8th December 2009

Simon Bartlett
Chairperson, E S Cornwall Scholarship Advisory Committee

Dear Mr Bartlett,

Re: ES Cornwall Scholarship – Third Quarterly Report

Please find enclosed my third quarterly report during my tenure of the E S Cornwall Memorial Scholarship, as required by the scholarship rules.

During the third quarter of 2009, I have been working for National Grid in the United Kingdom. This has afforded me valuable insights into the impact of significant volumes of intermittent renewable generation on the analysis and design of power networks, which I discuss in my report.

I welcome any feedback or questions from the committee or other interested parties on anything I have discussed in my report and my aspirations for the next quarter.

Yours faithfully,

Jonathan Dennis

Enclosures:

- E S Cornwall Scholarship 2008-2010 – Jonathan Dennis – Third Quarterly Report

ES Cornwall Scholarship 2008-2010
Jonathan Dennis

Third 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 significant 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.

As previously indicated, my overwhelming impression since commencing the scholarship is that the obstacles to the increased use of renewable generation are multi-faceted, and the technical difficulties listed above must be considered alongside the political, regulatory, and commercial obstacles. I have therefore sought to investigate and report on all of the transmission related obstacles to increased use of renewable generation.

This is the third of six quarterly reports required by the scholarship guidelines. It covers the third quarter of 2009. During this time I have been employed by National Grid, within their UK electrical network investment strategy development team. National Grid owns the electricity transmission network in England and Wales, and operates Great Britain's electrical power system. National Grid also owns and operates the UK's gas transmission network, as well as owning several gas distribution networks in the UK and several electricity and gas transmission and distribution networks in the USA. National Grid also owns several subsidiary companies involved in activities including metering, and developing interconnectors and offshore transmission networks.

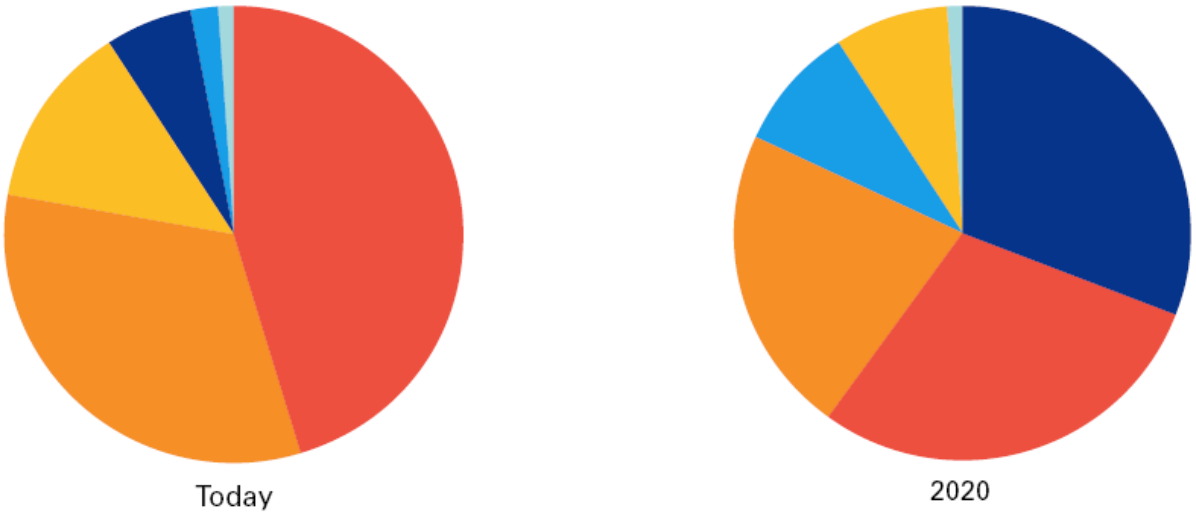
My main responsibility to date has been assisting with the compilation of a report describing how the UK's onshore and offshore transmission networks can be developed together in a coordinated and economical fashion. As this project is still ongoing with the report due to be published in late December 2009, I will refrain from discussing it or its findings until my next scholarship report. However, I am grateful to have been able to work on this project as it has given me the opportunity to liaise with a wide variety of people within National Grid and within various UK government departments, and has forced me to grapple with some of the issues created by such a significant increase in the amount of renewable generation. One significant observation has been the inadequacy of many existing policies and procedures used to plan power transmission systems when the proportion of intermittent generation is significant. I have therefore dedicated most of this report to elaborating on these difficulties and how they might be addressed.

UK Electricity Transmission Planning Context

In recent years, the UK's peak demand has been relatively unchanged at about 60GW and augmentations to the network have largely been driven by the connection of new generators and specific industrial loads. This is reflected in the structure of the system development team as most of the team is divided into regional teams that respond to grid connection requests, while a national team harmonises the work of the regional teams, prepares general/national reports and interfaces with the regulator.

With the expected increase in renewable generation, it was apparent that more widespread changes to the network would be required. It was unclear whether the existing planning criteria would be optimal and whether new transmission technologies might be able to play a role. Therefore, a new strategy team was established, and continues to be expanded. The team's mandate is to look forward 7 – 20 years when the proportion of renewable generation will be considerably higher than it presently is, and determine the most cost-effective practical manner of developing the transmission network to accommodate the changes in generation.

The changes that will be required to the UK's electricity fuel mix by 2020 in order to meet its emission targets are illustrated in the plot below. The scenario depicted in the 2020 pie chart is known as the 'Gone Green' scenario, and has been used as the basis for several recent public reports.



Source: Energy Trends (2009, Quarterly)Department for Business Innovation and Skills (2009)

Source: Department of Energy and Climate Change [1]

Some of the sensitivities the team has considered and the projected energy mix in 2030 have an even higher proportion of renewable intermittent generation. Being involved in the study of these scenarios has highlighted to me some of the challenges that are encountered and the shortcomings of conventional network design procedures. In the following subsections I have tried to outline my understanding of the issues, how they may relate to the Australian context, and possible means by which they can be overcome.

[1] *The UK Low Carbon Transition Plan*, HM Government, 15 July 2009 Available online at: http://www.decc.gov.uk/en/content/cms/publications/lc_trans_plan/lc_trans_plan.aspx

Impact of Renewable Generation Variability on Various Studies

One of the most fundamental and influential issues in transmission network planning is deciding upon the background conditions that the system will be designed to cater for. High level assumptions made about the background conditions can significantly alter the extent and nature of the network reinforcements which are subsequently found to be necessary.

Designing the 'relatively radial' sections of the transmission system close to load centres and generators is relatively straight-forward. As there is unlikely to be enough diversity within small region to a single region to be able to discount the co-incident peak of multiple loads or generation, the network should be designed so that it can transfer the maximum reasonably anticipated demand or the sum of the rated generation respectively. However, designing the backbone or meshed sections of a transmission system is more complex, as it depends on assumptions regarding:

- the variability and diversity of demand in different regions
- which generators are online and the level at which they are generating

Existing Procedures

Demand variation and diversity are nothing new, and procedures already exist to take account of them. Demand diversity is often taken account of by the way in which regional demands are aggregated. Since the co-incident peak of different regions is unlikely, the expected peak demand of a large region can be less than the sum of the peak demand of each sub-region. Demand variation is often taken account of by designing the network so that it can be operated within its technical limits during the two extremes in variability: peak demand and minimum demand. If the network is able to handle these two extreme situations, and provided that:

- there is sufficient opportunity in-between these two extremes to take maintenance outages, and
- reactive power flows can be controlled with small enough resolution to maintain an appropriate voltage profile at all loading levels,

then the network should be adequate for the full range of possible demand scenarios.

Historically, generation variability has usually only been considered to the extent of studying different possible locations for new generation and the impact of specific operational scenarios (such as the shut down of specific generators due to water shortages or fuel supply interruptions). In this case, a finite number of generation backgrounds would often be adequate to identify the impact of each eventuality and any network reinforcements that are required. The decision to reinforce the network would then typically be deferred until the

latest possible moment and would be based on the eventuality(s) considered most likely to proceed.

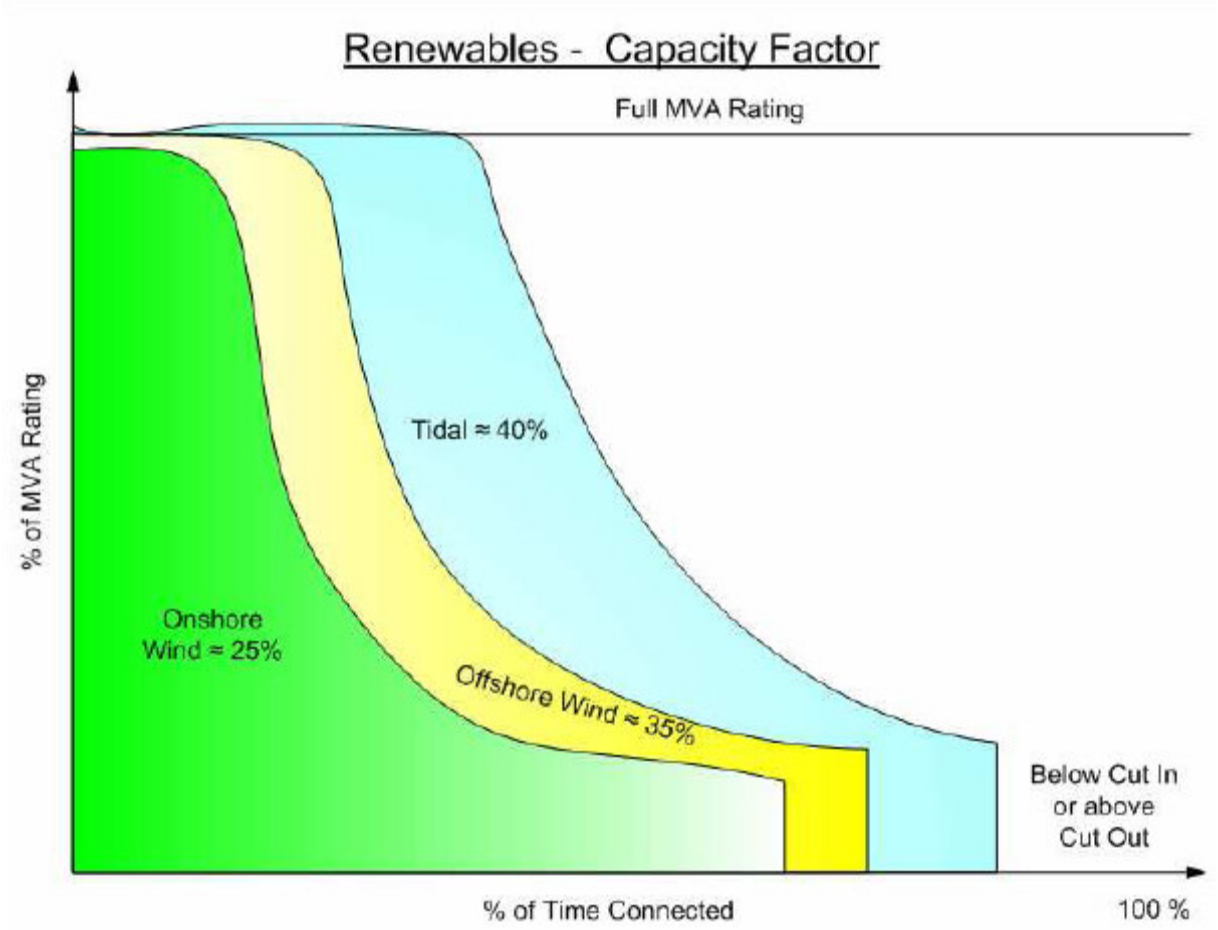
Day-to-day generation variability has tended not to be a significant issue to date. Historically, the generation mix has been dominated by fully-dispatchable high-inertia forms of generation with an average availability of 90% or greater. In this situation, the total installed capacity of generation is only likely to exceed the maximum anticipated demand by a limited reserve/surplus to allow for a small volume of generation to be out of service – typically a value between 10-20% of the maximum demand. It would not be economically viable for a generation base greater than this to be maintained, as some generation would be likely to never be utilised. With an average generator availability of 90% of greater, it is unlikely that more than one generator unit in each region would be out of service at the time of peak demand. When planning the network it is therefore likely to be adequate to consider a background with the most significant generator out of service (or where several generators could be most significant, a finite number of background scenarios where each generator unit is out of service).

When studying the peak demand condition, once a large generator unit has been removed from service almost all remaining generators will then have to be set close to their rated capacity in order for the demand to be met. Therefore, little discretion needs to be applied when selecting the generation background, and it is relatively clear whether augmentation is or isn't required.

When studying the minimum demand condition, the main additional problem that is usually highlighted is regional overvoltages that can result from the net capacitive charging of lightly-loaded circuits. Given that voltage issues are a local issue and that during minimum demand many generators will be offline, it is usually adequate and reasonable to assume that all of the generation close to the area of concern is offline – so again, little discretion is required.

Variability of Renewable Generation

Because of the intermittent nature of many forms of renewable generation, they usually have a capacity factor of 40% or less. The typical power output profile of wind and tidal generation in the UK is shown in the diagram below.



[2]

It can be seen in the plot that although each type of intermittent renewable generation has a typical capacity factor (e.g. 35% for offshore wind), a generator will often produce much less than this level, and will sometimes produce much more than this. The level that it generates at will be limited by the level of renewable energy available at the time. Given that the fuel cost of renewable generation is zero and the generator is likely to earn valuable renewable incentive credits for every MWh it produces, the effective cost of constraining off renewable generation when renewable energy is available would be especially high.

Impact on General Network Planning

Because the output of intermittent forms of renewable generation can often be very low or zero, sufficient non-intermittent generation must be preserved to maintain a secure supply of power. Consequently, as the amount of intermittent generation increases, the amount by

[2] *Supporting Tidal Developers with electrical design and grid connection*, Paul Smith, Senergy Econnect, 2nd Tidal Energy Summit '08, Available online at: www.senergyworld.com/UserFiles/Documents/econnect/ papers/0148TidalSummitPresentation2008PW.pdf

which the total installed capacity of generation exceeds the maximum anticipated demand will increase. As the level of reserve/surplus generation increases, a wider range of generation dispatch possibilities exist, necessitating greater discretion when developing background scenarios on which to base network studies and making it harder to define a finite number of background scenarios that adequately highlight the range of conditions which could result.

Even a 20% renewable *energy* target has the ability to significantly increase the range of generator backgrounds which could result. If only half of the renewable generation (i.e. 10% of all generation) were to be supplied by intermittent forms of renewable generation, and the average capacity factor of such generation is 35%, then renewable generation *capability* equivalent to approximately 30% of the *average* demand would need to be installed. This would likely increase the total installed generation capacity from 110-120% to 130-150% of maximum demand.

When the installed capacity of generation significantly exceeds demand, at times when there is high power production from renewable generation, conventional generation must to some extent, be displaced. The location of the intermittent generation relative to the conventional generation it displaces can have a significant effect on the network transfers which result. If the displaced generation is located close the renewable generation, then the effect on network transfers will be limited. However, if the displaced generation is distant then network flows throughout the network could be significantly impacted. For example, even if the bulk of intermittent renewable generation is installed in the south of Australia, if gas or coal-fired generation in New South Wales and Queensland is displaced, significant volumes of power could flow north through Transgrid's and Powerlink's network.

Assumptions regarding which generators are most likely to be displaced are therefore just as influential as assumptions regarding where new generation will be developed. Assuming where generation is going to be displaced could be even harder than assuming where renewable generation is online. Given that the market will ultimately determine which generation is displaced, the network will need to be robust to different ways in which this might happen. In the worst case, some existing generation may need to be constrained online to prevent circuits from becoming overloaded. Given the present structure of the Australia's National Electricity Market, this would probably either have to limiting the production from all of the renewable generation contributing to the overload, or having existing generation bid at a sufficient sufficiently low cost (likely to be significantly negative, given the negligible operating cost of renewable generation and the value of green-generation credits) to remain online, receiving compensation from the TNSP outside of the market. The cost of displacing renewable generation would need to be weighed against the cost of transmission reinforcements.

The output of intermittent renewable generation is linked to ambient weather conditions. Given the scale of weather systems, similar weather is likely to be experienced by all

intermittent generators within a particular region, and so their output is likely to be highly correlated. Likewise, conventional generators tend to be sited close to where their fuel originates from (e.g. in coal mining regions), and so there tends to be concentrations of the same type of generation which could all be displaced when renewable power is abundant. This correlation of output from multiple generators in the same region is likely to enhance the overall level of variability likely to occur, and therefore increase the range of conditions that the network will need to capable of handling.

Given the very wide range of generation and demand background scenarios that are possible (even at peak demand) and the sensitivity of network transfers to discretionary assumptions, it will be increasingly difficult to plan how the network should be upgraded in a rigorous and undisputable fashion. Whether a particular reinforcement is deemed necessary will depend on a view of how likely various different situations that require that reinforcement are. Everyday planning is therefore likely to become much more involved as many different scenarios will need to be identified and studied to determine their likelihood, the adequacy of the network to cater them, and what reinforcement options are available. The results for multiple scenarios will then need to be collated and 'common themes' identified. Given the broad range of possible backgrounds, it is likely that investment decisions will not be clear cut (i.e. a certain decision may be optimal some of the time whilst other options optimal at other times), which will make the regulation of TNSPs more complicated. Power system constraints could be utilised to prevent the power system from operating in states which have not been studied or which would not be economic to cater for. Ultimately decisions will need to be taken with a view to minimising the combined costs associated with:

- constructing and operating transmission infrastructure
- transmission constraints distorting the market
- interruptions to the supply of power to consumers

Essentially, a balance will need to be struck between the cost of building more transmission infrastructure and the cost of constraints and interruptions.

Impact on Fault Level and System Stability Studies

During minimum demand conditions, the potential for low-inertia and low-fault level renewable generation to comprise a significant proportion of the generation online makes it more likely that system stability and protection discrimination issues will be encountered.
In the example described previously, where 10% of electrical energy is supplied by intermittent forms of renewable generation, it was established renewable generation equivalent to 30% of the average demand would be required. If the minimum demand is 60% of the average demand, then it is possible that 50% of the minimum demand could be supplied by low-inertia and low-fault level renewable generation. In this case, only 50% of the minimum demand would be supplied by conventional generation, and there would be a very large number of combinations of generator that could be used to supply this.

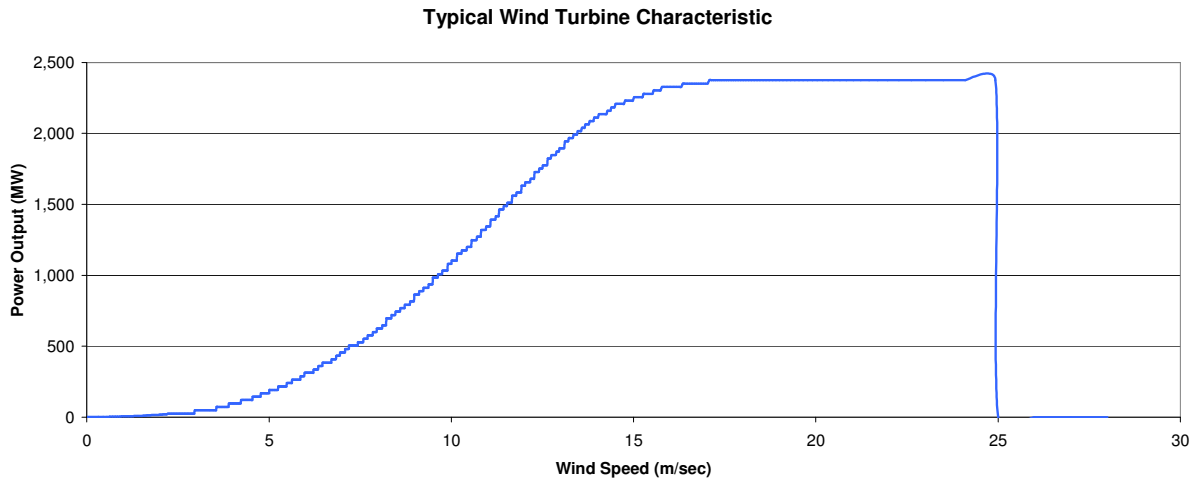
System stability and protection setting studies are already quite involved, since they can be sensitive to the output of specific generators. Performing such assessments on the full range of generation combinations that could occur would take a great deal of effort. The 'easy' option would be to constrain renewable generation offline so that a certain conventional generation base is preserved. However, given the high cost of constraining renewable generation, there would then be an onus on network/power system operators to prove that the security of the system would be compromised.

Example UK Generation Variability Study

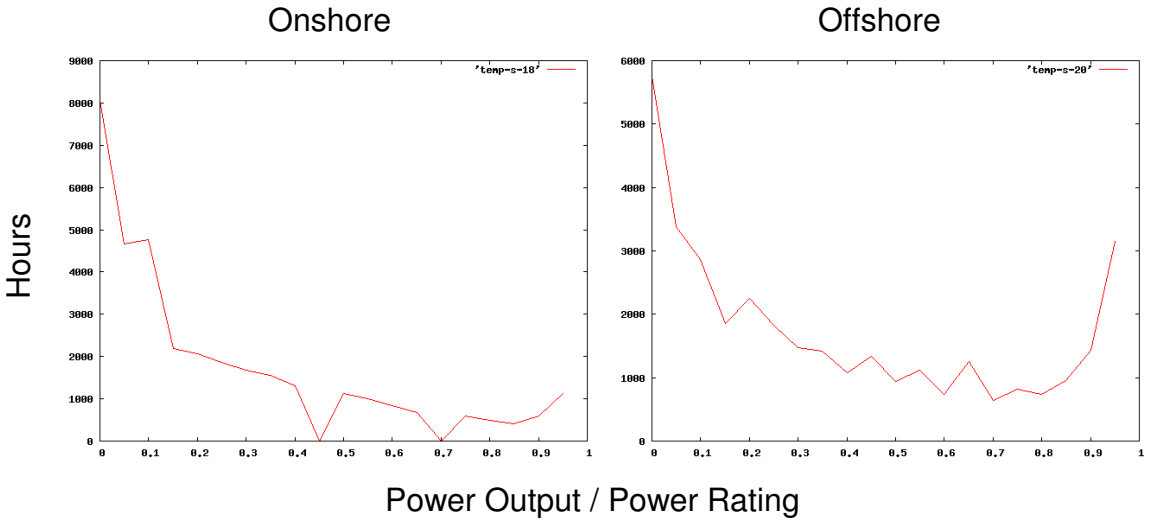
The general discussion so far is not particularly controversial, but is also not particularly applicable. The first step towards translating a high-level appreciation of how the network is likely to need to change, into firm network development plans is performing studies into how likely different background scenarios are to occur. Recognising this, National Grid recently completed a study into the wind generation scenarios that will be possible in the UK in coming years. I am grateful for National Grid's permission for me to present a summary of the study's findings. Although the study was focused on the UK, I believe that there are lessons which are applicable to Australia, and I believe the study serves as a good example of the type of work that will need to be performed in Australia (if it hasn't already been).

The main input to the study was hourly wind-speed data for the past 8 years at 27 sites across the UK – including locations where large onshore and very large offshore windfarms are proposed. The typical windspeed to power output characteristic of a wind turbine and the installed/proposed capacity of wind farms was then used to translate the wind speed into resulting power output.

The typical characteristic for a wind turbine is shown in the plot below. It can be seen that when the wind speed is less than about 15m/sec, the output of the wind turbine is limited by the amount of wind energy available to it. When the wind exceeds 15m/sec the turbine is limited by its rated power output capability, and 'feathers' the blades to spill excess wind energy. When the wind speed exceeds 25m/sec the forces on the turbine are too great to permit normal operation and the wind turbine must shut down, brake the blades and spill all wind energy. Although not the focus of this report it is worth pointing out that the greatest sudden changes in network power flows due to renewable generation experienced to date have resulted from storm fronts causing many wind farms in a region to switch from full output to shut down in quick succession.



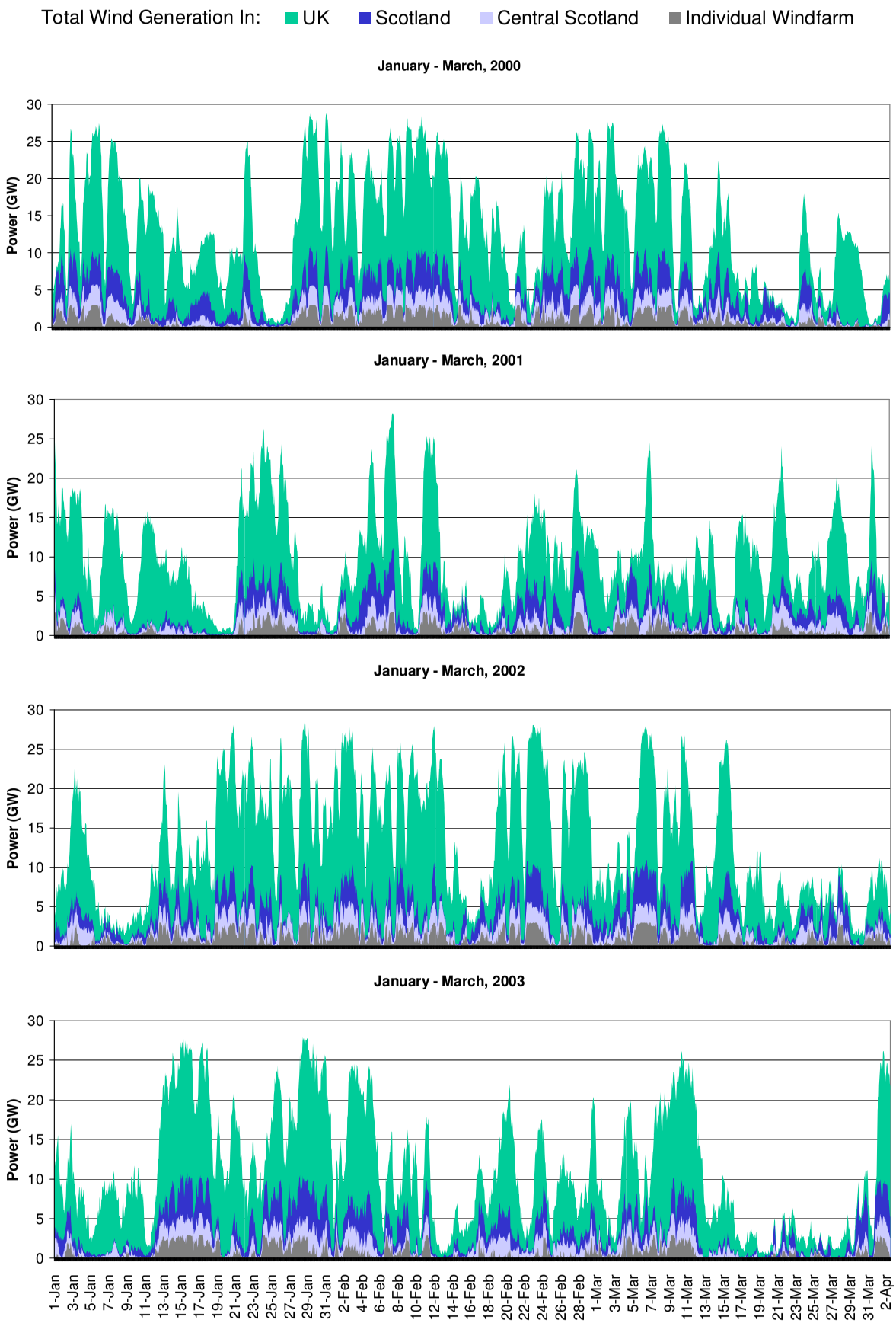
Considering the historical wind speed data and the typical turbine characteristic, the resulting power output profile of a representative onshore and offshore wind farm are shown below. The wind is generally stronger and more consistent offshore, and the effect of this can be seen in the more even distribution of power output levels. The peak at 100% power output is due to the range of different of different wind speeds at which the wind turbine can produce 100% of its rated output.



The historical wind data was then used to investigate the power output levels that would have resulted from the generation proposed to be built by 2020. The plots below show what the overall level of wind generation in the UK and regional subsets would have been during the winter months of 2000-2003.

It is interesting to note that:

- the variability of wind power production from day to day – it is quite possible to have 25GW of generation one day and none the following day
- the variability of wind energy production from year to year


Total Wind Generation In:
UK
Scotland
Central Scotland
Individual Windfarm
January - March, 2000
January - March, 2001
January - March, 2002
January - March, 2003
Power (GW)
0
5
10
15
20
25
30
1-Jan
3-Jan
5-Jan
7-Jan
9-Jan
11-Jan
13-Jan
15-Jan
17-Jan
19-Jan
21-Jan
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11-Mar
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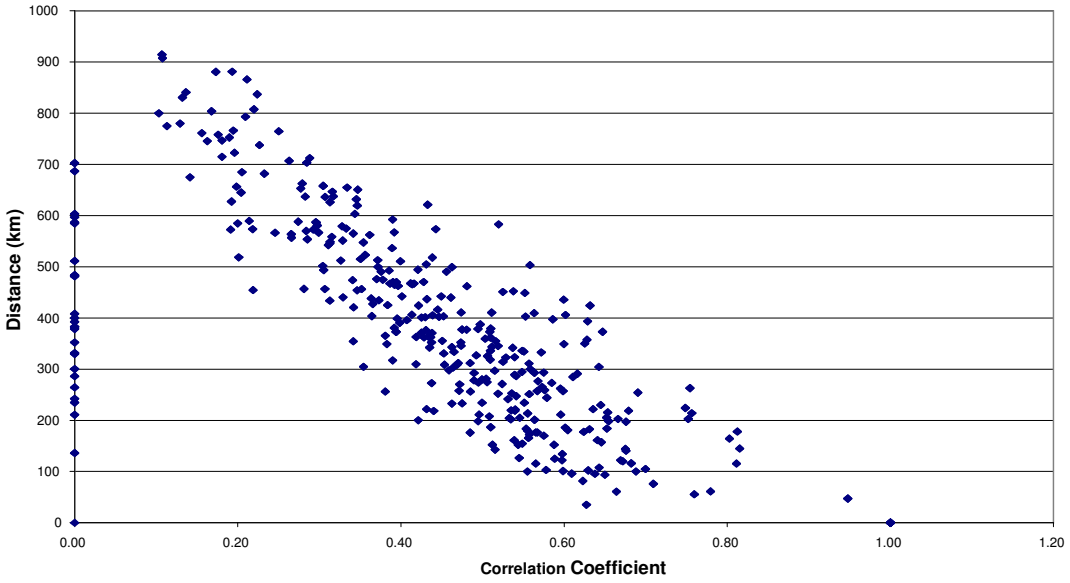
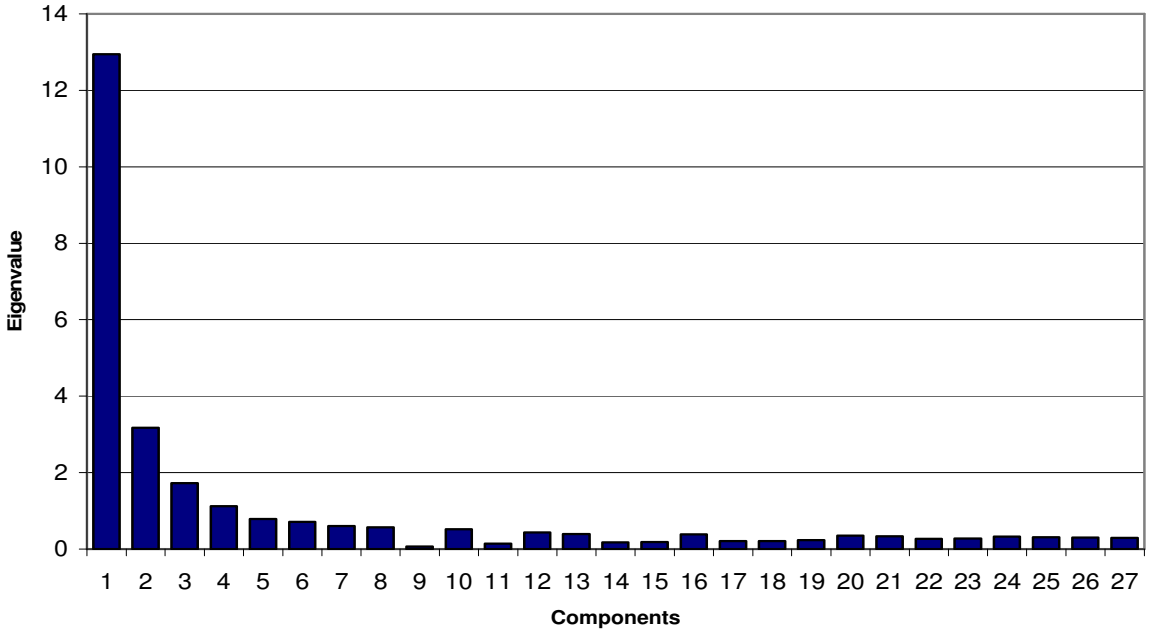
31-Mar
2-Apr

As National Grid is not only interested in the total volume of wind generation, but also its geographical distribution, the remainder of the analysis explored the correlation in power output between different groups of wind farms.

Unsurprisingly, the further wind farms are from each other, the less correlated they were found to be. The actual results are shown in the plot below.



With a view to identifying different background scenarios that should be studied, eigenvalue analysis was used to identify the significant underlying 'components' (or 'themes'). The relative weights of the different components identified are shown in the plot below. One was found to be dominant, and two or three others were less significant but still clearly discernable above the level of 'noise' in the data.



The scenario corresponding to each of the four most significant components is illustrated in the plots below.

Eigenvalue: 12.3	Eigenvalue: 3.2	Eigenvalue: 1.8	Eigenvalue: 1.1
Windy throughout the UK	Windy in the north of the UK and calm in the south (or vice-versa)	Windy in the west of the UK and calm in the east (or vice-versa)	Windy in the far north and south of the UK and calm in the centre (or vice-versa)

The identified components can now be used to develop background scenarios to assess the capability of the transmission system, and the corresponding eigenvalue used to weight the importance/priority of reinforcements required to cater for each scenario.

It should be pointed out that the east-west and north-south components could be understated in the above results, since the underlying data was based on the average wind speed over each hour, and weather systems can move over the UK from west to east quite quickly.

Nevertheless, it is clear that when it is windy in the UK, it is usually windy throughout the UK. The implication is that the UK is too small (compared to the size of the weather systems that affect the wind) for there to be any significant diversity between the output of different wind farms. The overall amount of power generated from wind will therefore tend to swing between quite high values and quite low values. Without diversity, there is likely to be a limit to how much intermittent generation can connect, which depends on the ramp-rates of the fully dispatchable generation. Because wind diversity in the UK is low, and the potential for other forms of renewable power production is limited, there is a strong case for developing greater interconnection with more distant regions, increased energy storage, and improved demand-side response. It is not surprising then that National Grid is constructing an

interconnector with the Netherlands, and has recently announced that it is investigating an interconnector with Norway (which has very high hydro reserves).

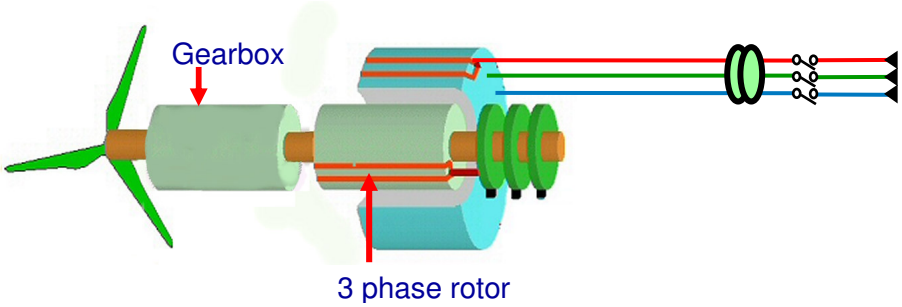
Whilst this study was focused on UK, I believe that it is a good example of the type of work that will increasingly need to be performed in Australia to identify the transfer capabilities the network will need to have in order for renewable generation to be effectively utilised and for supply security to be maintained. I believe that the key finding of this study could also apply to Australia – that to some extent it is the size of weather systems that power or hinder intermittent renewable generation that will dictate the scale of the transmission reinforcements that will need to be constructed in order for diversity to work effectively. Australia's key advantage is that several different forms of renewable generation are possible (although these may be somewhat correlated) and that Australia is vast enough that sufficient geographical diversity is likely to be possible using onshore transmission infrastructure – which is far less expensive and far easier to maintain than subsea infrastructure.

Given the structure of the Australian power industry, consideration should be given to who should be responsible for performing such studies. Because of the increasing ambiguity regarding what background conditions to assume when performing studies, and the sensitivity of the network reinforcements required to the assumed background conditions, the regulation of transmission network service providers (TNSPs) is likely to become much more difficult. Therefore, a possible new role for AEMO's new planning function may be to undertake such probabilistic assessments over all of Australia to define a set of background scenarios that the network should be able to accommodate and/or cutset transfer capabilities that are required for system security. Individual TNSPs using deterministic reliability criteria could then identify the most efficient way to reinforce the network to cater for the defined scenarios or provide the necessary cut-set transfer capability.

Impact of Converter Connected Generation on Various Studies

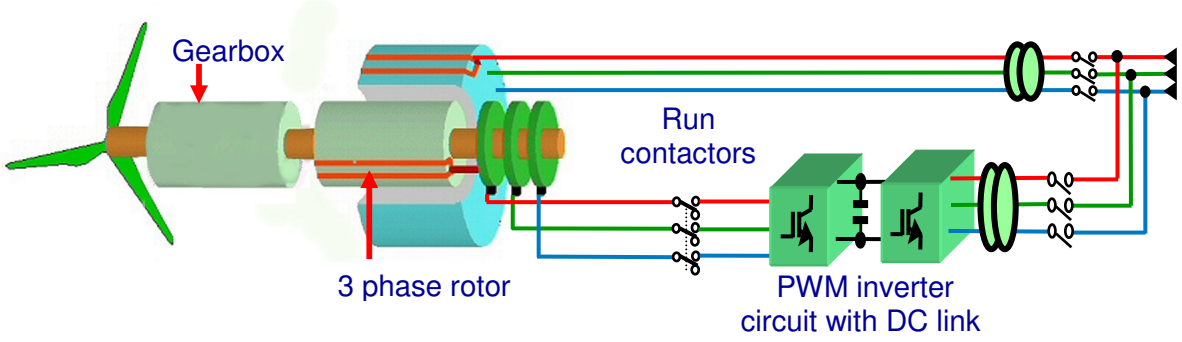
Historically, large power systems have been almost entirely dominated by large synchronous generators. However, the shift towards renewable generation is introducing various new types of generators onto the system.

Early wind turbines were commonly based on induction motors connected directly to the grid, due to their simplicity and low cost. However, induction generators have very little real controllability, consume reactive power and have poor fault ride through capability.

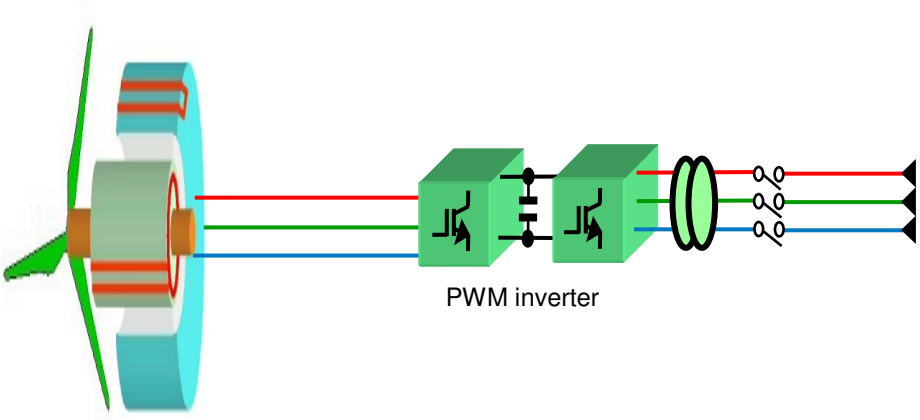


As the penetration of wind turbines has increased, many countries have applied increasingly strict requirements on them. Increasingly onerous grid-connection requirements have forced turbine manufacturers to move to more controllable (and more complicated and expensive) solutions.

A commonly installed solution today is the Doubly-Fed Induction Generator (DFIG). Whilst still an induction generator, a power converter connected to the rotor windings enhances the level of controllability, improves the power factor and can be coupled with a variable resistance closed-circuit to the rotor windings to improve fault ride through. The advantage of this design is that the power converter only has to be rated for part of the machines overall capability, reducing the cost of power electronics and the losses incurred during operation. The primary disadvantages are the need to regularly replace the rotor brushes, and the still-limited extent of controllability – especially when there is a large concentration of such machines at one location.



Increasingly, turbines are being installed that use power converters to completely isolate the turbine from the grid. These provide the maximum amount of controllability and enable any type of turbine to be used and operated at any frequency, including 0Hz (DC). However, such machines require power converters that are rated for the full capacity of the turbine, adding additional cost and losses. Nevertheless, this would seem to be the general direction that wind turbine technology is heading in, with new lightweight and low maintenance brushless DC direct-drive motors under development, to fully exploit the advantage of having the turbine fully isolated from the AC grid by the power converter.



Although 'full-converter generators' are most commonly found in wind turbines, they will likely be used for other low-density forms of renewable generation (e.g. wave, tidal, solar thermal), since it permits the turbine designer the flexibility to use any type of turbine, to maximise the power extracted from the renewable energy source. Full converters are already commonly used to convert the DC power produced by solar photovoltaic systems to the grid. Increasingly, power electronics are also being incorporated into loads. Electric-cars are a particularly interesting example since the power converter is combined with energy storage. Therefore, although the following discussion is focussed on wind turbines, it is likely to apply equally to other forms of renewable generation and domestic loads.

Presently the proportion of converter connected generation is limited, and its effect is therefore insignificant and can be disregarded. However, as the proportion of such generation increases, its response to dynamic power system events will become increasingly significant, and will need to be taken into account in transmission planning and design studies.

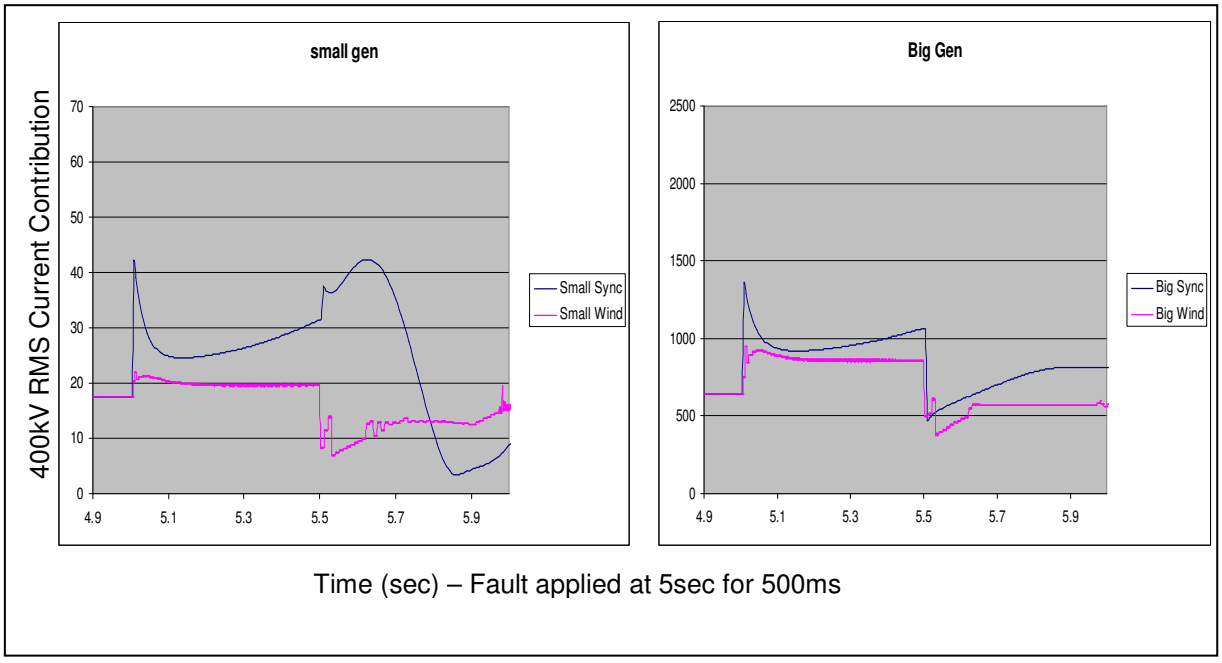
Impact on Fault Level & Voltage Stability Studies

Just as power converters enhance the controllability during the normal operation of the turbine, so they also influence the fault-characteristic of the turbine. Because power

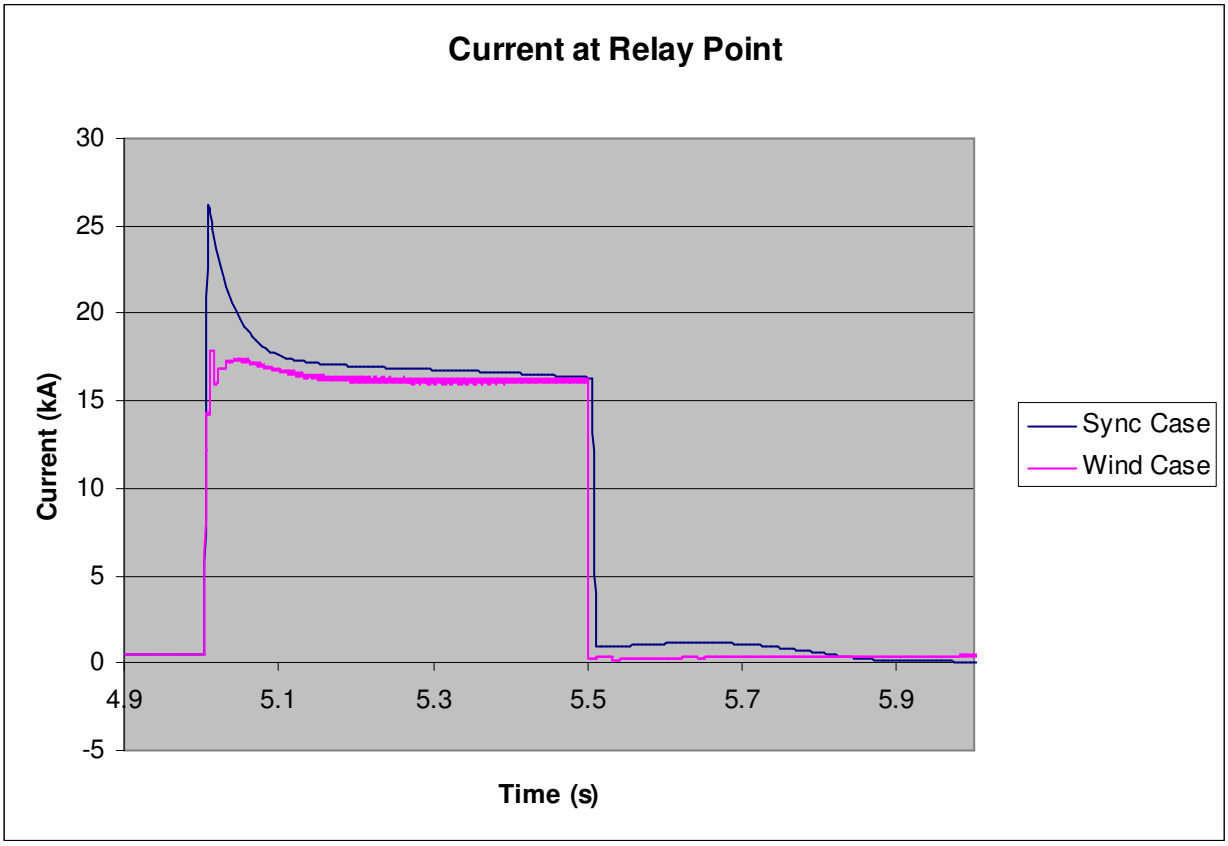
converters have a finite current limit, their fault response is relatively subdued, compared with conventional synchronous generators. Typically, a converter is limited to its normal rating, and perhaps a 10-30% short-term overload capability.

Unlike synchronous generators, inverter connected generators do not have an inherent characteristic behaviour, and can be programmed to respond to faults in whatever fashion is desired. In the UK, a requirement has recently been released for converter-connected generation to produce maximum reactive current during a fault, plus real-power in proportion to the retained voltage, in order to support the network during the fault. However, other responses are possible. In some European countries for example, there is a requirement for full reactive power during the fault but no requirement for real power.
In some cases, embedded converter-connected generation has been known to be programmed to provide no fault contribution (i.e. to stop all output during a fault), to avoid overloading the fault rating of local switchgear. Whilst this approach may reduce the cost to the developer of connecting renewable generation to the local network, it would clearly not be good for the power system at large to have significant volumes of generation that provide no fault contribution. I am not aware of such a standard in Australia yet. If a standard has not yet been developed, it is important that this is done to protect the security of the overall power system. When defining such a standard, consideration should be given to the characteristics of the Australian power system to ensure that the standard response(s) provide the maximum benefit to the power system.

The typical *fault contribution* from a synchronous generator (blue trace) and a UK compliant wind farm comprised of inverter-connected wind turbines (pink trace), is compared in the plots below, both for a small capacity installation (left) and a large installation (right).



In the event that all of the generation in the system were supplied by inverter-connected wind with a characteristic as above, the *fault-current measured by protection relays* would probably resemble the trace in the plot below.



The one clear difference in the measured fault current is the absence of an initial impulse. Depending on the specific circumstances in the local network, the fault level could also be much lower that what it presently is with entirely synchronous generation. This has several implications.

Future fault level studies will need to take account of the different fault contribution from inverter-connected generation. Because the fault - response of an inverter-connected turbine can be programmed, considering them in fault level studies could involve quite a bit of additional work. Present fault level analysis tools calculate the fault level contribution from different generators using known generator parameters and the standard response of synchronous generators. However, to take account of the different response of inverter-connected generators, it will likely be necessary to undertake time-domain studies, which are more complicated and far more computationally expensive. If a standard response is defined (or a number of different standards which can be selected from), it may be possible to incorporate these into the fault-level calculation tools to calculate the fault level in a similar fashion as how it presently is.

Future protection setting studies will also need to take account of the fault characteristic of inverter-connected generation. Given that the proportion of inverter-connected generation online within a region could vary significantly from day to day as the weather changes, in addition to the normal variation in demand, protection settings will need to be robust for a wider range of background conditions. The worst-case situation would be a low-demand high-renewable generation scenario, as the fault level could be quite low and the measured impedance could approach the impedance observed in intact high-demand low-renewable conditions. If distance protection were used, it might become necessary to reduce the relay load limit to prevent spurious protection operation, reducing the rating of the circuit. If unit protection is used, any impulse 'starter' functionality may need to be disabled.

Given the relatively long lifetime of HV infrastructure, consideration should be given now to the capabilities that protection systems will be required to have in the future. For example, relays should be procured that can have any impulse functionality disabled, and it may be advantageous to make greater use of differential protection – even using dual differential protection (with distance backup protection should communications fail). National Grid is in the process of reviewing its standard protection designs and relay specifications to ensure that they will still be fit for purpose in 20 years' time, and I am grateful for their permission to reproduce the plots (above) from this work.

Consideration should also be given to the impact of a low fault level on any 'classic HVDC' links, since these require a certain fault level to be able to commutate. In areas of the network where the proportion of inverter-connected generation could be very high, it may become necessary to intervene to prevent the fault level from becoming too low. This could be done by:

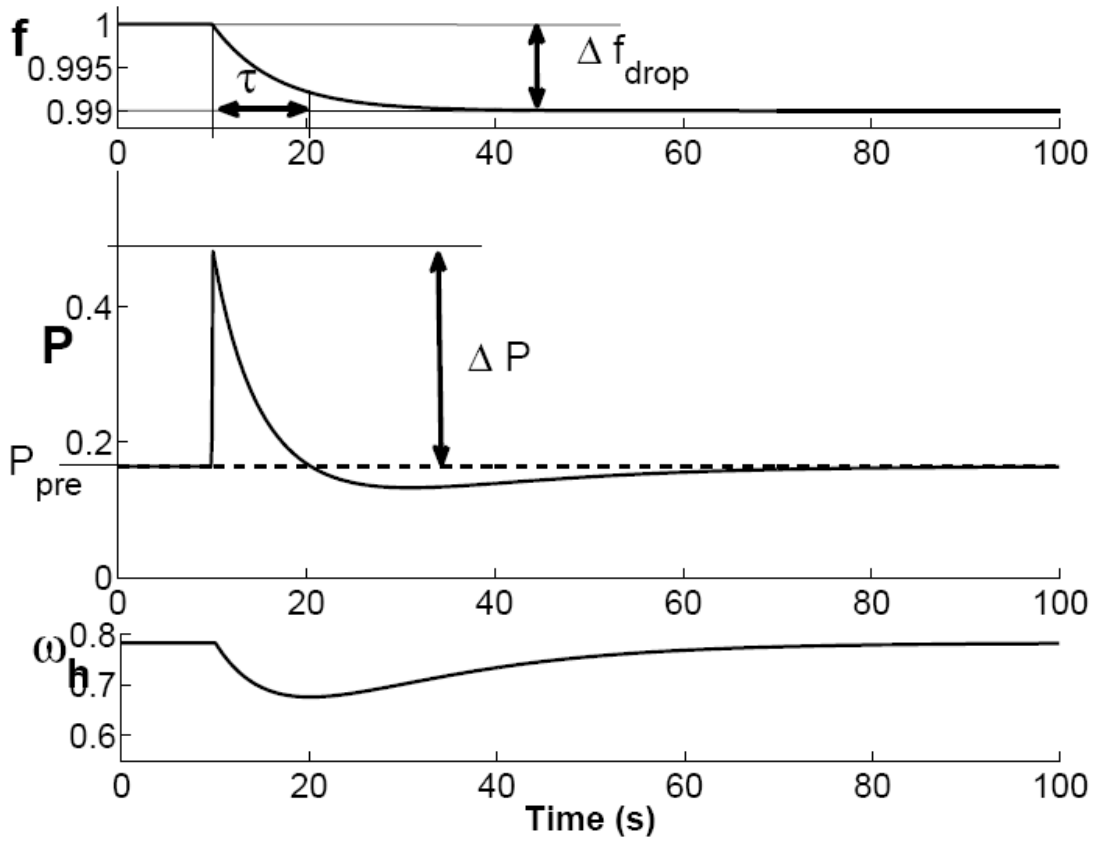
- requiring inverter-connected generation to have a higher short-term rating
- installing synchronous compensators
- using operational power system constraints (already being used in Denmark to maintain adequate fault level in high-wind low-demand situations)

Impact on Small Signal & Transient Stability Studies

The 'low-density' of many forms of renewable generation means that, in general, small light-weight turbines are used. Given that little energy is stored in the spinning rotors of such turbines, they do not naturally produce/absorb much power as the frequency varies, and therefore do not produce a significant inertial response to counteract frequency variations, as a large synchronous generator naturally would. When low-mass turbines displace conventional high-mass turbines, the overall inertia of the system will be lowered and small-signal and transient stability may be impacted.

However, where low-mass generators connect via a power converter, the power converter can be programmed to detect frequency-change events and respond in a particular fashion. In fact, it is possible to program the converter to emulate the inertial response of a synthetic generator to produce 'synthetic inertia'.

Whilst the mass of the rotor may be inadequate to naturally produce a significant inertial response to frequency variations of 0.5-2.0 Hz, the rotor does contain enough energy to produce a short term surge of power if the rotational speed of the rotor is permitted to drop significantly. The power converter can produce a surge up to the magnitude of the converter's short-term power rating, drawing power off of the rotor, slowing its rotation. The greater the 'surge' and the longer it lasts, the more the speed of the rotor will fall. If the available wind power exceeds the rating of the turbine (and the turbine was therefore spilling power prior to the low-frequency event), the blades will pitch into the wind to try to recover the rotor speed. Otherwise, following the surge the turbine may need to reduce its power output to below its pre-event value to enable the rotor speed to recover to its optimal value for power production. This is illustrated in the figure below:



[3]

If there is a requirement for a sustained increase in power (e.g. 60s raise Frequency Control Ancillary Service (FCAS)) from converter-connected renewable generation, then the only

[3] "Wind rotor inertia and variable efficiency: fundamental limits on their exploitation for inertial response and power system damping" by Barry Rawn & Peter Lehn. Presented at EWEC2008. Available online at: http://www.ewec2008proceedings.info/ewec2008/allfiles2/246_EWEC2008fullpaper.pdf

option is to operate the generation below the level of available power (i.e. ensure that some power in being spilled) pre-contingent, or to couple the generation with some form of energy storage. In situations where the proportion of such generation is high, it would therefore be best to utilise such generation for the fast and short-lived initial response and to save conventional generation for the slower forms of FCAS.

Suddenly reducing the output of a converter-connected turbine is not a problem, as while the turbine rotational speed can accelerate, the blades can simultaneously be pitched out of the wind (or equivalent, for other forms of renewable energy) to prevent the rotational speed from exceeding specifications.

Just as the controllers of converter-connected generation can be programmed to respond to frequency deviations, so too can they be programmed to detect power system oscillations or respond to an external signal, and vary the power output of the turbine in a manner that dampens the oscillation. Given the very fast response time that is possible with power electronics and the direct control over real power production, this could potentially be highly effective, if it is configured optimally.

Furthermore, converter-connected generation can also provide the same reactive power compensation and power quality filtering services that a STATCOM can provide. A number of wind turbine manufacturers have recently released offerings that can provide these services even when the wind is not blowing (and the real power output is therefore 0MW). This is achieved by adding an auxiliary supply to the DC bus of the power converter, as there would be in a STATCOM device.

Whilst converter connected generation has the potential to provide important services to the power system, a number of steps need to be taken to realise this potential:

- The value of converter-connected turbines needs to be assessed against the additional cost of the technology, especially if another solution would otherwise suffice. If the net value is positive, mechanisms may need to be put in place to incentivise or force developers to utilise the technology – otherwise they have no reason to incur the additional cost for such features. For example, National Grid has recently advised the industry that from 2015, turbines installed offshore will need to support synthetic inertia. An alternative may be to create another ancillary service, e.g. for power quality/small angle stability services. Ideally this arrangement would allow for the converter's programmed response to be updated from time to time as the power system changes, or ultimately, be configurable/selectable in real-time with input from a wide-area monitoring and control system.

- The benefits of converter-connection generation will only be realised if the controllers are configured appropriately. Studies therefore need to be undertaken to define the response that such turbines should provide. When performing such studies, the

intermittent availability of renewable generation and the ancillary services they provide should be considered, along the performance at varying levels of power output. Given that the response is fully programmable and the inertial response of a synchronous machine may not necessarily be the optimal response (to date, it has been the only available response), National Grid is presently conducting an investigation into what the optimal response in the UK would be. The optimal response may vary from power system to power system, region to region, and at different voltage levels.

- The response of converter-connected turbines needs to be taken into account when performing system stability studies. Therefore, procedures need to be established to develop models of the programmed response of such turbines, and to verify the response during commissioning.

Next Quarter

My primary responsibility during the next quarter will be completing the development of the first Offshore Development Information Statement, and then assisting with the collection of feedback from industry. In addition to my normal responsibilities, I have discussed my scholarship objectives with my manager and agreed the following development actions:

- participation in the code-compliance assessment of a wind farm
- sitting in on a couple of shifts in the control room – both on the network switching and generation dispatch desks
- visiting a major GIS substation in central London
- attendance at relevant meetings/presentations
- ongoing discussions with colleagues involved in a wide variety of relevant work (where much of the content of this report originated)

Acknowledgments

I would like to thank all of my colleagues for the warm and friendly manner with which they have welcomed me into the team and freely given of their time to explain the work that they are involved in. I am especially grateful to:

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- Beehun Tan, Manager – Strategy Development, for many good discussions, the opportunity to be involved in interesting work, and his interest in my development

- Helge Urdal, Manager – Generator Dynamic Performance and the entire GDP team, for their willingness to help me to learn about the dynamic issues associated with renewable generation, and let me sit in on their team meetings.

And ultimately, I wish to acknowledge my Lord and saviour Jesus Christ, for creating this world including me, and for granting all of the abilities that I have and all of the amazing opportunities I have received. Even more so, for dying for me to take the penalty of my rejection against Him, and calling me into a relationship with Himself. Soli Deo Gloria – to God alone be the glory.