Mr Jonathan Dennis
Solihull, United Kingdom

15th September 2009

Mr Simon Bartlett
Chairperson, E S Cornwall Scholarship Advisory Committee

Dear Mr Bartlett,

**Re: E S Cornwall Memorial Scholar – Jonathan Dennis**
**Second Quarterly Report**

Please find enclosed my first quarterly report for the E S Cornwall Memorial Scholarship for 2008-2010, which is a requirement set out in the scholarship rules.

My second quarter on the ES Cornwall Scholarship has provided valuable insight into:

- the design of offshore transmission networks and generation arrays,
- the market arrangements which exist in Great Britain, and
- the impact of significant embedded renewable generation in sub-transmission networks.

During this period I am grateful to have been able to attend the Cigre B4 Colloquium on recent advances and future applications of HVDC technology. My impressions from this conference are documented in a separate enclosed report.

I would welcome the committee's feedback on these reports and my aspirations for the next quarter.

Yours faithfully,

Jonathan Dennis

Enclosures:

- E S Cornwall 2008-2010 Quarterly Report 2
- Cigre B4 Colloquium Report

**ES Cornwall Scholarship 2008-2010**
**Jonathan Dennis**

# Second Quarterly Report

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## *Introduction*

My tenure of the E S Cornwall Memorial Scholarship commenced in January 2009 and continues until June 2010. My program is aimed at gaining experience in the measures being applied internationally by transmission companies to manage three main deficiencies of large centralised renewable generation, being:

- variability of renewable power generation over time,
- low inertia, poor fault ride through capability, and
- remote location necessitating long distance radial connections.

My overwhelming impression to date is that the obstacles to the increased use of renewable generation are multi-faceted. Indeed, the technical obstacles often seem insignificant when compared to the political, regulatory, and commercial difficulties. I have therefore sought to investigate and report on all of the transmission related obstacles to renewable generation.

This is the second of six quarterly reports required by the scholarship guidelines. It covers the period from mid April to the end of July, the second half of my tenure with Senergy Econnect in their Power Systems Analysis team. Senergy Econnect is a consulting firm that specialises in resolving issues related to the electrical connection of renewable generation. Please refer to my first quarterly report for background information about the company and the work that they perform.

Significant projects I was involved with during this period included:

- the completion of a high level design and cost estimate of the offshore arrays and transmission connection for a very large wave and tidal generation scheme,
- reviewing the exposure of a wind farm operator to balancing system charges; and
- investigating the connection options for a proposed renewable generator in a highly congested region of the grid.

This report documents what I have learned through these projects, and my impression of how these learnings may apply to the Australian situation.

This report should be read in conjunction with my Cigre B4 Colloquium report (attached), which explores the capabilities and future applications of HVDC technology. This technology will be key to facilitating the connection of remote renewable generation and enhancing the grid's controllability so that it can accommodate greater volumes of intermittent generation.

## *Offshore Network & Array Design*

A major piece of work I was involved with during this quarter was the high-level design and cost estimate of a high-voltage on and off-shore network, to connect multiple wave and tidal generation sites to the onshore main interconnected transmission system. At each site, medium voltage arrays were also designed to interconnect all of the turbines in each site. The work was in support of a developer's application to the Crown Estate for the development rights for certain areas of the seabed. As such, the details of the design are commercial-in-confidence. However, involvement in the work did offer a number of general learnings.

In the UK and more generally throughout Europe, there is a trend towards using cables for transmission projects in preference to overhead lines. This is due to a number of reasons:

- aesthetically, buried cables are less offensive than overhead lines,
- new infrastructure is required at a rapid rate and the delays associated with consenting overhead lines cannot be accommodated,
- there is need for much greater interconnection between regions, and the topography of northern Europe means that new links must cross seas; and
- there is an increasing trend towards offshore windfarms and tidal generation, due to:
    - suitable onshore locations for windfarms becoming exhausted,
    - the uncertainty and delays associated with consenting onshore windfarms (local governments have no incentive to permit windfarm development in their locale and often face public opposition)
    - offshore, wind is generally stronger, more linear and less variable
    - it is possible to install much taller towers offshore than would be allowed onshore, granting access to even better quality wind.

The cost of manufacturing offshore cables is greater than manufacturing onshore cables, but this can be more than offset by the ability to transport large volumes of offshore cable by ship, reducing the number of cable joints required. However, repairing cable failures offshore can be more complicated, expensive and time-consuming.

When selecting subsea cable routes, regard has to be given to:

- seabed condition (grain of sediment, drifting sand-dunes),
- surface activity (shipping can drag anchors and make installation & repair more difficult, some fishing techniques involve dredging the sea-floor),
- other cables and pipelines on the seabed,
- seabed topography,
- tidal currents,
- water depth,
- suitable landing sites; and
- environmentally sensitive areas.

Given the very high capital and repair cost of cables, cable protection options must also be carefully considered. Where possible, it is usually preferable to bury the cable and then place rocks on top. Cables can be specified with multiple layers of armouring, which can also help to protect the cable from damage during installation. In particularly vulnerable sections, such as when laying cables on bedrock or where cables come ashore, cast iron jackets can be installed around the cable. Whilst cable protection usually reduces the prevalence of cable faults, it also increases the time required to repair the cable should it fail.

For large offshore generators it is common to use 11kV or 33kV rings to interconnect individual turbines to a centrally located platform substation. On the platform, gas insulated switchgear is then used to interconnect multiple rings to step-up transformer(s) and in turn to a high voltage cable(s) which take the power ashore.

Presently, each wind farm has its own connection(s) back to the shore and into the grid. However, the UK is in the process of establishing a regime whereby offshore transmission operators will develop offshore high voltage networks that will connect multiple offshore wind and tidal farms to the onshore network. The regulator Ofgem has invited private consortiums to bid for the development rights in different regions to ensure that private companies bear the financial risk associated with such high cost infrastructure.

To support this regime, a new expanded version of the Security and Quality of Supply Standard was released in June 2009 which defines the standards that will apply to offshore arrays and networks [1]. A detailed cost-benefit analysis was used when defining the standards

[1] *NETS Security and Quality of Supply Standard*, Issue 2 - 24 June 2009, Available at: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/

to take account of the much higher cost of offshore infrastructure and the fact that there are few demand connections [2]. The reliability level required offshore is less onerous than what is required onshore. For example, rather than requiring full redundancy, the SQSS requires that offshore connections with a capacity greater than 90MW loose a maximum of 50% of their capacity for a credible contingency.

Ofgem is concerned that the onshore and offshore networks are developed in a co-optimised manner. To assist this, it has recently placed a new licence requirement on National Grid to produce an annual offshore transmission statement that demonstrates the coordination of the onshore network developments with the various offshore networks.

Offshore networks may find application in Australia's south, to connect offshore windfarms once suitable coastal locations have been exhausted. However, offshore networks are far less likely in Queensland due to:

- vast areas of sparsely populated land onshore and sensitive underwater habitats offshore
- obtaining consent for new overhead lines does not seem to be as difficult as in Europe (although this may change in time)
- the potential for renewable generation in the waters off the Queensland coast does not appear to be as great as that in Europe (and Southern Australia)

However, in some senses offshore networks are analogous to development of generation further inland to access Australia's geothermal resource – as expensive new transmission infrastructure will be required predominantly for the connection of new generation to the main transmission system. Whilst cheaper overhead lines should be able to be used instead of underground cables, the circuit lengths required will be much longer, and so the cost of developing this infrastructure will be similarly expensive. Because of the long circuit lengths, HVDC technology is a strong candidate for inland networks as it is for offshore networks.

Given the similarities, some of the measures undertaken to facilitate offshore networks in the UK could be considered for Australia:

- Certainly it would be more effective to coordinate the development of an inland transmission network rather than constructing dedicated connections for each inland generator.
- There may be value in developing a different reliability criteria optimised for the higher cost of infrastructure and small number of loads inland. For instance, permitting a certain percentage of the transfer to be lost following a contingency (this could be achieved using intertrips to selected generators). For any small loads

[2] Centre for Sustainable Electricity and Distributed Generation, *Cost Benefit Methodology for Optimal Design of Offshore Transmission Systems, July 2008, Available at:* http://www.sedg.ac.uk/Publication/Cost%20Benefit%20Methodology%20for%20Optimal%20Design%20of%20Offshore%20Transmission%20Systems.pdf

connected to the network, it may be more economic to pay a capacity payment to keep any existing generation operable for use following a contingency instead of providing a redundant connection.
- To reduce risk to the tax-payer (in those regions where transmission network service providers (TNSPs) are owned by the government), there may be benefit in private developers constructing and operating such links.

However, the following issues would need to be carefully considered:
- Coordination between inland network developers and the 'coastal' TNSPs, to ensure that the development of an inland network is done in a co-optimised and efficient manner
- Energy security, as although little or no load may be supplied directly by the inland network(s), as more generation is connected to the National Electricity Market (NEM) via less reliable inland links, it could impact on the overall security of the NEM.

The success of the UK's offshore regime should be evaluated before implementing similar arrangements in Australia. I have noted some scepticism within the UK industry regarding whether the offshore network regime (with separate offshore transmission network operators) will achieve its stated aims.

## *Market & Transmission Access Arrangements*

Another task I was involved with during the past quarter was the preparation of a document for a new generator explaining their responsibilities and exposure to charges under Great Britain's market arrangements.

The electricity market arrangements presently in force in Britain are quite different to those in Australia. Retailers predict the demand of their customers and make arrangements with generators to supply this energy. Generators then self-dispatch themselves to a level needed to cover agreements they have made. Trading parties (generators and retailers) must notify the system operator of the level that they will self-dispatch to or their expected demand for each time slot. This notification can be adjusted up to one hour before real-time. In addition to notifying the self-dispatch or load level, trading parties can indicate if they are prepared to deviate from this level, and what they would charge to do so.

In real-time[3] the system operator can select from offers to adjust the generation and demand to manage the following:

[3] Live information about the balancing market is available at: www.bmreports.com

Further information about balancing and settling arrangements is available at: http://www.elexon.co.uk/Publications/InformationSheets/default.aspx

- demands not equalling what was predicted by retailers
- generators failing to generate at the level they had advised
- power system incidents disconnecting generation or loads
- constraints in the transmission system preventing generators from generating as self-dispatched

The cost of accepting offers to vary generation/demand levels is passed onto those trading parties responsible for causing the mismatch. As such, there is greater onus on retailers to predict the exact level of demand, as they could be penalised if the load varies either way. At different times of the day/year it may be better to err on one side than the other, and so trading parties may deliberately over/under-estimate their demand. In a similar manner, generators are penalised if they deviate from the generation levels they have advised. This forces renewable generators to put considerable effort into producing accurate generation forecasts. Even with such forecasts, many wind farm owners will contract the operation of their wind farms to large generation companies with diverse generation portfolios. To avoid paying imbalance penalties, these generation companies can adjust the output of their conventional generators to compensate for any variation in their wind farms' output.

In many ways, these arrangements are much closer to a 'true' free-flowing market, with deals struck directly between generators and retailers and only minimal intervention from the system operator to keep the system in balance and handle any limitations of the transmission system. These arrangements significantly reduce the level of uncertainty for generators because if the network is unable to accommodate the level that a generator has self-dispatched to, the system operator will have to accept the generator's offer to reduce its output and pay the generator accordingly. These arrangements make it very straightforward to quantify the cost of any congestion in the network. Presently constraint costs are passed back to the market through the charges that all trading parties pay to cover the operation of the balancing and settling system. Unfortunately, the balancing arrangements also make it possible for generators to exploit system constraints and 'game' the system.

Another disadvantage of the UK's present market arrangements is that they have slowed the rate at which new renewable generation has been able to connect to the network, with generators waiting on the transmission upgrades needed for them to generate without constraint. This has resulted in a queue of generators waiting for connections with a combined capability of over 60GW.

On August 25, 2009, the Department of Energy and Climate Change announced that the UK would immediately change to 'interim connect and manage' arrangements. These arrangements will permit generators to commence operation as soon as local grid-connection infrastructure has been constructed, and be eligible for payment if constrained offline. Consultations are currently active on the development of the enduring means by which the

constraint costs paid out to generators will be re-couped from the market [4]. The consultation is exploring three different options:

- Socialised: costs will be shared between all users of the network.
- Hybrid: some, but not all of the additional constraint costs will be targeted at new entrant power stations.
- Shared Cost and Commitment: new and existing power stations can choose to commit to the network in return for greater certainty over charges, or to opt out and be exposed to additional constraint costs.

My impression is that the level of constraint in the Australian NEM is much greater than in the British transmission system. I suspect that if the UK's market design were to be implemented in Australia, the level of gaming could be so significant that the market's overall effectiveness would be severely compromised. Given the high cost of transmission upgrades in Australia and that the ultimate purpose of an energy market is to drive down the costs to the consumer, it is unlikely that the network's capacity could be increased to the point where a free-flowing market is viable.

However, I can also appreciate the benefits to generators (and prospective generators) in having an understanding of how they could be affected by the transmission system in the future. Although the AER regulatory test does have a 'market benefit' limb, its application is complex and sensitive to individual generator developments, and therefore does not provide guidance to generators in general about the future level of constraint they could be exposed to.

In my previous report, I explained that Great Britain's Security and Quality of Supply Standard (SQSS) defines a procedure by which required minimum boundary transfer capabilities can be determined from the level of generation capability and the demand forecast in the regions either side of the boundary. I believe that there may be value in adopting a similar approach in Australia to flag how much the main transmission 'backbone' will need to be upgraded to maintain system security as the proportion of intermittent generation increases. However, such an approach would also provide greater transparency to generators and improve their understanding of how they could be affected by transmission constraints in the future. An improved understanding of risk could reduce the hurdle for new generation.

Practically, the role of defining the necessary boundary transfers would most naturally sit with the Australian Energy Market Operator's new planning function, in consultation with the TNSPs. However the TNSPs should then be given the flexibility to choose how they upgrade and operate their network's to comply with the minimum transfer levels. Boundary transfers

[4] UK Department of Energy & Climate Change, 25 Aug 2009 - Press Release - Miliband takes action on queue to connect new power generation to the grid. http://www.decc.gov.uk/en/content/cms/news/pn093/pn093.aspx

More information about the active consultation regarding access arrangements is available at: http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx

should be defined with the ultimate goal of minimising the cost of energy to consumers while maintaining system security and complying with greenhouse gas reduction targets. Boundary capabilities could either be defined in terms of the generation and demand either side of the boundary (as it is in Britain) or be based on a high-level analysis of the energy potential and cost of power generation in different regions, and the cost of upgrading transmission infrastructure to securely move the power to the load-centres. The later method could be projected forward several years to provide clear guidance about the future capabilities of the network to generators.

Different transfer levels could be defined for different periods of the year and/or day to account for differences in the level of demand. Alternatively, the required boundary capabilities could be determined in real-time based on the actual level of demand and volume of available generation either side of each boundary. TNSP performance penalties and incentives could be tied to the extent to which actual boundary capabilities met the required levels, rather than to transmission constraints (which TNSPs have limited control over), average circuit availability or the forced outage of certain components. This would give TNSPs more flexibility in how they operate their networks (e.g. if/when to take outages), while providing clear guidance to TNSPs and generators alike. Penalties paid by TNSPs for not meeting required capability levels could be distributed to affected generators to provide a basic level of compensation and offset some of their risk.

## *Embedded Generation Congestion in Sub-Transmission Networks*

My final project with Senergy Econnect was investigating the viability and merits of different connection options for a proposed renewable generator which was seeking to connect to a highly congested part of the network. Whilst I was already familiar with how to perform such studies, the level of embedded generation was much greater than what I have encountered previously. Studying the network therefore offered some insight into the type of issues that could be experienced more generally if the push towards renewable generation results in greater levels of embedded generation. Due to the commercial nature of the work, I can only discuss it in very general terms.

The network under analysis was a 132kV sub-transmission network supplied from the main transmission system by a single 400kV grid supply point (GSP). The peak winter demand supplied by the GSP was several hundred megawatts. A very significant gas-fired power station, several large windfarms, and many moderately sized generators of unknown fuel source were embedded within the network. At times of low demand, the combined magnitude of embedded generation could greatly exceed the demand, resulting in several hundred megawatts flowing back out of the GSP and into the main transmission system.

The 132kV sub-transmission network was somewhat meshed, and care therefore needed to be taken to ensure that circuits could not become overloaded following a contingency. The distribution of the demand and the generation were such that the post-contingency flows on the network were close to the network's maximum capabilities regardless of the level of demand (i.e. winter peak, summer minimum, or in between). Because the items of plant that were close to overloading changed as the demand level changed it was difficult to identify a single network augmentation that would work effectively across the range of demand levels. In the end, an intertripping scheme was proposed as the most inexpensive and straightforward means of connecting the generator while maintaining the security of the network. This scheme would make use of signals available at the connection substation to trip the generator following certain network contingencies to avoid any post-contingency overloading on the network.

Whilst this option was best for the client, I was conscious that it would likely make operating the network even more complicated for the distribution network operator (DNO). I am unsure what discretion DNOs in the UK have to decline technically competent connection requests. In order for the DNO to take outages in the network, it would already be necessary to constrain some of the generation offline. In this case, there were a number of large generators which could be contacted easily. However, had the generation consisted only of small and domestic generation, it could be much harder to organise sub-transmission outages.

## *Next Quarter*

During my third quarter on the E.S. Cornwall scholarship, I will be employed by National Grid Electricity Transmission in their system strategy team. This team was established a year and a half ago to investigate how England's transmission network will need to be progressively expanded to accommodate the renewable generation needed to meet the UK's 20 20 20 targets. The team contributed significantly to the Electricity Network Strategy Group's 'Our Transmission Network: A Vision for 2020' report published earlier this year (discussed in my first quarter report). Since publishing this report, Ofgem has provided additional funding for more detailed investigation and design work, and the size of the team is expanding accordingly.

In an effort to co-optimise the development of the onshore transmission network with the various offshore transmission networks, Ofgem are requiring National Grid Electricity Transmission to develop an 'Offshore Transmission Statement'. I have initially been allocated to assist in its preparation. This will involve identifying the on-shore transmission upgrades that will be needed to facilitate the connection of the offshore networks at different locations. The combined cost of the on and off-shore works can then be estimated to identify the least-cost overall design. Involvement in this work should highlight the additional complexities involved in planning a transmission network during a rapid transition to renewable generation.

Other members of the team are engaged in a variety of tasks including:

- a fundamental review of Great Britain's Security and Quality of Supply Standard
- evaluating the new transmission technologies which are being considered to improve the network's transfer capability and controllability
- researching the new control techniques that are expected to be needed to manage sudden changes in generation patterns

I hope and expect that working alongside my colleagues will afford some insight into their work.

I also hope to spend some time speaking with members of National Grid's System Technical Performance team to learn more about the dynamic behaviour of wind turbines and their impact on the dynamic performance of the transmission system. This team was heavily involved in defining the connection standards which apply to wind turbines in the UK.

## *Acknowledgements*

Once again, I would like to gratefully acknowledge the assistance of all of my Senergy Econnect colleagues. I would especially like to acknowledge the assistance of Simon Cowdroy and Patrick Smart, who took considerable time to patiently explain offshore network design issues and the operation of Britain's balancing and settling system to me.

**ES Cornwall Scholarship 2008-2010**
**Jonathan Dennis**

# Cigre B4 Colloquium Report

I am very grateful to have been able to attend the recent Cigre B4 Panel Colloquium, held in Bergen, Norway from June 10-12, 2009. The conference afforded an excellent insight into:

- the present capabilities of HVDC technology,
- recent utility experience with FACTS and HVDC installations,
- novel uses of power electronics to support the power system, and
- the anticipated future requirements of power electronic devices.

This report outlines my impressions from the conference (grouped topically), followed by my view of how the various issues may apply to the Australian situation.

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# HVDC Converter Technologies

There are two basic types of HVDC converters available today: Line Commutated Converters (LCC) and Voltage Source Converters (VSC).

## *Line Commutated Converters*

LCC is the 'traditional' and mature form of HVDC, with the first installation energised in 1950. Commercially it is often referred to as 'classical' or 'conventional' HVDC. It uses thyristor switches, which block the flow of current until they are closed ('fired') at a controllable point on the voltage waveform. Once fired, the thyristors remain closed until a zero crossing in the current waveform when they naturally commutate open. Large specialized reactors and other filtering are required at the AC terminals of a LCC converter to restore a sinusoidal waveform. LCC converters consume reactive power (approx 60% of the real power transferred, with limited ability to control this value) and therefore require shunt capacitor banks to be installed on the AC terminals, which are often integrated with the filters. The AC network's fault level at the converter must be maintained at a high enough level (typically 2.5 times the rating of the converter) for the thyristors to reliably commutate open at the end of each cycle. If the fault level drops below this, a commutation failure can occur, interrupting the transfer of power. In order for the direction of power flow to be reversed, the DC polarity must also be reversed. If cables are used, a time delay must be integrated into the polarity reversal during which the system is unable to transfer power. Both underground cables and overhead lines can be used, although the need to reverse voltage polarity prevents polymeric (e.g. XLPE) cables from being used. LCC converters have been used with voltages up to 800 kV and capacities up to 3000 MW.

## *Voltage Source Converters*

The recent development of high voltage and high capacity Insulated-Gate Bipolar Transistors (IGBTs) has enabled the use of VSC converters. Commercially, VSC converters are known as HVDC Light or HVDC Plus. IGBTs can be switched both on and off very rapidly, making additional designs and features possible. VSC converters can independently control the flow of active and reactive power. The direction of power flow is controlled by adjusting the voltage phase angle rather than the polarity, which permits continuous operation and makes the use of lighter and cheaper XLPE cables possible. The flow of reactive power is controlled by adjusting the voltage magnitude at each terminal. VSC converters do not require a high fault level to operate, enabling the connection of weaker nodes, reducing the likelihood of the power transfer being interrupted by commutation failures 'in sympathy' with other network contingencies, and allowing the link to be used for black start. Presently, VSC converters cost

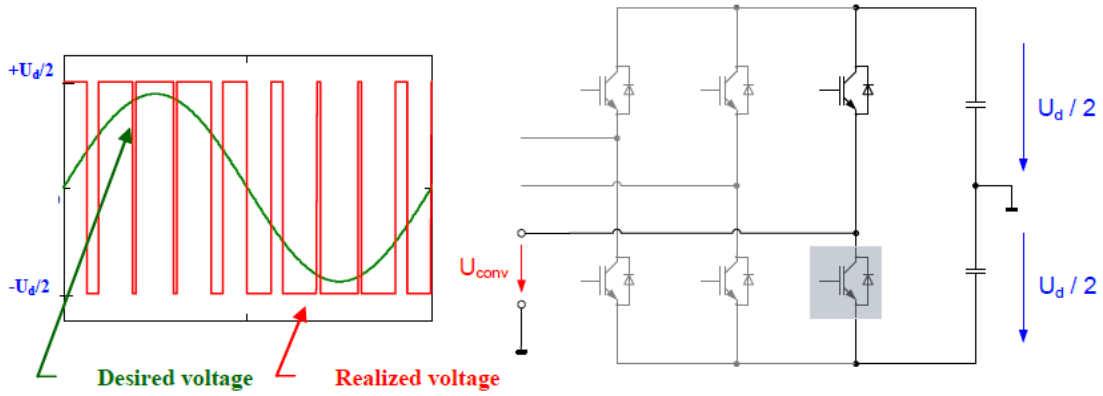
more, have higher losses and lower voltage (300kV) and power capabilities (500MW) than LCC converters. However, there is much ongoing research and development into the design of VSC converters and their design and capabilities change frequently. For instance, until recently, it was not possible to use VSC with overhead lines, but recent design changes now permit this.

There are two broad architectures of VSC converters: two-level and multi-level converters.

## Two-Level VSC Converters

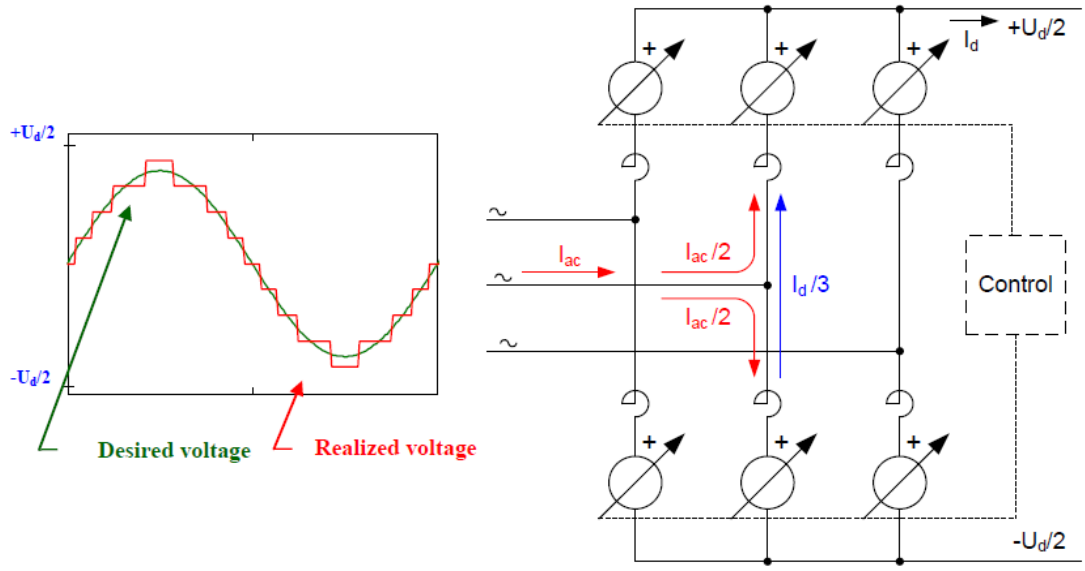
Two level converters were the first to be developed for VSC HVDC, and are still used in the ABB HVDC Light offering. These use a large central DC bus capacitor to maintain a steady DC bus voltage. Two switching units are used to adjust the AC voltage between plus and minus the DC bus voltage. Pulse width modulation is used to control the average magnitude of the AC voltage. A large specially designed AC reactor, star-delta converter transformer and shunt filters connected to each AC phase then act to filter out the high frequency components leaving a (mostly) sinusoidal waveform.

Large water-cooled air-cored reactors were observed at the ABB Light converter visited during the conference's technical tour.

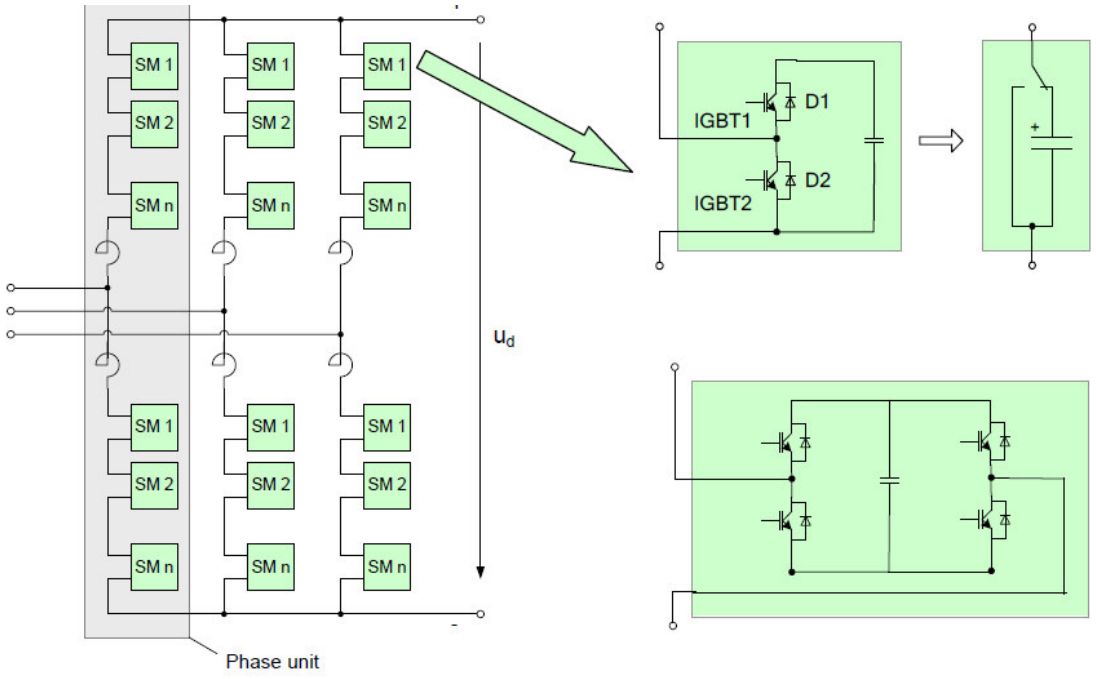



## Multilevel VSC Converters

Siemens have recently switched to using a multilevel VSC converter in their HVDC Plus offering, and Areva are in the process of developing their own multilevel VSC converter. Multilevel converters use a large number of DC capacitors, each of which can be switched such that the AC voltage is built up from small steps. The more levels that are used, the closer the voltage waveform will resemble a sinusoid.




The Siemens design is based around the use of standard submodules, each containing switching elements and a DC capacitor. A different number of submodules can be connected serially to meet design requirements of a particular job. Faulted submodules are automatically short circuited to allow the system to continue functioning, and would be entirely replaced. Reactors are installed on each converter branch to damp the flow of balancing current and minimize the magnitude of the current that would flow following a DC fault.




The main disadvantage of multilevel converters is that for the same DC voltage level, a multilevel design requires almost twice as many semiconductor switches (which require a larger footprint) and a much higher the level of DC capacitance than a two-level converter.

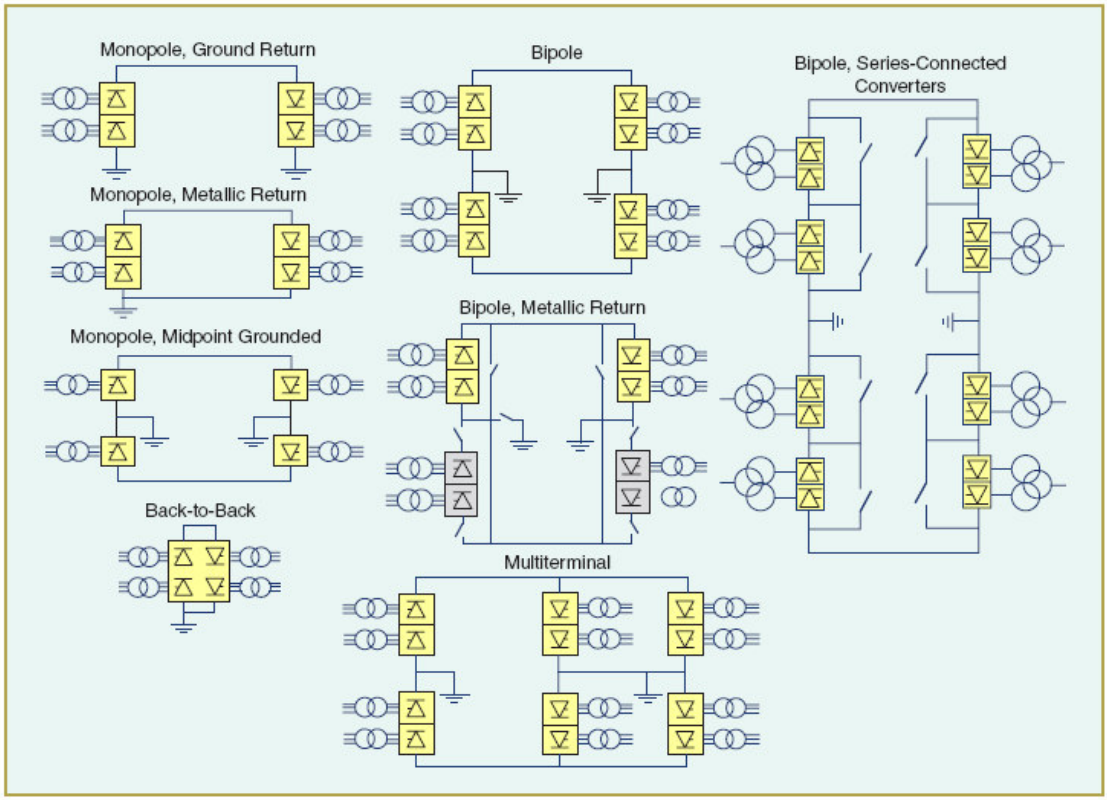
Advantages of multilevel architectures over two-level architectures are:

- Because the voltage waveform is naturally much closer to a sinusoid:
  - Smaller, standard AC reactors can be used
  - Less or no AC harmonic filtering is required (reducing the footprint of the AC switchyard)
  - Standard AC step-up transformers can be used
- Almost twice the power transfer capability
- The AC fault ride through capability is enhanced with a more stable DC bus voltage.
- Having individual capacitors on each switching element and different switching elements for each branch allows operation with continuous voltage phase imbalance, and improves the ride through of unbalanced AC network faults.
- Maintaining a constant voltage drop across each of the switches is more straightforward, and greater inaccuracy in switching times can be tolerated.

IGBT switches also have application in FACTS devices. Please see section 0 for details.

# HVDC Configurations

HVDC Systems can be configured in various ways, as illustrated in the figure below.



[5]

[5] IEEE Power & Energy Magazine March/April 2007 Vol. 5 No. 2

A single link is referred to as a 'monopole'. As with all electrical circuits, a return path must be provided for the current. When a monopole is used, this return path can either take the form of a parallel metallic conductor or of earth electrodes at each terminal to pass the current through the ground or water. The recently constructed NorNed HVDC link between Norway and the Netherlands (580km, 700MW, +/- 450kW, LCC) was originally proposed as a monopole scheme with sea-electrodes for the return path. However, public concern about EMF, the electrolysis effect it may have on nearby marine infrastructure, the formation of (small quantities of) toxic gases at the electrodes, and the effect that altered magnetic fields may have on navigation of both humans and animals at sea, forced the use of a bipole scheme. Sea electrodes were still installed as a backup for temporary use should one of the conductors fail.

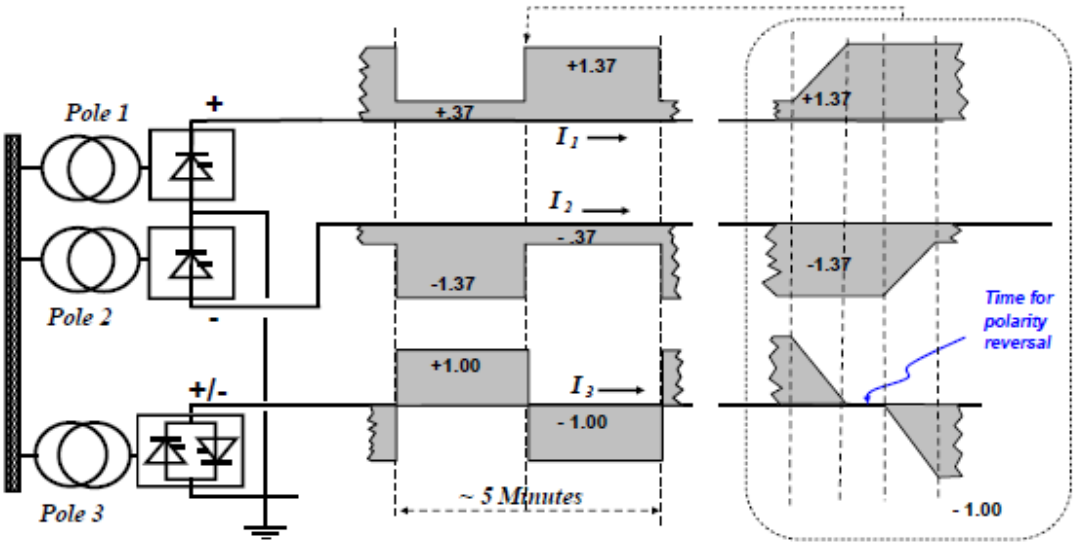
Two converters are often coupled together to form a bipole. By energizing the return current at the opposite voltage (i.e. same voltage magnitude but in the negative direction), it is possible to transfer power in the forwards direction. This enables twice the amount of power to be transferred for the same amount of conductor, although it does mean that both conductors must be insulated. Earth electrodes are used to provide an earth reference, to carry any unbalance current, and to carry the return current should one of the conductors fail.

The recently constructed NorNed HVDC interconnector uses a 'simplified bipole' design, which uses only one set of transformers and has the same number of thyristors as a monopole, but they are distributed in six thyristor columns.

The recently approved Storebælt HVDC link will interconnect the two asynchronous regions in Denmark (600 MW, 400 kV, LCC). It will initially be constructed as a monopolar system but will use an insulated metallic return cable to enable the system to be expanded to a bipole system at a later date.

The use of multi-terminal HVDC schemes is theoretically possible when using VSC HVDC, although this is not yet available commercially. Significant research and development is being invested and many multi-terminal schemes are already proposed (including the UK's 2020 Transmission Network proposal). Please see section 0 for more details regarding multi-terminal HVDC networks.

One of the conference presentations was for the conceptual design of a tri-pole HVDC system which could utilise an existing AC line to increase its capacity by up to 70%. The tripole consists of a VSC bipole paralleled by a LCC monopole; both configured and operated to exploit the thermal rating of all three phase positions without causing earth return current. This involves the short term alternate overloading and underloading of circuits, as shown in the diagram below.



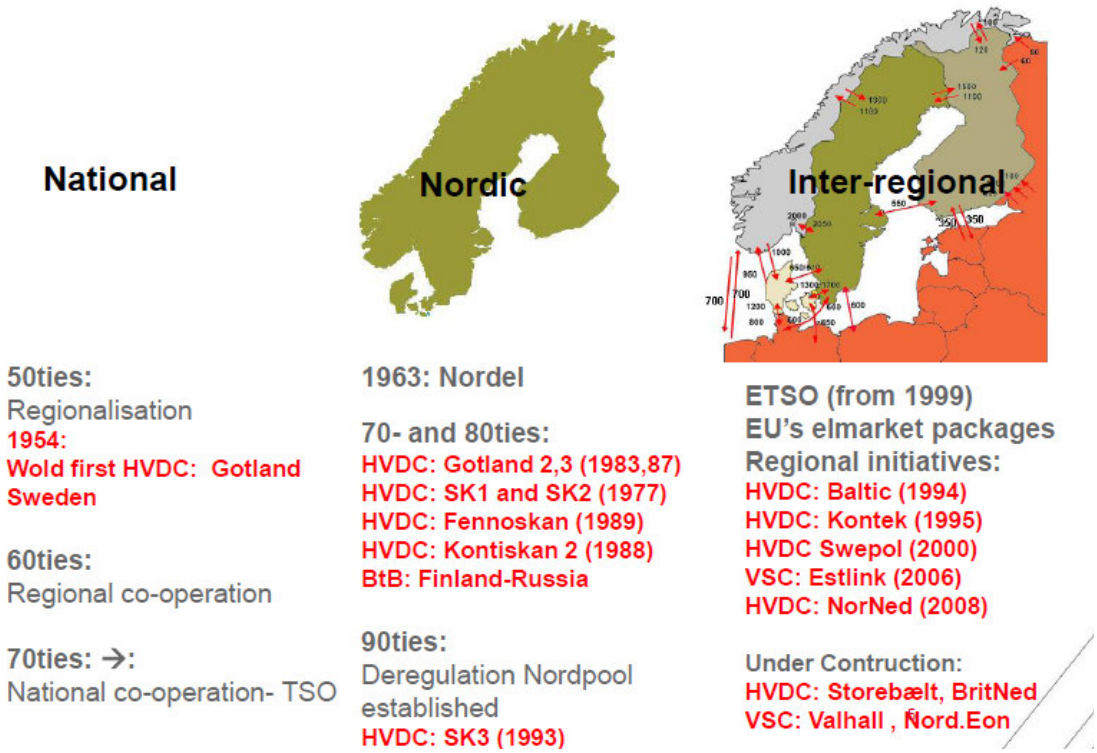

*Simplified schematic of tripole operation at maximum loading*

## Recent International Experience with HVDC

Classical HVDC technology is quite mature with many years of service experience from about 100 installations world wide, including overhead line and submarine cable schemes, and back to back schemes. Presently the total installed transfer capacity of LCC HVDC schemes in service is about 100 GW. LCC HVDC schemes with ratings up to 6400 MW, and voltages up to ±800 kV are either in service or under construction. In Australia, the 400kV 600MW Basslink interconnector and the 8.3kV 40MW Broken Hill back to back converter are based on classical HVDC.

The first commercial VSC HVDC scheme was commissioned in 1999. Presently there are seven schemes in service with a total rating of 894 MW. The largest is the ±150 kV, 350 MW Estlink scheme. A further five schemes with a combined capacity of 1678 MW are either under construction or are committed. These include voltages up to ±200 kV and capacities up to 500 MW. In Australia, both the 80kV 180MW Directlink and the 150kV 220MW Murraylink interconnectors are based on VSC HVDC.

Europe, particularly the Scandinavian countries have considerable experience with HVDC. The following slide outlines the various HVDC schemes which have been installed or are currently planed for the region.




The following sub-sections outline the benefits which have been gained and the difficulties which have been encountered (largely by the Scandinavian utilities) through using HVDC.

## *HVDC Benefits*

Some of the benefits of HVDC are well known:

- because a steady-state DC circuit has no shunt or series reactance, the losses in a DC circuit are considerably less than in an AC circuit, and long cable circuits without mid-point reactive compensation (necessary for subsea links) are made possible
- HVDC can be used to connect two asynchronous regions, and can stop the propagation of power fluctuations from one region to another

However, the controllability of HVDC has other benefits, described below.

### Controllable Power Transfer between Distant Nodes

An often overlooked benefit is the ability to control the magnitude and direction of power flow between two distant nodes, regardless of the voltage phase angle at each node. Several of the Transmission Network Operators (TNOs) at the conference cited this as a significant

operational benefit, stating that it improved overall network controllability, improved the sharing of power reserves across regions and generally improved the performance of the market by effectively broadening the market and increasing competition. The value of this feature is maximized when an HVDC link couples two regions with different generation and demand profiles. It is likely that the value of this feature will increase as the proportion of renewable generation increases.

The recently constructed Norned link, between Norway and the Netherlands highlights the value of this benefit. Norway's electricity is generated predominantly from hydro sources while the Netherlands is derived predominantly by fossil fuels. During 'wet' years, surplus hydro power will be exported from Norway to the Netherlands, displacing fossil fueled generators (and vice-versa). Transfer across the 700MW link has been such that the link has recouped almost one third of its €495M development cost in the first 9 months of its operation.

## Damping Low Frequency Power Oscillations in Parallel AC Network

It is well known that when HVDC is used to interconnect two regions, in can act as a firewall to power oscillations. However, the lower reliability of HVDC (compared to AC) often means that multiple HVDC links or a HVDC back-to-back installation which can be bypassed, is needed to provide an acceptable overall level of reliability. However, recent studies performed by the Chinese Southern Power Grid have shown that a HVDC link which is in parallel with an AC link can significantly damp low frequency power oscillations across the AC link. A supplementary control function uses AC network phasor measurements to monitor for any AC network power oscillations and adjust the power transferred by the HVDC link away from the set point value to counteract the oscillations. Therefore, as well as providing additional transfer capability itself, a HVDC link could lessen small system stability constraints on the AC network, releasing additional capacity.

## Coordination with AC System Protection

Power transfer across a HVDC link can be rapidly adjusted and could be programmed to respond to system contingencies to reduce their severity. For example, if a HVDC link was operating in parallel with an AC interconnector and the AC interconnector tripped, the HVDC link could very quickly increase its transfer (perhaps using its short term overload capability) to reduce the overloading of any parallel AC circuits and/or minimize any frequency deviations between two newly formed AC islands. This ability could release additional pre-contingent capacity in the AC network.

### Blackstart

Because VSC HVDC does not require any local reactive power or a certain fault level, it can be used to energise a dead bus. Provided one end of a VSC HVDC link is energized the link could be used to blackstart the AC network at the remote end. The power across the link could then be varied to maintain the nominal frequency, increasing the rate at which load and generation were brought back online.

The 150kV 350MW Estlink VSC HVDC link connects Finland and Estonia, and commenced operation in early 2007. In addition to voltage control, frequency control, reactive power control and damping control, the link also provides black start services to Estonia. The black start capability has been tested in practice and found to be a fast and reliable way of starting up a dead grid. Instead of starting with small units to power up bigger ones, the system can be restored in a matter of minutes from the Nordic power system (a different synchronous area). The link also helps to stabilize the system after the first units have been reconnected into the grid.

## *HVDC Downsides/Risks*

The main disadvantages presently associated with HVDC technology are:

- high converter losses
- poor converter reliability
- high capital cost

Recent utility experience in each of these areas is outlined below.

### Reliability

The failure rate of HVDC technology was cited by several of the TSOs present at the conference as a significant hurdle to its increased use. The failures tend to fall into two categories:

- comparatively frequent failures of the power converters or their control system, either causing no immediate forced outage or resolved within a day
- infrequent failure of the cables or transformers, leading to extended outages

Håkon Borgen, Executive Vice President of the Nordic TSO Statnett, summarised his company's recent experience by stating that "conventional HVDC technology has not delivered as required on quality in Scandinavia" in recent years. The NorNed HVDC link was installed towards the end of 2007. During commissioning the project encountered two subsea cable failures and a transformer failure. At least one of the cable failures is believed to have been due to a cable defect that was not detected during factory testing. Since commissioning

there has been one 14 day outage due to the failure of a land cable, and several short outages due to problems with the control system and its SCADA interface.

The NorNed experience was said to be representative of the other Nordic cable interconnectors. Notably, the SK3 interconnector also faced severe transformer outages last year. Based on this experience, Statnett representatives stressed the importance of investing in spare transformers and long lead time components for the cable and converters. Over the longer term, Statnett has experienced nine cable repairs since 1976 with the three Skagerrak cables. The 18 repair joints have all survived until now. Single core cables were used in the deep subsea sections of the NorNed link to make any cable failures faster and easier to repair. Double core cables were used in the shallow subsea sections to reduce EMF.

The contract for the converter stations of the new Storebælt Link in Denmark guarantees an uptime of at least 98.5%, with a forced outage rate (FOR) of less than five outages per year.

In 2005, the Nordic oil company StatoilHydro installed an ABB VSC HVDC link to their Troll A offshore platform to supply new variably frequency drives on the platform. StatOilHydro have been very happy with performance of the link, but helpfully provided a list of all of the faults encountered in the previous year:

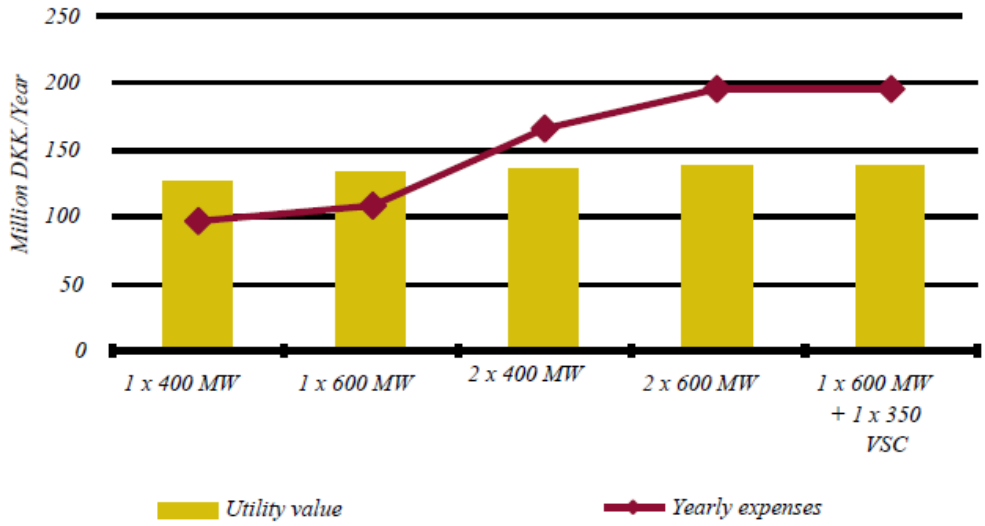
- Hard disc failure in the operator workstation computers at both ends of the link. The discs were changed under warranty.
- Weld leakage on a Swedewater cooling system pipe. Water leaked into the temperature transmitter for the cooling system which raised an alarm.
- 25 IGBTs failed and needed to be replaced. Often this was due to a loose fibre plug.
- Several control system printed circuit board failures. 8-10 cards were changed.
- Several software related failures, including:
    - Cases where the Operator Work Station has “locked” and required a hard reset.
    - Cases where the screen has “locked” (lilac icons on duty/stand-by systems) requiring the Intouch program to be reset.
    - Frozen alarm lists, necessitating a hard or soft reset.

StatoilHydro hastened to add that because of redundancy built into the system, most of these failures did not lead to a forced outage. Additionally, software upgrades were reducing the frequency of software failures.

## Capital Cost

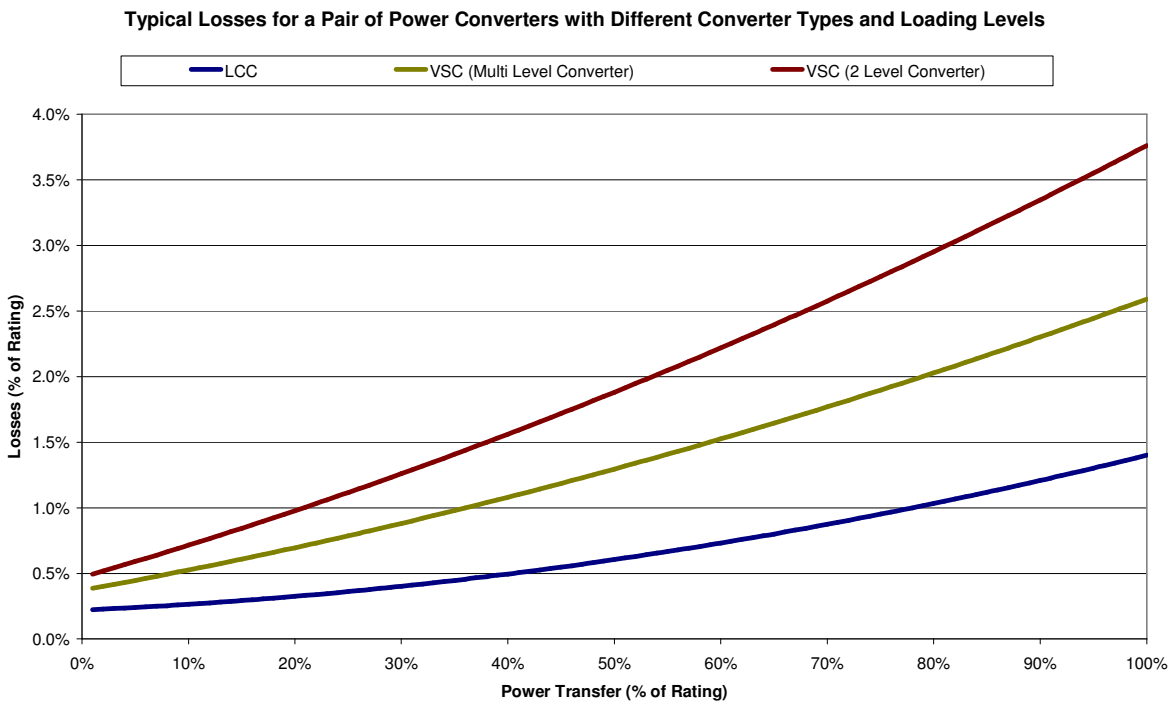
HVDC links can cost a very considerable amount of money. The development of the 700MW LCC 580km NorNed subsea interconnector cost €495 million. The cost was shared equally between Nordic TSO Statnett and Dutch TSO TenneT.

The cost of a HVDC link is highly dependent on different design options. Therefore, a thorough cost-benefit analysis is needed to consider utilization and the cost of construction, maintenance, repair, outages, and losses associated with different design options. The results of such a study for the Danish Storebælt Link are presented in the figure below. It can be seen that some design options are economically viable while others are not.




## Losses

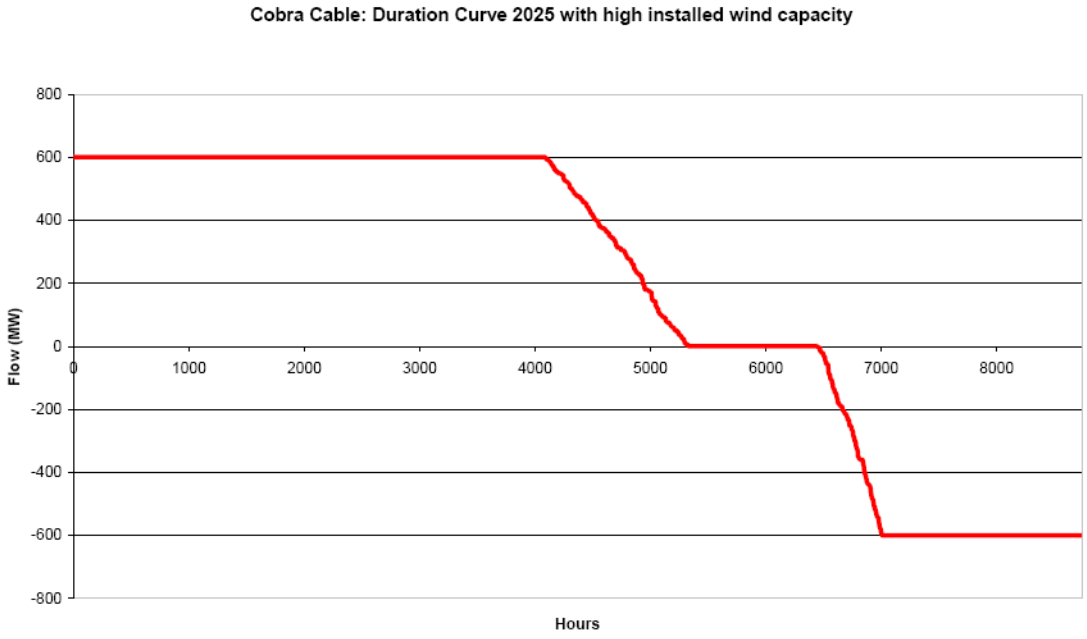
Transmission losses result from AC/DC conversion losses in the converters and from resistive losses in the DC conductors. Because a DC circuit is impeded only by the resistance of a conductor and not its reactance, the conductive losses are lower than AC transmission at the same voltage. However, the losses incurred in the conversion of electricity can be significant. Typical conversion losses are shown in the figure below.

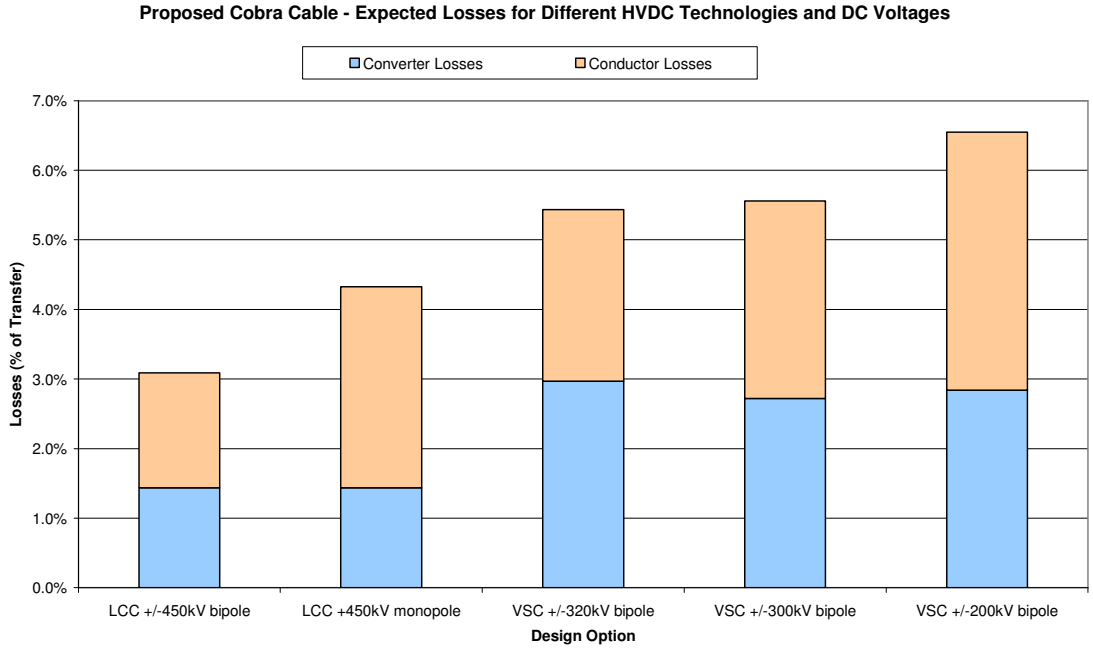



VSC converter losses are higher than for LCC HVDC primarily because the IGBT has a higher conduction loss than a thyristor, and a considerable power loss is incurred during turnoff of the IGBT. Recent development of VSC HVDC technology has a high focus on the reduction of the power loss. Multilevel VSC converters can be seen to have significantly lower losses than two level VSC converters.
The actual losses will depend on the configuration of the link, the type of the converter, and the DC voltage chosen.

The recently constructed NorNed interconnector (LCC, simplified bipole, +/- 450kV, 580km, 700MW) achieves losses of 4.2 % at full power transfer, which is very low for a 580km link.

Detailed loss studies have recently been conducted for the proposed 'Cobra Cable' subsea interconnector between Denmark and the Netherlands. With an expected transfer duration curve as shown in the figure below, the level of losses were calculated for different converter types and DC voltages.




Given that VSC converter technology is changing rapidly, loss estimates may need to be recalculated during the planning process.

## *Planning Issues*

### MultiInfeed Considerations

A LCC power converter is dependent upon a sufficiently 'strong' AC system voltage present at its terminals for the thyristors to commutate at the end of each cycle. If the fault level were to become too low, commutation failure could occur and the transfer of power across the HVDC link could be interrupted. Where there are multiple LCC HVDC systems in a region, care must be taken to ensure that the fault level will remain high enough following the loss of any one of the links to prevent the cascading failure of the remaining HVDC links.

### Subsynchronous Damping

HVDC converters have been known to reduce the damping of subsynchronous torsional modes of nearby generator units. Whether this has the potential to lead to inadequately damped oscillations should be studied, and if necessary, subsynchronous oscillation (SSO) countermeasures should be used. SSO countermeasures can take the form of subsynchronous damping controllers (SSDC) incorporated into the HVDC link's control scheme, and/or relays to trip the HVDC link should SSO exceed an acceptable level. It may be possible to develop a controller or relay that utilizes only local signals, although a recent study conducted for the Fenno-Skan HVDC link in Finland found it was necessary to draw on signals from a torsional monitoring scheme to work effectively. The torsional monitoring scheme in turn draws on measurements from around the network. Because field testing to verify study findings is not possible, disturbance recording should be incorporated into any torsional monitoring scheme to capture any incidents and help refine the models and improve the effectiveness of SSO countermeasures. It may be necessary to reassess the effectiveness of SSO countermeasures following the connection of new generators or changes to the network.

## *Project Delivery*

NorNed was put into commercial operation on 6 May 2008 after several years of planning and three years of intensive detailed engineering and construction work. NorNed's implementation has been based on seven major independent contracts (one converter contract, one civil construction contract in the Netherlands, two in Norway, two cable supply contracts and one cable installation contract). TenneT and Statnett have taken the resulting interface risk. The contractors have been co-insured under TenneT's and Statnett's construction all risk insurance specially arranged for NorNed. With the experienced mishaps (2 cable failures and a transformer failure) and challenges it is quite obvious that a contract arrangement more towards a turnkey structure would easily have created more delay caused by risk aversion. The split in two cable contracts was mainly caused by a maximum 3 year implementation requirement (cash flow). This has added to the interface complexity to a degree.

Separating responsibility for cable delivery and installation has led to unresolved liability discussions regarding the cable failures. Therefore it should perhaps be considered whether a testing of limits with respect to handling during different types of field work should be developed. Both manufacturers to NorNed turned out to be dependent on a certain number of repairs in order to cope with mishaps in their factories. It is important to establish a system for inspections and handling of non-conformities in order to maintain full product quality. It is also important to arrange sufficient float in the scheduling to allow for delays caused by repair of non-conformities.

## HVDC Networks

The development of a European 'Supergrid®' has been much talked about in recent years. The proposal makes extensive use of multi-terminal HVDC links to interconnect regional AC networks and vast offshore wind farms. With public opposition to onshore wind farms increasing, many of the TSOs present at the conference stated that their governments were pressuring them to immediately commence development of a supergrid. The disparity between the present capabilities of HVDC and what was needed to develop such a grid became a significant discussion point throughout the conference.

Most HVDC links have only two terminals (i.e. they are point to point), however, two three-terminal HVDC systems do presently exist: the SACOI (Sardinia- Cosrica- Italy) project constructed in 1965 (LCC, 200kV, 200MW), and replaced in 1992 (LCC, 200kV, 300MW) and the Quebec- New England scheme (LCC, 450kV, 2000MW) constructed in 1991. The latter was originally proposed as a five terminal scheme, but the two smallest terminals were later removed from the scheme as disturbances in the ac local network might have caused disturbances in the main dc transmission.

In LCC HVDC the DC current can only flow in one direction. To change the power direction requires changing the link's polarity. This is not a problem with two terminals, but becomes more problematic with multi- terminal schemes. VSC HVDC can allow current in both directions and there is no need to change the polarity when the direction of power is changed. This makes building a multi-terminal system with VSC easier than with LCC. Additionally, VSC HVDC does not suffer from commutation failures and is therefore more immune to disturbances in the ac grid.

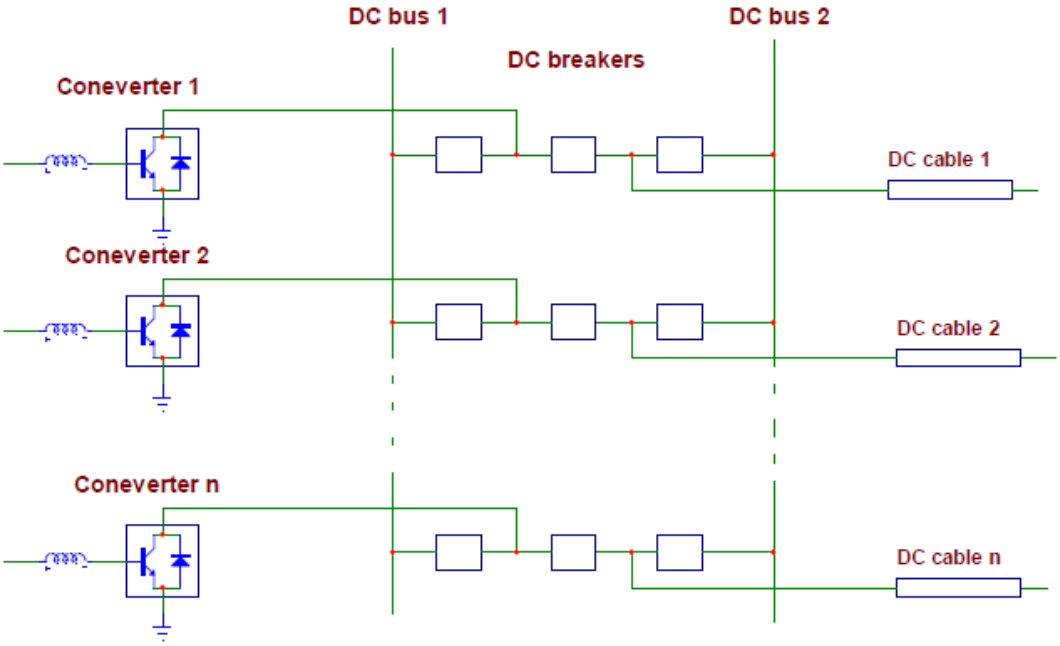
As well as making multi-terminal links easier, VSC HVDC makes the prospect of meshed HVDC networks closer to being possible. An interconnected HVDC network could offer significant advantages over multiple discrete HVDC links, including:

- Improved reliability at a lower cost through shared redundancy (just like a meshed AC network)
- Lower losses, as converter losses would only be incurred at the entry and exit points of the network.

These benefits would be gained at the cost of some controllability. While the power flowing into and out of the network could be controlled by the power converters, like an AC network, the distribution of current between parallel circuits would be inversely proportional to the resistance of each circuit.

Protecting an interconnected HVDC network would be much more complicated than protecting an AC network. Because a DC network does not have any reactance (only resistance), during a fault the fault currents flowing through the network could rise very quickly to very high levels and the network voltage would fall much lower and over a wider area. Suitable protection relays and circuit breakers do not presently exist. The requirements for DC circuit breakers differ from conventional AC breakers on at least two important parameters: they will have to break DC (with no zero crossing), and they will have to operate much faster. Given the severe consequences of loosing an entire HVDC network, protection would need to work very reliably.

Provided protection issues can be overcome, HVDC networks could be constructed in a similar fashion as HVAC networks. An HVDC switchyard would look very much the same as an HVAC switchyard. The figure below illustrates a breaker-and-a-half HVDC switchyard.




To date standardisation has not been a significant issue for HVDC as links have been designed and operated independently. However, the development of an integrated network makes standardization very important. A network will inevitably have to be built in stages and with equipment from different suppliers. While different stages and sections will initially have no contact with each, they will eventually need to be interconnected to form a network. If some design aspects are not standardised such interconnection may not be possible. Issues that will need

to be decided by utilities include voltage and capacity levels (i.e. functional issues). Issues that will need to be resolved by the equipment suppliers include protection and control protocols (implementation details). There was a consensus at the conference that an early discussion on standards was required and that the time for that discussion is probably now.

# FACTS

Although the conference largely focused on HVDC, Siemens did spend some time explaining how multilevel VSC technology benefits FACTS devices, and there was a presentation by Statnett regarding two recently constructed SVCs.

## *Multilevel VSC in FACTS Devices*

Multilevel VSC converters can also be used in FACTS applications. The VSC equivalent of a SVC is a STATCOM (although Siemens are referring their STATCOM offering as 'SVC Plus'). The main advantages over 'conventional' FACTS devices are:

- lower harmonic distortion, reducing or eliminating the need for harmonic filtering, reducing equipment footprint, and permitting standard modular designs using standard equipment
- the reactive power output capability varies in proportion to the voltage (rather than voltage squared), meaning that smaller devices can be used with the same effectiveness of supplying VARs following a contingency

Siemens has released a 'containerized' version of their SVC Plus product which consists of a ±50MVAr VSC converter and associated control equipment packed within a shipping container. To work, the converter needs to be connected to an external capacitor bank, reactor, transformer, cooling fan bank, and auxiliary power supply.

## *SVC with Bus Voltage*

Statnett presented on its recent experience with the development of two new SVCs. Due to the stringent harmonic performance levels specified, the SVCs had to be designed with three thyristor controlled reactors (TCR) and three filter branches. The system voltage at one of the substations is currently 300 kV, but there are plans for a 420 kV voltage upgrade of the substation. Using a SVC transformer with a 420/300 kV re-connectable primary winding was considered but found to be too heavy to be transported to the substation. The SVC was therefore designed for a 420 kV grid connection, but was commissioned with a 300 kV grid connection. The SVC is expected to be operated with a 300 kV grid connection for 5-10 years until the substation is upgraded to 420 kV. While it is connected at 300kV, the SVC will have reduced rating.

I later asked the presenter if the SVC was able to meet its harmonic limits at both voltage levels, and he confirmed that it could. This is significant because the LV bus voltage is often selected to optimise the harmonic filter design, and it is the different LV bus voltage at each SVC which makes it necessary to have 'unique' equipment at each SVC. If using three TCR branches makes it is possible to have acceptable harmonic levels with a widely varying LV voltage, then it may be possible to develop a 'standard' SVC design, usable in several network locations. A common set of spare components could then be held.

The SVCs are equipped with one main circuit breaker, which is situated on the primary (high voltage) side of the step-down transformer. It is therefore not possible to obtain selective disconnection of an earth fault on the secondary side of the transformer, and the whole SVC must trip. Both SVCs are equipped with an Earth Fault Locator, which automatically identifies the earth fault location and commences operation at reduced capacity with the faulty branch disconnected. The method consists of an automatic re-close sequence to connect and energize each branch until the earth fault is located.

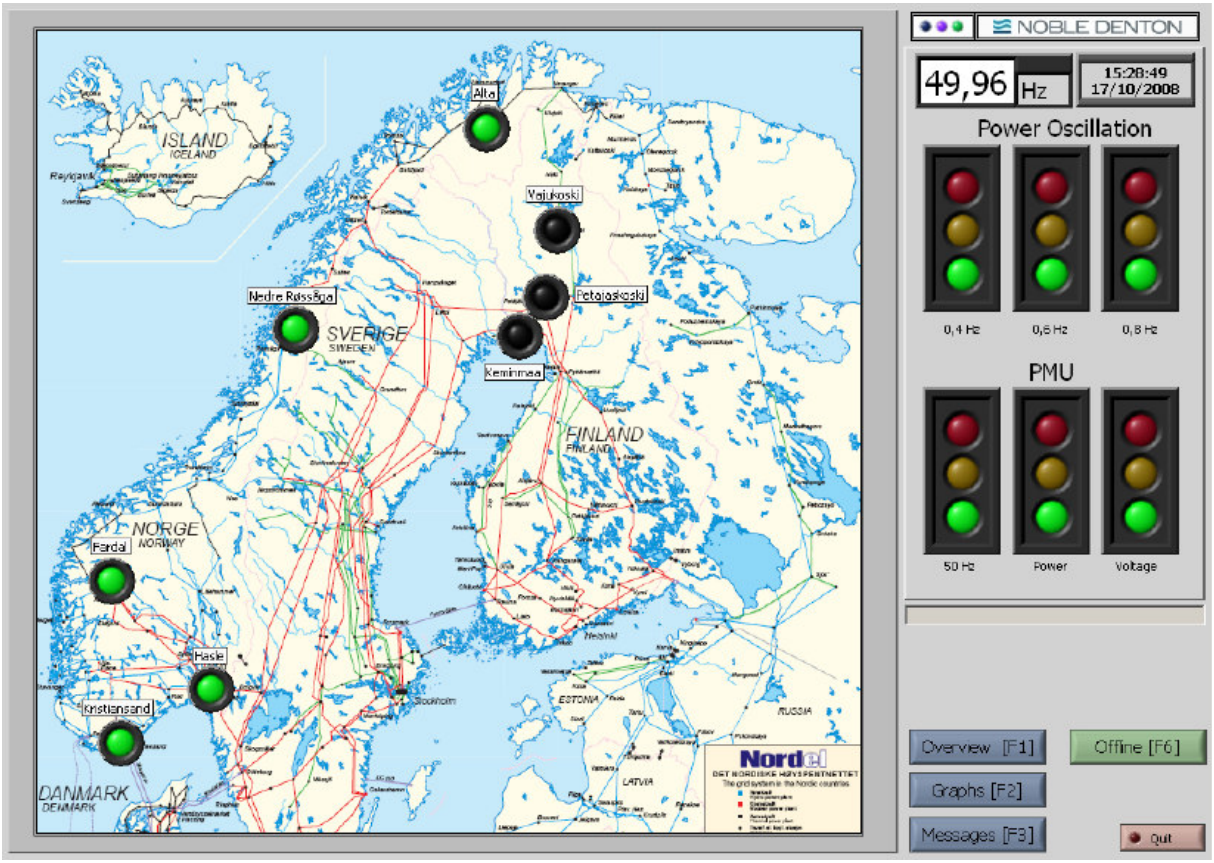
## Wide Area Monitoring and Control

In an effort to securely increase utilization of their grid, Statnett are developing a wide area monitoring and control system for their network in collaboration with ABB and the research body Sintef.

The focus from 2005 to 2007 was to develop a wide area *monitoring* system (WAMS). The system collects high speed synchronized information from phasor measuring units distributed throughout the network and uses specially developed algorithms to very quickly identify the level of damping for each mode of oscillation, and monitor any actual oscillation. The system has been quite successful, providing the following benefits:

- More information about the power system state
- Early warning to the operators if a disturbances may cause operational challenges
- Improved data for analysis and verification of faults
- Improved measurements and data for validation of simulation models for the power systems

A screenshot of the operator display is shown in the figure below.




Since 2008, the focus has shifted to developing a wide area power oscillation damper (WA POD) that uses information from the WAMS to control power system elements in a coordinated fashion and actively damp any power oscillations. PSSE simulation shows the WA POD to be quite effective. It will initially be interfaced with one of Statnett's SVCs. If successful, it could be interfaced with more elements. One possibility presently being investigated is interfacing with generator unit power system stabilizers. The system is capable of issuing controls within 10 and 150ms of a power system incident.

# Implications for the Australian Power System

## *A role for HVDC?*

Australia's renewable energy resources are spread around the country. Some are close to the major load centers, while others are very distant. Those renewable energy resources which are closest to the existing AC network will be utilized first. However, as the proportion of renewable generation increases, more diversity will be required to maintain a secure electricity supply: diversity in the types of energy sources, diversity of the location of energy sources (particularly for intermittent forms of renewable energy), and diversity in the demand (to reduce its overall variability). To realize this diversity and connect remote renewable generation, a significant amount of new transmission infrastructure will be needed.

The Australian power system has several regions with a strong concentration of generation, and several large load centers. The existing AC network has the greatest capacity between the areas of concentrated generation and the load centers. In order for renewable generation to produce energy, existing generation must be partly displaced for at least some of the time. The generation most likely to be displaced is the thermal generation with strong connections to the load centers. As the proportion of intermittent renewable generation increases, I expect that the use of energy-limited hydro generation is likely to become more strategic (i.e. making up any generation shortfall rather than base load operation). To facilitate this, the capacity of transmission connections to the Snowy Mountains and Tasmania may need to be increased.

Developing high capacity interconnectors between the existing and new generation nodes would allow bulk power to be moved around the country from where it is available to where it is needed, and would allow the existing AC infrastructure to continue to transport the power into each load centre. Such high capacity interconnection could be provided by very high voltage AC links. However, the small number of nodes and the very long distances involved and mean that multi-terminal HVDC or interconnected HVDC technology could be an attractive alternative, since:

- The overall losses could be far smaller with HVDC than HVAC transmission.
- It could be more cost effective. Over such long distances, the cost of the actual transmission line would be a high proportion of the overall scheme cost. HVDC could provide greater transfer capacity for the same investment in transmission lines. The additional cost of the converter stations would be offset by not needing mid-point substations to correct the power factor and voltage.
- The additional controllability of HVDC could improve the manageability of the power system and therefore improve security of supply.
- These benefits could be realized without having to change existing generator connections. With HVAC networks, the value of a higher voltage level is only fully realized if generation connects directly to that higher voltage.

At present, HVDC technology's level of reliability means that it would be unwise to rely on it exclusively. It is likely that reliability levels will improve as research and development continues. However, because of the additional complexity inherent in HVDC equipment, AC equipment is always likely to be more reliable. Therefore, I believe that there is still a role for a parallel AC transmission network: to transfer power in parallel with the HVDC network, to connect generation & loads along its route, and to provide a base level of reliability. A parallel HVDC network could assist the AC network by:

- Improving small signal stability by damping oscillations in the AC network,
- Enhancing controllability through quickly changing transfer levels following AC network contingencies, and
- Subsequently increasing the secure transfer capacity of the AC network.

Because of the reliability risks with new technology, I do not believe that Australia should be an 'early adopter' of interconnected HVDC networks. Given Europe's shorter distances, greater network redundancy and closer proximity to the equipment suppliers, I believe that European TSOs are better positioned to lead the market. Many European governments have already expressed their eagerness to roll out the technology as soon as it is available. Elsewhere, China is presently in the process of installing several very high capacity LCC HVDC links, to be operated in parallel with their AC network. Australia should monitor and learn from the European and Chinese roll out of HVDC technology before committing to its own widespread rollout.

However, I do believe that there is value in discussing the possibilities of HVDC and developing a high level plan of how the Australian system should be developed – using either HVAC or HVDC technology. Developing such a plan is likely to take several years, and implementing the plans will take much longer. Australia is unlikely to be able to meet its Kyoto targets if it waits to observe overseas experience before it commences planning. Having an overall plan is important, as the network development is likely to be delivered in stages over a period of time by different parties. Having a long-term plan will help to ensure that all of the constituent parts will act as a unified system, which is particularly important if a HVDC network is to be used.

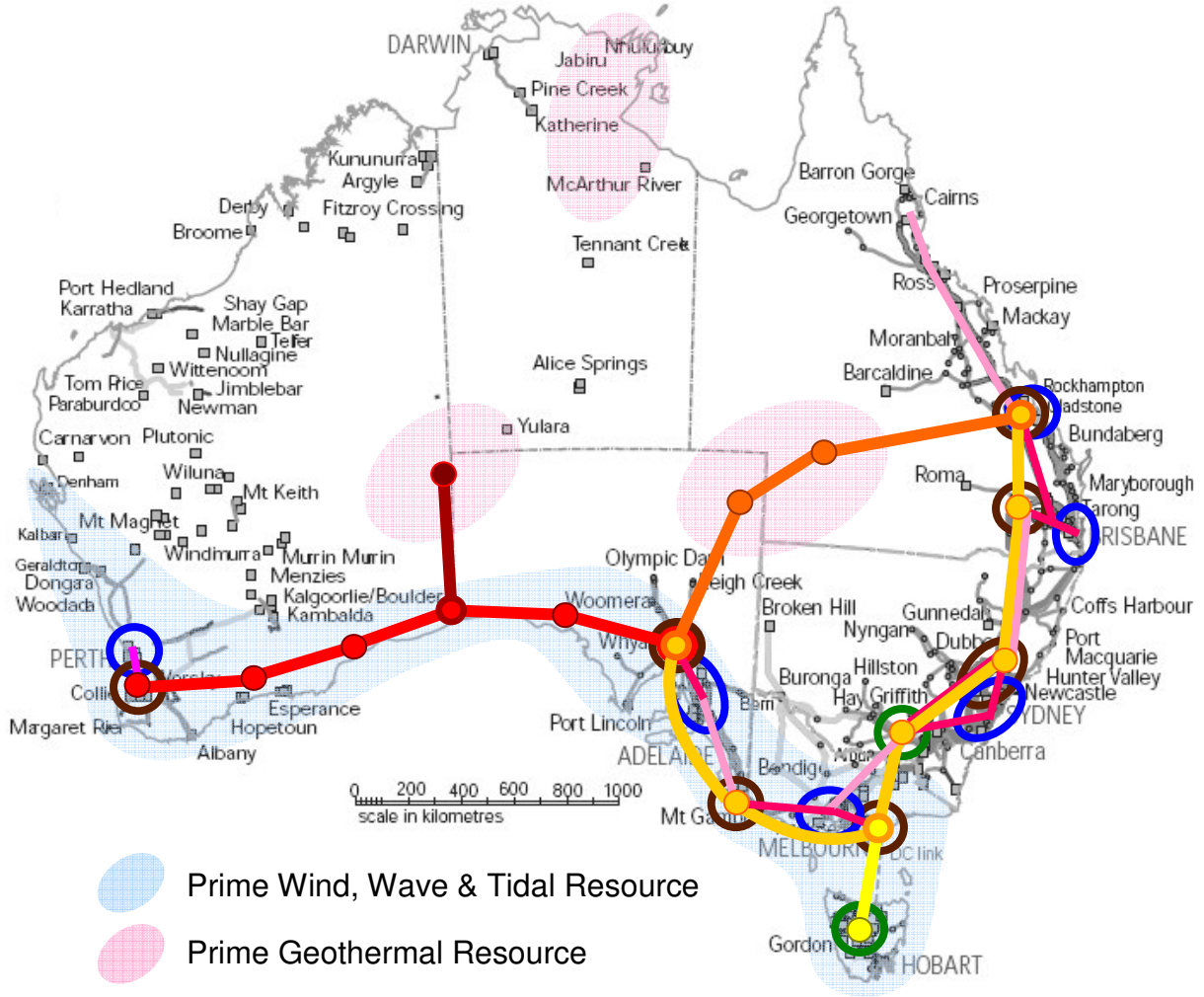
Over the page, I have sketched a very high level conceptual HVDC network that is consistent with the reasoning I have explained above. It is my hope that this report and the sketch might provoke some more discussion about the potential role of HVDC in Australia, and more generally, about how the transmission network should be developed to most effectively facilitate the required levels of renewable generation.

***Existing Network:***

- Major Load Centre
- Thermal Generation Node
- Hydro Generation Node
- Strong HVAC Transmission Path (500kV or 4+ 275/330kV circuits)
- Intermediate HVAC Transmission Path (2 to 3 275/330kV circuits)
- HVDC Connection (circuit & nodes)

***Conceptual HVDC Network:***

- Stage 1 – Interconnecting Existing Generation Nodes, Facilitating Increased Connection of Renewable Generation to the Existing AC Network
- Stage 2 – Connection to Geothermal Resource, Additional Renewable Energy Transfer into Queensland and Improved DC Network Redundancy
- Stage 3 – Connection to Wind & Wave Resource and Improved Load Diversity
- Stage 4 – Connection to Additional Geothermal Resource



## *FACTS Equipment Improvements*

Australia is already a keen user of FACTS equipment, and this is only likely to increase as the proportion of intermittent generation increases. At present, each FACTS installation is unique. I believe that there may be scope for more standardization of FACTS installations. Standardization could allow Transmission Network Service Providers (TNSPs) to reduce the total cost of ownership by holding less spares overall, requiring less training for field personnel, and shorter outages following a significant failure by having a more comprehensive set of spares.

Additionally, given the penalties applied to TNSPs for outages and the length of time it can take to repair damaged FACTS devices, it may be cost effective to specify that future SVCs include fault locating equipment and control systems that can operate the SVC (albeit at reduced output) with a faulted limb removed from service.

## *Wide Area Monitoring and Control*

Given the high cost of transmission infrastructure in Australia (due to the long distances needing to be covered) Australia has more to gain from the improved utilization of its existing infrastructure than many other countries. Given that small signal stability is often the most-limiting constraint on the Queensland to New South Wales Interconnector (QNI), a Wide Area Monitoring System (WAMS) that could measure the level of damping being applied to each mode of oscillation and record any actual instances of oscillation could afford a better understanding of the secure transfer limit and enable the system to be operated closer to that limit.

Presently, several of Queensland's SVCs run a local power oscillation damper (POD). However, identifying a suitable local signal for each POD is not always possible. With a WAMS, it may be possible to develop a Wide Area POD that utilizes more SVCs (including those SVCs closest to the major load center and therefore the most effective) to improve the level of damping and increase the secure transfer limit.