# CONCEPT STUDY:
# WESTERN OFFSHORE TRANSMISSION GRID

**ETSU K/EL/00294/REP**

**DTI/Pub URN 02/680**

**Contractor**
PB Power

The work described in this report was carried out under contract as part of the DTI Sustainable Energy Programmes. The views and judgements expressed in this report are those of the contractor and do not necessarily reflect those of the DTI.

First published 2002

Further Renewable Energy information from the Sustainable Energy Programme, and copies of publications can be obtained from:

Renewable Energy Helpline
Tel: +44 1235 432450
Email: NRE-enquiries@aeat.co.uk

## EXECUTIVE SUMMARY

The primary aim of this work is to perform a high level investigation of the feasibility of developing an offshore high voltage direct current (hvdc)[1] network for the connection of renewable energy sources sited along the western coast of Scotland, Northern Ireland, England, Wales and South-West England which would feed into the existing transmission system nearer to the centre of UK demand. This concept study is required to identify likely capacity requirements, network topology, possible points of interconnection with the existing network and will provide an estimate of overall cost. The study also makes comparison with the alternatives of upgrading the existing on-shore transmission networks, commenting on potential cost comparisons, technical and planning issues. The main findings are summarised below:

1. It is estimated that the connection of between 6-8 GW of renewable generation will be required to meet the existing Government target for 10% of electricity supplies to come from renewable energy sources by 2010. In the event of a 20% target being adopted for, say, 2020 – possibly moving on to a 60% target for 2050 as suggested by the Royal Commission on Environmental Pollution[2], some 20 and 45 GW respectively of additional renewable capacity could be required.

2. Recent renewable resource studies, notably that commissioned by the Scottish Executive, suggest that sufficient commercially exploitable renewable resource exists in the North and West of the UK to meet these targets. The problem of connecting this capacity onto the electricity networks can be considered in three parts; the gathering together and then connection of the resource locally, and the subsequent transmission of the associated power flows to load centres elsewhere within the UK.

3. Initial work undertaken by NGC relating to the variability of wind power generation output indicates that this should not present major operational problems. However, with present renewable technology a significant proportion of the connected system generation will need to be conventional in nature, i.e large synchronous generators, and constraints may need to be imposed on renewable generation at times of lower system demand. In addition, in order to allow system demand to be met at times when the wind resource is not available a significant proportion of, presumably fossil fuelled conventional generation will need to be available in reserve.

4. In terms of resource gathering whether onshore or offshore, ac, rather than dc, connection is likely to be most cost-effective. Subsequent connection of these resources locally will be constrained by the capability of the local networks, particularly in the north

[1] HVDC technology is generally adopted for longer distance cable based transmission as it does not suffer from excessive and wasteful capacitive current effects that would occur with the use of alternating current (ac). However, for onshore transmission ac is preferred as it allows cost effective transformation of voltage up and down between the economic voltage levels applicable to generation, transmission, distribution and customer utilisation.

[2] The Royal Commission on Environmental Pollution 22nd Report – "Energy – The Cchanging Climate" (2000) http://www.rcep.org.uk/newenergy.html

with ac connection likely to be the most cost effective for small local groupings but with hvdc connection being more appropriate for larger more distant groupings, particularly when feeding into weak parts of the existing onshore grid. If significant amounts of generation are to connect around the periphery of the system, particularly in the North, reinforcement of the local onshore networks will also be necessary

5. Existing transmission system capability in the North of the UK largely reflects historic and predicted power flows and therefore, if significant amounts of renewable generation is to be superimposed on the existing system power flows, reinforcement will be required unless equivalent existing generation in the area is displaced. The same is not true of the transmission network below the principal Midlands to South constraint, particularly so in the South West and South Wales, where significant capacity exists (3 – 6 GW) to accommodate additional generation or imports from elsewhere in the UK connecting at these locations.

6. However, as the connection of renewable generation is intended to displace a significant proportion of existing, fossil fuelled generation, then dependent upon the location of such displaced generation, the practical capability of the existing main 400 kV onshore grid may become significant. Under conditions of favourable generation displacement, up to about 4 GW of renewable generation could connect within Scotland, and a further 10 GW in England, north of the Midlands to South Constraint, essentially a line drawn roughly between The Wash and Cardigan Bay.

7. Regardless of the above, at some time in the future extensive reinforcement of the onshore grid may become necessary. Historically such reinforcements would have been largely based upon the construction of new additional overhead lines. However, this is likely to raise major planning and environmental issues which could be largely avoided by the use of hvdc links. HVDC links based upon submarine or underground cables could be used to bypass the congested transmission systems in the North and allow power to be injected into the existing transmission system at points where sufficient capacity exists.

8. The particular hvdc technology to be employed will be influenced by the point of interface with the existing networks. Connection to a relatively weak network, possibly at 132kV, could limit the transferable power to a few hundred MW and would require the use of voltage source hvdc converter technology. Connection to a stronger part of the network, say at 400kV, might allow blocks up to 2000MW to be connected using conventional hvdc technology.

9. Whereas the concept of using offshore hvdc links to transfer renewable energy from the North and West to elsewhere in the UK is feasible and likely to be economically justified at some point, the concept of a meshed hvdc "grid" designed to harvest and transmit renewable energy from a widespread area, would be difficult to justify due to the economies of scale which would tend to favour the use of hvdc for "point to point" transmission. For comparison purposes the estimated total capital cost of a 2000 MW

10. scheme based upon “point to point” transmission would range between about £ 790 M (200 km) and £ 1,700 M (700 km), whilst an hvdc “grid” concept scheme would be expected to have equivalent capital costs of between £ 1,700 M and £ 2,300 M.

11. The need for transmission network developments to accommodate additional transfers due to the connection of renewable generation in the North is likely to be a staged process, initially involving some reinforcement of the existing system but ultimately requiring radical measures such as the development of offshore hvdc links.

12. The cost of transmitting power over long distances is considerable and in extreme cases will approach the cost of developing the resource. Therefore, in order to minimise transmission, and hence overall costs to end users, when practical it will be appropriate to develop renewable resources in areas where their connection can be accommodated within the existing onshore grid, with the more distant resources and associated transmission being developed when “local” resources and the capability of the existing onshore grid are fully utilised.

13. The specific cost (i.e. the costs of transmitting 1 MW over a distance of 1 km, expressed in £/MW.km) of overhead lines is significantly less than submarine or underground cable alternatives and hence overhead lines would be expected to be used when practical and acceptable. However, where this is not the case, offshore submarine cable based schemes will provide a lower cost reinforcement than equivalent onshore ac or hvdc underground schemes. Furthermore, for onshore reinforcements associated with the connection of major tranches of offshore renewables, where converter costs will be essentially ”sunk”, serious consideration should be given to extending the hvdc link further towards the main load centres as an alternative to the use of ac underground cable based alternatives.

14. The timescales associated with the implementation of transmission schemes will be determined both by planning and consents, and also by manufacturing and construction/installation timescales. Whilst the planning and consents timescales can be highly variable, ranging from six months upwards, the overall manufacturing and construction/installation programme will typically take between 20 to 30 months, depending on the scale of the chosen scheme.

15. Issues requiring further investigation in order to take the study forward are presented in Section 9, however the main points are summarised below:

    – The role of major hvdc schemes needs to be considered within the context of a more detailed overall system study, including an assessment of the likely location and capacity of conventional generation under the increased renewable generation scenario and identification of fossil fuelled generation that would be displaced by wind powered generation and the impact of such displacements on onshore power flows and the operating costs of such displaced generation.

    – A more detailed examination of wind generation power output variations with time, covering short, medium and long term changes in power output due to wind speed variations, taking into account the effects of geographic diversity between likely wind farm locations.

- Identification of sites suitable for developing the required capacity of renewable generation including more detailed consideration of submarine cable routes and landfall issues.
- Identification of suitable locations for offshore and onshore hvdc converter stations and connecting substations.
- The use of multi-terminal and hybrid converter technology and the development of high power voltage source conversion equipment capable of operating at voltage levels of 500 kV.
- Determination of available manufacturing and installation capacity with respect to major hvdc submarine cable projects and identification of any potential shortfalls in such capacity.
- Further refinement of offshore and onshore transmission, and also network reinforcement, costs.

**CONTENTS**

**Page No.**

# 1. INTRODUCTION

## 1.1 Overall Aims and Objectives

The primary aim of this work is to perform a high level investigation of the feasibility of developing an offshore high voltage direct current (hvdc)[3] network for the connection of renewable energy sources sited along the western coast of Scotland, Northern Ireland, England, Wales and South-West England which would feed into the existing transmission system nearer to the centre of UK demand. This concept study is required to identify likely capacity requirements, network topology, possible points of interconnection with the existing network and will provide an estimate of overall cost. The study also makes comparison with the alternatives of upgrading the existing on-shore transmission networks, commenting on potential cost comparisons, technical and planning issues.

## 1.2 Background

It has been the United Kingdom Government policy to encourage the development and deployment of renewable energy sources in the United Kingdom wherever they have the prospect of being economically attractive and environmentally acceptable and as a result of this policy, in recent years the deployment of renewable energy technologies has gathered pace. This has largely been stimulated by the Non Fossil Fuel Obligation (NFFO) and Scottish Renewable Orders (SRO's), whereby a statutory obligation has been placed on the Electricity Industry to purchase power from renewable energy schemes.

More recently the Government has announced a target of 10% of all electrical energy to be generated from renewable energy sources by the year 2010, subject to the cost to the consumer being acceptable. The policy will be implemented through the renewables obligation (RO) that will require all licensed electricity suppliers to obtain an increasing proportion of electricity from "eligible" renewable sources[4]. Such a target implies about 40 TWh of renewable generation output by 2010, i.e. an increase of about 30 TWh above existing renewable output (including large hydro). This implies between about 6 GW and 8 GW of new renewable capacity, dependent upon the technology involved and the attendant load factors[5].

---

[3] HVDC technology is generally adopted for longer distance cable based transmission as it does not suffer from excessive and wasteful capacitive current effects that would occur with the use of alternating current (ac). However, for onshore transmission ac is preferred as it allows cost effective transformation of voltage up and down between the economic voltage levels applicable to generation, transmission, distribution and customer utilisation.

[4] Eligible renewable sources are defined as, onshore and offshore wind, wave and tidal stream power, photovoltaics, geothermal, biomass, energy from waste (using advanced technologies such as pyrolosis, gasification and anaerobic digestion), landfill and sewage gas and existing hydro less than 20 MW and all new hydro.

[5] Typical wind turbine generators load factor of about 30 % largely determined by wind conditions, whereas landfill and sewage gas would be expected to be better than 80 %, limited only by plant availability rather than any resource constraint.

Although not stated policy at present, increased renewable targets may be set for the post 2010 period, with potential targets of say 20 % renewable by 2020 and a longer term target of circa 60 % as per the recommendations[6] of the Royal Commission on Environmental Pollution. The renewable energy targets associated with the above corresponds to circa 90 TWh and 270 TWh respectively dependent, in the latter case on the Royal Commission assumption on underlying energy demand with implicit additional renewable generation capacity of about 20 GW and 45 GW dependent, as before on the dominant technology adopted.

The largest prospective source of additional UK renewables in the short to medium term is wind based plant located along the western seaboard, running from the north of Scotland and Outer Isles down to the Cornish Peninsula, with offshore wind powered plant being the dominant element. If this resource is developed in response to the renewables obligations, then it is evident that there will be a need to transfer many GW of renewable power to the mainland demand centres.

It is against the background outlined above that the aims and objectives of the present study have been framed.

[6] Royal Commission on Environmental Pollution, Energy - The Changing Climate published in June 2000

## 2. EXISTING TRANSMISSION NETWORKS

The present onshore electrical transmission infrastructure in Great Britain effectively tapers down as it progresses north, generally in line with historic power transfer requirements. In Northern Ireland the transmission system has been designed to deliver power from a limited number of coastal power stations to the main load centres but with some provision for power exchange with Ireland to the south.

The extent of the electrical transmission networks in the islands can be gauged from Figure 1, which presents the 400 kV and 275 kV transmission networks in the United Kingdom and also the 400 kV and 220 kV system in Ireland.


**Figure 1 – Existing Transmission networks**

Whilst an indication of the network capacity may be gauged from Figure 1, Figure 2 overleaf which makes use of The National Grid Company (NGC), Seven Year Statement (SYS) presentation technique, expanded to include relevant information from Scottish Power (SP) and Scottish and Southern Energy (S&SE) SYS's, indicates potential power transfers within the United Kingdom circa 2006/07, based upon the SYS forecast distribution of generation and demand at that time.

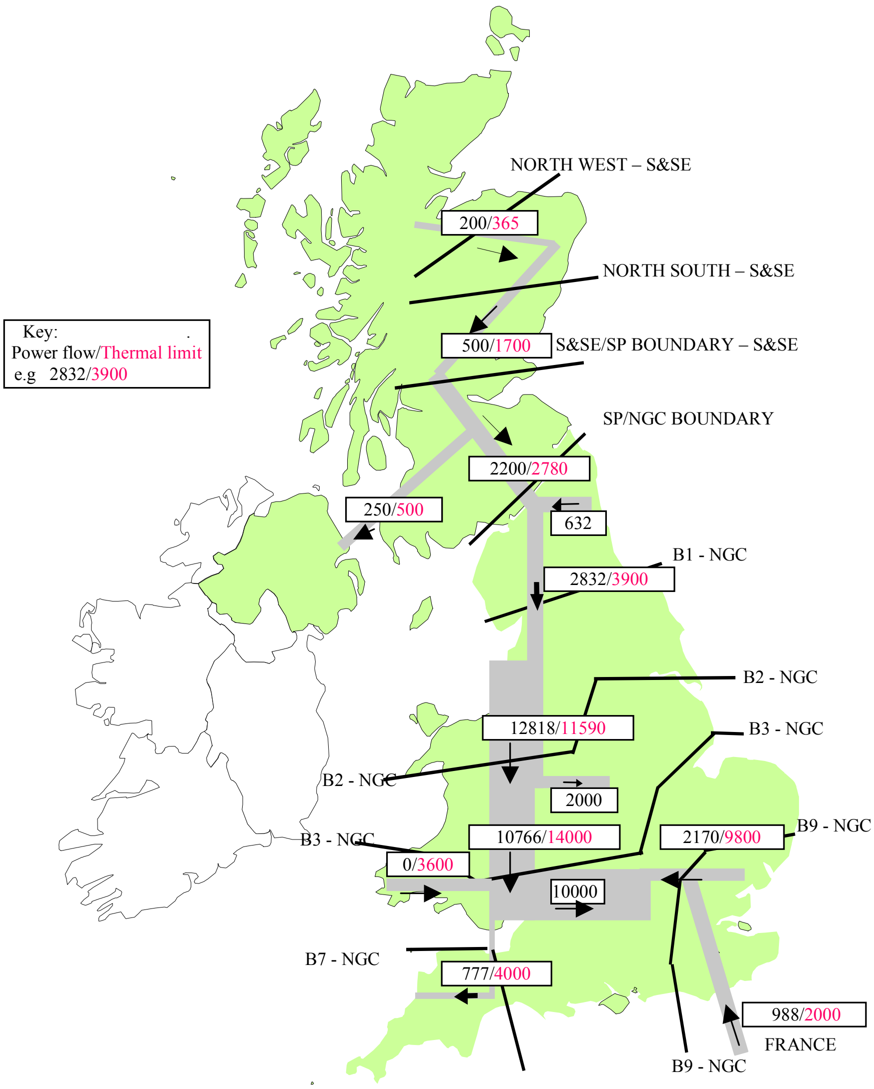



**Figure 2 - Forecast 2006/07 power flows and thermal transmission limits**

Figure 2 also shows the main transmission system "boundaries" which impose technical limits on power flows together with an indication of the boundary "thermal" capacity under prescribed[7] outage conditions. Whilst at the present time power flows may be limited to less than the thermal capacity due to restrictions imposed by consideration of system voltage levels and/or network stability, proven techniques are now available to overcome the bulk of such restrictions. If power flows in excess of existing circuit thermal ratings are required, consideration would firstly be given to reconductoring[8] existing circuits. However, at some stage additional circuits would need to be constructed which, in the light of the protracted

---

[7] Each of the existing transmission businesses must comply with "Licence Standards". These include a requirement that the system must be secured against certain planned and forced circuit outages. In the case of NGC, the system is required to be secure against the outage of any two circuits, with SP and S&SE operating to slightly less stringent requirements.

[8] By making use of conductors capable of operating at increased temperatures, it is possible to significantly increase the "thermal" capacity of many overhead line circuits.

delays in the construction of the “Second Yorkshire line”, due to local objections may impose practical restrictions on the extent to which renewable generation could be utilised.

It can be seen from Figure 2 that, power transfer capacity largely matches the forecast (and existing) power flows. If additional power flows were to be superimposed, due to the connection of significant amounts of renewable generation to the perimeter of the transmission system, reinforcement of the existing transmission network would be required. The exceptions to this statement are connections to the South-West of England and to Pembroke where capacity exists to accept significant additional generation.

The level of transmission reinforcement will be determined to a large extent by the location of generation output displaced by the renewable capacity. If the displaced generation is located in Scotland and the north of England, then the increase in power flows to the midlands and south may be minimal. However, if this renewable capacity displaced generation throughout the system including, for example imports from France, reinforcements of the midlands-south interconnections would also be required. If this were the case, due to planning issues associated with new overhead lines, the only practical solutions could be to establish appropriate underground cable links possibly employing hvdc technology.

## 3. RENEWABLE GENERATION

### 3.1 Capacity requirement

As stated earlier, the Government target of 10% of generation from renewable energy sources by the year 2010 implies the connection of between about 6 GW and 8 GW of additional renewable generation to the main transmission system. In the longer term a total of about 20 GW and 45 GW of renewable capacity may be required to meet possible future government targets and/or the objectives proposed by the Royal Commission on Environmental Pollution. For ease of reference, we restate the associated underlying energy requirements which are approximately 30 TWh by 2010, 90 TWh by 2020 and 270 TWh by 2050.

### 3.2 Location

The largest prospective source of additional UK renewables is plant located along the western seaboard, running from the north of Scotland and Outer Isles down to the Cornish Peninsula, with offshore, wind powered plant being the dominant element partly due to less restrictive planning constraints. Although there will be some increase in efficiency and load factor for the more northerly located plant, due to the higher average wind speeds, there will inevitably be an associated cost penalty due to the greater distance between the point of power generation and the main UK load centres. For example the Isle of Lewis where a large wind farm has recently been proposed is about 550 route-km from Wylfa on Anglesey, a potential connection point with the NGC grid.

The recent study of Scottish renewable generation capacity commissioned by the Scottish Executive[9] presents a “stacked cost energy curve” which is reproduced as Figure 3 below. This curve indicates onshore wind to be the lowest cost resource, with up to about 40 TWh being available for circa 2 p/kWh at the grid connection point. This is followed by offshore wind with a potential of about 80 TWh and a typical cost of about 3.5 p/kWh and with significant levels of wave and tidal resources appearing just above this cost level. It should be noted that the cost curve does not include network integration costs which are lower for onshore wind. The conclusion that may be drawn from this study is that from a Scottish viewpoint, onshore wind would be the least costly development and it is reasonable to assume that the same order of cost will apply to renewable resources elsewhere in the United Kingdom.

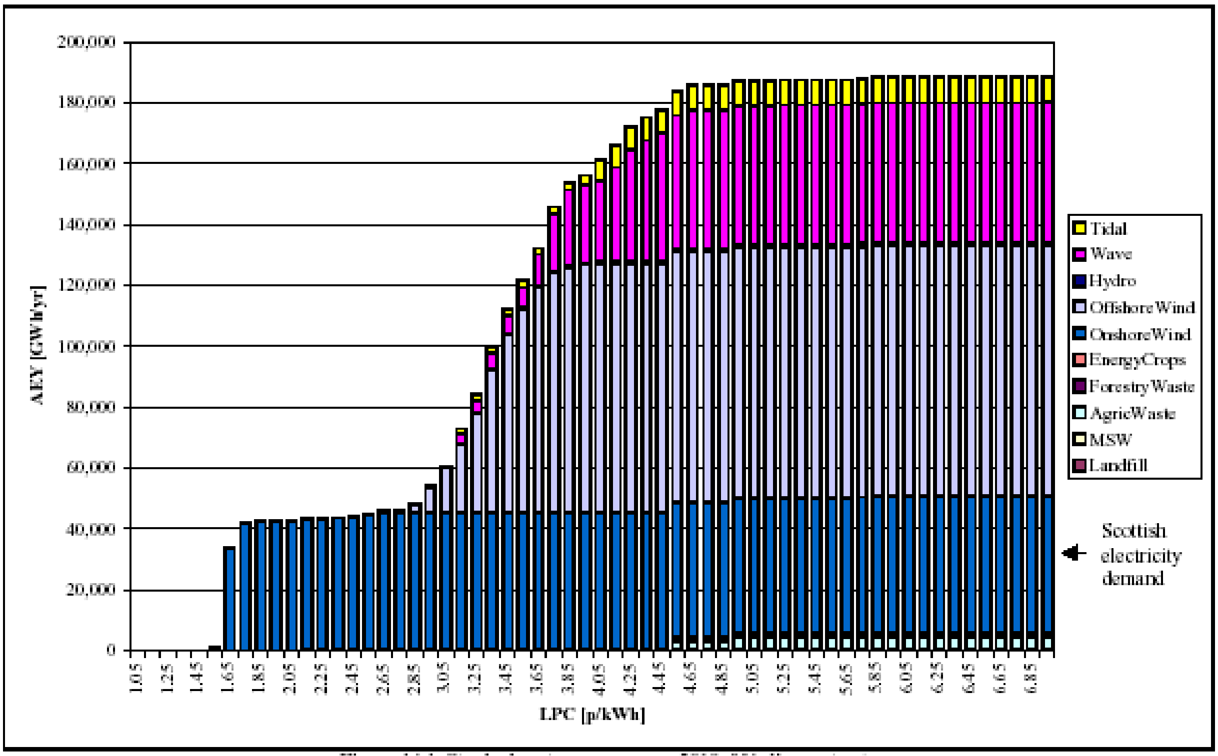



**Figure 3 – Scottish renewables “stacked cost curve”[10]**

It is likely that planning issues will limit the extent of onshore wind development, both with respect to the wind farm and also the implicit associated overhead line connection infrastructure. If underground cable connections are deemed essential on planning grounds then the connection cost advantage of onshore over offshore wind will reduce and may reverse. This, coupled with the assumed significantly reduced planning issues associated with offshore versus onshore wind may result in offshore wind being developed to the same, or greater extent than onshore, particularly in the longer term when saturation of the available practical onshore resource may occur.

---

[9] Renewable Energy Study, Document No. 2850/GR/02

[10] Stacked cost curve axis are, X axis LPC - Lifetime Production Cost (p/kWh) and Y axis, AEY – Annual Energy Yield (GWh)

From a practical viewpoint within the context of this study it is not unreasonable to consider large tranches (circa 100 MW or above) of onshore or offshore wind as being very similar with respect to collection and onward transmission, once such tranches have fully saturated the ability of the existing local distribution and transmission networks. Accordingly, for the purpose of this study we have considered the renewable resource to comprise 100 MW modules, subsequently grouped together into more manageable blocks for onward transmission to the main grid or load centres. Although these modules may then be located anywhere onshore or offshore, for the purpose of this report we have assumed that the bulk of the resource would be developed offshore, along the UK's western seaboard.

## 4. RENEWABLE CONNECTION ARRANGEMENTS

Fundamental to the bulk transmission of renewable power to the existing mainland transmission system (as considered in Section 5) are the electrical connection methods required to:

(i) collect power from the numerous individual generating units to form discrete wind farm groups;

(ii) provide some form of sub-transmission system to combine the output from a number of wind farm groups; and

(iii) efficiently transfer high levels of offshore renewable power to the mainland transmission system.

Feasible connection methods have been identified and are outlined below.

### 4.1 Local connections

Earlier studies undertaken by others indicate that offshore wind energy in areas such as the more northerly UK west coast can be "harvested" at a rate of about 10 MW/km$^2$[11]. On this basis a 1000 MW wind farm would occupy a total area of about 100 km$^2$ and would typically contain about 400 individual 2.5 MW units spaced at about 500 m in a chequerboard fashion. Information released by Crown Estates indicates individual wind farms leases for up to about 30 turbines have recently been granted. Based upon this farm size, a total of about 13 such farms would be required to deliver 1000 MW.

In keeping with the individual unit ratings, farm sizes and numbers outlined above, the first requirement of any electrical power transmission system will be to collect the outputs from the individual units making up a farm. Whilst consideration may be given to the use of direct current for the connection, which may provide some efficiency benefits with respect to energy capture, the most cost effective collection arrangement is likely to be 11 kV ac based

[11] The corresponding value for onshore resources adopted in the Scottish Executive study was 9 MW/km$^2$.

arrangement bringing together circa 100 MW groups of turbines prior to stepping up to a higher voltage for collection purposes prior to onward transmission.

## 4.2 Wind farm groupings

Prior to onward transmission it will be necessary to bring together a number of nominally 100 MW wind farm groupings in order to realise the economies of scale associated with onward transmission to the existing transmission grid. The choice of a nominal step-up voltage of circa 90 kV ac for offshore groups and either 66 kV or 132 kV for onshore groups is premised on this basis. Offshore, ac cable technology is well proven in this voltage range and results in a convenient balance between cable current ratings and capacitive charging effects and allows the transmission of power levels of circa 100 MW over distances of up to about 50 km. The use of such a voltage will therefore allow wind farm groupings dispersed over a considerable distance to be brought together in a cost effective manner prior to conversion to the required hvdc voltage.

To allow maximum utilisation of the ongoing transmission it may be appropriate to oversize the nominal wind farm groups, for example associating about 2200 MW of wind farm capacity with a nominal 2000 MW transmission link. By this means the inevitable diversity in individual turbine outputs can be used to ensure a more constant utilisation of the relatively high cost transmission capacity. The level to which this practice in adopted will depend upon the anticipated level of diversity and the trade off in the costs of transmission versus the value of any spilled energy at times of full output.

## 4.3 Onward transmission

The choice of connection voltage and technology for onward transmission will be very much dependent upon the interfacing point with the existing mainland transmission network. If, for example the interface was the 132 kV or 275 kV network in the north of Scotland, the network may only be unable to accept more than a few hundred MW's. In addition, with a relatively weak connection point, issues such as network voltage stability may be a major constraint. As such there are likely to be strong arguments for the use of hvdc employing voltage source converters[12] and operating at 100-150 kV, both as a transmission medium and also as a means of decoupling the wind generation grid from the main onshore network.

If, however the interface were a part of the network capable of accepting significantly larger amounts of power, then the more established, naturally commutating converter technology hvdc scheme would be indicated, operating at between 250 kV and 500 kV and capable of delivering up to 2000 MW of power over extreme distances. Due to the economies of scale there would be little incentive to adopt hvdc operating voltage levels and cable sizes which will deliver lesser amounts of power. The main UK 400 kV transmission network can readily accept such levels of power infeed and the source end requirements of circa 200 $km^2$ of wind farm area should not be an obstacle.

---

[12] Voltage source converter technology, presently marketed under the names "HVDC Light (ABB) and "HVDC Plus (Siemens) are better suited for integration within weak ac networks.

At the source end of such a link, for technical reasons associated with the absence of a synchronous source, it will be necessary to employ voltage source converters. This technology is based upon more recently developed and somewhat more expensive and lossy IGBT[13] technology in comparison with the thyristor based technology that has been employed for many years in hvdc applications. Although such voltage source converters have not yet been applied commercially at the voltage and power levels envisaged, we are not aware of any significant technical problems that are unlikely to be overcome in the near future. On this basis therefore we consider that a hybrid hvdc scheme based upon the use of voltage source converters at the source end and conventional converter equipment at the receiving end will provide a viable and suitable arrangement that can be practically realised within the envisaged time scales.

The use of a bi-polar arrangement is recommended[14], potential interference and corrosion effects that could be attributed to the mono-polar alternative particularly on routes running overland or parallel with the mainland and crossing gas and telecommunication cables, making such an alternative too problematic. The 2000 MW bi-polar arrangement does not however exclude short term operation in a mono-polar mode, following a sudden cable or converter outage which would disable one of the poles, thereby limiting the effective “plant loss” to within the 1000 MW of generation that the mainland system is normally operated to accept.

## 5. RENEWABLE POWER TRANSMISSION

A number of options for the transfer of significant levels of offshore renewable energy to the existing mainland transmission system have been considered. These include:

(i) HVDC grid – an interconnected offshore hvdc network capable of harvesting power from a number of offshore locations and feeding it into a number of points on the mainland;

(ii) Transmission of offshore resource to mainland system – collection of offshore renewable energy with point-to-point transfer to the mainland using either ac or hvdc transmission schemes;

(iii) Reinforcement of present mainland transmission system – to permit the transfer of renewable energy harvested off the west coast of Scotland to load centres in the South; and

---

[13] IGBT – Insulated Gate Bipolar Transistor, generally designed to operate in a high frequency (kHz range), pulse width modulated manner to interface after filtering with 50/60 Hz power sources.

[14] HVDC schemes can be based upon a single “monopole” arrangement, e.g.+500 kV, which relies upon earth or sea return current paths, or a “bipole” arrangement, e.g +/-500 kV where fully insulated “go” and “return” current paths are provided. The advantage of a monopole arrangement is essentially that of cost, as full “economy of scale” benefits can be gained at half the rating of an equivalent bipole scheme.

(iv) Transmission constraints bypass – utilising an offshore hvdc transmission link overcome the present north-south transmission constraints of the mainland system.

These options are discussed in more detail below.

## 5.1 HVDC grid

As outlined in Section 4, the economies of scale indicate that high power transmission over long distances would be undertaken by hvdc transmission. As stated earlier, hvdc technology is generally adopted for longer distance cable-based transmission as it does not suffer from capacitive current effects that occur with the use of alternating current (ac). The hvdc transmission scheme would receive the outputs from a number of wind farm groupings which could be brought together from a relatively wide catchments area where conventional ac technology was used.

The overall catchment area required to make full use of hvdc technology is only about 200 $km^2$, i.e. equivalent to a 14.1 km x 14.1 km square capable of generating up to 2000 MW. As such there will be little advantage in establishing a dispersed hvdc grid with the intention of collecting renewable energy over a greater area, or sited along the route of such a cable, as such an arrangement would implicitly mean sub-optimal usage of parts of the grid as well as the need for an increased number of expensive converter stations. This point may be illustrated by reference to Figure 4 overleaf, which presents a 200 $km^2$ square within the context of the potential overall transmission distances involved and also indicates the extensive area which may be brought together in a cost effective manner using conventional ac technology.

It should be noted that whilst Figure 4 presents the 200 $km^2$ area as a “square”, in practice due to constraints imposed by seabed depth and possibly seashore visual issues, such farms may need to be relatively narrow and constrained along the “horizon” line. However, as indicated the proposed ac technology will be able to bring together the outputs from such farms over the distances that may be involved. In addition, whilst such farms may be adjacent to the coastline, in many cases the coastal land may be quite unsuitable as a site for any collection substation and offshore arrangements as proposed may be more cost effective and manageable.

Whilst the argument presented above does not support the establishment of an hvdc grid as such, if a significant number of 2000 MW wind farm groupings and associated hvdc transmission originated in adjacent areas, then consideration could be given to the provision of some form of interconnection between such groups, such that any redundancy in the available transmission capacity could be shared, particularly at times of planned or forced outage of individual links

Ideally such links would be established and switched at ac. However to transfer the required power levels this would need to be at high voltage (400 kV) and the viable lengths of such interconnections would be quite short, i.e. circa 50 km, and hence may be of limited value.

Unfortunately, due to the absence of the hvdc equivalent to an ac circuit breaker[15], such interconnections if made at hvdc would require expensive converter type switching equipment and hence would be of similar costs to the main link, dependent of course on the distances involved.

It is evident from the above that scope for establishing interconnections between hvdc nodes will be relatively expensive, particularly if they are simply being provided to make use of opportunistic redundancy (or surplus capacity). It should also be noted that a permanent degree of redundancy could only be provided at a relatively high specific cost in relation to the underlying resource cost. These arguments indicate in favour of simply matching individual transmission assets with the associated resource blocks as discussed in Section 5.2.

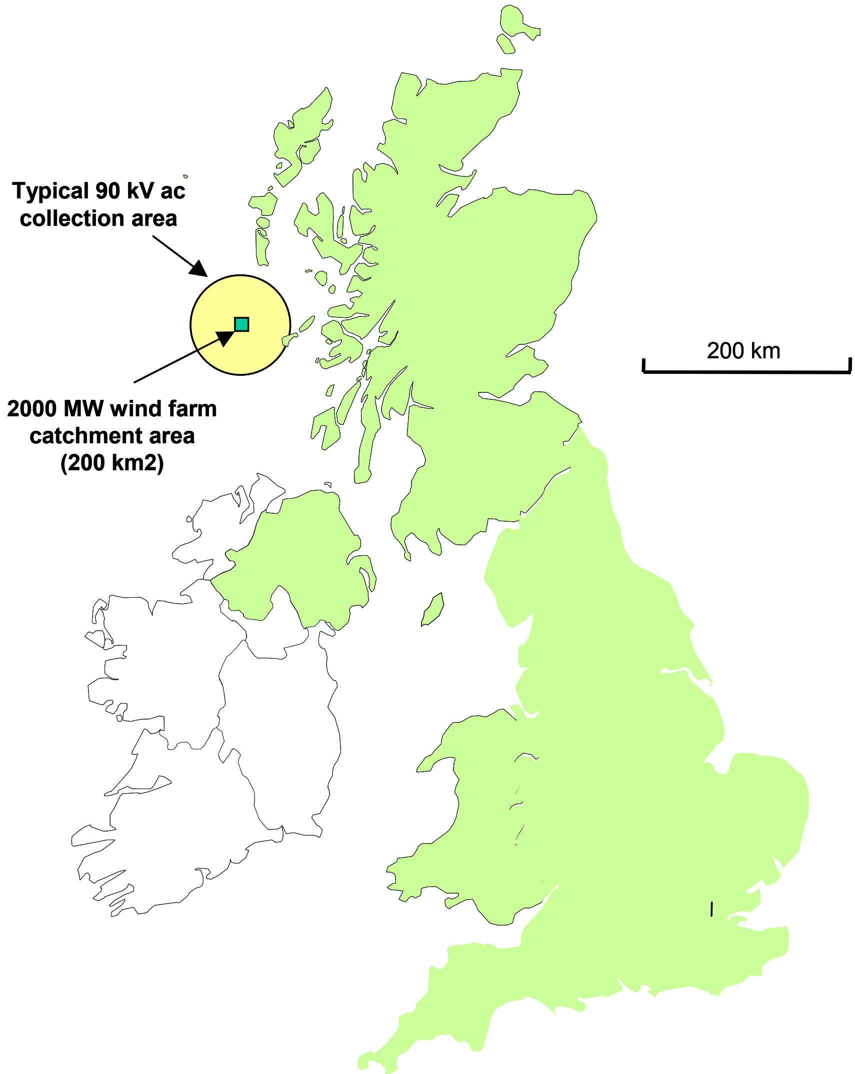



**Figure 4-Indicative renewable generation catchments areas**

[15] Essentially an electrical switch capable of interrupting high levels of current and voltage. Due to the alternating nature of ac, current zeros occur every 10 ms (for a 50 Hz) system which greatly assist with current interruption. Such current zeros do not occur with dc currents.

## 5.2 Transmission of offshore resource to mainland system

As described in Section 4, it is appropriate to consider the electrical infrastructure required to collect and transmit the output from major tranches of renewables as being made up from a local 11 kV system which will bring together the output from circa 40-50 individual wind turbines, or equivalent wave devices, into blocks of about 100 MW which will then be transformed up to 90 kV using conventional ac transformer technology in association with either,

(a) The scenario where the output from such blocks may be injected into the local, relatively weak onshore transmission network. In such a case one or more of the 100 MW blocks would be connected into the main transmission system using voltage source converter technology, or

(b) The scenario where the output from such blocks may be injected into parts of the main transmission system capable of accepting several GW of renewable output. In this case the outputs would be combined together offshore and then connected using more conventional hvdc technology, where such technology offers some economic advantage over the voltage source based alternatives.

Outline sketches of these two arrangements are presented in Figure 5 (a) and (b) overleaf which respectively presents examples of a 100 MW voltage sourced converter-based scheme and also of a 2000 MW hybrid converter based arrangement. It is recognised that in certain locations, individual ac groups may be able to connect directly with the adjacent onshore ac coastal grid system. In such cases only the ac elements of Figure 5 (b), i.e the 11 kV and 90 kV (or 132 kV) components may be needed for such connections.

Clearly the possibility exists for the ac connection of wind farm groups that are located sufficiently close (up to 50 km or so at 90 kV) to the existing mainland transmission system. The opportunity for such connections will be constrained by the capability of the local networks, particularly in the north with ac connection likely to be the most cost effective option for small local groupings. HVDC would be the most appropriate connection method for larger more distant groupings, particularly when feeding into weak parts of the existing mainland transmission system. If significant amounts of generation are to connect around the periphery of the existing mainland system, particularly in the north, reinforcement of the local onshore networks will also be necessary.

## 5.3 Reinforcement of present mainland transmission system

The capacity of the existing mainland transmission system in the North of the UK largely reflects historic and predicted power flows, therefore, should significant amounts of renewable generation be superimposed on the existing system power flows, reinforcement will be required unless equivalent existing generation in the area is displaced. The same is not true of the transmission network below the principal Midlands to South constraint, particularly so in the South West and South Wales, where significant capacity exists (3 – 6 GW) to accommodate additional generation or imports from elsewhere in the UK connecting at these locations.

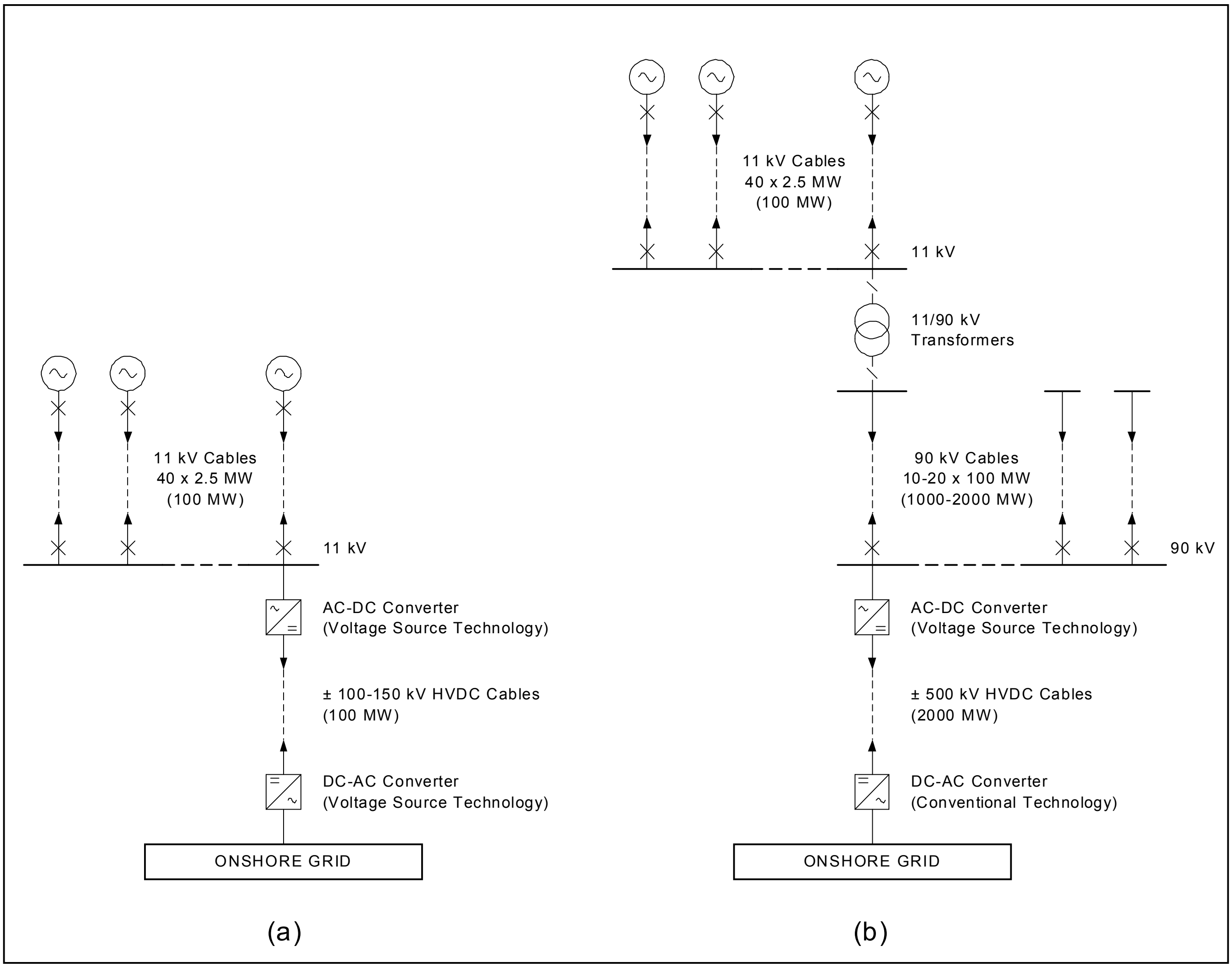



**Figure 5– “Western grid” network topology**

However, as the connection of renewable generation is intended to displace a significant proportion of existing fossil fuelled generation, then dependent upon the location of such displaced generation, the existing main 400 kV onshore grid may provide sufficient capacity. On the basis that local fossil fuelled generation will be significantly displaced, up to about 4 GW of renewable generation could connect within Scotland, and a further 10 GW in England, north of the Midlands to South constraint, essentially a line drawn roughly between The Wash and Cardigan Bay.

Regardless of the above, at some time in the future extensive reinforcement of the onshore grid may become necessary. Historically such reinforcements would have been largely based upon the construction of new additional overhead lines. However, this is likely to raise major planning and environmental issues that could be largely avoided by the use of hvdc links. HVDC links based upon submarine or underground cables could be used to bypass the congested transmission systems in the North and allow power to be injected into the existing transmission system at points where sufficient capacity exists, as described below.

## 5.4 Transmission constraints by-pass

Such a scheme could comprise either a dedicated hvdc “bypass” of the onshore grid, with an hvdc link originating, say at Hunterston in Scotland and terminating at Pembroke in Wales thereby bypassing the transmission constraints between the North and Southern parts of England and Wales, or as an alternative, an arrangement whereby a multi-terminal hvdc scheme was established. In the former case the costs and benefits of the arrangement would need to be compared with the alternatives of reinforcing the onshore grid.

The latter arrangement could comprise a scheme with nodes at Hunterston and Pembroke, connecting with the existing SP and NGC 400 kV transmission system, and with one or more intermediate, Irish Sea nodes to which renewable generation is connected. Such a ”grid like” arrangement could be considered both as a means of allowing renewable power to be delivered to the mainland and also as a form of reinforcement of the existing mainland grid. However, these main functions would tend to be mutually exclusive and, as it would be possible to collect the renewable generation capacity necessary to fully load the cable from a relatively small part of the Irish Sea (refer to Figure 4), it is unlikely to be competitive against individual, and shorter dedicated schemes as per Figure 5 above. In addition due to the relatively short “offshore” distances involved in the Irish Sea, lower power arrangements whereby the wind farm output is directly fed into the 132 kV system along the local coastlines may be more attractive.

# 6. INTEGRATION WITH THE ONSHORE GRID

## 6.1 Scotland

An indication of forecast power flows and potential transmission capacity of the existing UK transmission grids is presented on Figure 2. It can be seen that the grid in Scotland has only limited capacity to accept additional generation for onward transmission to the remainder of the UK. Potential exists to accommodate only about 750 MW of peak capacity, based upon the forecast 2006/07 power flows, with about 250 MW of this capacity being associated with the Scotland-Northern Ireland interconnection[16] and the balance with the England –Scotland interconnector. It should be noted that the implicit assumption that a further 500 MW of power could be exported from Scotland to England assumes the full adoption of FACT’s technology[17] to allow for “post fault” operation[18] of the interconnectors at near thermal rating, together with appropriate reinforcement elsewhere within the Scottish and England and Wales transmission systems.

---

[16] Security considerations may limit power flows from Scotland to Northern Ireland (NI) due to the limited ability of the NI receiving system to accommodate an implicit potential infeed loss of 250 MW.

[17] FACT’s, Flexible AC Transmission. PB Power were responsible for a project in Argentina to allow the multi circuit 500 kV system to operate at thermal rating over distances in excess of 1200 km, refer to “The provision of additional stabilisation facilities on the Argentinean electricity network”, DI Bailey and JM Rodríguez, Latin American Power Conference, Buenos Aires June 1998

[18] Transmission Licence security standards require the system to be planned and operated secure against an N-2 outage, i.e. the loss of two of the four interconnecting circuits.

The load factor of wind based renewable generation is generally taken as about 30 %, i.e. significantly lower than most conventional generation. It will therefore make economic and practical sense to "over install" renewable capacity on the grounds that coincident operation at peak capacity is unlikely and the economic consequences of constraining generation under such circumstances will be minimal. On this basis it would be reasonable to connect up to about 1000 MW of wind based renewable generation to the Scottish grid. However, if it is recognised that the primary intention is for the renewable generation to displace fossil fuelled generation, it is evident that significantly more renewable capacity could be connected within Scotland.

At the time of the peak power flows shown on Figure 2 about 3000 MW of fossil fuelled plant is assumed to be running. If this were to be completely displaced[19] by renewables, the indications are that up to about 4000 MW (4 GW) of renewable capacity could be connected at time of peak without requiring the construction of additional circuits to connect with England or Northern Ireland.

The ability to connect up to about 4 GW of renewable generation within Scotland would represent about half of the capacity necessary to meet the UK Governments 2010 targets. However any further increase in connected renewable capacity required to meet any later targets, or to provide further assistance with overall UK obligations would require the construction of additional circuits to connect with England and/or Northern Ireland.

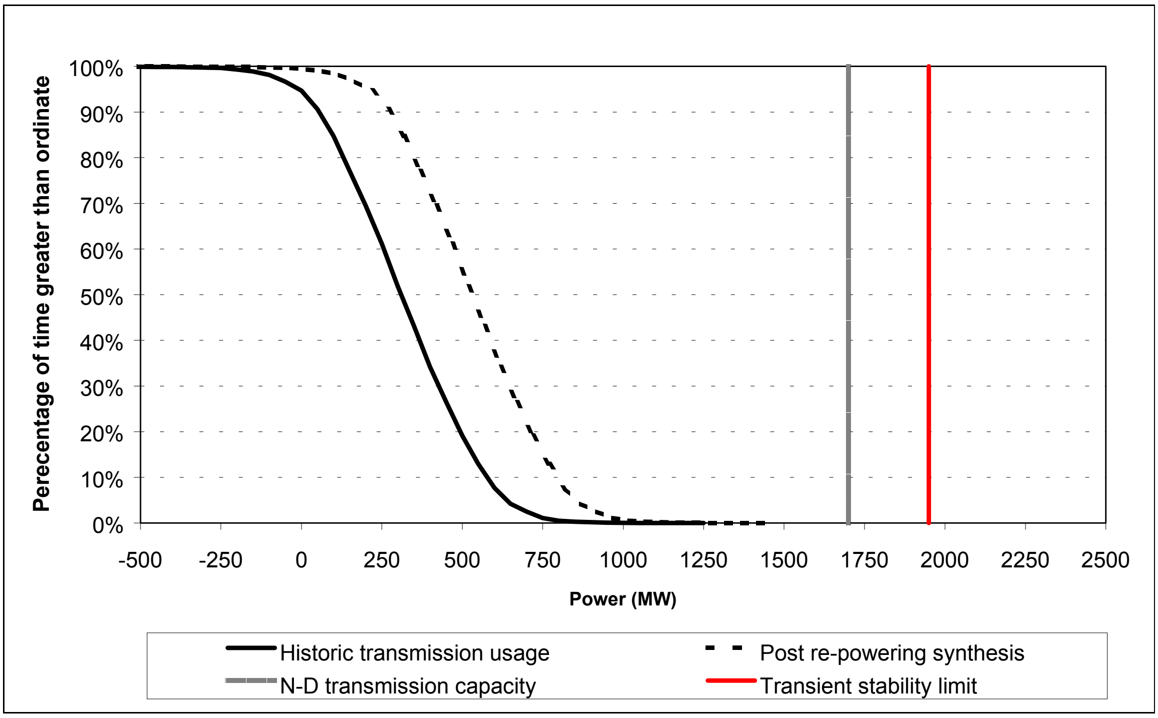
The points to which the above levels of renewable generation could be connected to the existing Scottish transmission infrastructure are quite limited, due to technical and security considerations. Work that PB Power reported on to Ofgem during 2001[20] indicated that up to about 2000 MW of additional plant could connect in the north of Scottish and Southern's area without requiring major reinforcement of the main 275 kV transmission system in the area or of the connections with Scottish Power. However, this was based on the renewable capacity being fully embedded within the existing transmission and distribution networks in the north and also assumed about 50 % diversity applying to the renewable resources.

It should be noted that in parts of the system, transmission capacity can exist away from the times of system peak which could allow for significant amounts of renewable generation to be transmitted. As an example we present below an analysis of historic data relating to one of the "transmission bottlenecks" on the S&SE system taken from the above referenced March 2001 report. However, in other parts of the mainland transmission system, power flows away from the time of peak demand may be more limiting than at times of peak due to significantly different generation despatch and demand balances.

---

[19] A balance of about 3,500 MW of nuclear and hydro based plant would remain connected within Scotland at that time which would be expected to be able to ensure satisfactory system operation. At times away from system peak, constraints may need to be placed on renewables due to considerations of system voltage and stability control, dependent in part upon the technology adopted for receiving end converter equipment and also other measures available to the transmission system operator.

[20] PB Power in association with IPA Energy Consulting, March 2001 report to Ofgem, Scottish and Southern Energy's transmission study.




However, if such capacity was to be brought to the north of Scotland from offshore, or Western Isle's based schemes, then some reinforcement of the existing onshore system would be required and there would be strong arguments in favour of "landing" such power further south, say at Hunterston in Scottish Power's area of supply.

## 6.2 England and Wales

As indicated in Figure 2 the ability of the transmission network in England and Wales is very dependent upon location. In the north of the country, near Carlisle, whilst about 1000 MW of capacity is indicated across NGC – B1 boundary, this capacity is dependent upon the level of increased export from Scotland referenced above. In addition, reference to Figure 1 indicates that it would generally be preferable to routing the connection of any major tranche of generation further south, towards Heysham, rather than to the Harker substation near to Carlisle. The exception to this would be wind-farms located in the vicinity of the Solway.

Further south, in the Irish sea and off north Wales, the termination point could be in Anglesey or in the Dee Estuary. The extent to which renewable capacity could be accepted is dependent upon the location of generation that is displaced by the renewables, as negligible transmission capacity is indicated for any south-easterly flow into the Midland or South. However, on the basis that the bulk of the generation in the north of England is fossil fuelled, other than the nuclear stations at Hartlepool and Heysham, then in excess of 20 GW of generating capacity is available to be displaced. From a practical viewpoint it is reasonable to assume that at least half of this generation would remain connected and operating under the shorter-term renewable scenarios, i.e up to say 2020, which implies up to about 10 GW of renewables could be accepted. Beyond that date plant retirements, new connections and the penetration of micro CHP, fuel cells or other technology could be expected to significantly change the conventional generation plant mix and distribution.

Further south again, namely South Wales and the South West, Figure 2 indicates between about 3 to 4 GW of renewable generation could be accepted at both locations without requiring major reinforcements other than the possible use of FACT's technology to enhance the capability of the existing infrastructure. The extent to which more deeply seated reinforcements would be required will again be determined by the distribution of displaced generation and the resultant changed main system power flows although this is less of an issue in these areas as only limited generation capacity is presently in place.

In the Midlands, South-central and South-east, the extent to which renewable generation can be accepted is again largely determined by generation displacement, both within the demand area and also in the areas from which supplies are obtained. As the bulk of the demand in the area, circa 13 GW is imported from largely fossil fuelled generation in the north, then there is significant scope for displacing such imports. The extent to which such renewable generation could connect directly into the network will be location specific and largely determined by displacing local generation, e.g at Fawley, in the Thames Estuary and in East Anglia. In addition there may also be some interaction with the hvdc link with France at Sellinge, noting that under the 2010 and later scenarios, the export of renewable energy to less well resourced parts of Europe may be appropriate.

## 6.3 Northern Ireland

In Northern Ireland the existing generation is essentially coastal based and the transmission network is designed to take this capacity and deliver it to the end users throughout the province. Examination of Figure 1 indicates that the network is well placed to accept renewable generation entering from either the north or from the northern Irish Sea. As a consequence the ability of the network to accept renewables will be largely determined by the system demand and the extent to which operational considerations would restrict generation displacement. It should be noted that at the present time the interconnections between the north and south in Ireland are quite constrained and may remain so. As such the possibility of making use of the "Irish" systems as a means of bypassing England's transmission constraints has not received any further consideration.

## 6.4 Operational issues

As touched on above, technical considerations will play a part in determining the extent to which renewable generation can be accepted onto the network, both with respect to location, or injection point, and in total. The bulk of the technical issues associated with individual injection points can be readily easily overcome by appropriate use of technology. The more significant global impact of renewable generation, both wind and wave is associated with its variability and the need for the system to be able to accommodate relatively continuing and rapid changes in output together with the need for the system to retain access to an adequate level of more conventional generation such that demand can be met at times of low wind and wave activity.

It should be noted however that the introduction of significant amounts of "variable" renewable generation would invariably reduce the annual load factor on conventional generation. As a consequence the Generator will attempt to recover fixed costs over a reduced number of unit sales with an inherent tendency to increase the associated energy costs. Whilst competitive pressures will invariably limit price increases from existing "sunk" cost generators, if new plant is required then an increased market price will be required to make such plant financially viable. Work that we reported on to Ofgem in August 2000[21], as part of NGC Price Control Review, indicates that for a new CCGT plant or a refurbished existing coal plant, reducing the station load factor from about 80 % to 40 % would increase the unit cost from circa 3p/kWh to 4.2 p/kWh.

Work by NGC, essentially investigating NETA type issues and reported to the DTI's Energy Advisory Panel[22] indicates that the variability of the wind power resource over periods of one and three hours, will not be an issue within the operational planning time scale, noting that there are significant benefits from having diverse sources as there is little correlation between individual wind farm groups when separated by more than about 100 km. In the case of the large tranches of renewable generation required to meet Government and possible other targets then the spread of resource catchments areas will be extensive with a consequent high degree of diversity between individual farm outputs. It is expected that similar behaviour would occur with respect to the large scale implementation of wave based energy resources.

With respect to daily and seasonal variations in wind farm output, although little information is currently available the indications are that offshore wind farms display very little diurnal effects, particularly during the more critical winter periods. The seasonal variation in mean wind speeds is more marked although importantly, it is less marked than the variations in system electrical demand. Accordingly, if sufficient wind powered generation is provided to assist with meeting winter peak demands then the expectation is that more than enough output will be available to support the reduced spring, summer and autumn system demands, albeit that with present technology the generation of last resort must invariably be conventional, fossil fuelled plant.

## 7. CAPITAL COST ESTIMATES

As stated earlier the nature of the renewable generation energy collection and transmission requirements lend themselves to costing on a modular basis.

### 7.1 Local collection system

We have estimated the capital costs of the 11 kV local collection system for 100 MW of renewable generation to be between £6 M and £13 M. Actual system costs will be dependent upon the layout of the individual generation units and the electrical connection arrangement adopted.

For our cost estimate we have assumed that the cost for the required 11 kV ac submarine cable will be of the order of £110 k/km with fixed mobilisation costs of £200 k. The cost of

[21] PB Power report to Ofgem, The Transmission Price Control Review of the National Grid Company (1997/98 to 2005/06) Operational Capital Expenditure Review, Final Report August 2000.

[22] Discussion Paper to DTI Energy Advisory Panel, September 2001

11 kV switchgear has been assumed to be £5 k per bay. For transformation to the sub-transmission voltage of 90 kV we have assumed that 3 x 40 MVA, 11/90 kV transformers will be required at around £300 k per unit. In addition the capital costs associated with the offshore platform that would be required to house the transformers and switchgear has been estimated at £500 k.

## 7.2 Sub-transmission system

We have estimated the capital costs of the 90 kV sub-transmission systems for each 100 MW module of generation to be between £2 M and £12 M. This wide variation in cost reflects our assumption that the output from numerous 100 MW modules of renewable generation may be gathered together over distances ranging from 5 km to 40 km.

Our capital cost estimate has assumed that the cost of the required 90 kV ac submarine cable would be around £280 k/km again with fixed mobilisation costs of £200 k. The cost of 90 kV switchgear has been assumed to be £500 k per bay reflecting the need for GIS (gas insulated switchgear) equipment for the offshore environment.

## 7.3 Offshore HVDC transmission system

### 7.3.1 100-500 MW scheme

For a 100-500 MW HVDC transmission scheme based on voltage source converter technology, the capital costs of the converter equipment are estimated to be £16-80 M (cost varies almost in proportion to rating), and the cost of the submarine cable is estimated at around £450 k/km. The associated specific transmission costs, i.e. £/MW.km, is dependent upon the cable lengths, as the converter costs become less significant as the transmission distance increases. For indicative purposes it is worthwhile considering possible extremes of, say a 100 MW, 50 km link and a 500 MW, 200 km link where the respective capital costs would be £46 M and £204 M respectively (including 20 % contingency allowance). The associated specific transmission costs therefore lie between about £ 9,200/MW.km and £ 2,040/MW.km.

### 7.3.2 2000 MW scheme

For a 2000 MW HVDC transmission scheme based on a hybrid converter arrangement (utilising voltage source and conventional converter technologies at the sending and receiving ends respectively), the capital costs of the converter equipment are estimated to be £340 M, whilst the cost of the submarine cable is estimated to be approximately £1,000 k/km. Again, for indicative purposes we have considered two possible extreme cases, i.e. a 200 km and a 700 km link, for which the capital costs would approximate to about £611 M and £1,161 M respectively (including 10 % contingency allowance[23]). The

---

[23] Note that the overall system capital cost estimates presented include a 10 % contingency allowance on all equipment / module costs stated previously, except in the case of voltage source converter equipment (and the associated 150 kV submarine cables) where we have included a 20 % contingency due to the greater uncertainty in manufacturer's cost data.

associated specific transmission cost, may therefore be taken to lie between about £ 1,527/MW.km and £ 829/MW.km.

## 7.4 Summary of hvdc system costs

We have estimated the overall system capital costs associated with the two network topologies presented in Figure 5 based on the unit costs of the various system modules outlined above, but including appropriate contingency allowances.

(i) For an offshore "grid" capable of collecting and transferring 100-500 MW of renewable energy to the onshore transmission system via an HVDC link based on voltage source converter technology, we estimate the capital costs would range from £55 M (the lower limit of cost expected for a 100 MW scheme with an HVDC link length of 50 km) to £340 M (the upper limit of cost expected for a 500 MW scheme with an HVDC link length of 200 km).

(ii) In the case of a "grid" capable of collecting and transferring 2000 MW via an HVDC link based on a hybrid of voltage source and conventional HVDC converter technology, we estimate the capital costs would range from £790 M (the lower limit of cost expected for a scheme with an HVDC link length of 200 km) to £1,700 M (the upper limit of cost expected for scheme with an HVDC link length of 700 km).

(iii) In the case of an offshore grid intended to collect renewable resources from a widely dispersed area, configured much like a classical onshore grid, the capital costs will be significantly greater than those indicated in (ii) above, largely as a large part of the economies of scale will be lost. Such a scheme would tend to comprise a combination of (i) and (ii) above and as such the capital costs will reflect the balance of the arrangement. On this basis, a lower cost of about £ 1,700 M would apply for a 2000 MW scheme made up of 100 MW modules brought together from distances of about 50 km and then transmitted over about 200 km, and a higher cost of about £ 2,500 M would apply to a scheme based upon bringing together widely dispersed 500 MW modules with the power then being transported over about 700 km. In practice this latter estimate will tend to overstate the costs, as the implicit collection distance, circa 200 km would imply somewhat shorter final transmission distances (say 500 km) and a total cost of about £ 2,300 may be more appropriate.

## 7.5 Onshore upgrade costs

Reference is made earlier in this report to the possibility of enhancing the onshore system such that maximum use could be made of the thermal capacity of existing transmission lines. It is not possible within the scope of this study to detail the plant requirements necessary to allow increased usage of specific parts of the existing network, however an estimate of the costs of network reinforcement on the NGC system can be gauged, by reference to the Transmission Network Use of System[24] charges applicable to generation connecting in different tariff zones. These charges are prepared on an annual basis and, in the years since "privatisation" have progressively moved towards providing stronger generation "locational" signals, by reflecting the network infrastructure and reinforcement costs associated with the location of generation in different parts of the system.

---

[24] Transmission Licence Condition C7 Statement for use of system and Connection to the System.

Figure 9.1 of NGC's 2001/02 SYS which outlines NGC's zonal boundaries is presented below. This figure also indicates the capability of the individual zones of the England and Wales transmission system to accept new generation. Equivalent, zonal information is not readily available for the other UK transmission businesses.

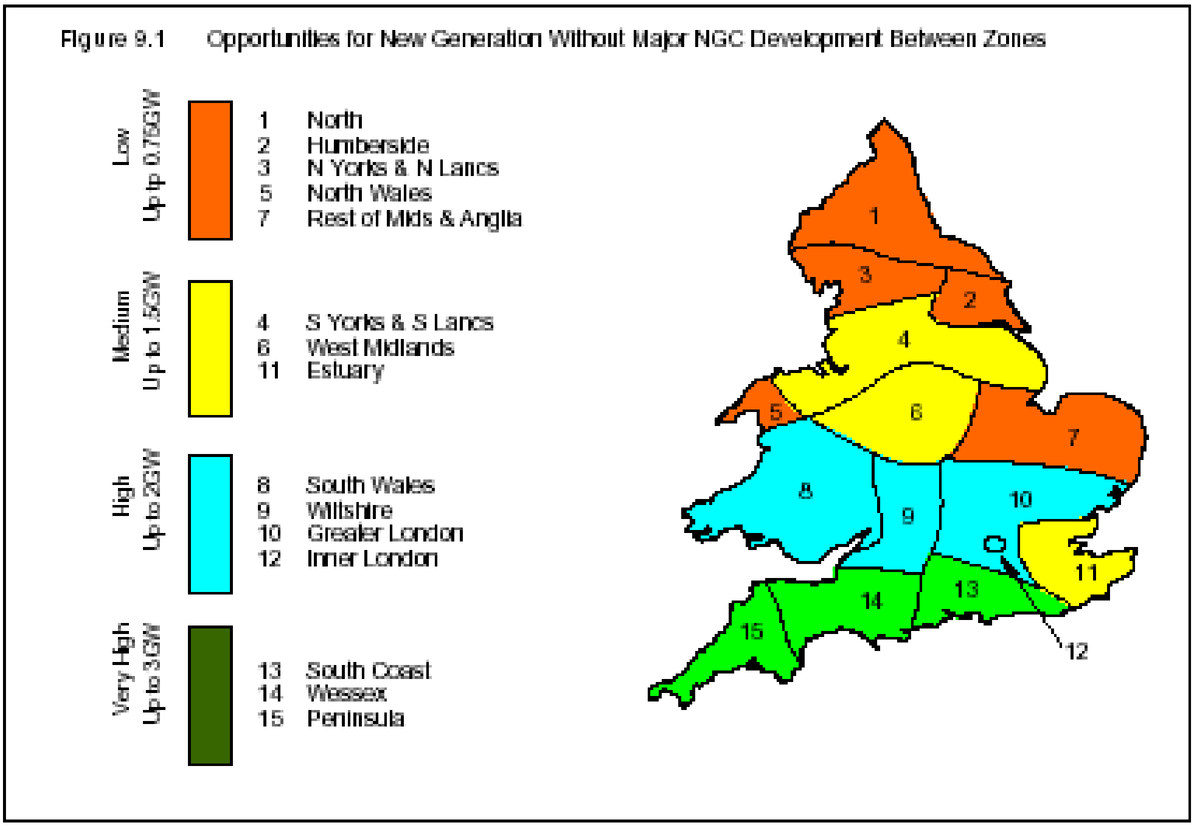



**Figure 6 – NGC 2001/02 SYS Generation "opportunity" figure.**

The figure presented above also indicates the levels of generation that can be accepted within individual zones without requiring major transmission reinforcements, essentially new overhead or underground circuits. The values indicated are similar to those identified in Section 6.2 but it should be noted that due to the disposition of the transmission lines, this connection capacity is available relatively close to the coast line in the peninsula, but essentially only at and to the east of Pembroke in South Wales, i.e. coastal connections north of Pembroke would require overland transmission. The approximate routing of existing 400 kV lines in this area can be gauged by reference to Figure 1.

Based upon capitalising NGC's stated charges for 2001/02[25] and identifying likely "source" and "receiving" zones, the associated specific transmission costs approximate to those presented in Table 1 below.

[25] Capitalised over 20 years at 8 % and using approximate mid-zone to mid-zone distances.

**Table 1**

| TUOS Tariff Zones | | £ /MW.km[26] |
|---|---|---|
| North | West Midland | 285 |
| North | Greater London | 252 |
| North- Wales | Greater London | 204 |
| South Wales | Greater London | -184 |
| Peninsula | Greater London | -314 |
| North- Wales | South Wales | 938 |

It should be noted that the TUOS charges upon which the above are based are based on the costs of accommodating a finite increment in generation. As such, in some instances the charge may increase if significant amounts of generation connected within a Tariff Zone, hence the negative reinforcement costs implied in the case of South Wales and the Peninsula (intended to attract generation in areas of generation shortage) may not be relevant if new capacity in excess of those indicated in Figure 6 were to connect. Nevertheless, the values given above do give a reasonable approximation to the level of reinforcement costs that would apply. It should be noted however that planning difficulties that could be associated with reinforcement, and may require under-grounding or the adoption of a higher cost reinforcement option, are not reflected in the above charges.

For comparative purposes and as a sanity check of the above values, it is worth noting that the estimated capital costs associated with the construction of a new 400 kV double circuit line approximate to about £ 150/MW.km, reflecting the basic line costs and some allowance for associated substation costs. This cost is therefore broadly comparable with the transmission reinforcements costs implicit in the differentials of NGC's TUOS charges for the North, West Midlands and Greater London.

As indicated above, planning difficulties are likely to introduce significant barriers to the construction of lengthy new overhead transmission lines. As a consequence new high voltage underground cable transmission may be necessary if additional transmission capacity is to be provided. On land, underground dc transmission will be significantly more expensive than at sea, as the economies of scale associated with laying long lengths of cable at sea will not apply. At sea it is possible to lay in excess of 100 km of hvdc cable at a time in comparison with maximum drum lengths of about 1 km which apply to similar cables on land. This, coupled with the attendant costs of jointing and excavation, as well as negotiating diversions along the route, will significantly increase hvdc cable circuit costs and hence the specific transmission cost of hvdc.

[26] The £/MW.km are based upon capitalising the differential in TUOS charge (per MW) between TUOS zones and dividing by the approximate distances between zone centres.

Historically, although associated with the attendant problems of managing significant capacitive charging currents, ac underground cable transmission has tended to be the preferred to hvdc for onshore underground development, as the overall circuit lengths can generally be minimised to make use of any capacity in the existing ac infrastructure, and converter costs can also be avoided. However, in situations where the converter costs are already essentially sunk, e.g. in the case of a 2000 MW long distance submarine cable link, then hvdc underground cable transmission is likely to be of comparable, or somewhat lower cost than the ac equivalent.

The estimated specific transmission cost of a 400 kV cable circuit of similar rating to existing 400 kV overhead lines will correspond to about £ 2,500/MW.km, assuming a circuit length of about 50 km[27] and a circuit rating of about 2000 MW. The cost for an equivalent hvdc circuit would be comparable, noting however that the circuit route length restrictions between compensation/switching locations would not apply and savings of about 5 % may be attributable to the avoidance of the reactive compensation costs associated with the ac alternative. These costs may be compared with the TUOS based costs referenced above, i.e. positive charges of between about £ 100/MW.km and £ 1000/MW.km, dependent upon the tariff zones selected, and a reinforcement cost associated with the unobstructed construction of a 400 kV overhead line circuit, typically about £ 150/MW.km.

## 7.6 Comparison of offshore and onshore transmission

Based upon the figures presented in Sections 7.4 and 7.5 it is possible to compare the indicative costs of offshore and onshore reinforcement. In the majority of cases, overhead line based onshore transmission reinforcement is clearly less expensive than the offshore, submarine cable based alternative, as would be expected, although in the case of transmission between say Wylfa (in Anglesey) and Pembroke (in South Wales) comparison of costs based upon NGC's TUOS tariffs and submarine cable costs, based upon extending a 500 km link by a further 100 km to take it from the vicinity of Wylfa to Pembroke, does indicate in favour of the submarine cable alternative.

However, in cases where transmission reinforcement by the use of overhead lines would not be possible or extremely expensive due to planning or geographic/terrain issues, the use of submarine cable links as opposed to onshore underground cables would become attractive. This is clearly the case for higher power, longer distance transmission where the specific costs of submarine transmission at between £ 827/MW.km and £ 1527/MW.km may be compared with equivalent onshore, underground cable costs of about £ 2,500/MW.km.

In addition to the above, attention is drawn to the possible attractiveness of continuing an offshore hvdc link overland towards the major load centres in cases where the required onshore grid reinforcements would only be achievable by the use of underground cable circuits.

---

[27] Taken as a practical limit between reactive compensation and switching locations, the costs of which are included in the specific cost.

# 8. DEVELOPMENT PROGRAMME

The expected development programmes for a 2000 MW “grid” with HVDC interconnection distances of 200 km and 700 km are presented in Figure 6.

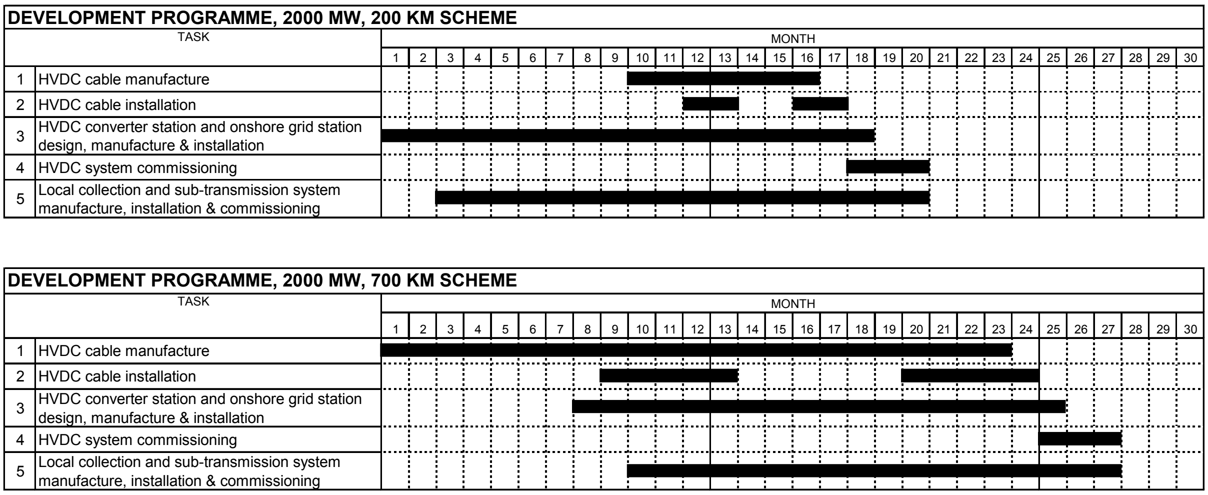



**Figure 6 - Outline development programmes for a 2000 MW “grid”**

The overall development time associated with a scheme based around a 200 km HVDC link is estimated at 20 months and is dominated by the 18 month period estimated for the design, manufacture and installation of the HVDC converter equipment and onshore station. For the scheme with a 700 km HVDC link the overall development time is increased to around 27 months of which 23 months would be required to manufacture the HVDC submarine cable.

For a bipolar HVDC link a pair of cables are needed. Hence for both of the above schemes the total length of HVDC submarine cable would be two times the route length.

Our estimation has assumed that the HVDC submarine cable could be manufactured at a rate of approximately 2 km/day. It is possible that this rate could be increased by making use of more than one cable manufacturer. The laying rate for the cable has been assumed to be 5 km/day for a single laying vessel. Bad weather months have been taken into consideration by assuming that laying operations may only take place for 6 months in any year.

Installation of the HVDC submarine cable would have to be performed using a specialised “turntable” type laying vessel of which there are only two in the world at present. Clearly realisation of the development programmes shown in Figure 6 would require sufficient forward planning to ensure these specialised resources are available.

The time taken to manufacture and install the 11 kV local collection and 90 kV sub-transmission infrastructure is estimated to be 18 months and is the same for both schemes. This reflects the more diverse range of ac cable manufacturer and the need for much less specialised and therefore more readily available laying vessels.

Voltage source converter stations are of modular design with a large number of standardised components and high degree of factory testing, thereby shortening the time periods associated with design and manufacture when compared to conventional converter equipment. The relatively small foot-print and reduced requirement for buildings and civil works also contribute to short implementation times which may be as short as 12 months.

It is important to note that we have not considered the development time associated with the renewable generation, but note that for 800 x 2.5 MW offshore wind units (ie 2000 MW) this is likely to be significant.

## 9. FURTHER WORK

We have identified a number of areas that require more detailed examination in order to take the study forward. These are presented below:

1. Further investigation of the role of major hvdc schemes needs to be considered within the context of a more detailed overall system study in conjunction with National Grid and other UK transmission system operators. This should include an assessment of the likely location and capacity of conventional existing under the increased renewable generation scenario, identification of fossil fuelled generation that would be displaced by wind powered generation and the impact of such displacements on onshore power flows and the operating costs of such displaced generation.

2. A more detailed examination of renewable generation power output variations with time, covering the likely range of short, medium and long term changes in power output due to wind speed variations, and taking into account the effects of wide geographic diversity between wind farm locations.

3. Identification of sites suitable for developing the required capacity of renewable generation coupled with outline consideration of submarine cable routes and issues such as cable burial/protection and landfall issues.

4. Identification of suitable locations for offshore and onshore hvdc converters and connecting substations.

5. The use of multi-terminal and hybrid converter technology in which voltage source converters, developed to handle high power levels and operating at up to 500 kV, act as an interface with the renewables source and work in tandem with conventional thyristor based converters at the main grid interface points.

6. Determination of available manufacturing and installation capacity with respect to major hvdc submarine cable projects and identification of any potential shortfalls in such capacity.

7. Further refinement of offshore and onshore transmission and network reinforcement costs.

## 10. CONCLUSIONS

The main conclusions of the study are as follows:

1. It is estimated that the connection of between 6-8 GW of renewable generation will be required to meet the existing Government renewable target. In the event of a 20% target being adopted for, say, 2020 – possibly moving on to a 60% target for 2050 as suggested by the RCEP, some 20 and 45 GW respectively of additional renewable capacity could be required.

2. Recent renewable resource studies, notably that commissioned by the Scottish Executive, suggest that sufficient commercially exploitable renewable resource exists in the North and West of the UK to meet these targets. The problem of connecting this capacity onto the electricity networks can be considered in three parts; the gathering together and then connection of the resource locally, and the subsequent transmission of the associated power flows to load centres elsewhere within the UK.

3. Initial work undertaken by NGC relating to the variability of wind power generation output indicates that this should not present major operational problems. However, with present renewable technology a significant proportion of the connected system generation will need to be conventional in nature, i.e large synchronous generators, and constraints may need to be imposed on renewable generation at times of lower system demand. In addition, in order to allow system demand to be met at times when the wind resource is not available a significant proportion of, presumably fossil fuelled conventional generation will need to be available in reserve.

4. In terms of resource gathering whether onshore or offshore, ac, rather than dc, connection is likely to be most cost-effective. Subsequent connection of these resources locally will be constrained by the capability of the local networks, particularly in the north with ac connection likely to be the most cost effective for small local groupings but with hvdc connection being more appropriate for larger more distant groupings, particularly when feeding into weak parts of the existing onshore grid. If significant amounts of generation are to connect around the periphery of the system, particularly in the North, reinforcement of the local onshore networks will also be necessary

5. Existing transmission system capability in the North of the UK largely reflects historic and predicted power flows and therefore, if significant amounts of renewable generation is to be superimposed on the existing system power flows, reinforcement will be required unless equivalent existing generation in the area is displaced. The same is not true of the transmission network below the principal Midlands to South constraint, particularly so in the South West and South Wales, where significant

capacity exists (3 – 6 GW) to accommodate additional generation or imports from elsewhere in the UK connecting at these locations.

6. However, as the connection of renewable generation is intended to displace a significant proportion of existing, fossil fuelled generation, then dependent upon the location of such displaced generation, the practical capability of the existing main 400 kV onshore grid may become significant. Under a favourable generation displacement scenario, up to about 4 GW of renewables generation could connect within Scotland, and a further 10 GW in England, north of the Midlands to South Constraint, essentially a line drawn roughly between The Wash and Cardigan Bay.

7. Regardless of the above, at some time in the future extensive reinforcement of the onshore grid may become necessary. Historically such reinforcements would have been largely based upon the construction of new additional overhead lines. However, this is likely to raise major planning and environmental issues which could be largely avoided by the use of hvdc links. HVDC links based upon submarine or underground cables could be used to bypass the congested transmission systems in the North and allow power to be injected into the existing transmission system at points where sufficient capacity exists.

8. The particular hvdc technology to be employed will be influenced by the point of interface with the existing networks. Connection to a relatively weak network, possibly at 132kV, could limit the transferable power to a few hundred MW and would require the use of voltage source hvdc converter technology. Connection to a stronger part of the network, say at 400kV, might allow blocks up to 2000MW to be connected using conventional hvdc technology.

9. Whereas the concept of using offshore hvdc links to transfer renewable energy from the North and West to elsewhere in the UK is feasible and likely to be economically justified at some point, the concept of a meshed hvdc "grid" designed to harvest and transmit renewable energy from a widespread area, would be difficult to justify due to the economies of scale which would tend to favour the use of hvdc for "point to point" transmission. For comparison purposes the estimated total capital cost of a 2000 MW scheme based upon "point to point" transmission would range between about £ 790 M (200 km) and £ 1,700 M (700 km), whilst an hvdc "grid" concept scheme would be expected to have equivalent capital costs of between £ 1,700 M and £ 2,300 M.

10. The need for transmission network developments to accommodate additional transfers due to the connection of renewable generation in the North is likely to be a staged process, initially involving some reinforcement of the existing system but ultimately requiring radical measures such as the development of offshore hvdc links.

11. The capital costs of renewable generation gathering, connection and associated transmission costs have been estimated for a number of scenarios. In the main it is possible to estimate such costs on a modular basis and a summary of these costs are presented below.

| Costing module | Rating | Range of costs | Technology |
|---|---|---|---|
| Local gathering/ collection costs | 100 MW | £ 6 M (compact farms) to £ 13 M (more dispersed farms) | 11 kV ac submarine cables |
| Sub-transmission costs | 100 MW | £ 2 M (close groupings) to £ 12 m (dispersed groupings) | 90 kV ac submarine cables |
| Transmission cost – lower power/ shorter distance | 100 MW, 50 km<br>500 MW, 200 km | £ 46 M<br>£204 M | HVDC submarine cable, vsc[28] technology |
| Transmission cost – higher power/ longer distance | 2000 MW, 200 km<br>2000 MW, 700 km | £ 611 M<br>£ 1,161 M | HVDC submarine cable, hybrid technology[29] |
| Total gathering/collection and transmission cost | 100 MW, 50 km<br>500 MW, 200 km<br>2000 MW, 200 km<br>2000 MW, 700 km | £ 55 M<br>£ 340 M<br>£ 790 M<br>£ 1,700 M | As detailed above |

12. It can be seen from the above that the costs of transmitting power over long distances is considerable and in extreme cases will approach the cost of developing the resource. Therefore, in order to minimise transmission, and hence overall costs to end users, when practical it will be appropriate to develop renewable resources in areas where their connection can be accommodated within the existing onshore grid, with the more distant resources and associated transmission being developed when "local" resources and the capability of the existing onshore grid are fully utilised.

13. For comparison purposes, the specific costs of offshore and onshore transmission reinforcement have been estimated, based on the transmission modules referenced above and also for alternative overhead and underground transmission reinforcements onshore. These specific costs are expressed as £ /MW.km, i.e. the costs of transmitting 1 MW over a distance of 1 km, although the costs presented below obviously reflect the economies of scale associated with the power transmission levels quoted.

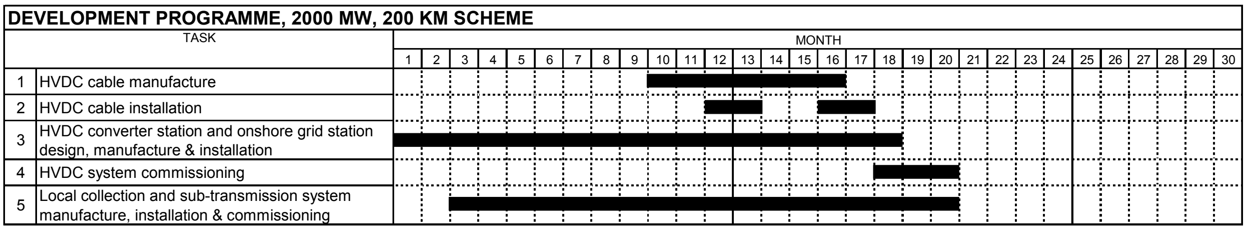
[28] Vsc – Voltage Source Converters utilising Insulated gate Bipolar Transistors (IGBT's)
[29] A combination of vsc technology at the resource interface and convention, thyristor based technology at the main grid interface.

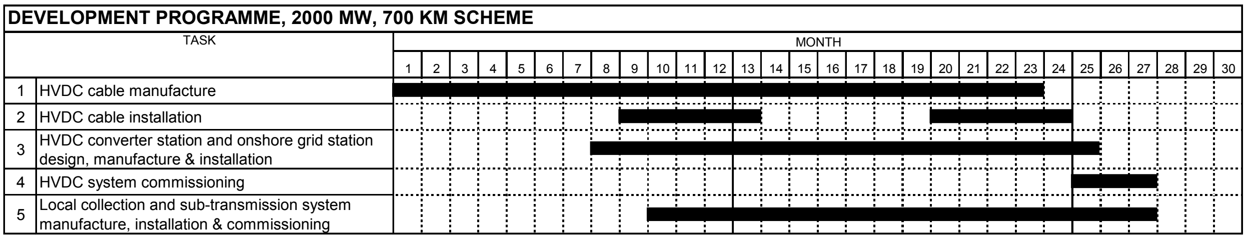
| Transmission mode | Module | Cost (£ /MW.km) | Location |
|---|---|---|---|
| HVDC vsc technology | 100 MW, 50 km<br>500 MW, 200 km | 9,200<br>2,040 | Offshore |
| HVDC hybrid technology | 2000 MW, 200 km<br>2000 MW, 700 km | 1,527<br>829 | Offshore |
| Enhancements of existing onshore grid | Within capability of existing network | 0 (or negative[30]) to 200-300 | Onshore |
| 400 kV ac overhead line | 3000 – 6000 MW, circa 100 km | 150 | Onshore |
| 400 kV underground cable | 3000 MW, circa 50 km | 2,500 | Onshore |
| +/- 500 kV hvdc underground cable | 2000 MW, incremental cost per km | 2,400 | Onshore |

14. It can be seen from the above table that specific transmission costs are significantly influenced by power transmission levels and distances and also, as expected, the use of overhead lines is significantly less expensive than submarine or underground cable alternatives and hence should be used when practical and acceptable. However, in cases where additional overhead lines are unlikely to be practical or accepted, offshore submarine cable based schemes will provide a lower cost reinforcement than equivalent onshore ac or hvdc schemes. Furthermore, for onshore reinforcements associated with the connection of major tranches of offshore renewables, where converter costs will be essentially "sunk", serious consideration should be given to extending the hvdc link further towards the main load centres as an alternative to the use of ac underground cable based alternatives.

15. The timescales associated with the implementation of transmission schemes will be determined by planning and consents, and also by manufacturing and construction/installation timescales. In the case of planning and consents, as evidenced by the protracted delays associated with the "2nd Yorkshire Line" transmission reinforcements associated with major new overhead lines are likely to be significant and also unpredictable. In the case of submarine and underground cable based transmission obtaining the necessary approvals should be more straightforward and a period of about 12 months is considered appropriate. During this time the necessary sea-bed or cable routing surveys can also be undertaken to allow for finalisation of the detailed cable routings and construction issues. Thereafter the timetable will be dominated by manufacturing and installation processes and indicative programmes are presented below for 2000 MW links of differing lengths.

[30] Negative costs, i.e overall cost savings are implicit in NGC Transmission Use of System charges for generation connection in South Wales and the Cornish Peninsula.




It should be noted that these programmes assume access to the necessary cable making factory capacity and also cable laying vessel capacity that can often be a barrier to the rapid implementation of such schemes and needs to be addressed at the same time as planning and consents.

Voltage source converter stations are of modular design with a large number of standardised components and high degree of factory testing, thereby shortening the time periods associated with design and manufacture when compared to conventional converter equipment. The relatively small foot-print and reduced requirement for buildings and civil works also contribute to short implementation times which may be as short as 12 months.

It is important to note that in the above, we have not considered the manufacturing and installation times associated with the renewable generation, but note that for 800 x 2.5 MW offshore wind units (ie 2000 MW) this is likely to be significant.