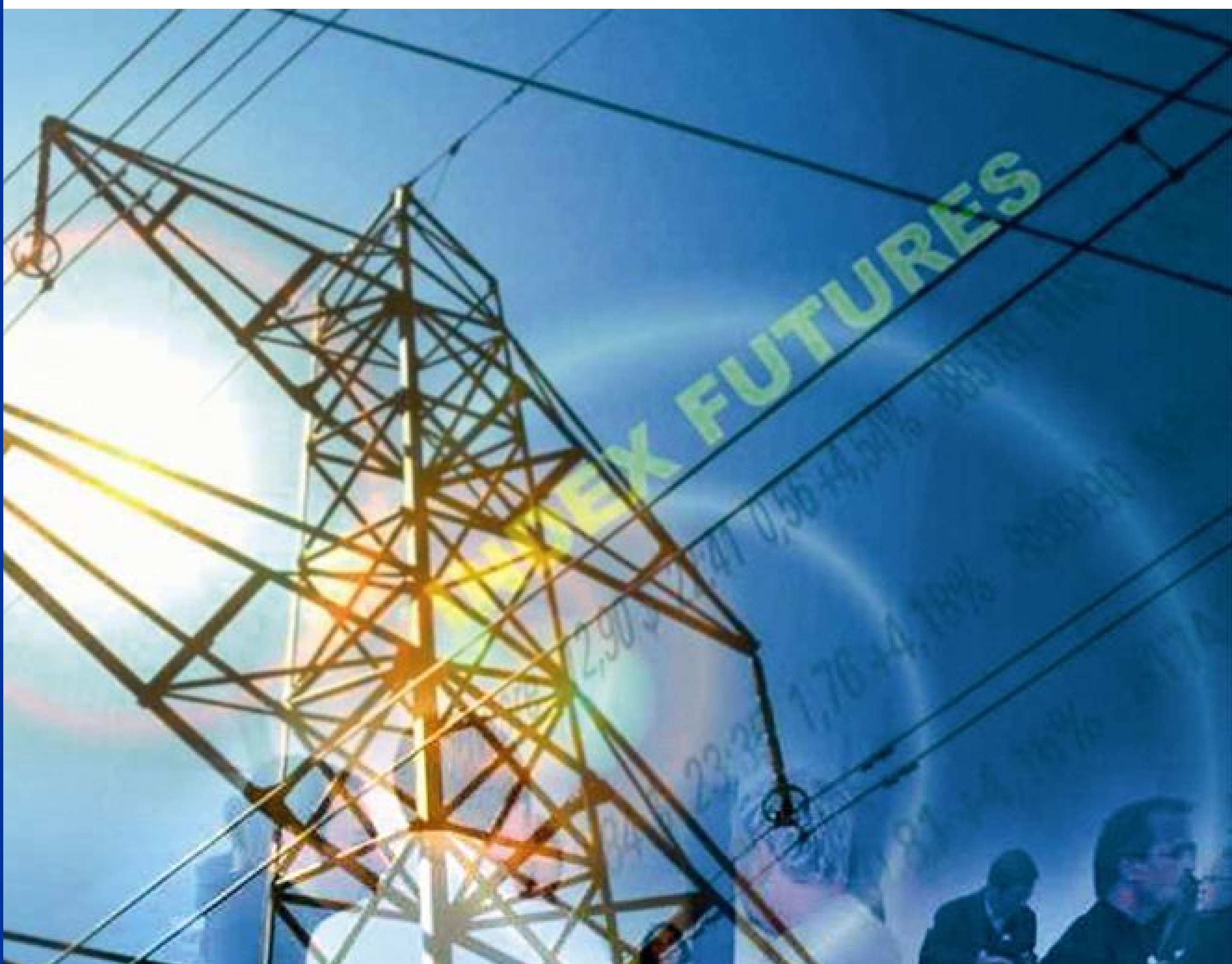
MODELLING THE CAITHNESS MORAY REINFORCEMENT – STAGE ONE

A report to Ofgem

1 April 2014



MODELLING THE CAITHNESS MORAY REINFORCEMENT

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EXECUTIVE SUMMARY

The Caithness Moray project comprises a potential set of transmission reinforcements which are critical to export proposed substantial new onshore wind generation in the far north of Scotland southwards through the Scottish transmission network and to the rest of the GB transmission system.

The total cost of the Caithness Moray project is indicated by SHE Transmission as being expected to fall within the range £1.3bn - £1.7bn and has been submitted to Ofgem for receipt of funding under the Strategic Wider Works (SWW) process established under RIIO-T1.

A preferred HVDC option has been proposed for assessment under the SWW process, and this option is compared to alternative options and to the counterfactual of not reinforcing the system.

Therefore, four transmission reinforcement options are explored and assessed by SHE Transmission and their consultants SKM for addressing the indicated Caithness Moray reinforcement needs, and are presented for Ofgem's assessment of the proposal:

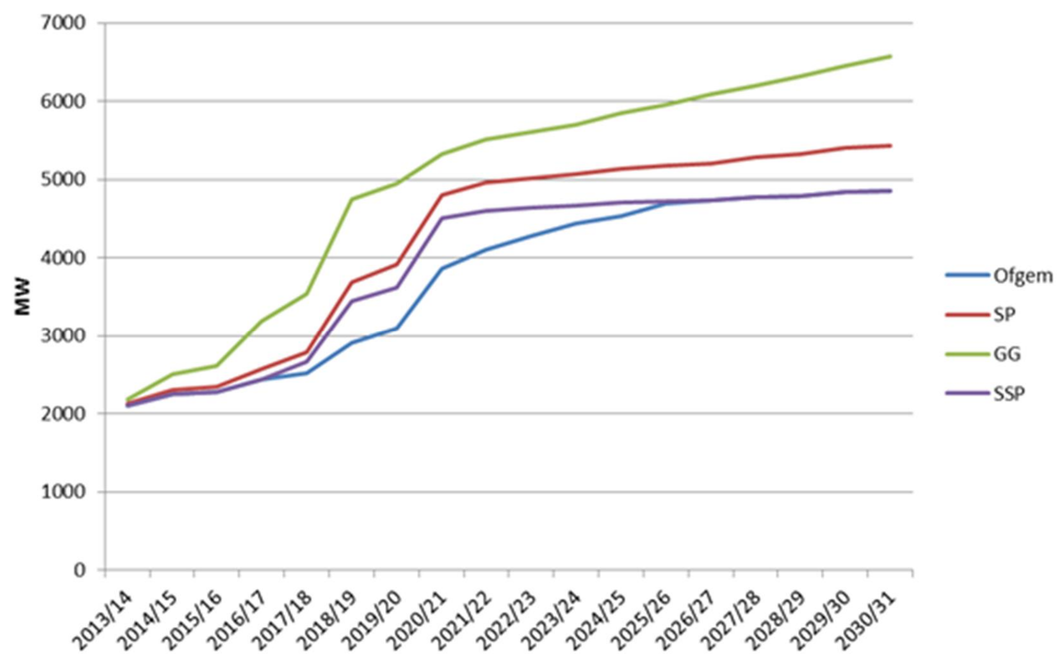
- Option 1a involves an HVDC subsea cable solution from Spittal in the Caithness area to Blackhillock in Moray, together with associated onshore works, and is expected to be operational by 2018. *This is SHE Transmission's recommended reinforcement option.*
- Option 2a involves an AC overhead solution along the coast of Caithness, upgrading to 275 kV the circuits from Dounreay down to Beauly, and is expected to be completed by 2026/2027 (However we note that Ofgem has indicated to Pöyry that this option is not considered by them to be viable).
- Option 1b comprises 1a and an additional AC Over Head Line (OHL) between Beauly and Blackhillock (BB400).
- Option 2b comprises 2a and the additional BB400.

The Need Case submitted by SHE Transmission to Ofgem under the SWW process – which encompasses both absolute requirement and proposed timing – is critically justified by a Cost Benefit Analysis conducted by SHE Transmission's consultant SKM which assesses the relative merits of the different reinforcement options identified above, under a number of four main generation scenarios:

- Slow Progression (SP) – consistent with National Grid's GB scenario of the same name, this is proposed by SKM to reflect a central case of likely renewable development in the north of Scotland based largely on known projects at various stages of development.
- Gone Green (GG) – this is consistent with National Grid's GB scenario of the same name and is proposed by SKM to reflect an optimistic, but achievable, rate of renewable growth as required to "put the UK on the route to a low carbon economy."
- Slower Slow Progression (SSP) - this is proposed by SKM to represent a downside rate of growth, and a slower rate of growth "than empirical evidence indicates".
- Ofgem – this is a scenario proposed by Ofgem which they asked SKM to include in its CBA for Caithness Moray reinforcement options which has slower renewable growth than SSP up to 2020 but then sustaining this to reaching SSP levels by 2026/27.

Figure 1 illustrates the different growth pathways assumed for renewables in northern Scotland under the four different generation scenarios considered.

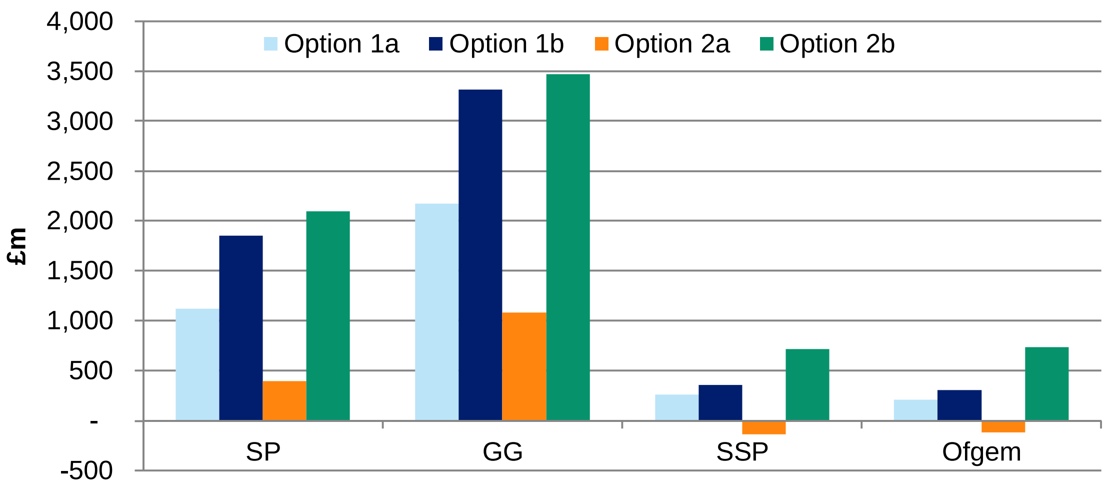
Figure 1 – Renewable growth in northern Scotland under the different scenarios



Source: SKM

The differing growth of renewables assumed in northern Scotland clearly has a critical impact on the CBA of different reinforcement options for Caithness Moray. Figure 2 summarises the central net present value (NPV) of the different reinforcement options for the four generation scenarios considered.

Figure 2 – NPV of all generation scenarios (£ 2013 prices)



Source: SKM

The CBA conducted by SKM calculates the NPV of the different transmission options for a period of 40 years. The net present value of an option is calculated as the balance between the lifetime expenditure (capital and O&M costs) and the net lifetime benefits that are expected to accrue from reduced energy constraint costs when additional transmission system capacity is made available. The constraints are modelled on yearly simulations at half-hourly granularity from the year 2013 (although the first reinforcements would only be ready in 2018) until the year 2030, and further years are extrapolated.[1]

SKM's CBA results for the proposed Caithness Moray reinforcement show that:

- There is a strong case for a transmission reinforcement in northern Scotland to increase the power transfer capacity for the main GB transmission system boundaries B0 and B1. This allows accommodating planned substantial new wind generation north of the B1 boundary.
- For the first stage of the reinforcements (options 'a', without the BB400 project), the HVDC subsea cable, Option 1a, provides a significantly higher NPV, whereas Option 2a does not, as it fails to address constraints across the B1 boundary. The NPV for Option 2a even becomes negative under low wind generation scenarios. This supports the rejection of Option 2a as a reasonable option.
- Based on constraint costs of £130/MWh as adopted in the base case scenario, Options 1b and 2b always provide positive NPVs. Option 2b returns the highest NPV under all four wind generation scenarios: being slightly higher than other options under the high wind scenarios SP and GG, and significantly higher than other options in relative terms for the low wind generation scenarios Ofgem and SSP. Only Option 2b provides a positive NPV under the sensitivity analysis to constraint costs of £100/MWh.
- Option 1b has higher early impact in boundary B1, by increasing the boundary capacity earlier than Option 2b.
- Under all scenarios and sensitivities, Option 2b consistently provides a higher NPV than Option 1a and 1b despite later commissioning of the reinforcement and thus significantly higher constraints in the period 2018 to 2024. This is due to the much lower investment costs incurred.

Based on our high level review of SKM's assessment, the CBA gives a reasonable indication of the relative merits of the reinforcement options and the sensitivity of these (individually and with respect to other options) to changes in key assumptions.

However, there are aspects of the CBA conducted by SKM which could be enhanced and/or refined to increase the robustness of the assessment and its conclusions. Principally these include:

- The modelling used by SKM to simulate the constrained energy volumes is fairly simple compared to state-of-the-art models normally used for generation dispatch studies and their implications for zonal power transfers.
- However, in the context of almost all generation north of B1 being renewable generation it may be sufficient/fit-for-purpose to provide reasonable constraint volume results in this specific case. But this needs to be tested versus the results from a

[1] It is worth mentioning that additional reinforcements to those described in the four options 1a, 1b, 2a and 2b, expected for 2017, are not included in the counterfactual, and hence also contribute to the calculation of constraints and the benefits of all options.

more sophisticated model capable of optimising all dispatchable technologies and looking at hourly replacement energy costs (marginal prices) in the market.

- In addition, the decoupling of constraint volume assessment from constraint value assessment is a simplistic approach and so is the use of a single value of constraint price (for each time period across the entire year) for costing the derived constraint volumes. Constraint prices are dynamic across a year and the correlation of these with weather patterns (as Renewable Energy Source (RES) generation increases) is increasing. Thus consideration of volumes and concurrent prices is very important for robust assessment of relevant constraint costs.
- Given the importance of weather patterns in determining constraints costs specifically for this CBA with large amounts of wind expected in the assessed region but also in GB as a whole, detailed modelling of weather and wind generation characteristics are critical, and are not addressed fully enough in the SKM CBA. The generation of wind profiles should test more weather years capturing the spatial and temporal correlations across different sites/locations to enable robust understanding of the impact on relevant boundary transfer flows and thus capacity requirements.
- Additional sensitivities to test the impact of (a) alternative demand growth profiles compared to the flat demand hypothesis assumed in the CBA; and (b) alternative natural hydro inflows patterns would provide additional robustness to the study.

Given the previous remarks, we recommend the following to Ofgem:

- Conducting an additional study allowing to confirm the reasonability of the constrained energy volumes calculated by SKM's model, i.e. that the simplified modelling approach, in this specific case, is providing reasonable results. In particular, a more detailed model should capture:
  - the impact of optimising pumped storage and dispatchable hydro within the whole GB system according to system needs; and
  - the interactions with the rest of GB in situations of high wind where the GB System Operator´s need to maintain a minimum level of flexible generation on the system means that it that wind curtailment is required for national reasons regardless of the whether the B1 boundary is an active local export constraint.
- Testing the sensitivity of constrained energy volumes to demand growth hypotheses and to the variability in historic natural hydro inflows
- Given the high sensitivity of NPVs to a different view of constraint prices i.e. £130/MWh to £100/MWh, and the use of these single values as simple multiplier to overall identified constraint volumes, there should be more detailed consideration of what are appropriate constraint price values to assume, under what circumstances they arise and how constraint prices vary within year and impact on overall constraint prices depending on different weather patterns. *[We note that this exercise was amended to the initial scope of the project, and the conclusions are explained in the Stage Two Report.]*

Given our analysis of the methodology and the data, we consider SKM's results to be reasonable in estimating the expected costs of constrained energy volumes, but with:

- factors that moderately overestimate total constraint volumes;
  - the model doesn't look at the interactions with the rest of GB system
  - the modelling of a fixed profile for dispatchable hydro and pump storage
- factors that underestimate total constraint volumes;

  - a potentially conservative load factor for wind power
- factors whose impact on constraint volumes is uncertain;
  - the use of one single weather year for wind, demand and hydro
  - the production of wind profiles of new farms based on existing farms
- factors whose impact on constraint costs is uncertain;
  - the use of one single cost of replacement energy throughout the year.

Adopting the recommendations of this report will enable Ofgem to better assess the reasonability of the results of the SKM CBA study and make the most robust decision about the Caithness Moray reinforcement submitted for funding by SHE Transmission.

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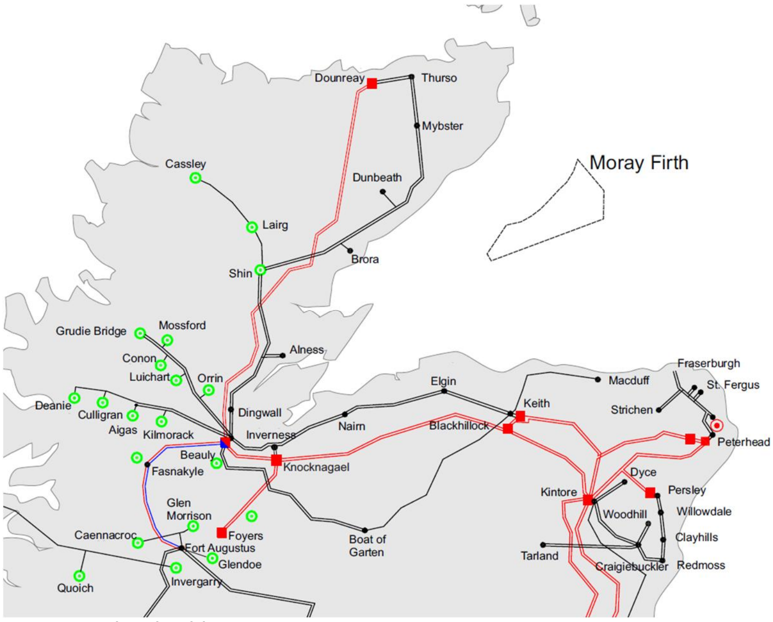
1. INTRODUCTION

1.1 Context

The Caithness Moray reinforcement is a very large transmission project in northern Scotland proposed by Scottish Hydro Electric Transmission plc (SHE Transmission) to support the expected growth of renewable generation capacity in the area. It is a key project of a wider set of reinforcements in the north of Scotland which will allow the integration of further renewable generation into the GB system by increasing the export capacity between the north and the south of Beauly and Blackhillock (see Figure 3 and Annex A).

Figure 3 – Transmission network in the Caithness Moray area



Source: National Grid – Ten Year Statement 2013

The proposed reinforcement involves an offshore HVDC link between the north of Caithness (in Spittal, near Mybster) and Blackhillock in Moray, and associated onshore works.

In the Needs Case this proposal is compared to an onshore reinforcement in the Caithness area rebuilding the existing 132 kV circuits between Beauly and Dounreay to 275 kV, and associated additional works.

SHE Transmission has requested Ofgem to assess its subsea HVDC proposal under the Strategic Wider Works (SWW) arrangements that were introduced as part of the electricity transmission price control RIIO-T1.

To put forward a project for consideration under the SWW mechanism, the relevant Transmission Owner (TO) must provide a needs case submission followed by a technical case submission. SHE Transmission submitted a Needs Case for this project in March 2013.

A significant part of the Caithness Moray reinforcement project assessment is informed by a Cost Benefit Analysis (CBA) submitted by the TO (or its consultant, SKM in this case) as part of the Need Case. This CBA is the most critical justification for the Need Case, as it explores the costs and the benefits of reinforcing the transmission system with the various options, versus the counterfactual of not reinforcing the networks (beyond the ongoing or committed works).

1.2 Scope of work

Constrained energy volumes are a key input to the CBA and play a predominant role in determining whether a large transmission project is economic. Constrained energy volumes are modelled based on the expected power flows from a range of generation scenarios, the available network capacity under different reinforcement strategies, and criteria in the National Electricity Transmission System Security and Quality of Supply Standards. Ofgem seeks support in reviewing and evaluating the energy constraints modelled by the SHE Transmission and their consultant SKM.

The scope of the work that Ofgem seeks with this report comprises:

- a summary and evaluation of the approach used by SKM to model future energy constraint volumes across different scenarios;
- a view on the implications of the evaluation on the quality of the modelled outputs;
- recommendations on further work or improvements to the modelling approach that might be needed to obtain most reasonable estimates of future energy constraint volumes.

Ofgem seeks to understand best practice in this type of studies as per state-of-the-art market modelling capabilities and industry standards, as well as the simplifications fit for the context of this specific project.

1.3 Structure of the report

In order to comply with Ofgem's requests in reviewing SKM's methodology in the CBA, the rest of the report is structured as follows:

- Section 2 contains a description and an evaluation of SKM's approach and recommendations; and
- Annex A contains a description of best practice in modelling power flows.

2. CAITHNESS MORAY CBA ASSESSMENT

2.1 General approach

The general approach of SKM is well designed, and clearly explained in the Need Case.

Prior to conducting the CBA, a good number of initial options have been considered (10), and pre-selected through a rigorous multi-criteria scoring and weighting system. A fair break-down of costs is provided. Several weightings are provided with detailed scoring results.

Regarding the CBA, we find the whole study to:

- consider sufficient scenarios and sensitivities to test generation and timing issues;
- analyse a reasonable number of years for a representative calculation of the NPV;
- compare with sufficient granularity (half-hourly) the expected flows and the boundary capacity; and
- make appropriate use of grid models to analyse border capacities.

We see merit in the preparation of data and the generation dispatching model, but raise the following concerns:

- the methodology of the dispatching model is simpler than a full optimisation model and does not capture some relevant hourly interactions with the rest of GB system;
- the sensitivity to the weather years (mainly wind production) is not robust due to use of one year of wind data and one year of hydro production data; and
- we understand that the wind profiles created for all new wind farms are matched to existing wind farms in the study area, which is reasonable but not as exact as using coherent wind speeds (respecting temporal and spatial relations); this brings higher uncertainty for new remote areas.

These issues and their impact are further discussed in following sections.

2.2 Models

SKM and SHE Transmission have used two models; Constrained Energy Flow Model (CEFM) for the calculation of constraint volumes, and PSSE (Power System Simulator for Engineering) for the calculation of boundary capacities.

2.2.1 Energy flow models

SKM's model CEFM is described in the document 'SKM Flow Model Description'. The CEFM *"determines, on a half hourly basis for each year from 2013 to 2030 the constrained energy that will result on each critical boundary identified. The constrained energy is the result of half hourly generation output within each zone, from this generation half hourly demand is 'netted off' and the resulting power flow compared to the boundary capability. If the net power flow is greater than the boundary capability then a constraint will occur."*

Indeed, the constrained energy volumes are the difference between the flows that would result from an optimal dispatch with unlimited network capacity, and the maximum flows allowed by the network.

We agree on the hourly (or half-hourly) approach as the most suitable to model constrained energy volumes.

However, it is the combination of the dispatch model methodology and the associated input data that are crucial to accurately representing the generation profiles, as well as the interactions with the interconnected area. Regarding this point, the modelling of the power flows does not follow best practice because:

- the CEFM model is not based on an optimisation of the generation costs as described in Annex A.3.1, and
- the interactions with the region south of boundary B1 are not modelled.

The implications of above concerns in terms of potential impacts are discussed below.

2.2.1.1 CEFM model

Both in modelling liberalised markets and regulated systems, state of the art dispatching models perform a least-cost optimisation of Short Run Marginal Costs (SMRC) to meet a given demand profile. Such a model solves for each period (typically hour or half-hour) the status and the power output of all power plants, respecting their individual specifications such as the start-up times, the maximum ramp rates, or the minimum up and down times.

We acknowledge that in the modelled region, north of the border B1, no thermal capacity exists, and a simpler model fit-for-purpose might be enough. As shown in Figure 16 of Annex B.1, Peterhead and Stoneywood thermal plants are just South-East of the B1 border. However, the Foyers Pumped Hydro Storage (PHS) plant, and the conventional dispatchable hydro plants (the non run-of-river) should be co-optimised to serve the net load of the system (defined as the load minus the production of intermittent sources such as wind power). This means that a model taking the pumped hydro and the conventional hydro plants as fixed inputs is not capable of adjusting their production to the system needs.

For instance, the model might curtail wind power during an hour in which the pumped storage is dispatched at full output based on a historic profile, instead of an optimal situation when the PSH plant will be required to be in full charging (demand) mode to reduce the constraint. This is especially relevant in a context of very high wind power penetration, as is expected beyond 2020 in Scotland.

Given the underutilisation of the flexibility of PSH production at Foyers in the current approach, this modelling approach is expected to overestimate total constraints. In this regard, SKM mentions in the “Further Update Note” of 17 July that they “*have explored the possible impact of operating the 300 MW of pumped storage to help ‘smooth’ out the output of wind, plus the operation of an additional 180 MW of hydro that is deemed ‘dispatchable’ to some extent*”. However the details of modelling such operation of PSH and hydro in the CEFM model are unclear.

SKM states in Q4 of the answers submitted to Ofgem on 8 July 2013 (New Q&A 1-16) that “*As discussed in the meeting with Ofgem and Kema, we have undertaken modelling with all 300 MW of PSY*[2] *in zone B1 set to zero*”.

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[2] PSY refers to the Pumped Storage, that Pöyry refers to as Pumped Storage Hydro (PSH)

We have post-processed the results of PSH related sensitivities from the raw material provided by SKM, which shows that, all else being equal under the SP generation scenario, this sensitivity modelling provides -21% constrained energy volumes in the period from 2018 to 2030. This implies that, all else being equal, constrained volumes could be closer to this sensitivity compared to the base case. Furthermore, we believe that a dynamic modelling of the operation of PSH and hydro along with wind output and the rest of GB would present a more complete picture of potential constrained volumes.

Additionally SKM states "*The results of our indicative analysis suggest that managing hydro to operate in tandem with wind, rather than in tandem with peak demand, may reduce constraints by around 5 per cent. However, as the proportion of wind output increases, then the capability of dispatchable hydro to smooth wind does not increase as it is operationally constrained by factors such as water storage and the size of the upper reservoir. In effect the benefit of dispatchable hydro erodes with the addition of more wind.*"

We point out that hydro should not be managed according to wind or to peak demand, but according to forecasted net load of the system (affected by both wind and demand). Also, the fact that hydro power has operational limits and it cannot compensate all the wind variations does not necessarily imply that hydro has less value, and the exact contribution of PSH to reduce constraints must be modelled with an optimised dispatch software.

2.2.1.2 Modelling the region south of B1

There is another aspect which cannot be captured by SKM's model. During some very windy hours on a national level coinciding with low demand, it is expected that the system will not be able to integrate all the available wind resource, regardless of the network capability. These situations are caused by significantly low demand or insufficient flexibility of the remaining generators to cope with the hourly (or half-hourly) net load of the system. For instance, nuclear plants cannot be disconnected from the grid for a few hours, and neither can some coal plants which are needed for the peak hours of the next day[3]. When these situations occur in GB across the studied period, some wind power will need to be curtailed from the system, and partly in the Scottish areas, even with free transmission capacity. Not capturing that these curtailments of wind will occur anyway because of other reasons than the network capability implies an over-estimation of constrained volumes associated to the network.

The impact of this simple modelling depends on the level and frequency of curtailments expected at GB level, which varies across scenarios and years.

2.2.2 Load flow models

The boundary limits have been provided by SHE Transmission, based on simulations performed with the load flow commercial program PSSE. PSSE is a robust tool used by TSOs worldwide, which confirms it as valid in performing load flow studies.

We observe that the modelling performed by SHE Transmission follows best practice, in calculating the boundary capacities for up to four borders, three types of seasons

3 As a reference, these situations occurred in Spain already in 2010, with circa 20,000 MW of wind power installed, during 200 hours and affecting 3 TWh (0,6% of the yearly available wind resource), and a maximum instantaneous curtailment of 5,000 MW of non-admissible wind power. Also, Germany occasionally curtails wind and solar energy for the same reason, for instance on 16 June 2013 with 5,000 MW affected.

(Summer, Winter and Spring/Autumn), and testing the N-1 and N-D Quality and Security Standards.

2.3 Input data

For the specific area modelled, several aspects are relevant in the preparation of input data:

- the quality of the wind profiles, capturing sufficient sensitivity to weather years and the realistic geographic and temporal correlations between all wind farms;
- the suitability of selected hydro production profile, which is used in a 'static' model; and
- the demand profiles in the modelled region.

In assessing the validity of the data produced by SKM, we make the following remarks:

- The input wind generation data is reasonable, but lacks robustness due to the use of one single year 2008/9 (as answered on 25 February 2014 to Pöyry's questions sent to Ofgem). Also, it is not fully clear how the methodology ensures that the time and space correlations of all future wind farms are captured. SKM's use of historic wind speeds and power curves combined with real measurements for calibration is a good approach, provided that the space and time correlations between all wind farms are reflected. But we understand from the answers provided to Pöyry and A3 of the answers of 8 July provided to Ofgem, that the wind historic wind speeds in the new locations are not used, and instead SKM "*use a half hourly average output of the existing large wind farms in 2008/9 within each of the study zones".* [4] The impact of using a single year on the constrained energy volumes is uncertain and this sensitivity requires modelling.
- A single average wind capacity factor of 28% is used, considered by SKM to be conservative given the expected load factors of 35% to 44% in Western Isles, Shetland and Orkney (from DECC's study mentioned in the answers to Pöyry). This conservative assumption would be avoided by using more weather years, through historic wind speeds in the mentioned areas. Higher load factors resulting from installed wind in these mentioned areas would indeed increase the constraints calculated, as mentioned by SKM in reference to the 30% load factor sensitivity.
- In the answers they provided on 25 February, SKM mentioned that in the absence of data from the Western Isles, a profile from B02 wind generation is used with a 15% uplift to reach a load factor of 36%. Whilst this approach is not unreasonable given the lack of available wind farm data, the use of consistent wind speeds would be desirable. The impact of this approach is not expected to be significant, but this should be tested for greater robustness.
- The static profile used for hydro and pumped storage hydro, in line with the CEFM model, has been previously discussed. The impact of the difference in this modelling with the real dispatching capabilities of those hydro plants, is expected to be relevant, and Pöyry's post-processing of SKM results shows -21% constrained energy volumes when the PSH and the dispatchable conventional hydro are set to zero.

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4 Table 4 of the 'SKM Flow Model Description' document, included in Annex C.1 of this report, shows hourly inputs changing from 85% down to 6% and then back up to 95% within one same day (perhaps a real stormy day, or a change in wind direction).

- The demand profiles used are from 2008/9 and coincide with the year used for wind data, which is positive as it ensures capturing a potential correlation between wind and demand. Also, SKM state that "*2008/2009 demand has been used and assumed flat until 2030*". We have confirmed that this assumption is quite consistent with DECC SP scenario. However, best practice recommends the use of several weather years to capture potential wind-demand correlation and inter-year variation in wind load factors.

2.4 Outputs

A large number of results have been provided, regarding energy constraints, and costs of these constraints.

The outputs of the load flow studies performed by SHE Transmission are also provided, and we do not assess them in the scope of this report.

We provide an evaluation of the outputs regarding the volume of constrained energy and the associated costs in the following sections.

2.4.1 Energy flows and volume of constraints

A good range of results have been provided for multiple cases, including:

- the base case, corresponding to a Slow Progression scenario and central;
- sensitivities to installed generation (Gone Green, Ofgem and Slow Progression);
- timing of reinforcements (+/- 1 year, +/- 2 years); and
- modelling of the Pumped Storage Hydro.

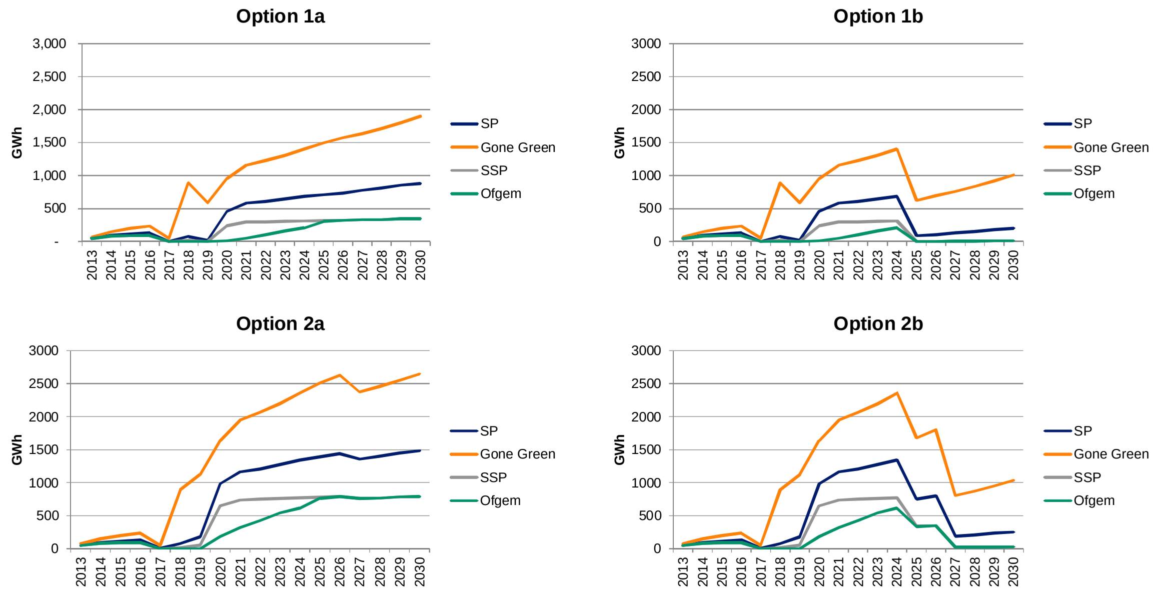
Additional financial sensitivities have also been studied, without considering the impact on the constrained energy volumes.

The file "CM cash flow analysis" in its sheet "Flow results" contains the results of different cases, combining multiple permutations of generation scenarios, transmission options, timing sensitivities and modelling sensitivities. These amount to 216 tables, each providing the yearly constrained volumes from 2013 until 2030.

To illustrate some of the results provided by SKM, we present some comparable results in the following figures.

Figure 4 compares the constrained energy volumes obtained for reinforcement options 1a, 1b, 2a and 2b, under the generation scenarios SP, GG, Ofgem and SSP. These sensitivities show that higher installed renewable energy increases considerably the constraint energy volumes. E.g. in all reinforcement options the GG sensitivity provides the highest constraints.

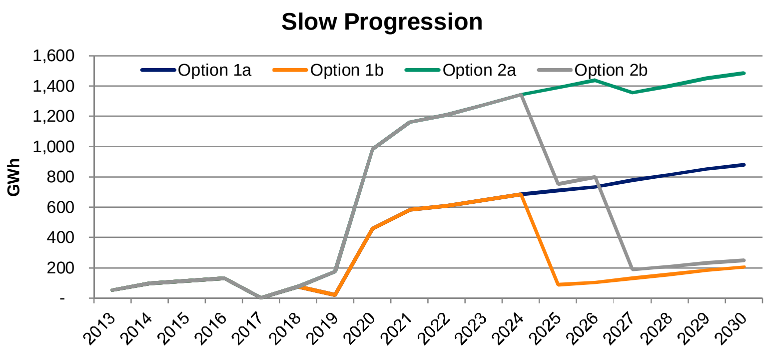
Figure 4 – Constrained energy volumes under different generation scenarios



Source: Elaborated by Pöyry from SKM CBA results

Figure 5 directly compares the impact of reinforcement options on constrained energy volumes for the base generation scenario Slow Progression. We can observe how the constraints are dramatically reduced for the 'b' options, when BB400 becomes operational. We can also observe how under options 1a and 1b the constraints are much lower than for 2a and 2b until the year 2027 when all reinforcements of the AC solution are in place, as compared to the earlier installation of the HVDC solution by 2018. The highest constraints of Option 2a support SHE Transmission's suggestion that it should not be considered given the much higher constraint volumes expected. The following figure shows that after 2024, Option 2a leads to 75% higher constraints than Option 1a, and seven times the constraint volumes of options 1b and 2b.

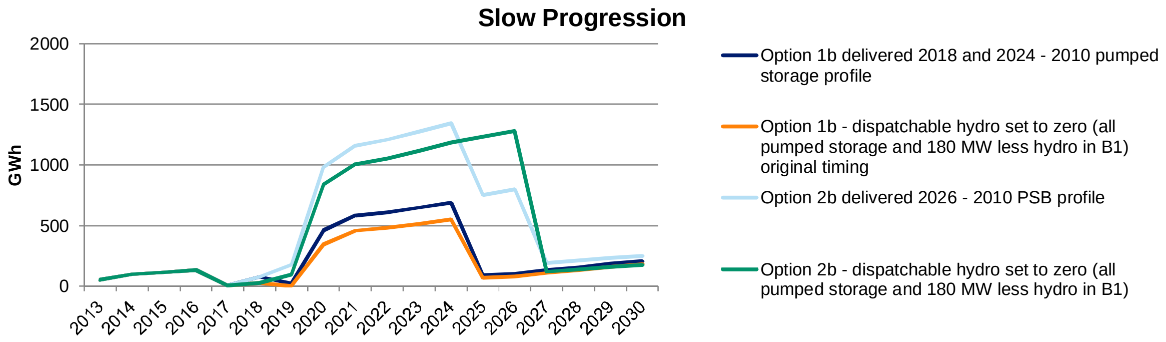
Figure 5 – Constrained energy volumes under different reinforcement options



Source: Elaborated by Pöyry from SKM CBA results

Figure 6 presents the results of the constrained volumes for the SP scenario under two different modelling approaches of the hydro, (a) using the 2010 profile and (b) setting the PSH and 180 MW of conventional hydro to zero. These results support the argument that an optimised modelling of the hydro resources has a significant impact on constraint volumes, which is -21% in this case when set at zero versus the fixed 2010 profile.

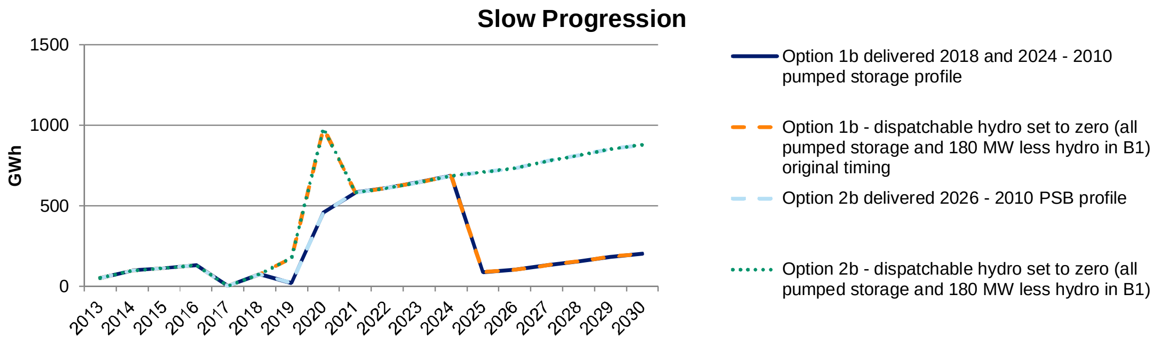
Figure 6 – Constrained energy volumes under different hydro modelling approaches



Source: Elaborated by Pöyry from SKM CBA results

Figure 7 shows the effect of delaying the BB400 reinforcement by two years (Beauly-Blackhillock 400kV) in the base case scenario. It illustrates how for years 2019 and 2020 the constraints are significantly higher. (Whether these additional constraint costs are offset by the benefits of delaying the investment can only be observed by analysing the financial model.)

Figure 7 – Constrained energy volumes under



Source: Elaborated by Pöyry from SKM CBA results

The results provided by SKM are sufficiently abundant and sufficiently clear in allowing the analysis of all sensitivities described in the CBA.

All results reviewed by Pöyry for different reinforcement options and sensitivities to inputs or to modelling approaches are found to be reasonable. They also vary in the expected directions (e.g. higher wind capacity north of the boundaries B0 and/or B1 leads to higher constraints, lower hydro production leads to lower constraints) and in reasonable amounts.

This suggests that the model responds correctly to changes in inputs and validates the sensitivities analysed.

2.4.2 Costs of constraints

We have a specific concern in the use of a single value for the replacement energy cost for the whole year, given the volatile prices expected, which sometimes go down to zero and even turn negative under the high wind penetration scenarios, but also present high spikes. Although the tender specifications focus on the volume of energy constraints, we point out that the value of these constraints is critical for the CBA, and the use of a full market model as described in Annex A.3.1 would shed light on this issue.

2.5 Scenarios and sensitivities

SKM have performed the study around a central base case scenario, following the 'Slow Progression' scenario as defined by National Grid in its 'UK Future Energy Scenarios'[5] and referenced in the Ten Years Statement 2013[6]. The SP scenario is currently more credible according to our own forecasts and we agree on its selection as a base case.

Wind generation scenarios in the region north of the B1 border (see Figure 17 in B.2) are modelled through sensitivity analysis.

In addition to the sensitivities that affect the results of the constrained energy volumes, financial parameters sensitivities have also been tested regarding:

- the capex costs of the reinforcements; and
- the constrained energy costs.

These provide a clear picture of how the NPV of a decision is affected by non-technical factors equally to the technical ones.

Despite a very complete set of scenarios and sensitivities, we miss additional sensitivities to support assumptions performed by SKM, such as:

- Sensitivity to demand profiles as:
  - only one demand profile has been used from the year 2008/2009; and
  - a zero growth has been assumed from 2008 until 2030.

  It doesn't seem trivial that different demand growths, as expected by the GG scenario, will not impact the constrained energy volumes at least in a perceptible way.
- Sensitivity to the hydro production has not been tested, whereas it doesn't seem trivial that very wet or very dry years may significantly impact the constrained energy volumes.

2.6 CBA assessment

The CBA assessment is clear in presenting results of the four main options considered, 1a, 1b, 2a and 2b against the counterfactual of not reinforcing the networks. The costs of constraints under all options are presented against the counterfactual of not reinforcing the transmission system.

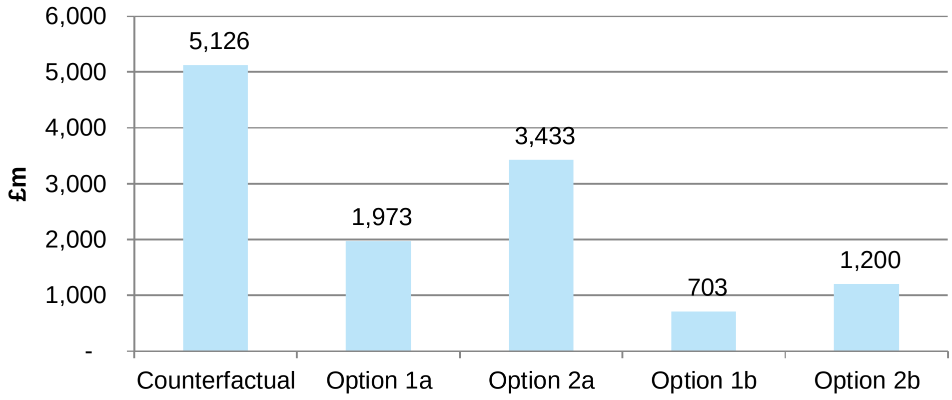
5 http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

6 http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/Current-statement/

Figure 8 presents the lifetime constrained energy costs for the four reinforcement options considered. As stated by SKM, option 1b clearly provides the highest savings in constrained energy costs followed by option 2b. However, these higher savings of the HVDC option come at a higher investment cost hence in pure economic terms it is the NPV of the different options that must be compared.

The constraints costs of the different reinforcement options represent the costs of constraints that remain still after the transmission reinforcements, in times of very high Renewable Energy Sources (RES) production. Completely removing all constraints from the system would need further reinforcements and would imply a low use of the capacity during most hours of the year, which is not most likely not cost-effective (although this has not been tested by SKM).

Figure 8 – Constrained energy cost comparison

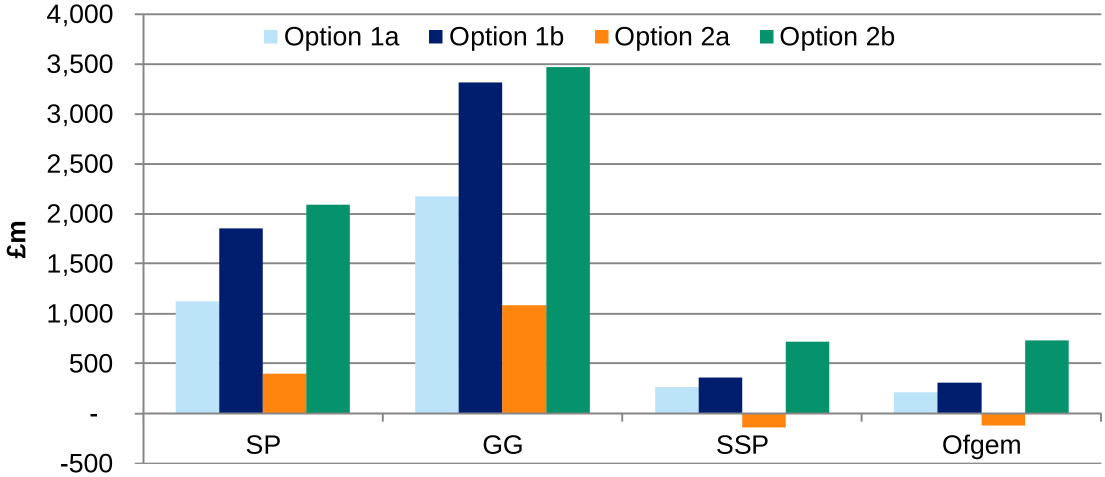


Source: SKM

Figure 9 shows the final NPVs of the different options, considering their net savings in constrained energy as well as their investment costs. As stated by SKM, the main conclusions of the CBA assessment are:

- All results show that there is a strong case for the reinforcement of the B0 and B1 boundaries.
- For the first stage of the reinforcements (options ‘a’, without the BB400 project), the subsea HVDC proposal, Option 1a, provides a significantly higher NPV, with Option 2a even becoming negative under the low wind generation scenarios, which suggests the rejection of Option 2a as a real option given its significantly higher constraints volumes and resulting costs.
- Options 1b and 2b always provide positive NPVs, with Option 2b returning a higher NPV under all four wind generation scenarios: slightly higher under the high wind scenarios SP and GG, and significantly higher in relative terms for the low wind generation scenarios Ofgem and SSP.

Figure 9 – NPV of all generation scenarios (£ 2013 prices)



Source: SKM

The sensitivity to the timing delays or advancement of the AC option and the BB400 projects are clearly explained:

- For Option 1a, results indicate that under the central case, the Least Worst Regret (LWR) timing is to delay the investment by one year.
- For Option 1b, the results show that the greatest NPV under the SP/GG scenarios is achieved when delivering the HVDC link on time in 2018, but the BB400 reinforcement 3 years earlier than planned.
- For Option 2a, the results show that the NPV is negative under the lower generation scenarios. The results also show that there is no benefit of advancing the AC works.
- For Option 2b, the results indicate that, under SP the most beneficial timing is delivery of the BB400 two years early. Under the lower generation scenarios Ofgem/SSP the option of LWR is to deliver the BB400 one year later and under the higher generation GG scenario the option of LWR is to bring forward the entire AC investment to 2021.
- Overall the option of LWR is 2b advanced to 2021 under the higher GG scenario and delivered on time in the central SP scenario.
- Following the HVDC option would lead to a regret of £240m if delivered on time in the central scenario. Regret would be minimised if the construction of the BB400 was advanced to 2022.

The sensitivities to the capex costs increase in 10% to 20% obviously reduce the NPVs, however all originally positive NPVs remain positive. This result proves the robustness of the conclusions with reference to relatively small cost increases. We point out that Asset Value Adjusting Events have been presented in the past significantly above +20% over initial budget. For instance in the Beauly-Denny reinforcement, an AVAE of +200% over budget occurred for a section, mainly as a consequence of the environmental works to be performed, of which undergrounding was responsible for the most part. Whilst there are contingency costs included in both options (30% for the AC option and 16% for the HVDC option), we still anticipate there is the possibility of additional costs increases. Therefore we believe that further sensitivities testing the impact of higher costs increases would be worth considering to account for the different risks involved. An interesting sensitivity analysis could provide, for robustness of the assessment, the percentage cost increase that would lead to an NPV equal to £0.

Finally, the sensitivity to the costs of constrained energy brings interesting analyses. A cost of constrained energy of £100/MWh, as opposed to the central £130/MWh, very significantly decreases the NPVs. Also, all options except 2b reach a negative NPV under the Ofgem and the SSP scenarios. Under the SP and GG scenarios, all NPVs remain positive but with a decrease of £0.4b to £1.3b depending on the reinforcement option. Given our concern on the calculation of the replacement energy cost, further sensitivities to constrained energy costs would provide higher robustness.

Subject to (a) the relevance of the flagged modelling issues on constrained volumes, and (b) the relevance of the flagged methodology issues in preparing the input data, results provided suggest that:

- there is a strong case to reinforce the boundaries B0 and B1 in order to accommodate the Scottish wind in the north of the B1 border;
- of all the options, Option 2b provides the highest NPV in all four considered wind development scenarios for the central cases –slightly higher in SP and GG, and significantly higher in Ofgem and SSP, and is the least worst regrets option;
- option 1 has higher early impact in boundary B1, which allows delaying the reinforcement of BB400 and involves higher flexibility to delayed installation of wind projects; and
- different timing sensitivities still provide higher NPVs for option 2b over 1b, and overall Option 2b is the option of Least Worst Regret.

2.7 Recommendations

Although the CBA conducted by SKM and SHE Transmission is thorough and clear in most aspects, we have raised a few concerns in this report which require validation before making a robust decision on the Caithness Moray reinforcement.

We hereunder summarise our recommendations to Ofgem:

2.7.1 System modelling

We recommend checking the impact of the modelling issues raised, to quantify the impact of:

- Not having used an optimisation model capable of adjusting the hydro production to the future needs of the system under high wind penetrations.
- Not having modelled the interactions with the rest of GB system, making the assumption that all available wind can be fed into the system when sufficient transmission capacity exists.

2.7.2 Data validation

We recommend validating the input data prepared by SKM, by:

- Using a different methodology in preparing the hourly (half-hourly) profiles, ensuring that:
  - enough weather patterns are used;
  - spatial and temporal correlations of the wind farms are respected; and

  - the latest data is used (power curves, wind speeds).
- Requesting to SKM to check the sensitivity of their analysis to:
  - demand forecasts scenarios; and
  - natural hydro inflows.
- Changing the fixed annual cost of replacement energy by a dynamic co-incident calculation process, or by using constrained optimised runs that calculate system variable costs under different options as explained in the Annex on Best Practices.

2.7.3 Decision making

Given our analysis of the methodology and the data, we perceive SKM's results to be reasonable in estimating the expected costs of constrained energy volumes, but with:

- factors that moderately overestimate total constraint volumes:
  - the model doesn't look at the interactions with the rest of GB;
  - the modelling of a fixed profile for dispatchable hydro and pump storage.
- factors that underestimate total constraint volumes:
  - a conservative load factor for wind power.
- factors whose impact on constraint volumes is uncertain:
  - the use of one single weather year for wind, demand and hydro;
  - the production of wind profiles of new plants from existing plants.
- factors whose impact on constraint costs is uncertain:
  - the use of one single cost of replacement energy throughout the year.

Following the recommendations of this report will allow Ofgem to assess the reasonability of the results of the CBA study (or eventually the need to perform additional work) in order to make a most informed decision.

ANNEX A – BEST PRACTICE IN POWER FLOW MODELLING

A.1 Overall methodology

Assessing the future costs of an electricity system involves modelling the costs of the different elements of the value chain. Ideally, in planning the system and making strategic decisions, all resulting system costs under the different considered options should be evaluated. In practice, in evaluating transmission projects, this is not possible and it is generally assumed that the decisions made in the generation or transmission activities do not significantly affect the costs of the remaining activities downstream in the value chain shown in Figure 10.

Figure 10 – Supply chain of the electricity sector

However, the interactions between the transmission network and the generation projects can be fundamental, to the point that some generation projects only go forward provided that a network with sufficient export capacity exists, and allows the sales of energy in the wholesale markets.

The Socio Economic Welfare (SEW) represents the total benefits for the sector, or, in economic terms, the addition of the Consumer Surplus and the Producer Surplus. Following strictly the economic theory[7], each scenario has its own SEW, as both the generators gain a surplus above their costs, and the consumers pay less than their – theoretical- willingness to pay. However, the SEW associated to a transmission project 'X" generally refers to the difference between the SEW of a scenario 'S1' that includes the project and the counterfactual scenario 'S0' that doesn't. Hence the SEW of project X generally refers to the gains for society of executing the project.

There are several methodologies to calculate the SEW of a transmission project:

- To model the total generation costs in the scenarios 'S1', with the project, and 'S0', without the project; this methodology doesn't assign the gains to the producers or consumers;
- To model the wholesale prices associated to a dispatch, and build the Consumer Surplus (how much money is saved) and the Producer Surplus (how much higher profit). A 'Congestion Rent' must be added to the CS and the PS when modelling multiple coupled markets, since the sell and buy prices are different in a value called 'congestion rent' which is typically managed by the owners of the interconnectors; and
- To model the cost of constrained energy volumes under scenarios S0 and S1, when all remaining variables are assumed to remain constant, and the cost of constraints can be calculated or estimated externally.

7 Principles of Microeconomics, N. Gregory Mankiw

All of the above methodologies are possible in estimating the SEW of a specific project. The suitability of one or another methodology must be assessed on a case by case basis, and depends on the confidence in the ability to simulate the market behaviour, the availability of adequate models and information, the purpose of the study, or other system specificities that suggest one particular option.

Provided that all methodologies are deemed equivalent for a specific case, best practice suggests always choosing the simplest option.

In GB. the *Guidance on the Strategic Wider Works arrangements in the electricity transmission price control RIIO-T1* points out the potential impacts on consumers of the uncertainty around the timing and cost of some large transmission project. If these investments are undertaken earlier than needed this may lead to higher costs due to unnecessary spending. On the other hand, delayed delivery may involve higher costs to manage network constraints, higher CO_2 emissions and possible risks of security of supply. The SWW arrangements require that several factors support the need for the project, including the expected increase in generation as well as the forecast costs to consumers if transmission constraints are expected to constrain generation. This approach is sound and fit-for-purpose, given that:

- the total costs of the generation activity are higher, in the range of ten times those of the transmission activity; and
- the availability of the primary resources (renewable or conventional) is limited to certain areas whereas transmission networks generally offer several options.

In this context, the overall methodology in conducting transmission Cost-Benefit Analyses (CBAs) in GB investigates a given generation scenario (or set of scenarios), and analyses the alternative transmission options to choose the one that offers maximum value.

Various elements of best practices in evaluating a transmission project are described in following sections including the relevance of those, where applicable, to the Caithness Moray reinforcement.

A.2 Scenarios and sensitivities

Because many future decisions are uncertain, it is insufficient to assess the suitability of a project under one unique possible future. What if the fuel prices are very different from now? Or what if some wind developers decide not to invest? How do these variables affect the results of the CBA?

These questions are answered by using different scenarios, which represent potential futures on which the modellers have no control. For instance, demand growth, fuel prices, or installed renewable capacities which depend on political decisions etc.

There is not a unique approach as to which scenarios and sensitivities to build. Conceptually, both scenarios and sensitivities are used to test how the results vary as a function of an uncertain input. The main uncertainties that are expected to provide significantly different results are generally grouped in scenarios. A scenario modifies a set of variables which are expected to evolve coherently and represent a possible future world (for instance a higher demand growth should come with higher installation of wind projects).

When the impact of one specific input needs to be tested around a central expected value, it is recommended to perform sensitivity analyses. Sensitivities allow testing the impact of one input on the results, all other variables remaining equal.

The number of scenarios and sensitivities to test depends on:

- the difficulty to forecast a variable in the horizon considered (the further in time, the higher number of scenarios tested; for instance ENTSO-E's Ten Years Network Development Plan 2012 considered two scenarios for 2020, and the 2050 roadmap includes 4 scenarios – also called visions);
- the degree of randomness (for instance historic variability of wind and hydro productions);
- the expected impact of said variable on results;
- the relevance, the costs and the risks of the underlying decision; and
- the resources available in terms of time, people and tools.

Expert judgement is needed in designing the scenarios and sensitivities to test, however the potential impacts of variables that today are not relevant should be checked as counter-intuitive relationships may arise.

A.3 Models

In order to estimate the yearly costs of the electricity system on a specific horizon, the operation of the system should be modelled with the highest possible accuracy given a specific set of inputs. There is an obvious compromise between the accuracy of the study and the availability of high quality inputs: a very detailed 5-minute-step model would not make sense if 5-minute inputs prepared for the purpose are not credible. Both the model and the data affect results, and a balanced combination of model and data quality is definitely recommended in choosing one or another option.

Also, very simple models that are built to fit for purpose may provide as good as or even better results than very complex standard or commercial models that include more variables.

In modelling the system behaviour and the power flows, two different types of studies need to be performed: energy dispatch studies, and load flow studies. Typical models for these activities are further described.

A.3.1 Energy dispatch models

Typical energy dispatch models for complex power systems are fed with specifications and costs of all available power plants, and with the system demand and constraints. They are used to model the expected plants dispatch (ON/OFF status and power output) under an objective function. Because perfect markets theoretically lead to lowest production costs, the modelled objective function is the minimisation of variable production costs (or Short-Run Marginal Costs, SRMC), subject to any generation constraints (such as start-up times, maximum ramp-ups) or implicit network constraints (such as maximum power output in a constrained zone, or a must-run constraint on a plant that is needed to ensure voltage control in a specific bus of the network).

Energy dispatch models are also called Unit Commitment tools, as they precisely decide the commitment of the plants. They are the market scheduling tools used for scheduling purposes in systems such as Ireland, many North American markets, and most island systems.

These models can be used for scheduling purposes (daily or weekly scheduling), or for planning purposes (yearly or multi-year modelling).

Dispatch models are sometimes called Market Models, when they are used to model the expected outcomes in a market environment in which participants submit bids. Note that although market algorithms have the same function of providing an optimal generation schedule, the typical algorithms in the market processes are generally different and much less complex than Unit Commitment tools, in line with a much simpler structure of the inputs (input bids are generally formed of simple blocks of power and incremental prices). The market algorithms are currently being redesigned in many countries where the integration of renewable energies involves more and more complex decisions and flexible operation of the power plants.

Dispatch models can take countless forms, depending on the complexity of the system and the constraints to consider. They can use many different mathematical techniques, which require different modelling of the generation system, and require different computation times. Linear programming models offer the best compromise between accuracy and speed. Mixed-Integer programming models are significantly slower but capture better the start-up constraints of specific units. Stochastic Unit Commitment tools allow making scheduling decisions based on multiple uncertain wind profiles. Security Constrained Unit Commitment tools allow to model load flows associated to a dispatch and to redispatch plants to solve network issues.

Figure 11 shows some input and output data of Pöyry's in-house developed market model BID3.

Figure 11 – Extracts from Pöyry's market model BID3

Source: Pöyry

The choice of a model for energy flow studies such as the CBA for a network reinforcement should be fit-for-purpose, whilst allowing considering all constraints that are relevant to the problem. An expert opinion is necessary in understanding the system to be modelled, the available information, the available models, and the available resources.

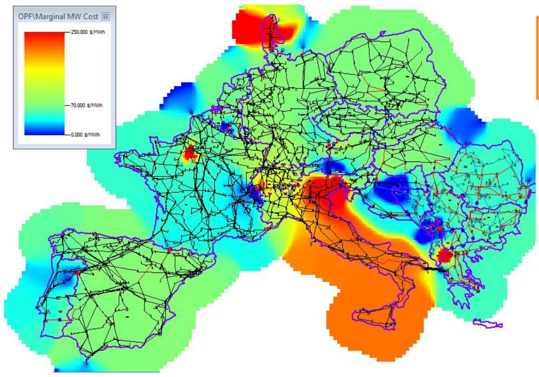
A.3.2 Load flow models

Load flow models address a different issue. These models look at the transmission system conditions in one particular instant (a snapshot), and solve the voltages and the flows through all the elements of the transmission system. A model of all the generators, demands, transmission lines, transformers, and other elements is required. From given generation outputs of all power plants, and demand in all the modelled nodes, resulting voltages in all nodes and flows through the lines are calculated and compared to the physical capacities and the security and quality standards set in the grid codes. Note that maximum flows and allowed voltages do not only depend on physical capacities and steady-state conditions, but on any security criteria that is violated under the considered contingencies. A contingency is an unexpected failure of any element of the transmission system, including the tripping of a generation unit, or the loss of a transmission line or a transformer.

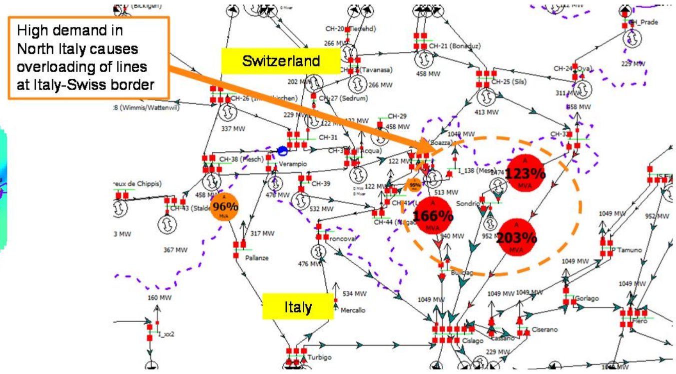
The following figure shows Pöyry's Load Flow model, PowerWorld.

Figure 12 – Extracts from Pöyry DC LF model

Example of LMP



Example of load flow and constraint identification



Source: PowerWorld

The 'N-1' security criterion means that the system must remain stable (not lead to partial or total blackouts) even if any single element of the system fails; hence all potential failures are tested on one generation dispatch, and if any single element causes an inadmissible problem that cannot be solved by the network topology (the connection or disconnection of network elements), such a dispatch is not allowed and must be modified. An 'N-2' operation means that the system is operated in such a way that it can cope with the failure of two elements of the grid, and is sometimes applied when two circuits share the towers over long distances (the fall of a tower in a storm would indeed imply the simultaneous loss of these two circuits).

The compromise between a safer operation of the system, and the higher cost of a safer operation, is a matter jointly decided by the grid operators and the regulatory authorities. The European Network Codes under development set minimum common requirements to all European interconnected systems. It is a common practice to operate the European systems with an 'N-1' policy, and 'N-2' for double circuits.

The load flow studies typically provide network constraints such as maximum flows through lines, or boundaries. The boundaries are clear in the case of single lines or interconnectors, and slightly more complex in meshed networks in which the energy has multiple routes. These studies allow confirming the maximum flows that are admissible through a boundary, and the reason for said limitation: the physical capacity of a line, or inadmissible voltages in steady state, or frequency or voltage violations after the tripping of an element of the system.

The results of interest for modelling purposes are the maximum flows through boundaries, so that these constraints can be considered in the energy dispatching models. Sometimes single values are used across the whole year, or sometimes they can be more dynamic in line with patterns of connected/disconnected plants, and changing hourly flows in the neighbouring areas of the interconnectors (or boundaries).

A.4 Input data

Input data must be consistent with the energy dispatch model. In general, today's computer power allows performing at least hourly calculations for all 8760 hours of the year, or up to half-hourly calculations.

In complex systems with several generation technologies, a number of elements are critical in modelling flows to ensure that the results are robust and accurate:

- the modelled region must be wide enough to capture the relevant interactions between all zones that can affect the flows in the studied area.
- all 8760 hours of the year must be modelled, to ensure that the interactions between all elements in the system are reflected accurately, and a variety of weather patterns should be modelled to capture the variation driven by weather events.
- weather is a critical feature of any market models looking at future market behaviour given the growth of RES (wind and solar). Furthermore, consistency of weather patterns across modelled regions is critical, ensuring that wind, solar and temperature are consistent both temporally and geographically.
- sufficient representation of plant constraints, including optimisation of start-ups and part-loading, plant ramping, minimum on and off constraints and temperature dependent starts.
- a balance must be struck between Linear Programming (where plant constraints are approximated as linear) and Mixed Integer Linear Programming, depending on the balance of runtime and accuracy.

However, ideally a model should be developed as simple as possible, as long as it considers all features relevant to the system analysed. Some of the previous elements may not be needed in more simple systems or for a specific simple scope. More complex models requiring more and more complex input data do not necessarily provide more accurate results when the available data is not of optimal quality.

For example, we acknowledge that the studied area for the Caithness Moray reinforcement does not have thermal dispatchable generation north of the B1 border (see Annex A), and little dispatchable hydro. This may allow the use a simpler model and leave more resources to test scenarios and sensitivities.

Best practice suggests the use of a SRMC optimisation model to capture the expected production of hydro resources that can be optimised (the run-of-river resources must be considered with fixed hourly profiles). Also, an optimisation model allows capturing the flows from the southern region of B1 boundary to the north, as there are interactions between the manageable plants of both regions (north of B1, and rest of GB). There may also be a few occasions in the year in which there is an excess of wind at national level, and wind energy must be curtailed both in the north and the south of B1; in these situations it makes more sense to flag that wind curtailments are not caused by the network limits, and that this curtailed energy should not account for the benefits of the transmission project. This is another reason why best practice would be the use of a full optimisation model for the whole GB area, or even further to capture the interactions between GB and its neighbours.

We note that in a situation in which no single generation plant is subject to an optimised dispatch, such is the case of run-of-river hydro, wind, solar and marine energy (in absence of large scale storage resources), more simple fit-for-purpose models can provide equally consistent results. However, in a scenario in which situations of national wind curtailment may occur, these might not be captured by a simplified model; this must be checked with a more accurate model.

A.4.1 Outputs

Two types of outputs must be analysed: the volumes of constrained energy, and the costs. Note that transmission projects allowing very large and frequent flows, but involving low price differentials of £1/MWh (for instance a CCGT unit replacing another slightly older CCGT unit) may not provide a very high socio-economic welfare and thus may not be profitable for consumers. Conversely, a transmission project allowing to integrate more wind energy with a variable cost of £0/MWh replacing expensive coal or gas, may provide high benefits even if these situations occur less frequently.

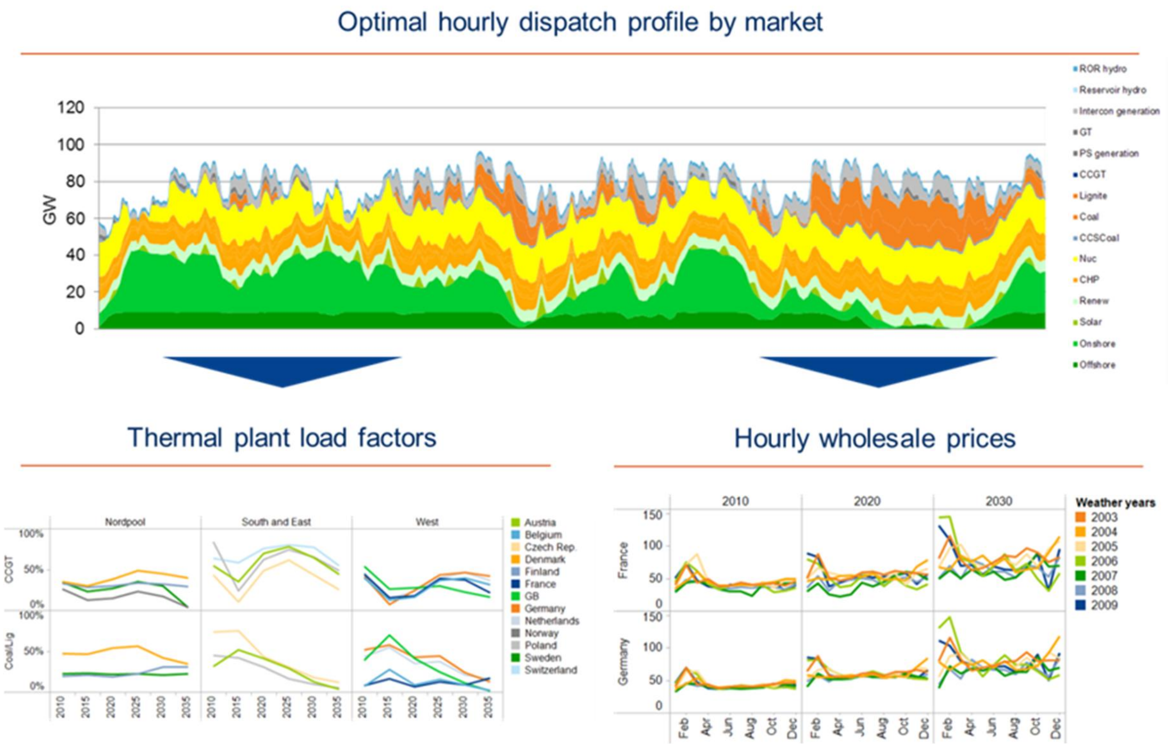
Both the volumes and the costs of constrained energy matter in determining the benefit of a transmission project. It is relevant to point out that only a co-incident determination of curtailments and the power prices when these situations occur can assess the replacement costs for the system. This effect is especially relevant in GB under increasing penetration of renewable energies at national level, which have a significant impact on the volatility of the hourly power prices (reaching even negative values, when some plants pay in order not to be disconnected).

A.4.2 Energy flows and volumes of constraints

The flow models provide hourly (or half-hourly) generation results which allow checking the hourly flows through the boundaries.

As an example of an energy flow model, Pöyry's BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high level metrics such as total system cost and economic surplus. A selection of BID3 results is shown below.

Figure 13 – Hourly dispatch and related metrics



Source: Pöyry BID3 based analysis

Constrained runs of the dispatch models (activating the maximum flows between zones) provide a dispatch which ensures that maximum capacities are not violated. A constrained run would provide the expected costs of a constrained operation of the system, but does not register how much energy has been redispatched as a consequence of capacity constraints. However in a situation where only renewable energy is fed into the system with a SRMC of £0/MWh, the constrained energy volumes can be calculated as the difference between the input resources, and the output dispatch taken by the system i.e. if the system has not taken 'free energy', it can only be caused by a grid constraint (except for situations of national curtailment, as described in Section 2.2.1.2). Alternatively, when dispatchable units exist and they are not taken, the reason can be a grid constraint or the fact that other generators are indeed cheaper in other areas.

Constrained runs can also provide the differences in constraint energy volumes by performing a run with the transmission project, and without. The differences in the flows through a border are exactly the difference in constrained energy volumes associated to the project.

An unconstrained run of the dispatch model is unrealistic in that it will provide outputs that are impossible as they violate security criteria. Such a run allows however to test the total constraint energy volumes, by post processing all the hours in which the output flows exceed the capacity of the boundary. An unconstrained run does not allow explicitly calculating redispatch costs, as it doesn't model the alternative constrained dispatch. However, in the particular case where only renewable sources exist with a SRMC of £0/MWh, an estimation of the cost of the alternative generation can be obtained by analysing the system marginal costs when the constraints occur. I.e. if wind energy is curtailed because of grid capacity constraints when the system marginal cost is £50/MWh, this reference is a fair approximation of the replacement costs. (An accurate modelling with constrained runs would actually confirm whether the alternative constrained dispatch has the same marginal cost or whether it changes to different plants or technologies).

Best practice suggests constrained modelling as the most accurate if both volumes and costs are to be assessed. However the choice of the model depends on the concerns of the decision maker, and the possibility to assess externally the costs of those constraints.

We note that best practices in conducting a CBA should focus on both the volumes and the costs of the constraints, as a strong effort in reaching +/- 5% accuracy in the volumes might be offset by a lower +/- 30% accuracy in the costs.

A.4.3 Costs of constraints

The cost of constraints or 'replacement energy' costs are the difference between costs of the energy 'bid off' and the replacement energy 'bid on' and captures both the underlying opportunity costs and potential . In this case on

The co-incident calculation of the costs of constraints with energy dispatching models is discussed in the previous section. The cost of the replacement energy which is needed when constraints occur does not depend on the cause of the constraint, but does depend on system dispatch (i.e. which are the marginal units in that particular time) and resulting market prices when these constraints occur.

As previously flagged, this effect is especially important in the context of very high wind penetration in GB with very volatile prices expected which reflects the underlying volatility of generation delivering energy onto the GB electricity system depending on prevailing weather patterns (wind and solar).

For purposes of assessing transmission infrastructure projects the CBA is limited in first instance to considering the system management costs relative to the costs of the investment i.e. the 'replacement energy' costs as described here.

A.4.4 Wider benefits

From the perspective of the GB energy sector and in the context of the UK Government's energy policies such as commitment to 2020 renewables targets – there are potential wider benefits from transmission infrastructure projects, especially where they are perceived to enable Government energy policy to be realised or most economically realised. These benefits indirectly drive further benefits (or losses) for the overall GB energy sector and/or the national economy.

Thus there may be instances for some very large and strategic investments where these wider benefits should be considered, where the pure transmission investment case based on 'replacement energy' based CBA doesn't stack up.

The scope of wider benefits of transmission projects which enable renewable energy projects to be realised can potentially encompass a number of aspects, including:

- reduce CO_2 emissions;
- create more local jobs;
- reduce energy dependency from fossil fuel imports;
- reduce risks of primary energy cost increases; and
- reduce the risks of natural and economic consequences of climate change.

Under current UK Government energy policy, the value for society of producing energy from renewable sources is thought to be higher than the cost of replacement energy with fossil fuels taking into account the monetised cost of carbon. This underpins the various subsidy schemes adopted by the UK Governments including ROCs, LECs and the forthcoming CfD FiT scheme.

However, a complete and precise valuation of all the wider benefits would require listing and valuing all aspects of society indirectly affected by higher RES integration; which is a complex theoretical academic exercise.

At a country level, there are binding national environmental targets for each of the European Member States, and UK has a 15% target of its primary energy demand from renewables by 2020. This binding target implies that penalties may apply to Member States that do not comply with their target, although the level of the penalty is currently undefined.

As regards the CO_2 targets, the 20% reduction objective is a European one, and individual targets and consequent penalties of €100/ton for non-compliance apply only to individual CO_2 emitter entities. This implies that there is no strict direct CO_2 penalty for UK citizens by a lower integration of RES, but for the European price of CO_2 allowances that need to be produced and sold elsewhere.

In the GB context, there is also a question regarding the impact that a transmission project may have on the level of development of renewable generation (principally wind generation) going forward, and the concept of 'frustrated generation' i.e. generation which is not allowed to connect without the relevant transmission infrastructure in place. For generation based on weather resource which is not equivalent across locations nationally in GB such as wind, 'frustrated generation' can mean that:

- wind capacity (or any other renewable technology) is required to locate somewhere else to meet the environmental targets, but at lower performance delivery and/or higher costs; or
- the relevant 'frustrated' wind capacity (or any other renewable technology) does not relocate and simply does not build, which can potentially incur the indirect costs of moving further away from renewables and/or carbon emission targets (potential penalties, higher fossil fuels imports etc.)

A potential approach to quantify the losses for the country of incurring higher frustrated wind projects is to value the frustrated energy at the value of the wider benefits. In assessing the potential risk of frustrated projects, the frustrated energy implies an equivalent frustrated wider benefit for society.

This argument follows the same principle of accepting that load shedding implies lower generation costs for consumers, but at the expense of reducing their comfort or even avoiding their economic activity; failing to value the customers' willingness to pay for the energy is an insufficient approach in assessing the benefits of load shedding. In the same way that shed energy can be valued at the Value Of Loss of Load (VOLL) as a proxy for the customer's loss, a theoretical value of unfulfilled objective should apply to a foregone target, provided that equivalent energy is not replaced by alternative – even if less efficient and/or more costly sources.

However, it is not straightforward nor within the scope of this work of this report to indicate, the valuation of direct costs of alternative RES producers; and the penalties associated to a non-compliance with the environmental targets.

A.5 CBA assessment

So far, we have discussed the methodology to replicate system behaviour under different scenarios, and calculate the costs and the benefits of different options.

Once multiple scenarios have been modelled, and yearly calculations are available, a further two steps are needed to come to an investment decision:

- calculating the Net Present Value (NPV) of each option for the targeted group; and
- making a decision based on the multiple NPVs.

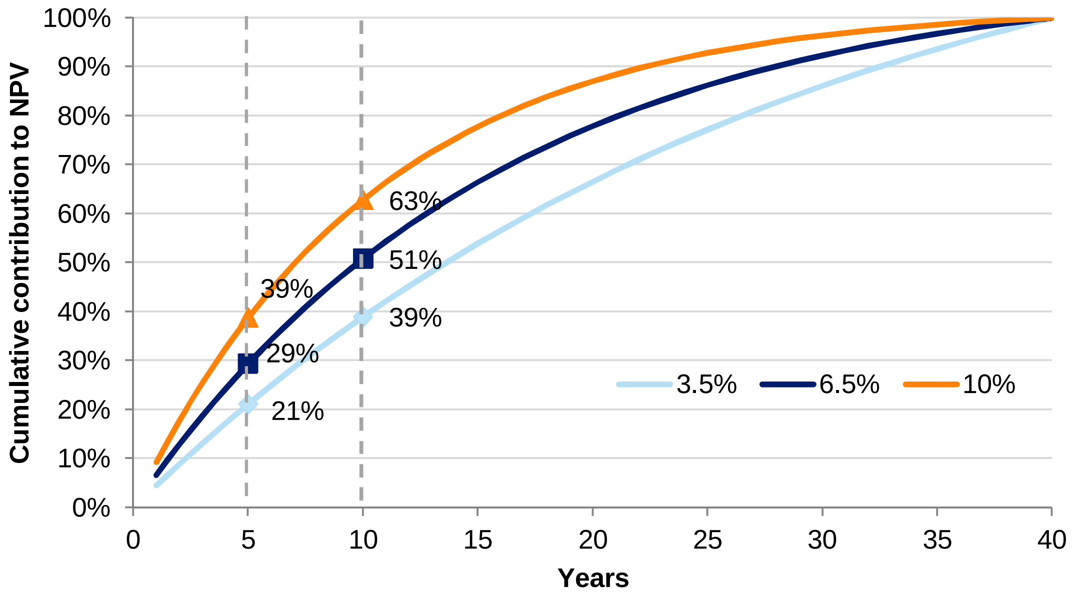
A.5.1 NPV calculation

A transmission investment is generally amortised over a life time of, generally, 40 years. It would make sense to calculate the NPV for such a period, by bringing the yearly savings to the present value of the year in which the decision is to be made. In fact, this process is similar to the valuation of a project by a company, where the company in this case is the electricity consumers.

From the calculated yearly savings in generation costs (eventually using the constrained energy volumes), a discount factor is applied based on the cost of capital, and all discounted yearly values are added to obtain the project NPV. The Group of Joint Regulators recommended in 2012 adopting the Spackman approach for large infrastructure projects with risky investments from private companies but long lived public benefits; it suggests using the company's WACC (6.25% in this case) to discount capital expenses and the Treasury's Social Time Preference Rate (3.5%) to discount costs and benefits.

It is interesting to observe how the contribution to the project NPV rapidly decreases for years far away from the investment decision. This means that the most important years to consider are the initial ones. Figure 14 shows the cumulative contribution of the discounted benefits from years 0 to X (on the X axis), in percentage terms, as a function of the discount rate. For instance, at a 6.5% discount rate, 51% of the project benefits come from the first 10 years.

Figure 14 – NPV contribution vs. Discount rate (cost of capital)



Source: Pöyry

Additionally, beyond a period of 5 to 10 years, uncertainties grow exponentially and other future decisions affect the system behaviour. For instance the delay in a transmission project may imply frustrated development of new generation, and the comparative analysis becomes unequal. Assuming for the comparative analysis a same generation scenario regardless of the decision of reinforcing the network and the counterfactual of not reinforcing it, becomes more unrealistic for far horizons.

As discussed in Section A.4.3, a transmission scenario potentially leading to frustrated wind projects does not only incur different generation costs, but also lower fulfilment of the environmental targets. The lower fulfilment of environmental targets has a penalty for the system which can be quantified using as a proxy the lost wider benefits previously described.

As regards the valuation of the risk of a system incurring frustrated projects, rather than valuing known frustrated projects, the use of scenarios weighted by their probability of occurrence is a common practice.

Because of the previous factors, best practice recommends looking at the lifetime of the project, searching a positive NPV already by the first 5 to 10 years.

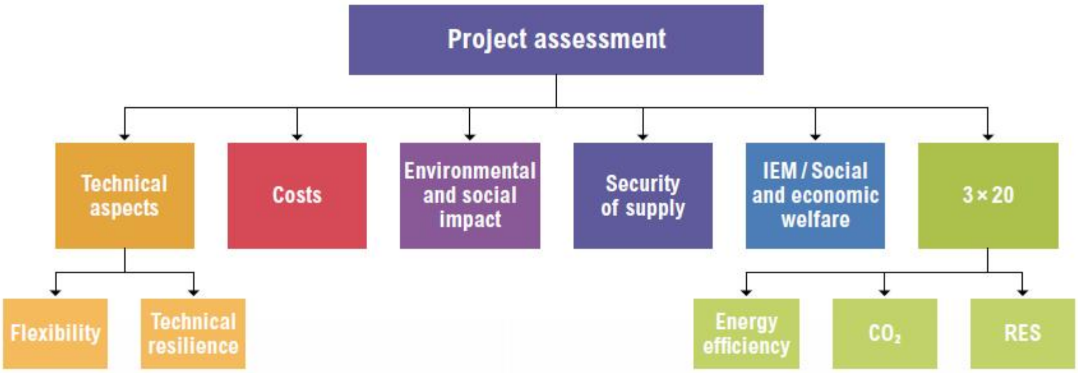
A.5.2 Decision making

A.5.2.1 Multi-criteria decision making

Decision making shall consider the NPV of a project as the main indicator of the economic benefits. The consideration of other external benefits such as the impact on employment, the reduction of fuel imports or other side effects on the economy, may be of great importance for the decision maker (or stakeholders), but are not discussed in this report.

We provide however in Figure 15, as an example of best practice, the indicators calculated by the TSOs for ENTSO-E's Ten Years Network Development Plan 2012, in assessing the impact of transmission projects of pan-European significance.

Figure 15 – Multi-criteria assessment of projects of pan-European significance in ENTSO-E's TYNDP 2012



Source: ENTSO-E Ten-Year Network Development Plan 2012

On top of the SEW, which includes the variation in direct savings in generation costs, additional indicators considered are:

- grid transfer capacity increase, which quantifies the impact on a constrained border;
- the RES integration, losses variation and CO_2 emissions variation, which value the benefits with respect to the three pillars of the 20-20-20 European targets;
- security of supply, which quantifies the improved margins or reduced LOLE in the region considered;
- the technical resilience and flexibility indicators refer to the technical performance of the assets in the grid:
- the social and environmental impact and the project costs.

A.5.2.2 Multi-scenario decision making

As regards the assessment of several scenarios, different possibilities may occur:

- all scenarios provide same conclusion; or
- different scenarios provide different conclusions.

Naturally, the first case is ideal for a robust decision making. In the second case, several approaches are possible in making the final go/no go decision:

- The method of the Weighted Sum allows considering all scenarios and sensitivities in one single number, by weighting each potential NPV by a probability of occurrence – generally built from higher level or 'expert' estimates- and adding them. This final value represents the statistical expected value of the NPV (not that the expected NPV does not necessarily coincide with the NPV of the expected scenario).
- An alternative approach is to make the decision based on the single most likely scenario, although the robustness of the decision is obviously decreased if other plausible scenarios suggest opposite decisions.

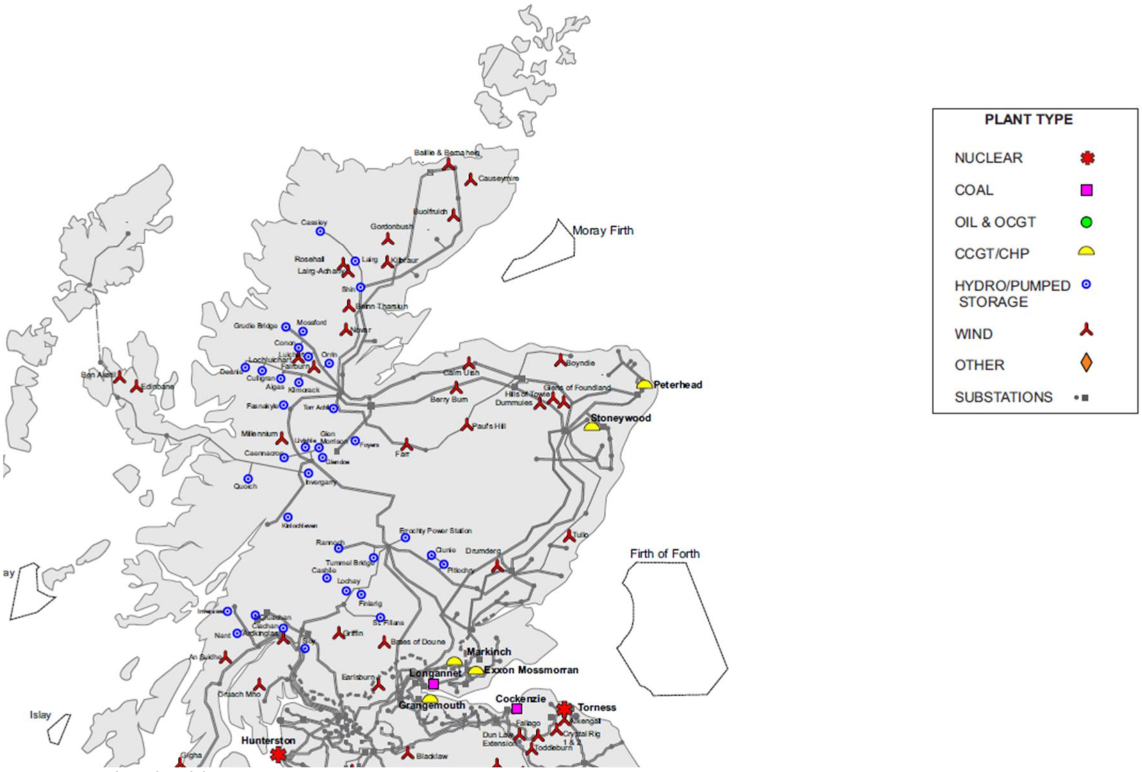
Given unavoidable uncertainties when planning very long life infrastructures, no perfect approach can be provided, and risk must inevitably be assumed. The sharing of this risk between the investor and the consumer, as set by the design of the remuneration scheme, is an issue for further discussion.

We note, finally, that planning the system should not pursue guessing the future and preparing for it, but rather preparing in a cost-efficient way for all the possible futures.

ANNEX B – CAITHNESS MORAY PROJECT

B.1 Installed generation in Scotland

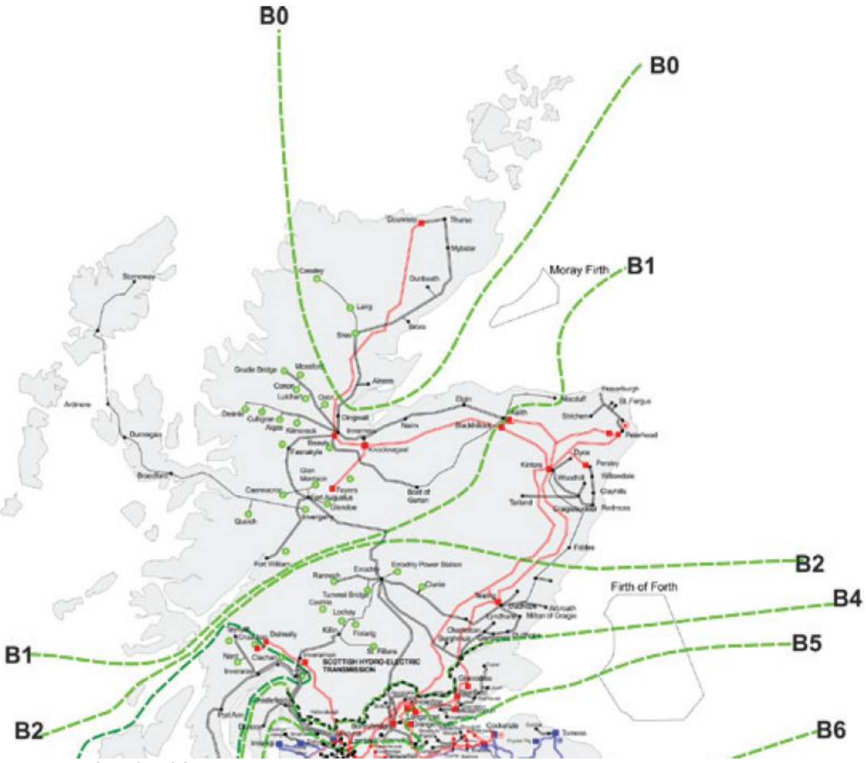
Figure 16 – Existing power stations in Northern Scotland



Source: National Grid – Ten Year Statement 2013

B.2 Transmission boundaries in GB

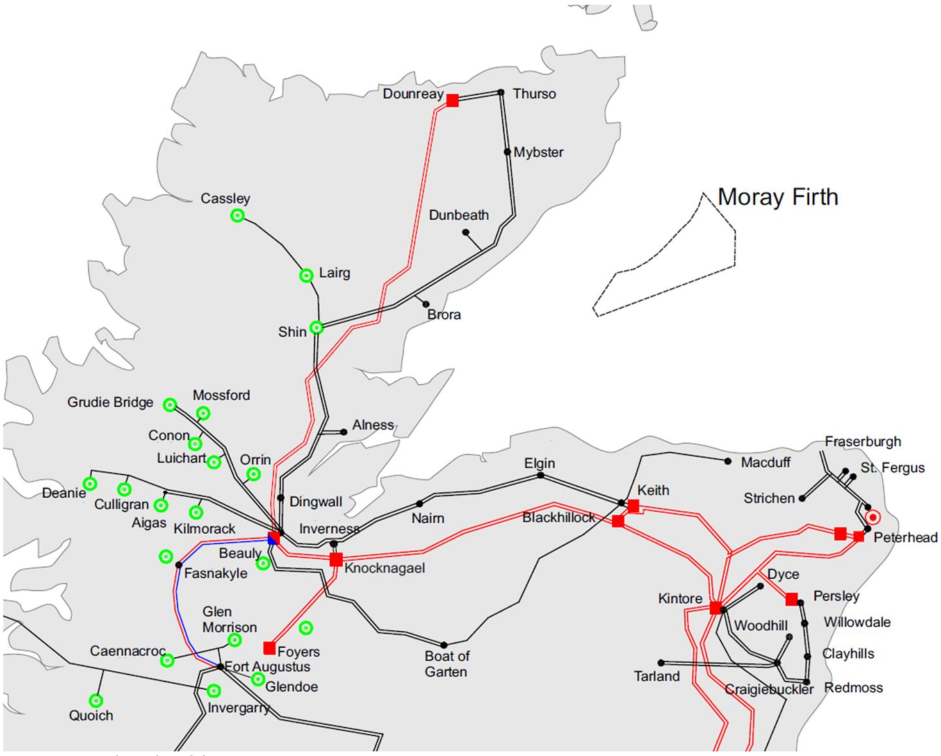
Figure 17 – Transmission boundaries in the north of GB



Source: National Grid – Ten Year Statement 2013

B.3 Transmission network in the Caithness Moray area

Figure 18 – Transmission network in the Caithness Moray area



Source: National Grid – Ten Year Statement 2013

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ANNEX C – SKM MODELLING

C.1 Wind production input

Load Fa rs		All Year	28.3	31.2
		Winter	32.3%	37.6%
		Spring/Autumn	32.4%	36.1%
		Summer	20.4%	20.4%
			North	South
Date	Half hour	Season	Output (%)	Output (%)
01-Apr	1	Spring/Autumn	85.1%	69.0%
01-Apr	2	Spring/Autumn	85.3%	62.0%
01-Apr	3	Spring/Autumn	85.5%	59.9%
01-Apr	4	Spring/Autumn	85.7%	73.0%
01-Apr	5	Spring/Autumn	68.5%	49.7%
01-Apr	6	Spring/Autumn	64.0%	28.0%
01-Apr	7	Spring/Autumn	43.4%	49.3%
01-Apr	8	Spring/Autumn	50.0%	31.5%
01-Apr	9	Spring/Autumn	51.5%	28.7%
01-Apr	10	Spring/Autumn	32.8%	6.7%
01-Apr	11	Spring/Autumn	33.6%	25.1%
01-Apr	12	Spring/Autumn	19.7%	38.2%
01-Apr	13	Spring/Autumn	18.1%	27.5%
01-Apr	14	Spring/Autumn	13.5%	22.4%
01-Apr	15	Spring/Autumn	8.4%	2.5%
01-Apr	16	Spring/Autumn	6.3%	11.1%
01-Apr	17	Spring/Autumn	7.3%	16.8%
01-Apr	18	Spring/Autumn	7.7%	15.1%
01-Apr	19	Spring/Autumn	7.1%	18.8%
01-Apr	20	Spring/Autumn	9.3%	21.0%
01-Apr	21	Spring/Autumn	10.7%	22.0%
01-Apr	22	Spring/Autumn	8.5%	24.2%
01-Apr	23	Spring/Autumn	10.2%	19.3%
01-Apr	24	Spring/Autumn	25.2%	30.6%
01-Apr	25	Spring/Autumn	10.0%	21.8%
01-Apr	26	Spring/Autumn	15.0%	39.0%
01-Apr	27	Spring/Autumn	16.2%	51.6%
01-Apr	28	Spring/Autumn	12.2%	68.1%
01-Apr	29	Spring/Autumn	23.2%	57.2%
01-Apr	30	Spring/Autumn	43.5%	82.2%
01-Apr	31	Spring/Autumn	47.9%	75.8%
01-Apr	32	Spring/Autumn	56.4%	83.3%
01-Apr	33	Spring/Autumn	85.3%	90.0%
01-Apr	34	Spring/Autumn	70.4%	92.2%
01-Apr	35	Spring/Autumn	77.8%	95.8%
01-Apr	36	Spring/Autumn	75.7%	94.5%
01-Apr	37	Spring/Autumn	85.7%	85.8%
01-Apr	38	Spring/Autumn	72.0%	78.3%
01-Apr	39	Spring/Autumn	85.2%	88.2%
01-Apr	40	Spring/Autumn	91.3%	96.4%
01-Apr	41	Spring/Autumn	93.4%	94.3%
01-Apr	42	Spring/Autumn	94.5%	89.8%
01-Apr	43	Spring/Autumn	94.7%	89.6%
01-Apr	44	Spring/Autumn	95.3%	46.0%
01-Apr	45	Spring/Autumn	93.6%	49.2%
01-Apr	46	Spring/Autumn	93.8%	70.5%
01-Apr	47	Spring/Autumn	90.7%	60.4%
01-Apr	48	Spring/Autumn	88.1%	48.7%

Source: SKM

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