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Assessment of overall robustness of the transmission investment proposed for additional funding by the three GB Electricity Transmission Owners

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By order of Ofgem

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Context of this Report

As part of the GB Transmission Access Review (TAR) jointly conducted by Ofgem and the Department of Energy and Climate Change (DECC), the TAR Final Report proposed the introduction of enhanced transmission investment incentives to enable the GB Transmission Owners (TOs) (National Grid Electricity Transmission (NGET), Scottish Hydro Electric Transmission Limited (SHETL) and SP Transmission Limited (SPTL) to invest ahead of signalled need by anticipating future demand for connections to their networks and investing efficiently to ensure timely delivery of capacity. This proposal is being taken forward by Ofgem through its work on enhanced transmission investment incentives (the TO incentives project).

Complementing this work, the TOs produced a joint study for the Electricity Network Strategy Group (ENSG) to identify future network reinforcements to accommodate increases in renewable and conventional generation by 2020 in line with Government targets for renewable generation. Following the ENSG work, the TOs identified network investment proposals valued at circa. £5bn and submitted these to Ofgem for consideration of additional funding for pre-construction and/or construction costs in TPCR4, a number of these projects are currently proposed to commence construction within the current price control period, i.e. before April 2012.

To support Ofgem in the identification and development of appropriate funding arrangements for relevant projects; KEMA was commissioned to conduct an independent review of the overall robustness of the system-wide system development plan jointly produced by the TOs to facilitate the achievement of the Government's 2020 targets.

Underlying 2020 generation assumptions

In the ENSG study, it was concluded that the GB electricity sector would need to produce 147TWh from renewable generation by 2020. On this basis the ENSG devised a "Gone Green" generation scenario which was consistent with delivering this renewable output with corresponding capacity projections.

Within the modelling undertaken, three generation portfolios were considered to deliver 147TWh of renewable generation. These portfolios were constructed by varying the capacity and locational assumptions for wind generation to be commissioned in England, Wales and Scotland. The three variants were as follows:

- 6.6GW of wind capacity in Scotland (25.7GW of wind capacity in England & Wales) – this is consistent with the Scottish Executive's explicit renewable capacity target for 2020;

- 8.0GW of wind capacity in Scotland (24.3GW of wind capacity in England & Wales) reflecting a moderate view of the extent to which the Scottish Executive's renewable capacity target might be exceeded by 2020; and

- 11.4GW of wind capacity in Scotland (20.9GW of wind capacity in England & Wales) reflecting the most economic delivery of wind capacity based on generation economics alone.

Overview of the proposed TO investments

18 transmission investments (project schemes) were submitted to Ofgem in September 2009 for consideration of additional funding. The scope of each scheme is summarised in Table 1.

Table 1 – List of TO proposed schemes and their scope

Scheme (Proposer)	Scope
Knocknagael (SHETL)	New 275kV substation providing 75MW of capacity across boundary B1 and operational flexibility
Western Isles link inc. Lewis infrastructure (SHETL)	450MW HVDC link between Western Isles and Beauly on mainland Scotland
Beauly-Dounreay (SHETL)	2nd circuit on route plus Dounreay upgrade providing 100MW of transfer capacity across boundary B0 and 800MW across boundary B1
Beauly-Blackhillock-Kintore (SHETL)	Reconductoring along route to provide 500MW of additional transfer capacity across boundary B1
Hunterston-Kintyre link (SHETL/ SPTL)	132kV AC link with 150MW export capacity from southern Kintyre to main Scottish network
SPTL-NGET Interconnection (SPTL)	Installation of series compensation on SPTL network – part of a package delivering 1100MW across boundary B6
Anglo – Scottish incremental works (NGET)	Installation of series compensation; plus reconductoring of Harker-Quernmore on NGET network – part of a package delivering 1100MW across boundary B6
East-West upgrade (SPTL)	New underground cable Torness-Eccles and the voltage of the northern side of the Strathaven-Wishaw-Kaimes double circuit overhead line route, from 275kV to 400kV – part of a package delivering 1100MW across boundary B6

Scheme (Proposer)	Scope
East Coast upgrade (SPTL/SHETL)	Uprating Kintore- Kincardine from 275kV to 400kV, new substations at Kincardine, Grangemouth and Harburn, upgrading of Blackhillock-Kintore, new substations at Rothienorman and Alyth and upgrading of Blackhillock and Kintore substations to provide 700MW extra capability across boundary B4, 450MW across boundary B5 and 250MW across boundary B6.
Western HVDC link (NGET/ SPTL)	1800MW offshore HVDC link between Hunterston and Deeside creating extra capacity across boundaries B6 and B7
Eastern HVDC link (NGET/SHETL)	1800MW offshore HVDC link between Peterhead and Hawthorn Pit creating extra capacity across boundaries B4 and B6
East Anglia (NGET)	Various route reconductoring; substation upgrades; Quad Boosters; creating additional capacity across various local boundaries i.e. 2.5GW across boundary EC3; 3.75GW across boundary EC4; 4.75GW across boundary EC5; and 2.0GW across boundary EC6
London (NGET)	Reconductoring of two routes in London providing a 1,500MW increase in capability of the London network to accommodate power flows from the North East
North Wales (NGET)	New circuit; reconductoring of others; new substations and substation upgrades escalating transfer capacity across local North Wales boundaries; specifically 2GW for boundary NW3, 3.25GW for NW2 and 4.2GW for NW1
Central Wales (NGET)	Creation of a 400kV spur to mid-Wales enabling connection of 800MW of generation
South West (NGET)	New 400kV line; uprating of other lines to 400kV and some substation rebuild and upgrades providing 1.75GW of extra export capacity out of the South West
Humber (NGET)	2250MW onshore HVDC link enabling incremental 2.25GW of transfer south from the Humber area (into East Anglia via Walpole) and 1GW expansion of boundary B8
Shetland (SHETL)	600MW HVDC link between Shetland and north mainland Scotland. There are two different options being considered (i) a “” point to point link; and (ii) a link with an intermediate offshore hub with higher rated circuits between hub and mainland Scotland to facilitate potential future offshore grid.

Notes:

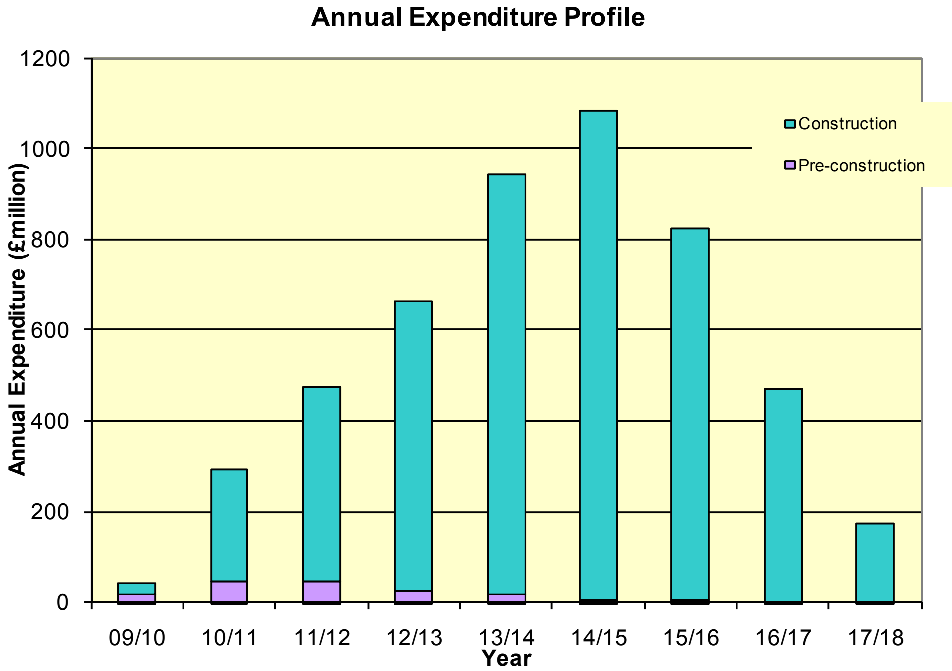
(i) Three of the above projects, namely SPTL-NGET Interconnection, Anglo-Scottish Incremental works and East-West upgrade are combined by KEMA under Figures 2 and 3 under the heading “Scottish Interconnectors” as they most directly relate to upgrade of the existing Scottish interconnector circuits.

(ii) The three projects in (i) above are grouped with the East-Coast upgrade by NGET under the heading “Incremental Upgrade” as one of the B6 expansion options evaluated within its CBA exercise conducted for the ENSG.

At the time of this report there is still significant uncertainty surrounding the detailed design that SHETL propose to pursue. Therefore the Shetland project is not included in the summary/comparison charts (Figures 1 to 3).

When aggregated together, the proposed package of transmission investments from all TOs presents the investment profile shown in Figure 1.

Figure 1 – Aggregate investment profile for all schemes proposed by the TOs



In aggregate, significant capex requirements are being forecast in the early to middle years of TPCR5 which at the time of KEMA's work was assumed by all parties to commence in April 2012. However, very shortly before KEMA issued this Report (21 December 2009), Ofgem announced that TPCR5 will now commence in April 2013 following a 1 year extension of TPCR4 to ensure alignment of TPCR5 with the conclusions of the ongoing RPI-X@20 Review due to complete in late 2010. As all TO submissions and KEMA analysis was conducted on the prior understanding/basis that "normal" TPCR periods were in force; KEMA believes it is not appropriate to change this basis of the analysis in this Report to reflect the new TPCR4 and TPCR5 periods but will clearly highlight where it refers to each that these relate to the prior understanding/basis i.e. TPCR4 would run until 2011/12 and TPCR5 would commence from 2012/13.

2014/15 shows the peak annual expenditure. Although funding for preconstruction activities are sought during the TPCR4 period, a large proportion of expenditure will fall during the TPCR5 period. This highlights that some expenditure may need to be assessed within the TPCR5 investment assessment process (and following Ofgem recent announcement also within assessment undertaken for determining the TO allowances for the TPCR4 one year extension) when the certainty associated with the need for the investment might be better understood.

Inclusion of the Shetland scheme adds in excess of £100m per annum during the period 2010/11-2013/14 (c. £200m in 2012/13) and would align 2013/14 total costs closely with those of 2014/15.

Figure 2 and Figure 3 provide other perspectives regarding the proposed investments; firstly an overview of absolute project costs and corresponding unit costs relative to the incremental network capacity provided (this is calculated on a simple £/kW basis by dividing scheme costs by the capacity provided across the key constrained boundary; and thus may not fully capture all the benefits provided by the scheme, e.g. increased operational flexibility); and secondly scheme rankings by forecast expenditure during TPCR4 up to 2011/12 (given this was the understanding of all parties of the TPCR4 period at the time of this work). It should be noted that three schemes have been combined as these form part of an integrated package of network reinforcements to deliver additional transfer capacity across transmission Boundary B6 (the Scotland-England border). The (Scottish) East Coast upgrade, as indicated by NGET, should also be considered within these B6 reinforcements and was included as one of an integrated 4 scheme option entitled “Incremental Upgrade” which is viewed by the TOs as the preferred initial expansion option for boundary B6.

Figure 2 shows that some early SHETL schemes have relatively £/kW costs. However, for the Knocknagael, the underlying rationale for the investment goes beyond capacity enhancements and includes additional operational flexibility. For others, such as the Western Isles link and the Hunterston-Kintyre link, costs reflect the remote generation locations and the corresponding network solutions required to enable exports to the wider network. Some schemes provide capacity benefits across more than one boundary. Nonetheless these £/kW figures highlight the need to scrutinise the costs and the benefits of some schemes and network capacity additions when undertaking the ‘need’ analysis.

The largest schemes in absolute cost terms have been proposed by NGET (either individually or as project leader) with the bulk of expenditure being incurred during TPCR5. Whilst these proposed investments are large in absolute terms, these appear on first level examination to be more cost effective in releasing capacity (£/kW) than some of the earlier (and smaller) schemes. However, it should be recognised that the Western HVDC link unit cost is high. The key issue in terms of anticipatory funding for these schemes is the degree of uncertainty regarding investment need and timing where such need and timing has been derived from underpinning generation assumptions and other key modelling inputs. With respect to the three possible options for expanding Scotland-England transfer capacity across Boundary B6 in terms of implementation priority, the Scottish Interconnector upgrade scheme(s) appear to the preferable first choice versus either offshore HVDC link in terms of overall and average cost.

In Figure 2; due to interdependencies, three schemes (i) SPTL-NGET interconnection; (ii) Anglo-Scottish incremental works; and (iii) East-West upgrade, have been combined under the heading "Scotland Interconnectors".

Both of the Shetland related investment options, i.e. link or offshore hub, represent some of the largest schemes at £548m (link) or £679m (hub) and are therefore the most expensive in £/kW terms at £913/kW or £1132/kW respectively.

Figure 2 – Forecast project costs and corresponding £/kW costs of network capacity

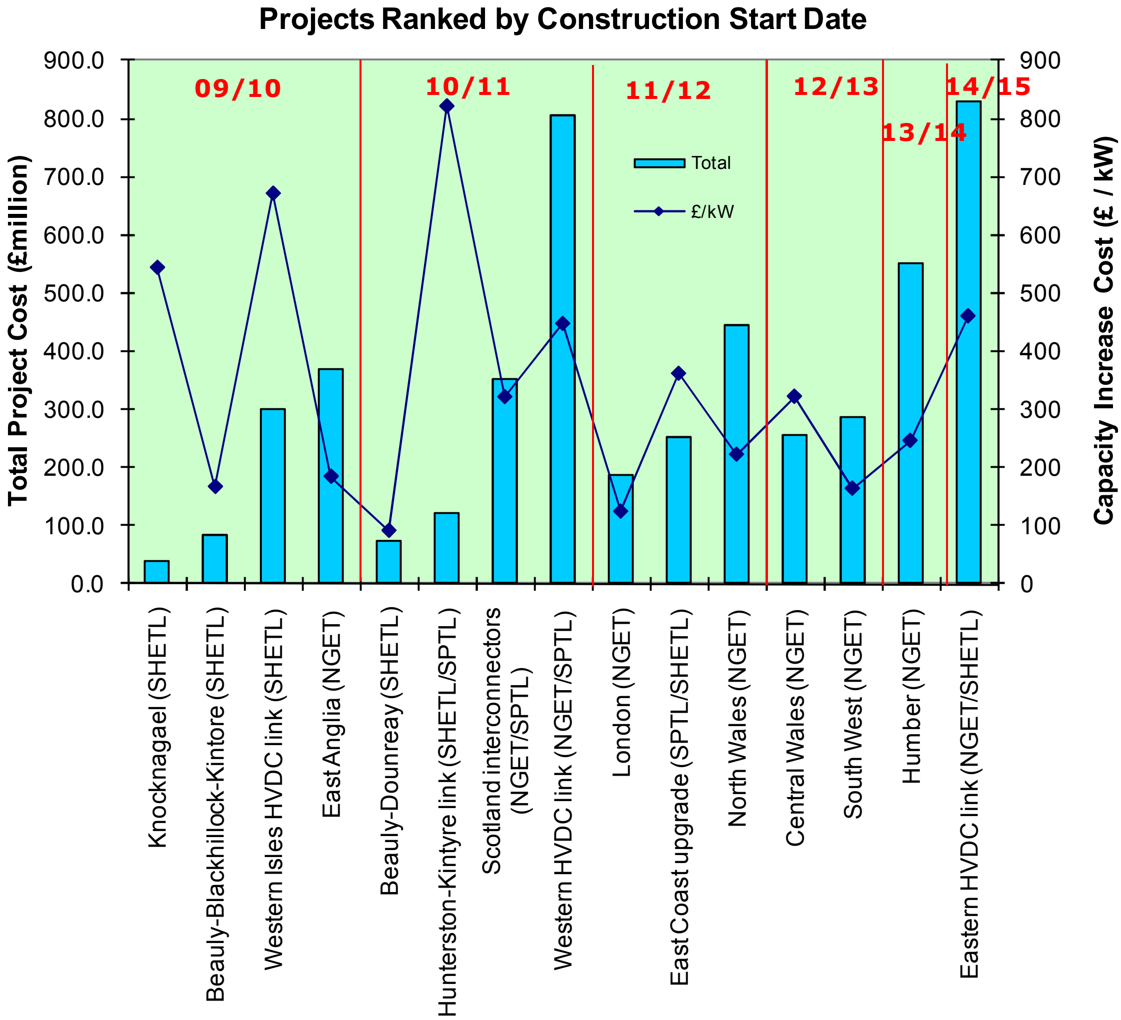
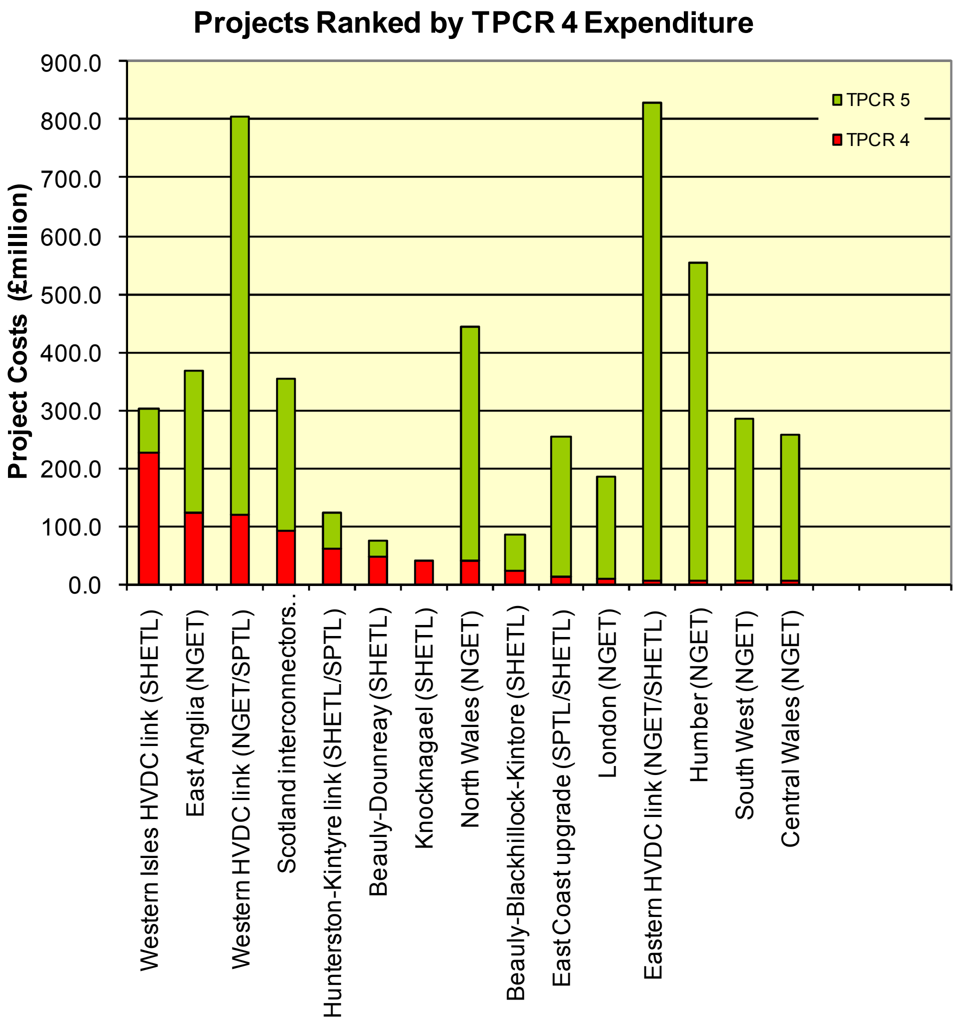


Figure 3 ranks projects by expenditure incurred during TPCR4 up to 2011/12 (given this was the understanding of all parties of the TPCR4 period at the time of this work) including construction and pre-construction costs. Varying amounts of pre-construction costs have already been approved within TPCR4, especially those where the TOs were seeking to incur expenditure during 2009/10. In total, c. £800m of additional funding has been identified for the current "normal" TPCR4 period (i.e. up to 2011/12) over and above that already approved.

It can be seen that TPCR4 expenditure (for the "normal" TPCR period up to 2011/12) is sought for each of SHETL's 5 schemes (totalling c. £411m) with the largest contribution arising from the proposed Western Isles link scheme (£224m). However, there is also significant proposed expenditure during TPCR4 (up to 2011/12) arising from NGET led schemes (circa.£350m) which principally arises from three schemes; the East Anglia (£122m), Western HVDC link (£118m) and NGET's component of the bundled Scottish Interconnector schemes (circa.£60m attributed to NGET). The remaining c. £40m relates to SPTL's Scottish Interconnector schemes.

If included in Figure 3, either variant of the Shetland scheme i.e. link or offshore hub, would represent one of the largest schemes and would also be the project seeking the most additional funding for construction within the remaining "normal" TPCR4 period (2010/11-2011/12) at c.£240m (link) or £310m (link with hub).

Figure 3 – Proposed scheme costs ranked by materiality of proposed TPCR4 investment



KEMA's assessment of the level of certainty of need and timing of proposed schemes

Based on an extensive review of the TOs' individual proposed schemes (see Section 4 and Appendix A), a review of the overall investment plan (Section 5) and the evaluation of the supporting cost benefit assessment (see Section 6); a summary of investment requirement certainty and timing for each scheme is provided in Table 2 with respect to those schemes commencing construction in the financial years 2010/2011 and 2011/2012.

Table 2 provides KEMA's project summary in relation to the (i) certainty of need; (ii) certainty of timing; (iii) materiality of additional TPCR4 funding sought; and (iv) degree of interaction with other schemes.

Table 2 – Scheme need, timing, scope, interactions; and level of TPCR4 funding sought

Scheme	Timing	Certainty of need	Certainty of timing	Appropriate -ness of Scope	Materiality of additional TPCR4 funding	Interaction with other schemes
Knocknagael (SHETL)	09/10 - 11/12	High	High	High	Medium	Stand alone
Western Isles link inc. Lewis infrastructure (SHETL)	09/10 – 13/14	Medium	Low	Medium	Very High	Stand alone (partly drives BBK and East Coast upgrade)
Beauly-Blackhillock-Kintore uprating (SHETL)	09/10 – 14/15	High	High	Medium – High	Low-Medium	Partly driven by Western Isles, Beauly-Dounreay, and Shetland
Beauly-Dounreay (SHETL)	10/11 – 12/13	High	High	High	Medium	Stand alone (partly drives BBK and East Coast upgrade)
Hunterston-Kintyre link (SHETL/ SPTL)	10/11 – 13/14	High	High	Medium	Medium – High	Stand alone
Scottish Interconnector upgrade[1]	10/11 – 14/15	Medium - High	Medium	Medium	Medium – High	Interactive with East Coast Upgrade and HVDC link schemes
East Coast upgrade (SPTL/SHETL)	11/12 – 17/18	Medium - High	Medium	Medium – High	Low	Interactive with Scottish interconnector upgrade and HVDC link schemes
Western HVDC link (NGET/ SPTL)	10/11 – 15/16	Low - Medium	Low	Medium	High	Interactive with Scottish Interconnector, East Coast Upgrade and Eastern HVDC link schemes

Scheme	Timing	Certainty of need	Certainty of timing	Appropriate-ness of Scope	Materiality of additional TPCR4 funding	Interaction with other schemes
Eastern HVDC link (NGET/ SHETL)	09/10 – 12/13 (pre-con only)	Low - Medium	Low	Medium	Low	Interactive with Scottish Interconnector, East Coast Upgrade and Western HVDC link schemes
East Anglia (NGET)	09/10 – 16/17	High	High – Medium	High	High	Stand alone (partly drives London)
London (NGET)	11/12 – 15/16	High	High	Medium – High	Low	Partly driven by East Anglia
North Wales (NGET)	11/12 – 16/17	Low	Low	Low – Medium	Low – Medium	Stand alone
Central Wales (NGET)	12/13 – 15/16	Low	Low – Medium	High	Low	Stand alone
South West (NGET)	12/13 – 16/17	Low	Low	High	Low	Stand alone
Humber (NGET)	13/14 – 16/17	Low	Low	Medium	Low	Stand alone
Shetland (SHETL) - either link or offshore hub variant	10/11 – 14/15	Low	Low	High	Very High	Stand alone (partly drives BBK and East Coast upgrade)

1. Comprises Anglo-Scottish incremental works (NGET), SPTL-NGET interconnection scheme (SPTL) and East - West upgrade (SPTL).

KEMA believes that at a high-level, the overall investment plan presented by the 3 TOs is a coherent collection of schemes and that the majority can be considered solely on their own merits without reference to other schemes in the plan. Some schemes have interdependencies such as the East Anglia investment influencing London requirements. The remainder are closely linked to the expansion of transfer capability across the Scotland/England transmission Boundary B6 and thus it is the scheme interaction(s) which need particular scrutiny within this subset of schemes.

In general, schemes with the highest level of uncertainty regarding need and timing are those with the later construction commencement dates (e.g. during TPCR5) or those with longer term completion dates. This reflects the greater uncertainty associated with medium-longer term generation developments and there will be further opportunities to review such schemes as part of the TPCR5 process. However, all schemes incur some pre-construction costs within TPCR4 timeframes. It does appear reasonable for the GB TOs to undertake pre-construction works in advance. However, the funding of such pre-construction works should not be taken as a guarantee that subsequent construction funding will be approved given the level of uncertainty of need and timing surrounding some schemes.

KEMA review of schemes relating to expansion of Scotland-England (B6) boundary

Within Table 2 that there are a number of schemes relating to expansion of transfer capacity from Scotland to England across Boundary B6. Within the analysis undertaken for the ENSG report, the proposed requirement and timing for these B6 related schemes was informed by a cost benefit assessment (CBA) undertaken by NGET; and this work was used by the TOs as a key input to the funding submissions to Ofgem in September 2009.

Within the ENSG process, 3 potential options were identified for expansion of Scotland-England transfer for which additional funding is being sought. These options are as follows:

1) “Incremental Upgrade” of the existing Scottish Interconnector;

2) Western offshore HVDC link connecting Hunterston to Deeside; and

3) Eastern offshore HVDC link connecting Peterhead to Hawthorn Pit.

The first option includes upgrading the Scottish Interconnectors with Series Compensation equipment for both SPTL and NGET, SPTL’s East-West upgrade and the SPTL/SHETL East Coast upgrade (note that SHETL is not seeking funding for the East Coast upgrade during TPCR4). KEMA is comfortable that the combination of scheme provides not just an appropriate and effective means of delivering capacity increases to 4400MW across Boundary B6 but also seeks to incorporate capacity expansion requirements across other key neighbouring boundaries such as B4, and B7/7a.

KEMA is equally comfortable that the three options represent practical alternative options for substantially expanding transfer capability across the B6 boundary. Thus the primary area of uncertainty is the relative merits and timing of the individual schemes.

CBA modelling assumptions

As with most CBA modelling exercises, input assumptions have the potential to significantly influence both results and conclusions. With respect to the B6 boundary related CBA undertaken by NGET, four aspects have been identified as having potentially significant impact on outputs:

1. Wind generation load factor assumption(s);

2. Application of plant merit orders in deriving constraint volumes;

3. Application of bid and offer prices in deriving constraints prices; and

4. Future generation patterns and the weighting of generation scenarios.

In addition, any upward cost revisions for the B6 boundary related schemes (particularly the HVDC links) should be considered by NGET when reviewing the CBA e.g. there have been some increases in B6 scheme costs between the ENSG CBA exercise conducted in Spring 2009 and the request for additional funding to Ofgem made by NGET/SPTL in September 2009.

Table 3 below summarises key CBA assumptions/factors as undertaken by NGET. The table highlights assumption sensitivities, identifies credible alternative assumptions, and discusses how such alternative assumptions might impact on CBA conclusions.

Table 3 – Overview of key CBA assumptions, alternative views and potential implications

Factor	ENSG Baseline Assumption(s)	Alternative views	Implications for investment of alternative views
Wind load factor	35% for onshore and offshore	Onshore wind has typically delivered a 28% load factor although may be higher in northern Scotland. Offshore wind expected to be better but current proposed projects indicate similar performance	Use of historic performance levels might reduce the investment requirements that are primarily dependent on/driven by new wind generation

Factor	**ENSG Baseline Assumption(s)**	**Alternative views**	**Implications for investment of alternative views**
Plant merit order	Plant allocated to base, marginal or "split" status according to historic running; no locational factors considered by fuel type.	Changing generation mix may change presumed status of some key conventional plant, especially in Scotland; adoption of locational costs would change relative merits of specific plants within plant type categories	Unclear. This will depend on which plants are adjusted and any interactions; and will vary by boundary. However, for B6, as a general rule changes in merit order which make Scottish plant more marginal and English plant more base will reduce investment requirements and vice versa.
Bid/offer prices	Derived per plant category; using an assumed relationship of bid prices = 0.5* generator wholesale price and offer price = 2* generator wholesale price	Seek to reflect average historic levels of bid/offer prices and/or average levels of cost of constraints (c. £60/MWh). Alternatively seek to model bid/offer prices aligned with LRMC principles.	Impact could be higher or lower dependent on historic period considered and exact definitions used to derive bid/offer prices and the cost of constraints. Given a longer term outlook there appears to be greater likelihood of downside risk to the benefits assumed within the investment cases based on CBA.
Scenario weighting of three future generation patterns	Equal weighting of variants of 6.6GW, 8.0GW and 11.4GW of wind in Scotland within the overall Gone Green scenario	Varied weightings e.g. placing varied emphasis on the scenarios	For example, should greater weighting be given to the scenarios with lower levels of wind generation in Scotland this would reduce resultant investment requirements across boundary B6.
Investment costs	Cost estimates at April 2009 e.g. Western HVDC link costed at £697m	Values as submitted for additional funding in September 2009 e.g. Western HVDC link now costed at £722m excluding majority of Deeside costs.	Higher transmission investment costs must be justified by higher constraints costs to achieve same CBA outcome. With revised (increased) transmission investment costs, the CBA conclusions for particular B6 related reinforcements could become uneconomic.
Time horizons for constraint cost estimations and enduring cost assumptions	15yrs was initially (2015-2029) used in ENSG CBA work; NGET has since proposed extending the CBA time horizon to 40yrs (2015-2054). Costs for 2021 and beyond assumed equal to those in 2020	Constraints benefit horizon aligned with asset life but level of constraints avoided will vary as future demand, generation patterns, and generation prices evolve	Concern that this extrapolation approach for forecasting constraint costs throughout the assumed asset life will overstate the long-term level of constraints avoidance benefits.

Factor	ENSG Baseline Assumption(s)	Alternative views	Implications for investment of alternative views
Cost of transmission losses	Assumed to be c.£60/MWh	CBA model assumes wholesale prices of £50/MWh falling to £40/MWh	Whilst a relatively minor part of the CBA, alignment to modelled wholesale prices will reduce benefits modelled and could impact on marginal CBA results

Derivation of constraint prices

The cost of resolving constraints is a key CBA factor and also subject to considerable uncertainty. KEMA recognises there may be short term circumstances where there is a potential requirement for a high proportion of Balancing Services actions to resolve constraints, such as those experienced within 2008/09 due to ongoing work to expand the Scottish interconnector capacity. KEMA is not convinced that it is appropriate to assume a high proportion of Balancing Services actions on an enduring basis to resolve constraints across B6. This is based both on the relative levels seen for B6 in previous years and the expectation that issues as seen in 2008/09 will not be observed on an enduring basis.

KEMA also recognises that the cost of resolving constraints from year to year will be volatile as demonstrated by history, reflecting key drivers such as the level of wholesale fuel and thus power prices but also annual generation and network outage patterns. However, in predicting such levels of constraints costs on a longer term enduring basis, KEMA believes it reasonable to consider the average costs seen over past 5 year period as a potential indicator of the likely level of long term constraint resolution costs.

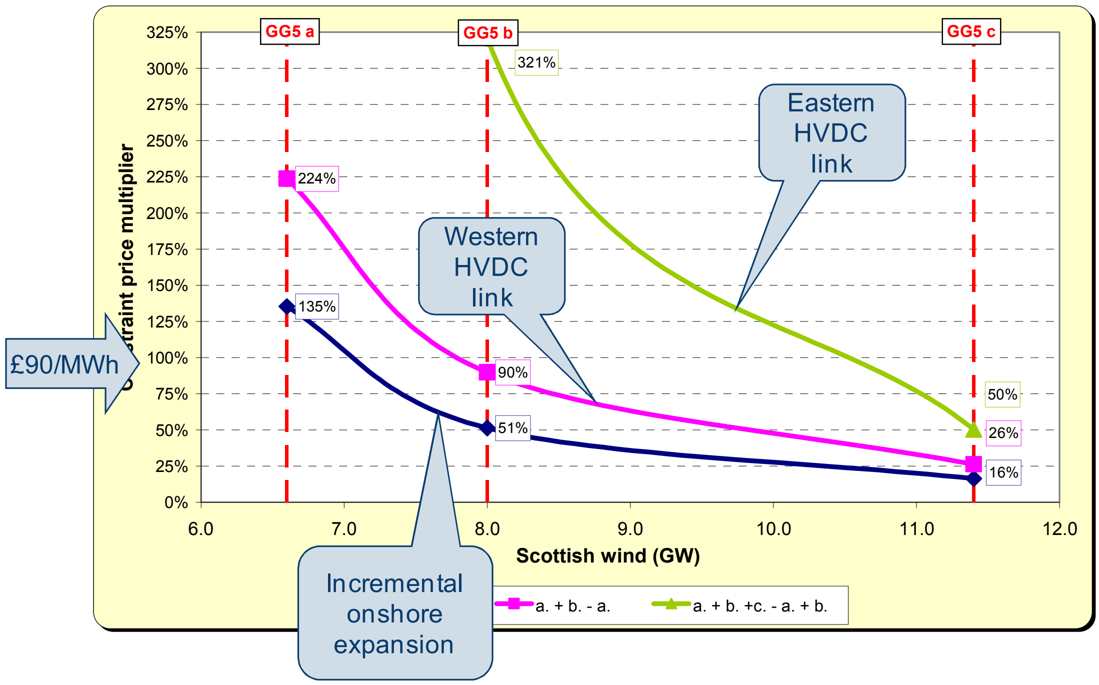
It is not evident that this history was fully considered in deriving the underlying bid and offer prices in the CBA undertaken within the ENSG process, nor that fundamental economic principles for long-term market behaviour have been full considered. As such KEMA believes the bid and offer prices within the CBA modelling and the consequent derived constraints prices may be overstated; and this is a key contributor to the potential risk to the CBA conclusion that two investments across B6 are definitely merited.

Transmission investment sensitivity to the level of constraint costs

Material changes to bid and offer prices will have an impact on the cost of constraints and thus the outcomes of the CBA analysis. KEMA has reviewed constraint price thresholds for the 3 variants of the “Gone Green generation scenario” against the permutations of B6 transfer expansion investment options. These thresholds indicate the average level of constraint resolution prices required to justify different investments for B6 transfer capacity expansion.

During KEMA's investigations, NGET produced a chart (replicated in Figure 4) to illustrate constraint price thresholds for Boundary B6 reinforcement permutations using material from the ENSG Cost Benefit Analysis. These price thresholds were used by NGET as the basis for justifying two B6 reinforcements for additional funding. Figure 4 shows the thresholds where one, two or all three Boundary B6 reinforcement options are implemented, i.e. incremental works (series compensation) first, followed by the Western HVDC link and finally the Eastern HVDC link. These curves assume constraint benefits are realised over a fifteen period from 2015-2029.

Figure 4 – Constraint price thresholds to justify B6 expansion investments – 15yrs constraints recovery period



'a.-0' = implementation of "Incremental Upgrade" schemes for B6
'a. +b. – a.' = incremental addition of Western HVDC link to Incremental Upgrade works
'a. + b. + c. – a. + b.' = final incremental addition of Eastern HVDC link to previous two reinforcements

It should be noted that to calculate constraints savings for the period 2021-2029, NGET extrapolated the modelled level of constraints calculated for 2020. KEMA is concerned that this approach may overstate the constraint costs avoided in these years as it takes no account of relevant changes in other factors over a ten year period.

NGET also provided a similar chart for comparison purposes providing an estimate of constraint savings accruing over an assumed 40 year asset life (2015-2054). The estimation of constraint savings for the period 2021-2054 were similarly extrapolated based on the calculated level of constraints in 2020 and assumed no changes in any other factors over the 35 year period.

The impact of these different time horizons, ceteris paribus, on requirements for B6 reinforcements is illustrated in Figure 5.

Figure 5 – Comparison of two constraint benefits time horizon scenarios used to justify B6 expansion investments

Assessment period	Proposed reinforcement	Scottish wind capacity (GW) – Key uncertainty		
		6.6	8.0	11.4
15 Year Assessment period	Incremental onshore expansion	✗	✓	✓
	Western HVDC Link	✗	?	✓
	Eastern HVDC Link	✗	✗	✓
40 Year Assessment period	Incremental onshore expansion	✓	✓	✓
	Western HVDC Link	✗	✓	✓
	Eastern HVDC Link	✗	✗	✓

Note: All other assumptions unchanged between the two assessments

Boundary B6 investment requirements are therefore highly influenced by wind generation capacity assumptions in Scotland and are also sensitive to changes in other assumptions. This underlines the importance of establishing an agreed forecasting methodology. Regardless of the time horizon under consideration, it can be seen that the particular variant of Gone Green generation scenario is crucially important in determining which B6 boundary expansion options are economic.

The CBA modelling conclusions are highly sensitive to assumed bid/offer prices (i.e. the derived constraint costs) and the relative weighting of the renewable generation scenarios. These sensitivities could lead to different conclusions regarding the level (and timing) for B6 reinforcements. This CBA analysis thus raises questions as to whether two investments for B6 are merited at this time.

There are number of factors which could impact CBA modelling outcomes. Whilst different CBA assumptions have the potential to reinforce or undermine proposed investment cases, Table 3 would suggest there is a greater probability that the drivers for investment will be reduced.

Key ongoing/future developments of regulatory codes/frameworks

National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) Review

There are concerns that the current NETS SQSS could; result in potentially inefficient outcomes regarding the integration of variable renewable generation within the GB transmission system. The Fundamental Review of SQSS is seeking to address these concerns and avoid any adverse impacts on the development of a low carbon future. This review should provide an opportunity to complement primary infrastructure based network operation and planning philosophies with wider solutions to deliver smarter, secure and a more cost effective future transmission network.

GB Transmission Access Reform

In its Consultation Paper released in August 2009, DECC indicated an initial view that a form of “Connect and Manage” transmission access should be implemented. A Connect and Manage approach differs from an Invest-then-Connect approach as it enables generators to obtain transmission access following completion of local connection work rather waiting until completion of the wider transmission reinforcement works.

The key feature of transmission access reform impacting upon the proposed network investments to facilitate 2020 renewables targets is that under a Connect and Manage approach, the completion of wider network reinforcements, such as expansion of the transfer capacity between Scotland and England across Boundary B6, does not act as the determinant of the earliest possible connection of renewable generation, i.e. it is not necessary for all potential transmission expansion projects to be implemented before renewable generation can connect and commence exports – albeit it is recognised there may be a risk of some constraining off of such generation in some parts of the network in these circumstances.

In addition, where there is high uncertainty regarding the need or timing of particular transmission reinforcements, any decision to postpone such investments, should not delay the connection of renewable generation whilst the impact on future constraint costs should be closely monitored. Consequently, reforms to transmission access arrangements need to be considered when evaluating requirements to make early commitments for substantial transmission reinforcement works. Should a Connect & Manage option be implemented and a corresponding increase in constraint costs is apparent, then the need for investments may become clearer.

KEMA's conclusions on proposed schemes

In total, 18 schemes have been nominated by the GB TOs for additional funding including the proposed Shetland Link (whether point-to-point or containing an offshore hub). KEMA's concluding remarks on these proposed investments are as follows (noting that commentary is provided on the basis of the original understanding of both the TOs and KEMA at the time of information submissions and assessment that TPCR5 would commence in 2012/13):

TPCR5 Schemes

Four NGET schemes (Central Wales, South West, Humber and Eastern HVDC) do not require construction funding in the current Price Control (TPCR4) period. Currently, these are all subject to high uncertainty of both need and timing given their strong dependence on future generation volumes. Therefore KEMA agrees with the TOs that no decision needs to be made regarding construction funding for these schemes at this stage; and they should be assessed as part of the TPCR5 process; but that pre-construction funding appears reasonable.

KEMA notes that whilst the ENSG process earmarked the Eastern HVDC link as the 3rd of three B6 expansion options (Incremental Upgrade, Western HVDC link and Eastern HVDC link), given the headline results of the CBA modelling and given the dependency on key assumptions regarding generation patterns and other factors in the CBA modelling, KEMA believes that there is uncertainty regarding the need and timing for this scheme. Differing assumptions/expectations impact conclusions ranging from no investment requirement through to the Eastern HVDC link being the preferred B6 expansion option. In addition, some of the CBA modelling results also imply that the Eastern HVDC link may actually represent a more effective single capacity expansion option for Boundary B6 than the proposed Scottish Interconnector upgrade works and that it may also be a preferable 2nd stage option comprising the Western HVDC link. However, given the uncertainties over generation patterns which might favour the Eastern HVDC link and uncertainties over the most effective route and design of the Eastern HVDC link, it seems appropriate that the Scottish

Interconnector Incremental Works schemes are viewed as the preferred 1st stage capacity expansion option; and the Western HVDC link might be the better 2nd stage option.

Schemes commencing 2011/12

There are five schemes proposed to commence construction in 2011/12, the last year of the current price control (TPCR4). Within these five schemes it is noticeable that four – namely the East Coast upgrade, East-West upgrade, London and North Wales incur a relatively small proportion of the total scheme costs in this first year, especially the latter three schemes. This is highlighted in Table 4 below.

Table 4 - First year and total scheme costs for schemes starting in 2011/12

Scheme	First Year Construction Spend in 11/12 (Last Year of TPCR4)	Total Scheme Cost	Percentage of scheme expenditure
Anglo-Scottish Incremental works	£47m	£182m	26%
East-West upgrade	£8m	£83m	10%
North Wales	£23m	£444m	5%
East Coast upgrade	£7m*	£253m	3%
London	£4m	£186m	2%

* This is a joint SPTL/SHETL scheme. However, only SPTL submitted construction costs for this scheme and SHETL are not planning any expenditure before 2013/14

The critical issue for the latter schemes in the table above is that longer term large-scale investment expenditure could be triggered and committed through the approval of relatively small sums at this stage during TPCR4.

Given the low materiality of expenditure relative to the scope of construction works proposed in 2011/12 for these schemes, KEMA does not believe that a delay of scheme construction commencement into the TPCR5 timeframe will unduly impact or delay the ability of the TOs to deliver these schemes. Furthermore given the level of uncertainty associated with both the need and timing of these schemes KEMA believes that it is not appropriate to commit additional TPCR4 funding for construction works at this stage, especially for North Wales, and London; and it may equally be the case for (i) the East Coast upgrade scheme unless SPTL can demonstrate the constraint cost avoidance benefits by coordinating their works under the East Coast upgrade scheme with the works for SPTL's East-West scheme; and/or (ii) the East-West upgrade scheme unless SPTL can demonstrate the benefits provided by aligning the Torness-Eccles cable element with the SPTL-NGET Interconnection scheme. Again, the funding of pre-construction works appears reasonable.

Schemes commencing 2010/11

There are five schemes proposed to commence construction in 2010/11 namely:

- Beauly-Dounreay;
- Hunterston-Kintyre;
- SPTL-NGET Interconnection works;
- Western HVDC link; and
- The Shetland Islands link.

Of these, KEMA believes Beauly-Dounreay and Hunterston-Kintyre are required within relatively short timescales and it is appropriate to allocate additional funding for construction of these schemes within TPCR4. These initial recommendations will need to be justified further based on Ofgem's determination of the efficient cost of delivery and the practicality of the proposed timing of commencement of construction (which KEMA understands there may be a deliverability issue for Hunterston-Kintyre).

The SPTL-NGET Interconnection works commits a small amount (£5m) of expenditure in 2010/11 which relates to circuit turn-in rearrangements and these are indicated by SPTL to be timed to coincide with other planned outages in the locality which is argued will save £20m of constraints costs for the construction works. Thus whilst KEMA believes it would be possible to commence construction of this scheme in 2011/12 without impacting on the completion date, it accepts that there is a economic reason due to circumstances specific to this scheme which merit 2010/11 commencement of construction.

As highlighted in Section 8.2.1, the Western HVDC link as proposed would entail £92m of additional funding for construction works in TPCR4 but would essentially trigger a commitment to £687m within TPCR5. However, from its extensive assessment of the CBA modelling exercise used to justify B6 related investments, KEMA believes there is strong uncertainty of not just the timing but also the need for the Western HVDC link. Also if an enduring Connect & Manage arrangement were to be implemented, KEMA believes a delay to commencing construction of the Western HVDC link, if subsequently deemed to be required would not impose a delay on proposed connection of new renewable generation in Scotland. Consequently, there does not appear to be strong urgency to commence the construction of Western HVDC link in 2010/11 and that it could be considered as a future TPCR5 scheme commencing from 2012/13 or later. However KEMA believes it would be appropriate for the proposed pre-construction funding to be provided.

SHETL is currently considering two design options for the connection to Shetland, one comprising a point-to-point link from Shetland to the mainland and the other including an intermediate offshore hub with higher circuit ratings to the mainland. The Shetland Link has similar characteristics to the proposed Western Isles Link project. It forms a high cost radial transmission link whose rationale is predominantly dependent upon the consenting and financial viability of large wind farm developments. Clearly both links also have a role in facilitating the connection of smaller or community scale distributed renewable schemes and in securing demand.

SHETL intends to submit additional information regarding the Shetland link in January 2010 which is likely to be similar in detail to that already provided for the Western Isles Link. It is currently anticipated that the Shetland link project programme will run some months behind that of the Western Isles in delivery timescales.

The need and timing of the Shetland scheme is dependent on the development of a 550MW onshore wind farm project. SHETL acknowledges the uncertainties associated with this wind farm development and has made clear that its request for funding is conditional upon developer financial commitment. This conditional funding approach seems reasonable given the outstanding wind farm consent and financial viability issues.

Schemes commencing 2009/10

Finally there are four schemes for which construction has commenced in 2009/10. These are all SHETL schemes and consist of:

- Knocknagael (this scheme will be completed within TPCR4);
- Beauly-Blackhillock-Kintore;
- East Anglia and
- Western Isles.

Of the above four schemes, KEMA believes three, namely Knocknagael, Beauly-Blackhillock-Kintore and East Anglia (at least in part) are required within short timescales and it is appropriate to proceed and to allocate additional funding for construction works within the TPCR4 period based on Ofgem's determination of efficient costs of delivery.

KEMA notes that the East Anglia scheme is delivered over an extended period and consists of a number of modular sub-schemes such that the final overall outturn scheme could be truncated or modified as greater certainty of the final requirement becomes better understood over the next 2-3 years. Specifically KEMA believes commitment by Ofgem to additional funding for construction works for East Anglia under TPCR4 should not automatically trigger a commitment to granting the residual scheme expenditure for the proposed scheme and that the latter part/elements of the East Anglia scheme should be revisited during TPCR5.

The fourth scheme, Western Isles, is subject to significant uncertainty regarding need and particularly timing of construction given (i) the current contractual and consents status of proposed generation projects on the Western Isles; and (ii) a statement from SHETL to only proceed where user commitment remains in place. SHETL has made clear that funding is conditional upon developer financial commitment, and it has quantified a cost benefit case for a trigger level at 150MW of generator user commitment. This conditional funding approach appears reasonable given the outstanding consent and financial viability questions associated with the renewable development on Lewis.

Final remarks

It is clear that substantial network investment will be required to facilitate the substantial increases in renewable generation required to deliver 2020 targets. It is also clear that substantial uncertainty regarding generation location remains and this has a major impact on the level of network investment required, particularly for enabling transfers from Scotland to England.

Furthermore traditional approaches to determining the necessary level of network investment to accommodate new generation, which are peak based, are not ideally suited to assessing the requirements imposed by substantial new volumes of wind generation – indeed some key assumptions within the existing deterministic SQSS based investment approach are subject to challenge and currently are under formal industry review. Thus the use of cost benefit analysis (CBA) modelling techniques is regarded as a more appropriate approach; but it inevitably places strong focus on both the robustness of the CBA methodology and assumptions adopted. KEMA's view is that based on market data and evidence it has compiled, the CBA analysis and underlying assumptions as used overstate the requirement for network capacity across Boundary B6.

KEMA's final three observations are:

1. That these conclusions regarding the certainty of need and timing of the proposed TPCR4 network investments will not impact the ability of renewable generation needed to connect by 2020, i.e. it will not delay or increase the cost of connecting.

2. Excluding other potential barriers (planning restrictions etc.), KEMA believes the forecast level of renewable generation required to meet 2020 targets can be connected in Great Britain by 2020 but that this does not necessarily require the proposed level of additional transmission network investment as submitted to Ofgem for additional funding (particularly during TPCR4), in order to do so in an economic manner.

3. Given the anticipated implementation of an enduring Connect and Manage approach to transmission access, where there is high uncertainty over the need and/or timing for major transmission reinforcement investments, any decision to postpone proposed investments; if subsequently demonstrated to be necessary in light of generation developments;

    a. Will not delay the connection of renewables generation; and

    b. Subject to appropriate ex-ante consideration of potential constraints costs, represents the least regret approach from a consumer cost perspective compared to the alternative of premature commitment to major network investments.

1 INTRODUCTION

Under the GB Transmission Access Review jointly conducted by Ofgem and the Department of Energy and Climate Change (DECC), the Transmission Access Review[1] (TAR) Final Report proposed the introduction of enhanced transmission investment incentives to encourage the GB Transmission Owners (TOs) to invest ahead of signalled need by anticipating future demand for connections to their networks and investing efficiently to ensure timely delivery of capacity. This proposal is being taken forward by Ofgem through its work on enhanced transmission investment incentives (the TO incentives project)[2].

Complementing this work, Ofgem also asked the TOs to undertake a joint study, overseen by the Electricity Network Strategy Group (ENSG) to identify the future reinforcements likely to be needed to accommodate the likely increase in renewable and conventional generation by 2020. Through this work[3], published in summary form in March 2009, and later in full in July 2009, the TOs have put forward proposals for c. £5.5bn of investment, a significant proportion of which is currently proposed to commence construction within the current price control period. In the context of the ENSG work and Ofgem's work on TO incentives, the TOs have sought additional funding for this investment, above the existing price control allowances. In September 2009, as part of it's enhanced TO incentives work, Ofgem issued a consultation document providing details of these TO funding requests[4].

To support Ofgem in the identification and development of appropriate funding arrangements for relevant projects; Ofgem sought an independent review of (a) the overall robustness of the system-wide system development plan jointly produced by the TOs to facilitate the achievement of the Government's 2020 targets, and (b) the justification for proceeding with and the forecast capital expenditure of relevant projects, particularly those that are proposed to commence construction during the current price control period. This complements work being separate work being undertaken to assess the deliverability, design and costs of the individual schemes.

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1 Documents available at: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx

2 See the following documents available at the link in footnote 1:
"Transmission Access Review – Initial Consultation on Enhanced Transmission Investment Incentives", Ofgem (175/08), 19 December 2008
"Transmission Access Review - Enhanced Investment Incentives Open Letter: Consultation on Short Term Measures", Ofgem (12/09), 27 February 2009
"Transmission Owner Incentives Licence Modification – Decision letter", Ofgem, 31 March 2009

3 Documents available at: http://www.ensg.gov.uk/index.php?article=126

4 Transmission Access Review – Enhanced Transmission Investment Incentives: Update and Consultation on Further Measures", Ofgem (110/00), 8 September 2009

KEMA's work commenced in September 2009 and has considered additional information provided by the TOs during the project. KEMA's analysis progressed further after release of Ofgem's Initial Proposals document in November 2009[5], which reflected KEMA's initial findings and thinking at that time. Preliminary final findings were presented at a Stakeholder Workshop held on 7 December 2009[6]; and these were further refined in the light of subsequent TO feedback to produce the final findings as detailed in this Report, It is recognised that the TOs intend to provide further project information to Ofgem in future. This final report documents the assessment undertaken by KEMA including analysis of the additional TO information provided after the Initial Proposals document; and final TO feedback received following the Stakeholder Workshop.

Finally, it is important to note that at the time of this KEMA assessment work both KEMA and the TOs were operating under the understanding that TPCR5 would commence in 2012/13. Whilst this Report has been issued shortly after the Ofgem announcement to extend TPCR4 by one year – the analysis and commentary provided in this Report reflects the understanding of KEMA and the TOs during the period of information submissions and assessment and is retained on the basis of this TO and KEMA understanding (although some clarifications for the reader are provided where felt necessary).

[5] "Transmission Access Review – Enhanced transmission Investment Incentives: Initial Proposals (135/09)", issued 3 November 2009

[6] KEMA's slides and those of Ofgem, the TOs and PB Power can be found at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=181&refer=Networks/Trans/ElecTransPolicy/tar

2 SCOPE OF THIS REPORT

Ofgem is seeking an independent review of the TOs' proposed investment to facilitate the achievement of the Government's 2020 targets for renewables. The review is to be conducted at two levels; specifically a review of the overall plan and a detailed review of the component schemes. KEMA has been commissioned to undertake the review of overall robustness of the system-wide system development plan jointly produced by the TOs, namely National Grid Electricity Transmission (NGET), SP Transmission Ltd (SPTL) and Scottish Hydro Electric Transmission Ltd (SHETL). Within this assessment Ofgem has tasked KEMA to conduct an assessment of:

- The key assumptions underlying the determination of need for transmission capacity and the reasonableness of these assumptions, including a comparison against the current level of user commitment for connecting to and accessing the transmission network;

- The range of uncertainties that the TOs took into account when evaluating the need for transmission capacity, the relative weighting given to such uncertainties, and the way such uncertainties were taken into account in the investment plan;

- The fundamental guiding principles of the investment plan, for example the role of the deterministic planning criteria of the Standard of Quality and Security of Supply vs. the consideration of cost-benefit analysis; one-off investment cost against life-time operational costs; optimisation against a range of scenarios vs. keeping options open for uncertain future;

- The appropriateness of the evaluation methodology of all the key cost elements;

- The adequacy of considering alternative investment and/or operational measures to accommodate the same increase in users' need; the representation of all efficient measures available in operational timescale and the evaluation of effectiveness and/or risks associated with credible operational alternatives;

- The coherence of the system-wide solution, in particular, whether and how important inter-dependencies between individual investment projects are addressed in TOs' investment plan.

In this context, this Report documents KEMA assessment of the TOs proposed system-wide investment plan; and the Report is structured as follows:

- **Section 3**: describes KEMA's approach to the assessment covering both the process it followed and the information on which its assessment was based.

- **Section 4**: provides an overview of KEMA's high level assessment of the component schemes within the investment plan, providing (a) details of the schemes themselves including costs, deliverables and key dependencies/interactions; and (b) KEMA's views on the certainty of requirement, reasonableness of scope, certainty of timing, and cost effectiveness of each scheme.

- **Section 5**: details KEMA's assessment of the overall modelling approach adopted by the TOs; the development and use by the TOs of key underlying assumptions and inputs details KEMA's assessment of the overall robustness of the investment plan covering (a) review of the TOs' consideration of future uncertainties as well as alternative investment and non-investment options and (b) review of the interactions between schemes and/or TOs; and the coherence of the system wide plan

- **Section 6**: details KEMA's review and assessment of the Cost Benefit Assessment (CBA) modelling exercise conducted within the ENSG work and used as the basis for determining the relative merits, need and timing of the three boundary B6 related reinforcement options. These three B6 related reinforcement options represent the most interactive schemes within the TOs proposals for additional funding and also represent a significant proportion of the proposed TO investments. This assessment includes identification of key assumptions underpinning the CBA modelling and assessment of the sensitivity of the CBA modelling outcomes to potential different views/values of these assumptions.

- **Section 7**: provides KEMA's view of three key ongoing regulatory/market processes which may have an impact of the level of investments proposed by the 3 GB TOs. These are the GB SQSS Review, the GB Transmission Access Review; and the RPI-X@20 Review.

- **Section 8**: provides KEMA's conclusions from its assessment as discussed in Sections 4 to 6; and consequent recommendations for Ofgem in relation to the overall need, scale, phasing of the plan and thus implications for Ofgem funding of plan.

- **Appendix A (Section 9)**: details KEMA's high level assessment of the component schemes within the investment plan, as underpinning the overview provided in Section 4.

3 APPROACH TO ASSESSMENT

KEMA adopted a similar assessment approach to review of the overall plan produced by the ENSG and the component schemes (at a high level) as would be adopted within a Price Control Review process. An outline of the process followed by KEMA is provided below:

- Firstly, KEMA undertook a comprehensive review of the information relating to the system-wide system development plan jointly produced by the GB Transmission Owners (TOs) to facilitate the achievement of the Government's 2020 targets, which formed the basis of submissions to Ofgem for additional TO funding to finance the proposed investment schemes. This information consisted of:

  - Information contained within the ENSG document 'Our Electricity Transmission Network: A Vision for 2020' (full Report, issued July 2009),

  - Information contained within the Ofgem document "Transmission Access Review – Enhanced Transmission Investment Incentives: Update and Consultation on Further Measures", (issued 8 September 2009), and

  - Data provided directly to Ofgem by the TOs relating to the proposed investment schemes before commencement of the project.

- Secondly, based on this initial information review, KEMA identified a number data/information requests and clarification questions regarding:

  - The overall investment plan and how it was developed; and

  - Key aspects of individual component investment schemes.

  The questions were prioritised with some requiring responses within short timescales prior to the TO clarification meetings on 7 and 8 October 2009; and those where responses were to be provided before 12 October 2009, i.e. shortly after the TO clarification meetings.

- Thirdly, as indicated above, KEMA (with Ofgem and PB Power) met each of the TOs to discuss both the overall investment plan and the component schemes. KEMA's focus at these meetings was to obtain TO perspectives on how the need, scope and timing of component schemes and the overall plan were identified. KEMA also wished to explore TOs views on key dependencies and interactions of the investment schemes within the proposed overall investment plan.

- Straddling these first TO meetings, KEMA engaged in a Q&A process with the TOs (conducted via Ofgem) to obtain further information, confirm KEMA's understanding and to ensure an informed assessment of the proposed investment plan. Where necessary KEMA engaged bilaterally with the TOs subsequent to the initial TO meetings to help facilitate this.

Alongside this Q&A process, KEMA conducted its assessment and steadily evolved its observations and conclusions which form the basis of this report. It should be noted that KEMA's analysis progressed further after release of Ofgem's Initial Proposals document in November 2009[7]. Furthermore KEMA presented its preliminary final findings at a Stakeholder Workshop on 7 December 2009 and these were further refined in the light of TO feedback at that Workshop and shortly after. As such this Final Report reflects a process of engagement and dialogue between the TOs and KEMA which has been ongoing since project commencement in September 2009.

[7] "Transmission Access Review – Enhanced transmission Investment Incentives: Initial Proposals (135/09)", issued 3 November 2009

4 REVIEW OF COMPONENT SCHEMES

In this Section KEMA provides an overview of its assessment of the individual schemes. A key assumption within this Section is that relevant Transmission Investment for Renewable Generation (TIRG) works, in particular the upgrading of the Beauly-Denny route in the SHETL network (currently awaiting final approval from the Scottish Government), will be consented and constructed as planned.

In this Section, KEMA provides an overview of the assessment undertaken for the 18 individual schemes. A more comprehensive coverage of the schemes and the associated scheme assessment results, observations and conclusions is provided in **Appendix A.** This Section therefore provides:

- An overview of the schemes – using charts to illustrate both their location and other key features which are apparent when the schemes are viewed collectively; and

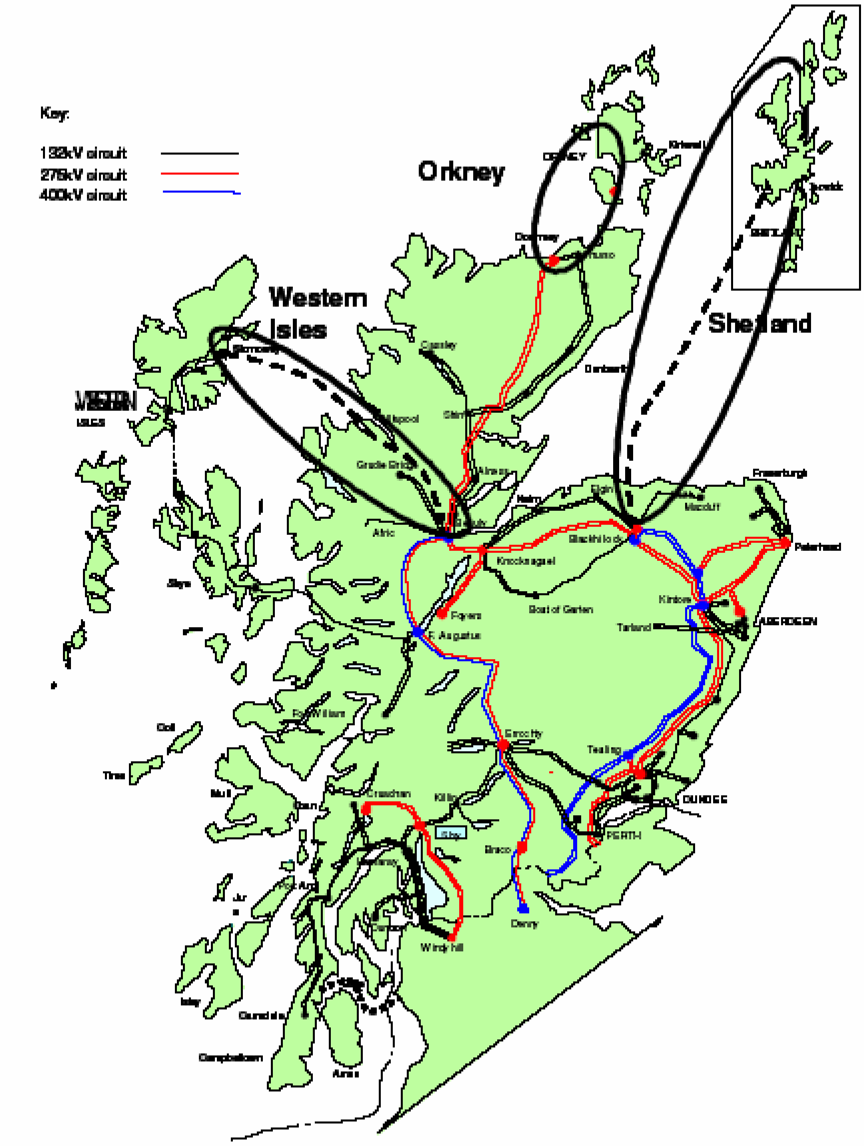
- An overview of KEMA's assessments – using two tables to collate the individual scheme details; and KEMA observations.

4.1 Illustrative overview of proposed schemes

This Section provides an overview of the transmission network extensions and reinforcements identified by the GB TOs for additional funding. The four diagrams provide in this section incorporate the core, Scottish island links, SHETL's and SPTL's networks and the Main Interconnected Transmission System in England and Wales respectively. These diagrams highlight the extensive nature of the schemes) and their diverse locations across the GB transmission network.

The general objective of the broad portfolio of network investments is to enable substantial enhancements in north to south power flows from the northernmost and outer-lying parts of the GB network towards the major demand centres in England including London and the south east. The underlying investment driver for 2020 is the anticipated portfolio and pattern of generation required to meet the Government targets for renewables. Much of this new renewable generation will consist of wind generation and will be located in northern and outlying parts of the GB network both onshore and offshore.

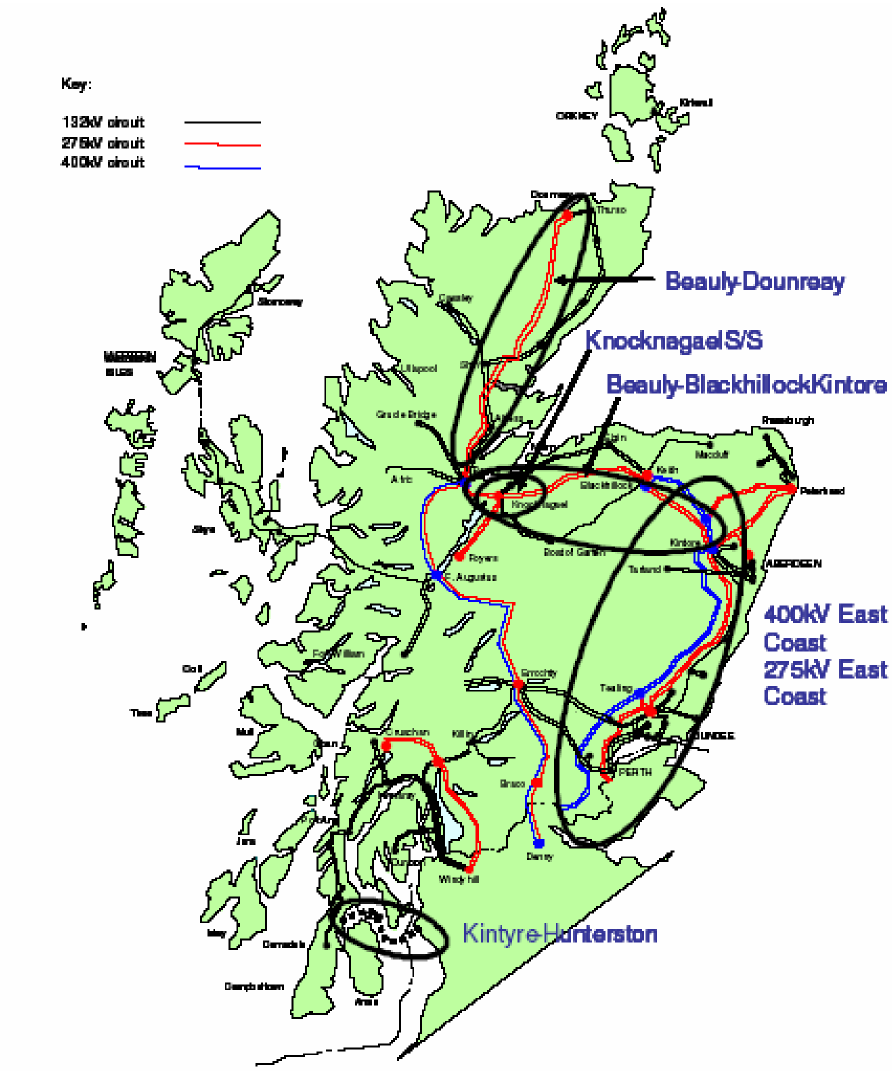
Figure 6 - Proposed Scottish network reinforcement schemes – island links



Source - the Full ENSG Report “Our Electricity Transmission Network: A Vision for 2020”, published July 2009

It can be seen there are three island link schemes proposed in Scotland, one to the Western Isles, one to the Shetland Islands each of which would employ subsea HVDC links and one to the Orkneys which would employ a subsea AC link. The Orkney scheme has not been submitted by SHETL and thus is also not considered in this report.

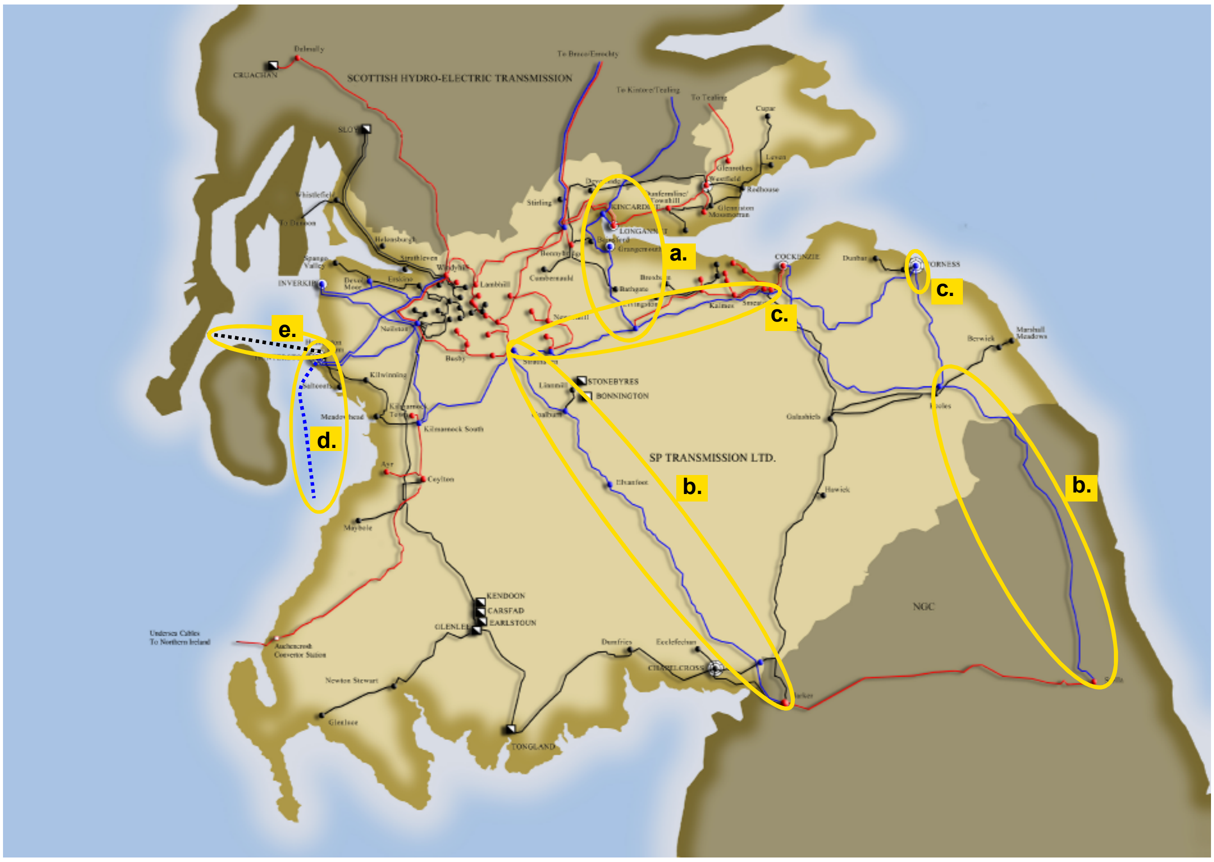
Figure 7 - Proposed Scottish network reinforcement schemes - core network (SHETL)



Source - the Full ENSG Report “Our Electricity Transmission Network: A Vision for 2020”, published July 2009

It can be seen the bulk of the network schemes are to reinforce the lateral and eastern legs of the northern Scotland transmission ring and radial reinforcements onto the ring running from Dounreay in northernmost Scotland along the eastern coast of Scotland down towards England. In addition, the above diagram shows the proposed linkage of the southern end of the Kintyre peninsula to the mainland Scottish transmission network. The diagram does not show the proposed East-West upgrade works which would impact on the circuits between Strathaven and Cockenzie in the SPTL region (this route is visible on the diagram for SPTL network reinforcements Figure 8 as provided below).

Figure 8 - Proposed Scottish network reinforcement schemes - core network (SPTL)



Source – SPTL, Dec 2009

The above diagram illustrates the network reinforcements within the SPTL region namely:

a. SPTL element of East Coast upgrade work (remainder is within SHETL region as shown in Figure 9 for SHETL core reinforcement works);

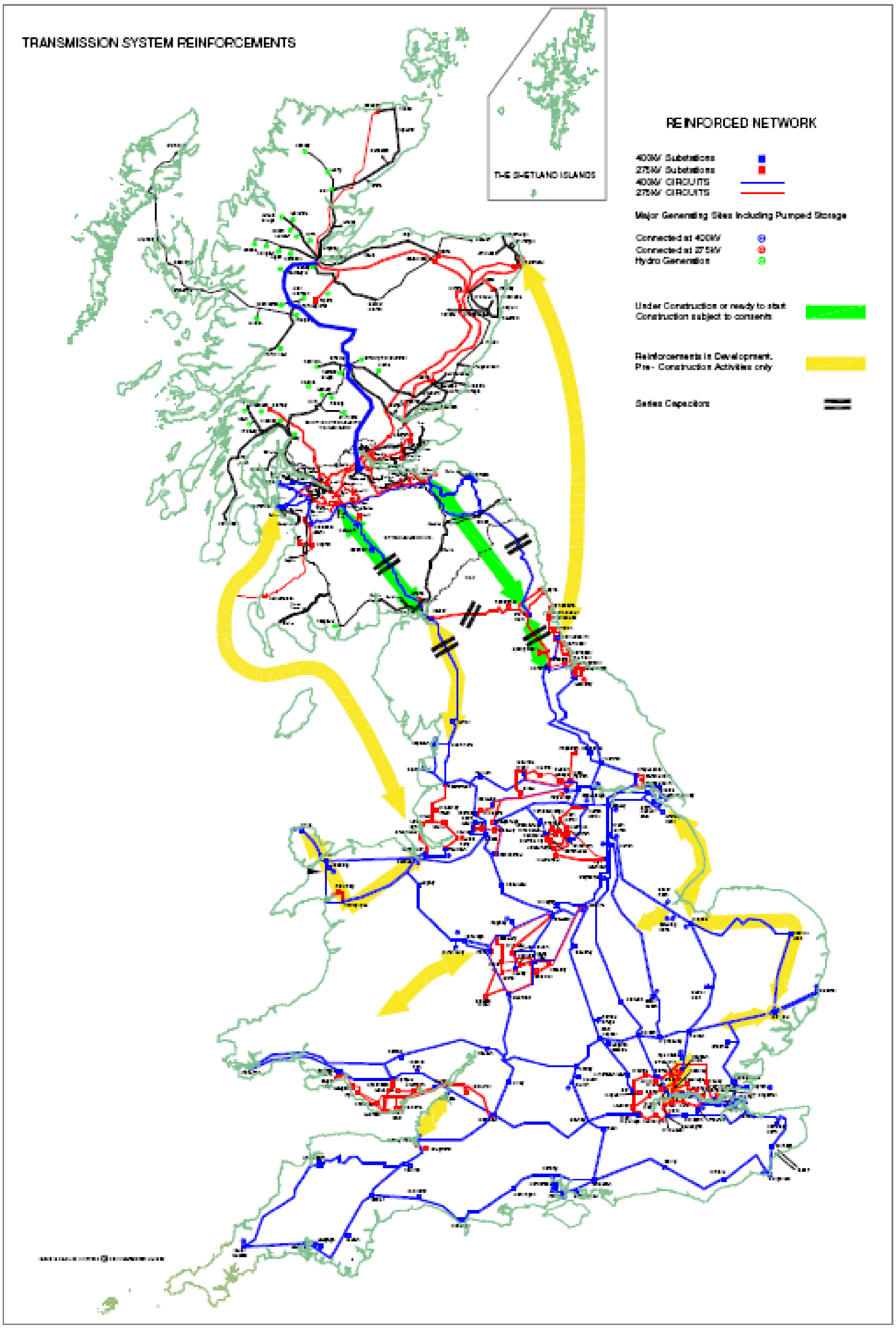
b. Series compensation on each of west and east circuits of the existing Scottish interconnector circuits;

c. East-West upgrade scheme;

d. Western HVDC link; and

e. Hunterston-Kintyre link (joint project with SHETL who are lead party and thus is shown in diagram for SHETL island links).

Figure 9 - Proposed England & Wales schemes - inc. cross border reinforcement



Source - the Full ENSG Report “Our Electricity Transmission Network: A Vision for 2020”, published July 2009

The above diagram highlights the range of schemes across the England & Wales network but that the major proposed reinforcements relate to improving cross-border transfer capability between Scotland and England, and the predominant focus on reinforcement of the eastern side of the NGET network to enable increased power flows from new generation to southern demand centres and London in particular.

It should be noted that the link between Scotland and England off the east coast (the Eastern HVDC link (see Appendix A Section 9.17)) has only been included for pre-construction funding as it is regarded as the third step of a potential 3 step expansion process to enhance Scotland-England transfer capability and the TOs regard the timescales for construction of this link as reasonably distant. However, evaluation of this scheme has taken place as it is valid as a potential alternative to the equivalent west coast scheme (the Western HVDC link (see Appendix A - Section 9.9). The Western HVDC link is the TOs preferred option for which additional construction related funding is being sought.

Furthermore for two of the schemes; namely the Scottish East Coast upgrade, and the Eastern HVDC link, are nominally joint TO schemes involving SHETL and SPTL. However, only the scheme partners (SPTL and NGET respectively) submitted requests to Ofgem for the funding of these schemes. This reflects the fact that these schemes would incur no expenditure in TPCR4 for SHETL and the position that SHETL has clearly stated is that it does not engage in anticipatory network investments and they would have sought to put forward the request for capex within the TPCR5 process. In this review KEMA requested the full costs of these schemes including SHETL costs as this is required to undertake a proper assessment of the schemes.[8]

There are two potential variants of HVDC link to Shetland (as discussed in Section 9.18) which have different costs and it remains unclear at the time of this report which variant SHETL will pursue. Thus Shetland costs are not included in the Table 5 or the summary/comparison charts (Figures 9 to 11) but we note the likely impact/position of Shetland for each.

[8] KEMA notes there is a potential issue for Ofgem here in that if part of the scheme as required by another TO was granted additional funding then by default SHETL might subsequently obtain funding by default on the basis its works are needed to complete and provide the full benefits of the complete joint scheme without having previously undergone the same level of review; and/or without the scheme as a whole have been properly reviewed.

An overview of the scheme costs (excluding Shetland) including annual phasing of pre-construction (purple shading) and construction costs (blue shading) is provided below in Table 5 below.

Table 5 - Scheme Phasing of Pre-Construction and Construction Costs

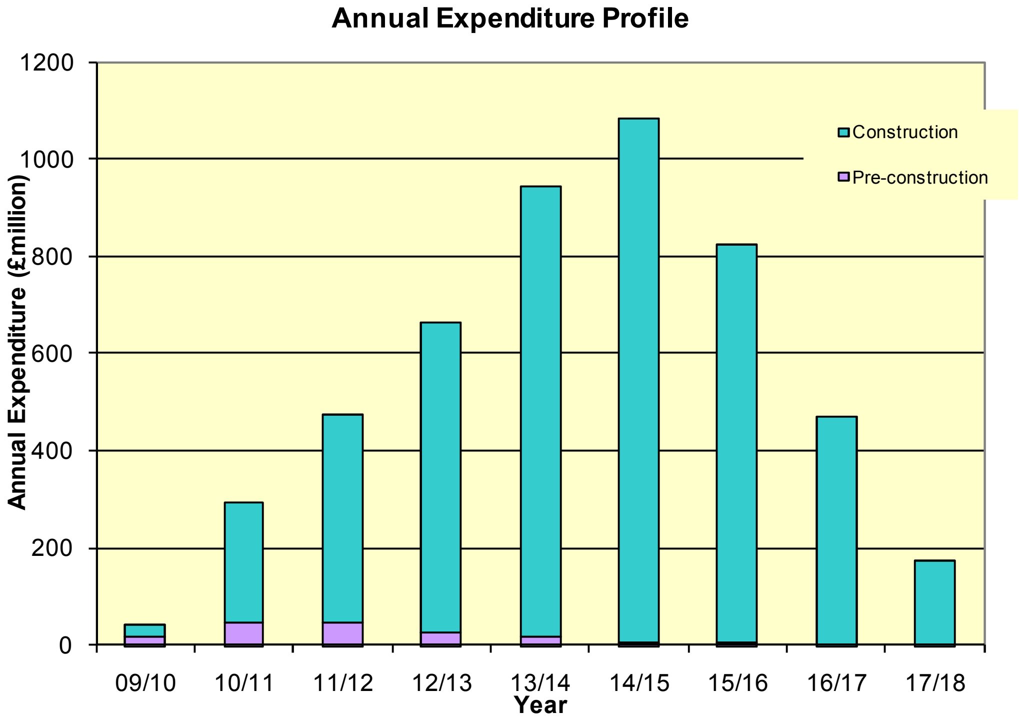
Project Name	TO(s)	Cost £m - see notes	Price Base used	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Knocknagael	SHETL	0.0	2009/10									
		41		6	25	10						
Western Isles link (incl. Lewis infrastructure)	SHETL	0.3	2009/10	0.3								
		302		9	106	108	67	11				
Beauly-Blackhillock-Kintore	SHETL	2.3	2009/10	1.2	1.1							
		81		5	13	3	11	36	12			
East Anglia	NGET	15.1	varies by cost element	3	5.9	3.2	3					
		353		2	35	73	58	55	62	54	14	
Beauly-Dounreay	SHETL	1.2	2009/10	1.2								
		71			21	24	26					
Hunterston-Kintyre link	SHETL/SPTL	1.4	2009/10	0.9	0.3	0.2						
		122			23	35	37	28				
SPTL-NGET interconnection	SPTL	3.1	2008/09	0.5	0.6	2						
		85			5	15	27	27	11			
Anglo-Scottish incremental	NGET	11.3	2008/09	0.8	5	4.5	1					
		171				47	73	43	8			
Western HVDC link	NGET/SPTL	26.3	2008/09	5.6	11.3	9.4						
		779			20	72	147	233	216	91		
East Coast upgrade	SPTL/SHETL	4.7	2008/09	0.3	1.2	2.1	0.2	0.7	0.2			
		248				7	24	70	64	44	25	15
East-West upgrade	SPTL	2.6	2008/09	0.2	0.5	1.9						
		80				8	14	24	24	10		
London	NGET	7.1	2008/09	0.1	3	2				2		
		179				4	52	70	43	9		
North Wales	NGET	25.9	2008/09	1.3	7.0	7.2	7.4	3				
		418				23	78	117	110	70	20	
Central Wales	NGET	6.5	2008/09	0.5	1.2	1.8	2	1				
		251					15	80	91	65		
South West	NGET	12.5	2008/09	0.7	2.7	2.1	3	2.5	1.5			
		273					8	90	110	55	10	
Humber	NGET	18.0	2008/09	0.3	2	3.7	7	5				
		535						45	175	175	140	
Eastern HVDC link	NGET/SHETL	11.6	2008/09	0.4	1.5	4.4	1.3	2.0	2.0			
		817							153	248	258	158
Total		**4955**		39	290	470	661	940	928	575	209	0
Total pre-construction		**149.8**		17	43	44	25	14	4	2	0	0
Total construction		**4805**		22	248	430	637	928	1079	821	467	173

Notes:
1- for joint projects, costs are combined costs of both TOs
2 - for the East Coast upgrade, costs are quoted for both SPT and SHETL (even though SHETL has not requested any funding at this point in time)
3 - for the Eastern HVDC link, costs are quoted for both NGET and SHETL (even though SHETL has only partially requested pre-construction funding at this point in time)
4 - for some projects, the quoted costs reflect a mix of different price bases for different cost elements, common inflation assumptions to be agreed

It can be seen the total costs of the proposed schemes amounts to £4.955bn comprising £150m of pre-construction costs and £4.805bn of construction costs across the period 2009/10-2017/18. If the Shetland scheme were included in either form; i.e. HVDC link with or without offshore hub; the overall total would rise to £5.503bn-£5.634bn, comprising £151m of pre-construction costs and £5.353bn-£5.484bn of construction costs

When aggregated together, the profile for the proposed package of transmission investments from all TOs is illustrated in Figure 10 below:

Figure 10 - Aggregate investment profile for all schemes proposed by the TOs



In aggregate, significant capex requirements are being forecast in the early to middle years of TPCR5 (which at the time of KEMA's work was assumed by all parties to commence in April 2012. However, very shortly before KEMA issued this Report (21 December 2009), Ofgem announced that TPCR5 will now commence in April 2013 following a 1 year extension of TPCR4 to ensure alignment of TPCR5 with the conclusions of the ongoing RPI-X@20 Review due to complete in late 2010[9]. As all TO submissions and KEMA analysis was conducted on the prior understanding/basis that "normal" TPCR periods were in force; KEMA believes it is not appropriate to change this basis of the analysis in this Report to reflect the new TPCR4 and TPCR5 periods but will clearly highlight where it refers to each that these relate to the prior understanding/basis i.e. TPCR4 would run until 2011/12 and TPCR5 would commence from 2012/13.

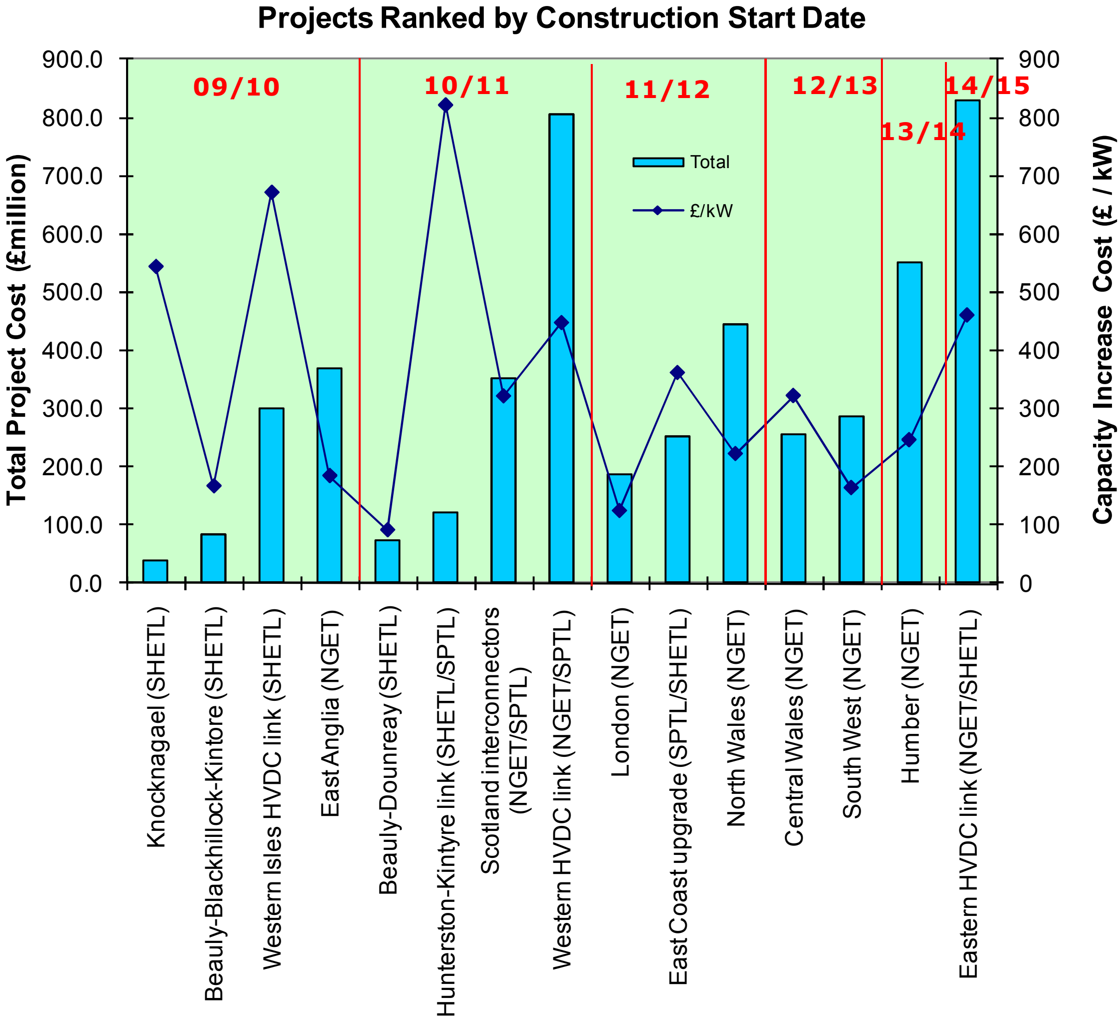
[9] The formal letter published by Ofgem announcing this can be found at http://ofgem.gov.uk/Pages/MoreInformation.aspx?docid=11&refer=Networks/Trans/PriceControls/TPCR5

2014/15 shows the peak annual expenditure. Inclusion of Shetland scheme would add in excess of £100m per annum over the period 2010/11-2013/14 (c.£200m in 2012/13) and would align 2013/14 total costs with those of 2014/15.

Although funding for preconstruction activities are sought during the TPCR4 period, a large proportion of expenditure will fall during the TPCR5 period. Consequently, where the need, timing and thus need for funding of the schemes is uncertain this highlights that some expenditure may need to be assessed within the TPCR5 investment assessment process (and following Ofgem recent announcement also within assessment undertaken for determining the TO allowances for the TPCR4 one year extension) when the certainty associated with the need for the investment might be better understood.

The charts below (Figure 11 to Figure 12) provide other perspectives of the schemes; namely (i) an overview of the absolute cost and the corresponding unit cost relative to the incremental network capacity provided for each scheme (this is calculated on a £/kW basis by dividing scheme costs by the capacity provided across the key constrained boundary; and thus may not capture all the benefits provided by the investment); and (ii) a ranking of scheme by proposed expenditure in the TPCR4 period up to 2011/12 (given this was the understanding of all parties of the TPCR4 period at the time of this work). In the chart; due to their inter-linkage, three schemes (i) SPTL-NGET interconnection; (ii) Anglo-Scottish incremental works; and (iii) East-West upgrade, have been combined under the heading “Scotland Interconnectors” as they form the core part of an integrated package of network reinforcements to deliver an additional 1100MW of transfer capacity across Boundary B6 (the Scotland-England border).

Figure 11 – Forecast project costs and corresponding £/kW costs of network capacity



Putting aside the need case for the above schemes; as clearly this will always be the first part of any assessment of their individual merits; this chart provides a very simple high level indication of the cost of network capacity in £/kW terms being delivered by the schemes as well as their overall cost.

It can be seen that some early SHETL schemes appear expensive in £/kW terms. For Knocknagael this is because the £/kW measure does not reflect the benefit nor the underlying purpose of the scheme which is to provide operational flexibility and to precede network developments connecting into Knocknagael For others, such as the Western Isles link and the Hunterston-Kintyre link, costs are primarily driven by generation location and the corresponding network solutions to enable exports to the wider network. Some schemes provide capacity benefits across more than one boundary. Nonetheless these £/kW numbers highlight the potential need for greater scrutiny of the costs and benefits of schemes and their network capacity additions when undertaking the need analysis.

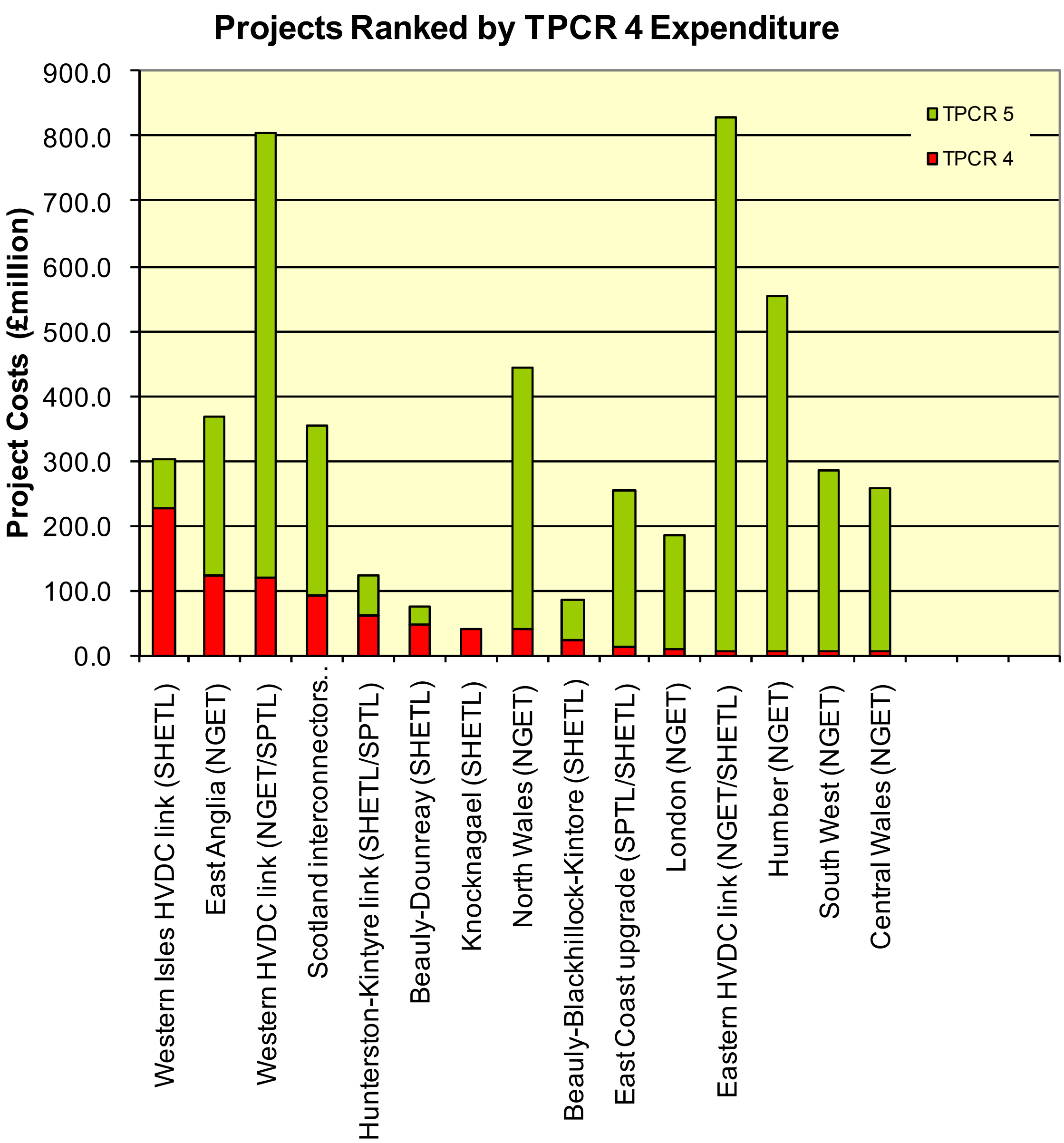
The largest schemes in absolute cost terms have been proposed by NGET (either individually or as lead part) and are generally towards the end of the 2010-2020 period. Whilst these proposed investments are large in absolute terms, these appear more cost effective in releasing capacity than some earlier smaller schemes in simple £/kW terms. However the Western HVDC link £/kW is high. Thus the key issue in terms of considering the approval of anticipatory funding for these schemes is the degree of uncertainty regarding investment need and timing (e.g. based on generation assumptions and key modelling assumptions).

Noting the three possible options for expanding Scotland-England transfer capacity across Boundary B6; the chart indicates that in terms of priority of implementation, the Scottish Interconnector upgrade scheme(s) would appear to the preferable first choice versus either offshore HVDC link in terms of overall and average cost. This observation remains valid if East Coast upgrade costs are included. The (Scottish) East Coast upgrade, as indicated by NGET, should also be considered within these B6 reinforcements and was included as one of an integrated 4 scheme option entitled “Incremental Upgrade” which is viewed by the TOs as the preferred expansion option for boundary B6.

Finally, either variant of the Shetland scheme i.e. HVDC link with/without offshore hub, would represent one of the largest schemes at £548m (link) or £679m (with hub) and would be the most expensive in £/kW terms at £913/kW or £1132/kW respectively.

The chart below (Figure 12) shows project ranked by expenditure they propose to incur in TPCR4 up to 2011/12 (given this was the understanding of all parties of the TPCR4 period at the time of this work). It should be noted that (a) both pre-construction costs and construction costs are included in this chart and (b) the indicated TPCR4 funding represent the level of additional funding that is being sought by the TOs and has not yet been granted by Ofgem.

Figure 12 - Proposed scheme costs ranked by materiality of proposed TPCR4 investment



In total, c. £800m of additional funding (comprising pre-construction and construction costs) has been identified for the current TPCR4 period. It can be seen that there is TPCR4 expenditure (for the "normal" TPCR period up to 2011/12) associated with each of SHETL's 5 schemes (totalling c. £411m) with the largest scheme contribution arising from the proposed Western Isles link scheme (£224m). However, there is also significant proposed expenditure during TPCR4 (up to 2011/12) arising from NGET led schemes (c.£350m) which principally arises from three schemes, [i.e.] the East Anglia scheme (£122m), Western HVDC link

(£118m) and their part of the bundled Scottish Interconnector scheme (c.£60m attributed to NGET). The remaining c. £40m relates to SPTL's Scottish Interconnector schemes.

If included in Figure 11 above, either variant of the Shetland scheme would require most additional funding for construction within the remaining "normal" TPCR4 period (i.e. 2010/11-2011/12) seeking c.£240m (link) or £310m.

4.2 Overview of KEMA's assessment of proposed schemes

Appendix A provides detailed coverage of the 18 proposed individual schemes which have been put forward by the 3 GB TOs for additional funding to facilitate the achievement of the Government's 2020 targets for renewables. This Section provides a summarised overview of each scheme and KEMA's assessment of them. Thus in this Section, we provide two tables which respectively provide:

- **Table 6: a summary overview of the proposed schemes** – covering (a) scope; (b) cost; (c) timing; (d) indicated network capacity benefits; (e) critical drivers/dependencies; and (f) interactions with other schemes

- **Table 7: KEMA's assessment of the proposed schemes** – covering (a) certainty of need; (b) reasonableness of scope; (c) certainty of timing; (d) cost effectiveness (in terms of provision of capacity across the primary targeted network boundary).

Within the summary tables it should be noted that KEMA has clustered together four schemes relating to expansion of the Scotland-England transfer capacity across Boundary B6, as these have been indicated by the TOs to represent a collective (and interactive) solution delivering 1100MW additional transfer capacity to Boundary B6 under the title "Incremental Upgrade" within NGET's CBA exercise (as discussed in Section 6). The four schemes are:

- SPTL's SPTL –NGET interconnection (Appendix A - Section 9.7);

- NGET's Anglo – Scottish incremental works (Appendix A - Section 9.8);and

- SPTL's East-West upgrade scheme (Appendix A - Section 9.10).

- SPTL/SHETL's East Coast upgrade scheme (Appendix A - Section 9.11)

KEMA has structured the tables such that all these four proposed 1st stage “B6 expansion” related schemes can be viewed together. Thus additionally the two offshore HVDC options are also brought together as these are essentially viewed to be competing options for 2nd and 3rd stage expansion of Boundary B6 transfer capability. Thus all NGET schemes only relating to the England & Wales transmission network follow these “B6 expansion” schemes in order of proposed scheme commencement.

In Table 7 KEMA uses a 5 step traffic light colour coding to clearly indicate its view of (i) certainty of need; (ii) reasonableness of scope; (iii) certainty of timing and (iv) cost effectiveness with at one extreme a green dot (●) representing “high/strong” and at the other, a red dot (●) representing “low/weak”.

Table 6 – Summary overview of Proposed Schemes

Scheme (Proposer)	Scope	Cost (to £m)	Timing (Constrn)	Benefit/capability provided	Critical drivers and dependencies	Interaction with other schemes
Knocknagael (SHETL)	New 275kV substation	£41m (09/10 prices)	09/10 - 11/12	75MW of capacity across B1. Operational flexibility	Inverness growth north west Scottish renewables	None
Western Isles HVDC link (SHETL)	450MW HVDC link between Western Isles and Beauly	£302m (09/10 prices)	09/10 – 13/14	450MW of export capacity from Western Isles to mainland Scotland	Both the scale and timing are critically dependent on expectation for generation	Generation export driving need for BBK reconductoring
Beauly-Blackhillock-Kintore uprating (SHETL)	Reconductoring along route	£83m (09/10 prices)	09/10 – 14/15	500MW of additional transfer capacity across B1	The volume of generation connecting in north west Scotland	Additional export capability to Beauly provided via the Western Isles and Beauly-Dounreay schemes partly drive the requirement. Some dependency of BK element on Shetland and more localised generation developments
Beauly-Dounreay uprating (SHETL)	2nd circuit on route plus Dounreay upgrade	£72m (09/10 prices)	10/11 – 12/13	100MW of transfer capacity across boundary B0 and 800MW across boundary B1	Volume of generation connecting above boundary B1 in locality of Dounreay	Feeds into need for BBK reconductoring
Hunterston-Kintyre link (SHETL/ SPTL)	150MW HVDC link	£123m (09/10 prices)	10/11 – 13/14	150 MW export capacity from southern Kintyre to main Scottish network	Driven by volume of proposed generation (156MW by 2012; 121 thereafter by 2020)	None – stand alone

Scheme (Proposer)	Scope	Cost (to £m)	Timing (Constrn)	Benefit/capability provided	Critical drivers and dependencies	Interaction with other schemes
SPTL-NGET interconnection (SPTL)	Installation of series compensation	£88m (08/09 prices)	10/11 – 14/15	These schemes in combination are indicated to provide 1.1GW further transfer capability across boundary B6. As part of an integrated approach these schemes cannot be simply uncoupled to provide smaller incremental transfer capability expansion for B6	Schemes depend on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) wind capacity driven transmission requirements. Key justification provided by cost benefit analysis (CBA) of scheme costs (alongside the East Coast upgrade scheme in 9.11) versus reduced constraints costs.	These schemes are explicitly linked by SPTL and NGET. Individual scheme designs are interactive. Another boundary B6 upgrade scheme (East Coast upgrade - 9.11) could be viewed as competing option to expand boundary B6 capability with potential offshore HVDC links (see Appendix A Section9.9 and/or 9.17). SHETL schemes (see Appendix A section 9.1-9.3 and 9.5-9.6) and SPTL/SHETL East Coast upgrade scheme (See Appendix A Section 9.11) and consequent increased generation flow south underpin requirement for scheme.
Anglo-Scottish incremental works (NGET)	Installation of series compensation	£182m (08/09 prices)	11/12 – 14/15			
East-West upgrade (SPTL)	New u/g cable and the voltage of the northern side of the Strathaven-Wishaw-Kaimes double circuit overhead line route, from 275kV to 400kV	£83m (08/09 prices)	11/12 – 15/16			

Scheme (Proposer)	Scope	Cost (to £m)	Timing (Constrn)	Benefit/capability provided	Critical drivers and dependencies	Interaction with other schemes
East Coast upgrade (SPTL/SHETL)[1]	Uprating Kintore - Kincardine line - Harburn line; from 275kV to 400kV building new 400kV substations at Kincardine, Grangemouth and Harburn; upgrading of Blackhillock-Kintore route; new substations at Rothienorman and Aylth and upgrading of Blackhillock and Kintore substations	£253m (08/09 prices)	11/12 – 17/18	In isolation it is indicated to provide 700MW extra capability across B4, 450MW across B5 and 250MW across B6. However for B6, there is an interaction with the SPTL and NGET series compensation schemes and also the East-West upgrade scheme (e.g. via the Torness-Eccles constraint) which may mean that the benefits of this scheme with respect to B6 evaporate.	Scheme depends on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) associated SHETL schemes (Appendix A Section 9.1-9.3 and 9.5-9.6), (iii) associated SPTL/NGET led schemes (Appendix A Section 9.7, 9.8 and possibly 9.10) (iv) subsequent behaviour of conventional generation at Peterhead and (v) wind capacity driven transmission requirements.	In order to be effective this scheme requires a number of schemes in southern Scotland /Northern England (Appendix A Section 9.7, 9.8, and 9.10) to be completed. It will also require reconductoring between Beauly and Blackhillock (Appendix A Section 9.3) and the northern end of this East Coast upgrade (Appendix A Section 9.11). There is possible interaction with the Eastern HVDC link (Appendix A Section 9.17); which could be considered to be an alternative way of increasing power transfer capacity between northern and southern Scotland. Requires (unsubmitted) additional SHETL part of scheme to uprate circuits between Kintore and the SHETL/SPTL boundary.

Scheme (Proposer)	Scope	Cost (to £m)	Timing (Constrn)	Benefit/capability provided	Critical drivers and dependencies	Interaction with other schemes
Western HVDC link (NGET/ SPTL)	1800MW offshore HVDC link between Hunterston and Deeside	£805m (08/09 prices)	10/11 – 15/16	1800MW extra capacity across boundary B6;	Scheme depends on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) wind capacity driven transmission requirements. Key justification provided by cost benefit analysis (CBA) of scheme costs versus reduced constraints costs.	Assessed as a competing option for B6 expansion against a group of 4 boundary B6 Scottish Interconnector upgrade schemes (9.7, 9.8, 9.10 and 9.11) and a possible Eastern HVDC link (9.17). SHETL schemes (Appendix A Section 9.1-9.3 and 9.5-9.6) and SPTL/SHETL East Coast upgrade scheme (Appendix A Section 9.11) and consequent increased generation flow south underpin requirement for scheme. There is potential interaction with the North Wales scheme (9.13) as both schemes will complete for transmission capacity south of Deeside.
Eastern HVDC link (NGET/SHETL)	1800MW offshore HVDC link between Peterhead and Hawthorn Pit	£829m (08/09 prices)	09/10 – 14/15 (pre-con only)	1800MW extra capacity across boundary B6;	Scheme depends on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) wind capacity driven transmission requirements. Key justification provided by cost benefit analysis (CBA) of scheme costs versus reduced constraints costs.	Assessed as a competing option for Boundary B6 expansion against a group of 4 B6 Scottish Interconnector upgrade schemes (as discussed in Appendix A Section 9.7, 9.8, 9.10 and 9.11) and a possible Western HVDC link (as discussed in Appendix A Section 9.9). SHETL schemes (Appendix A Section 9.1-9.3 and 9.5-9.6) and SPTL/SHETL East Coast upgrade scheme (Appendix A Section 9.11) and increased generation flows south underpin scheme requirements.

Scheme (Proposer)	Scope	Cost (to £m)	Timing (Constrn)	Benefit/capability provided	Critical drivers and dependencies	Interaction with other schemes
East Anglia reinforcement (NGET)	Route reconductoring; substation upgrades; Quad Boosters	£368m (08/09 prices)	09/10 – 16/17	2.5GW across boundary EC3; 3.75GW across EC4; 4.75GW across EC5; 2.0GW across EC6	driven by a mix of new onshore and offshore generation (nuclear; CCGT; wind)	Would feed into requirement for London scheme. In longer term if Humber scheme went ahead this would underpin requirement
London reinforcement (NGET)	Reconductoring of two routes in London	£186m (08/09 prices)	11/12 – 15/16	Scheme provides 1,500MW increase in capability of London network to accommodate power flows from the North East i.e. across LN1	Principally, volume of generation in East Anglia, but also general increased flows from Midlands, projected changed demand behaviour within London and also behaviour of generation/interconnectors around wider London area	Increased transfer capacity provided by East Anglia scheme (and thus expected increased generation exports) will underpin need for London scheme
North Wales reinforcement (NGET)	New circuit; reconductoring of others; new substations and substation upgrades	£444m (08/09 prices)	11/12 – 16/17	Escalating transfer capacity across local North Wales boundaries; specifically 2GW for boundary NW3, 3.25GW for NW2 and 4.2GW for NW1	This scheme is critically dependent on the anticipated new generation both within North Wales and off the coast of North Wales.	Although largely stand alone there is a potential interaction with the Western HVDC link in relation to possible need for network reinforcements south of Deeside
Central Wales spur (NGET)	Creation of 400kV spur to mid-Wales	£258m (08/09 prices)	12/13 – 15/16	Enables connection of 800MW of generation (assumed to be wind) in Mid-Wales.	The merit of this scheme is dependent on whether the 800MW of generation materialises in Mid-Wales	None – stand alone

Scheme (Proposer)	Scope	Cost (to £m)	Timing (Constrn)	Benefit/capability provided	Critical drivers and dependencies	Interaction with other schemes
South West reinforcement (NGET)	New 400kV line; uprating of other lines to 400kV and some substation rebuild and upgrades	£286m (08/09 prices)	12/13 – 16/17	This scheme provides 1.75GW of additional export capacity out of the South West area across boundary SW1	The key driver for this scheme is anticipated new generation in the South West, principally replanted nuclear generation at Hinkley Point and new CCGT generation; but also potential offshore generation of the Cornwall and Devon coasts.	None – stand alone
Humber/Anglia HVDC link (NGET)	2250MW onshore HVDC link	£553m (08/09 prices)	13/14 – 16/17	Enables incremental 2.25GW of transfer south from the Humber area (into East Anglia via Walpole)	This scheme is driven by the volume of new CCGT and offshore wind generation which might connect in the Humber area approaching 2020	If this scheme were to proceed it would further underpin the need for the East Anglia scheme
Shetland (SHETL)	600MW HVDC link between Shetland and mainland Scotland. Two options (i) a point-to-point HVDC link; or (ii) link with intermediate offshore hub.	£548m or £679m (09/10 prices)	10/11 – 14/15	600MW of export capacity from Shetland to the GB mainland. The offshore hub variant would enable higher rated circuits between hub and mainland Scotland to facilitate potential future offshore grid.	Both the scale and timing are critically dependent on a large generation project	Generation export would further underpin need for Beauly-Blackhillock-Kintore reconductoring and East Coast upgrade or Eastern HVDC link

1 Only SPTL submitted costs for anticipatory funding to Ofgem; but full scheme cost shown based on SHETL information provided to KEMA. SPTL construction works start 2011/12; SHETL construction works start 2013/14.

2 NGET and SHETL have only submitted costs for pre-construction works relating to this scheme; but full scheme costs are shown based on NGET and SHETL information provided to KEMA. NGET and SHETL construction works would start in 2014/15.

Table 7 – Summary of KEMA's Assessment of Proposed Schemes

Scheme	Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
Knocknagael (SHETL)	● first (small) step in facilitating new renewables.	● straightforward creation of substation.	● required as one of schemes possible before RETS which creates capacity.	● reasonable cost for new substation but extra transfer capacity costs £544/kW.
Western Isles HVDC link (SHETL)	● Whilst substantial generation seeking/ contracted with GBSO to connect; very little is consented yet or likely to be in next 3 months.	● Scheme scaled to contracted generation under least cost approach. Appears to be least regret option under cost benefit analysis but may present constraints should generation exceed that presently contracted. Alternative scope, using twin 450MW onshore cables within the initial scheme scope in terms of scale, design and phasing may be more robust should significant new generation emerge aligned with the upper capacity forecasts.	● 73MW out of 433MW contracted has consents. No more than 235MW expected to do so by Q1 2010. SHETL will not build unless securitised by the generation driving the need case; and at present generation will face high costs whilst no certainty of status. Thus believe 2010/11 start for construction is highly uncertain, although Beauly-Denny works at Beauly will allow for physical connection and energisation of the link in 2012 and export from Lewis of whatever initial volumes of renewables are then able to commission.	● The scheme represents the least cost option based on contracted generation. This CBA assessment may change where generation expectation changes. Also the scheme costs for export of renewable power are very high at £672/kW due to the nature of the scheme and technical solution (subsea HVDC link).
Beauly-Dounreay uprating (SHETL)	● Up to 2GW of new generation seeking to connect above B0.	● Scheme would enable export from new generation forecast to connect by 2014.	● Scheme timed to enable 722.5MW generation expected by 2014 to proceed unconstrained. The 1.27GW seeking to connect thereafter underpins the case to proceed as proposed.	● At the cost proposed, the scheme is a highly cost effective creation of additional transfer capacity at £91/kW.

Scheme	Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
Beauly-Blackhillock-Kintore uprating (SHETL)	The scheme is required to enable the export of the substantial (new) renewable generation from north west Scotland southwards towards demand.	The general proposal to reconductor and uprate capacity along the BBK route is reasonable. Arguably BK reconductoring driven by wider generation developments but BK asset replacement needs and achieved efficiency of scheme costs via early one-off reconductoring of full BBK route supports inclusion.	Given the scale and timing of new renewables generation in north west Scotland the proposed timing is reasonable.	The scheme is highly cost effective creation of extra capacity across B1 at £166/kW.
Hunterston-Kintyre link (SHETL/ SPTL)	Strong certainty of need given the total volume and underlying mix of generation seeking to commission	Scheme scaled to contracted generation. A larger scale link, may be more robust to future uncertainty	SHETL will not build unless securitised by generation driving the requirement. Given timescales for first wave of generation (2012) and their status (50MW project recently consented) we would expect reasonable certainty that the link needs to proceed as proposed but envisage possible 1 year slippage of start if generation commissioning dates slip.	The scheme represents the least cost option based on contracted generation but the scheme costs for export of renewable power are very high at £819/kW partly due to the required nature of the scheme (with a long sub-sea AC cable) but also seemingly high for the works proposed.
SPTL-NGET interconnection (SPTL)	There is reasonable (but not complete) certainty that B6 capacity needs to be expanded from 3.3GW by 2020 and in that as it is the most cost effective of the three competing B6 expansion options,	Both NGET and SPTL indicate there remains some scope/scheme design refinement to be undertaken regarding their Series Compensation scheme. However in broad terms, the scope appears reasonable and	Given the dependence on key assumptions within the CBA relating to generation and its performance; as well as constraints costs which drive the timing of the scheme there is reasonable uncertainty over the	–/ In its own right, the SPTL series compensation scheme and the NGET series compensation and the SPTL East-West upgrade scheme each appear highly cost effective at £98/kW and £203/kW respectively for

Scheme	Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
Anglo-Scottish interconnection (NGET) East-West upgrade (SPTL)	this scheme would be required.	relevant interactions properly considered.	merited timing of this scheme. KEMA also notes that the proposed 2010/11 works are timed to coincide with another local outage to seek to avoid potential high (£20m) constraints costs.	B6 capacity; whilst the SPTL East-West upgrade scheme appears less cost effective £413/kW. However, the interaction with other B6 upgrade schemes suggests it should be considered within an overall package of 3 or possibly 4 schemes to deliver 1.1GW at a cost of c. £321/kW (3 schemes exc. East Coast upgrade) up to c. £551/kW (4 schemes inc. full costs of East Coast upgrade).
East Coast upgrade (SPTL/SHETL *but only SPTL submitted costs*)	●● Given presumed scale of future renewable generation in the north west of Scotland there is reasonable case for expansion of boundary B4 capability. There is also reasonable certainty that boundary B6 capacity needs to be expanded from 3.3GW and this scheme contributes to the most cost effective solution for initial expansion to 4.4GW; although the CBA suggests that if only one of three proposed B6 expansion options proceeded the Eastern HVDC link (Appendix A Section 9.17) is a viable alternative to this scheme.	●● Appears to be an appropriate and effective way of reinforcing B4 and B5; and provides a wider benefit for B6. However, the CBA suggests that if only one of three proposed B6 expansion options proceeded, the Eastern HVDC link (Appendix A - Section 9.17) is a viable alternative to this scheme delivering greater initial B4 capacity expansion.	● There is significant uncertainty, as the date when these reinforcements are required depends not only on the timing of new generation in the SHETL area but also the commissioning of a number of other transmission schemes.	●/● Based on full scheme costs for SPTL and SHETL this scheme appears reasonably cost effective for B4 capacity expansion at £361/kW. If considered within an overall package of 4 schemes to deliver 1.1GW across boundary B6 then is part of an expensive package at a cost of c. £551/kW.

Scheme	Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
Western HVDC link (NGET/SPTL)	There is reasonable certainty that boundary B6 capacity needs to be expanded from 3.3GW but far less certainty what capacity expansion is required, particularly beyond 4.4GW. The Western HVDC link is currently proposed as the 2nd stage of B6 expansion whereas the Eastern HVDC link is currently proposed as the 3rd stage of B6 expansion where there appears to be no immediate need case subject to further review of other B6 expansion options. The need case is particularly dependent on the treatment of new generation and CBA modelling assumptions.	The Western HVDC scheme scope is reasonable should a Western HVDC link prove necessary. The Eastern HVDC scheme scope in its own right depends on the future pattern of generation in Scotland; especially if it is viewed to help provide additional capacity across B4. Otherwise, there is potential for the link to connect at different points in the Scottish and English networks and in particular, further south of the Scottish network (e.g. Torness) which would reduce the scope (in terms of HVDC cable route km). At this stage exact routing and associated scope remains unclear.	Given uncertainty over the extent of B6 expansion required above 3.3GW; and in particular whether and to what extent it should exceed 4.4GW and uncertainty regarding the most cost effective delivery options, there is some uncertainty over the timing of both of these schemes – this is exacerbated by concerns over which merits proceeding first e.g. simple review of the CBA suggests the Eastern HVDC link is preferable. As the proposed 2nd and 3rd stages of B6 expansion, the timing is particularly dependent on the timing of new generation and validity of key CBA assumptions).	Each scheme appears relatively expensive at £447/kW (Western) and £460/kW (Eastern) for B6 capacity. The Eastern HVDC link has a current proposed Peterhead-Hawthorn Pit route. It also provides benefits on boundaries B4 and B5. If the route is shortened (e.g. Torness-Hawthorn Pit) then it would become more cost effective.
Eastern HVDC link (NGET/SHETL *but only NGET submitted costs and only for pre-construction*)				
East Anglia reinforcement (NGET)	Certainty of need is high given range of substantial generation proposed in the area and backed by major industry players	In general scope of overall scheme seems reasonable. Scheme is indicated as modular in that following the sequence of works proposed within the overall scheme will deliver escalating transfer capability and thus deemed appropriate the scheme could be curtailed or later developments delayed until deemed required.	Given the range and timing of generation developments, the extent of works and thus the extended scheme delivery timeframe, there is strong justification for proposed start timing but slippages in generation connections and/or dates may mean that similar slippages can be accommodated for the latter components of the overall package of related works.	The scheme delivers a substantial amount of transfer capacity in the East Anglia area at a low cost of < c. £184/kW for whichever boundary is used as denominator (£190/kW being the highest value derived from 2GW of additional capacity being delivered at Boundary EC3).

Scheme	Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
London reinforcement (NGET)	● Given KEMA's positive assessment of the requirement/ timing of the East Anglia scheme and the exposure to wider generation behaviour issues; there is reasonable certainty of need.	●● The general scope seems reasonable to deliver enhanced capacity based on the indicated current network.	● Given the generation and network drivers for this scheme; the proposed timing to commence works appears to be reasonable.	● This scheme to deliver enhanced SE network capacity into London from the north east appears highly cost effective at £124/kW. However, KEMA notes the scheme costs appear high for the works specified.
North Wales reinforcement (NGET)	● There is high uncertainty of need for the scheme in partial or full form – given the dependence at this stage on relatively speculative generation developments in terms of scale and location. In particular, the full scheme as proposed would appear to be (i) a strong example of anticipatory TO investment; and (ii) as such, subject to high uncertainty of need.	●● Should the capacity and location of the anticipated generation materialise, the scope appears reasonable. However, the uncertainties around the generation forecast suggests that a reduced scope and/or more phased development of the scheme might be more appropriate e.g. the 2nd Wylfa-Pentir route may not be the first priority and/or needed.	● The high degree of uncertainty regarding the potential volume and location of new generation inevitably increases the uncertainty regarding the proposed timing of the scheme but also the sequencing of individual scheme components.	● Should the forecast generation underpinning the scheme emerge as predicted, the full proposed solution appears cost effective at £211/kW across NW3 – which is the most onerous measure – assuming that there are no network problems to the south of Deeside. A reduced scope of scheme would be even more cost effective on NW3.
Central Wales spur (NGET)	● The requirement for this scheme is based on a Welsh Assembly aspiration as outlined in TAN8 and partly supported by an NGET indicated 300MW wind farms seeking to connect in the "TAN8 region". Consequently, there is high uncertainty regarding investment need and the scheme represents a clear example of anticipatory TO investment within the schemes.	● On the assumption that sufficient generation will seek to connect in Mid-Wales thus meriting an additional transmission spur; under current planning standards the proposed scope of the scheme appears reasonable; as it is probably the lowest scale spur which could sensibly be constructed at 400kV transmission voltage.	●● Given the sole reliance on projected generation interest and the uncertain status of such generation there is strong uncertainty over the timing of associated investment.	● In terms of delivering generation export capacity from North Wales (assumed to be up to 2,000MW given N-1 based 400kV construction); under current planning standards, this scheme is relatively cost effective at £322/kW. However, the key question will be, if the spur is built on an anticipatory basis will that network capacity be meaningfully used by new generation siting in Mid-Wales.

Scheme	Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
South West reinforcement (NGET)	● There is high uncertainty regarding investment requirements for this scheme given its dependence on new generation connections which are expected to connect before 2020.	● Should the forecast generation in the South West materialises the scope of the scheme appears reasonable.	● The same uncertainty over generation connection which impacts on certainty of need also makes the timing of this scheme highly uncertain.	● Where the scheme proceeds as proposed the additional network capacity provided highly cost effective at a cost of £163/kW.
Humber/Anglia HVDC link (NGET)	● The need for this scheme is contingent on new generation which is largely speculative at this stage, especially the potential Round 3 offshore projects.	● Where the generation arises driving the need for the substantial extra transfer capacity south from the Humber; the HVDC link is one option. However, given lead time and new IPC process, it seems possible that a new onshore OHL route might be equally viable (and potentially more economic).	● There is high uncertainty of timing given the dependence on relatively speculative forecasts of generation developments approaching 2020.	●● Given a requirement to increase transfer capacity south of the Humber region; the cost effectiveness of the HVDC link scheme would be moderate at £246/kW, although this would be decreased if some of the East Anglia reinforcement costs were allocated to this scheme. However, if it were deemed viable to address the requirement via an OHL solution then this would be expected to be even more cost effective.
Shetland (SHETL)	● The project in either form (link with/without offshore hub) is dependent on a large generation project which has yet to receive consent.	● The scheme is scaled to meet the capacity of the contracted generation project plus some potential local small generation.	● SHETL will not build unless securitised by the generation project driving the need case; and at present generation will face high costs whilst no certainty of status. Thus believe 2010/11 start for construction is uncertain.	●● The project is high cost at £913/kW for the "point-to-point link and £1132/kW for the offshore hub option – albeit the hub will enable cheaper connection of offshore renewables.

The levels of uncertainty associated with scheme justification in terms of investment requirement and construction timing is variable. Inevitably, schemes scheduled to commence construction in the next year financial year (i.e. 2010/11) should benefit from the most complete investment justification. However unit costs (£/kW) vary across the portfolio of schemes reflecting the diverse range of capacity enhancement solutions available to the TOs. These solutions range from the reconductoring of existing circuits, construction of new transmission circuits (overhead and underground), and insertion of series compensation capacitors within existing infrastructure through to new submarine HVDC links. Schemes scheduled to commence construction in the short term are characterised by capacity enhancement to existing infrastructure and are generally more modest in terms of scope and cost.

A number of later schemes appear to be particularly anticipatory in nature, being either (a) reliant on uncertain forward projections of generation with limited project clarity and/or user commitment; or (b) pre-emptive i.e. by providing transmission capability as a means of attracting generation to locate in a particular region. SHETL has adopted an alternative approach whereby schemes have been nominated for funding on a “non-anticipatory” basis which reflect (i) contracted generation commitments as seen at this present time - thus view of need, timing and scope can/could change accordingly at relatively short notice), and (ii) funding required within the TPCR4 period. To illustrate this point, SHETL has not included their element of costs for the East Coast upgrade scheme as discussed in Section 9.11 for NGET, within their submission.

This Section has assessed individual schemes according to proposed construction commencement. However, it is clear that for a number of schemes which relate to the provision of enhanced transfer capacity across boundary B6 (the Scotland-England border) where there are either explicit linkages or direct interactions, including uncertainties regarding priority of progression. There are also interactions between other schemes in relation to (a) export capacity from northern Scottish renewables southwards towards major demand centres and (b) regional interactions along Eastern England into London.

These interactions and the general coherence and robustness of the overall plan developed by the TOs as part of the ENSG process are examined further in Sections 5 and 6.

5 ASSESSMENT OF OVERALL ROBUSTNESS AND COHERENCE OF SYSTEM WIDE PLAN

This Section assesses the overall robustness and coherence of the system wide package of investments as assembled by the GB TOs. The Section is split into two parts:

1. Coherence as a plan – this examines the key interactions within the system wide package of investments, specifically the interactions between the component schemes as previously discussed in Section 4.

2. Robustness as a plan – this provides a review of the general modelling approach and in particular a review of the key dependencies and assumptions; and sensitivity of the proposed investments to potential changes to/different views of these

5.1 Coherence of the plan – key interactions

The investment plan as produced for the ENSG to enable 2020 renewables targets to be met was produced under a collaborative effort between the three TOs; with NGET leading the assessment and Cost Benefit Analysis of the Scotland – England Boundary 6 expansion options. For the other schemes spanning the Scottish TO regions, the lead was assumed by either SHETL (Hunterston - Kintyre) or SPTL (East Coast upgrade). Most of the schemes have been developed by a single TO to deliver a suitable supporting network and compliant with the GB NETS

The 18 schemes under consideration as submitted to Ofgem for additional funding consideration can be classified under 4 main categories. These are:

1. Stand alone schemes which are driven by localised/regional new connection assumptions; and whose need and timing is not impacted by other schemes. These are:

    a. Shetland link (with or without offshore hub)

    b. Western Isles link

c. Beauly – Dounreay uprating

d. Hunterston – Kintyre AC link

e. East Anglia reinforcements (a sequence of related sub-schemes)

f. North Wales reinforcements (a sequence of related sub-schemes)

g. Central Wales spur

h. Humber/Anglia link

i. South West reinforcements

The independence of the England & Wales schemes is confirmed by lack of related constraints being identified within the B6 focused CBA work (which also modelled key boundaries in England, namely B8 – North to Midlands, B9 - Midlands to South, and B15 - Thames Estuary). It is noted that there is a weak interaction between the three Scottish schemes ((a), (b) and (c)) and other schemes to reinforce Boundaries B4, B5, B6 and B7), and also possibly between the North Wales and Western HVDC link.

2. The network investments around London are driven by generation developments and associated network reinforcements outside of the immediate locality. The London investments arise from the changing generation mix (including the England-France interconnector) in SE England but in particular the anticipated increase in generation around East Anglia. The associated network reinforcement enable higher power transfers towards the north east London area.

3. KEMA has separately classified schemes which represent a cascade of investments to enable renewable generation in Northern Scotland to be exported south on the GB transmission network. These include:

   a. Knocknagael

   b. Beauly - Blackhillock – Kintore; and

c. East Coast upgrade

KEMA notes that the primary purpose of the East Coast upgrade is to increase transfer capability on the eastern transmission circuits in Scotland which cross Boundary B4 in Northern Scotland. However the Scottish East Coast upgrade also impacts the B6 related schemes and NGET has stated that this investment also forms an integral part of the B6 “Incremental Upgrade” works.

4. Schemes relating to the expansion of the Scotland-England transfer capability across Boundary B6. These essentially comprise the following three investment options:

   a. B6 “Incremental Upgrade” work consisting of (a) SPTL’s “SPTL-NGET interconnection” scheme , (b) NGET’s “Anglo-Scottish incremental works” scheme, (c) SPTL’s proposed East-West upgrade scheme, and (d) SPTL/SHETL’s proposed East Coast upgrade scheme;

   b. Western offshore HVDC link; and

   c. Eastern offshore HVDC link.

   These B6 expansion options are highly interactive at two levels (i) the composition/design of the options themselves – in particular for the “Incremental Upgrade” which comprises 4 individual scheme whose individual scheme designs are interlinked to form the overall solution; and (ii) between the options to optimise the ordering/combination of schemes to meet different levels of anticipated B6 transfer capability requirements. These “B6 expansion” options were subject to the most intensive analysis within the ENSG process and in particular were the focus of CBA. NGET has also indicated that localised CBA could be applied to justify the need and timing of the East Anglia, London and South West schemes.

On the basis of the above KEMA believes that at a high level, the overall investment plan represents a coherent collection of schemes and that the majority, i.e. the schemes in category 1 above, can be considered solely on their own merits with no reference to other schemes in the plan. Others listed in categories 2 and 3 above can be judged to have dependencies on other schemes such as the East Anglia investment influencing London requirements. The remainder are closely linked to the expansion of transfer capability across Boundary B6 and thus the scheme interaction which need particular scrutiny are within this subset of schemes. These interactions and the coherence of the proposed approach to B6 expansion is subject to detailed discussion as follows.

5.1.1 Interaction of schemes expanding possible Scotland-England transfers

The TOs have identified 3 potential options to expand Scotland-England transfer capacities. These options are as follows:

1) "Incremental Upgrade" of the existing Scottish Interconnector's transfer capacity which will be 3,300MW following completion of TIRG related works. This "Incremental Upgrade" option includes four of the schemes discussed in Section 5 above namely:

    a) A SPTL proposed series compensation scheme ("SPTL – NGET interconnection", Appendix A - Section 9.7)

    b) A NGET proposed scheme comprising series compensation and reconductoring of Harker - Quernmore ("Anglo-Scottish incremental works", Appendix A – Section 9.8)

    c) SPTL's proposed East-West upgrade scheme (Appendix A – Section 9.10)

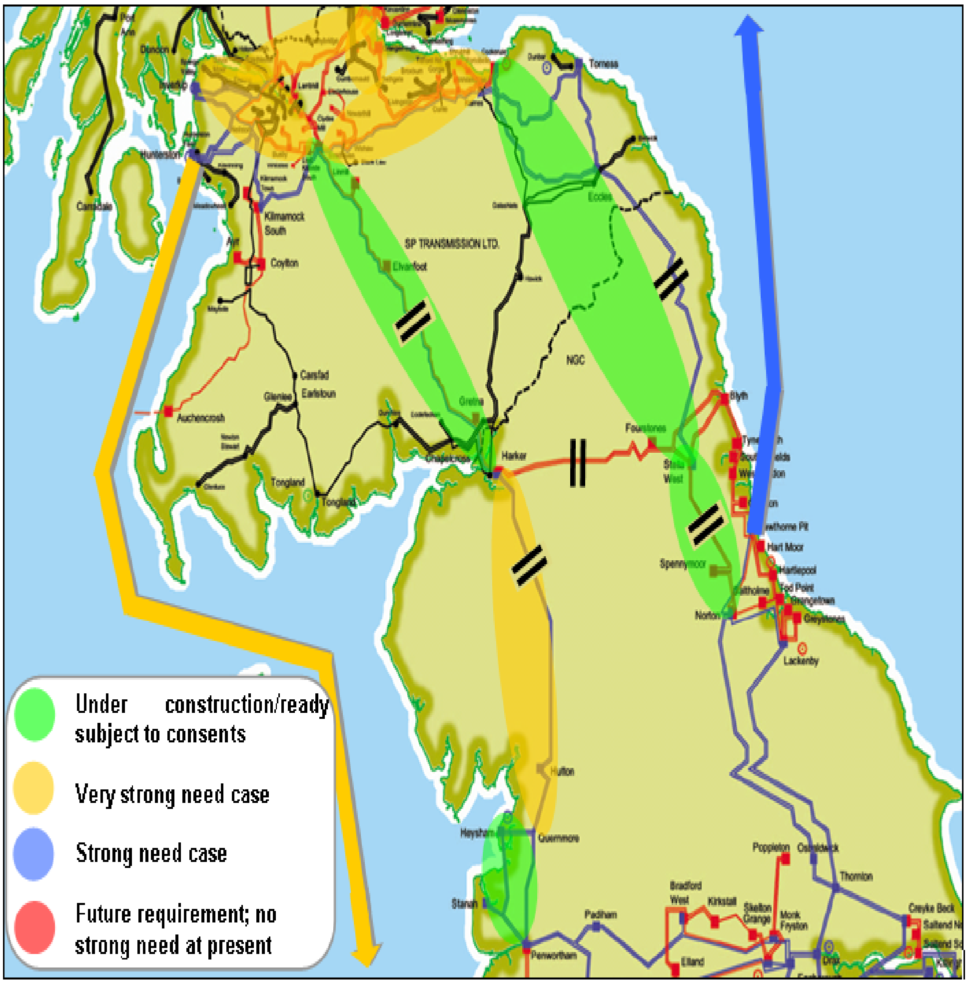
    d) SPTL/ proposed East Coast upgrade scheme (Appendix A – Section 9.11)

2) Western offshore HVDC link connecting Hunterston to Deeside (Appendix A – Section 9.9); and

3) Eastern offshore HVDC link connecting Peterhead to Hawthorn Pit (Appendix A – Section 9.17)

These scheme options and the TOs' view of investment urgency are illustrated below:

Figure 13 – Illustration of proposed Boundary B6 reinforcement options



In reviewing potential approaches to the expansion of B6 capacity, NGET confirmed that a range of individual options and combinations had been examined previously (as addressed in a Report produced for NGET by PTI Siemens in April 2006 and December 2006). For the ENSG work, NGET packaged these options on the basis of cost and benefit in the context of 2020 generation, resulting in the three options presented for additional funding. However, it is noted that alternative approaches requiring new overhead line (OHL) construction in south Scotland and/or northern England have been discounted on the basis that achieving timely consents would be challenging. NGET also stated that a new western overhead line route would need to be about 300km in length, and the estimated costs, allowing for the undergrounding of some sections, would be high at c. £1bn or more (a conventional OHL route is still estimated by NGET and SPTL to be c. £0.8bn i.e. close to or more expensive than the proposed offshore HVDC links). An eastern overhead line route would be much shorter, but NGET state that it would only provide limited additional capacity (around

650MW); however, it may still be cost-beneficial depending upon the total requirement for capacity across B6.

Nonetheless KEMA is comfortable that the three options represent practical options for substantial expansion of the transfer capability across the B6 boundary. Thus the primary area of uncertainty is the relative merits of each initiative and associated scheme interactions as addressed through the CBA modelling exercise.

5.1.1.1 Interaction of schemes within B6 “Incremental Upgrade” works

Under the ENSG process, NGET indicated that the initial objective was to maximise the utilisation of the existing Cheviot lines as the most cost effective approach to initially expand B6 capacity beyond 3,300MW and realise up to 4,400MW transfer capability. NGET’s process to determine reinforcement options for this “Incremental Upgrade” was to model network transfers of 4.4GW from Scotland to England, identify GB SQSS non-compliances and then devise reinforcements to solve non-compliances in turn. NGET then sought to confirm that each reinforcement ‘package’ provided an optimum solution. On this basis NGET concluded that a package of four schemes, comprising the “Incremental Upgrade” works, represented the optimal solution.

Specifically, NGET states that:

- the Cheviot series compensation (covering NGET and SPTL works) consisting of an optimised number of sites & locations – would enable B6 stability limits to match thermal limits; and the associated Harker-Hutton-Quernmore reconductoring (included within the NGET “Anglo-Scottish incremental works” scheme in Appendix A – Section 9.8) provides increased capacity across B7;

- the SPTL East-West upgrade comprising 400kV uprating provides increased capacity by resolving some post-fault thermal constraints but also reduces impedance between east and west interconnector circuits and thus improves voltage and stability performance; and

- the SPTL/SHETL East Coast upgrade, whilst primarily providing increased capacity across the B4 boundary, also provides benefits for B6 under certain fault conditions. The East Coast upgrade will also require investment by SHETL although SHETL is not seeking funding for this upgrade during TPCR4.

Consequently NGET indicate that all of the above incremental upgrades (as captured in Appendix A - Sections 9.7, 9.8, 9.10 and 9.11) are linked and need to be undertaken to realise 4,400MW transfer capability across B6 and will coincidently deliver wider system transfer capability benefits for Boundaries B4 and B7/7a. Specifically a boundary capability of 4400MW on B6 is achieved by the combination of five elements, namely:

a) SPTL East-West upgrade, i.e. a double circuit 400kV route from Strathaven through Smeaton to Torness.

b) SPTL and NGET installation of Series Capacitors;

c) NGET reconductoring of Harker–Hutton–Quernmore;

d) SHETL East Coast, i.e. uprating from Kintore to Tealing to Kincardine from 275 to 400kV; and

e) SPTL East Coast, i.e. a new substation at Harburn in the Strathaven to Smeaton route south-east of Edinburgh, and uprating from Longannet/ Kincardine to Harburn from 275 to 400kV.

NGET have indicated that (a) (c) (d) and (e) above are primarily developed to expand transfer capability across other boundaries but all interact with boundary B6 to some extent. When considered together, these combined investments determine the overall series compensation requirement.

NGET indicate that one study result showed that reinforcements (a) - (d) above gave 250MW less capability across Boundary B6. This is because, in the absence of (e), the 400kV elements in SHETL of Beauly-Denny and Kintore to Kincardine are not connected to the 400kV Strathaven to Smeaton to Torness and southwards in SPTL. Accordingly, the stability capability of the B6 boundary is impaired, by approximately that 250MW; in particular under the Eastern contingency of the Stella to Eccles fault, the generation at Peterhead is not directly connected at 400kV to the remaining Strathaven to Harker route, and so the stability performance is weaker. Thus B6 capability, if reinforcements (a) to (d) alone are done, (on top of the TIRG works, of course) would be circa 4150MW.

KEMA concludes that the TO explanations regarding scheme interactions is reasonable and that the schemes provide a means of delivering capacity increases to 4400MW across

Boundary B6 and also seek to incorporate capacity expansion requirements across other key neighbouring boundaries such as B4, and B7/7a.

In seeking to address the stability issues present around B6, NGET have indicated that series compensation has been chosen to address the B6 stability issues because:

- Compensation is needed to ensure compliance with SQSS standards for both system voltage and stability at levels within the thermal capability of the boundary;

- The stability requirement is based on transient rather than dynamic performance and is caused by low voltages immediately following interconnector faults;

- NGET regards series compensation as most effective solution for resolving both of the above issues at a lower cost than Static Var Compensators (SVCs) and Statcoms; and

- NGET does not believe that modifying the Grid Code requirements for wind farms to either increase the reactive capability requirement or to introduce a Power System Stabiliser (PSS) requirement would reduce the level of compensation required.

KEMA has reviewed the information provided by NGET to support this case and believes it presents a reasonable supporting case for the series compensation deployment, although more additional analysis would be beneficial in the following areas:

- Selection of an appropriate combination of controlled series and shunt compensation to deliver an optimised solution. Increased voltage drop across line impedance is one source of the fall in network voltage following a line outage. However, once a fall in network voltage has occurred, items such as induction machine increase their operating slip value to maintain torque and this causes an increase in their reactive power demand and further adds to the fall in network voltage. Series capacitance on lines will certainly reduce the fall in voltage due to line impedance. However, once voltage has fallen, the reactive demand of the induction machine load will increase and this demand is likely to be accommodated more readily by shunt SVCs and StatCOMs at the appropriate location than by series compensation (the effectiveness of shunt compensation will be heavily dependent on location, and it is not clear if the location was optimised).

The results provided as part of the additional information from NGET in response to KEMA questions on Boundary B6 stability issues indicate that SVC compensation provides much better post disturbance performance than series capacitive compensation.

- Analysis to confirm whether the introduction of PSSs at generation sites (synchronous, DFIG or Fully rated Converter wind farm generation) can reduce the magnitude and duration of current swings through transmission lines following large network disturbances, potentially reducing compensation equipment rating requirements. It is apparent, however, this has not been considered in the studies undertaken, and thus the potential benefits not identified or quantified.

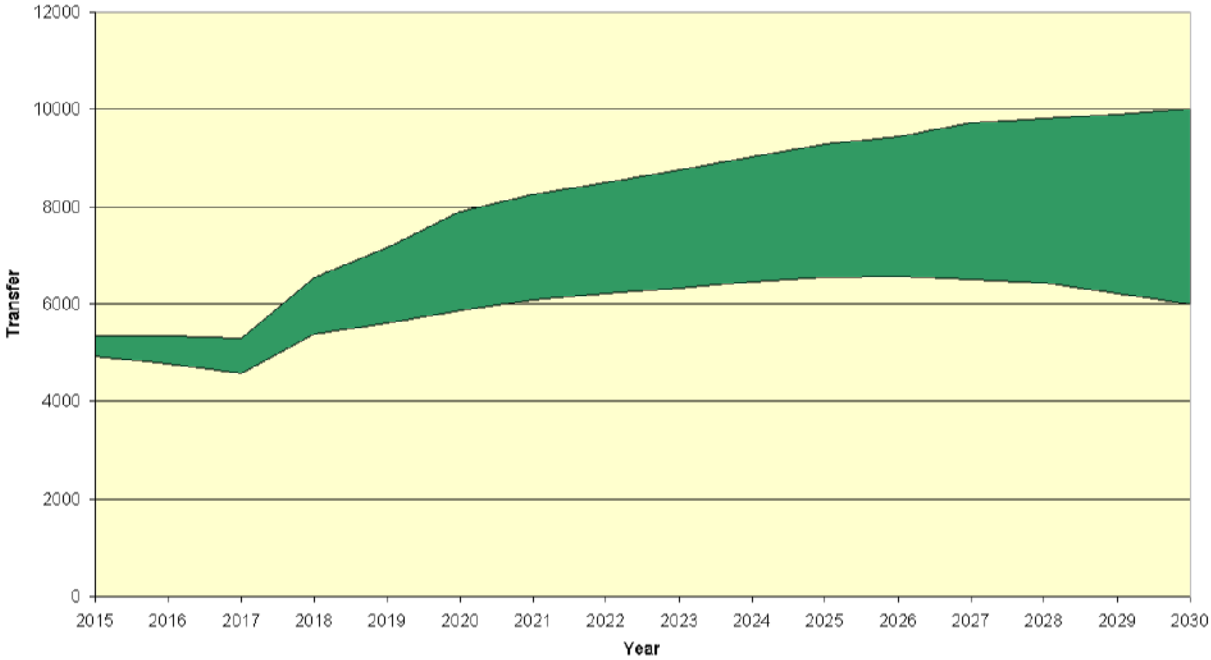
- In their two key reports[10] associated with the evaluation of network stability and power transfer across the interconnector, NGET stated that the basic mechanisms underlying many of the findings in these reports are not fully understood and they recommended that further investigations were required to be carried out to try to understand how the various combinations of synchronous machines, DFIGs, and IGs influence stability and hence Interconnector transfer capability.

5.1.1.2 Interaction of options for expansion of B6 transfer capability

From the modelling undertaken regarding the impact of the three variants of the Gone Green generation scenario (i.e. 6.6GW, 8GW and 11.4GW of wind generation capacity in Scotland); the ENSG analysis delivered a "fan" of potential (unconstrained) Boundary B6 power flows as shown below:

[10] Generic Analysis the GB Electricity Transmission System in the Long Term, National Grid 2008, and Anglo-Scottish Interconnector Stability Studies, National Grid 2006

Figure 14 – Fan diagram of unconstrained B6 boundary flows



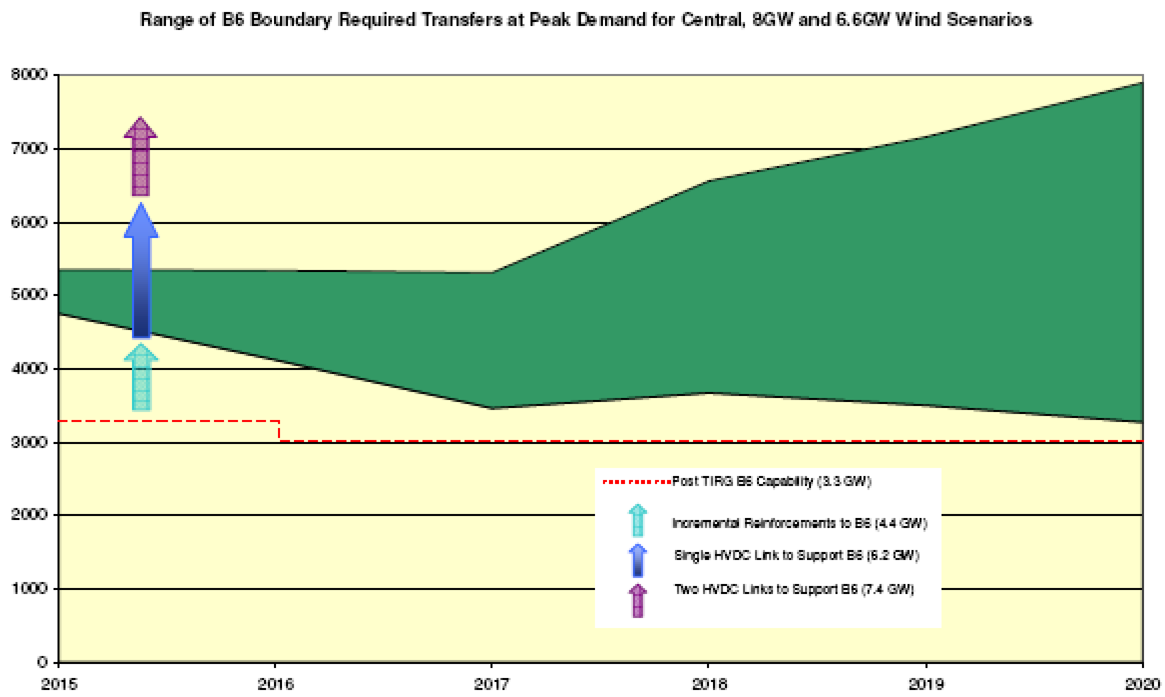
The top of the range aligns with the flows associated with 11.4GW of renewables in Scotland and the bottom of the range aligns with 6.6GW of renewables in Scotland. The lower figure aligns with the Scottish Executive's Scotland renewable generation target; the higher figure is based on TO economic generation siting assumptions to deliver the 2020 renewables targets. Inevitably, there will be uncertainties associated with the actual level of renewables connecting within this range and the resultant transfer requirements.

However, it can be seen that even the bottom of the range is beyond the 3,300MW Boundary B6 transfer capability which will be delivered by TIRG related works. Furthermore NGET has indicated that the "Incremental Upgrade" to 4,400MW may not meet potential power flow requirements post 2018. In addition, the incremental reinforcement would not resolve potential thermal limits across Boundary B7/7a (North of England boundaries north and south of Heysham respectively) later in the next decade.

Having discounted the 3rd OHL option as a viable development, NGET identified two potential offshore HVDC link options (East and West) which significantly expand Boundary B6 transfer capability and also address Boundary B7 and B7a thermal limits. The HVDC link between Hunterston and Deeside provides increased capability across all above boundaries; whereas the HVDC link between Peterhead-Hawthorn Pit resolves B6, but provides limited capability across boundaries B7 & B7a. However, this may provide additional capacity across boundaries B4 and B5.

In order to determine the optimum approach for staged expansion of the B6 transfer capability; NGET conducted a cost benefit analysis (CBA) of transfer capability expansion options across B6. This, including the ongoing TIRG works and the relationship to the 3 variants of the Gone Green scenario is illustrated below.

Figure 15 – Potential future Boundary B6 flows vs. proposed B6 capacity expansion



The TOs indicate that the “Incremental Reinforcements” are merited under the Gone Green generation scenario variant with 6.6GW of Scottish wind; that an additional HVDC link is merited under the 8.0GW variant and the 2nd HVDC link is merited under the 11.4GW variant. The CBA undertaken by NGET indicated that only the first two expansions are currently merited given the uncertainty over future generation investments explaining why additional funding for the “Incremental Upgrade” and Western HVDC link schemes are being sought by the relevant TOs (i.e. NGET and SPTL) at this stage.

KEMA has reviewed the CBA work in depth and can confirm that the general modelling approach adopted appears robust. Thus, KEMA has examined key assumptions, inputs and dependencies within this CBA modelling and the potential implications these have for both need and timing of investments.

5.2 Robustness of the plan – key dependencies and assumptions

This Section explores the robustness of the plan to future uncertainty and potential changes to the key assumptions adopted by the TOs when identifying component schemes and the plan as a whole.

The implications of key assumptions have been examined for the nominated network reinforcements. In particular the key assumptions which (a) are subject to some uncertainty/debate and/or (b) if altered, could materially impact on the level of network investment identified.This Section considers the following four areas of dependency and key assumptions:

1. Uncertainties regarding future generation capacities;
2. Potential changes of in assumed performance and treatment of wind;
3. Stability studies used to identify constraint limits for B6 (Anglo-Scottish) boundary; and;
4. Dependency on key assumptions in the CBA modelling for “B6 related” schemes.

5.2.1 Impact of uncertainty/potential changes in generation forecasts

The network investments identified by the GB TOs were devised to deliver Government 2020 emission reduction targets with a substantial contribution be sourced from the electricity sector through investments in renewable generation, predominantly wind power. In the ENSG study, assumptions were made regarding the contribution of other industry sectors (such as transport) to reduction in CO_2 emission and it was determined that in order to achieve the required contribution from the GB electricity sector, that c. 147TWh of renewable and low carbon generation would need to be commissioned by 2020.

The assumed generation scenario is consistent with delivering this level of renewable output with corresponding capacity projections. This scenario was denoted ‘Gone Green’ and its key features are as follows.

- Plant closures:
  - 12 GW Coal and Oil LCPD;
  - 7.5 GW Nuclear;
  - Some gas and additional coal.

- Significant new renewable:
  - 32 GW wind (21 GW offshore & 11 GW onshore);
  - Some tidal, wave, biomass & solar PV.

- Significant new non renewable build:
  - 3 GW of new nuclear;
  - 3 GW of new supercritical coal (some with CCS);
  - 11 GW of new gas.

The detailed annual capacity mix which underpins this is provided below:

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Nuclear (M)	1,450	1,450	980	980	0	0	0	0	0	0	0	0	0	0	0
Nuclear (A)	8,365	8,365	8,244	8,244	8,244	8,244	8,244	8,244	8,244	8,244	5,894	5,894	4,813	2,403	2,403
Nuclear (P)	1,190	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Existing Nuclear	*11,005*	*11,015*	*10,424*	*10,424*	*9,444*	*9,444*	*9,444*	*9,444*	*9,444*	*9,444*	*7,094*	*7,094*	*6,013*	*3,603*	*3,603*
New Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	1,650	3,300
Total - Nuclear	*11,005*	*11,015*	*10,424*	*10,424*	*9,444*	*9,444*	*9,444*	*9,444*	*9,444*	*9,444*	*7,094*	*7,094*	*6,013*	*5,253*	*6,903*
Coal - LCPD In	19,773	19,863	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,545	17,598	16,624	16,624
Coal - LCPD out	8,502	8,514	8,464	8,464	8,464	8,464	7,500	5,491	3,559	0	0	0	0	0	0
New Clean Coal	0	0	0	0	0	0	0	0	850	1,600	1,600	1,600	1,600	1,600	1,600
CCS Coal	0	0	0	0	0	0	0	0	0	1,600	1,600	1,600	1,600	1,600	1,600
Total - Coal	*28,274*	*28,378*	*28,371*	*28,371*	*28,371*	*28,371*	*27,407*	*25,398*	*24,316*	*23,108*	*23,108*	*22,745*	*20,798*	*19,824*	*19,824*
CCGT	22,285	22,360	22,362	22,412	22,412	22,412	21,747	21,747	21,747	21,747	20,847	20,182	19,937	19,937	19,937
CHP	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725
Gas - Other	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534
Total Existing Gas	*25,544*	*25,619*	*25,621*	*25,671*	*25,671*	*25,671*	*25,006*	*25,006*	*25,006*	*25,006*	*24,106*	*23,441*	*23,196*	*23,196*	*23,196*
New CCGT	0	0	905	1,805	3,090	3,950	6,100	6,100	6,960	8,265	8,635	10,455	10,455	10,455	10,455
CCS Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CHP	0	0	0	0	499	499	499	499	499	499	499	499	499	499	499
Total - Gas	*25,544*	*25,619*	*26,526*	*27,476*	*29,260*	*30,120*	*31,605*	*31,605*	*32,465*	*33,770*	*33,240*	*34,395*	*34,150*	*34,150*	*34,150*
Oil	3,442	3,442	3,442	3,442	3,442	3,442	3,442	3,442	3,442	0	0	0	0	0	0
MGT	429	429	429	429	429	429	429	429	429	429	429	429	429	429	429
AGT	752	769	769	769	769	769	769	669	635	373	373	373	373	339	339
Pumped Storage	2,513	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744
Offshore Wind	0	10	10	10	410	788	1,488	2,373	3,343	4,107	5,594	7,578	11,258	14,608	18,458
Onshore Wind	944	1,117	1,470	2,378	2,753	3,405	4,828	5,718	6,474	7,190	7,921	8,639	9,454	10,096	10,989
Biomass	45	45	45	90	90	440	576	576	576	776	776	776	776	776	776
Biofuel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tidal & Wave	0	0	0	0	0	0	0	0	0	0	50	160	610	1,110	1,410
Total Renewable (exc hydro)	*989*	*1,172*	*1,525*	*2,478*	*3,253*	*4,633*	*6,892*	*8,667*	*10,393*	*12,073*	*14,341*	*17,153*	*22,098*	*26,590*	*31,633*
Hydro	1,028	1,028	1,080	1,080	1,080	1,080	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128	1,128
Interconnector	1,988	1,988	1,988	1,988	1,988	1,988	1,988	1,988	1,988	2,488	2,488	2,488	2,988	2,988	1,988
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	75964	76582	77298	79201	80780	83020	85848	85514	86984	85557	84944	88549	90720	93445	99138

3 variants of this ‘Gone Green’ scenario were developed to deliver the 147TWh of renewable and low carbon generation. This was done by varying the mix of wind generation assumed to commission by 2020 in Scotland and England & Wales. The three variants were as follows:

- 6.6GW of wind capacity in Scotland (25.7GW of wind capacity in England & Wales) – this is consistent with the Scottish Executive’s explicit renewable capacity target for 2020;

- 8.0GW of wind capacity in Scotland (24.3GW of wind capacity in England & Wales) – this variant reflects a more moderate view of by how much the Scottish Executive’s renewable capacity target might be exceeded by 2020; and

- 11.4GW of wind capacity in Scotland (20.9GW of wind capacity in England & Wales) – this case was viewed to represent the most economic delivery of wind capacity based on generation economics alone.

A number of the schemes proposed by the TOs for additional funding are independent of the Gone Green scenario variants. However, the schemes linked to the expansion of Scotland to England transfer capability across Boundary B6 are impacted by the scenario variant. Specifically, of the three potential B6 investment options, the TOs indicate that only one expansion is merited under the 6.6GW variant, and two are merited under the 8GW variant with 3 justified under the 11.4GW variant.

Consequently, the merits of the proposed investment options for expansion of Boundary B6 transfer capacity are highly dependent on the assumed proportion of wind generation locating in Scotland versus England (given the assumed overall total of 32.3GW of wind capacity).

Investment requirements for boundary B6 are influenced by the relative weighting of the different generation scenarios. As a central case the NGET adopted an equal weighting across all three generation variants of the Gone Green scenario (i.e. each of the above three variants had a likelihood of 1/3). This forms the basis of the CBA conclusions regarding B6 related investment proposals. Some sensitivity analysis was undertaken changing the assumed likelihood of different Scottish wind capacity penetrations - specifically 6.6GW was allocated a likelihood of 44%, 8GW a likelihood of 33% and 11.4GW a likelihood of 22%. NGET states that this sensitivity analysis has no material impact on the conclusions of the CBA exercise i.e. 2 of the 3 B6 investment options remain justified. However, the different variants of the Gone Green scenario represents a key influencer of the conclusions arising from the CBA exercise...

5.2.2 Impact of potential changes in performance and treatment of wind generation

5.2.2.1 Treatment of wind in the application of deterministic GB SQSS

It is important to review the basis and the implications regarding the treatment of wind power within the GB SQSS framework. Two key factors have a potentially significant impact on transmission investment requirements as discussed in the following sections.

5.2.2.1.1 Contributory wind power is modelled at 40% of rated generation capacity.

The required transfer capability across system boundaries is determined from two components, i.e. Planned Transfer and Interconnection Allowance. For determining the Planned Transfer, generation is uniformly scaled down, proportional to its winter peak availability, to meet demand. The resulting power flows across the boundaries represent the Planned Transfers. The Interconnection Allowance, determined from the Circle Diagram, is then added to the Planned Transfer to reflect the need to increase boundary flows arising from changes in availability of generation in respective areas. To carry out transmission studies, and given the significant penetration of wind power in the future plant mix, it is necessary to decide what level of output it is reasonable to assume from a group of wind generators as a contribution to peak security. In this Section we discuss the assumptions made in the ENSG related studies that all contributory wind is modelled at 40% of rated capacity.

Although wind generation will displace energy produced by conventional plant its ability to displace capacity of conventional generation is limited. Inevitably, the contribution of wind generation towards securing peak demand is limited as a consequence of wind power being far less 'dependable' than conventional plant in terms of availability. The ability of wind generation to displace capacity from conventional plant is a key consideration. We are concerned that in ENSG studies the assumed value of capacity credit of wind generation of 40% is inconsistent with other published work in this area (as discussed below) by a significant margin. The justification for the use of a 40% capacity credit figure for wind generation has not been provided by the GB TOs.

It is important to recognise that the percentage contribution of wind generation to securing peak demand reduces as the overall penetration of wind generation increases. For example, according to still relevant studies undertaken by the CEGB, the capacity credit of wind generation at penetration levels of 3% by energy is 29%; while for the level of penetration of 15%, the capacity value of wind reduces significantly to 16%. Comprehensive reviews conducted by the UKERC[11] confirm the lower capacity value of wind. Recent E.ON work[12] suggests a capacity value of wind power in the range 8% to 10%, given that the UK wind power will be concentrated in relatively limited geographical areas, rather than widespread across the country as assumed in a number of previous studies. Applying such high values of wind capacity credit (40%) in the plant margin evaluations, as used in the report to the ENSG, will overestimate the need for transmission reinforcement for peak conditions and may not be justified by the assumption of otherwise potentially large constraints off-peak.

5.2.2.1.2 Contributory wind is rescaled to 72% of its rated capacity in Planned Transfer Calculations

Given the fundamental principle associated with the deterministic network design standard, wind generation, due to its limited contribution/ability to secure peak demand, should drive less transmission capacity investment compared to conventional plant. In reality, there is little economic justification for building electricity transmission infrastructure on the basis of securing demand from wind energy sources[13]. A key component of the determination of necessary transmission capacity is the use of an availability factor to indicate the expected contribution/presence of generation at time of peak demand.

In the Planned Transfer calculations, the use of a 60% availability factor for wind generation has been justified by the TOs on the basis of the maximum expected aggregate output from a large geographically dispersed wind generation portfolio equating to 60% of the total wind generation capacity installed (this 60% availability factor corresponds to 72% scaling factor in

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[11] R. Gross, P. Heptonstall, D. Anderson, T. Green, M. Leach & J. Skea "The cost and impacts of intermittency", UKERC report, March 2006 ,www.ukerc.ac.uk/content/view/258/852

[12] Andy Boston, Securing Power Supplies in the 2020s, www.sussex.ac.uk/sussexenergygroup/documents/spru_conf_-_security_of_supply_in_2030.pdf

[13] The economic justification for building electricity transmission infrastructure for wind energy sources is more dependent the costs of constraining power generation, particularly from renewable sources.

plant transfer calculations)[14]. However, the ENSG 2020 Report makes no statements regarding the relevance of this analysis in relation to transmission capacity requirements for wind generation to contribute to securing peak demand, i.e. the key requirement in the deterministic element of the present GB SQSS. Even if 60% is an appropriate representation of the maximum output of a portfolio of wind generators, this is of no significance for assessing the ability of wind generation to secure peak demand and hence it has no relevance to GB SQSS[15] analyses. Such an approach is inconsistent with the overall GB SQSS philosophy as it potentially allocates more capacity than is appropriate to a less secure generation resource[16].

Recent analyses conducted by SEDG[17] on the incorporation of wind power within the present GB SQSS framework has demonstrated that the availability factors for wind power in exporting areas, for significant wind penetration levels, would be in the region of 20% for low diversity wind (corresponding to wind farms in limited geographical areas) and 30% for high diversity wind (larger geographical areas)[18].

In summary, we are concerned that overstated the contribution of wind generation to both peak demand security and security driven network capacity (through corresponding availability and scaling factors), are inconsistent with international literature in this field and will overestimate transmission network reinforcement requirements viewed purely from the perspective of meeting peak demand. The significance of this overstated contribution on various reinforcements is not clear for each of the transmission boundaries under consideration.

The proposed reinforcements across the B4 /B6 /B7 boundaries which are predominantly driven by high constraint cost assumptions within the CBA result in proposed network capacity increases which effectively avoid any requirements for network capacity sharing between wind and conventional plant. Therefore, in these instances, the assumptions

[14] Development of the 60% Wind A factor, Paper by National Grid in support of RETS proposals, April 2004; and also addressed in the GSR001 report to the GB SQSS Review Group.

[15] In fact this logic would in fact allocate more capacity to a less secure generation resource: a wind farm with a non-diverse output profile (less reliable) would require more capacity than a wind farm with a diverse profile (more reliable), which directly opposes the basis of the SQSS as the contribution of non-diverse wind generation to secure peak demand is lower than that of a diverse wind resource.

[16] The maximum output (in per unit) of a single wind farm with a non-diverse output profile (less reliable) would be higher than the output (in per unit) of a group of wind farms with a diverse profile (more reliable). Hence, according to this method, higher values of network capacity (in per unit) would be allocated to less reliable than for more reliable generation, which is inconsistent with the deterministic transmission planning standard as the contribution of non-diverse wind generation to secure peak demand is lower than that of a diverse wind resource. Hence, the transmission capacity associated with non-diverse wind profile should be lower, not higher as the logic of this method suggests

[17] Imperial College, The Impact of Intermittent Generation on Transmission Network Investment, February 2009 www.berr.gov.uk/files/file52021.pdf

[18] These are to be compared with the availability factor of 60% used in ENSG 2020 work.

regarding wind generation contributions to reliability will have negligible impact. However, under lower constraint cost scenarios, an overstated contribution of wind generation towards securing demand becomes more significant. In particular, the network reinforcements associated with the connections of offshore wind may be affected by these assumptions.

5.2.3 Impact of potential changes in stability study conclusions associated with Anglo – Scottish boundary

Given that the proposed reinforcements of the Anglo – Scottish boundary in the ENSG Report are driven by stability considerations, it is important to understand the exact nature of the instability phenomena being addressed, the associated generation assumptions, the locations of the proposed compensation equipment and how these interactions have been modelled, including the associated control strategies. It is also important to consider the ability of power electronic connected wind generation to deliver dynamic and transient performance beyond that of conventional synchronous generators.

The transmission network connecting Scotland and England comprises of two double circuit 400kV routes; one on the western side of the country and the other on the east together with limited 132kV interconnection. The capability of the circuits across this boundary is currently limited by stability restrictions to a maximum power transfer of 2200MW and reinforcements that are currently underway (to be completed 2012/13), will increae the export capability from Scotland to England to around 3300MW. Given that the proposed reinforcements of the Anglo – Scottish boundary in the ENSG Report are driven by stability considerations, it is important to understand the exact nature of the instability phenomena being addressed, the associated generation assumptions, the locations of the proposed compensation equipment and how these interactions have been modelled, including the associated control strategies.

For this purpose we have considered relevant material in the two following documents: (i) "Business Plan System Studies 2005, Anglo – Scottish Interconnector Stability Studies", April 2006 and (ii) "Generic Stability Analysis of the GB transmission system in the long term", 2008 and subsequent discussions with the National Grid. Both of the studies state that more work is required to fully understand the phenomena observed and the benefits of alternative control strategies to be fully comprehended. Key issues KEMA has identifed are:

- Studies carried out provide an invaluable assessment of the influence that wind generation would have on the dynamic and transient behaviour of the GB network for the scenarios considered[19]. However, one of the key concerns is that it is difficult to identify from observed responses the fundamental causes for particular characteristics displayed[20]. We believe that an understanding of basic dynamic influences, interactions and characteristics is essential if future developments of the network are to proceed on a sound and reliable basis. In light of this concern we have requested further clarifications associated with instability phenomena observed. From the analysis carried out in earlier studies, it appears that the key cause of instability associated with wind generation technologies is caused by the lack of dynamic voltage support. Whilst wind generation can contribute significantly to network damping, compared with synchronous generation, its capability of injecting reactive power into the network to provide voltage support following system faults is limited. Fixed Speed Induction Generator (FSIG) based wind generation absorbs reactive power and is dependent on the network being capable of maintaining voltage levels following faults to achieve fault ride through. Doubly Fed Induction Generator (DFIG) based wind generation can contribute positively to network support in the form of damping contribution and fault ride through capability. However, reactive power contributions to network voltage support following network faults is limited by the design constraints of its converters.

- Solutions to the potential lack of dynamic reactive support at particular locations could include both shunt and series compensation solutions, both of which will have strengths and weaknesses in the particular context, driven by both location and control strategy. We believe that suitably controlled shunt compensation, with the introduction of a Power System Stabiliser (PSS) loop within the control scheme, could enable the negative damping influence of the voltage control loop to be overcome and a significant contribution to be made to network damping and post fault performance. In addition, the introduction of a PSS loop into the shunt compensation control scheme could reduce significantly the VAR rating required to achieve fault ride through. We are concerned that appropriately controlled shunt compensation based solutions, may not have been given sufficient consideration in the analysis of the proposed reinforcements associated with Anglo – Scottish boundary.

- In recent years, there has been significant discussion concerning the influence of wind farms on system operation and stability and the consensus of opinion is as follows:

[19] However the scenarios analysed do not directly correspond to the scenarios in the ENSG report.

[20] This is partially influenced by the complexity of the network and the interactions that influence its dynamic behaviour, and the fact that any generator is influenced to a greater or lesser extent by the behaviour and characteristics of each and every other generator and element on the network.

- FSIG based wind farms can contribute significantly to network damping[21], but are vulnerable to network faults.

- The control flexibility and capability of DFIG based wind farms enable such generation to contribute positively to network operation in terms of voltage recovery following faults and improved system damping.

- A DFIG has the potential of providing superior dynamic and transient performance than that of a conventional synchronous generator. Application of PSS control to DFIGs could provide significant network support under both small and large disturbances. Bulk wind generation via DFIG based wind farms, suitably controlled, can be accommodated on a network without introducing problems of transient or dynamic stability and can contribute positively to network operation and enhance network dynamic characteristics.

The concern here is that the potential contribution of suitably controlled DFIGs to positively contribute to stabilising network has not yet been considered in sufficient depth in the ENSG related studies. NGET does not require DFIG based generation to provide PSS functionality which could conceivably enhance system stability characteristics. Detailed studies will need to be undertaken to determine if any savings in the proposed network reinforcements could be achieved by suitably controlling DFIGs.

In the ENSG Report, alternative operational measures to increase the power transfers across the Anglo Scottish boundary do not appear to have been considered in particular depth. The application of inter-tripping schemes may represent alternative solutions to some of the proposed network reinforcements. It is interesting to note that studies carried out by NGET[22] show that inter-tripping of two Longannet sets (1156 MW) would increase the transfer

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21 The operating characteristic of an induction machine is such that torque changes are related directly to speed changes. With an induction generator, therefore, under oscillatory system conditions the torque variations produced are predominantly in phase with speed variations. Consider the situation where an induction generator feeds power into a system, predominantly supplied by synchronous generators and where oscillatory conditions exist. Since an induction generator operates super-synchronously, any increase in system frequency reduces the difference between the rotor speed and its stator frequency and therefore results in a reduction of the generator power output. If the power demanded by the system load is considered essentially fixed, then this reduction imposes an increased electrical power from the synchronous generators. Since the frequency of the system is dictated by the rotor speed of the synchronous generators, the power variations produced are essentially in phase with the rotor speed variations. Consequently, under oscillatory conditions the power variation imposed on the synchronous generators is predominantly damping power so that the introduction of an FSIG on to a system improves the system damping.

22 "Business Plan System Studies 2005, Anglo – Scottish Interconnector Stability Studies", April 2006

capability of the boundary by about 800MW in 2007, and 1000MW in 2011 and 2013. This was found to be more optimistic than shown in the RETS studies[23]. Given that such operational measures would be needed relatively infrequently, i.e. under very windy conditions with high output from wind generation in Scotland, it may be economic to make provision for increased frequency response capability during such conditions, rather than undertaking extensive network reinforcement investments. In future, such frequency response services could be delivered by both generation and demand. NGET's rationale for advocating network investments as opposed to operational measures is based on the economics of network infrastructure at currently observed constraint prices.

There significant body of international experiences in applying sophisticated intertripping schemes, more commonly called System Protection Schemes (SPS) outside UK[24]. SPS have been used to solve numerous technical issues such as voltage, thermal and stability problems. They can enhance the transfer capabilities of the existing network, and hence postpone or even eliminate the need for more costly network reinforcement. In many instances, particularly in North and South America but also in Sweden and Australia, a tightly linked network of relays has provided an intelligent protection system that can release latent capacity of the existing network, and has efficiently substituted for investment in network reinforcement. In many applications a central controller may be utilised in order to reduce the likelihood of protection system malfunction, particularly in the situation where a complex set of individual schemes are interacting.

For example, in Manitoba, Canada, during wet hydrological conditions, power is exported to neighbouring interconnected systems, particularly to the U.S. Under high export conditions, loss of any one circuit, without remedial action, could result in cascade tripping of all remaining circuits between Manitoba and the U.S., Ontario and Saskatchewan systems. This cascade tripping, without a suitably designed SPS in place, would have severe consequences in the region. The installation of this SPS has allowed the maximum power transfer capability between Manitoba and the U.S. system to be increased from a few hundred megawatts to over 2000MW. According to Manitoba Hydro, this was a very cost-effective and efficient solution, as the alternative was to build significant additional interconnected AC transmission to maintain system stability under high export conditions.

[23] Ofgem, Transmission investment for renewable generation, Final proposals, December 2004 288/04, www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/9139-28804.pdf

[24] We have identified a body of industry relevant practices recently presented at CIGRE (particularly at the last three CIGRE conferences) and it is clear that SPS can be used to postpone or eliminate reinforcement related investment in grid infrastructure.

5.2.4 Dependency on key assumptions in the CBA modelling for “B6 related” schemes

5.2.4.1 Application of cost benefit analysis (CBA)

High penetrations of low capacity value generation sources such as wind power will inevitably require conventional generation to be available to the System Operator to ensure that sufficient generation capacity is available during demand peaks (within the current, business as usual, system operation paradigm without significant interactions with the demand side or storage capacity). Thus, the emerging system would feature an increasingly large generation capacity margin which exceeds demand by a significant amount[25]. Under these conditions, the network design for systems with significant penetration of wind should create an optimally constrained network that facilitates the economically efficient sharing of network capacity between wind and conventional generators (i.e. on windy days, wind generation will tend to occupy the available transmission capacity and on non-windy days, conventional generation will use the available capacity). The potential risk associated with increasing alignment between transmission capacity and aggregate installed generation capacity (conventional and renewable), is the creation of extensive and costly transmission network with low overall utilisation.

Sharing of network capacity is illustrated in Figure below, in which some 2000 MW of conventional generation and 2000MW of wind generation are connected in same geographic area. The analysis demonstrates that in this case, the total of 4000MW of generation capacity can be connected to the system via a transmission circuit with (secure) capacity of only 2396 MW - 2536 MW (for wind generation capacity factors of 30% and 35% respectively) in order to achieve 85% load factor operation of the conventional plants (a typical maximum value of base plant load factors) and accommodate 100% of wind power output. In order for this high level of sharing of network capacity between conventional generation and wind generation to be achieved, conventional generation needs to be flexible; hydro, coal or gas plants would generally be able to follow to changes in wind production, but not the present nuclear plant. The level of sharing and the corresponding need for transmission investment will depend on the relative magnitude of the cost of constraints versus cost of transmission.

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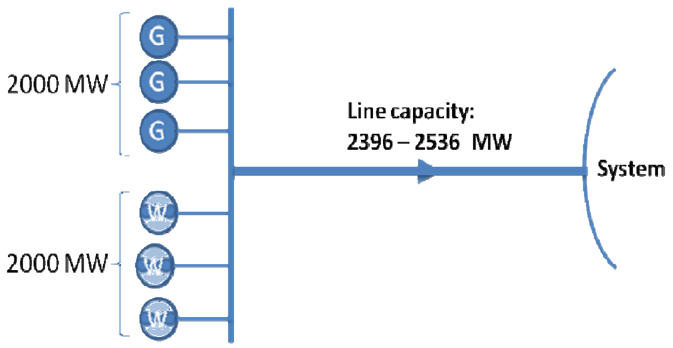
25 Consider the following example: in a system dominated by conventional generation, 60GW peak demand would be supplied with about 72 GW of generation which is equivalent to a 20% capacity margin. If another 30GW of wind is added to this mix, it will displace, say 4.5GW of conventional capacity (using an optimistic assumption that wind has a capacity value of 15%); in this system there is now a total generation installed capacity of 97.5 GW to supply 60GW of peak, approaching 60% capacity margin.

Figure 16 – Example of network capacity sharing between wind and thermal generation

Sharing of network capacity between
flexible conventional generation and wind power



The need for transmission investment will depend on the relative magnitude of the cost of constraints versus cost of transmission. As wind generation has a low marginal cost it is generally uneconomic to constrain such output. Consequently, the requirement for economic efficiency (ensuring demand can access low cost generation) is more likely to drive transmission capacity investment in future than reliability considerations. It is also important to note that the overall reliability of future transmission system should be higher than that in the present system, as additional capacity over and above that minimum required by the reliability requirements may be justified on the grounds of economic efficiency.

Cost Benefit Analysis is already a component of the current GB SQSS and used to balance the costs of transmission investment against the benefits of reinforcement (i.e. reduction of constraint costs over the life span of the investment). However, to date (in the system with conventional generation), there are only limited examples where additional transmission capacity beyond that deemed necessary to meet reliability considerations was justified on the grounds of economic efficiency. Therefore, a key practical implication of future requirements to assess transmission investments according economic efficiency principles rather than reliability considerations is the need for an efficient and transparent CBA methodology to be established. Given that the present GB SQSS does not yet provide guidance as to exactly how CBA should be conducted, it will be important to establish appropriate modelling practices and the basis for deriving the required input data. The absence of an agreed methodology for conducting CBA with appropriate input data is a major source of uncertainty in relation to the justification of the proposed transmission investments.

5.2.4.2 Key assumptions within the CBA modelling exercise

Regarding the CBA modelling framework, the following key issues are identified:

- Ideally, CBA should cover the life span of the transmission investment. Multi-year assessments of the system operation implications should be undertaken by considering daily and seasonal variations in generation and demand for a spectrum of credible backgrounds. Future generation and demand scenarios need to be specified considering changes during the life time of the transmission assets including commissioning of new and decommissioning of old generating plant, maintenance outages etc. Although these factors are mentioned in the ENSG 2020 Report, the detailed CBA assumptions cover the period up to 2020 – after which an extrapolation approach is applied to the 2020 results for constraints costs and losses to derive the overall cost/benefit results. Extrapolating constraint costs in this manner over extended time horizons is a significant model simplification and likely to overstate the constraint avoidance benefits.

- The seasonal and daily variation in demand and particularly wind generation must be adequately represented. Oversimplified representations, as seems to be the case in the ENSG Report, could risk overstatement of investment requirements in future.

- It is critically important that CBA is conducted considering the entire GB transmission network, as the application of CBA to limited number of boundaries may inflate the need for transmission and lead to overinvestment.

- Generation running orders, operating patterns, availabilities and load factors, must be adequately represented and reflect the economic and technical reality of system operation.

- Application of various operational measures, dynamic line rating, advanced maintenance techniques, application of inter-tripping schemes, demand management all aimed at maximising the utilisation of the transmission assets.

We have reviewed the CBA methodology adopted by the GB TOs and the additional information provided by NGET. Particular aspects of interest are associated with modelling of demand and wind, outage duration assumptions, plant running hierarchies, profiles for commissioning and decommissioning generation plant and application of operational measures and their impact on volumes of constraint costs.

The CBA undertaken by NGET is composed of two main models (i) a first model simulates system operation for a given set of boundary capacities (across 6 boundaries) and forecasts operation in future; and (ii) a second model that consolidates all costs for final economic assessment: transmission investment cost, cost of outages (including maintenance and construction outage), cost of constraints and cost of losses.

We found that CBA modelling approach adopted considered constraints across multiple boundaries simultaneously. The analysis of Anglo-Scottish boundary (B4, B6, and B7) excludes consideration of boundaries further north and further south of border. The materiality of this simplification is believed not to be significant.

Representation of wind and demand profiles within CBA model was found to be suitable. Demand is presented through two sets of 8 level load duration curves, one for winter and one for summer. Wind is modelled through probability distributions that correspond to the seasons. Furthermore, correlation between wind power outputs across the zones is considered although it is not clear how correlation coefficients were determined and how this choice impact on the network reinforcement proposed.

Bids and Offers accepted to alleviate network constraints are not optimised as the model considers only those generators that are in the areas just above and just below of the constrained boundary. This potentially overvalues cost of constraints, but it is not clear how material or otherwise this simplification may be.

Allocation of marginal generation in unconstrained dispatch is proportional to its zonal availability, which may not represent real system conditions. The impact of this assumption on the volume and costs of constraints is unclear.

Losses are priced at £60 /MWh uniformly and independently from the constraints forecast. However, from the CBA model, the price of electricity decreases from £50/MWh in 2007 to £40/MWh in 2020, because of significant wind power penetration. Hence, the price used to evaluate cost of losses is found not be consistent with modelled dispatches and may overestimate cost of losses and hence overstate the benefits of reinforcements.

It is important to observe that the reinforcements identified in the ENSG Report would result in a low level of transmission capacity sharing between conventional plant and wind generation. It is also important to recognise that this absence of sharing is driven by the high assumed price of constraints leading to a virtually unconstrained transmission network. In other words, the capacity of the reinforced transmission network will be such that under peak demand condition the network will be to accommodate simultaneous maximum output of all generation in Scotland, both conventional and renewable and that there will be little sharing of capacity between these two technologies.

6 REVIEW OF COST BENEFIT ANALYSIS (CBA) AND KEY MODELLING ASSUMPTIONS

The focus of this Section is the CBA modelling exercise undertaken by NGET to determine the relative merits of the three identified investment options to reinforce the B6 boundary and thus expand transfer capability between Scotland and England. Inevitably, any CBA exercise requires a broad range of input assumptions to address future uncertainties and some of these assumptions will have greater impact on CBA outputs than others. Therefore this Section provides KEMA's view of the key factors/assumptions which underpin the CBA modelling and highlights the potential impact of applying different assumptions.

NGET states that the accuracy of the forecasted investment costs associated with the 3 B6 expansion options does not materially impact the CBA modelling conclusions. In addition, NGET also states that sensitivity analysis indicates that a substantial (30%) fall in these cost estimates would not change the proposed investment case to proceed with two reinforcement options within the period up to 2020.

This Section discusses the significance of the following three CBA assumptions:

1. Wind generation load factor assumption(s);
2. Application of plant merit orders in deriving constraint volumes; and
3. Application of bid and offer prices in deriving constraints resolution costs *(note – scenario weighting is revisited in this Section).*

6.1 Modelling of constraint costs over different transmission boundaries

NGET has modelled constraint volumes across transmission boundaries B8 and B9 for each generation and investment scenario and has concluded that these are not sufficiently material to require additional investments. This suggests that all relevant investments have been appropriately included in the CBA for each B6 related boundary expansion option. However, the constraint volume modelling undertaken by NGET does indicate some meaningful constraint volumes of circa1500GWh and a cost of £150m on boundary B15 'Thames Estuary' in all 2015 cases, and slightly greater values in 2020. However, NGET has commented that this may not be a particularly realistic result, and merely reflects too tight a boundary limit of 6000 / 5500 / 5000MW modelled in the CBA. NGET further indicate that they are confident that operational measures, for example better use of London quad boosters, will largely eliminate these constraints but that they left them in the CBA studies, to "add an apparent verisimilitude that some E&W constraints were being modelled and observed".

6.2 Wind generation load factor assumption(s)

To conduct the CBA, assumptions need to be made regarding the potential operating regimes for the different types of generation plant. The assumptions utilised by NGET are provided below.

Table 8 – Probabilistic output distributions for types of generation used in CBA

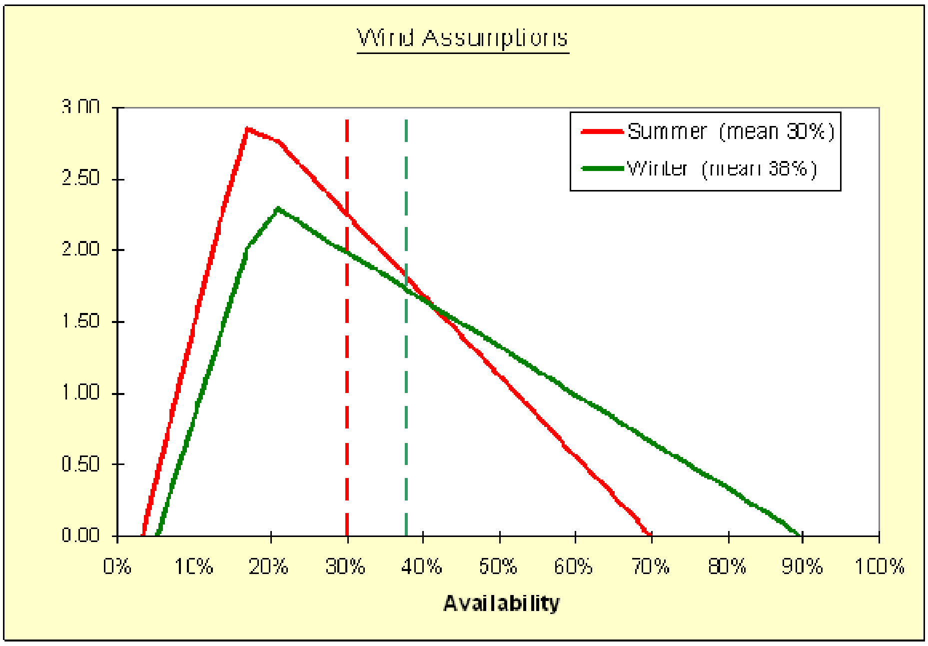
	Distribution Type	*mean_win*	*mean_sum*	*stdev*
Nuclear	Binomial	80%	70%	
Wind	Triang	38%	30%	
Base_Gas	Binomial	90%	85%	
Base_Coal	Binomial	85%	75%	
France	Max	100%	100%	
Water (1-4; 5-8)	Normal	60% ; 10%	60% ; 5%	4%
Marg_Gas	Binomial	90%	85%	
Marg_Coal	Binomial	85%	75%	
PumpStor (1-4; 5-8)	Binomial	90% ; 25%	90% ; 15%	
Britned	Max	50%	40%	
Oil	Binomial	95%	85%	
Aux GT / Main GT	Normal	95%	95%	3%

Wind Triangular Distribution Parameters

	min	*ml*	*max*	*mean*
summer	3%	17%	70%	30%
winter	5%	19%	90%	38%

CBA analysis will be sensitive to these assumptions and in particular those relating to wind generation given this to be main form of new generation connecting in Scotland. An illustration of the availability assumption(s) adopted for wind is provided below:

Figure 17 - Probabilistic output distributions used for Wind plant within CBA



NGET indicate that the wind assumptions derive an average annual load factor of 35%; based on 30% average load factor in summer and 38% average load factor in winter as shown in the chart. This load factor assumption covers both onshore and offshore wind. There are two potential sensitivities of this assumption.

1. It is accepted that there is relatively limited history of wind generation performance in GB and much of that relates to a relatively localised concentration in Scotland. However, NGET indicate that their observed average performance of this onshore wind generation to date has been c.28%. Nonetheless they predict improved overall average performance going forward (partly due to increased presence of offshore wind in the wind portfolio) within their adoption of 35%. However, KEMA notes that within its supporting role to Ofgem on the OFTO process; its review of offshore projects expectations for load factor (c.28%) would call into question the validity of this assumption.

2. It is generally recognised that offshore wind generation should obtain higher load factor than onshore and NGET acknowledge this, indicating the 35% is higher than it would otherwise be if only onshore wind were being modelled i.e. differential performance of onshore and offshore wind is reflected in the overall average output performance distribution.

It is assumed that the connection of new wind in Scotland will be predominantly onshore which will provide a key driver of the changing power flows across Boundary B6 and associated transmission investments. Thus any material change to the structure and/or level of wind generation modelling in the CBA will have an impact on the outcomes of the CBA analysis, and could be material. Based on a range of studies conducted both in the UK and internationally, the assumptions used within the ENSG analysis regarding outputs from wind generation appear slightly optimistic.

6.3 Application of plant merit order in deriving constraint volumes

A fundamental component of the CBA is the derivation of the constraint costs arising from generation patterns. This is because constraints costs largely determine the investment case for the particular projects under consideration (it is acknowledged that transmission losses also impact the benefit case but this is regarded as a 2nd order effect).

The first key component of this assessment of constraints costs is the determination of volumes. These volumes will be fundamentally driven by the assumed plant running or merit order. NGET allocated all generation to particular plant type categories as shown in Table 9 below, dividing gas and coal plant into base and marginal sub-categories. In general, NGET allocated generation stations to a particular category although in the case of coal and gas capacity was apportioned between base load and marginal sub-categories according to historic plant operation and forecasts of relative positions within the merit order. The allocation of plant and capacity is shown in the table provided by NGET below:

Table 9 – Allocation of GB generation to "Base" and "Marginal" categories in CBA modelling

[Table removed for confidentiality reasons]

It is not clear how the plant capacity for "Coal_split" categorised plant is allocated to "Base Coal" or "Marginal Coal" and what these capacity allocations are. The precise allocation of these will potentially have a material impact on the CBA modelling results.

As is evident from Table 9 above, there is no locational distinction of plant within these plant types i.e. each plant within a plant type category is assumed to behave identically i.e. to have same power cost/price. NGET indicate that an annual merit order based on these plant types is applied within the CBA against an aggregate demand curve to determine plant operation across the year i.e. from base load to peaking plant with nuclear and wind being first to be despatched to meet demand. NGET highlights that where the demand curve cuts across a plant type category they mechanistically uniformly scale all generation within that category (i.e. there is no plant specific selection/withdrawal adopted to seek to match demand).

Consequently constraint costs are based on the mechanistic matching of generation to demand using the deemed merit order applied consistently across the year(s). This highlights some key dependencies/assumptions which might impact on the modelled constraints volumes under the CBA work. These are as follows:

The initial allocation of coal and gas plant capacity to their respective base and marginal sub-categories will set a national pattern of generation within these sub-categories. Any material changes to the plant capacity allocations to the different categories would potentially alter these geographic dispositions within the coal and gas sub-categories and potentially create materially different power flows from the matching of generation to demand using the plant type based merit order.

The determination of the plant type merit order will also impact on the derived power flows and therefore future constraint volumes. There are three aspects to consider here:

Firstly, the setting of the plant type merit order is important. Whilst this is largely intuitively obvious; the key variable is likely to be the relationship of marginal gas to marginal coal, i.e. the merit order despatch hierarchy to meet demand. The CBA work assumes marginal coal plant is more expensive than marginal gas plant and applies this assumption for each year throughout the time period of the analysis. If this ordering were switched either for years in part of the period or for the full period (on the basis that coal and gas prices move in such a way to make coal more economic than gas) then this could have a meaningful impact on derived constraint volumes under the CBA modelling.

Secondly, the application of the plant merit order is uniform across the year. Historically there have been changes in relative economics between marginal coal and marginal gas plant between summer and winter due to the more cyclical behaviour of wholesale gas prices. The CBA analysis does not account for this potential summer/winter switching; and whilst this might represent a refinement versus wholesale annual switching of economic plant type ranking as discussed above, nonetheless it could drive a meaningful change in observed constraint volumes from the CBA modelling.

Thirdly, there is no consideration of plant specific and locational factors in the plant type merit order. Within the marginal coal and gas plant types in particular there is likely to be some relative difference in plant economics due to (a) comparative plant thermal efficiencies; and (b) the impact of unavoidable locational factors such as gas and electricity transmission network charges. For example, these could be sought to be applied when balancing the incremental plant to the demand level by ranking plant capacity within the plant type categories (rather than adopt uniform scaling). At the extreme it could be used to derive a plant by plant merit order. This more refined treatment of the plant merit order could lead to differing constraint volumes emerging from the CBA modelling.

The application of merit orders based on plant types to meet demand represents a key driver of the power flows across B6 which will underpin the CBA results for B6 related transmission investments. Thus any material change to the structure and/or application of the plant merit order will have an impact on the outcomes of the CBA analysis and could be material.

6.4 Application of bid and offer prices to derive constraint prices

6.4.1 Constraints resolution prices arising from ENSG CBA modelling

The table below provides full details of the derived average price of resolving constraints for each of the three variants of the Gone Green Scenario (GG5a = 6.6GW of wind in Scotland; GG5b = 8.0GW; GG5c = 11.4GW) against each possible permutation of B6 reinforcement options (essentially (i) Incremental works on the Scottish Interconnectors to provide 1100MW additional capacity to B6; (ii) Western offshore HVDC link between Hunterston and Deeside providing 1800MW extra capacity for B6; and (iii) Eastern HVDC link between Peterhead and Hawthorn Pit providing 1800MW extra capacity for B6).

Table 10 – Constraint costs and average prices of resolving constraints in CBA modelling

£m	2015/16 Winter Capability	2015/16 5c (11.4GW)	2015/16 5b (8.0GW)	2015/16 5a (6.6GW)	2020/21 Winter Capability	2020/21 5c (11.4GW)	2020/21 5b (8.0GW)	2020/21 5a (6.6GW)
0_Curr_Auth								
B4	*3.050 GW*	36.1	25.1	10.0	*3.050 GW*	466.1	129.6	59.6
B6	*3.300 GW*	213.9	182.1	83.0	*3.000 GW*	343.2	82.8	29.5
B7a	*5.000 GW*	17.4	16.0	12.1	*5.200 GW*	0.3	0.2	0.1
Other Eng & Wales	*n/a*	131.7	128.0	121.1	*n/a*	203.8	170.4	167.3
GB		**399.2**	**351.2**	**226.3**		**1,013.3**	**383.1**	**256.6**
Constraint price (£/MWh)		*94*	*92*	*88*		*95*	*82*	*80*
a_Incr_Rein								
B4	*3.750 GW*	2.2	1.1	0.1	*3.750 GW*	188.2	27.2	7.4
B6	*4.400 GW*	101.2	82.1	34.9	*4.350 GW*	190.1	35.5	12.1
B7a	*5.000 GW*	70.0	59.1	31.1	*5.200 GW*	7.9	3.3	1.3
Other Eng & Wales	*n/a*	137.6	133.3	125.5	*n/a*	190.9	169.3	167.8
GB		**310.9**	**275.5**	**191.5**		**577.1**	**235.4**	**188.6**
Constraint price (£/MWh)		*96*	*96*	*91*		*89*	*81*	*80*
b_Huer-Dees DC								
B4	*3.050 GW*	31.3	22.1	9.3	*3.050 GW*	430.6	125.1	58.9
B6	*4.900 GW*	9.7	7.2	1.1	*4.600 GW*	22.5	0.5	0.0
B7a	*7.000 GW*	0.3	0.3	0.2	*7.200 GW*	0.0	0.0	0.0
Other Eng & Wales	*n/a*	114.2	112.8	112.4	*n/a*	188.3	164.4	165.2
GB		**155.5**	**142.4**	**123.0**		**641.4**	**290.0**	**224.1**
Constraint price (£/MWh)		*81*	*81*	*81*		*88*	*79*	*79*
a+b_Incr & Huer_DC								
B4	*3.750 GW*	1.9	0.9	0.1	*3.750 GW*	172.2	26.5	7.3
B6	*6.000 GW*	4.8	3.5	0.7	*5.900 GW*	10.2	0.3	0.0
B7a	*7.000 GW*	1.4	1.0	0.4	*7.200 GW*	0.3	0.1	0.0
Other Eng & Wales	*n/a*	116.5	114.9	113.4	*n/a*	174.7	165.0	166.8
GB		**124.6**	**120.3**	**114.5**		**357.5**	**191.9**	**174.1**
Constraint price (£/MWh)		*83*	*83*	*82*		*81*	*79*	*79*
c_Pehe-Hawp DC								
B4	*4.600 GW*	0.0	0.0	0.0	*4.600 GW*	60.0	2.4	0.2
B6	*4.900 GW*	21.2	14.1	2.2	*4.600 GW*	168.6	14.0	1.3
B7a	*5.600 GW*	45.3	37.6	15.2	*5.800 GW*	9.7	3.2	1.3
Other Eng & Wales	*n/a*	131.8	128.0	120.6	*n/a*	190.0	167.3	166.8
GB		**198.3**	**179.7**	**138.0**		**428.4**	**186.9**	**169.6**
Constraint price (£/MWh)		*94*	*92*	*87*		*88*	*80*	*80*
a+c_Incr & Pehe_DC								
B4	*5.300 GW*	0.0	0.0	0.0	*5.300 GW*	13.2	0.0	0.0
B6	*6.000 GW*	6.8	4.5	0.7	*5.900 GW*	71.1	2.6	0.2
B7a	*5.600 GW*	58.1	45.5	16.3	*5.600 GW*	48.5	7.0	1.5
Other Eng & Wales	*n/a*	135.8	130.7	121.3	*n/a*	180.7	166.0	166.8
GB		**200.6**	**180.7**	**138.3**		**313.5**	**175.6**	**168.5**
Constraint price (£/MWh)		*96*	*94*	*88*		*84*	*79*	*80*
b+c_both_DCs								
B4	*4.600 GW*	0.0	0.0	0.0	*4.600 GW*	53.8	2.4	0.2
B6	*6.500 GW*	0.2	0.1	0.0	*6.200 GW*	11.1	0.0	0.0
B7a	*7.600 GW*	0.7	0.4	0.0	*7.600 GW*	0.4	0.0	0.0
Other Eng & Wales	*n/a*	115.6	114.2	113.1	*n/a*	170.2	166.3	167.2
GB		**116.5**	**114.7**	**113.1**		**235.5**	**168.7**	**167.3**
Constraint price (£/MWh)		*82*	*82*	*82*		*79*	*79*	*80*
a+b+c_Incr & both DCs								
B4	*5.300 GW*	0.0	0.0	0.0	*5.300 GW*	12.4	0.0	0.0
B6	*7.600 GW*	0.1	0.0	0.0	*7.500 GW*	4.6	0.0	0.0
B7a	*7.600 GW*	0.7	0.4	0.0	*7.600 GW*	3.2	0.0	0.0
Other Eng & Wales	*n/a*	115.6	114.2	113.1	*n/a*	169.9	166.4	167.2
GB		**116.4**	**114.7**	**113.1**		**190.1**	**166.4**	**167.2**
Constraint price (£/MWh)		*82*	*82*	*82*		*79*	*80*	*80*

In the above table, it can be seen that for all reinforcements constraint prices are highest in GG5c, which has the greatest volume of Scottish wind capacity. Most constraint prices are clustered in the range £80-£90/MWh. NGET state this is largely a function of the difference between the Offer price of the constrained-on plant (typically Marginal Gas or Marginal Coal, at £100/MWh and £120/MWh respectively) and the Bid price of constrained-off plant (typically Base Gas or Base Coal, at £10/MWh and £15/MWh respectively. It is not clear; that this is the case but the key observation is that £80-90/MWh appears to represent a high cost of resolving constraints.

6.4.2 Potential methods for setting of bid and offer prices to derive constraint costs

In an efficient and competitive market, constraint prices should reflect the fundamental economics of system operation and investment revenue recovery. The basis for what constitutes efficient constraint prices has been discussed in various publications, for example:

- In a system designed under a vertically integrated utility (central planning approach) the fuel cost differential would be the primary driver for transmission expansion to create an optimally constrained network[26]. This is the fuel cost of dispatching out-of-merit-generation to manage congestion on the network (i.e. the fuel cost differential between the constrained areas). The 2004 study by SKM based their assessment of the proposed transmission expansion plans on this assumption, using a value of between £1 and £5/MWh as the efficient cost of constraints in the UK system. For example, this might reasonably reflect the net increase in fuel cost resulting from reducing output at Longannet and increasing output at Drax.

- Under BETTA, the costs of constraints are seen in the Balancing Mechanism (BM). In addition, as BETTA is a commoditised market, the fixed costs of generation investment may also emerge in the BM alongside fuel costs. Partial recovery of generation investment costs in BM will increase the cost of constraints signalled by the market. Ofgem's final decision document on transmission investment with renewables sought to take account of investment cost recovery through the BM and developed a methodology for calculation of the recovery amount based on observed spark and dark spreads (as a proxy for operation and capital investment costs). Using

[26] Strictly, this assumes uniform investment cost of generation across the system. However, there are no fundamental problems to include generation investment cost differentials in the transmission design.

this approach, Ofgem estimated a value of between £10 - £15/MWh for transmission constraints[27].

In an efficient market, it is likely that peaking plant will recover investment costs both within the wholesale energy markets and through other mechanisms to achieve a break even or small profitable position. In which case, the efficient constraint costs should be somewhere between the ranges presented by SKM and Ofgem. However, it is recognised that this assumed market efficiency may not reflect the current or ongoing characteristics of the GB electricity market; and that in this case it could be argued that it reasonable to expect that average constraints costs will be higher.

Indeed a Frontier Economics Report[28] recently issued by Ofgem as part of its input into the ongoing review of GB transmission access arrangements uses bid-offer prices per plant type to determine potential costs of constraints under a "Connect and Manage" approach to transmission access. These are based on applying a bid "mark down" and offer "mark up" adjustment to the underlying SRMC of the plant type. Frontier Economics cite that these mark downs and mark ups are "based on Ofgem's observed BM behaviour in England & Wales, adjusted such that modelled congestion costs in 2009/10 equal expected outturn congestion cost for 2009/10". The resultant bid "mark downs" and offer "mark ups" versus the SRMC per plant type are shown below:

[27] The extent to which investment cost recovery will be seen in the balancing mechanism (and so incorporated into constraint costs) will vary according to the cost recovery of the system peaking plant. Two extreme examples of peaking plant behaviour can be considered:

a. *Peaking generation recovers all cost in the energy market*: All generators will recover their investment in energy market during peaks. In this instance only fuel costs will be seen in BM and constraint costs will be based only on the fuel price differential.
b. *Peaking generation recovers investment costs outside of energy market (e.g. ancillary services)*: Infra-marginal (mid-merit) plant recovers less than full investment costs in the energy market. Therefore, some part of the investment costs of the infra-marginal generators is diverted to BM. In this instance offers in the BM will include fuel and a part of the fixed costs of generation investment.

[28] An assessment of the potential impact on consumers of connect and manage access proposals, Frontier economics, November 2009.

Table 11 – Bid "Mark Downs" and Offer "Mark Ups utilised by Frontier Economics

Generation technology	Bid – mark downs from SRMC	Offer – mark ups from SRMC
Wind	50	N/A
Nuclear	50	N/A
Coal	5	35
Hydro	50	N/A
Gas	15	35
Pumped Storage	50	N/A
Heavy Oil	50	100
OCGT	50	250

Frontier Economics

It can be seen that; depending on the plant replacement and displacement assumptions regarding constraint resolution, the Frontier Economics approach would indicate typical costs of £40/MWh (coal replacing coal), £50/MWh (gas replacing gas) or perhaps higher (e.g. if gas replaced coal) though this is not transparent from the table. This compares with average annual volume weighted bid and offer prices as seen for coal and gas plant in the period 2005-09 as shown below:

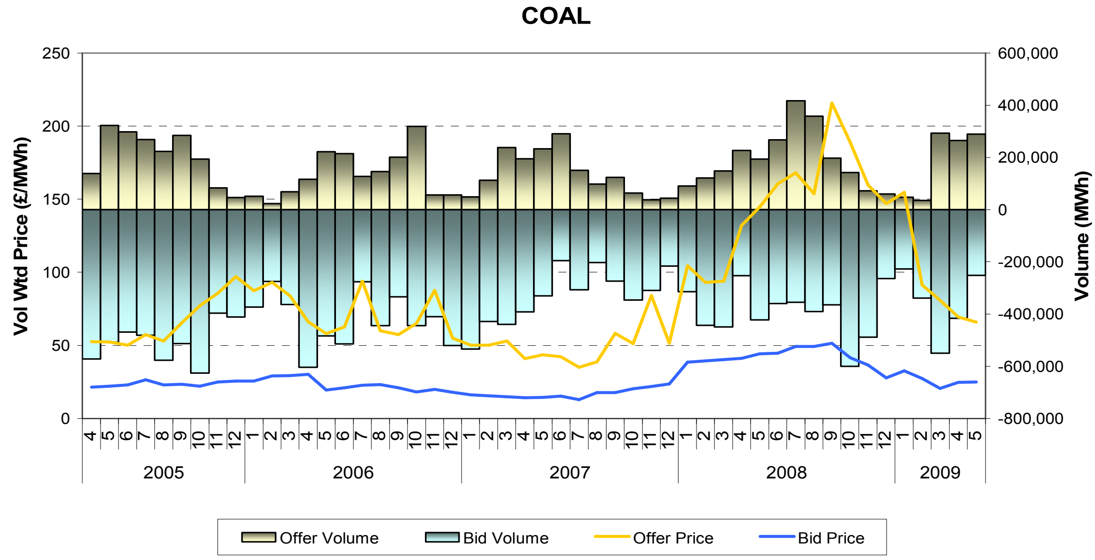
Table 12 – BETTA average accepted Bid and Offer prices for coal and gas plant

	Coal			Gas		
Year	Volume weighted bid price (£/MWh)	Volume weighted offer price (£/MWh)	Derived Bid/offer spread (£/MWh)	Volume weighted bid price (£/MWh)	Volume weighted offer price (£/MWh)	Derived Bid/offer spread (£/MWh)
2005	23.4	59.9	36.5	23.9	93.8	59.9
2006	22.9	67.0	44.1	22.8	105.7	82.9
2007	16.7	46.5	29.8	18.6	60.1	41.5
2008	42.2	152.7	110.5	37.8	105.4	67.6
2009	24.9	77.0	52.1	25.3	78.7	53.4
Average	*26.0*	*80.6*	*54.6*	*25.7*	*88.7*	*61.1*

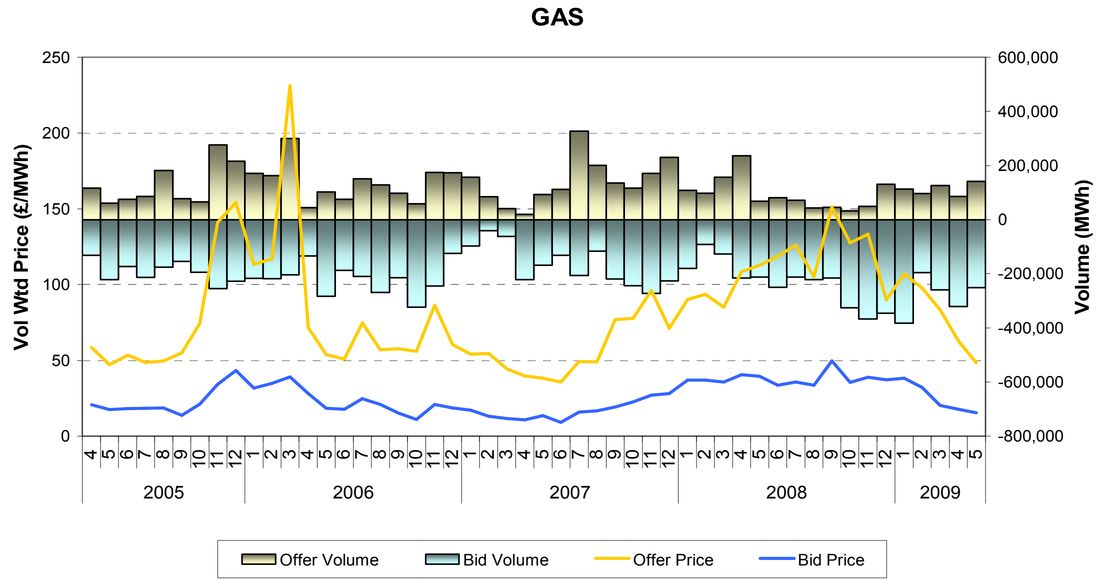
Source: NGET

This historic behaviour suggests average constraint prices of circa. £55-60/MWh but can range in any given year between £30-110/MWh. Clearly historic behaviour will reflect market circumstances such as prevailing wholesale fuel and power prices as well generation and network outage patterns but also other factors such as plant operating and related bidding strategies. This explains the degree of movement in bid, and particularly offer prices, and is further illustrated by the bid/offer price and volume charts for coal and gas plant as collective plant groups over the last 5 years.

Figure 18 – Monthly Bid/Offer prices and volumes for coal and gas plant since April 2005



Source: NGET



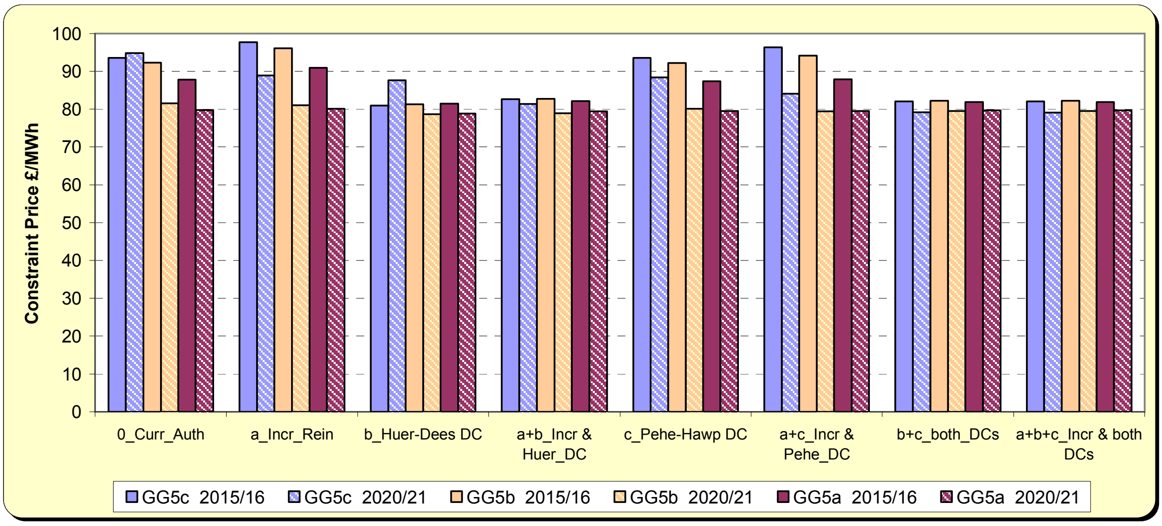
Source: NGET

Again these charts show how bid/offer prices vary over time. Thus the critical question is - what is a reasonable forward assumption for the average level of constraints costs in the GB electricity market.

6.4.3 Derivation of bid and offer prices within the CBA modelling

NGET have provided a chart illustrating the assumed outturn average cost of resolving constraints in 2015/16 and 2020/21 for each of the three variants of the Gone Green generation scenario ((GG5a = 6.6GW of wind in Scotland; GG5b = 8.0GW; GG5c = 11.4GW) against different permutations of B6 boundary expansion options. This is shown below:

Figure 19 – Average cost of resolving constraints per scenario studied in CBA modelling



Source: NGET

Given the discussion in Section 6.3.1 above, a key uncertainty of NGET's CBA analysis is whether a derived average figure of typically £80-£90/MWh as indicated above as resulting from its CBA modelling represents an appropriate price for transmission constraints. A key concern is that the long term network investment decisions could be based on high constraint prices, thereby overstating transmission investment requirements.

In providing a rationale for their underlying bid and offer price assumptions, NGET indicates that there is a historically observed relationship between wholesale power prices and the average level of accepted bid and offer prices as seen in the GB Balancing Mechanism.

NGET states that average annual bid prices are c. 0.5 times wholesale power prices levels and offer prices are c. 2 times wholesale power price levels and there is evidence to support this statement (NGET provided internal analysis to demonstrate this apparent relationship), though KEMA notes this includes all actions taken in the balancing mechanism and thus includes many actions resolving issues other than constraints e.g. short term reserve provision.

In the ENSG Report the above relationship of bid and offer prices to wholesale power prices is indicated to be used as a guide in setting of bid and offer prices for each plant type used within the CBA modelling i.e. the deemed wholesale market price/cost of each plant type is assumed to follow this relationship. In practice, however, NGET indicates that the bid and offer prices they apply are driven by observed bid and offer prices in recent history; and that they use the bid and offer price relationship set the power price per plant type and seek to verify the general appropriateness in a back-calibration of the CBA model by observing outturn power prices from unconstrained generation despatch to meet demand across the year. The bid and offer prices NGET used within the ENSG CBA modelling is shown in the table below:

Table 13 – Bid and Offer prices used by NGET in CBA modelling

Fuel Type	Bid Price (£/MWh)	Offer Price (£/MWh)
Nuclear	-100	n/a
Wind	-50	n/a
Base_Gas	10	40
Base_Coal	15	60
France	20	80
Water	23	90
Marg_Gas	25	100
Marg_Coal	30	120
PumpStor	75	300
Britned	90	360
Oil	100	400
Aux GT / Main GT	150	500

Source: NGET

It can be seen that the bid/offer spreads per plant type are wide and much wider than those adopted by Frontier Economics in its modelling of constraints costs under a “Connect & Manage” form of GB transmission access regime (see above) – although NGET do adopt a more granular structure than Frontier Economics by splitting both coal and gas plant into

Base load and Marginal sub-categories. Equally it is interesting to compare these prices with historic behaviour (e.g. average annual bid offer prices and spreads as provided for coal and gas plant above).

The spreads for marginal gas and coal plant are substantial at £75/MWh and £90/MWh. However, as highlighted previously the true bid/offer spreads from CBA constraint resolution actions are even higher depending on the type of plant in different locations and the consequent necessary combinations of which plant are constrained off and which plant are constrained on. For example;

1. replacing a base load Scottish coal plant with a marginal English coal plant would cost £105/MWh; and

2. replacing a base load Scottish gas plant with a marginal English coal plant would cost £110/MWh.

NGET indicate this explains the generally high derived CBA average constraint price for resolving B6 constraints of between £80/MWh to £90/MWh as reported in the ENSG Report and the supporting CBA documentation.

6.4.4 **History of constraints prices under BETTA**

The bid and offer prices per plant type are critical to deriving the ultimate total cost of constraints. NGET provided supporting information regarding the bid and offer price assumptions and the average price of constraints emerging from the CBA modelling in the form of historic average constraints prices seen under BETTA and information regarding the typical average annual accepted bid and offer prices for various plant types within the GB Balancing Mechanism under BETTA. Some of the historic bid and offer price information for coal and gas plant has been provided already in Section 6.3.2 above.

From the perspective of assessing historic constraints costs, the figure below as provided by NGET shows annual accepted volumes (TWh), costs (£m) and hence prices (£/MWh), of all BM and Trade actions labelled as for constraints by NGET's internal BM action tagging process, as is being discussed for potential use in formal constraint separation and tagging within the BM. The underlying data is from January 2005 to May 2009, shown by calendar year, and NGET breakdown constraints costs between England & Wales (EW), Scotland (SC) and across the B6 Cheviot boundary (CH).

Table 14 – BETTA constraints volumes and costs for E&W, Scotland and Cheviot region

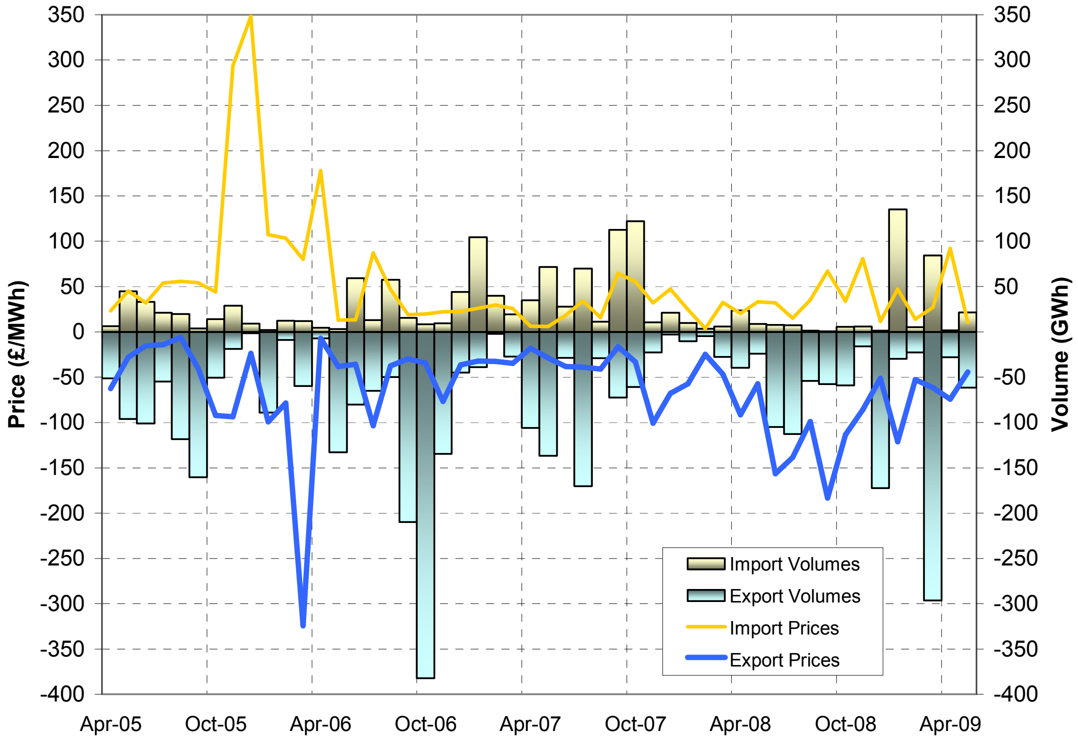
Years	REGION	EXP COST £m	IMP COST £m	EXP VOL TWh	IMP VOL Twh	EXP PRICE £/MWh	IMP PRICE £/MWh
2005	CH	£11.1	£1.7	-0.190	0.037	-58.5	46.9
	EW	£6.4	£5.5	-0.379	0.079	-16.9	70.2
	SC	£4.3	£10.7	-0.084	0.066	-51.3	162.7
2005 Total		**£21.8**	**£18.0**	**-0.653**	**0.182**	**-33.4**	**99.1**
2006	CH	£45.9	£0.1	-0.484	0.003	-94.8	32.4
	EW	£7.1	£8.4	-0.221	0.227	-31.9	36.8
	SC	£24.0	£1.0	-0.560	0.009	-42.9	108.3
2006 Total		**£77.0**	**£9.5**	**-1.265**	**0.240**	**-60.9**	**39.5**
2007	CH	£8.9	£4.8	-0.256	0.085	-34.7	56.9
	EW	£12.2	£17.1	-0.374	0.499	-32.7	34.2
	SC	£1.6	£1.6	-0.067	0.061	-23.7	26.2
2007 Total		**£22.7**	**£23.5**	**-0.697**	**0.645**	**-32.6**	**36.4**
2008	CH	£37.0		-0.356		-103.9	n/a
	EW	£12.3	£2.3	-0.105	0.080	-117.1	28.7
	SC	£22.6	£0.0	-0.222	0.001	-101.5	32.6
2008 Total		**£71.9**	**£2.3**	**-0.683**	**0.081**	**-105.1**	**28.7**
2009	CH	£12.6	£0.0	-0.209	0.001	-60.4	32.3
	EW	£5.6	£9.1	-0.086	0.248	-65.5	36.7
	SC	£9.7		-0.143		-67.4	n/a
2009 Total		**£27.9**	**£9.1**	**-0.439**	**0.248**	**-63.7**	**36.7**
Grand Total		**£221.3**	**£62.4**	**-3.737**	**1.396**	**-59.2**	**44.7**

Source: NGET - Note that export volumes are conventionally reported negative; and so export prices are reported as negative (they in fact are really positive incurred costs by NGET).

Each metric in the data set is quite volatile, with Cheviot export volumes particularly variable with costs ranging from £9m to £46m and prices from -£58/MWh to -£104/MWh. However from the point of view of the ENSG CBA work, the important metric is the export constraint price. This has averaged £59.2 /MWh over the 4½ years 2005–2009, but NGET indicate has been higher than this recently.

NGET further illustrate the volatility of constraint prices in the chart below, which shows monthly import and export prices and volumes across GB (imports being acceptance of bids; exports being acceptance of offers to relieve constraints).

Figure 20 – Average monthly GB constraint import and export volumes and prices



Source: NGET

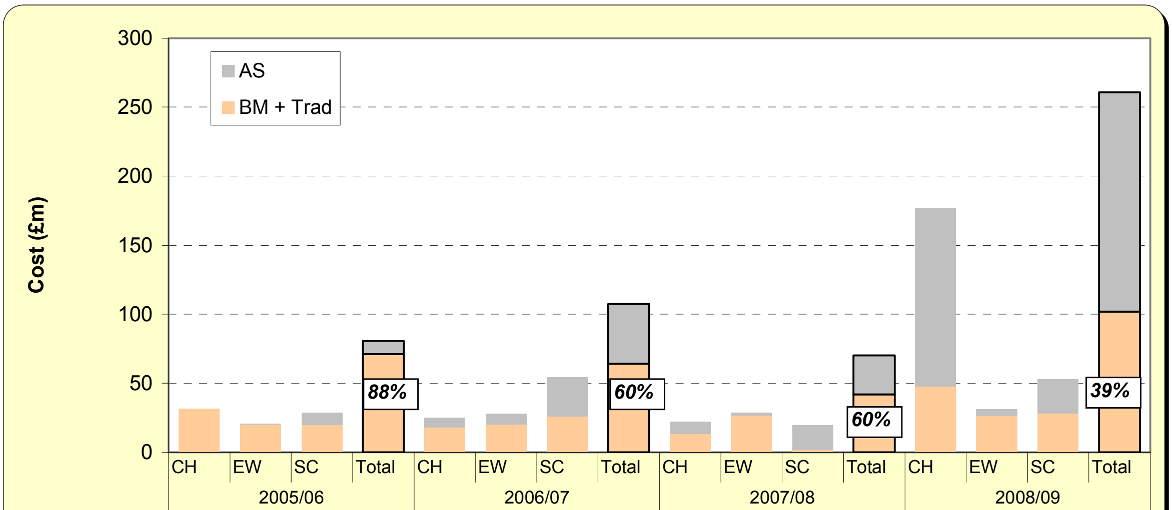
NGET refer to this analysis to indicate that:

- GB constraint prices can be volatile (e.g. sharp peaks in winter 2005) but these price peaks do not, in most instances, coincide with high volumes;
- Import prices are generally in the range £20 - £50/MWh, apart from winter 2005/6, and show a definite increase since spring 2008;
- Export prices are generally in the range -£40 - £80/MWh, but again since spring 2008 these have become more severe, averaging some -£100/MWh; and
- Export volumes are notably more volatile than the import volumes and can easily be twice the magnitude.

NGET stress that the above information only covers the prices paid to resolve constraints in the Balancing Mechanism, and also via forward locational trading. They indicate that when constraint volumes are projected to be severe, they also seek to resolve the constraints via Balancing Services contracts.

The balance of cost between Balancing Mechanism + Energy Trading, and these Balancing Services contracts, is shown below:

Figure 21 – Ancillary Services + BM & Trading costs for E&W, Scotland and Cheviot area



	2005/06 CH	2005/06 EW	2005/06 SC	2005/06 Total	2006/07 CH	2006/07 EW	2006/07 SC	2006/07 Total	2007/08 CH	2007/08 EW	2007/08 SC	2007/08 Total	2008/09 CH	2008/09 EW	2008/09 SC	2008/09 Total
AS	0.0	0.7	8.9	9.6	7.1	7.7	28.5	43.3	8.8	1.8	17.7	28.3	129.2	4.8	24.9	158.9
BM + Trad	31.6	19.9	19.6	71.1	17.8	20.4	26.0	64.2	13.4	26.7	1.8	41.9	47.8	26.2	27.9	101.9

Source: NGET – NGET indicate that this information is only readily available on a financial year basis; thus the numbers do not directly align with those in the table of constraints costs per region but are consistent.

NGET indicates that for an export constraint, the typical Balancing Services contract form is to 'buy off' generator sets at a station in the exporting group; i.e. to pay the Generator to declare unavailable for the whole period of the contract. Depending on one's prior view of how many hours per day that the generator set was going to declare both available and in-merit to run, one can assign an arbitrarily low or a very high volume to the ancillary contract; which in turn can translate into an arbitrarily high or very low constraint price for the contract.

For this reason, NGET prefers not to quote an all-inclusive price of historic constraints and that the Balancing Mechanism price can only be taken as a surrogate for the total price. In the case of severe constraints, that require NGET to go for Balancing Services contracts, they indicate this is unlikely to be representative, and they highlight that in the figure above it can be seen that the proportion of Balancing Services cost as a fraction of the total constraint cost has risen recently[29]. Hence NGET believes that "the average constraint price of c.

[29] NGET indicate that, in fact, this chart shows the percentage contribution by Balancing Mechanism + Energy Trading and this is falling year on year.

£90/MWh as used in the ENSG CBA is consistent with the average of £59.2/MWh quoted as the historic 4½-year average of BM export prices".

KEMA recognises there may short-term circumstances where there is a potential requirement for a high proportion of Balancing Services actions to resolve constraints – such as those experienced within 2008/09 due to ongoing work to expand Scottish Interconnector capacity to 3.3GW substantially reducing transfer capacity in the summer months. However, KEMA is not convinced that it is appropriate to assume a high proportion of Balancing Services actions on an enduring basis to resolve constraints across B6 which is the focus of the CBA assessment. This is based both on the relative levels seen for B6 in previous years and the expectation that issues as seen in 2008/09 will not be observed on an enduring basis.

Equally, KEMA recognises that the cost of resolving constraints from year to year will be volatile as demonstrated by history, reflecting key drivers such as the level of wholesale fuel and thus power prices but also annual generation and network outage patterns. However, in predicting such levels of constraints costs on a longer term enduring basis, KEMA believes it reasonable to consider the average costs seen over the 5 year period since BETTA was implemented as a potential indicator of the likely level of long term constraint resolution costs. It is not evident that this history was fully considered in deriving the underlying bid and offer prices in the CBA undertaken within the ENSG process nor that fundamental economic principles for long term market behaviour have been fully considered. Consequently, KEMA believes the bid and offer prices within the CBA modelling and the resultant derived constraints costs may be overstated; and therefore potentially undermines the CBA conclusion that two transmission reinforcement investments are required for the B6 boundary.

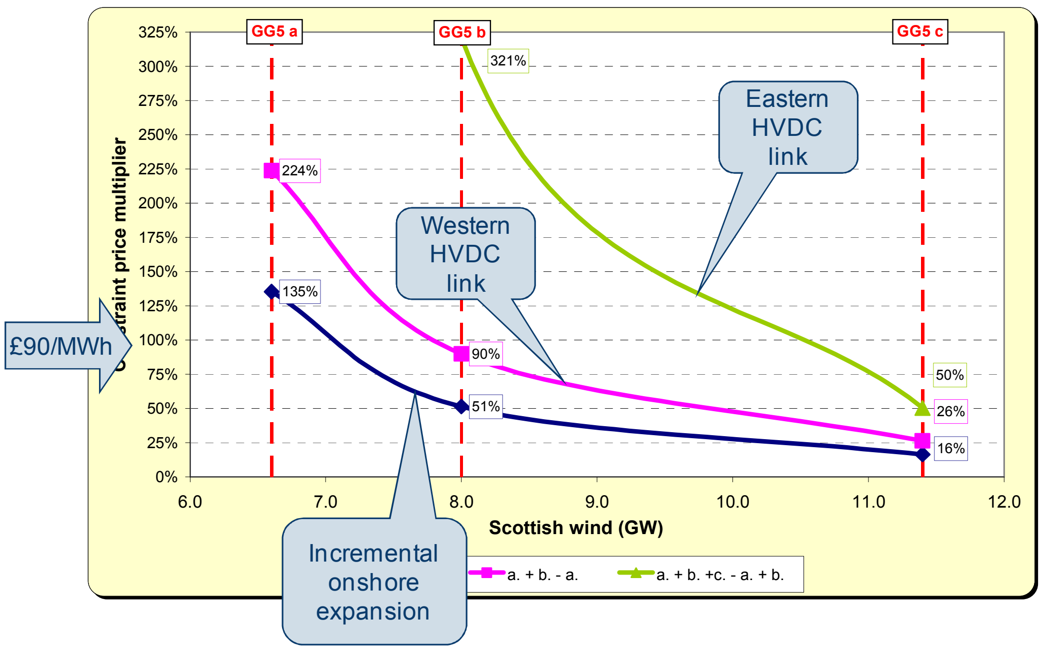
6.4.5 Sensitivity of CBA results to potentially different levels of constraint resolution costs

Any material change to the bid and offer prices will have an impact on the outcomes of the CBA analysis and could be material. Consequently, KEMA requested confirmation of the constraint price thresholds for the 3 variants of the Gone Green generation scenarios against which the proposed B6 expansion options are economically justified. Assuming no other input parameter changes (apart from updates to the costs of the investment schemes) these thresholds indicate the average constraint prices required to justify investment in the different permutations of boundary B6 investment options.

NGET has expressed these constraint price thresholds in terms of a percentage multiplier of the outturn constraint price. For example, a multiplier of 50% would suggest constraint prices would need to fall by 50% before the viability of the relevant reinforcement option(s) became marginal and if the previous outturn were £90/MWh then this would infer a required level of £45/MWh. Clearly, the lower the multiplier the greater the reduction in constraint prices there is which can be accommodated for a particular package of investments before becoming non-viable. Similarly, where the value is >100% the proposed reinforcement scheme(s) is already non-viable.

During KEMA's investigations, NGET produced a chart (replicated in Figure 22) to illustrate constraint price thresholds for Boundary B6 reinforcement permutations using material from the earlier ENSG Cost Benefit Analysis. These price thresholds were used by NGET as the basis for justifying two B6 reinforcements for additional funding. Figure 22 shows the thresholds where one, two or all three Boundary B6 reinforcement options are required, i.e. incremental works (series compensation) first, followed by the Western HVDC link and finally the Eastern HVDC link. These curves assume constraint benefits are realised over a fifteen period from 2015-2029.

Figure 22 – Constraint price thresholds to justify B6 expansion investments – 15yrs constraint recovery period



'a.-0' = implementation of "Incremental Upgrade" schemes for B6

'a. +b. – a.' = incremental addition of Western HVDC link to Incremental Upgrade works

'a. + b. + c. – a. + b.' = final incremental addition of Eastern HVDC link to previous two reinforcements

This analysis was undertaken using the scheme cost estimations from the ENSG Report. Consequently, these curves overstate the reduction in constraints prices required to make a particular investment marginal. For example, the Western HVDC link was modeled assuming a cost of £697m which was subsequently increased to £722m (excluding the majority of Deeside costs) in the subsequent funding submission to Ofgem.

It should be noted that to calculate constraints savings for the period 2021-2029, NGET extrapolated the modelled level of constraints calculated for 2020. KEMA is concerned that this approach may overstate the constraint costs avoided in these years as it takes no account of relevant changes in other factors over a ten year period. These curves demonstrate that:

1. Under the first variant of the Gone Green generation scenario (GG5a) which assumes 6GW of renewables in Scotland by 2020, in line with the Scottish Executive targets, none of the B6 boundary reinforcement investment options appear necessary.

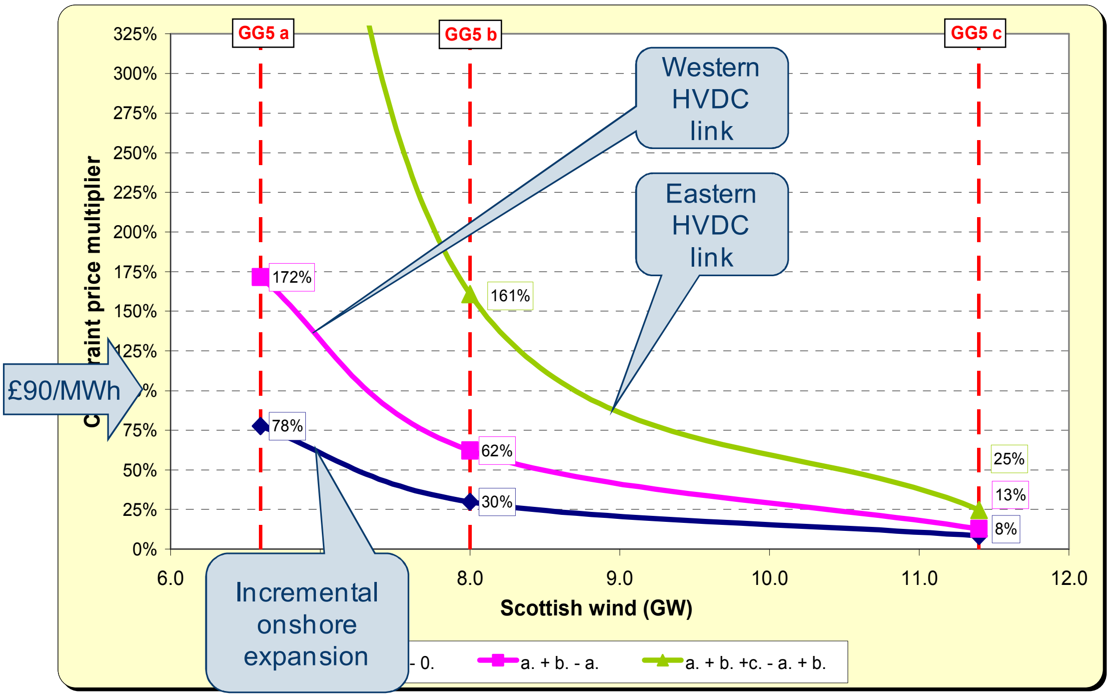
2. Under the second variant of the Gone Green generation scenario (GG5b), which assumes 8GW of renewables in Scotland by 2020, a single reinforcement scheme (Incremental works) appears justified to 50% of modelled constraint resolution prices (i.e. c. £40/MWh) but that the merits of two reinforcement schemes (Incremental works plus Western HVDC link) need only a 10% reduction in modelled constraint prices to question the economics of the second reinforcement (i.e. down to c.£72/MWh compared with an observed historic average of c.£60/MWh). Three B6 reinforcement schemes are not merited.

3. Under the third variant of the Gone Green scenario (GG5c which assumes 11.4GW of renewables in Scotland by 2020 all three reinforcement schemes would be merited down to 50% of modelled constraint resolution prices (i.e. c. £40/MWh); and two reinforcement schemes would be merited down to c.25% of modelled constraint resolution prices (i.e. c. £20/MWh).

NGET also provided a similar chart for comparison purposes providing an estimate of constraint savings accruing over an assumed 40 year asset life (2015-2054). The estimation of constraint savings for the period 2021-2054 were similarly extrapolated based on the calculated level of constraints in 2020 and assumed no changes in any other factors over the 35 year period.

The impact of these different time horizons, ceteris paribus, on requirements for B6 reinforcements is illustrated in Figure 23.

Figure 23 – Constraint price thresholds to justify B6 expansion investments – 40yrs constraints recovery period



'a.-0' = implementation of "Incremental Upgrade" schemes for B6
'a. +b. – a.' = incremental addition of Western HVDC link to Incremental Upgrade works
'a. + b. + c. – a. + b.' = final incremental addition of Eastern HVDC link to previous two reinforcements

Features of Figure 23 assuming a 40 year asset life of the reinforcement infrastructure:

1. One B6 boundary reinforcement (the Incremental Upgrade) is required under the first variant of the Gone Green generation scenario (6.6 GW Scottish wind capacity),.

2. Under the second variant of the Gone Green generation scenario (8 GW Scottish wind capacity), two reinforcement schemes (Incremental works and Western HVDC link) appear merited down to c.60% of modelled constraint prices (i.e. c.£54/MWh) Three reinforcement schemes are not merited.

3. Under the third variant of the Gone Green scenario all three reinforcement schemes would be merited, e.g. modelled constraint resolution prices would need to fall to c. £20/MWh or less to change the CBA conclusions.

No input assumptions differ between these two charts other than the time horizon for the assessment of constraint costs (15 versus 40 years), and specifically the duration of extrapolating 2020 constraint costs. This demonstrates the importance of establishing an agreed assessment methodology. Irrespective of the time horizon under consideration, it can be seen that the economics of B6 boundary expansion options can be sensitive to the Scottish wind generation scenario under consideration.

KEMA is concerned that the extrapolation technique adopted could materially overstate constraint costs, thus improving the economics of transmission network reinforcement. This concern is particularly relevant for the 40 year constraint cost assessment and hence KEMA regards the 15 year approach to be more robust.

The 15 year case indicates that under GG5b, the requirement for two B6 reinforcements is sensitive to underlying bid/offer price assumptions and in combination with other potential assumption changes (e.g. wind load factor, generation patterns) this could undermine the investment case for more than one reinforcement scheme for Boundary B6.

The 40 year case indicates that under scenario variant GG5b, the requirement for two B6 reinforcements is more robust as a 40% reduction in constraints costs (from circa. £90/MWh - £54/MWh) is required to change the economics of network investment. However, given the potential variations in CBA input assumptions, the historic average level of constraints costs and the strong reliance on extrapolation assumptions, KEMA believes the case for two reinforcements remains uncertain.

For the purposes of the ENSG work, NGET assumed an equal weighting for each scenario and this underpins the CBA conclusion that two B6 reinforcement schemes (Incremental works and Western HVDC link) are required. Whilst NGET indicated that the conclusion was robust to an adjusted weighting of 44%/33%/22% for scenario variants GG5a (6GW Scots wind), GG5b (8GW Scots wind) and GG5c (11.4GW Scots wind) respectively; this requires all other key assumptions to remain unchanged. KEMA is doubtful whether the overall cost benefit result is robust to wider variations in input assumptions.

Consequently, conclusions from the CBA modelling are sensitive to the level of bid/offer prices assumed (thus the derived constraint resolution costs) and the weighting of the generation scenarios. KEMA believes that alternative combinations of input assumptions could easily produce different end conclusions regarding the level (and timing) of B6 reinforcement options and particularly the short-term requirements to commit to the Western HVDC link.

7 RELEVANT FUTURE GB REGULATORY AND MARKET DEVELOPMENTS

In this Section we discuss the impact that potential regulatory/market reforms may have on the process of evaluating TO investments; three key areas are considered as follows:

1. The fundamental review of the GB SQSS;

2. The GB Transmission Access Review (TAR) process; and

3. The RPI-X@20 review of network utility price regulation.

It is important to recognise that these initiatives may incentivise the release of network capacity through operational measures and may potentially reduce constraint costs and or network reinforcement requirements. As such each of these and their potential impacts on the level of TO investments necessary to facilitate the achievement of the Government's renewables targets for 2020 are discussed below.

7.1.1 Review of GB SQSS and its potential impact

In determining the reinforcements necessary under the scenarios considered in the ENSG Report, the current GB SQSS was used for the majority of schemes. The transmission network design standards set out criteria and methodologies that are used in the planning and operation of the GB transmission system; the criteria presented in the standard represent the minimum requirements for planning and operations. The overall aim of the transmission security standard is to ensure that the transmission network does not unduly restrict generation in securing demand and to facilitate market operation. The standard is composed of two parts, usually referred to as the deterministic element and the subsequent cost-benefit part. The deterministic element specifies the requirement for network capacity driven by the need to securely meet peak demand. However, additional network capacity may be justified if a network designed in accordance with deterministic security criteria would result in excessive network constraints costs. In this case, cost benefit analysis (CBA) is then applied to balance the costs of investment against the cost of constraints over the life time of the network assets concerned. The standard was originally established for a system predominately supplied by conventional generation (i.e. thermal or hydro generation). With the expected significant increase in intermittent generation, it became apparent that it may be necessary to update the GB SQSS and 2008[30] the GB Transmission Licensees proposed a change to the GB SQSS to include the effects of onshore wind generation. However, this consultation did not result in any formal change to the GB SQSS and this initiative has been superseded by the Fundamental Review of GB SQSS, which is ongoing.

Although there are variations, most transmission planning and operational practices internationally are still centred on the historic deterministic “N-2 / N-1” type criteria developed in late 1940s. These deterministic standards have been used to guide electricity transmission network reinforcement and operation since that time. Although the networks, designed (and operated) in accordance with these deterministic standards have delivered secure and reliable supplies to customers, the key issue being evaluated over the last several years has been whether a future evolution of such an approach is required. In operational timescales, the key question is associated with the rules that are used to determine an optimal volume of network capacity that should be released to network users.

Establishing the optimal level of network capacity that should be made available by network operators in real-time must appropriately balance the value that users attribute to the level of network capacity released, against the cost of reserves, losses and expected costs of interruptions (caused by forced outages of generation and network facilities) that is associated with the released network capacity. Major concerns with the present standard are:

- Deterministic standards do not (accurately) reflect the levels of operational risk and costs that the power system users actually face. The binary approach to risk in the deterministic standard is fundamentally problematic. System operation at any given point in time is considered to be exposed to no risk at all if the occurrence of any selected single contingency does not violate the operational limits, while the system is considered to operate at an unacceptable level of risk if the occurrence of a credible contingency would cause some violations of operating limits. Clearly, neither circumstance is correct, as the system is indeed exposed to risks of failure even if no single circuit outage leads to violations of operating constraints, and the risk of some violations may be acceptable if these can be eliminated by an appropriate post fault corrective action.

[30] http://www.nationalgrid.com/NR/rdonlyres/B6B8CABD-6D2C-4D1E-A48F51789CA93484/22606/GBSQSS_Review_for_Onshore_Intermittent_Generation.pdf

- The degree of security provided by deterministic security criteria, using generic rules applied in all situations, may not be optimal in a particular instance as the cost of providing the prescribed level of security is not compared with the reliability profile (cost) delivered. Recent analysis shows that such generic rules in the present standard may be very inefficient in individual circumstances. Similar findings were presented in the Review of the Standards conducted in 1994.

- The present deterministic GB SQSS framework may prevent technically effective and economically efficient non-network solutions from being adopted. In contrast to the historical (deterministic) approach of delivering network flexibility through redundancy in primary assets only[31], there has been a clear trend in making use of advances in various technologies. Such technological advances could be used to provide the flexibility through more sophisticated system operation techniques such as dynamic line rating, special protection schemes, coordinated control, application of advanced maintenance techniques and application of advanced decision making tools. Equally the application of non-network solutions particularly through demand response and generation solutions to network problems could provide benefit. Only within a cost benefit framework can alternative solutions to network problems be compared.

- Given that the outage probabilities, failure rates and repair times of transmission lines and other equipment vary considerably, it is therefore not possible to deduce a single value to be used in a deterministic standard to quantify the risk the system is exposed to. Such a deterministic standard might be good on average but it may not be appropriate when considering individual cases. Recent analysis shows that the present standards would unduly limit the amount of capacity that should be released to network users, particularly during fair weather conditions.

In summary, the concerns are that the present standards can result in potentially inefficient outcomes, may not deliver value for money to network users, may impose barriers for innovation in network operation and prevent implementation of technically effective and economically efficient solutions that enhance the utilisation of the existing assets. The Fundamental Review of GB SQSS seeks to address these overarching concerns that the historical approach to network planning and operation is inefficient and could adversely impact the development of the UK low carbon future. There is an opportunity to shift the network operation and design philosophy from network infrastructure centric solutions to

[31] Work conducted in the development of ER P2/6 demonstrates well established fact that redundancy cannot be universally used as a measure of security.

become more open to all solutions and deliver smarter, secure and cost effective transmission network.

In summary, cost/benefit based approaches to network security could lead to more of the existing network capacity being released to network users, thereby resulting in a reduction in constraint costs and reduced need for network reinforcement to accommodate any given expectation of the volume and siting of connection of wind generation.

7.1.2 **Review of GB transmission access arrangements**

A major review process which is currently underway and which is expected to have a substantial impact on the relationship between connection of new generation (in particular renewables in Scotland) and the network required to facilitate their connection is the "Reform of Grid Access" review being conducted by DECC after the Secretary of State was asked by Ofgem to intervene in resolving GB transmission access arrangements.

There is concern that the current transmission access arrangements which can be characterised as "Invest-then-Connect" (i.e. all network reinforcements deemed necessary to be in place under SQSS based assessment of the impact of the connection must be in place before then generator can have access to the network) are acting as a blockage to the connection of substantial volumes of renewable generation. In parallel specific options/models for reform of transmission access arrangements were also pursued under the existing industry governance processes.

However, given a prolonged process of review circa.12-18 months; DECC were asked by Ofgem to directly intervene and to use the powers of the Secretary of State under the Energy Act to determine and implement a new enduring form of transmission access arrangements. Having considered the pace of reform, DECC have decided to use these powers and have initiated a consultation process to enable it to decide what the revised enduring form of transmission access arrangements should be and to mandate their implementation in 2010.

In its Consultation Paper released in August 2009[32], DECC indicated that their initial view was that a form of "Connect and Manage" regime should be implemented in 2010 and highlighted 3 potential variants of this approach which might be appropriate. This consultation formally closed on 17 November and DECC are now reviewing industry and

[32] Improving Grid Access, DECC Consultation document, issued 26 August 2009

other stakeholder responses with a view to formulating a final decision which it will communicate early in the New Year for implementation at the earliest possible opportunity within 2010.

A Connect and Manage approach is fundamentally different form a Invest-then-Connect approach as it enables generators to obtain access to the transmission system following completion of local connection works although they might be subject (depending on the variant of the model) to interim tailored network charges until completion of the wider transmission works deemed necessary. It should be noted that Ofgem has already instigated and approved the implementation of an Interim Connect and Manage arrangements, pending the outcome of the wider review. Under these Interim arrangements, NGET (as GBSO) is utilising its quarterly reporting procedures to get generators to flag requirements for earlier connection and then proceed to provide Interim Connect & Manage based connection offers.

The key feature of this transmission access reform (and the Interim arrangements) which impacts on the proposed network investments to facilitate 2020 renewables targets is that under a Connect and Manage approach the completion of wider network reinforcements, such as expansion of the transfer capacity between Scotland and England across Boundary B6, does not act as the determinant of the earliest possible connection of renewables generation. As such, even assuming all the network reinforcements identified under the TO Investment process are required, it is not necessary for them to be in place before associated renewable generators can connect and export power onto the transmission system.

Furthermore, where there is uncertainty regarding the need or timing for particular transmission reinforcements any decision now to postpone proposed investments, if subsequently shown to be incorrect in light of generation developments; should not delay connection of renewable generation or curtail output. Against this background, it might be prudent where there is high uncertainty over the need and/or timing for major transmission reinforcement investments to delay investment decisions until there is greater certainty, the risk/consequence being potentially higher short-term constraints costs than would otherwise have been the case. It should be noted that under a Connect and Manage transmission access arrangement, constraint volumes (and thus costs) could be increased in the medium term relative to an Invest-then-Connect arrangement. However, the consequent risk that these investments are subsequently found not to be required (for whatever reason e.g. generation developments or review of the GB SQSS) will be reduced. This assessment will need to be made on a case by case basis to identify where it is reasonably expected that the benefit of saving unnecessary investment is greater than the potential cost increase incurred via higher constraints costs.

As such this forthcoming reform to transmission access arrangements should be taken into account by Ofgem when considering the requirement to make early commitment to funding of substantial investment costs relating to reinforcement works which are dependent on factors which are highly uncertain.

The costs of transmission network constraints (BSUoS charges) are currently allocated among generators and demand on a non-location specific basis. Future arrangements for the allocation of constraint costs may become more cost reflective (as discussed in the current DECC consultation paper), which would effectively make generators more responsive to the constraint costs they cause. As a result of such a change in the allocation of BSUoS charges, the overall costs of network constraints may reduce and depending upon the form of any cost-reflectivity, such a change in BSUoS allocation could also impact on the cost benefit need case for some investments associated with network reinforcement.

7.1.3 **Review of RPI-X and its potential impact**

It is important to recognise that in addition to the fundamental review of the GB SQSS, and GB transmission access arrangements, wider developments in the field of network regulation and associated incentive frameworks could potentially improve the availability of network capacity and avoid over reliance on asset heavy solutions.

The existing regulatory framework rewards network investment over operational alternatives, potentially discouraging the implementation of effective and economically efficient 'non-network' solutions as an alternative to the conventional asset-based solutions. Some of the current initiatives under discussion in the smart-grid debate encourage consideration of more sophisticated system management measures through an increased use of the demand-side and consideration of advanced real-time network control techniques. These are potential options that contribute to the release of additional network capacity and the control services have the potential to increase network utilisation and function as an economic alternative to the reinforcement of network infrastructure.

The future of network regulation, being considered under the RPI-X@20 initiative, will consider the fundamental question of whether the level of network capacity released to network users in operational timescales is delivering optimum value for money to users.

Mechanisms may need to be established that provide assurances to all parties (network users, network operators and the regulator) that an appropriate balance is being struck between costs and benefits in the decision-making process associated with the release of network capacity in real-time and the provision of additional infrastructure. Such practices may also remove barriers to implementing innovations to enhance efficiency of network operation and development.

Although some of non-network solutions are being considered, the present regulatory framework may become a barrier to taking full advantage of such techniques given the current absence of incentives for non-network solutions to be compared on equal footing. In this context, modifications to the regulatory framework that might incentivise release of network capacity through operational measures could result in reduction in constraint costs and reduced need for network reinforcement.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 Summary of KEMA's assessment

Based on its review of the TOs' individual proposed schemes, the review of the overall plan and the supporting cost benefit assessment modelling exercise; KEMA has formed the following view of the relative certainty of need and timing for each investment scheme. In addition, KEMA has assessed the potential requirement for additional funding under the current TPCR4 period. A summary of the key findings are outlined in the table below.

Table 15 summarises KEMA's conclusions regarding (i) certainty of need; (ii) certainty of timing and highlights (iii) materiality of additional TPCR4 funding sought for each of the projects proposed.

Table 15 – Scheme need, timing, scope, interactions; and level of TPCR4 funding sought

Scheme	Timing	Certainty of need	Certainty of timing	Appropriate-ness of Scope	Materiality of additional TPCR4 funding	Interaction with other schemes
Knocknagael (SHETL)	09/10 - 11/12	High	High	High	Medium	Stand alone
Western Isles link inc. Lewis infrastructure (SHETL)	09/10 – 13/14	Medium	Low	Medium	Very High	Stand alone (partly drives BBK and East Coast upgrade)
Beauly-Blackhillock-Kintore uprating (SHETL)	09/10 – 14/15	High	High	Medium – High	Low-Medium	Partly driven by Western Isles, Beauly-Dounreay, and Shetland
Beauly-Dounreay (SHETL)	10/11 – 12/13	High	High	High	Medium	Stand alone (partly drives BBK and East Coast upgrade)

Scheme	Timing	Certainty of need	Certainty of timing	Appropriate-ness of Scope	Materiality of additional TPCR4 funding	Interaction with other schemes
Hunterston-Kintyre link (SHETL/ SPTL)	10/11 – 13/14	High	High	Medium	Medium – High	Stand alone
Scottish Interconnector upgrade[1]	10/11 – 14/15	Medium - High	Medium	Medium	Medium – High	Interactive with East Coast Upgrade and HVDC link schemes
East Coast upgrade (SPTL/SHETL)	11/12 – 17/18	Medium - High	Medium	Medium – High	Low	Interactive with Scottish interconnector upgrade and HVDC link schemes
Western HVDC link (NGET/ SPTL)	10/11 – 15/16	Low - Medium	Low	Medium	High	Interactive with Scottish Interconnector, East Coast Upgrade and Eastern HVDC link schemes
Eastern HVDC link (NGET/ SHETL)	09/10 – 12/13 (pre-con only)	Low - Medium	Low	Medium	Low	Interactive with Scottish Interconnector, East Coast Upgrade and Western HVDC link schemes
East Anglia (NGET)	09/10 – 16/17	High	High – Medium	High	High	Stand alone (partly drives London)
London (NGET)	11/12 – 15/16	High	High	Medium – High	Low	Partly driven by East Anglia
North Wales (NGET)	11/12 – 16/17	Low	Low	Low – Medium	Low – Medium	Stand alone
Central Wales (NGET)	12/13 – 15/16	Low	Low – Medium	High	Low	Stand alone
South West (NGET)	12/13 – 16/17	Low	Low	High	Low	Stand alone
Humber (NGET)	13/14 – 16/17	Low	Low	Medium	Low	Stand alone

Scheme	Timing	Certainty of need	Certainty of timing	Appropriate -ness of Scope	Materiality of additional TPCR4 funding	Interaction with other schemes
Shetland (SHETL) - either link or offshore hub variant	10/11 – 14/15	Low	Low	High	Very High	Stand alone (partly drives BBK and East Coast upgrade)

1. Comprises Anglo-Scottish incremental works (NGET), SPTL-NGET interconnection scheme (SPTL) and East - West upgrade (SPTL).

KEMA believes that the overall investment plan represents a coherent collection of schemes and that the majority can be considered solely on their own merits with no reference to other schemes in the plan. Others can be judged to have dependencies on other schemes such as the East Anglia investment influencing the London requirements. The remainder are closely linked to the expansion of transfer capability across Boundary B6 and thus the scheme interaction(s) that need particular scrutiny are within this subset of schemes.

In general, schemes with the highest level of uncertainty of need and timing are those schemes with later start dates i.e. in TPCR5 and/or longer term completion dates. This reflects the naturally greater uncertainty in generation developments which is the principle drivers of the need and timing of the schemes. This is to be expected and there will be a natural opportunity to review theses schemes further as part of the TPCR5 process. However all schemes incur, to a greater or lesser degree, pre-construction costs within TPCR4 and. KEMA believes it remains reasonable for the GB TOs to undertake the associated pre-construction works deemed necessary to finalise and implement each scheme.

Within Table 15 above that there are a number of schemes, relating to expansion of transfer capacity from Scotland to England across Boundary B6. Furthermore, it can be seen that of those schemes with material impact on additional funding requirements within TPCR4 timescales; generally have the higher cost in simplistic £/kW terms of network capacity provided. Within the earlier ENSG analysis, the proposed requirement and timing for these B6 related schemes was informed by the CBA undertaken by NGET; and this work was used by the TOs to support funding requests submitted to Ofgem in relation to proposed schemes to reinforce B6 in September 2009. Therefore this CBA exercise forms a crucial foundation for the justification of the schemes put forward for additional funding. Thus both the robustness of modelling approach and the criticality of key assumptions has been subject to extensive review by KEMA. KEMA is satisfied that the general modelling approach adopted by the CBA, appears to be robust.

Three potential options were presented to enable expansion of Scotland-England transfer for which additional funding is being sought. These options are as follows:

1) “Incremental Upgrade” of the existing Scottish Interconnector. This option actually includes four of the schemes put forward for additional funding;

2) Western offshore HVDC link connecting Hunterston to Deeside; and

3) Eastern offshore HVDC link connecting Peterhead to Hawthorn Pit.

The first option includes four of the schemes put forward for additional funding. KEMA is comfortable that the combination of scheme provides not just an appropriate and cost effective means of delivering capacity increases to 4400MW across Boundary B6 but also seeks to optimally incorporate capacity expansion requirements across other key neighbouring boundaries such as B4, and B7/7a.

- KEMA is comfortable that the three options probably represent the most practical alternative options for substantial and effective expansion of the transfer capability across the B6 boundary. Thus the primary area of uncertainty is the relative merits and timing of the 3 B6 expansion options and in the case of the “Incremental Upgrade” works the timing of the four component individual schemes.

The results of the CBA modelling are extensively reported in Section 6; as are the key assumptions underpinning the modelling exercise. Section 6 further illustrates both the potential for alternative views/values of the assumptions and their consequential impact on the overall CBA analysis. In particular, four aspects have been highlighted which have significance on the modelling outcomes:

1. Wind generation load factor assumption(s);

2. Application of plant merit orders in deriving constraint volumes;

3. Application of bid and offer prices in deriving constraints prices; and

4. Weighting of generation scenarios to determine forward view to cover uncertainty.

In addition any upward cost revisions for the B6 boundary related schemes (particularly the HVDC links) should be included by NGET when reviewing the CBA.

The table below summarises KEMA's view of the key assumptions/factors within the CBA modelling exercise and suggests potential alternative views/values, discusses the reasons why these values might be considered , and then highlights the potential impact on the conclusions of the CBA.

Table 16 – Key CBA assumptions, alternative views and potential implications

Factor	ENSG Baseline Assumption(s)	Alternative views	Materiality	Implications for investment of alternative views
Wind load factor	35% for onshore and offshore	Onshore wind has typically delivered a 28% load factor although may be higher in northern Scotland. Offshore wind expected to be better but current proposed projects indicate similar performance.	Potential 20% reduction in average contribution to power flows. Biggest MW transfer impact in areas of assumed/forecast high levels of wind generation	Use of historic performance levels might reduce investment requirements primarily dependent on/driven by new wind generation
Plant merit order	Plant allocated to base, marginal or "split" status according to historic running; no locational factors considered by fuel type.	Changing generation mix may change presumed status of some key conventional plant, especially in Scotland; adoption of locational costs would change relative merits of specific plants within plant type categories	Under ENSG bid/offer price assumptions - change of a coal plant from base to marginal status increase bid price from £15/MWh to £30/MWh and increases offer price from £60/MWh to £120/MWh; change of a gas plant from base to marginal status increases bid price from £10/MWh to £25/MWh and increase offer price from £40/MWh to	Unclear. This will depend on which plants are adjusted and any interactions; and will vary by boundary. However, for B6, as a general rule changes which make Scottish plant more marginal and English plant more base will reduce investment requirements and vice versa.

			£100/MWh. Bulk of Peterhead and part of Longannet assumed to be base load generation.	
Bid/offer prices	Derived per plant category; using an assumed relationship of bid prices = 0.5* generator wholesale price and offer price = 2* generator wholesale price	Seek to reflect average historic levels of bid/offer prices and/or average levels of cost of constraints (c. £60/MWh). Alternatively seek to model bid/offer prices aligned with LRMC principles.	Materiality will vary dependent on the assumptions adopted. However calibrating to the historic average constraint resolution cost of £60/MWh would represent 25% or greater impact	Impact could be higher or lower dependent on historic period considered and exact definitions used to derive bid/offer prices or "the cost of constraints". On balance though given a long term outlook there appears to be greater likelihood of downside risk to investment cases based on CBA.
Scenario weighting of three future generation patterns	Equal weighting of variants of 6.6GW, 8.0GW and 11.4GW of wind in Scotland within the overall Gone Green scenario	Varied weightings e.g. placing varied emphasis on the scenarios	Materiality varies by investment case and by generation scenario.	For example, on the assumption greater weighting is given to the scenarios with lower levels of wind generation in Scotland this would reduce the strength of case for investment across B6.
Investment costs	Cost estimates at April 2009 e.g. Western HVDC link costed at £697m	Values as submitted for additional funding in September 2009 e.g. Western HVDC link now costed at £722m excluding majority of Deeside costs.	Offshore HVDC links are currently viewed to be 10-15% more expensive than originally viewed under ENSG	Higher investment costs require higher levels of constraints costs to achieve same level of CBA outcome. Marginal CBA cases for certain reinforcements under certain scenarios could become negative.

Time horizons for constraint cost estimations and enduring cost assumptions	15yrs was initially (2015-2029) used in ENSG CBA work; NGET has since proposed extending the CBA time horizon to 40yrs (2015-2054). Costs for 2021 and beyond assumed equal to those in 2020	Constraints benefit time horizon aligned with asset life but level of constraints avoided will vary as future demand, generation patterns, and generation prices evolve	Choice of horizon has major impact on CBA results; as does assumption of long term level of annual constraints costs	Concern that the extrapolation approach for forecasting constraint costs throughout the assumed asset life will overstate the long-term level of constraints avoidance benefits.
Cost of transmission losses	Assumed to be c.£60/MWh	CBA model assumes wholesale prices of £50/MWh falling to £40/MWh	Losses are a relatively minor part of the CBA – but could impact on marginal CBA results	Alignment to modelled wholesale prices will reduce benefits modelled and could impact on marginal CBA results

It is noted that there are number of key factors for which alternative assumptions could impact CBA modelling outcomes. Whilst differing CBA assumptions have the potential to reinforce or alternatively undermine proposed investment cases, the review of the assumptions in the table above would suggest there is a greater probability that the drivers for investment will be reduced and in particular the timing of reinforcements required to expand transfer capacity across Boundary B6; This analysis also appears to call into question the CBA conclusion that two investments for Boundary B6 are definitely merited i.e. it may be that in revisiting/sensitivity testing key CBA assumptions it may be subsequently determined that only one reinforcement for Boundary B6 is required to economically cover the range of forward uncertainties regarding the level and location of renewable generation.

8.2 KEMA's final conclusions

8.2.1 Overall Plan

The £5bn of additional investment proposed by the TOs for additional funding in the period up to 2020 represents a substantial incremental investment on the GB transmission networks equivalent to total capex funding for the 3 GB TOs under the current TPCR4.

The pattern of renewable generation which could arise is highly uncertain and this is recognised in the three variants of the Gone Green scenario, flexing the capacity of wind generation between Scotland and England. In this context it is clear from the information provided that the variant of the Gone Green scenario has;

a. a substantial impact on the presumed level of transmission investment required across the Scotland-England border (Boundary B6) – ranging from no investment requirement to in excess of £2.2bn of investment required; or.

b. no material impact on the need and timing of the other submitted (non-B6 related) schemes.

Given the above, the CBA modelling exercise utilised specifically focused on assessing the merits of potential Boundary B6 related schemes. The outcome of this CBA modelling exercise concludes that two B6 related schemes are merited and that these should be the incremental works and the Western HVDC link. Where two reinforcements are required KEMA believes there is an arguable case that the Eastern HVDC link may be a more effective investment than the Western HVDC link and that this view has not been convincingly dismissed by the analysis. .

However, the outcome of the CBA modelling exercise is critically dependent on a number of key assumptions and whilst KEMA accepts that there is some uncertainty over what these assumptions should be; it believes that on balance that the assumptions adopted are overly favourable to the need for investment to expand Boundary B6 capacity. Based on the information provided to KEMA under this review it believes there is very strong uncertainty that two B6 related schemes are required and that the timing of need for the second scheme (i.e. the indicated choice of Western HVDC link) is not urgent. KEMA believes that a delay would allow further consideration of what is the appropriate second stage expansion of the B6 boundary and such a delay would also allow the TOs to firm up on the appropriate exact final scheme given they have indicated some key uncertainties still remain (e.g. for the Western HVDC link, it is not yet certain Hunterston will be the landing point in Scotland).

It is also important to note that should an enduring Connect & Manage transmission access arrangement be implemented, KEMA believes a delay to a 2nd stage expansion of B6, if subsequently deemed to be required would not impose a delay to the connection of proposed new renewables generation in Scotland. KEMA also notes that committing to £92m of additional funding in TPCR4 would essentially trigger a commitment to £687m of expenditure within TPCR5. KEMA believes Ofgem should carefully consider the merits of the requirement and level of additional funding for any second stage expansion of the B6 boundary under TPCR4.

8.2.2 **Scheme specific**

In total, there are 18 schemes put forward by the TOs for additional funding.

KEMA's views on these are as follows (noting that commentary is provided on the basis of the original understanding of both the TOs and KEMA at the time of information submissions and assessment; that TPCR5 would commence in 2012/13):

TPCR5 Schemes

Four schemes, namely Central Wales, South West, Humber and Eastern HVDC link, do not require construction funding in the current Price Control (TPCR4) period. These are also each subject to high uncertainty of both need and timing given their strong dependence on highly uncertain future generation volumes. KEMA recommends that no decision is made on additional construction funding for these schemes at this stage; and they should be revisited as part of the TPCR5 process; but that pre-construction funding should be granted.

KEMA notes that whilst the investment appraisal process has earmarked the Eastern HVDC link as the 3rd of three Boundary B6 expansion options (Incremental Upgrade, Western HVDC link and Eastern HVDC link), given the headline results of the CBA modelling and the dependency on key assumptions regarding generation patterns and other factors in the CBA modelling; there is considerable uncertainty about the need and timing for this scheme. In particular it is worth highlighting that some CBA modelling results suggest that the Eastern HVDC link may represent a more effective single capacity expansion option for Boundary B6 than the proposed Scottish Interconnector upgrade works and that it may be a preferable 2nd stage option to the Western HVDC link.

Schemes commencing 2011/12

There are five schemes proposed to commence construction in 2011/12, the last year of the current price control (TPCR4). Within these five schemes it is noticeable that four – namely the East Coast upgrade, East-West upgrade, London and North Wales incur a relatively small proportion of the total scheme costs in this first year, especially the latter three schemes. This is highlighted in Table 17 below.

Table 17 - First year and total scheme costs for schemes commencing 2011/12

Scheme	First Year Construction Spend in 11/12 (Last Year of TPCR4)	Total Scheme Cost	Percentage of spend
Anglo–Scottish incremental works	£47m	£183m	26%
East-West upgrade	£8m	£83m	10%
North Wales	£23m	£444m	5%
East Coast upgrade	£7m*	£253m	3%
London	£4m	£186m	2%

* This is a joint SPTL/SHETL scheme. However, only SPTL submitted construction costs for this scheme and SHETL are not planning any expenditure before 2013/14

The obvious issue for the latter four schemes is that large investment expenditure could be triggered by granting of additional funding of relatively small sums in TPCR4 for the commencement of construction for these schemes. Given the low materiality of spend/scope of construction works proposed in 2011/12 for these schemes, KEMA does not believe that a delay of scheme commencement into the TPCR5 timeframe will unduly impact on the ability of the TOs to deliver these schemes to the proposed scheme completion dates. Furthermore, given the level of uncertainty associated with both the need and timing of these schemes KEMA believes that it may not be appropriate to commit to additional TPCR4 funding for construction works. This is particularly the case for North Wales, and the London scheme; and it may equally be the case for (i) the East Coast upgrade scheme unless SPTL can demonstrate the constraint cost avoidance benefits by coordinating their works under the East Coast upgrade scheme with the works for SPTL's East-West scheme; and/or (ii) the East-West upgrade scheme unless SPTL can demonstrate the benefits provided by aligning the Torness-Eccles cable element with the SPTL-NGET Interconnection scheme. However, KEMA believes it would be appropriate to fund pre-construction works.

Schemes commencing 2010/11

There are five schemes proposed to commence construction in 2010/11 namely:

- Beauly-Dounreay;
- Hunterston-Kintyre;
- SPTL – NGET interconnection;

- Western HVDC link; and

- Shetland.

Of these, KEMA believes Beauly-Dounreay and Hunterston-Kintyre are required and it is appropriate to allocate additional funding for construction of these schemes within TPCR4. This recommendation would still need to be based upon Ofgem's determination of the efficient cost of delivery and the practicality of the proposed timing of commencement.

The SPTL – NGET interconnection scheme commits a small amount (£5m) of expenditure in 2010/11 related to circuit turn-in rearrangements and these are to be timed to coincide with other planned outages in the locality which is argued will save £20m of constraints costs for the construction works. Thus whilst KEMA believes it would be possible to commence construction of this scheme in 2011/12 without impacting on the completion date, it accepts that there is a economic reason due to circumstances specific to this scheme which merit its 2010/11 commencement.

As highlighted in Section 8.2.1, the Western HVDC link as proposed would entail £92m of additional funding for construction works in TPCR4 but would essentially trigger a commitment to £687m within TPCR5. However, from its assessment of the CBA modelling exercise, KEMA believes there is strong uncertainty of not just the timing but also the need for the Western HVDC link. Also under the anticipated implementation of an enduring Connect & Manage arrangement KEMA believes a delay to the Western HVDC link, if subsequently deemed to be required would not impose a delay on proposed new renewables generation in Scotland. As such KEMA does not believe there is any urgency to commence construction of the Western HVDC link in 2010/11 and that it could be considered as a future TPCR5 scheme commencing from 2012/13 or later. However KEMA believes it would be appropriate for the proposed pre-construction funding to be provided.

SHETL is currently considering two options for a connection to Shetland, one comprising a point-to-point link from Shetland to the mainland and the other including an intermediate offshore hub with higher circuit ratings to the mainland. The Shetland Link has similar characteristics to the proposed Western Isles Link project. It forms a high cost radial transmission link whose rationale is predominantly dependent upon the consenting and financial viability of large wind farm developments. Both links have a role in facilitating the connection of smaller or community scale distributed renewable schemes and in securing demand.

SHETL intends to submit additional information regarding the Shetland link in January 2010 which is likely to be similar in detail to that already provided for the Western Isles Link. It is currently anticipated that the Shetland link project programme will run some months behind that of the Western Isles in delivery timescales.

The need and timing of the Shetland scheme is dependent on the development of a 550MW onshore wind farm project. SHETL acknowledges the uncertainties associated with this development and any request for funding will be conditional upon receiving developer financial commitment. This conditional funding approach is reasonable given the outstanding wind farm uncertainties.

Schemes commencing 2009/10

Finally there are four schemes for which construction has commenced in 2009/10. These are all SHETL schemes and consist of:

- Knocknagael (this scheme will be completed within TPCR4);
- Beauly-Blackhillock-Kintore;
- East Anglia; and
- Western Isles

Of the above four schemes, KEMA believes three, namely Knocknagael, Beauly-Blackhillock-Kintore and East Anglia are required and it is appropriate to continue to construct/proceed with these; and to allocate additional funding for construction works within TPCR4 based on Ofgem’s determination of the efficient cost of delivery.

KEMA notes that the East Anglia scheme is delivered over a prolonged period and consists of a number of modular sub-schemes such that the final overall outturn scheme could be truncated or modified as greater certainty of the final scheme requirement materialises over the next 2-3 years. Specifically KEMA believes commitment by Ofgem to additional funding for construction works for East Anglia under TPCR4 should not automatically trigger a commitment to granting the residual scheme expenditure for the proposed scheme and that the latter part/elements of the East Anglia scheme can and should be revisited under TPCR5 process.

The fourth scheme, Western Isles, is subject to significant uncertainty regarding particularly the timing of construction given (i) the current contractual and consents status of proposed generation projects on the Western Isles; and (ii) a statement from SHETL to only proceed where user commitment remains in place i.e. a willingness of generators to securitise transmission works. SHETL has made clear that the request for funding is conditional upon developer financial commitment, and it has quantified a cost benefit case with a 150 MW trigger level regarding user commitment. SHETL's proposed conditional funding approach seems appropriate given the renewable development uncertainties on Lewis.

8.2.3 **Final remarks**

It is clear that substantial network investment will be required to facilitate the increases in renewables generation required to enable 2020 targets to be met. It is equally clear that there is substantial uncertainty of where this generation might connect and this has a major impact on the exact level of network investment required in particular for enabling transfers of power form Scotland to England.

Furthermore, traditional approaches to determining the necessary level of network investment to accommodate new generation, which are peak based, are not ideally suited to assessing the requirements imposed by substantial new volumes of wind generation. Indeed some key assumptions within the existing deterministic SQSS based investment approach are subject to challenge and currently are under formal industry review. Thus the use of cost benefit analysis (CBA) modelling techniques is a reasonable approach; but it inevitably places strong focus on both the robustness of the CBA methodology and assumptions adopted. KEMA's view is that based on market data and evidence it has compiled, the CBA analysis and underlying assumptions as used overstate the requirement for network capacity across Boundary B6.

KEMA's final three observations are:

1. That these conclusions regarding the certainty of need and timing of the proposed TPCR4 network investments will not impact the ability of renewable generation needed to connect by 2020, i.e. it will not delay or increase the cost of connecting.

2. Excluding other potential barriers (planning restrictions etc.), KEMA believes the forecast level of renewable generation required to meet 2020 targets can be connected in Great Britain by 2020 but that this does not necessarily require the proposed level of additional transmission network investment as submitted to Ofgem for additional funding (particularly during TPCR4), in order to do so in an economic manner.

3. Given the anticipated implementation of an enduring Connect and Manage approach to transmission access, where there is high uncertainty over the need and/or timing for major transmission reinforcement investments, any decision to postpone proposed investments; if subsequently demonstrated to be necessary in light of generation developments;

    a. Will not delay the connection or curtail the output of renewable generation; and

    b. Subject to appropriate ex-ante consideration of potential exposure to short-term constraints costs, is the least regret approach from a consumer cost perspective compared to the alternative of premature commitment to major network investment.

APPENDIX A

9 KEMA'S REVIEW OF COMPONENT SCHEMES

This Section provides details of KEMA's high level assessment of each of the investment schemes put forward individually or jointly by the GB TOs for additional funding to facilitate the achievement of the Government's 2020 targets for renewables. A key assumption within this Section is that relevant Transmission Investment for Renewable Generation (TIRG) works, in particular the upgrading of the Beauly-Denny route in the SHETL network (currently awaiting final approval from the Scottish Government), will be consented and constructed as planned. Each sub-Section addresses a specific scheme and provides:

1. Scheme detail including the scheme proposer, the indicated requirement/drivers for the scheme, the content/investments within the scheme, the proposed timing of scheme construction works, the transmission capacity/capability provided by the scheme, the suggested scheme cost and any dependencies/inter-actions;

2. KEMA's view of robustness of the TOs' indicated drivers for each scheme including assessments of relevant dependencies on predicted drivers and interactions with other schemes;

3. KEMA's interpretation of the investment requirement and high-level assessment of the scope of the proposed scheme solution – this is assumed under current GB SQSS planning standards;

4. KEMA's view of the proposed timing of the scheme; and

5. KEMA's summary view of the scheme.

Within this Section the proposed schemes for additional funding are presented and discussed in chronological order reflecting the proposed start time for construction works.

Finally, KEMA uses a 5 step traffic light colour coding to indicate its view of (i) certainty of need; (ii) reasonableness of scope; (iii) certainty of timing and (iv) cost effectiveness with at one extreme a green dot (●) representing “high/strong” and at the other, a red dot (●) representing “low/weak”.

9.1 Knocknagael (SHETL)

9.1.1 Scheme details

This scheme has been proposed by SHETL and construction has already begun in 2009/10, with the scheme due to be completed in 2011/12. It has been identified for advancement by SHETL following requests by Ofgem to identify those projects which provide incremental network capacity and which could be implemented ahead of major RETS work to help facilitate early connection of new renewables plant.

The scheme consists of establishing a new 275kV substation at the Foyers tee point on the Beauly-Blackhillock route, and marshalling circuits accordingly to enable SHETL to “move” the Inverness demand centre from the congested 132kV network to this new 275 kV Knocknagael substation. The scheme only delivers an small capacity benefit of 75MW via the creation of the new substation – the principal benefit is the relief of congestion on the local 132kV network and the increased operational flexibility it provides to manage the 275 kV network in that area. The scheme is essentially dependent on the increase in demand at Inverness (the UK’s fast growing town) and whilst increased wind generation in northern Scotland is also a factor, essentially it has no dependencies and interactions.

SHETL indicate a total cost, in 2009/10 prices, for this scheme of £41m (to the nearest £m).

9.1.2 Headline Assessment

KEMA’s headline assessment of the proposed Knocknagael scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
75MW of capacity across B1.	Inverness growth north west Scottish	None

Operational flexibility.	renewables	

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● first (small) step in facilitating new renewables.	● straightforward creation of substation.	● required as one of schemes possible before RETS which creates capacity.	● reasonable cost for new substation but extra transfer capacity costs £544/kW.

Knocknagael represents a small (first) piece within the overall portfolio of network reinforcements required to enable the connection of; and transfer of power from substantial new renewables seeking to connect in north west Scotland. Whilst the scheme only appears to deliver a small capacity benefit (at relatively high cost) it needs to be viewed in this broader context. Also given the volume of other network reinforcements expected/required to take place to facilitate renewables targets for 2020, it seems sensible given the certainty of requirement to construct Knocknagael where there is a timely opportunity to do so.

KEMA's initial view is that the need, scope and timing of this scheme appear reasonable.

9.2 Western Isles link including Lewis infrastructure (SHETL)

9.2.1 Scheme details

This scheme has been proposed by SHETL and construction is indicated to begin in 2009/10, with the scheme due to be completed in 2013/14.

The driver/purpose of the scheme is to enable substantial onshore island wind generation to export power into the main Scottish and thus GB network. Specifically these projected generation investments include:

- Beinn Mhor Power – 300MW onshore wind farm to be built in two stages; Stage 1 – 140MW and Stage 2 160MW. Part of stage 1 (13 turbines comprising 39MW) already has Section 36 consent and the full Stage 1 scheme has been approved by the

Western Isles Council and is now subject to final approval from the Scottish Government.

- Pairc – 94MW onshore wind farm to be built by SSE Airtricity which is awaiting a decision on Section 36 consent.

- Lewis Wind Power – 150MW onshore wind farm proposed to be built near Stornoway. It has not yet submitted a grid connection application and the project's initial Section 36 application was rejected but it is seeking to reapply.

- Smaller wind farms – 38MW of small onshore wind farms, of which 34MW have consent

The scheme consists of the creation of a direct link between the Western Isles, specifically from a planned new substation at Grabhir on Lewis, and Beauly GSP in Northern Scotland via a combined overland and subsea HVDC connection. Thus it includes (i) a new HVDC underground cable route from Beauly to the north west Scottish coast (including an AC/DC convertor station at Beauly), (ii) an HVDC subsea link between this Scottish west coast and the east coast of Lewis (one of the Western Isles), (iii) 132kV HVDC cables from the east coast of Lewis to a new substation at Grabhir (including installation of an AC/DC convertor station), and (iv) upgrade works to the 132kV network on Lewis to establish a connection between Grabhir and the existing network at Stornoway to facilitate transmission access for distributed generation and reduce reliance on existing diesel plant at Stornoway for demand security.

The Western Isles HVDC link would enable up to 450MW of generation to be exported from the Western Isles onto the main Scottish (and thus GB) transmission network. SHETL indicate that their cost benefit analysis suggests a threshold of 146MW of wind generation will make the link cost effective based on an assumed carbon price of £51/MWh. Consequently, the key dependency/interaction is the volume and timing of onshore wind generation (and potential other renewables projects) which is predicted/expected to connect on the Western Isles and Lewis in particular. By connecting into Beauly the scheme would also represent part of the generation export requirement driving reconductoring of Beauly-Blackhillock-Kintore (BBK) - see Section 9.3.

SHETL indicate a total cost (including all pre-construction works), in 2009/10 prices, for this scheme of £302m (to the nearest £m).

9.2.2 **Headline Assessment**

KEMA's headline assessment of the proposed Western Isles scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
450MW of export capacity from Western Isles to mainland Scotland	Both the scale and timing are critically dependent on expectation for generation	Part of generation export driving need for BBK reconductoring

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● Whilst substantial generation seeking/ contracted with GBSO to connect; very little is consented yet or in next 3 months.	● Scheme scaled to contracted generation under least cost approach. Appears to be least regret option under cost benefit analysis but may present constraints should generation exceed that presently contracted. Alternative scope, using twin 450MW onshore cables within the initial scheme scope in terms of scale, design and phasing may be more robust should significant new generation emerge aligned with the upper capacity forecasts.	● 73MW out of 433MW contracted has consents. No more than 235MW expected to do so by Q1 2010. SHETL will not build unless securitised by the generation driving the need case; and at present generation will face high costs whilst no certainty of status. Thus believe 2010/11 start for construction is highly uncertain, although Beauly-Denny works at Beauly will allow for physical connection and energisation of the link in 2012 and export from Lewis of whatever initial	● The scheme represents the least cost option based on contracted generation. This CBA assessment may change where generation expectation changes. Also the scheme costs for export of renewable power are very high at £672/kW due to the nature of the scheme and technical solution (subsea HVDC link).

		volumes of renewables are then able to commission.	

The initial KEMA view is that the need, scope and timing of this scheme would be reasonable only if all of the GBSO contracted generation projects currently being pursued on Lewis go forward. However, SHETL asserts they will only proceed with the scheme on a securitised basis i.e. no commencement of construction on an anticipatory basis. It is very unclear at present what volume of generation will actually proceed and in what timescales. In this context, KEMA notes only 59MW of the proposed 582MW of wind generation have consent. This situation could change in future should the Scottish Executive grant permission for the 140MW Stage 1 of Beinn Mhor Power's project and the 94MW Pairc scheme to proceed – this could increase consented capacity to 254MW by end January 2010. Section 36 consent for the 160MW Stage 2 of Beinn Mhor has not been submitted and the 150MW Lewis Wind Power project was recently rejected though Lewis Wind Power is currently seeking to re-apply on a modified basis. KEMA notes Lewis Power does not have a connection agreement with the GBSO and the capacity of the link proposed by SHETL is not sufficient to accommodate all other contracted generation (without need for incurring constraints and/or expanding the capacity of the link).

SHETL's proposed approach to install a single 150kV 450MW HVDC link is driven by (i) the forecast level of new generation based on contract but awaiting constructed i.e. 423MW, (ii) SHETL's cost benefit analysis which suggests a threshold of 146MW of wind generation will make the 450MW link cost effective based on an assumed carbon price of £51/MWh and (iii) the single cable option represents the most economic solution. This 146MW falls within the volume of generation SHETL anticipate to have planning consents granted by early 2010 (and thus would be willing to proceed).

SHETL's own economic analysis highlights that on a simple economic consideration a 200kV 600MW cable would be the most economic option of enabling the potential full 583MW of generation currently proposed to export to the Scottish mainland. However, 200kV cable is not yet fully proven technology and a 600MW link would be both more expensive and face the same flexibility issue should >583MW of cumulative generation subsequently connect in later years. SHETL is exploring the possibility of twin 450MW rated cables for the onshore part of the route to:

(i) provide future flexibility with respect to generation uncertainty – in the interim this would provide 450MW firm capacity, and reduced network losses;

(ii) avoid repeated planning processes and construction works along the onshore route which is environmentally sensitive for up to 900MW of generation on the Western Isles, i.e. the second 450MW subsea cable could be installed as required at a later date without facing such issues;

(iii) such an approach whilst more costly than a single 450MW cable onshore is claimed to be cheaper than a 600MW cable solution; and

(iv) recognise the proven nature of 150kV cable as the preferred solution for transfers up to the 450MW capacity threshold.

Whilst the current scheme does not feature this twin overland cable option – SHETL indicates that upon completion of an ongoing assessment to be provided to Ofgem in early 2010, this option could become the favoured approach to best address the high level of future generation uncertainty.

Notwithstanding the above, the unit cost of the capacity created is high although it is accepted that this is largely unavoidable given the location of the generation and required nature of the scheme. Furthermore, at this stage, given (i) SHETL's position that investment will not proceed on an anticipatory basis (ii) the current status of the proposed Western Isles generation, and (iii) the limited changes expected by Q1 2010 regarding the status of the generation projects required to securitise the works; KEMA believes the key issue is the timing of scheme commencement and that currently it is highly uncertain that the scheme will need to commence construction in 2010/11.

9.3 Beauly-Blackhillock-Kintore (SHETL)

9.3.1 Scheme details

This scheme has been proposed by SHETL and construction has already begun in 2009/10, but due to the extensive nature of the works the scheme is not due to be completed until 2014/15.

The driver/purpose of this scheme is to enable substantial new wind (and potentially marine) generation to be able to “export” power southwards down the main Scottish and ultimately GB network. The scheme simply consists of reconductoring the existing 275kV double circuit with higher capacity conductor; and will deliver an additional 500MW of transfer capacity along the route – this would be sufficient to meet generation consistent with the ENSG 8GW Scottish renewables scenario (the mid-scenario). The key dependency/interaction of this scheme is the level of renewable generation which connects in northernmost Scotland (north and north west) and thus requires being able to export its power south towards demand centres in Scotland and England. To this extent the construction of the Western Isles HVDC link and the Beauly-Dounreay uprating (as discussed in Sections 9.2 and 9.5 respectively) to enable exports from outlying parts of the network would underpin the requirement for this scheme, in order to allow aggregated power flows to flow south through the Scottish network.

SHETL indicate a total cost (including all pre-construction works), in 2009/10 prices, for this scheme of £83m (to the nearest £m).

9.3.2 Headline Assessment

KEMA’s headline assessment of the proposed Beauly-Blackhillock-Kintore is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
500MW of additional transfer capacity across B1	The volume of generation connecting in north west Scotland	Additional export capability to Beauly provided via the Western Isles and Beauly-Dounreay schemes partly drive the requirement for BBK. Some dependency of BK element on Shetland and more localised generation developments

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● The scheme is	●● The general	● Given the scale	● The scheme is

required to enable the export of the substantial (new) renewable generation from north west Scotland southwards towards demand.	proposal to reconductor and uprate capacity along the BBK route is reasonable. Arguably BK reconductoring driven by wider generation developments but BK asset replacement needs and achieved efficiency of scheme costs via early one-off reconductoring of full BBK route supports inclusion.	and timing of new renewables generation in north west Scotland the proposed timing is reasonable.	highly cost effective creation of extra capacity across B1 at £166/kW.

The initial KEMA view is that the need, scope and timing of this scheme appears reasonable given the volume of renewable generation contracted to connect both within the next 5 years and further out towards 2020. Whilst it is not certain that the reconductoring of the Blackhillock-Kintore Section is subject to same drivers as the Beauly-Blackhillock Section (being driven by more localised generation developments and potential Shetland link); SHETL has provided a written response confirming their assessment (a) that this is the case, (b) that it would alleviate transmission constraints especially ahead of Beauly-Denny and (c) indicating that this route Section is due for asset replacement otherwise within the next 5 years. As such there is an apparent strong argument that it is both appropriate to accelerate this reconductoring work for Blackhillock-Kintore (and to include uprating in the process) given future outage workload and that it is cost effective to do so from a procurement perspective. Thus, at this stage, we believe that it is probably reasonable for the scheme as presented by SHETL to proceed as proposed.

9.4 East Anglia (NGET)

9.4.1 Scheme details

This scheme has been proposed by NGET; and so far Ofgem has only approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated annually up to 2012/13). However, some construction work on the scheme has already begun in 2009/10 and due to its extensive nature the full proposed scheme would not be due to be completed until 2016/17.

The indicated driver/purpose of this extensive scheme is to facilitate the export of power from (i) an anticipated 3-4GW of Round 3 offshore wind farms forecast to be built off the East Anglia coast and connect into the Norwich Main or Sizewell substations, (ii) anticipated replanting/expansion of nuclear generation at Sizewell as well as (iii) expected additional CCGT capacity in the region, such as at Sutton Bridge. The scheme seeks to substantially increase thermal transfer capability from the East Anglia network south towards London and the major demand centres in the south east.

The scheme consists of a number of modular components which NGET indicates it will commence in the following sequence:

(i) Extension of the Bramford 400kV substation, including two circuit turn ins;

(ii) Reconductoring of the Bramford to Norwich to Walpole 400kV circuits, consisting of;

   a. In a first stage; reconductoring of Norwich to Walpole; and

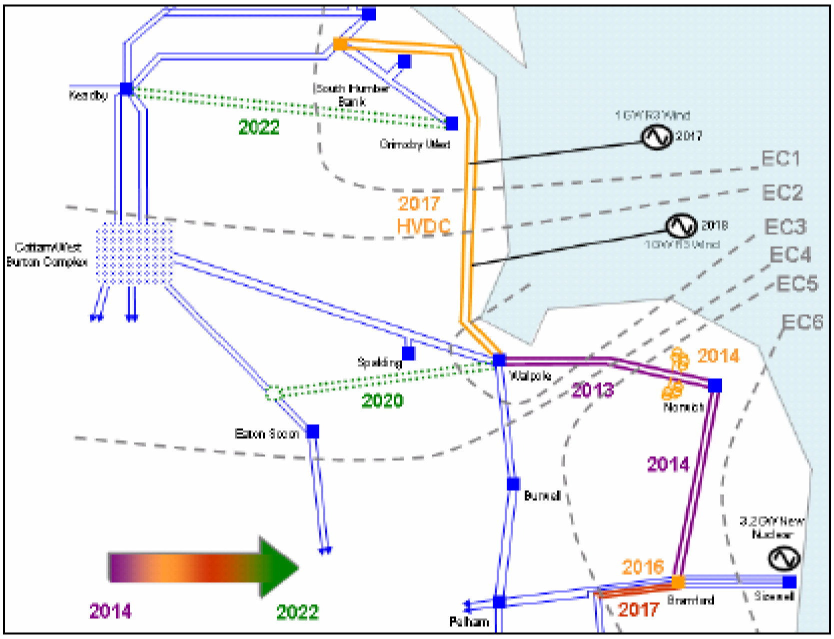
   b. In a second stage; reconductoring of Bramford to Norwich

(iii) Construction of a new 400kV overhead line circuit from Bramford to Twinstead Tee.

(iv) Installation of two quad boosters on the Walpole-Pelham 400kV circuits; and

This major scheme would substantially enhance export capability of a number of localised network boundaries and also a wider Midlands to south boundary (denoted EC4). NGET indicate that the scheme if delivered in the sequence it intends will provide escalating transfer capability in the East Anglia region as each stage/sub-scheme is completed. However, the increase in transfer capacity across the key impacted boundaries provided by the full scheme would be 2,000MW (boundary EC 6), 2,500MW (boundary EC3), 3,750MW (boundary EC4) and 4,750MW (boundary EC5). These boundaries are shown in the diagram below, alongside the proposed phasing of works for the East Anglia scheme and also the Humber scheme as discussed in Section 9.16:

Figure 24 – Illustration of East Anglia/Humber network and proposed schemes and timing



Source - the Full ENSG Report “Our Electricity Transmission Network: A Vision for 2020”, published July 2009

As evident from the highlighted drivers for this scheme, the key dependencies behind this scheme is the volume of nuclear and Round 3 offshore wind generation expected to commission in or off the coast of East Anglia. There are no real interactions with other schemes (although it is worth highlighting that if the proposed Humber scheme as discussed in Section 9.16 (onshore HVDC link between say probably the Humber network (near Killingholme) and Walpole were to proceed it would reinforce/underpin the long term requirement for the reinforcements proposed in this East Anglia network upgrade scheme.

In a response to a KEMA question of clarification, NGET indicate a total cost (including all pre-construction works), for this scheme of £368m (to the nearest £m).

9.4.2 **Headline Assessment**

KEMA's headline assessment of the proposed East Anglia scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
2.5GW across boundary EC3; 3.75GW across EC4; 4.75GW across EC5; 2.0GW across EC6	driven by a mix of new onshore and offshore generation (nuclear; CCGT; wind)	Would feed into requirement for London scheme. In longer term if Humber scheme went ahead this would underpin requirement

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● Certainty of need is high given range of substantial generation proposed in the area and backed by major industry players	● In general scope of overall scheme seems reasonable. Scheme is indicated as modular in that following the sequence of works proposed within the overall scheme will deliver escalating transfer capability and thus deemed appropriate the scheme could be curtailed or later developments delayed until deemed required.	●● Given the range and timing of generation developments, the extent of works and thus the extended scheme delivery timeframe, there is strong justification for proposed start timing but slippages in generation connections and/or dates may mean that similar slippages can be accommodated for the latter components of the overall package of related works.	● The scheme delivers a substantial amount of transfer capacity in the East Anglia area at a low cost of < c. £185/kW for whichever boundary is used as denominator (£184/kW being the highest value derived from 2GW of additional capacity being delivered at Boundary EC3).

The initial KEMA review is that this scheme in general appears justified given the range of generation activity onshore and offshore in the East Anglia area. NGET confirms in response to a KEMA question on the scheme that some of the projected generation which drives the full scheme requirement is not yet firm (Round 3 wind farms being an obvious example) and some firm projects (Sizewell and Sutton Bridge B) have slipped in timing recently, However, there is substantial volume of work to be done, and strong interaction with other reinforcement works and outages in East Anglia over the period, which thus necessitates an extended construction period. Thus, to avoid the risk of high constraint costs under a "Connect and Manage" GB transmission access regime which will be implemented in 2010, KEMA believes the proposed start time appears reasonable.

NGET confirm that the scheme can be viewed as modular to some extent, especially the latter two elements. They indicate that if the proposed sequence of works is followed this will deliver escalating transfer capability towards the full benefit provided by the completion of the full scheme. As such KEMA believes this provides NGET with some flexibility to curtail or delay latter parts/sub-schemes to fit with updated expectations of requirement and timing of need as time goes on. Nonetheless to enable full scheme delivery, it would be important to commence the early schemes as planned. At this stage KEMA believes (i) the scheme in general has a high certainty of need, (ii) the scope seems reasonable with a degree of flexibility through its modular approach to respond to changes in future expectations, (iii) that to ensure NGET's ability to complete the full scheme within the necessary timescales, the proposed commencement timing is justified; and (iv) it represents a cost effective creation of additional transfer capacity to enable renewable generation to meet major demand centres' requirements.

9.5 Beauly-Dounreay (SHETL)

9.5.1 Scheme details

This scheme has been proposed by SHETL, and Ofgem has approved pre-construction works (to be incurred in 2009/10) for additional funding. Construction work is due to begin in 2010/11 and due to be completed by 2012/13.

The driver/purpose of the scheme is to upgrade the capacity of the line between Dounreay and Beauly to enable transfer of both expected wind power projects and potential future marine generation schemes in the area. Currently there is 263.4MW of transmission and distribution connected generation capacity in the Dounreay area, with a further 722.5MW of generation (consisting of a large number of small wind and hydro schemes on the mainland and in the Orkneys, connecting by subsea link to Thurso) contracted to connect by 2014. In addition, a further 1270.4MW of generation is contracted to connect in later timescales – this includes a proposed 700MW tidal stream generation scheme in the Pentland Firth off the northern Scottish coast near Dounreay. Finally, 18.1MW of additional generation capacity is currently seeking a connection contract with the local distribution network.

This scheme consists of installing a 2nd 275 kV circuit on the existing towers on the current Beauly-Dounreay 275kV route, plus installation of two Quad Boosters (QBs) on the 132 kV circuits between Beauly and Shin Grid Supply Points (GSPs). Finally to accommodate this upgrade in line capacity there would also need to be some works at Dounreay 275 kV substation to enhance its capability i.e. to install second Supergrid Transformer and upgrade 275kV and 132kV busbars to double configuration.

The upgrade in route capacity would be 800MW. The key dependency/interaction for this scheme is the volume of onshore and offshore wind generation predicted near Dounreay and also the volume of foreseen potential marine generation schemes. Also by connecting into Beauly the scheme would also represent part of the generation export requirement driving reconductoring of Beauly-Blackhillock-Kintore (BBK) - see Section 9.3.

SHETL indicate a total cost (including all pre-construction works), in 2009/10 prices, for this scheme of £72m (to the nearest £m).

9.5.2 Headline Assessment

KEMA’s headline assessment of the proposed Beauly-Dounreay scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
100MW of transfer capacity across boundary B0 and 800MW across boundary B1	Volume of generation connecting above boundary B1 in locality of Dounreay	Feeds into need for BBK reconductoring

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness

● Up to 2GW of new generation seeking to connect above B0.	● Scheme would enable export from new generation forecast to connect by 2014.	● Scheme timed to enable 722.5MW generation expected by 2014 to proceed unconstrained. The 1.27GW seeking to connect thereafter underpins the case to proceed as proposed.	● At the cost proposed, the scheme is a highly cost effective creation of additional transfer capacity at £91/kW.

The initial KEMA view is that the need, scope and timing of this scheme appears reasonable given the volume of renewable generation contracted to connect both within the next 5 years and further out towards 2020. The fact that the majority consists of relatively small projects means that in principle the requirement is less exposed to a particular scheme withdrawal than might otherwise be the case. We note that within the latter capacity forecast to connect by 2020, 700MW (35%) of the expected new capacity relates to one specific scheme, namely the 700MW tidal stream generation scheme in the Pentland Firth but equally there would be a further proposed reinforcement requirement in the longer term should the full 2GW of generation materialise. Thus at this stage, whilst we believe the scheme should be subject to a review of the proposed costs, we believe the scheme as proposed has high certainty of need, the scope is reasonable and the timing appropriate.

9.6 Hunterston-Kintyre link (SHETL/SPTL)

9.6.1 Scheme details

This scheme has been jointly proposed by SHETL and SPTL, and Ofgem approved the full pre-construction works (to be incurred in 2009/10) for additional funding. Construction work is due to begin in 2010/11 and due to be completed by 2013/14.

The driver/purpose of the scheme is to create a link between the Kintyre peninsula and the main Scottish transmission network to enable the "export" of both onshore wind power and potential future marine generation schemes in the area. There is currently 188.4MW of generation either transmission or distribution connected on the Kintyre peninsula – consisting of a mixture of small wind with a few small hydro projects. A further 155.9MW is contracted for connection by 2012; and a further 120.5MW is contracted for connection by 2020; each consisting of a number of small predominantly wind projects. In addition, currently another 25.5MW of projects are seeking contracts to connect to the local distribution network on the Kintyre peninsula.

The scheme consists of a 132kV sub-sea AC link between Hunterston (on the south west coast of Scotland within the SPTL region) and the southern end of the Kintyre peninsula (which lies within the SHETL region). The link would provide 150MW of transfer capacity between Kintyre and the main Scottish (and thus GB) transmission network. The key dependency of this scheme is on the volume of generation connecting on the Kintyre peninsula (or just offshore).

SHETL/SPTL indicate a total cost (including all pre-construction works), in 2009/10 prices, for this scheme of £123m (to the nearest £m).

9.6.2 **Headline Assessment**

KEMA's headline assessment of the proposed Hunterston-Kintyre scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
150 MW export capacity from southern Kintyre to main Scottish network	Driven by volume of proposed generation (156MW by 2012; 121 thereafter by 2020)	None – stand alone

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● Strong certainty of need given the total volume and underlying mix of generation seeking	● Scheme scaled to contracted generation. Larger scale link, may be more robust to future	● SHETL will not build unless securitised by generation driving the requirement.	● The scheme represents the least cost option based on contracted generation but the

to commission	uncertainty	Given timescales for first wave of generation (2012) and their status (50MW project recently consented) we would expect reasonable certainty that the link needs to proceed as proposed but envisage possible 1 year slippage of start if generation commissioning dates slip.	scheme costs for export of renewable power are very high at £819/kW partly due to the required nature of the scheme (with a long sub-sea AC cable) but also seemingly high for the works proposed.

There is a substantial volume in terms of numbers (42 projects) and MW capacity (301.9MW) of projected generation seeking to connect on the Kintyre peninsula; in addition to the present 188.4MW which export power via the 132kV circuits along the Kintyre peninsula. Given the generally small scale of the proposed generation projects and their relatively large numbers, the merits of the scheme are not particularly affected by any particular generator scheme, thus it appears to be robust to some generation schemes potentially not proceeding.

The fact that 156MW propose to proceed by 2012 and a large project (50MW at A Chruach) has recently received consent suggest proposed timing is currently reasonable but given SHETL will only proceed where the generation driving the requirement provides securitisation there remains a risk that any slippage in generation commissioning dates may impact on need for 2011/12 commencement of scheme works. Thus the initial KEMA view is that the need, scope and timing of this scheme appear reasonable given current status of generation but the cost of the capacity created is very high (although this is essentially unavoidable given the location of the generation and required nature of the scheme).

9.7 SPTL-NGET interconnection (SPTL)

9.7.1 Scheme details

This scheme has been proposed by SPTL and Ofgem has approved the full pre-construction works for the period 2009/10-11/12 for additional funding. Construction work on the scheme would be due to begin in 2010/11 and would be due to be completed in 2014/15.

The driver/purpose of this scheme (coupled with the scheme proposed by NGET in 9.8 below) is to enable the full thermal capacity of the Scottish Interconnectors (4,400MW) to be realised by relieving the existing substantial stability constraints which otherwise limit the export capacity to c.3,300MW. The SPTL scheme consists of the use of series compensation on the Scottish side of the SPTL-NGET interconnection ("Scottish Interconnector") by installing 6 series capacitors at Strathaven (1 x 100MVar), Coalburn (1 x 100MVar), Elvanfoot (1 x 255MVar), Moffat (1 x 255MVar)[33] and Eccles (2 x 255MVar).

The scheme, coupled with the NGET scheme in Section 9.8 and the SPTL East-West upgrade scheme discussed in Section 9.10, will bring the stability capability of the Scottish Interconnector circuits into alignment with the thermal transfer capability of 4,400MW and thus delivers c. 1,100MW extra export capacity between Scotland and England.

The key dependency is the capacity and operating performance of new renewable generation projected to connect in Scotland and the anticipated generation patterns within Scotland relative to the available transmission capacity.

This SPTL scheme has been linked with the equivalent NGET scheme in Section 9.8, the SPTL East-West upgrade scheme (see Section 9.10) and also the SPTL/SHETL East Coast upgrade scheme (see Section 9.11). These 4 schemes are presented in the ENSG (full) Report as the first stage of a potential three potential reinforcements to expand export capacity between Scotland and England. In terms of timing, these interconnector upgrade works are scheduled to precede the proposed offshore HVDC links as discussed in Section 9.9 and 9.17 below. These 4 linked schemes were bundled within the ENSG Report's CBA for Boundary B6 expansion options although certain elements also deliver capacity expansion benefits to other boundaries; in particular the East Coast upgrade provides a primary benefit to B4. As such, in principal, it does not require the higher levels of potential

[33] Note: SPTL/NGET suggest that the series compensation at Moffat could be alternatively placed at Harker in England within the NGET region.

volumes of new renewables (i.e. the 11.4GW Scottish wind scenario) connecting in Scotland to arise to drive its requirement (assuming it rightly precedes the two proposed HVDC links). It is also to some extent driven by the reinforcement of the proposed SHETL network as discussed in Sections 9.1-9.3 and 9.5 and the proposed Hunterston-Kintyre link (discussed in Section 9.6) which would facilitate increased power flows from northern Scotland, through the Scottish network and onwards towards England.

In isolation, this scheme would provide a relatively small and sub-optimal benefit with respect to reinforcing boundary B6 in terms of cost effectiveness as the scheme has been designed as a component of a broader overall package. SPTL indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £88m (to the nearest £m).

9.7.2 **Headline Assessment**

KEMA's assessment of this proposed (SPTL) SPTL-NGET interconnection scheme is summarised in the two tables below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
In conjunction with equivalent NGET scheme (see 9.8); it is indicated to provide 0.9GW further transfer capability across boundary B6. However, there is an interaction with other schemes, principally the East-West scheme (and Torness-Eccles constraint - see 9.10) which means this capacity increment would not be achievable if this scheme were to proceed in isolation.	Scheme requirements depend on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) other wind capacity driven transmission requirements. The key justification for this project is provided through the CBA undertaken by NGET when considered in conjunction with the costs of related schemes 9.8, 9.10 and 9.11 relative to reduced constraints costs.	This SPTL scheme is closely related to the equivalent NGET interconnector investments (see 9.8). These schemes also interact with the scope of SPTL East-West Scheme (see 9.10). Together with 3 other onshore B6 upgrade schemes (as discussed in 9.8, 9.10 and 9.11), these potential investments could be viewed as a competing option to expand B6 capability with potential offshore HVDC links (see 9.9 and/or 9.17). SHETL

		schemes (9.1-9.3 and 9.5-9.6) and SPTL/SHETL East Coast upgrade scheme (9.11) and the consequent increased power flows south underpin requirement for scheme.

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
●● There is reasonable (but not complete) certainty that B6 capacity needs to be expanded from 3.3GW by 2020. Should the lowest renewable generation capacity variant materialise, NGET's CBA indicates that this investment may not be justified. However, under the other renewable scenario variants, the onshore interconnector upgrades are the most cost effective of the three competing B6 expansion options, albeit only marginally justified for 8GW of	● Both NGET and SPTL indicate there remains some scope/scheme design refinement to be undertaken regarding their Series Compensation scheme. However in broad terms, the scope appears reasonable and relevant interactions properly considered although further consideration of alternative design options would appropriate.	● Given the dependence on key assumptions within the CBA relating to generation and its performance; as well as constraints costs which drive the timing of the scheme there is some uncertainty over the timing of this scheme. KEMA also notes that the proposed 2011/12 works are timed to coincide with another local outage to seek to avoid potential high (£20m) constraints costs.	●/●● This scheme appears cost effective at £98/kW for B6 capacity. However, the interaction with other B6 upgrade schemes suggests it should be considered within an overall package of 3 or possibly 4 schemes to deliver 1.1GW at a cost of c. £321/kW (3 schemes exc. East Coast upgrade) up to c. £551/kW (4 schemes inc. full costs of East Coast upgrade).

renewable capacity in Scotland.			

There will probably be a need to increase transfer capacity across the B6 boundary from 3.3GW and that this scheme, together with the equivalent NGET scheme and the SPTL East-West scheme (and possibly also the SPTL/SHETL East Coast upgrade scheme) could be justified subject to further investigation of stability assumptions. On this basis the general scope and timing of this scheme appears reasonable. Furthermore, whilst KEMA believes that a 1 year delay to the initial works pending confirmation of exact scheme design would not create a delivery issue (i.e. would not affect end date), its coincidence in 2010/11 with the outage for the Eccles-Stella upgrade will avoid potentially additional constraints costs if undertaken in 2011/12 (SPTL estimate £20m of constraint costs would arise in 2011/12 for a 10 week outage consistent and KEMA notes this is consistent with observed costs for outages leading to non-intact network situations which further exacerbate the severity of Boundary B6 constraints). However, given the extensive interactions of this scheme with other relating to expanding B6 transfer capability and also the dependence on NGET's CBA, KEMA believes there is some uncertainty regarding the need and timing for this scheme. In addition, there appears to be limited risk associated with aligning the timing of this scheme with the equivalent NGET investments in 2011/2012 whilst design details are finalised.

9.8 Anglo-Scottish incremental works (NGET)

9.8.1 Scheme details

This scheme has been proposed by NGET and so far Ofgem has only approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated annually up to 2012/13). Construction work on the scheme would be due to begin in 2011/12 and would be due to be completed in 2014/15.

The driver/purpose of this scheme (coupled with the scheme proposed by SPTL in 9.7 above) is to enable the full thermal capacity of the Scottish Interconnectors (4,400MW) to be realised by relieving the existing substantial stability constraints which otherwise limit the export capacity to c.3,300MW. The NGET scheme consists of two elements:

(i) placement of series compensation on the Harker-Hutton 400kV circuits in far north west England; and

(ii) reconductoring of each of the Harker to Hutton and Hutton to Quernmore Tee 400kV circuits.

The NGET scheme, coupled with the SPTL scheme in 9.7 above, will bring the stability capability of the Scottish Interconnector circuits into alignment with the thermal transfer capability of 4,400MW and thus delivers c. 1,100MW extra export capacity between Scotland and England.

The key dependency is the capacity and operating performance of new renewable generation projected to connect in Scotland and the anticipated generation patterns within Scotland relative to the available transmission capacity.

This scheme is closely linked with the similar SPTL scheme in Section 9.7, the SPTL East-West upgrade scheme (see Section 9.10) and also the SPTL/SHETL East Coast upgrade scheme (see Section 9.11). These 4 schemes are presented in the ENSG report as the first stage of a potential three potential reinforcements to expand export capacity between Scotland and England.

In terms of timing, these Scottish interconnector upgrade works are scheduled to precede the proposed offshore HVDC links as discussed in Section 9.9 and 9.17 below. These 4 linked schemes were bundled within the ENSG Report's CBA for Boundary B6 expansion options although certain elements also deliver capacity expansion benefits to other boundaries; in particular the East Coast upgrade provides a primary benefit to B4. As such, in principal, it does not require the higher levels of potential volumes of new renewables connecting in Scotland (i.e. the 11.4GW Scottish wind scenario) to arise to drive its requirement (assuming it rightly precedes the two proposed HVDC links). It is also to some extent driven by the reinforcement of the proposed SHETL network as discussed in Sections 9.1-9.3 and 9.5 and the proposed Hunterston-Kintyre link (discussed in Section 9.6) which would facilitate increased power flows from northern Scotland, through the Scottish network and onwards towards England.

NGET indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £182m (to the nearest £m).

9.8.2 **Headline Assessment**

KEMA's headline assessment of the proposed scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
In conjunction with equivalent SPTL scheme (see 9.7); it is indicated to provide 0.9GW further transfer capability across boundary B6. However, there is an interaction with other schemes, principally the East-West scheme (and Torness-Eccles constraint - see 9.10) which means this capacity increment would not be achievable if this scheme were to proceed in isolation.	Scheme requirements depend on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) other wind capacity driven transmission requirements. The key justification for this project is provided through the CBA undertaken by NGET when considered in conjunction with the costs of related schemes 9.7, 9.10 and 9.11 relative to reduced constraints costs.	This NGET scheme is closely related to the similar SPTL scheme (see 9.7). These schemes also interact with the scope of SPTL East-West Scheme (see 9.10). Together with the 3 other onshore B6 interconnector projects (as discussed in 9.7, 9.10 and 9.11), these potential investments could be viewed as a competing option to expand B6 capability using offshore HVDC links (see 9.9 and/or 9.17). SHETL schemes (9.1-9.3 and 9.5-9.6) and SPTL/SHETL East Coast upgrade scheme (9.11) and the consequent increased power flows south underpin requirement for scheme.

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
🟢🟠 Should the lowest capacity renewable generation scenario variant materialise,	🟠 Both NGET and SPTL indicate there remains some scope/scheme design refinement to	🟠 Given the dependence on key assumptions within the CBA relating to generation and its	🟢/🟠🔴 This scheme appears cost effective at £203/kW for B6 capacity. However,

NGET's CBA indicates that this investment may not be justified. However, under the other renewable scenario variants, the onshore interconnector upgrades are the most cost effective of the three competing B6 expansion options, albeit only marginally justified for 8GW of renewable capacity in Scotland.	be undertaken regarding their Series Compensation scheme. However in broad terms, the scope appears reasonable and relevant interactions properly considered although further consideration of alternative design options would appropriate.	performance; as well as constraints costs which drive the timing of the scheme there is some uncertainty over the timing of this scheme. KEMA also notes that the proposed 2011/12 works are timed to coincide with another local outage to seek to avoid potential high (£20m) constraints costs.	the interaction with other B6 upgrade schemes suggests it should be considered within an overall package of 3 or possibly 4 schemes to deliver 1.1GW at a cost of c. £321/kW (3 schemes exc. East Coast upgrade) up to c. £551/kW (4 schemes inc. full costs of East Coast upgrade).

As for the similar SPTL scheme comprising series compensation investment, in isolation this scheme would provide a relatively small and sub-optimal benefit with respect to reinforcing boundary B6 as the scheme has been designed as a component of a broader package.

It appears likely that there will be a need to increase transfer capacity across the B6 boundary from 3.3GW and that this scheme, together with the similar SPTL scheme and the SPTL East-West upgrade scheme (and possibly also the SPTL/SHETL East Coast upgrade scheme) could be justified subject to further investigation of stability assumptions. On this basis, the general scope and timing of this scheme appears reasonable. However, given the extensive interactions of this scheme with others relating to expanding B6 transfer capability and also the dependence on NGET's CBA, KEMA believes there is some uncertainty regarding the need and timing of this scheme.

9.9 Western HVDC link (NGET/SPTL)

9.9.1 Scheme details

This scheme has been jointly proposed by NGET and SPTL; and so far Ofgem has approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated in 2011/12). Construction work on the scheme would be due to begin in 2010/11 (at Deeside) and would be due to be completed in 2015/16.

The driver/purpose of this scheme is to substantially increase transmission capacity to enable output from forecast new renewable generation capacity in Scotland to be exported to England. A key factor will be enhanced power flow capability through the network created by proposed network reinforcements on the SHETL and SPTL networks as discussed in Sections 9.1 - 9.3 and 9.5 - 9.6 above. The scheme consists of a 1,800MW offshore HVDC link between Hunterston and Deeside requiring new 400kV substations (including AC/DC converter stations) to be built at both Hunterston and Deeside. This is shown in the diagram below with the other proposed schemes for enhancing Scotland-England export capacity (i.e. the SPTL “SPTL-NGET interconnection” scheme and the SPTL/SHETL East Coast upgrade scheme discussed in Sections 9.7 and 9.11 respectively; the NGET “Anglo-Scottish Incremental works” scheme discussed in Section 9.8 and the joint NGET/SHETL Eastern offshore HVDC link scheme discussed in Section 9.17).

Figure 25 – Illustration of routes of the two proposed HVDC links (Western and Eastern)

This new Western HVDC link would provide substantial additional capacity between Scotland and England also additional capacity across the upper North of England.

The link as proposed by NGET is in addition to the increase in Scottish interconnector export capacity provided by the incremental SPTL and NGET works described in Sections 9.7 and 9.8. The Western HVDC link represents a second step in expansion of Scotland-England export capacity to meet increased renewable generation in Scotland. Consequently, this investment is highly dependent on the volume of new renewable generation projected to locate in Scotland and also the predicted operational performance of such generation as well as generation patterns within Scotland in general (derived from operating assumptions for other Scottish plant within the overall GB market) driving powers flows through the Scottish networks towards the English transmission network. A key interaction will be enhanced power flow capability created by proposed network reinforcements on the SHETL and SPTL networks as discussed in Sections 9.1 - 9.3 and 9.5 - 9.6 above.

Furthermore a potential Eastern offshore HVDC link of equal capacity has been identified to link Peterhead and Hawthorn Pit. This potential link is discussed in Section 9.17. However, it is important to note that the NGET currently view the Western HVDC link as the preferred option for the “second stage” expansion of Scotland-England export capacity i.e. it would precede the Eastern HVDC link in any 3 stage process. Whilst the cost-benefits for the Western and Eastern HVDC links are similar (within 5-10%) NGET favours the Western HVDC link as the 2nd stage B6 reinforcement for the following reasons:

(b) the Western HVDC link is claimed to have a higher cost benefit than the Eastern HVDC link in earlier timescales (between 2015 and 2020);

(c) generation sensitivity studies indicate that the Western HVDC link appears more robust in earlier timeframes. However, by 2020 the Eastern HVDC link is viewed as more robust); and

(d) there is greater route and scheme design certainty for the Western HVDC link due to there being more uncertainty regarding both onshore and offshore generation on the eastern side of Scotland).

NGET/SPTL indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £805m (to the nearest £m).

9.9.2 **Headline Assessment**

KEMA’s headline assessment of the proposed Western HVDC link scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
1800MW extra capacity across boundary B6;	Scheme depends on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) wind capacity driven transmission requirements. Key justification provided by	Assessed as a competing option for B6 expansion against a group of 4 B6 Scottish Interconnector upgrade schemes (as discussed in 9.7, 9.8, 9.10 and 9.11) and a possible Eastern HVDC link (as discussed in Section 9.17).

	cost benefit analysis (CBA) of scheme costs versus reduced constraints costs.	SHETL schemes (9.1-9.3 and 9.5-9.6) and SPTL/SHETL East Coast upgrade scheme (9.11) increase generation export requirements to England. There are also potential interactions with the North Wales scheme (9.13) as both schemes will compete for transmission capacity south of Deeside.

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
●● There is reasonable certainty that B6 capacity needs to be expanded from 3.3GW but far less certainty what capacity expansion is required, particularly beyond 4.4GW. The Western HVDC link is currently proposed as the 2nd stage of B6 expansion. The need case is particularly dependent on the treatment of new generation and CBA modelling assumptions.	● The scheme scope is reasonable should a Western HVDC link prove necessary. However, there is some uncertainty regarding the preferred sequence of B6 expansion schemes, particularly relative to the Eastern HVDC link.	● Given the uncertainties regarding the extent of B6 expansion required (i.e. beyond 3.3GW or 4.4GW) and the most cost effective delivery options, the timing of this scheme is also uncertain. This is exacerbated by uncertainties over which HVDC link should be developed first. It should be noted that the NGET CBA suggests the Eastern HVDC link is preferable. As the proposed 2nd stage of B6 expansion, the timing is particularly	●● This scheme is one of the more expensive network reinforcements at £447/kW for B6 capacity.

		dependent on the timing of new generation capacity and the validity of key CBA assumptions.	

Whilst KEMA can initially see the logic of the NGET/SPTL proposals, uncertainty remains whether the Western HVDC link is interchangeable with the Eastern HVDC link as the preferred option for creating additional export capacity across the Scottish border. The Western and Eastern HVDC links are subject to different implementation issues (planning and routing complexities for example for the Western HVDC link vs. scheme design option uncertainty for the Eastern HVDC link). For the Western HVDC link, KEMA also believes there could be potential knock-on reinforcement works south of Deeside (especially arising with potential interactions with the North Wales scheme (9.14) and a proposed interconnector with Ireland connecting at Deeside).

The Western and Eastern HVDC links also have differing relative merits with the Western HVDC link potentially better addressing the pattern of renewables foreseen to connect earlier in the period out to 2020; whilst the Eastern HVDC link better addresses the longer term pattern of renewables by 2020 and potentially provides a viable alternative (and greater) capacity expansion for Boundary B4 to that provided by the East Coast upgrade (as discussed under Section 9.11). A simple review of the CBA modelling conducted for the ENSG suggests that if only one capacity expansion option were to be implemented; then the Eastern HVDC link would be the most effective in cost benefit terms.

In summary, whilst the ENSG process has identified the Western HVDC link as the 2nd of three B6 expansion options, given the results of the CBA modelling, the dependency on key assumptions regarding generation patterns and other factors in the modelling, KEMA believes that there is considerable uncertainty about the need and timing for this scheme.

From the review of the modelling methodology for B6 related investments, the outcome of the CBA is sensitive to a number of key assumptions. Whilst KEMA accepts that some assumption uncertainties are inevitable KEMA is concerned that the assumptions adopted may overstate boundary B6 investment requirements. Based on the CBA sensitivity information provided there is particular uncertainty whether two B6 related schemes are required. Therefore KEMA believes Ofgem should carefully consider the merits of additional funding for any second stage expansion of the B6 boundary during TPCR4.

KEMA believes there is very strong uncertainty of not just the timing but also the need for the Western HVDC link and thus KEMA does not believe there is any urgency to commence the Western HVDC link in 2010/11 and that it could possibly be considered as a future TPCR5 scheme commencing from 2012/13 or later. However KEMA believes it would be appropriate for the proposed pre-construction funding to be provided.

9.10 East-West upgrade (SPTL)

9.10.1 Scheme details

This scheme has been proposed by SPTL; and Ofgem approved the full pre-construction works for the period 2009/10-11/12 for additional funding. Construction work on the scheme would be due to begin in 2011/12 and would be due to be completed in 2015/16.

The driver of this scheme is the predicted volume of new renewable generation in Scotland and the consequent higher power flows through the Scottish network facilitated in part by the network reinforcements proposed within Sections 9.1-9.3, 9.5-9.6 and 9.11). The purpose of this scheme is to minimise series compensation requirements in the related Scottish interconnector upgrade schemes as discussed in Section 9.7 (“SPTL-NGET interconnection) and Section 9.8 (Anglo-Scottish incremental works). Taken together, these investments will enable the Scottish Interconnector circuits to provide 4,400MW transfer capacity between Scotland and England.

The scheme consists of:

(i) Upgrading the voltage of the northern side of the Strathaven-Wishaw-Kaimes double circuit overhead line route, from 275kV to 400kV; and

(ii) Installing a second 400kV cable (per phase) on each of the Torness-Eccles 400kV circuits.

Although the scheme provides a headline 200MW enhanced transfer capability on the Scottish interconnectors; it is understood that the main purpose of the East-West upgrade is to complement the design of the proposed series compensation schemes which increase the capacity of the Scottish Interconnector circuits from 3,300MW to 4,400MW. SPTL has also indicated that the Torness-Eccles route represents a key constraint to potential transfers across the B6 boundary and regardless of the two Series Compensation schemes would restrict capacity to 3.4GW i.e. only 100MW above the 3.3GW currently being implemented.

Again, the key dependency is the volume of new renewable generation forecast to locate in Scotland, the performance of such generation and the anticipated generation patterns across Scotland driving increased powers flows south through the Scottish network towards England.. A further factor will be enhanced power flow capability through the Scottish transmission networks created by the proposed network reinforcements within the SHETL and SPTL networks as discussed in Sections 9.1 – 9.3 and 9.5 – 9.6; and also in Section 9.11 below.

SPTL indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £83m (to the nearest £m).

9.10.2 Headline Assessment

KEMA's headline assessment of the proposed East-West upgrade scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
In isolation it is indicated to provide 200MW extra capability. However there is an interaction with the SPTL and NGET series compensation schemes and possibly the East Coast upgrade scheme (e.g. via the Torness-Eccles constraint) which means this scheme should be considered as a package of investments delivering 1.1GW expansion of B6	Scheme depends on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) wind capacity driven transmission requirements. The key justification for this scheme is provided by the NGET CBA of scheme costs (with the schemes discussed in 9.7, 9.8, and 9.11) versus reduced	The scheme design interacts with SPTL series compensation scheme (see 9.7). When considered with the 3 other onshore B6 related upgrade schemes (as discussed in 9.7, 9.8 and 9.11), these provide an option to expand B6 capability in preference to the offshore HVDC links (see 9.9 and/or 9.17). Other SHETL schemes as detailed in 9.1-9.3 and 9.5-9.6 plus

capability.	constraints costs.	the SPTL/SHETL East Coast upgrade (9.11) interact with requirements for this investment.

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
●● There is reasonable (but not complete) certainty that B6 capacity needs to be expanded from 3.3GW by 2020. Should the lowest renewable generation capacity variant materialise, NGET's CBA indicates that this investment may not be justified. However, under the other renewable scenario variants, the onshore interconnector upgrades are the most cost effective of the three competing B6 expansion options, albeit only marginally justified for 8GW of renewable capacity in Scotland.	● Both NGET and SPTL indicate there remains some scope/scheme design refinement to be undertaken regarding their schemes largely comprising installation of series compensation (9.7 and 9.8). However the scope appears reasonable and relevant interactions properly considered although further consideration of alternative design options would appropriate.	● Given the dependence on key assumptions within the CBA relating to generation and its performance; as well as constraint costs which influence project scheduling, there is some uncertainty over the timing of this scheme. KEMA also notes that the proposed 2010/11 works are timed to coincide with another local outage to seek to avoid potential high (£20m) constraints costs.	●● This scheme appears costly at £413/kW for B6 capacity. However, the interaction with other B6 upgrade schemes suggests it should be considered within an overall package of 3 or possibly 4 schemes to deliver 1.1GW at either a cost of c. £321/kW (3 schemes exc. East Coast upgrade) or at a higher cost of c. £551/kW (4 schemes inc. full costs of East Coast upgrade).

NGET has confirmed that the East-West upgrade scheme in the SPTL region is part of a package of measures associated with upgrading the capacity of the Scottish interconnector circuits to 4400MW, and represent the most cost-effective way of achieving this capacity.

In the ENSG report this SPTL East-West upgrade scheme, the SPTL and NGET series compensation based schemes (in Sections 9.7 and 9.8 above) and the SPTL/SHETL East Coast upgrade scheme (see Section 9.11 below) are presented as the first stage of a potential three stage process to expand export capacity between Scotland and England, preceding either of the proposed offshore HVDC links. It is to be highlighted that whilst the 4 schemes are bundled together within the NGET CBA, certain elements, deliver primary capacity expansion benefits to other boundaries such as the East Coast upgrade providing a primary benefit to B4.

It appears likely that there will be a need to increase transfer capacity across the B6 boundary from 3.3GW and that this scheme, together with the equivalent SPTL interconnector scheme and the SPTL East-West upgrade scheme (and possibly also the SPTL/SHETL East Coast upgrade scheme) could be justified subject to further investigation of stability assumptions. On this basis, the general scope and timing of this scheme appears reasonable. However, given the extensive interactions of this scheme with others relating to expanding B6 transfer capability and also the dependence on NGET’s CBA, KEMA believes there is some uncertainty regarding the need and timing of this scheme.

9.11 East Coast upgrade (SPTL/SHETL)

9.11.1 Scheme details

Whilst this scheme requires investments in each of SPTL’s and SHETL’s TO regions, only SPTL has submitted construction costs commencing during TPCR4. Ofgem has already approved the full pre-construction works for the period 2009/10-11/12 for additional funding. KEMA has considered the complete project, comprising both SPTL and SHETL pre-construction and construction costs in this scheme review. Construction work on the SPTL part of the scheme is proposed to begin in 2011/12 and would be due to be completed in 2015/16. Construction work on the SHETL part of the scheme would be proposed to commence in 2013/14 and complete by 2017/18.

The driver/purpose of the scheme is to enable enhanced power transfer from new renewable generation connected in northern Scotland through the SPTL network towards the demand centres in southern Scotland and further beyond into England.

The scheme will essentially uprate the existing transmission corridor south from Kincardine towards Edinburgh to 400kV creating an east coast 400kV transmission corridor from Kintore (in SHETL's licensed) area to Kincardine, and on to a new substation called Harburn (near Livingstone) via Grangemouth. The scheme consists of upgrading the voltage rating; to 400kV double circuit operation of:

(i) the Kintore -Kincardine line - Harburn line (SHETL/SPTL works); and

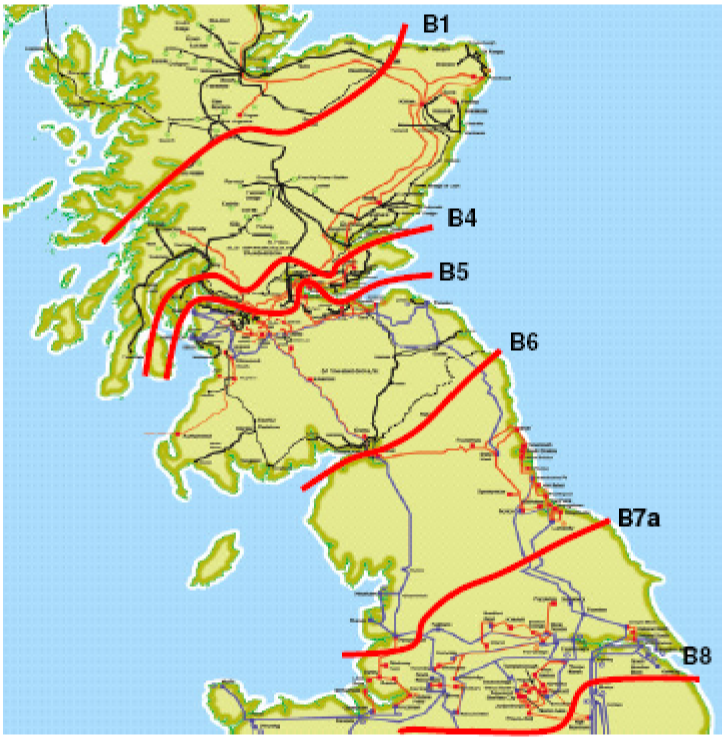
(ii) constructing three new 400kV substations at Kincardine, Grangemouth and Harburn (SPTL works only)

(iii) upgrading of Blackhillock-Kintore route

(iv) new substations at Rothienorman and Aylth and upgrading of Blackhillock and Kintore substations

The scheme seeks to deliver both increased thermal transfer capacity and reduced system impedance and to facilitate improved transient stability performance of the combined system in the SPTL network. As a consequence it will increase transfer capacity across a key mid Scotland boundary (B4) by 700MW, the south Scotland boundary by 450MW (B5) and will add 250MW capability to the Scottish interconnector circuits (B6 boundary). These boundaries are shown in an illustration of key boundaries for Scotland and northern England provided below:

Figure 26 – Illustration of key boundaries for Scotland and northern England



Source - the Full ENSG Report "Our Electricity Transmission Network: A Vision for 2020", published July 2009

Key dependencies for this scheme is the capacity of new renewable generation in northern Scotland (i.e. within the SHETL region), and the enhanced power flows which would be facilitated by earlier network reinforcements as proposed by SHETL as discussed in Sections 9.1 to 9.3 and 9.5, but particularly the Beauly-Blackhillock-Kintore (9.3) route capacity upgrade (and Beauly-Denny completion) driving greater powers flows through the Scottish network towards England.

The scheme is believed to be predicated on completing the Scottish East-West upgrade works (see Section 9.10).

SPTL indicate a total cost (including all pre-construction works), in 2008/09 prices, for their part of this scheme of £137m (to the nearest £m). However SHETL also incur costs under this scheme of £116m (although SHETL is not seeking funding during TPCR4), and thus the total scheme cost is £253m (to the nearest £m).

9.11.2 **Headline Assessment**

KEMA's headline assessment of the proposed East Coast upgrade scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
In isolation the SPTL/SHETL East Coast upgrade is indicated to provide 700MW extra capability across B4, 450MW across B5 and 250MW across B6. However for B6, there is an interaction with the SPTL and NGET series compensation schemes and also the East-West upgrade scheme (e.g. via the Torness-Eccles constraint) which may mean that the benefits of this scheme with respect to boundary B6 are more tenuous.	This scheme depends on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) associated SHETL schemes (9.1-9.3 and 9.5-9.6), (iii) associated SPTL/NGET schemes (9.7, 9.8 and possibly 9.11) (iv) subsequent behaviour of conventional generation at Peterhead and (v) wind capacity driven transmission requirements.	In order to be effective this scheme requires a number of schemes in southern Scotland /Northern England (9.7, 9.8, and 9.11) to be completed. It will also require reconductoring between Beauly and Blackhillock (9.3) and the East Coast upgrade (9.11). There is possible interaction with the Eastern HVDC link (9.17): this could be considered to be an alternative way of increasing power transfer capacity between northern and southern Scotland. Requires additional SHETL works to uprate circuits between Kintore and the SHETL/SPTL boundary.

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
🟢🟠 Given presumed scale of future renewable generation in the north west of Scotland there is	🟠 Appears to be an appropriate and effective way of reinforcing B4 and B5; and provides a wider benefit for B6.	🟠 There is significant uncertainty, as the date when these reinforcements are required depends not only on the timing of	🟠/🔴 Based on full scheme costs for SPTL and SHETL this scheme appears reasonably cost effective for B4

reasonable case for expansion of B4 capability. There is also reasonable certainty that B6 capacity needs to be expanded from 3.3GW and this scheme contributes to the most cost effective solution for initial expansion to 4.4GW; although the CBA suggests that if only one of three proposed B6 expansion options proceeded the Eastern HVDC link (9.17) is a viable alternative to this scheme.	However, the CBA suggests that if only one of three proposed B6 expansion options proceeded, the Eastern HVDC link (9.17) is a viable alternative to this East Coast upgrade scheme delivering greater B4 capacity expansion.	new generation in the SHETL area but also the commissioning of a number of other transmission schemes.	capacity expansion at £361/kW. If considered within an overall package of 4 schemes to deliver 1.1GW across B6 then is part of an expensive package at a cost of c. £549/kW.

KEMA notes that SHETL has chosen not to pursue funding for this scheme until 2013/14 i.e. within the TPCR5 period. In response to a KEMA question of clarification, SHETL indicated their construction works would cost £59.3m over the period 2013/14-2015/16 (pre-construction work will cost £1.7m over the period 2009/10-2011/12. However, SPTL have indicated that they propose to commence construction of their works on the East Coast upgrade scheme in 2011/12 as they believe there are considerable operational benefits from coordinating their commissioning works with that of the East-West upgrade scheme. They indicate that such coordination “could deliver lower (constraints) costs for the consumer” – though the detail of how this benefit arises and it materiality is not specified.

This East Coast upgrade scheme is indicated to provide capacity expansion benefits for B4 in particular but also B5 and (possibly) B6. It has been grouped with a number of other “Incremental Upgrade” scheme for the Scottish interconnector circuits (as covered in Sections 9.7, 9.8 and 9.11) and by association sought to be justified on a cost benefit basis against B6 related network constraints. However, given renewable generation in the north west of Scotland and the associated SHETL scheme to enable export of that renewable generation southwards through the SHETL network there appears a strong case based on expansion of the B4 boundary capability i.e. it is important to recognise that the investment requirement is not solely driven by B6 expansion.

This East Coast upgrade scheme, the SPTL and NGET series compensation based schemes (in Sections 9.7 and 9.8 above), and the SPTL East-West upgrade scheme (see Section 9.10 above) are presented in the ENSG report as the first stage of a potential three stage process to expand export capacity between Scotland and England i.e. it is proposed to precede each of the proposed offshore HVDC links linking Scotland and England as discussed in Section 9.9 and 9.17 below.

It is likely that there will probably be a requirement to increase transfer capacity across the B4 and B5 boundaries, and that this scheme is the most cost-effective way of undertaking this task. However, although the general scope of this scheme would seem to be reasonable there are extensive interactions with other transmission schemes designed to improve the flow of power southwards from the SHETL area; these interactions make it difficult to be certain about the timing of the scheme. Specific to this scheme KEMA also notes that the Eastern HVDC link scheme could be viewed as an alternative initial option to the East Coast upgrade and therefore an Eastern HVDC link may undermine/remove the requirement for the East Coast upgrade. Consequently, KEMA believes that there is reasonable uncertainty about the need and more so the timing for this scheme.

9.12 London (NGET)

9.12.1 Scheme details

This scheme has been proposed by NGET; and Ofgem has approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated annually for 2010/11-11/12 and subsequently in 2015/16, for assessment of a potential stage 2 scheme). Construction work on the scheme would be due to begin in 2011/12 and would be due to be completed in 2015/16.

Historically, the network in and around London was developed to secure demand in the capital and its surroundings, when the major generation sources were the oil and coal fired plant in the Thames Estuary, or the coal-fired plant in the East and West Midlands. Additionally, it handled transfers to and from the interconnector at Sellindge, which until NETA 2001 were typically 2,000 MW power imports to the UK.

Since NETA power flows around London have changed as generation patterns and in particular the French interconnector behaviour has changed. Going forward, several factors are viewed to drive a need for additional transmission capacity in the London area. Specifically:

(i) increased generation in East Anglia and the Thames Estuary,

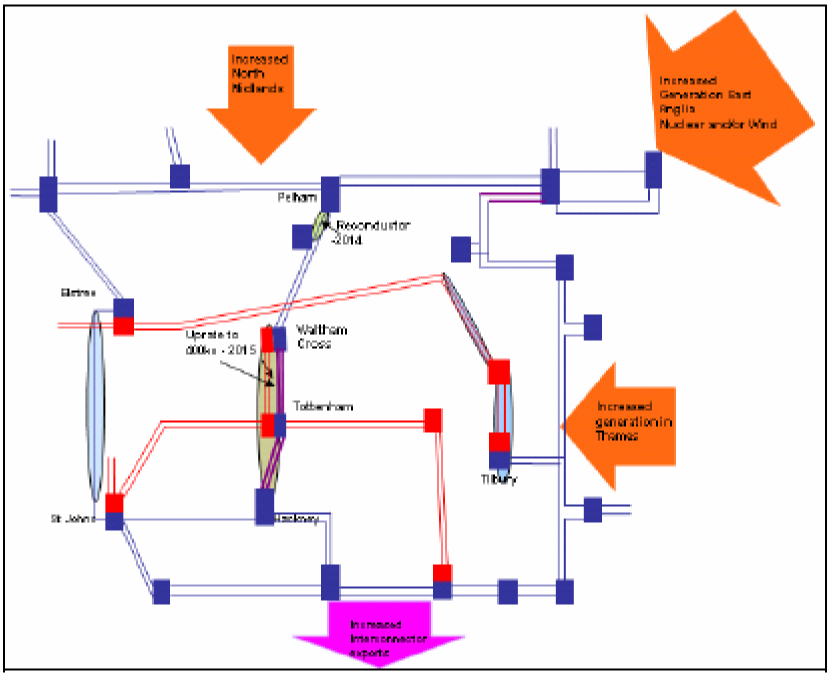
(ii) potential increase in interconnection with mainland Europe; and

(iii) the potential for future demand increases associated with the electrification of transport and/or the decarbonisation of space heat;

These factors would drive a need for additional transmission feeding central London from the north-east, and ultimately a need to reinforce east-west ties.

The proposed reinforcement is to uprate a 275 kV overhead line from Waltham Cross to Hackney via Brimsdown and Tottenham to 400 kV, constructing new 400 kV substations at Tottenham and Brimsdown. In addition NGET propose to reconductor (and thus uprate) the existing 400kV Pelham-Rye House – Waltham Cross route To address potential longer term London network reinforcement needs NGET are also requesting pre-construction funding (for 2015/16?) to consider potential upgrade from 275kV to 400kV of the Tilbury-Warley-Elstree circuits. Both are illustrated in the diagram below together with the proposed phasing of work and the high level investment drivers.

Figure 27 – Illustration of proposed London scheme and key drivers of need



Source - the Full ENSG Report “Our Electricity Transmission Network: A Vision for 2020”, published July 2009

The capacity provided by this network reinforcement (Waltham Cross-Hackney) is an increase of 1,500MW in import capability into London from the north east.

There are no key interactions with other schemes proposed for additional funding by the GB TOs. However, clearly any enhancement of the East Anglia area of the transmission network (as discussed in Section 9.4) will underpin the requirement for the London reinforcements in order to accommodate the potential additional power flows from East Anglia. Otherwise the essential key dependency is the assumed volume (and timing) of new generation to the north east and east of London as well as the potential future capacity and behaviour of interconnection with mainland Europe (and thus interaction with mainland European energy markets).

NGET indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £186m (to the nearest £m).

9.12.2 Headline Assessment

KEMA's headline assessment of the proposed London scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
Scheme provides 1,500MW increase in capability of London network to accommodate power flows from the North East i.e. across LN1	Principally, volume of generation in East Anglia, but also general increased flows from Midlands, projected changed demand behaviour within London and also behaviour of generation/interconnectors around wider London area	Increased transfer capacity provided by East Anglia scheme (and thus expected increased generation exports) will underpin need for London scheme

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● Given KEMA's positive assessment of the requirement/ timing of the East Anglia scheme and the exposure to wider generation behaviour issues; there is reasonable certainty of need.	●● The general scope seems reasonable to deliver enhanced capacity based on the indicated current network.	● Given the generation and network drivers for this scheme; the proposed timing to commence works appears to be reasonable.	● This scheme to deliver enhanced SE network capacity into London from the north east appears highly cost effective at £124/kW. However, KEMA notes the scheme costs appear high for the works specified.

At this stage given the underlying mix of generation drivers and KEMA's positive assessment of the need and timing for the East Anglia scheme (which will facilitate increased power flows into London from the north east), the case to proceed with the proposed pre-construction engineering works for the SE transmission network around London appears reasonable. However, given the overall scale of the scheme (£186.5m) it is questionable whether the scheme needs to commence with £4m of expenditure in 2011/12 i.e. in the last year of TPCR4 – the remaining £182.5m is incurred over the remaining 4 years. KEMA sees no reason why this initial expenditure cannot be postponed until 2012/13 and would not expect it to have an impact on the deliverability of the scheme to the targeted completion date.

9.13 North Wales (NGET)

9.13.1 Scheme details

This scheme has been proposed by NGET and Ofgem has only approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated annually up to 2013/14). Construction work on the scheme would be due to begin in 2011/12 and due to the extensive nature of the works would not be completed until 2016/17.

The main investment drivers for this scheme are the anticipated generation developments onshore and offshore in the North Wales area, particularly around Anglesey, encompassing:

(i) commissioning of Round 2 offshore wind farms;

(ii) substantial volumes of Round 3 offshore wind farms expected to seek connection at or near Wylfa;

(iii) potential additional interconnection with Ireland landing at Wylfa;

(iv) potential replanting of the Wylfa nuclear plant (existing plant is expected to close within next 2 years); and

(v) ongoing presence of the Pumped Storage plant at Dinorwig and Ffestiniog.

The proposed scheme consists of:

(i) Uprating the second circuit between Penisarwaun and Trawsfynydd from 132 kV to 400kV circuit (using the existing towers). This includes replacing a Section of 132 kV cable by a 400 kV cable;

(ii) Construction of a new 400 kV substation at Penisarwaun

(iii) Installation of 400/132 kV transformer to replace local SPTL (Manweb) supply;

(iv) Reconductoring of the Trawsfynydd to Treuddyn Tee 400kV circuit;

(v) Construction of a second Wylfa to Pentir line;

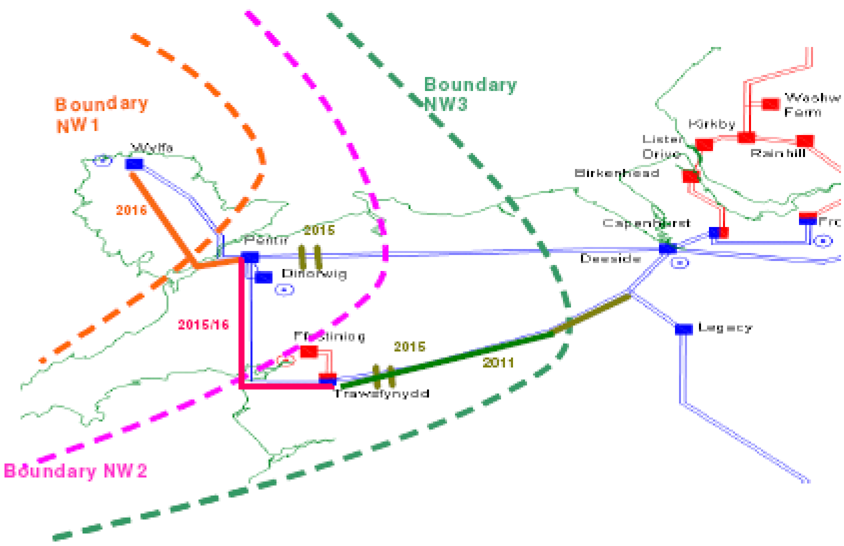
(vi) Construction of a new 400kV substation at Wylfa;

(vii) Extension of the existing Pentir 400kV substation.

(viii) Installation of series compensation on each of the Pentir-Deeside and Trawsfynydd to Treuddyn circuits;

The scheme as a whole would deliver cascading increased transfer capability across a number of localized North Wales boundaries ranging from 4,250MW (boundary NW1 around Anglesey) down to 2,750MW (boundary NW3 covering North Wales, going into Deeside). These boundaries and the phasing of the scheme works are shown in the diagram below:

Figure 28 – Illustration on North Wales network and proposed North Wales scheme



Source - the Full ENSG Report “Our Electricity Transmission Network: A Vision for 2020”, published July 2009

There are potential interactions with the Western HVDC link scheme terminating at Deeside, in terms of potential network issues south of Deeside which may need to be addressed, where one or both schemes proceed. The key dependency/driver as indicated above is the volume (and timing) of increased onshore and offshore generation in the vicinity of Anglesey in North Wales.

There is also a potential interaction with the central Wales scheme (9.14) as there is a possible future reinforcement from Trawsfynydd (or some point east of Trawsfynydd) to the new Central Wales supply point.

NGET indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £444m (to the nearest £m).

9.13.2 **Headline Assessment**

KEMA's headline assessment of the proposed North Wales scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
Escalating transfer capacity across local North Wales boundaries; specifically 2GW for boundary NW3, 3.25GW for NW2 and 4.2GW for NW1	This scheme is critically dependent on the anticipated new generation both within North Wales and off the coast of North Wales.	Although largely stand alone there is a potential interaction with the Western HVDC link in relation to possible need for network reinforcements south of Deeside

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● There is high uncertainty of need for the scheme in partial or full form – given the dependence at this	●● Should the capacity and location of the anticipated generation materialise, the scope appears	● The high degree of uncertainty regarding the potential volume and location of new generation inevitably increases the	● Should the forecast generation underpinning the scheme emerge as predicted, the full proposed solution

stage on relatively speculative generation developments in terms of scale and location. In particular, the full scheme as proposed would appear to be (i) a strong example of anticipatory TO investment; and (ii) as such, subject to high uncertainty of need.	reasonable. However, the uncertainties around the generation forecast suggests that a reduced scope and/or more phased development of the scheme might be more appropriate e.g. the 2nd Wylfa-Pentir route may not be the first priority and/or needed.	uncertainty regarding the proposed timing of the scheme but also the sequencing of individual scheme components.	appears cost effective at £211/kW across NW3 – which is the most onerous measure – assuming that there are no network problems to the south of Deeside. A reduced scope of scheme would be even more cost effective on NW3.

KEMA's view is that the need, scope and timing of this scheme are highly dependent on the precise assumptions regarding the volume and equally importantly location of new generation. At this stage such generation forecasts are highly speculative and uncertain. Consequently, KEMA believes this scheme, has greatest uncertainty over the scope (if deemed required) and timing of the scheme - more so than any other in Section 9.

KEMA suspects that this scheme (as proposed) whether considered in isolation or in conjunction with the proposed Western HVDC link may impact wider network reinforcement requirements south of Deeside. NGET has not identified any wider reinforcement requirements but has suggested the presence of the Western HVDC link will mitigate such further reinforcement requirements that might otherwise be driven by the North Wales scheme (as proposed). KEMA has had further dialogue with NGET regarding this issue and NGET maintain there are no issues arising on the network south of Deeside which need to be addressed. It is not within the scope of KEMA's assessment to conduct detailed network modelling and whilst we accept NGET's answers are provided in good faith we remain concerned given the extent of potential network developments to the west and north of Deeside (particularly this North Wales scheme, the proposed Ireland interconnector, and the proposed Western HVDC link) that there may be additional network reinforcement needs not yet identified which may be triggered by one or a combination of these developments.

KEMA notes that this scheme is suitable for phased development and that the new line Pentir – Wylfa, and possibly also the cable replacement on the Penisarwaun - Trawsfynydd circuit, are potentially long lead-time projects, where an early start may prove advantageous.

At this stage KEMA views all aspects of the North Wales scheme as highly uncertain and the costs of the proposed network solutions as proposed are high.

9.14 Central Wales (NGET)

9.14.1 Scheme details

This scheme has been proposed by NGET and Ofgem has approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated annually up to 2013/14). Construction work on the scheme would be due to begin in 2012/13 and would be due to be completed in 2015/16.

The Welsh Assembly Government Technical Advice Note 8 (TAN8) identifies an onshore wind generation target of 800 MW; and that this could come from central Wales, the area identified as providing the majority of wind resource in Wales. However, at present central Wales is distant from the main interconnected transmission system. To facilitate/enable connection of onshore wind generation in central Wales, new transmission assets including overhead line and (probably) cable Sections would need to be commissioned in order to connect the new generation to the transmission network.

As any such onshore wind generation in central Wales is expected to be made up of a number of small to medium wind farms, the current proposal is to create a hub substation to which all wind farms connect. A single transmission route will then be used to connect to the transmission network in the Legacy-Shrewsbury-Ironbridge circuits. Currently it is proposed to construct a new central Wales to Ironbridge 400kV circuit and a new 400kV central Wales substation for the connection of multiple wind generation sites consistent with delivery of TAN8 objectives.

Based on 400kV double circuit construction we would expect the proposed transmission spur under this scheme would be capable of at least 2000MW transfer capacity which would provide flexibility for any future transmission growth requirement.

The key dependency/interaction of this project is the likelihood and potential volume of onshore wind generation which might seek to connect in North Wales if such a transmission network spur existed. Currently, NGET indicate that two developers have signed Connection Agreements for wind farms in the "TAN8 region" totalling 300MW and that they hold a Modification Agreement with the local DNO to build a new substation to accommodate a further 500MW of projects seeking a distribution voltage connection in the region.

NGET indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £258m (to the nearest £m).

9.14.2 Headline Assessment

KEMA's headline assessment of the proposed Central Wales scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
Enables connection of 800MW of generation (assumed to be wind) in Mid-Wales.	The merit of this scheme is dependent on whether the 800MW of generation materialises in Mid-Wales	None – stand alone

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
The requirement for this scheme is based on a Welsh Assembly aspiration as outlined in TAN8 and partly supported by an NGET indicated 300MW wind farms seeking to connect in the "TAN8	On the assumption that sufficient generation will seek to connect in Mid-Wales thus meriting an additional transmission spur; under current planning standards the proposed scope of the scheme	Given the sole reliance on projected generation interest and the uncertain status of such generation there is strong uncertainty over the timing of associated investment.	In terms of delivering generation export capacity from North Wales (assumed to be up to 2,000MW given N-1 based 400kV construction); under current planning standards, this

region". Consequently, there is high uncertainty regarding investment need and the scheme represents a clear example of anticipatory TO investment within the schemes.	appears reasonable; as it is probably the lowest scale spur which could sensibly be constructed at 400kV transmission voltage.		scheme is relatively cost effective at £322/kW. However, the key question will be, if the spur is built on an anticipatory basis will that network capacity be meaningfully used by new generation siting in Mid-Wales.

KEMA's view at this stage is that the Central Wales is a strong example of anticipatory TO investment. In this case it is driven by Welsh Assembly aspirations as outlined in TAN8 and supported to some extent by some initial generation interest in the area (as represented by the two new connection agreements for 300MW of wind generation in the "TAN8 region") and potential local DNO development (i.e. proposed 500MW capacity distribution voltage substation). Consequently, under current planning standards, KEMA's initial view is that the proposed scheme might be deemed to be reasonable and cost effective <u>if</u> the generation requirement materialises. However this generation connection requirement is both highly uncertain in scale and timing and thus presents high uncertainty of need, and timing as well as high potential for stranded asset costs to be borne by NGET, the consumer or both.

9.15 South West (NGET)

9.15.1 Scheme details

This scheme has been proposed by NGET and Ofgem has approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated annually up to 2014/15). Construction work on the scheme would be due to begin in 2012/13 and would be due to be completed in 2016/17.

There is a limited additional export capacity out of the south west peninsula (i.e. Cornwall, Devon, Somerset, Dorset) and the investment driver(s) of this scheme relate to potential increases in generation capacity in the region, including the potential for a large aggregate capacity of gas fired generation (e.g. such as that connected at Langage, near Plymouth), and the possible nuclear replanting at Hinkley Point. Although not viewed as a strong driver, planned offshore wind generation associated with future wind leasing rounds would further add to this requirement. Thus the purpose of this scheme is to enhance the export capacity from the south west into the wider transmission network.

Proposed reinforcements would be to:

(i) Uprate the existing Hinkley-Bridgwater 275kV circuit to 400kV;

(ii) construct a new 400 kV circuit between Bridgwater and Seabank, with minor rearrangement of existing lines in the Bridgwater area;

(iii) build a new 400kV substation at Hinkley;

(iv) extend the existing 400kV Seabank substation; and

(v) replace the existing 275kV Bridgwater substation with a 400kV substation.

The proposed schemes represent an increase of 1,750MW in transfer capacity in the south west transmission network of England. There are no interactions with other schemes assessed within this Report but the requirement is clearly dependent on the volume of generation assumed to commission in the south west and the consequential potential export of power created.

NGET indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £286m (to the nearest £m).

9.15.2 **Headline Assessment**

KEMA's headline assessment of the proposed South West scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes

This scheme provides 1.75GW of additional export capacity out of the South West area across boundary SW1	The key driver for this scheme is anticipated new generation in the South West, principally replanted nuclear generation at Hinkley Point and new CCGT generation; but also potential offshore generation of the Cornwall and Devon coasts.	None – stand alone

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● There is high uncertainty regarding investment requirements for this scheme given its dependence on new generation connections which are expected to connect before 2020.	● Should the forecast generation in the South West materialises the scope of the scheme appears reasonable.	● The same uncertainty over generation connection which impacts on certainty of need also makes the timing of this scheme highly uncertain.	● Where the scheme proceeds as proposed the additional network capacity provided highly cost effective at a cost of £163/kW.

NGET indicate there is a strong degree of uncertainty surrounding the need and timing for this scheme and KEMA would concur with this view. The scheme is principally driven by expectations for new nuclear and CCGT generation in the South West – the level and timing of these are currently unclear. Where the scheme is required the scope as proposed appears both a sensible and reasonable approach; and the cost effectiveness of the scheme would be high (though it should be noted that, while it facilitates low-carbon generation, it probably facilitates less renewable generation than any other proposed scheme). Thus the scheme is anticipatory in nature but reasonable if it were decided that such anticipatory investment would be appropriate to undertake.

It is also noted that the proposed reinforcement potentially has a long lead time as it might require a difficult consent process for the proposed new line.

9.16 Humber (NGET)

9.16.1 Scheme details

This scheme has been proposed by NGET and Ofgem has approved the pre-construction works for 2009/10 for additional funding (further pre-construction works are indicated annually up to 2013/14). Construction work on the scheme would be due to begin in 2013/14 and would be due to be completed in 2016/17.

The purpose of this scheme is to potentially enable transfer of substantially increased power flows out of the Humber area as driven by potential high volumes of Round 3 offshore wind generation off the Humber and Northumberland coasts, estimated to be 4-8GW by 2020.

The scheme consists of a proposed onshore HVDC link from Humber to Walpole and associated substation works at Humber and Walpole (including installation of AC/DC conversion capability). The HVDC link is indicated to be sized at 2,250MW capacity and an illustration of it is provided in Section 9.4 showing all the potential network reinforcement schemes on the eastern side of England.

The key dependency as evident from the purpose of the scheme is the actual volume of offshore wind generation in the Humber/Northumberland coastal areas which proceed and commission.

NGET indicate a total cost (including all pre-construction works), in 2008/09 prices, for this scheme of £553m (to the nearest £m).

9.16.2 Headline Assessment

KEMA's headline assessment of the proposed Humber/Anglia link scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
Enables incremental 2.25GW of transfer south	This scheme is driven by the volume of new CCGT and	If this scheme were to proceed it would further

from the Humber area (into East Anglia via Walpole)	offshore wind generation which might connect in the Humber area approaching 2020	underpin the need for the East Anglia scheme

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● The need for this scheme is contingent on new generation which is largely speculative at this stage, especially the potential Round 3 offshore projects.	● Where the generation arises driving the need for the substantial extra transfer capacity south from the Humber; the HVDC link is one option. However, given lead time and new IPC process, it seems possible that a new onshore OHL route might be equally viable (and potentially more economic).	● There is high uncertainty of timing given the dependence on relatively speculative forecasts of generation developments approaching 2020.	●● Given a requirement to increase transfer capacity south of the Humber region; the cost effectiveness of the HVDC link scheme would be moderate at £246/kW, although this would be decreased if some of the East Anglia reinforcement costs were allocated to this scheme. However, if it were deemed viable to address the requirement via an OHL solution then this would be expected to be even more cost effective.

The requirement and timing of this scheme is reliant on relatively speculative forecasts of potential generation developments onshore and offshore (i.e. Round 3 wind farms) in the Humber region. Consequently, in KEMA's view there is high uncertainty of need and timing. From Q&A dialogue with NGET it seems that there also remains reasonably high degree of uncertainty over the proposed scheme scope/solution to enable enhanced transfers south from the Humber area into the East Anglia network via Walpole. In particular, whilst the onshore HVDC link is currently the solution put forward by NGET for anticipatory funding (largely based on perceived ease of implementation), it is clear that options are being considered regarding the viability of creating a new an OHL route. In KEMA's view, given the uncertainty over timing and general expected close to c.2020 timeframes, the OHL option is probably viable from a timely delivery perspective given the recently implemented IPC process for progressing planning consents for major infrastructure projects (across a number of sectors) in England & Wales. Thus there is some uncertainty over the final scope of a Humber/Anglia link scheme. Nonetheless, regardless of the final option, based on the costs of the HVDC link proposal which KEMA would expect to be the highest cost approach, KEMA views the creation of such a link would be a cost effective way to release renewable generation exports south towards the major demand centres in South East England.

At this stage KEMA would view all aspects (need, timing and scope) of the Humber scheme as uncertain; and at this point in time it would represent a clear case of anticipatory funding.

As an overhead line based ac scheme would potentially have a long lead time, there may be benefits in undertaking early investigation to ascertain the viability of an overhead line based solution.

9.17 Eastern HVDC link (NGET/SHETL)

9.17.1 Scheme details

This scheme was identified as potential alternative or supplementary option to the Western HVDC link within the ENSG study. At present, whilst it would be a joint NGET/SHETL scheme it has been put forward by NGET/SHETL for pre-construction funding alone – although KEMA considers the full scheme, comprising all NGET and SHETL pre-construction and construction costs in this scheme review. So far Ofgem has only approved the pre-construction works for 2009/10 for additional funding and NGET indicates desired further pre-construction works annually up to 2013/14. NGET currently indicate they would envisage construction work on the scheme would not be due to begin until 2014/15 with completion in 2017/18.

The driver/purpose of this scheme is to substantially expand/add to the export capacity of the Scottish Interconnector to enable exports from forecast renewable generation capacity in Scotland to major GB demand centres further south. The scheme consists of a 1,800MW offshore HVDC link between Peterhead (on the north east coast of Scotland in the SHETL region) and Hawthorn Pit (in the north east of England in the NGET region); and would require AC/DC conversion capability at Peterhead, a new 400kV substation (including AC/DC conversion capability) at Hawthorn Pit and upgrading of the Hawthorn Pit – Norton 400kV line. The link is illustrated in the diagram in Section 9.9 of this Report which illustrates all the potential schemes relating to increasing transfer capacity from Scotland to England.

This new Eastern HVDC link would provide substantial i.e. 1,800MW additional capacity across the Scottish Interconnector circuits (boundary B6), and also across the internal SPTL boundaries B4 and B5. There would be some limited additional capacity across the upper North of England.

The link is currently proposed by NGET as being required over and above the incremental increase in Scottish Interconnector export capacity provided by the incremental SPTL and NGET works described in Sections 9.8 and 9.9; and the preferred 1,800 MW Western HVDC link between Hunterston and Deeside as described in Section 9.9. The Eastern HVDC link is viewed as the third step in expansion of Scotland-England export capacity to meet increased renewable generation in Scotland. It is therefore highly reliant on the volume of new renewable generation projected to connect in Scotland combined with the technical and operational performance of such generation as well as generation patterns within Scotland in general (derived from operating assumptions for other Scottish plant within the overall GB market).

Furthermore, NGET has confirmed that the exact nature of the Eastern HVDC link could be revised in the light of longer term generation developments, in particular the siting of generation in northern Scotland, which could support movement of the Scottish connection point from Peterhead down to Torness (thus delivering a cheaper scheme through reduced length of subsea HVDC cable required).

As discussed in Section 9.9, a potential Western HVDC link of equal capacity has been identified which would link Hunterston (in south west Scotland within the SPTL region) and Deeside (in North West England within the NGET region). However, for the purposes of this Section it is important to note that NGET currently view the Eastern HVDC link as the less preferred option for “third stage” expansion of the Scotland-England export capacity to meet increased Scottish renewables generation i.e. it would not precede the Western HVDC link in any 3 stage process of expanding Scotland-England export capacity. NGET has indicated that whilst by 2020 the relative cost benefits of the Eastern and Western HVDC links are similar (within 5-10% under main scenarios), the Eastern HVDC link:

(a) has a less strong cost benefit case by 2015 than the Western HVDC link (but generally a stronger case by 2020); and

(b) is less robust to some key generation sensitivities that NGET assessed in addition to the main 3 generation scenarios initially studied for the purposes of the cost benefit analysis.

(c) is subject to greater uncertainties over scheme routing and design given greater prevailing uncertainties both onshore and off the eastern coast of Scotland, as well as novel scheme designs which need to be explored with equipment manufacturers e.g. there could be potential for tee-ing in some offshore wind projects

NGET indicate a total cost for their works (including all pre-construction works), in 2008/09 prices, for this scheme of £429m (to the nearest £m). SHETL have submitted their pre-construction costs for this scheme of £4m (to the nearest £m) but have not submitted the estimated costs for their construction works on this scheme. KEMA anticipates that these SHETL costs will be similar to those incurred by NGET; such that the total cost of the scheme would be c. £829m in 2008/09 prices (to the nearest £m).

Given, the proposed timing and degree of uncertainty of design for the Eastern HVDC link, at this stage NGET and SHETL have sought additional funding to cover the proposed pre-construction works associated with this scheme to explore options with equipment suppliers and consequently firm up on scheme design and routing of the link.

9.17.2 **Headline Assessment**

KEMA's headline assessment of the proposed Eastern HVDC link scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes

1800MW extra capacity across boundary B6;	Scheme depends on assumed (i) overall volume of Scottish renewable generation connecting by 2020; (ii) impact on conventional generators and (iii) wind capacity driven transmission requirements. Key justification provided by cost benefit analysis (CBA) of scheme costs versus reduced constraints costs.	Assessed as a competing option for B6 expansion against a group of 4 B6 Scottish Interconnector upgrade schemes (as discussed in 9.7, 9.8, 9.10 and 9.11) and a possible Western HVDC link (as discussed in Section 9.9). SHETL schemes (9.1-9.3 and 9.5-9.6) and SPTL/SHETL East Coast upgrade scheme (9.11) and increased generation flows south underpin scheme requirements.

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
There is reasonable certainty that B6 capacity needs to be expanded from 3.3GW but far less certainty what capacity expansion is required, particularly beyond 4.4GW. The Eastern HVDC link is currently proposed as the 3rd stage of B6 expansion where there appears to be no immediate need case subject to	The Eastern HVDC scheme scope in its own right depends on the future pattern of generation in Scotland; especially if it is viewed to help provide additional capacity across B4. Otherwise, there is potential for the link to connect at different points in the Scottish and English networks and in particular, further south of the Scottish network (e.g.	Given uncertainty over the extent of B6 expansion required above 3.3GW; and in particular whether and to what extent it should exceed 4.4GW and uncertainty regarding the most cost effective delivery options, there is strong uncertainty over the timing of this scheme – this is exacerbated by concerns over which merits proceeding first e.g. simple	This scheme appears relatively expensive at c. £460/kW for B6 capacity for current proposed Peterhead-Hawthorn Pit route. However, it also provides benefits on boundaries B4 and B5. If the route is shortened (e.g. Torness-Hawthorn Pit) then it would become more cost effective.

further review of other B6 expansion options. However, simple review of the CBA suggests the Eastern HVDC link is preferable to the Western HVDC link as the 2nd stage expansion option for B6. Thus the need case is particularly dependent on the treatment of new generation and CBA modelling assumptions.	Torness) which would reduce the scope (in terms of HVDC cable route km). At this stage exact routing and associated scope remains unclear.	review of the CBA suggests the Eastern HVDC link is preferable.	

Whilst KEMA can initially see the logic of the NGET's proposals, it is still open to debate that the Western HVDC link might be interchangeable with an Eastern HVDC link as the preferred option for creating additional export capacity across the Scottish border i.e. from Scotland to England, where such a link is deemed necessary. Each of the Western and Eastern HVDC links face different issues (planning and routing complexities for example for the Western HVDC link vs. scheme design option uncertainty for the Eastern HVDC link). For the Western HVDC link, KEMA also believes there is potential knock-on reinforcement works south of Deeside (especially arising with potential interactions with the North Wales scheme (9.14) and a proposed interconnector with Ireland proposed to connect at Deeside).

Each of the Western and Eastern HVDC links also have differing relative merits with the proposed Western perhaps better addressing the pattern of renewables foreseen to connect earlier in the period to 2020 and thus having more certainty attached to them; whilst the Eastern HVDC link better addresses the longer term pattern of renewables by 2020 and potentially provides a viable alternative (and greater) capacity expansion for Boundary B4 to that provided by the East Coast upgrade. Furthermore simple review of the CBA modelling conducted for the ENSG suggests that if only one capacity expansion option were to be implemented; then the Eastern HVDC link would be the most valuable in cost benefit terms.

In summary, whilst the ENSG process has earmarked the Eastern HVDC link as the 3^{rd} of three B6 expansion options, given the headline results of the CBA modelling, the dependency on key assumptions regarding generation patterns and other factors in the CBA modelling, KEMA believes that there is considerable uncertainty about the need and timing for this scheme. Differing assumptions/expectations can lead to conclusions which range from a potential view of no need to a potential view it should be the preferred B6 expansion option.

From its extensive assessment of the CBA modelling exercise used to justify B6 related investments, the outcome of the CBA modelling exercise is critically dependent on a number of key assumptions and whilst KEMA accepts that there is some uncertainty over what these assumptions should be; it believes that on balance that the assumptions adopted are overly favourable to the need for investment to expand B6 capacity. Based on the information provided to KEMA under this review it believes there is very strong uncertainty that two B6 related schemes are required. Thus even where the Eastern HVDC link is deemed to be preferable 2^{nd} stage option to the Western HVDC link, KEMA believes Ofgem should carefully consider the merits of the requirement and level of additional funding for any second stage expansion of the B6 boundary under TPCR4.

Some CBA modelling results suggest that the Eastern HVDC link may represent a more effective single capacity expansion option for Boundary B6 than the proposed Scottish Interconnector upgrade works (consisting of the four schemes reviewed in Sections 9.7, 9.8, 9.10 and 9.11). However, given the uncertainties over generation patterns which might favour the Eastern HVDC link and uncertainties over the most effective route and design of the Eastern HVDC link on balance, it seems appropriate that the Incremental Works schemes are viewed as the preferred 1^{st} stage capacity expansion option and that on balance the Western HVDC link might be the better 2^{nd} stage option – though this is not certain.

As such KEMA believes there is very strong uncertainty of not just the timing but also the need for the Eastern HVDC link and no decision on construction funding should be made at this stage but that it would be appropriate for the proposed pre-construction funding to be provided.

9.18 Shetland link/offshore hub (SHETL)

9.18.1 Scheme details

The driver/purpose of the scheme is to enable the 550MW Viking onshore island wind generation project to export power into the main Scottish and thus GB network; although it would also enable connection of local distributed generation on Shetland; and would reduce reliance on the existing diesel power station on Shetland. At present SHETL have identified two alternative approaches to connection of Shetland to the Scottish mainland;

1. Shetland link – a “straightforward” point to point link from Shetland to the mainland.

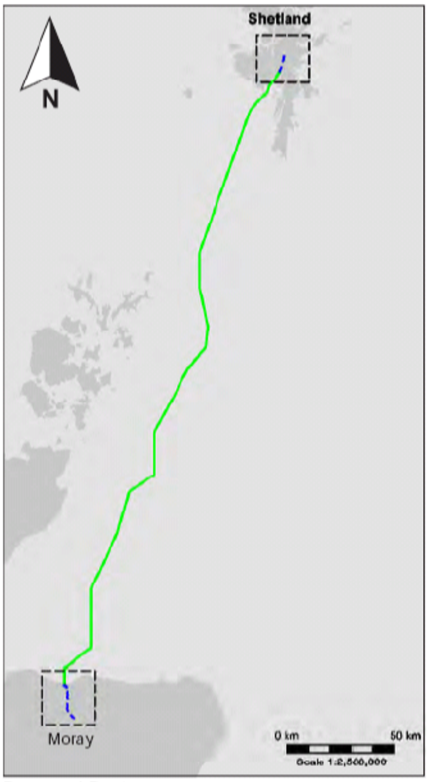
2. Shetland offshore hub – a point to point connection routed via an offshore hub which would enable the connection of other offshore developments and the potential development of an offshore grid (this latter option was recently announced with access to some contributory EU funding).

It is not yet clear which of these two scheme options will be taken forward by SHETL; although just before publication of this Report, SHETL received EU funding in relation to the proposed offshore hub approach; but each are proposed to commence construction in 2010/11 with completion by 2014/15. Each scheme is briefly illustrated and discussed below:

Shetland Link

As indicated above this scheme would comprise a simple link between Shetland and the Scottish mainland and this is illustrated below.

Figure 29 – Illustration of proposed "simple" Shetland link scheme



Proposed Route

This scheme option would consist of single 600MW HVDC circuit between Upper Kergord on Shetland and Blackhillock on the Scottish mainland comprising:

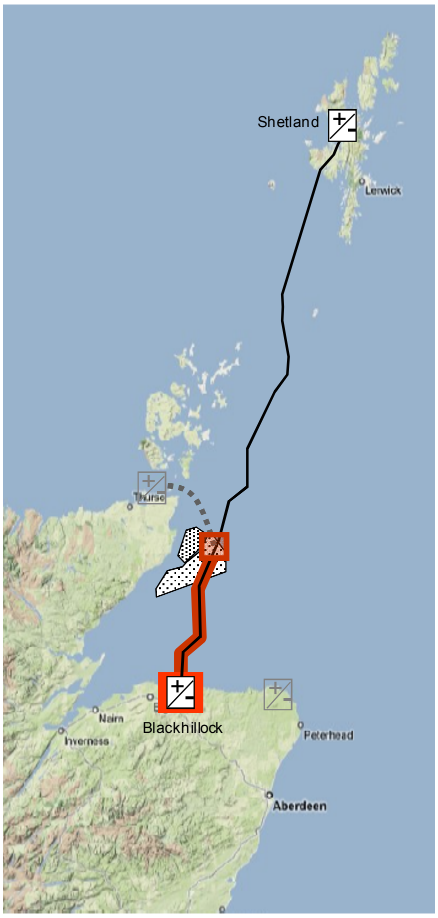
- 8km underground Upper Kergord inland on Shetland to Weisdale Voe on the coastline);
- 320km subsea to Port Gordon on the main Scottish coast; and
- 17km underground Port Gordon to Blackhillock

SHETL indicate a total cost (including all pre-construction works), in 2009/10 prices, for this scheme of £548m (to the nearest £m)

Shetland offshore hub

As indicated above this scheme includes an offshore hub at an intermediate point in the link between Shetland and the Scottish mainland and this is illustrated below.

Figure 30 – Illustration of proposed offshore hub variant of Shetland link scheme



The key distinction between this scheme and the simple link previously described is the creation of an intermediate node in the Shetland Link and the increased rating of circuit from the offshore hub to Blackhillock. This scheme is believed to provide some key benefits; specifically it would:

- address the Dounreay/Caithness second phase upgrade which SHETL foresees is required in the longer term
- accommodate proposed marine generation around Orkney & Pentland Firth
- accommodate proposed offshore wind farms in the Moray Firth

SHETL indicate a total cost (including all pre-construction works), in 2009/10 prices, for this scheme of £679m (to the nearest £m) i.e. some £130m more than the “simple” Shetland link.

9.18.2 **Headline Assessment**

KEMA's headline assessment of the proposed Shetland Isles scheme is summarised within the two tables provided below:

Benefit/capability provided	Critical dependencies	Interaction with other schemes
600MW of export capacity from Shetland to mainland Scotland	Both the scale and timing are critically dependent on expectation for a single large generation project	Generation export would further underpin need for Beauly-Blackhillock-Kintore reconductoring and East Coast upgrade or Eastern HVDC link

Certainty of need	Reasonableness of scope	Certainty of timing	Cost effectiveness
● The project in either form (link or offshore hub) is critically dependent on one large generation project which has yet to receive consent.	● The scheme is scaled to meet the scale of the large contracted generation project plus some potential local small generation.	● SHETL will not build unless securitised by the generation project driving the need case; and at present generation will face high costs whilst no certainty of status. Thus believe 2010/11 start for construction is highly uncertain.	●● The project is very expensive at £913/kW for the "simple" link and £1132/kW for the offshore hub option – albeit the hub will enable cheaper connection of offshore renewables.

The initial KEMA view is that whilst the Shetland scheme is ambitious, the scope of the two options for the Shetland scheme are both reasonable in their own right and that the offshore hub option presents a flexible approach to potential future offshore developments and potential creation of an offshore grid of one form or another. However, the immediate need and timing of the Shetland scheme in either form is critically dependent on the status and progress of the large 550MW Viking onshore wind project proposed to be built on Shetland. This project has created much debate on Shetland, given its scale and whilst it was first mooted 5 years ago only submitted a planning application in May 2009; the outcome of this being currently awaited. As for the Western Isles scheme which is subject to similar uncertainty (albeit not exposed to the fortunes of just one project); SHETL asserts they will only proceed with the scheme on a securitised basis i.e. no commencement of construction on an anticipatory basis. It is very unclear at present if Viking will actually proceed and in what timescales.

It is accepted that the proposed nature of the Shetland scheme if it were to proceed is largely unavoidable given the location of the generation; and that the more expensive variant (offshore hub) presents a number of attractions from the perspective of providing flexibility to accommodate future offshore developments. However, it cannot be avoided noting that the unit cost of the capacity created is exceedingly high (albeit the hub option will provide the ability for cheaper connection of offshore renewables – thus the £/kW rate would fall in this circumstance) and an order of magnitude higher than the majority of other schemes proposed by the TOs for additional funding in order to facilitate connection of and export of power from renewables in order to meet 2020 targets.

Putting the very high cost of the scheme in terms of delivering renewables generation to one side; KEMA believes the key issue is the timing of scheme commencement and that currently it is highly uncertain that the scheme will need to commence construction in 2010/11. In this context it is very unclear that additional funding is required in the timescales currently proposed by SHETL.