. If this assumption is incorrect, then the estimated costs of construction constraints would be slightly higher.

Kendoon line

2.80 SKM provided SP Transmission with data for this project on volumes of constrained energy for different levels of installed wind generation capacity.

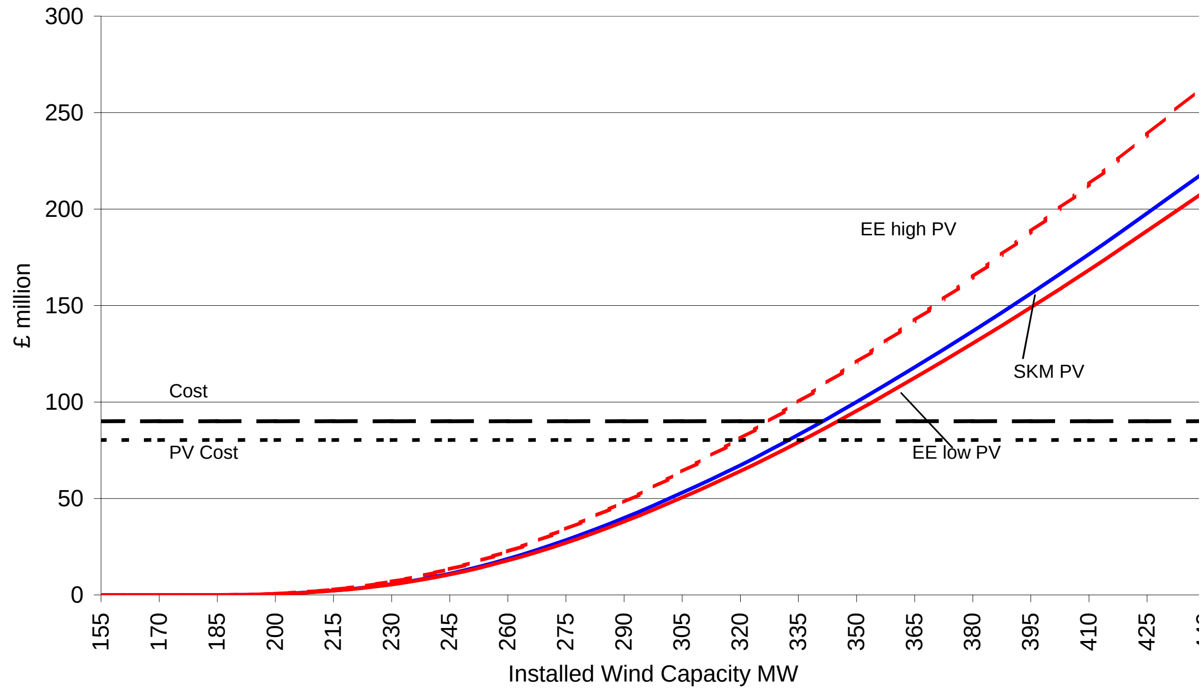
2.81 Chart 2.4 presents the result of the revaluation of the Kendoon reinforcement, using both the higher and lower values discussed earlier for constrained renewable energy. In addition to changing the valuation assumptions, Europe Economics made adjustments to reflect the following methodological issues:

(a) Using data on underlying volumes of constraints to replicate SKM result in figure 38 of the report, it seems that SKM has calculated the present value of benefits assuming that benefits begin accruing immediately, rather than in 2008/09, the completion date of the planned reinforcement. Correcting for this, other things constant, slightly lowers the present value of the benefits both because they are more heavily discounted and because the valuation attached to renewable output is lower further into the future.

(b) The construction costs for this project do not appear to be quantified in present value terms. (The same issue arises later for the Beauly-Denny project.) Figure 38 in the

SKM report uses the total cost of £90 million from Table 15 of the same report, which Europe Economics assumes in the absence of any statement to the contrary to present non-discounted figures. Chart 2.4 compares the different scenarios of present value benefit both to the SKM cost figure and to a cost figure that has been calculated in comparable present value terms using data from Table 15 of the SKM report.

Chart 2.4: The Kendoon Line Reinforcement



2.82 With all the quantifiable changes made, the investment would seem to be justified when connected wind capacity reaches 320 MW to 335 MW. This is lower than the threshold of 350 MW calculated by SKM.

2.83 There appears to be an inconsistency between the treatment of offers under quote for the interconnector and Kendoon reinforcements. For the interconnector reinforcement, the SKM projection of 4,000 MW of renewable capacity appears to include projects under quote. However, in classifying the Kendoon project as additional investment, Ofgem appears to take into account only the 228 MW of renewable generation capacity which SKM states is already connected, under construction or has accepted a connection quote. SKM states that there are an additional 165 MW of capacity are under quote in the Kendoon area. This suggests that the reinforcement proposal would be justified on the preferred valuation assumptions provided that 55 per cent of this capacity is likely to go ahead.

2.84 The 400 kV Kendoon reinforcement proposed by SP Transmission includes an element of over-sizing to allow for a possible third interconnector between Scotland and England. It may therefore be possible to achieve similar savings in constrained energy from a “fit for purpose” 132 kV network reinforcement, at a significantly lower cost than the larger 400 kV reinforcement. If the costs of the reinforcement investment could be halved with the benefits remaining constant, then only around 35 per cent of connections under quote would need to go ahead for the project to be justified.

2.85 The justification for over sizing depends on the need for a third Scotland – England interconnector. The indicative calculations on the interconnector reinforcements presented later imply that this third interconnector could be economically justified in the near future, though further analysis is needed on the issue.

2.86 Further evaluation of the Kendoon proposals requires analysis by SP Transmission of the likely level of future connections in this area, and the incremental costs and benefits of oversizing the reinforcement.

Scotland England interconnector

2.87 This section provides indicative calculations for those interconnector scenarios which are most relevant to SP Transmission: the combined reinforcement of the interconnector and North East ring, and stage one interconnector reinforcement only. In each case, indicative calculations are presented both for the scenario with all existing generation and for the scenario with the closure of Longannet and Cockenzie.

2.88 Alongside its “economic” valuation exercise, SKM’s report presents market valuations of the benefits of interconnector reinforcement which use our preferred valuation and capitalisation assumptions, except for the valuation placed on savings in losses. It also appears that, for the interconnector calculations, SKM took into account the fact that the benefits of reinforcement would only begin to accrue once construction has been completed. However, there are two areas where SKM’s calculations appear inappropriate, and where Europe Economics has revised SKM’s calculations:

(a) the treatment of reductions in losses; and

(b) the valuation of constraint costs during construction.

Reductions in losses

2.89 The SKM analysis differs from the Beauly-Denny and Kendoon lines in that savings in losses and the benefit of early asset replacement have been credited to capital costs.

2.90 In reply to the data request, SKM provided data on volumes of savings in losses for the interconnector reinforcement with the North East ring, in the Longannet/Cockenzie closure scenario: a constant 540 GWh per year for installed wind capacity up to 6,000 MW. Further guidance from SKM suggested that this volume would be dominated by loss reductions arising from the interconnector reinforcement, with the additional loss benefit associated with the North East reinforcement likely to be small. Therefore, in the absence of further data, Europe Economics treated this level of loss saving as equally applicable to both the combined reinforcement of the interconnector and North East ring and to stage one reinforcement only.

2.91 Although the figure for loss savings provided by SKM was for the scenario in which Longannet and Cockenzie close, in the absence of further data this figure was also used for the scenarios which assume all existing generation remain in operation. This may be a conservative assumption (i.e. the true loss benefits may be higher in these scenarios), given that these plant will tend to increase flows across the interconnector.

2.92 Europe Economics could not establish exactly how SKM has taken into account the annual savings in losses. SKM indicates that savings in losses have been valued at £45/MWh, capitalised and credited against the present value construction cost. Doing this, however, and taking account of the fact that the benefit of loss savings would not begin till after construction was complete, would lead to present value of savings in losses of circa £260 million, more than the total construction cost in SKM Table 15. This seems to be in stark disagreement with the values indicated in SKM Figure 33 for the NPV cost minus credits for savings in losses and early asset replacement, and the figure of £32 million for loss savings quoted on page 98.

2.93 Given this opaqueness, Europe Economics removed the benefit of loss reductions and early asset replacement from the cost calculations and has instead based its cost figures on the present value of the construction costs from SKM Table 15. The benefit from savings in losses was then valued at the preferred value of £32.5/MWh and capitalised over 40 years (taking into account that benefits begin after the construction period), giving a present value benefit from savings in losses of approximately £189 million. The present value benefit lines in Charts 2.5 to 2.8 below show the combined benefit of savings in losses and constrained energy. The benefits from early asset replacement were not taken into account in the quantitative analysis below as the relevant data were not available.

Constraints during construction

2.94 The other major issue is the cost of increased constraints during construction. It is important to value the future savings in constrained energy and the constraints during construction in a consistent way. SKM, using a value of £1/MWh for constrained energy, has valued these costs to be £30 million. These costs are significantly higher when the preferred market valuation is used, and have an important bearing on the analysis given that these costs occur sooner in time than the benefit of subsequent constraint reductions and hence are less heavily discounted when considered in present value terms. In fact, using the preferred valuation assumptions discussed in the previous section, the constraint costs during construction add up to more than twice the construction cost, as demonstrated by Charts 2.5 to 2.8 below.

2.95 The constraint costs incurred during construction are likely to be affected by the timing of the reinforcement work. If there are no changes through time to the conventional plant on the system, then delays to construction work may increase constraint costs due to higher levels of renewable penetration. However, as agreed with SP Transmission, no attempt has been made to quantify timing issues in this analysis.

2.96 The estimation of the cost of constraints during construction in present value terms assumed, for practicality, that the constraints were spread evenly within the period of construction constraints as presented in Table 14 of the SKM report.

2.97 SKM's figure of £30 million has been interpreted as applying to the combined interconnector and North East ring reinforcement scenario, with all existing generation in place. It has not been possible to re-value explicitly the construction constraint costs for the other three scenarios due to lack of data. Therefore, Europe Economics made the assumptions described in the following paragraphs for the purpose of this analysis.

2.98 The further data provided by SKM shows that the constrained annual energy volumes for the interconnector with North East ring project without Longannet/Cockenzie are 44 per cent of the constrained energy volumes with all existing generation when 6,000 MW of renewable energy is connected (rising steadily from 1 per cent with 1,400 MW renewables connected). From this it was assumed that the constraints during construction for the Longannet/Cockenzie closure scenarios are 50 per cent of the construction constraints with all existing generation. This is viewed as a very conservative assumption, as wind capacity is not likely reach 6,000 MW until the end of the construction period, if at all.

2.99 The period of construction outages in Table 14 of the SKM report was used to provide an estimate of the proportion of constraints during construction that would still be incurred if only the stage one reinforcement went ahead. Again, it was assumed that the constraints are equally divided among the outage weeks. Based on this approach, Europe Economics assumed stage one reinforcement alone would give rise to roughly 70 per cent of the outage time that would be associated with the whole project.

2.100 The construction constraints for stage one reinforcement with closure of Longannet/Cockenzie closure were therefore calculated as 35 per cent (70 per cent times 50 per cent) of the total constraints during construction for the combined project with all existing generation.

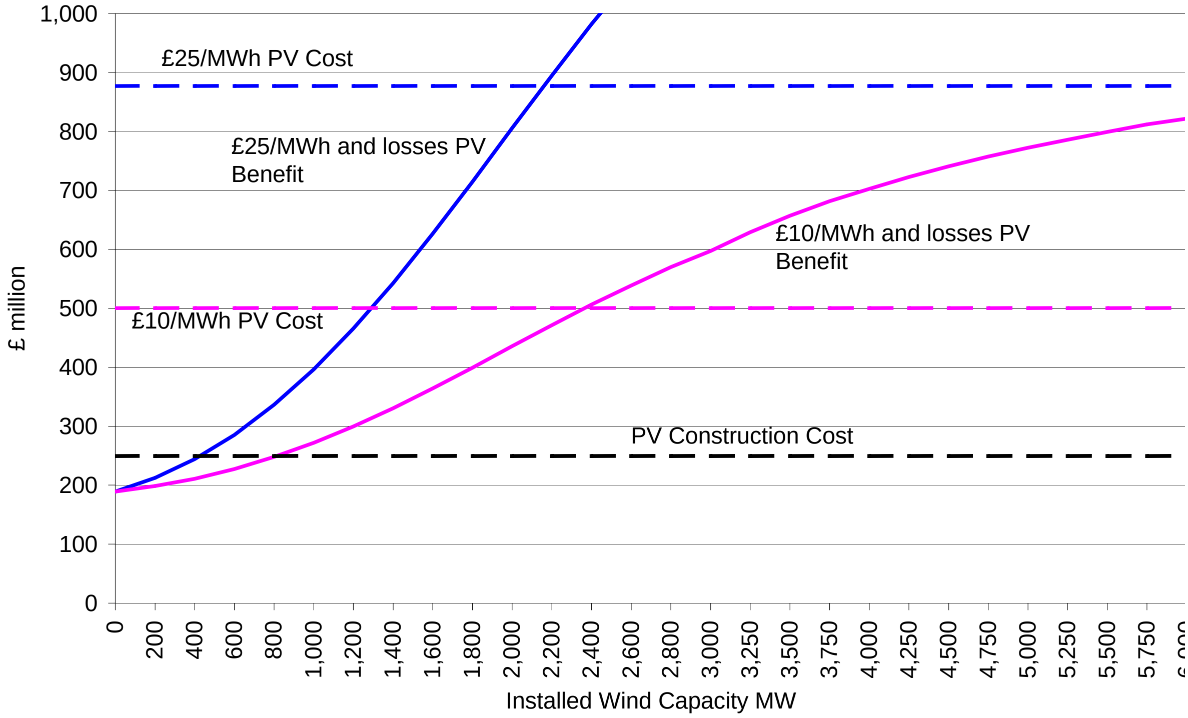
Indicative results

2.101 Chart 2.5 shows indicative results for the combined interconnector and North East ring reinforcement, with all existing generation in place. The benefit lines comprise the present value of reductions in losses and constraints, with the latter valued at £25/MWh and £10/MWh. The chart also shows the combined present value of construction and constraint costs, as well as the present value of construction costs only.

2.102 For the high valuation of constrained energy, the investment should go ahead with approximately 2,200 MW of wind energy coming connected in Scotland, and with approximately 2,400 MW installed capacity for the lower valuation.

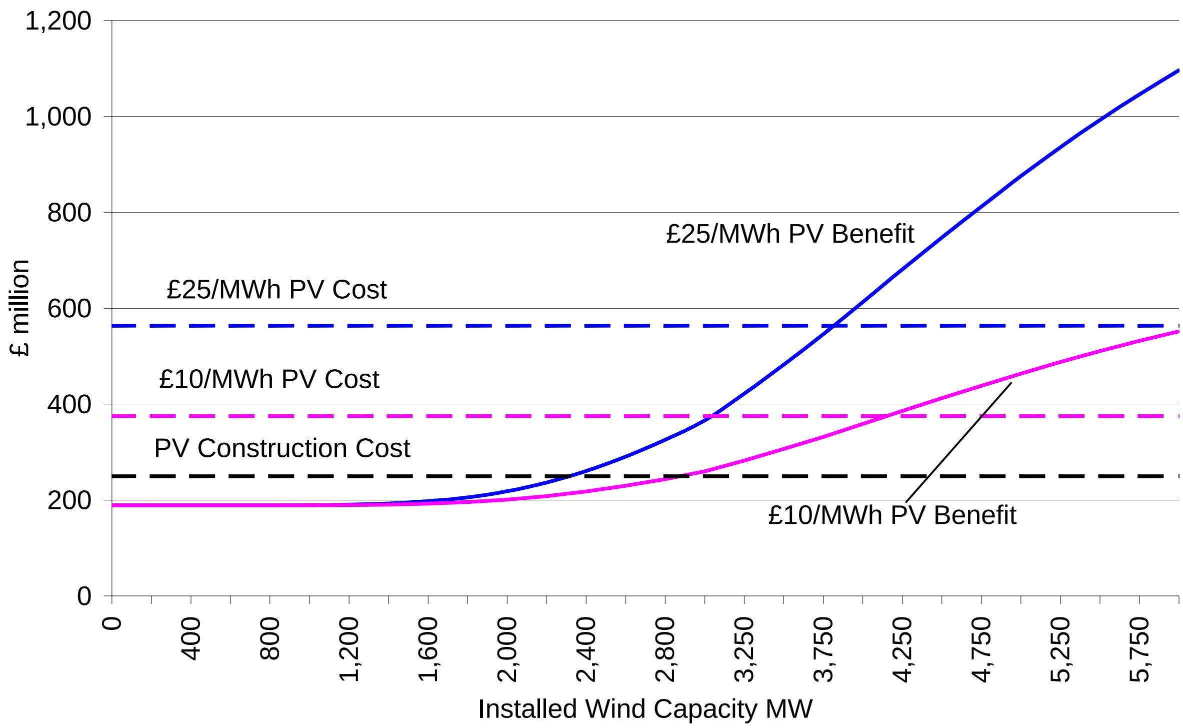
2.103 As discussed earlier, actual loss savings in this scenario may be higher than the assumed level (which was based on closure of Longannet and Cockenzie). This would reduce threshold wind capacities below the above levels.

Chart 2.5: The Interconnector with North East Ring



2.104 Chart 2.6 presents indicative results for the scenario in which both the interconnector and North East ring are reinforced, but Longannet and Cockenzie are closed. The threshold volume of renewable generation required for the project to be justified is 3,800 MW to 4,250 MW.

Chart 2.6: The Interconnector with North East Ring, closure of Longannet/Cockenzie



2.105 Charts 2.7 to 2.8 present the stage one reinforcement only. The results indicate threshold capacities from 1,500 MW to around 1,800 MW with all existing generation and from 2,600 MW to 3,200 MW for stage one with closure of Longannet and Cockenzie.[8]

2.106 A combination of two factors explain the initially counter - intuitive result that the stage one reinforcement would be justified at lower levels of renewable penetration using a lower valuation for constrained energy. First, using a higher valuation of benefits also increases the valuation of the constraints during construction. Second, the benefit from savings in losses alone would justify the physical construction cost of stage one, and it comprises a large portion of the benefits at the low levels of installed wind capacity, dominating the effect of savings in constrained energy volumes.

2.107 As with the combined reinforcement, the savings in losses for the scenario in which all existing generation remains in operation may be higher than the level assumed in constructing Chart 2.6. Adjusting for this would further increase the estimated benefit and lower the threshold capacity for this scenario.

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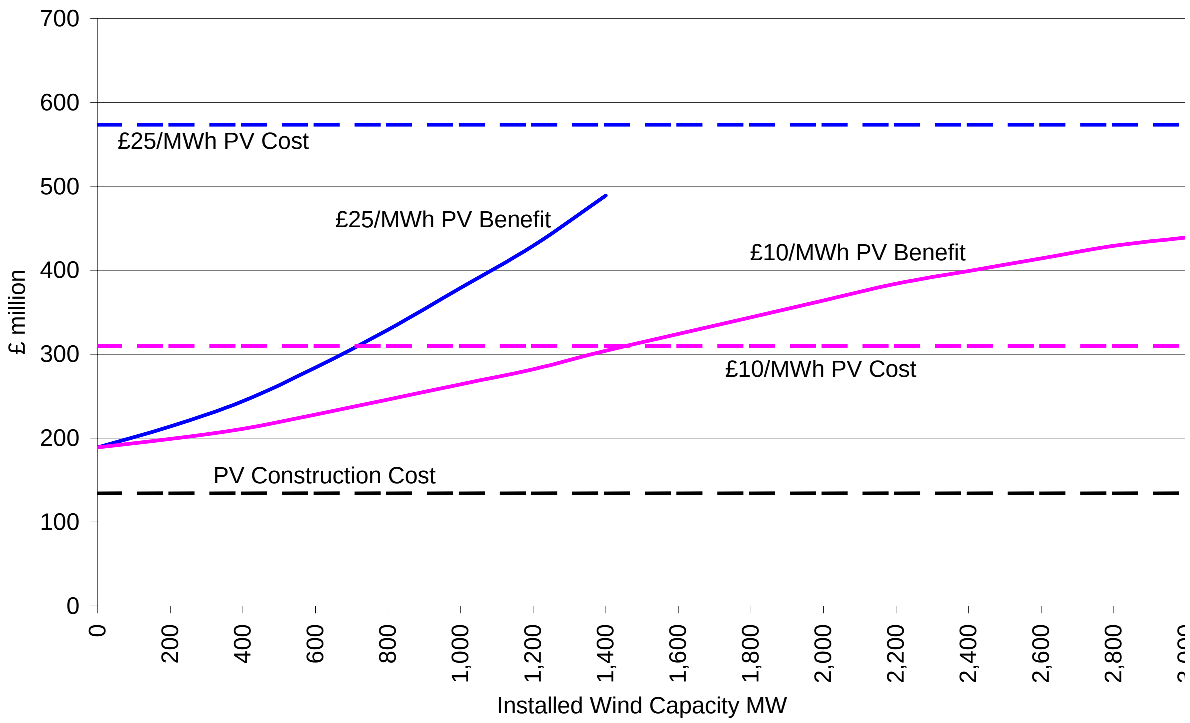
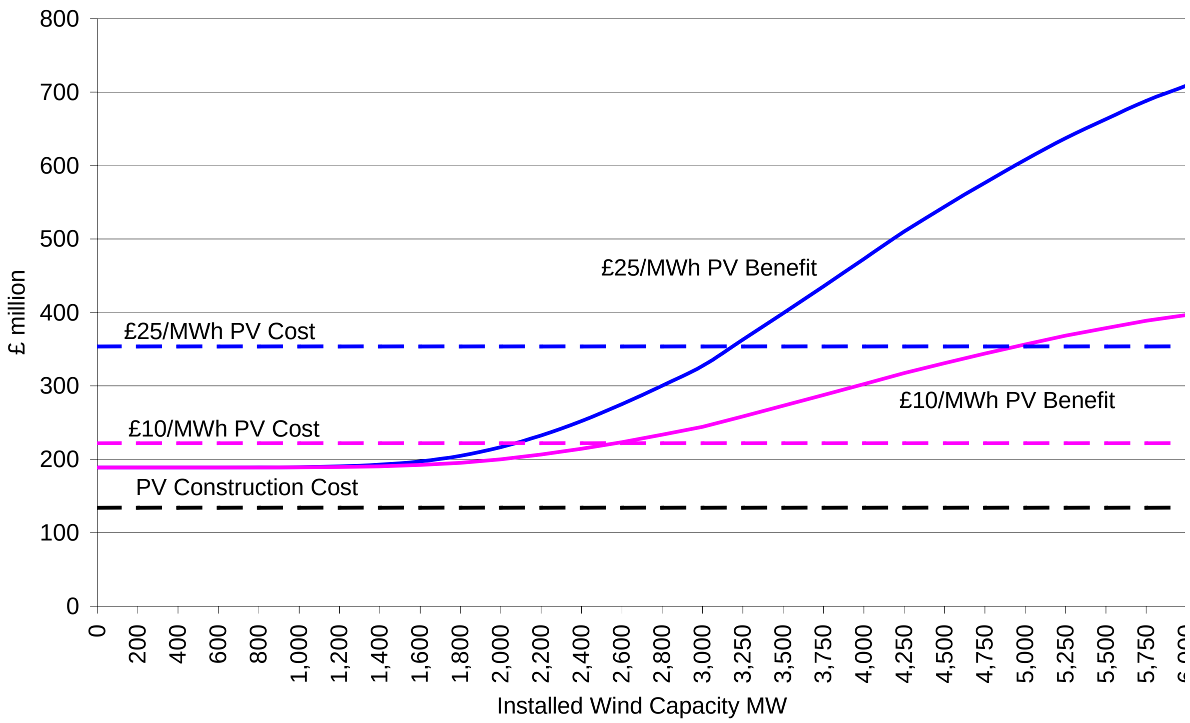
8 The estimate of break even level of wind capacity for chart 2.7 is based on a conservative extrapolation, as the data in SKM figure 34 does not go further than 1,400MW for the £25/MWh benefit line.

Chart 2.7: The Interconnector Stage One



Note: the £25/MWh PV benefit line could not be extended further due to lack of data.

Chart 2.8: The Interconnector Stage One, closure of Longannet/Cockenzie



2.108 Table 2.5 summarises the above results and compares them with those obtained by SKM.

Table 2.5: Renewable capacity required to justify investment (MW)

		SKM		Europe Economics	
		All existing generation	Closure of Longannet and Cockenzie	All existing generation	Closure of Longannet and Cockenzie
Interconnectors and North East ring	£25/MWh	900	3,100	2,200	3,800
	£10/MWh	1,700	4,300	2,400	4,250
	£1/MWh-£5/MWh	5,000	6,100	n/a	n/a
Interconnectors only	£25/MWh	600	2,600	1,800	3,200
	£10/MWh	1,000	3,600	1,500	2,600
	£1/MWh-£5/MWh	3,700	5,000	n/a	n/a

2.109 As with SKM's market valuation, the conclusions associated with these revised calculations are that the stage 1 reinforcement is justified (based on SKM's projection of 4,000 MW of renewables by 2010). Additional analysis of the incremental cost-benefit case for the North East ring would be needed to reach a conclusion on whether the full project should go ahead. The reinforcements would give rise to additional benefits from early asset replacement which are not reflected in the revised calculations.

2.110 These conclusions stem primarily from the recommended switch to a market-based valuation of constraints. The net effect of modifying SKM's market valuation (by increasing the value placed on constraint costs during construction and taking full account of the capitalised benefit of loss reductions) varies between scenarios. Threshold capacities increase for the scenarios with all existing generation, but the effect is less clear-cut effect for the scenarios in which Longannet and Cockenzie close.

2.111 Given that the scenarios in which Longanet and Cockenzie close are associated with higher threshold levels of wind generation, an important question (particularly in relation to the combined interconnector and North East reinforcement) concerns the likelihood of these stations closing without any new build of conventional plant taking place in Scotland. Europe Economics has not attempted to analyse this issue.

2.112 This use of a market valuation affects the cost-benefit case for a third Scotland – England interconnector, and hence the justification for over-sizing the Kendoon line. Page 102 of the SKM report finds a possible third interconnector costing £300 million, which would remove the remaining annual constrained energy volumes, justified at 6,000 MW of installed wind capacity. Valuing the remaining constrained energy in the third column of SKM Table 17 at market values, the third interconnector would be justified at 3,000 MW and 4,000 MW respectively for the £25/MWh and £10/MWh valuations, assuming that benefits begin accruing in year 2010/11, there are no savings in losses and no increased constraints during construction. Though a crude measure, this does indicate that a third interconnector line could be justified in the near future, and hence oversizing the Kendoon reinforcement should not be ruled out. Much more analysis, however, is needed on this issue before any firm conclusions are drawn.

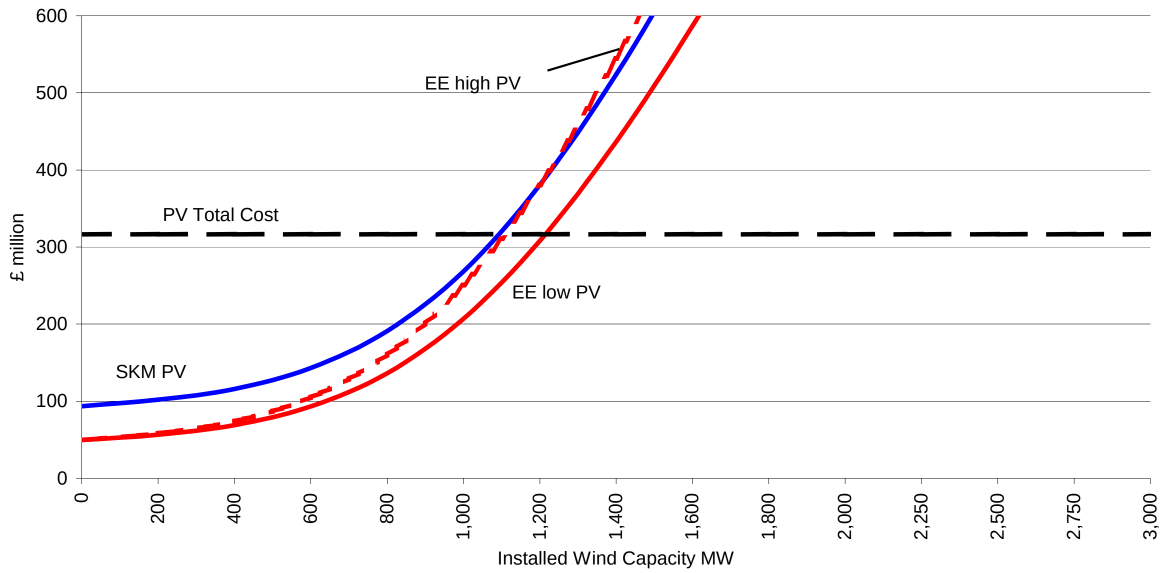
Beauly-Denny line

2.113 Table 16 of the SKM report provides the volumes of energy saved due to reductions in constraints and losses from the proposed reinforcement investment. These were first analysed using SKM valuation and capitalisation assumptions to reproduce the result presented in Figure 24 of the SKM report.

2.114 The replication revealed that the construction costs seem to have been taken as the total nominal cost across the construction years (SKM report Table 15), instead of being assessed in present value terms. Also, the capitalisation of the benefits from savings in constrained energy and losses seems to assume that they begin accruing immediately, rather than after the 4-year construction period. In addition to correcting for these two aspects and re-valuing benefits using the preferred assumptions, Chart 2.9 also adds the present value of constraint costs during construction, estimated at the lower renewable value, to the cost of the project. Using the higher renewable value for the construction constraints would raise the PV total cost line by £5 million, with no material effect on the conclusions.

2.115 As seen in Chart 2.9 these changes do not make much difference to the level of wind generation that would justify the proposed reinforcement in this case. The investment would be justified when between 1,000 MW to 1,200 MW of wind energy is connected. This is because the higher value placed on constrained renewable generation and the discounting of construction costs is offset by the later start-date assumed for benefits and the inclusion of constraint costs during construction.

Chart 2.9: The Beauly-Denny line reinforcement



2.116 The shape of the graph is different from the original SKM benefit line, because reductions in losses (where we use a lower valuation) is more important than the reduction in constrained renewable energy (where we use a higher valuation) when few renewables are connected. Hence overall we get an lower valuation in this region. The reverse is true for high levels of renewable connections, because the reduction in constrained energy grows significantly with renewables volume whereas the reduction in losses does not.

Sloy stage 2

2.117 SKM's cost-benefit analysis for the Sloy stage 2 reinforcement only considers the impact when 300 MW of wind capacity is installed, given that this is the volume of renewables currently under construction/contract. SKM states that the present value benefit of reduced constraints is £43 million, set against a construction cost of £21 million. Given the clear cost-benefit case implied by these figures, SKM has not analysed savings in losses or constraints during construction.

2.118 SKM has valued the savings in constrained hydro and wind energy at £45/MWh. The report does not give a division of the constrained energy volume between these two types of generation. Using the market values for wind energy for all of the implied constrained energy volume, the value of savings rises from SKM's £43 million to £53-£67 million depending on which market value is used for renewable energy. This, however, overestimates the benefit of constrained hydro energy savings. As a sensitivity check, the implied energy volume was assumed to be half wind and half hydro. When the lowest of the market valuations discussed earlier in the report were used for both wind and hydro constriants, the present value of benefits was of £38 million. Therefore SKM's conclusion that benefits are likely to be greater than costs does not change, although any savings in losses and constraints during construction should be taken into account as well.

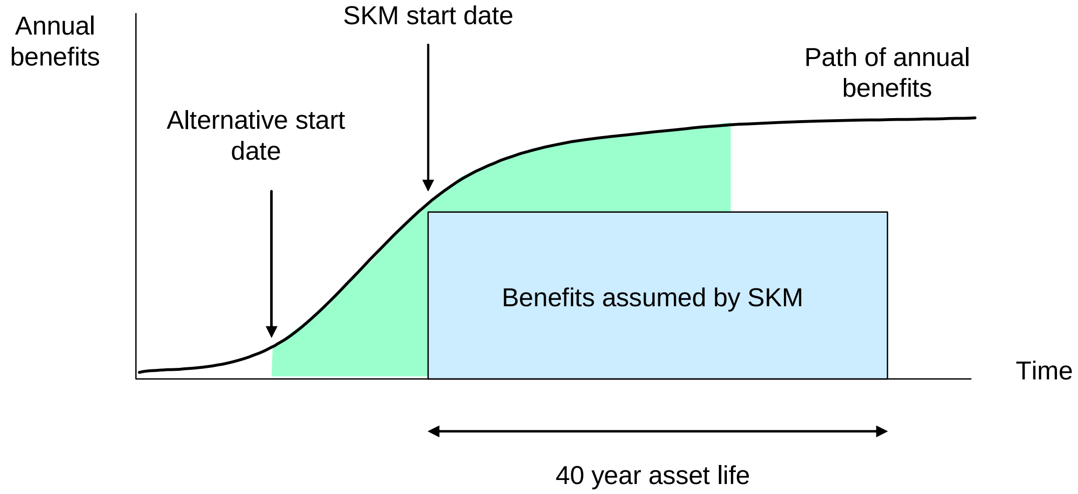
Timing Issues

2.119 SKM's approach to timing issues is to analyse what level of renewable capacity is required in order to justify reinforcement, and then to identify the year by which that level of renewable capacity is projected to come on stream.

2.120 While this approach might appear correct at a superficial level, Europe Economics suggests that more careful analysis of timing issues would be appropriate. This is because SKM's approach appears to assume implicitly that the same level of renewable generation would be connected to the network throughout the lifetime of the assets installed at the time of reinforcement.

2.121 If the volume of renewable connections continues to grow after the date at which reinforcement work has been completed, then it is possible to envisage a situation in which a proposed reinforcement might yield a positive NPV even if completed before renewable connections have reached the "break-even" volume calculated by SKM. This is because the lower benefits achieved in early years would be offset by benefits above the level assumed by SKM in subsequent years. This effect is illustrated in Chart 2.7.

Chart 2.7: Treatment of Timing Issues



2.122 Where there are a number of different start dates which would yield a positive NPV, it would appear optimal for the project to go ahead in the year in which the net benefit is maximised. Hence the criteria for whether the start date of the project should be brought forward or delayed is whether the marginal benefits of the change in timing are greater than the marginal costs.

2.123 Table 2.4 summarises the marginal benefits and costs of bringing forward the investment in Chart 2.7 from the SKM start date.

Table 2.4: Marginal Benefits and Costs of Bringing Forward Investment

Marginal benefits	Marginal costs
Reduced constraints and losses in additional early years of reinforcement	Lost benefit in last few years of SKM asset life since assets wear out earlier (1)
Construction outages occur in years when less renewable generation has connected	Construction outages occur in years when ROC price is higher
	Constraint costs during construction are incurred earlier in time
	Capital costs are incurred earlier in time

(1) While the annual volumes of constrained energy and losses may be high in these years, the benefits would be heavily discounted and in the case of renewables a low premium value is attached to output this far into the future.

2.124 Additional issues are raised by consideration of the uncertainty attached to projections of future benefits. Dixit and Pindyct (1994) argue that a higher hurdle rate is appropriate for large, irreversible investments which take place in a context of uncertainty, because by investing the option of waiting for better information is extinguished.[9] This suggests that in order to justify bringing forward investment, the expected benefits would have to be higher than implied by deterministic analysis of the factors in Table 2.4 so as to compensate for increased uncertainty over whether benefits will materialise.

2.125 Based on this analysis, Europe Economics concludes that there is a possibility that reinforcement proposals might be justified at an earlier date than suggested by SKM. However, quantitative analysis would be needed to establish whether this was the case.

[9] Dixit, Avinash and Pindyck, Robert (1994) “Investment Under Uncertainty”, Princetown University Press.

3 OFGEM PROPOSALS

3.1 Europe Economics has qualitatively assessed the proposed classification of projects by Ofgem, and the mechanisms proposed for funding baseline, incremental and additional investment.

Classification of Projects

3.2 The concept of classifying individual investment proposals according to whether they are justified on a cost-benefit basis seems appropriate. It also seems reasonable to use categories which broadly correspond to:

(a) projects which are justified;

(b) projects where there is uncertainty over whether the benefits will outweigh the costs;

(c) projects which are not justified at this stage.

3.3 Nonetheless, some of the proposed reinforcements appear to have been placed in the wrong categories, both in light of SKM's own analysis and even more so in light of the revised results presented in the previous section.

SKM analysis

3.4 Firstly, the classification of the proposed Kendoon line as additional investment seems to be at variance with SKM's own conclusions. It is true that SKM recommended against sanctioning of the project as presented at this stage, and advocated investigation of a lower cost alternative. However, the SKM report also stated:

> It is therefore considered that the proposed reinforcement is very close to achieve enough wind generation capacity to be justified. (p105)
>
> … there is a need to provide additional network capacity in this area. (p115)
>
> … in any case reinforcement circuits required. Justified initial design and engineering works £2.3m. (p8 and 118)

3.5 SKM's conclusions would therefore appear to justify treating this project as incremental investment, particularly given the recommendation that funding should be provided for initial design and engineering works.

Indicative calculations by Europe Economics

3.6 The indicative calculations by Europe Economics presented in the previous section have implications for the classification of individual projects, as follows:

(a) there is little change to the case in favour of the Beauly-Denny reinforcement, particularly if the preferred higher valuation (£40/MWh) is used for replacement conventional generation;

(b) when a market valuation is placed upon constraints, stage one of the England/Scotland interconnectors upgrade is sufficiently justified to be classified as baseline investment;

(c) the case for classifying the Kendoon line as incremental investment is somewhat further strengthened, although the decision as to whether the project should be classified as additional or incremental investment ultimately depends on the proportion of connection enquiries which are likely to become firm. The use of a market valuation also suggests that there may be a potential case for a third interconnector (and hence over-sizing of the Kendoon line). Uncertainty over the volume of renewable connections in the area and the need for further analysis to identify the incremental benefits and costs of over-sizing suggest that classifying the project as baseline investment remains inappropriate at this stage;

(d) the case in favour of treating Sloy area reinforcements as baseline investment is strengthened.

Summary

3.7 Table 3.1 summarises the conclusions of the above discussion with regard to the classification of the four projects which involve expenditure by SP Transmission.

Table 3.1: Classification of Projects Involving SP Transmission

Reinforcement	Ofgem initial classification	Europe Economics classification	Comments
Beauly-Denny	Baseline	Baseline	-
England/Scotland interconnectors upgrade	Incremental	Baseline	Upgrade justified, using market valuation of constraints
Kendoon area connection infrastructure	Additional	Incremental or additional	Issue of oversizing still needs to be addressed
Sloy area reinforcements	Baseline	Baseline	-

3.8 The following sections provide comments on the funding mechanisms proposed by Ofgem for each of its categories of investment.

Baseline Investment

3.9 Ofgem proposes the baseline investment should be funded through a revenue allowance calculated to recover regulatory depreciation and a return on net assets. The regulator suggests that initially the revenue allowance could be based on SKM's estimate of the project costs. After five to ten years, actual investment costs would be incorporated in the regulatory asset value, provided costs had been properly incurred and there was no evidence of inefficiency.

3.10 The regulator proposes the following with regard to the timing of revenue allowances:

(a) licensees would be able to recover pre-construction costs before planning consents for a project have been granted;

(b) after relevant planning consents have been obtained and construction has started, licenses would receive a revenue allowance for interest during construction, which Ofgem suggests might be based on the estimated cost of debt finance used to set the overall cost of capital;

(c) after construction had been completed, licensees would receive a revenue allowance consistent with the full cost of capital and depreciation.

3.11 Ofgem proposes that output measures should be set in advance for each project, perhaps based on SKM's assessment of the increase in network capacity and capability that the project would deliver. Ofgem would then undertake an *ex post* review to determine whether these outputs had been delivered. Where licensees had delivered higher outputs with benefits to system users, then the licensee might be allowed a higher level of return. Conversely, where outputs were lower than agreed and this had a detrimental impact on system users, licensees would receive lower returns, possibly by adjusting revenue pro-rata to performance in delivery of outputs.

Commentary

3.12 The proposal to fund investment through revenue allowances is appropriate, given that projects in the baseline category are expected to yield benefits which are unambiguously greater than costs.

3.13 The proposal to fund only interest during the construction phase would appear to run counter to economic theory. Given that the cost of debt is below the overall cost of capital, Ofgem's proposal would mean that licensees received less than the efficient level of financing cost.

3.14 Europe Economics recognises the arguments in favour of not allowing licensees to benefit from delays during the construction phase. The firm suggests two options for achieving this goal while providing companies with revenues that cover efficient *ex ante* financing costs:

(a) Ofgem could estimate the *ex ante* difference in revenue implied by the use of the cost of debt rather than the full cost of capital over the planned period of construction work. This difference could be provided to the licensee in the form of a lump sum, thus preserving timing incentives at the margin (ie, the licensee would still receive only the cost of debt for any *delay* in construction work). This option would be relatively simple to incorporate into the regulator's existing proposals.

(b) In order to provide optimal incentives, the regulator could calculate revenue on the basis of the full cost of capital, but design an adjustment mechanism whereby any advance or delay to construction work would give rise to revenue adjustments designed to reflect the marginal economic benefit or cost of changes in project timing. For example, for a project delay the penalty might reflect additional constraint costs associated with extended construction outages, as well as the cost associated with the benefit of reduced constraints and losses coming on-stream later. Clearly, this would represent a much more complex mechanism.

3.15 Europe Economics suggests that if output measures are agreed for sanctioned reinforcements they should be based on variables fully within the control of transmission licensees (e.g. installation of assets of an agreed technical specification). The firm understands that the transfer capacity of network assets may partly depend on exogenous factors such as generation despatch and system operation.

3.16 The use of a simple pro-rata scaling mechanism for under-delivery of outputs is unlikely to provide the correct incentive, since there is no evidence to suggest that it would reflect the economic cost associated with the under-delivery of outputs.

3.17 If Ofgem wishes to provide incentives with regard to the delivery of outputs, the firm suggests the following two options:

(a) The regulator could retain discretion over the level of any revenue adjustment where outputs differed from the agreed level. This would allow any reward or penalty for over- or under-delivery of outputs to be set in line with an *ex post* estimate of the resultant economic benefits or costs, perhaps with a ceiling to the revenue exposed to such adjustments to limit the risk faced by licensees. If companies were unhappy with such regulatory risk, they would be free to seek regulatory approval for any re-scoping of the project where justified by cost-benefit analysis, in which case there would be corresponding adjustments to the allowed level of forward-looking project costs.

(b) Alternatively, Ofgem could pre-specify revenue adjustments for over- or under-delivery of outputs, based on *ex ante* estimates of the associated economic benefits or costs. However, this approach may be more difficult to implement given the need to project potential economic impacts. (Note that pro-rata scaling falls into the category of pre-specified revenue adjustments, but without any economic basis for the proposed level of adjustment.)

Incremental Investment

3.18 For incremental investment, Ofgem proposes that the licensees should receive a revenue allowance for planning stage costs, such as scoping out the necessary investment work and obtaining planning permission. This would avoid delays by permitting pre-construction work to proceed, while allowing time to resolve uncertainties over whether the full project should go ahead.

3.19 The regulator states that the proposed revenue allowances would be based on SKM's assessment of the likely development costs of each project prior to April 2007. Before any application is made for planning permission, Ofgem would review whether each project should be treated as baseline or additional capacity, perhaps as part of the next full transmission price review.

Commentary

3.20 The proposals for funding the pre-construction costs of incremental investment would seem appropriate. Funding these costs could be considered as the purchase of an "option" to allow the full project to go ahead at an earlier date than would otherwise be possible should it be demonstrated that the benefits exceed the costs.

Additional Investment

3.21 Ofgem is not proposing guaranteed revenue allowances to fund additional investment, given that this investment category is intended for projects not expected to yield a net benefit. The regulator states that these projects could be reclassified as baseline or incremental investment if appropriate in light of new information.

3.22 Nonetheless, Ofgem does suggest two mechanisms whereby additional investment could be funded, if transmission licensees were sufficiently confident that future levels of constraint costs and renewable generation would justify the investment. These two mechanisms — a revenue driver and longer-term commercial arrangements with generators — are designed to protect consumers from funding stranded assets and are discussed in more detail below.

Revenue driver

3.23 Under this approach, Ofgem would specify a revenue driver at the beginning of each project which would allow the licensee to recover revenue in proportion to the number of additional generators which connect to the network as a consequence of the reinforcement. This would allow the company to earn higher returns for successful projects, while exposing it to lower returns if less generation connected to the network than the licensee had anticipated.

Commentary

3.24 Given that Scottish companies are vertically integrated, adoption of a revenue driver would require careful consideration of whether it might distort incentives with regard to the location of plant by affiliated generation businesses. Such a distortion could arise because, by locating plant in areas where network reinforcements had been made on the basis of a revenue driver, the group as a whole would earn additional revenue even if the economics would otherwise dictate a different choice of site.

3.25 Setting aside the above issue, an optimal revenue driver would reflect the benefit of reduced constraints and losses arising from the reinforcement at different levels of renewable connections. In theory, this would provide transmission licensees with optimal incentives to trade off the economic benefits, costs and risks of the proposed investment.

3.26 It is worth noting that an optimal revenue driver might not be proportional to the volume of connections: SKM's analysis suggests that the reduction in constraints arising from network reinforcements can sometimes increase disproportionately with higher volumes of generation connections.

3.27 From the perspective of the transmission licensee, a revenue driver might need to offer the opportunity to make very significant returns in order to induce companies to undertake investment. Economic reasons for this include the following:

(a) *Cost of capital* — companies would face a higher cost of capital to the extent that exposure to a revenue driver increased non-diversifiable risk. Risks associated with locational decisions by generators would appear to be specific to the project and hence diversifiable. However, there are some risks that might be linked to macroeconomic factors. For example, the size of the RO may vary depending on macroeconomic developments, given that the obligation is defined as a percentage of electricity sales. Likewise, the enthusiasm of voters and the government for expenditure on renewables might be greater in times of economic prosperity.

(b) *Real option premium* — as discussed earlier, Dixit and Pindyct (1994) argue that a higher hurdle rate is required to induce firms to commit to a large, irreversible investment in a context of uncertainty, because by investing they forego the option of waiting for better information. This suggests that the *ex ante* hurdle rate applied to network reinforcements funded through a revenue driver might include a premium to cover this real option value, in addition to the base cost of capital.

(c) *Ex post returns* — the above considerations relate to the *ex ante* return required by investors. In order to achieve the necessary *ex ante* return, the revenue driver would need to allow the possibility of higher *ex post* returns if the project was successful in order to offset the possibility that the project may fail and thus achieve low *ex post* returns. The Productivity Commission in Australia took account of this issue in its 2001 report on the access regime for gas pipelines:[10]

> Investments in essential infrastructure will … be deterred if regulated terms and conditions are not expected to provide a sufficient return. A particular problem here is that the possibility of earning higher than normal profits if a project proves to be very successful may be required to balance the possibility that the project will fail.

3.28 Ofgem's document does not set out how a revenue driver would work over the lifetime of the transmission reinforcement. For example, the proposals do not state whether the revenue driver would apply just for an initial period (after which the assets might be added into the regulatory asset value), or whether the revenue driver would apply throughout the lifetime of the assets. It seems unlikely that transmission licensees would invest in network reinforcements without a high degree of certainty over the approach that the regulator will take towards the capital expenditure at future price reviews.

Longer-term contractual arrangements

3.29 The alternative approach suggested by Ofgem is that transmission licensees might agree longer-term commercial arrangements with generators benefiting from the investment. In return for entitlement to longer-term access rights, generators would guarantee/underwrite payment of transmission charges over the long term.

Commentary

3.30 Ofgem's suggestion lacks detail as to how such arrangements would work in practice. For example, it is not clear:

(a) whether the capital expenditure will be funded through price controls or by treating transmission charges under the long-term agreements as excluded revenue;

(b) whether the level of transmission charges agreed with generators will be based on the standard transmission use-of-system tariff, set at an administered level calculated for that specific reinforcement or subject to commercial negotiation;

(c) whether transmission licences would agree sufficient funding to cover the entire cost of the reinforcement, or simply enough to demonstrate that a threshold proportion of the project cost was guaranteed (with the rest expected to come from future connections);

(d) whether reinforcements would be considered justified when commitments to purchase long-term access rights matched the incremental capacity provided by the

[10] Productivity Commission (2001), "Review of the National Access Regime; Inquiry Report", September.

reinforcement, or the sum of the capacity of the existing network in that area *and* incremental capacity; or

(e) how the arrangements would fit with current obligations and procedures with regard to offering terms for connection and use of the system.

3.31 While it is difficult to analyse the suggested mechanism without further details, the following paragraphs consider the level of transmission charges and the threshold for considering an investment justified.

3.32 The transmission charges specified in long-term agreements could either be based on the standard use-of-system tariff or calculated specifically for the reinforcement in question. There are potential problems with both of these options:

(a) *standard use-of-system tariff* — these charges may yield either less or more revenue than required to fund a specific network reinforcement, given that they are calculated by modelling system-wide impacts of additional generation and that they apply to broad zones of the network.. Therefore, these charges may not easily be compatible with the funding of specific reinforcements outside the main price control;

(b) *special tariff for generators that benefit from reinforcement* — while a more localised charge could be calculated to yield the level of revenue required to fund reinforcement, this would effectively turn the long-term access arrangements into a deep connection charge (since generators would be committing themselves to funding deep reinforcement required for their connection). This would:

– run counter to the move in recent years from deep to shallow connection charging at both transmission and distribution level;

– give rise to potential co-ordination problems where large numbers of small generators were jointly responsible for precipitating an investment. In addition to the practical difficulties of agreeing long-term arrangements in such circumstances, each generator would have an incentive to free-ride on other generators willing to sign longer-term agreements with the transmission company;

– raise questions about the treatment of generators who subsequently connected in the area and used the same transmission assets.

3.33 Additional problems arise where proposed network reinforcement involves strengthening the existing network (as opposed to extending the network into a new area). These problems concern the criteria for evaluating whether long-term agreements are sufficient to warrant investment:

(a) If investment is considered justified when long-term sales of firm access rights match the *incremental* capacity associated with the reinforcement, then investment could take place in circumstances where the reinforcement is subsequently found to be unnecessary (because pre-existing network capacity proves sufficient to meet out-turn demand for firm access rights).

(b) On the other hand, it may be over-stringent to consider reinforcement to be justified only when long-term sales of firm access rights match pre-existing network capacity *plus* incremental capacity. This is because some existing generators may be unwilling to commit to long-term agreements (e.g. to limit project risk), and because some of the final demand for firm access rights will come from future new build projects. Therefore, this criterion might prevent some reinforcements from proceeding, even though *ex post* they might turn out to be justified by out-turn demand for access rights.

3.34 Overall, it is very unclear how the mechanism would work in practice. High-level consideration of issues such as the level of transmission charges and the criteria for sanctioning investment suggests that serious difficulties may arise with each of the options for the detailed design of such a mechanism.

3.35 It also seems likely that if sufficient generation capacity was firmly committed to connecting to the network so as to make such arrangements feasible, then there would be enough evidence to justify treatment of the project as baseline investment.

Overall conclusion on additional investment

3.36 Europe Economics agrees with Ofgem that it would not be appropriate to guarantee funding for projects, which are not justified on a cost-benefit basis. However, as discussed in the following sections, the firm considers that significant returns would need to be available to induce investment on the basis of a revenue driver, and that there are serious problems with reliance on longer-term commercial arrangements with generators. Hence the firm considers that these mechanisms should not be regarded as a substitute for careful consideration of any new information that may emerge which would justify re-classifying individual projects as baseline or incremental investment.