Treatment of strategic capacity in determining local TNUoS for the Western Isles link

CLIENT: Uisenis Power Limited

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Confidentiality and Limitation Statement

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1. INTRODUCTION

Uisenis Power has commissioned Baringa Partners to prepare this paper which considers the treatment of strategic capacity in determining the Local TNUoS charges for the proposed Western Isles Link, in the case that such a link includes a second underground HVDC cable as a strategic anticipatory investment. Consideration of the locational element of wider TNUoS is outside the scope of this paper.

We note that the costs are indicative given that the project is still at the design and development phase, and no key procurement contracts have been placed at this time.

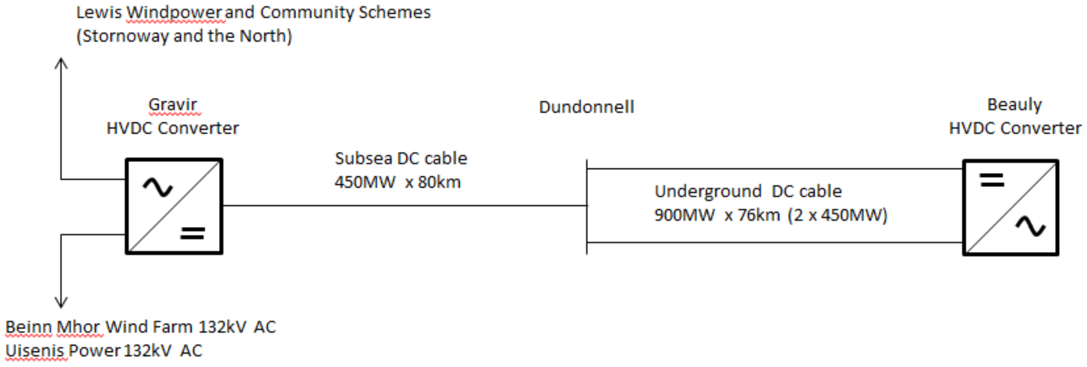
2. BACKGROUND

2.1. Proposed scheme

The Western Isles Link is a proposed 450 MW connection (including certain equipment to allow the capacity to be increased to 900 MW in due course) to the Western Isles, for the purpose of connecting proposed renewable generation.

The Western Isles Link will be rated at 450 MW, comprising HVDC converters at Beauly on the mainland and Gravir on Lewis. The two converters will be connected by 156km of DC cable. A single 80km subsea section rated at 450 MW will be installed under the Minch connecting Gravir to Dundonnell on the mainland and a 76km double underground cable section with a combined capacity of 900 MW (2 x 450 MW) will connect Dundonnell to Beauly. This arrangement is shown below Figure 1.

Figure 1 Schematic diagram of Western Isles Link



We understand that the installation of two underground DC cables is proposed due to the lower incremental costs of installing a second cable in parallel, and the high environmental impacts of installing it at a later date. As far as we are aware, this cable does not provide any additional redundancy to the connection, and is purely an anticipatory investment which would be of benefit if further generation is connected in future and a second 450 MW HVDC subsea cable was laid.

2.2. Policy background

With the recent conclusion of Project TransmiT we now have a methodology to allow the TNUoS tariffs to be estimated for those generators to be developed on the Western Isles and connected to the Western Isles Link. The new methodology developed under CUSC Modification Proposal 213 (CMP213) has addressed the following:

- Reflecting the costs imposed by different types of generators on the electricity transmission system;
- Taking account of the development of HVDC circuits that will run parallel to the AC transmission network; and
- Taking account of the island connections comprised of sub-sea cable technology, such as those being considered in Scotland

This methodology has been approved by Ofgem and will be implemented on 1 April 2016. Under this methodology TNUoS charging for island links will be based on the specific costs of these links, and the full costs of converters will be included.

The following discussion and TNUoS calculations are based on the new charging methodology developed under CMP213.

2.2.1. Transmission charging methodology overview

Transmission charges are split into three components:

- **Wider locational charges**, calculated based on the impact of generation or demand on flows on the transmission system.
- **Local charges**, levied on directly connected generation to reflect costs of assets that are local to the generator.
- **Residual charges,** calculated to ensure recovery of the total revenue pot. The generation residual is charged to all transmission connected generators, and the demand residual is charged to all demand.

2.2.2. Local asset charging

The charging methodology calculates Local Circuit Tariffs using the length of the transmission asset, and an expansion factor for the technology type used. This expansion factor would be based on an average unit cost for AC assets, or in the case of the new methodology a specific factor will be determined for the HVDC technology to be used for the island links. Users only pay for the capacity they require, with any oversizing (which may simply be a result of transmission assets being available in a limited number of set ratings, or perhaps due to anticipatory investment) being socialised via the generation and demand residuals.

For example, if a 50 MW generator made use of a local asset with a rating of 250 MW, the generator would pay local TNUoS based on 50 MW Transmission Entry Capacity (TEC), rather than on the 250 MW rating of the transmission asset. This is equivalent to the generator paying charges based on 20% (50/250) of the cost of the 250 MW asset. The generator’s charge is based on the expansion cost appropriate to the 250 MW asset, rather than on the expansion cost of a 50 MW asset (which might be higher, for example if 50 MW asset operates at a lower voltage).

2.2.3. Generation:Demand split

The existing charging methodology recovers transmission costs (Maximum Allowed Revenue, MAR) in a ratio of 27% Generators to 73% Demand (the G:D split)[1]. The recovery of any additions to MAR through new investment are therefore split between generation and demand in this ratio. This is achieved through varying the generation and demand residual tariff components, which are added to locational tariffs.

This has two implications relevant to this paper:

- In the case of local assets where the cost is targeted at a specific generator, the addition of new local assets may cause the generation residual to decrease to maintain the 27:73 split. This assumes that the capacity of generation connected to the asset is the same as the capacity of the asset. If a much lower amount of capacity is connected, it is possible for the generation residual to increase since little revenues is recovered from users of the local asset.
- The demand residual is not affected by the amount that specific generators are charged for a local asset, because the fraction of MAR charged to demand remains at 73%.

3. ESTIMATED COST BREAKDOWN

The total cost of the Western Isles Link is currently estimated to be £750m. This figure has been broken down as shown in Table 1.

Table 1 Cost breakdown for Western Isles Link (2014 prices assumed)

Element	Percentage of total	Estimated Cost (£m)
Subsea HVDC and onshore substation works	51%.	£383m
Double HVDC underground cable	49%	£368m
Total	**100%**	**£750m**
Incremental cost of second HVDC underground cable now	11%	£83m
Cost of installing a second underground cable in future	*N/A*	*£285m*[2]

4. PROPOSED CHARGING APPROACH FOR HVDC UNDERGROUND CABLES

The second underground HVDC cable solely constitutes a strategic anticipatory investment, which will enable future generation connections via the addition of a second sub-sea HVDC cable.

Below we describe a proposed methodology for how the costs of the underground cables should be factored into charging.

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[1] We note that CMP224 proposes that the G:D split is reviewed regularly to ensure that generators do not pay more that €2.50/MWh on average, as required by EC Regulation 838/2010. We ignore this proposal for the purposes of this paper.

[2] Cost of installing second cable at later date taken to equal cost of installing first cable.

A. Description

Calculate charges using the average cost of the two cables (i.e. assume the cost of a single cable is 24.5% of the total cost of the link, based on the costs above). This is equivalent to assuming a 900 MW capacity for the underground section of the link and calculating an expansion constant on this basis.

Under this approach, 75.5% of the cost of the Western HVDC Link is targeted at generators connecting to the first link (assuming that the first link is fully utilised).

B. Charging Outcome (see Appendix A for details)

- Generators connecting to the first cable and those connecting to a future second cable are treated equally with both paying £105/kW/yr (including both local & wider TNUoS).
- Assuming that the cable is fully utilised:
    - Assuming the link is fully utilised, the additional revenue from Western Isles generators (£47m) means that all other generation tariffs reduce to maintain the G:D split. The total decrease required across all wider generation tariffs to maintain the G:D split is £32m, (out of approximately £730m paid by generators in total). All generation tariffs *decrease* by approximately £0.42/kW/yr, due to a reduction in the generation residual. This is a decrease of 4% on the average generation tariff.
    - All demand tariffs *increase* by approximately £0.75/kW/y, due to an increase in the demand residual. This is an increase of 2% on the average demand TNUoS tariff. The impact of the demand tariff increase on the annual average domestic consumer electricity bill is approximately 40p or a 0.07%.increase. The total increase in revenue recovered from demand tariffs is £42m.

Note that if the cable is not fully utilised, the generation residual would reduce by a smaller amount. The demand residual would be unchanged.

C. Known Precedents

Our understanding is that this approach is currently consistent with the approach taken in the charging methodology for all local and wider assets with spare capacity.

5. FURTHER ILLUSTRATIVE EXAMPLES

In this section we explore the tariff implications of two hypothetical design variants

- A single 900 MW underground cable
- A single 450 MW underground cable

We consider these for the purposes of illustrating the charging examples. We use simplifying assumptions on the relative costs of alternative schemes, and therefore these examples should be considered illustrative only.

5.1. Implications of a hypothetical single underground 900 MW HVDC cable

As noted above, we understand that the two cable arrangement does not provide redundancy (i.e. if one cable fails, both are taken offline). The two 450 MW underground cables might therefore be considered to be similar to a single 900 MW cable. Therefore it is instructive to consider the charging options for a hypothetical single 900 MW underground cable (with a 450 MW sub-sea cable). We assume that the overall costs are the same as the proposed scheme above.

Assuming that the actual rating of 900 MW is assigned to the underground section, and 450 MW to the sub-sea section, the tariff would be £105/kW/yr, which is the same as under the approach above.

Alternatively, if the entire link (sub-sea and underground) were treated as though rated at 450 MW despite that fact that the underground section has been installed as a 900 MW cable, users would pay the full cost of the spare capacity on the underground cable and the total TNUoS charge would be £136/kW/yr. In this case, users would be paying for capacity they cannot make use of.

5.2. Implications of a single underground 450 MW HVDC cable

We consider an example in which only a single 450 MW underground HVDC cable is built, and we assume that if the second cable were added at a later point it would have cost as much as the installation of the first HVDC underground cable (£285m). This demonstrates the impact of the strategic investment in the proposed scheme.

In the near term (before the second link is required), there would be a saving of £83m. There would be a saving of £0.08/kW/yr on demand tariffs.

However if the second cable was installed at a later date at a cost of £285m, then this would represent an increase of £202m, relative to installing both cables at the same time. The increase in demand tariffs relative to the proposed scheme of installing both cables at the same time would be £0.2/kW/yr.

6. CONCLUSIONS

We have proposed a potential approach for local transmission charging on the Western Isles Link to deal with the anticipatory strategic investment in the second underground HVDC cable.

The proposed approach, as detailed in Section 4, is consistent with the existing approach to local asset charging, and would ensure that generators connected to both the first and second links to the Western Isles would be charged in an equitable manner.

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7. APPENDIX A

7.1. Calculation of TNUoS

Calculations for TNUoS on the Western Isles link are shown below. Values may not calculate exactly due to rounding.

Appendix Table 1 Calculations for Western Isles TNUoS

WI Link Capital Costs (total £750m)	Capex breakdown (£m)
Underground - 2 x 450MW (49%)	368
Subsea and converters - 450MW (47%)	353
AC substation works (4%)	30
Total	**750**

Overall TNUoS	£/kW/yr
Western Isles Link - HVDC (A + B)	90.6
Western Isles Link - AC (C)	0.4
Wider (zone 1)	14.1
Total	**105.0**

HVDC TNUoS - Underground Cable Section (A)		
Project cost	368	£m
Annuity factor	0.058	
Overhead factor	0.018	
Capacity	900	MW
Length	76	km
Security factor	1	
Cable cost	408	£/MWkm/yr
Expansion constant	12.9	
Cable expansion factor	31.65	
Local charge (£/kW/yr)	**31.03**	(A)

HVDC TNUoS - Converters and Subsea (B)		
Project cost	353	£m
Annuity factor	0.058	
Overhead factor	0.018	
Capacity	450	MW
Length	80	km
Security factor	1	
Cable cost	744	£/MWkm/yr
Expansion constant	12.5	
Cable expansion factor	59.53	
Local charge	**59.53**	(B)

AC TNUoS - AC works (C)		
Total AC works costs (Beauly & Gravir)	30	£m
Local substation charge (Gravir 132kV with redundancy) (£/kW/yr)	**0.387**	(C)

7.2. Calculation of impact on generation and demand residuals

Appendix Table 2 Calculations of impact on residual

	Counterfactual	With Western Isles link
Cable cost (£m)		750
Annuity factor		0.058
Overhead factor		0.018
Annual cable cost (£m)		**57**
Cable users (MW)		450

MAR (£m)	2,645	2702
Recovered from generation (£m)	714	730
Recovered from cable users (£/kW)	0	105
Recovered from cable users (£m)	0	47.3
Delta in generation residual (£m)	0	-31.9
Delta in generation residual (£/kW)	**0**	**-0.42**

Recovered from demand (£m)	1931	1972
Delta in demand residual (£m)	0	41.6
Delta in demand residual (£/kW)	**0**	**0.75**