Field Experience with Synchronous Wind Turbines in New Zealand and Scotland:

Instances of short-circuit current contributing to system stability, and an instance of frequency instability.

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***Abstract* — Synchronous wind turbines, directly grid-connected, provide about 10% of New Zealand's wind power at a 48 MW wind farm that has been running since 2006. A further 4 MW of these turbines have been installed in Scotland since 2013. Experience will be presented of instances of voltage support during low-voltage events in New Zealand by provision of large short-circuit current, as well as general reactive power support in response to a commercial incentive.**

In addition an interesting experience will be presented of brief islanding of the synchronous wind turbines alongside some inertia-less turbines in the Orkney Islands, Scotland. This led to a suspected pole-slip event which caused some mechanical damage to the turbine's drive-train because of unexpectedly high rates of change of frequency. However this damage was limited to the drive-train's mechanical torque-limiting system and did not damage the gearbox or generator.

The positive attributes of synchronous wind turbines are also discussed in the context of the September 2016 blackout in South Australia and the growing demand for these attributes in Europe, China and Australia. With at least three technologies for enabling synchronous wind power having been installed world-wide, including one with a long track record in one of New Zealand’s windiest sites, it raises the question why the accepted "Types 1-4" list of wind turbine grid-connection options excludes synchronous wind turbines.

Keywords- synchronous wind turbines

I. INTRODUCTION

Protecting the gearbox of a full-span variable pitch wind turbine was the original motivation for inventing the torque-limiting gearbox (TLG) system in the late 1980s [1]. High-slip induction generators, directly grid-connected were the norm then. The torsional compliance they provided was sufficient to moderate torque and power excursions so that standard deviation (relative to rated) of about 25% was achievable. With occasional excursions to three or four standard deviations, the result was that gearbox application factor, K_a, needed to be at least 2.0. So a 500 kW turbine needed a 1000 kW gearbox, a significant penalty in terms of turbine capital cost. Reducing K_a by fundamental torque control was a focus of several R&D projects at Britain’s Wind Energy Group Ltd during the author’s time there.

The synchronous generator played a role in the invention of the TLG, not as an end in itself, but by providing a moment of insight which led to the concept of mechanical torque limitation. Wind Energy Group was researching synchronous generation on a 250 kW turbine in Devon using a fluid coupling to provide a slip characteristic. The author was tasked with installing and commissioning the synchronous generator to replace the existing induction machine. Instead of the familiar, simple contactor-closing to bring the induction machine on line, synchronization now required speed controlling the turbine for some time, until random wind fluctuations brought the generator in phase with the grid. What was remarkable was that, even in gusty gale-force winds on that cliff-top Devon site, the speed control pre-synchronisation gave a standard deviation lower than 1% of the set-point. This was using the very same pitch-control system that struggled to achieve a standard deviation of 25% when controlling about a power setpoint.

The insight this led to was that pre-synchronization, the turbine was in a variable-speed mode with constant (near-zero) reaction torque from the drive-train, an infinite slip mode. What if we could also keep torque constant at rated power, transitioning from a low-slip mode to an infinite-slip mode, relying on the blade pitch system to keep speed under control? Then we could solve the gearbox torque transient problem and achieve a much lower value of K_a, with consequent cost and reliability benefits. And since electrical faults and gust loads against generator rotor inertia [2] are a known source of gearbox torque transients, mechanical torque-limitation was selected as a key part of the TLG system. By using a radial piston pump for torque-limitation on a differential stage at the high-speed end of the gearbox, it could happily remain almost stationary below rated, keeping efficiency high where it matters and minimizing the amount of power that this sub-system needed to be rated at.

Two years later, a further research project on that same Devon turbine proved the TLG concept, with a synchronous generator but this time without a fluid coupling. Ironically, at the time the ability to run a synchronous generator directly on line was regarded as a side-benefit, and one of dubious value since, as colleagues pointed out in the late 1980s “wind power will always be a small part of the generation mix and anyway Britain has a massively stiff electricity grid”.

II. SYNCHRONOUS WIND POWER IN NEW ZEALAND

Fast forward nearly thirty years and perceptions about synchronous generation in a renewable energy future are starting to change. Power electronic converter (PEC) technology has become widespread in solar and wind power applications and grid operators are starting to question whether their grids are as strong and stiff as they used to be, and as they need to be.

In the intervening period the author returned to his native New Zealand and set about establishing a business designing and building 500 kW wind turbines that combine two load-reducing technologies so as to be able to compete against cheap hydro power in an unsubsidised economy. The TLG was one of those technologies and it was paired with the synchronous generator, in part because it had some technical advantages, but as much because, being mass-produced for the diesel genset market, it is less expensive than the induction generator option.

A. Reactive Power Provision by the Prototype Windflow 500

In 2003 the prototype Windflow 500 was installed near Christchurch, New Zealand, connected into the network owned by Orion New Zealand Ltd at 11 kV. At the time Orion offered incentives for the production of real and reactive power at times of local system peaks. These were called controlled demand periods (CDPs), typically lasting 15 minutes and signalled using ripple control transmission. Accordingly the prototype was programmed to maximize revenue from a mix of real and reactive power according to the wind conditions:

- In good winds real power was maximized and as much reactive power was added as possible while staying within the generator's kVA limit
- Below cut-in winds, reactive power could be maximized, up to the generator's kVA rating. To enable this synchronous condenser mode, a 22 kW pony motor was installed with a belt-drive to the generator (which has a one-way clutch on its cardan shaft from the gearbox) to enable the generator to be synchronised while the wind turbine remained parked. Figure 2 shows an example of this operation, a 15 minute CDP when the generator exported 550 kVAr while importing about 15 kW to overcome its losses. Notice the feature in the middle of the CDP when the voltage stepped down due to the action of an auto-tap-changer at the local substation, no doubt due to the fact that our synchronous condenser mode was driving up the network voltage by exporting 550 kVAr. With the buy-back rate for kVAr during CDPs being about half that of kW, this more than paid for the kW consumption. Year-round, this provided about a third of the turbine's revenue while Orion kept this scheme in place.

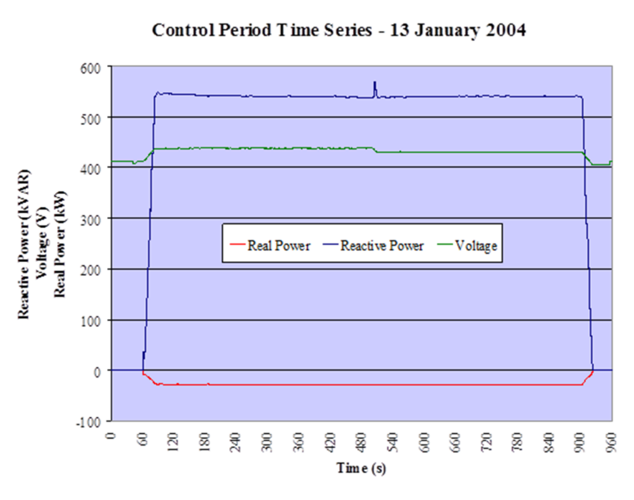


Figure 2. Synchronous Condensor operation of the Protoype near Christchurch (wind speeds below cut-in)

B. Voltage Control and Low Voltage Fault ride-through at Te Rere Hau

Following the prototype's successful demonstration near Christchurch, Windflow secured financing for a 48 MW wind farm which was built on the Manawatu Saddle of the Tararua Ranges in the lower North Island. The electrical grid connection was made in two phases:

- Initially in 2006 an 11 kV connection was used for the first five turbines (2.5 MW). Despite the local network company's assurances, this line proved incapable of carrying 2.5 MW or even 1.5 MW. So for the first two years, the wind farm was de-rated to 1.0 MW (5 x 200 kW). Even then the 11 kV conductors were susceptible to significant voltage rise, which caused problems for a neighbouring air traffic control radar station. Fortunately we were able to take advantage of the generator's excess kVA rating and run on its stability limit, importing about 260 kVAr to bring down the voltage. So for the first two years, when we exported 1.0 MW from the pilot wind farm, we were also importing 1.3 MVAr of reactive power to control the voltage. Figure 1 illustrates the capability curve of the synchronous generator:

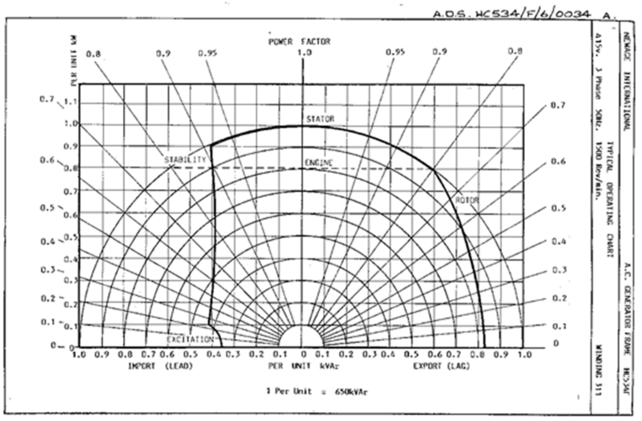


Figure 1. Characteristic Curve of the Windflow 500's Synchronous Generator

- Subsequently, as the rest of the wind farm was built out in 2007-2011, a double circuit 33 kV connection was installed to a 220 kV substation at the neighbouring Tararua Wind Farm. Being more or less directly connected to the main backbone of New Zealand's transmission system, there ceased to be any issue requiring voltage control, reactive power support or any of the ancillary services that the synchronous generator could provide. In accordance with the system operator's instructions, the turbines have been operated in power factor control mode, at about 0.98 exporting. It was surprising to the author that nothing more sophisticated was asked, but with hindsight it is clear that New Zealand's high-quality, hydro-based electricity system has little need of these ancillary services. So the generators have behaved themselves with little to report except for some low-voltage ride-through events that would have escaped our attention if they had not triggered the recording function within the SEL relay installed at each turbine. Figure 3 illustrates one of these events.

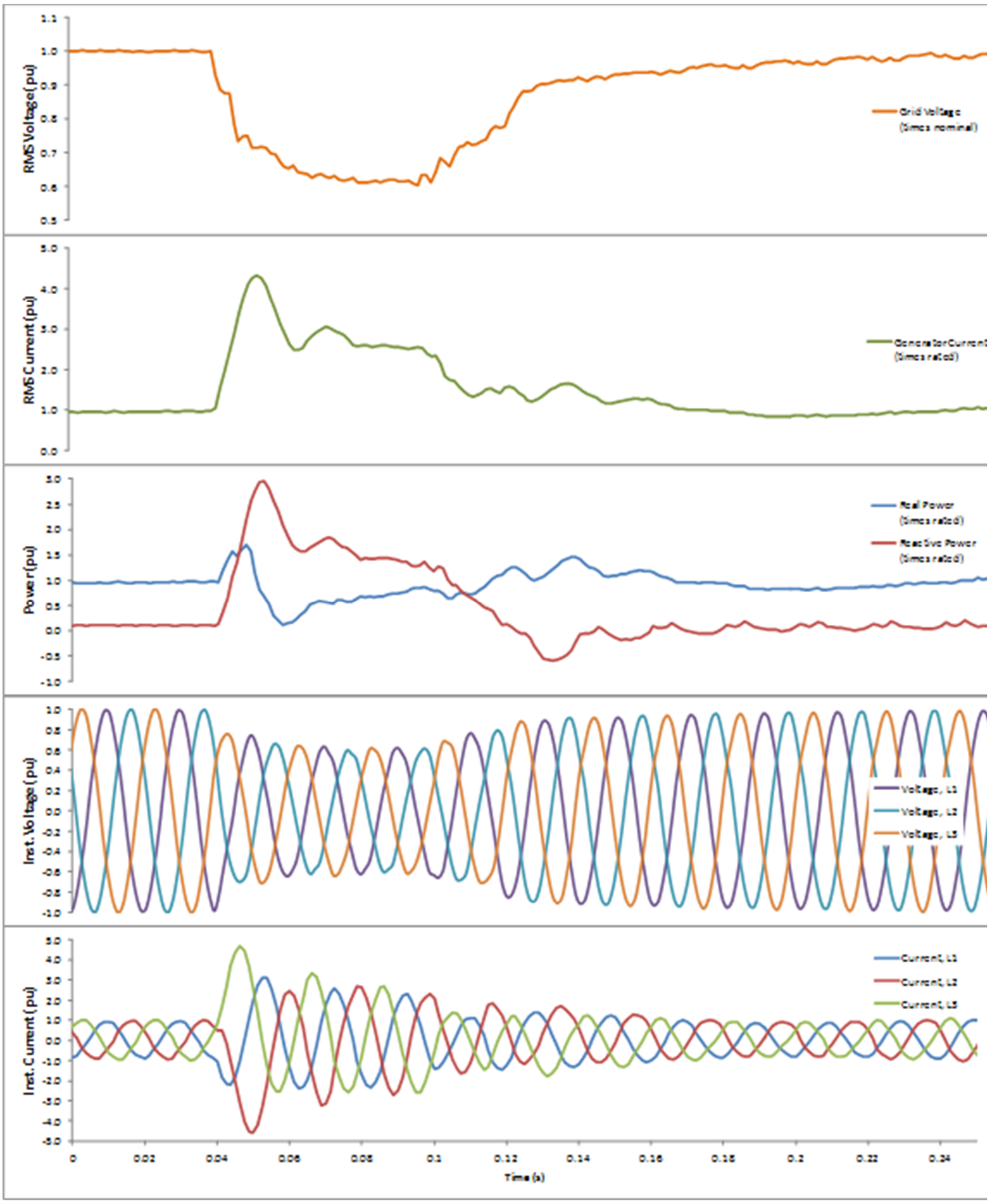


Figure 3. Fault response of Windflow 500 synchronous turbine during voltage sag event, 8 September 2012, at the 48 MW Te Rere Hau wind farm, New Zealand. This shows an example of short-circuit current contribution and ride-through of a Windflow synchronous turbine during a system voltage disturbance that lasted around 100 ms (0.1 seconds). It is the same basic response as any other “conventional” generating plant on the grid. The top pane shows the voltage dip on the gird. The second pane shows the short-circuit current response. The third pane show the real and reactive power response, and in particular the red trace shows reactive power immediately being exported to oppose the dip in voltage. This is initially at about 0 kVAr but shoots up to 3 times rated before settling as voltage recovers. The bottom two panes show instantaneous voltage and current from the generator and show the turbine remaining online and returning to approximately pre-fault levels shortly afterward. Note that the peak current on one phase is nearly five times the rated current (it was at rated before the disturbance) and that this peak precedes the maximum voltage dip. By opposing the voltage dip, it reduces its magnitude.

III. SYNCHRONOUS WIND POWER IN SCOTLAND

With the Te Rere Hau wind farm complete and the market for wind farms in New Zealand entering a stagnant phase, Windflow turned to the UK's feed-in-tariff market for single 500 kW installations. Between 2013 and 2016, Windflow installed eight turbines (4 MW) at six different locations in Scotland. The electrical attributes of the synchronous generator seem to have assisted with processing our grid connection applications, but have not been otherwise valued by the network companies, 500 kW being insignificant in the scheme of things. As at Te Rere Hau, the generators have been operating generally uneventfully in power factor control mode, close to unity.

A. *Islanded Operation with Inertia-less Neighbours?*

A significant event occurred on 27 January 2017 on the Orkney Islands north of Scotland. Two of our turbines were operating at the time in a part of the network called Zone 1a, which powers the north of Mainland Orkney and islands to the north-west of the group. 10-15 MW of power electronic connected (PEC) wind turbines are also connected to Zone 1a at Burgar Hill, Hammar's Hill, Rousay, Gallowhill (Westray) and Eday. Zone 1a is on a spur line which can become islanded if a circuit-breaker opens at a metering point around Finstown, west of Kirkwall. Figure 4 shows the voltage and current on one of the phases, as well as the frequency recorded by the SEL relay at one of our turbines. The data captured was about 15 seconds before a complete blackout (not captured here).

It is difficult to determine what caused these unusual traces. The frequency steps up to 60 Hz and down to 43 Hz must be some kind of artefact of the SEL relay's algorithm. They are impossible to reconcile with the actual voltage or current waveforms. Almost certainly the system fault that caused the blackout about 15 seconds later was causing the network's protection systems to activate.

However we know from damage done to our torque-limiting pumps, and from an impact sensor on the pallet having been triggered, that some torsional shocks occurred in our drive-trains. Wild frequency swings would be consistent with this mechanical evidence. Thus we have speculated that these traces were caused by an isolator opening around Finstown, causing Zone 1a to become islanded momentarily, before reclosing with the rest of the system which was slowing down due to whatever system fault had occurred (and which would lead to a blackout shortly thereafter).

According to this theory, during the 2-300 milliseconds that our two synchronous turbines (1 MW total) were islanded with 10-15 MW of PEC turbines, the frequency became unstable as the PEC systems are not configured with a frequency–setting capability and have zero inertia. Thus the PEC waveforms became arbitrary, and their greater power rating was able to jerk our smaller synchronous generators around.

Whether or not this theory is accurate, it illustrates what an inertia-less system might look like, and thus why electricity systems need generators to have inertia.

The other thing it has illustrated is that the TLG is effective at protecting the main gearbox from torsional shocks. Unlike other synchronous wind turbine drive-trains, the use of hydrostatic torque reaction (rather than hydrodynamic torque transmission) means that the TL pump can act as a sacrificial element in the event of pole-slip or similar events. As the Australian Energy Market Operator stated in their October 19, 2016 "Update Report - Black System Event In South Australia On 28 September 2016":

> '*Fault ride-through strategies for synchronous machines are fundamentally different to those for non-synchronous power electronic based devices.*
>
> *A synchronous machine responds to disturbances by virtue of its physical characteristics (size, mass, rotational inertia) and by the action of its automatic voltage regulator. This provides fault ride-through capability and network voltage support. Unlike most power electronic based devices, these generators do not necessarily switch into a distinct fault ride-through mode. The primary concern for a synchronous machine during multiple, successive faults is the mechanical stresses placed on the turbine and generator.*'[3]

The event in the Orkneys on January 27 was an illustration of this concern in action and has vindicated the TLG architecture as providing a robust, cost-effective way of dealing with it. The TL pump prevents the drive-train from being over-stressed but can experience damaging speed excursions. If so, it is relatively inexpensive to refurbish and is small enough to be swapped out uptower without the need for a mobile crane. The generator holding-down bolts are naturally rated to absorb these sort of shocks due to rotor inertia effects. The support structure, being designed to handle wind turbine loads, is not over-stressed.

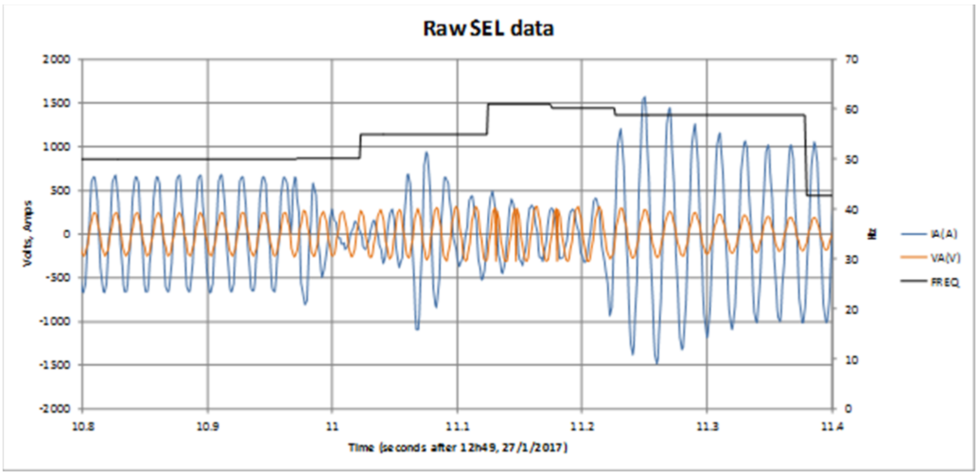


Figure 4. Current, Voltage and Frequency data from suspected islanding event 27 January 2017

IV. THE LVS SYSTEM

A limitation of the TLG system for wind turbines has previously been that, on its own, it was a narrow-band form of variable speed operation. The turbine:generator gear ratio is not fixed but infinitely variable due to a differential stage in the gearbox. Relative to “synchronous turbine speed”, which is defined as the speed when the generator is synchronised (eg at 1500 rpm) and the TL pump is stationary, the design speed variation of the wind turbine has been 0 to +5%. This has kept the TL pump rating to only 5% of wind turbine rating (eg 25 kW for a 500 kW turbine), minimising capital and maintenance costs, but reducing the turbine’s aerodynamic efficiency in low winds.

This limitation is not important in a high wind country like New Zealand where IEC class 1 sites have been developed to date and hundreds of megawatts of even windier sites (up to 12-13 m/s) are consented, waiting to be developed when the market re-emerges.

But in most sites around the world it is essential to have broad-band variable speed capability because low winds dominate the energy histogram. In response Windflow has developed an extension to the TLG system called low-variable-speed (LVS). The concept is to keep the power rating of the hydraulics low (matched to the TLG hydraulic rating – say 5% of turbine rating) by tailoring the broad-band range to be active primarily in low winds. This achieves the main objectives of broad-band variable speed operation which are to reduce cut-in wind speed, improve energy capture and reduce sound levels. The overall speed range can be tailored to individual turbine designs, but typically the result is two modes of variable speed operation:

- -40% to 0% variation relative to synchronous turbine speed in low winds (LVS mode)
- 0% to 5% variation in medium and above-rated winds (TLG mode)

The LVS system has been successfully developed now in Windflow’s class 2/class 3 turbine, the 45-500, in a 60 Hz unit in Texas and a 50 Hz unit in Scotland. It has recently been patented in several countries including China.

Importantly, the LVS system makes no difference to the way the synchronous generator operates, synchronised with the grid, with no power electronics.

V. AN IDEA WHOSE TIME HAS COME?

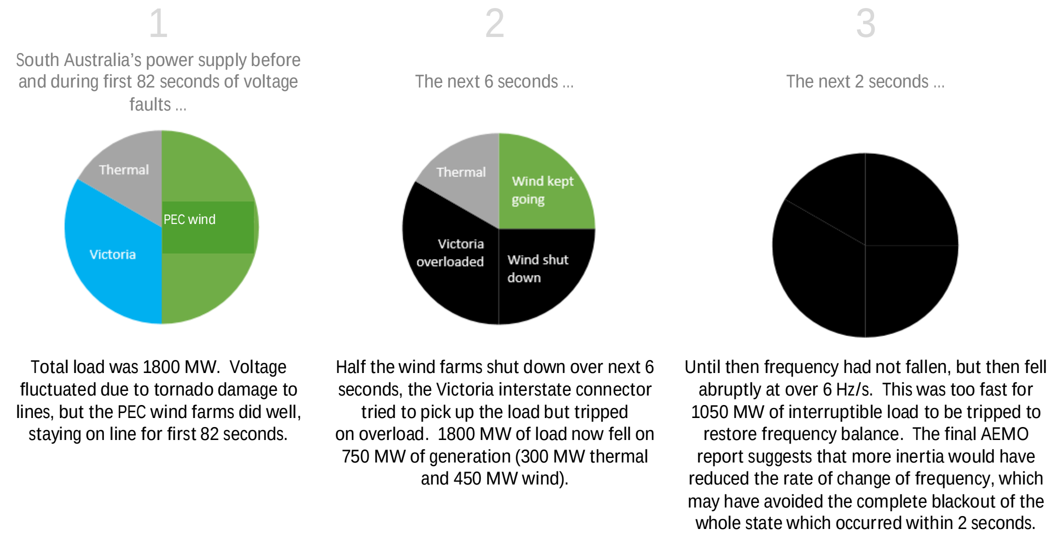
The attributes of synchronous generators are coming into focus in Australia, Europe and China as these economies invest significantly in asynchronous renewable energy and retire synchronous fossil-fired power stations. The South Australian blackout of 28 September 2016 in particular has made “synchronous generation” almost a household word. The pie-charts in Figure 5 illustrate the progress of the blackout.

Physical inertia and large amounts of short-circuit current are two attributes, in terms of which PEC systems can not compete with synchronous generators. Both these attributes come into play in achieving voltage and frequency stability during fault situations. Short-circuit current up to 10 times rated can stabilise voltage faults and assist protection systems to operate quickly, while it also has an important role to play in the synchronous effect which links the physical inertia of all generator rotating sets on a grid to provide a virtually instantaneous response to moderate the rate of frequency change in a load imbalance situation.

These attributes of synchronous generators are well-understood and trusted in electricity systems around the world. The drive to renewable energy, essential if we are to avert the worst effects of anthropogenic climate change, is causing a real tension as to how to retain these attributes. For example Figure 6 shows the trend in inertia, as exceedance lines, in the South Australian system between 2010 and 2016. It shows that the growth in connections of wind and solar power between 2010 and 2016, has led to inertia levels reducing significantly, by a factor of three or four at the 95%-ile level.

The following is an excerpt from the Final Report in June 2017 by the Australian Government’s Chief Scientist, Dr Alan Finkel, “Independent Review into the Future Security of the National Electricity Market” [4]:

> *‘Security and reliability have been compromised by poorly integrated variable renewable electricity generators, including wind and solar…Security should be strengthened through Security Obligations for new generators, including regionally determined minimum system inertia levels.…Technologies that provide a fast frequency response (FFR), including ‘synthetic inertia’ from wind turbines, can partially compensate for a decrease in physical inertia. However, international*



South Australia’s power supply before and during first 82 seconds of voltage faults ...

Total load was 1800 MW. Voltage fluctuated due to tornado damage to lines, but the PEC wind farms did well, staying on line for first 82 seconds.

The next 6 seconds ...

Half the wind farms shut down over next 6 seconds, the Victoria interstate connector tried to pick up the load but tripped on overload. 1800 MW of load now fell on 750 MW of generation (300 MW thermal and 450 MW wind).

The next 2 seconds ...

Until then frequency had not fallen, but then fell abruptly at over 6 Hz/s. This was too fast for 1050 MW of interruptible load to be tripped to restore frequency balance. The final AEMO report suggests that more inertia would have reduced the rate of change of frequency, which may have avoided the complete blackout of the whole state which occurred within 2 seconds.

Figure 5. Progress of the South Australia Blackout

experience shows that at present, in large power systems, FFR cannot provide a complete substitute for physical inertia.'

Similar concerns are being voiced in Europe. A 2014 study by ETH Power Systems Laboratory, [5] showed:

- At times now, due to wind and solar, there are times when inertia for the German system is half its historical level.
- Halving inertia is dangerous for the German system and it would be desirable to have more inertia-rich devices on line in connection with high use of renewable energy resources.

And Commission Regulation (EU) 2016/631 [6] entered into force in 2016, under which system operators can require an inertia response from wind.

In summary the attributes of synchronous generators are increasingly becoming topical as asynchronous forms of renewable energy increase their penetration into previously fossil-dominated grids. Windflow has been developing its synchronous wind turbine technology in New Zealand, Scotland and the USA and has over 600 turbine-years of track record. New Zealand in particular has been a technically and commercially challenging testing ground, where the main advantage of the synchronous system has been that it is fundamentally cost-effective.

Windflow's synchronous generators have performed as would be expected, largely in simple power factor control mode. Instances of voltage control, reactive power support and low voltage fault ride-through have arisen and again the synchronous generators have performed as would be expected.

The issue of potential mechanical damage due to successive grid faults or pole-slip events has been found to be manageable with the hydrostatic torque-reaction architecture of Windflow's patented system.

For those who are unaware that the synchronous wind power is an option, the conclusion to be drawn is that synchronous wind power is possible, proven and cost-effective. This raises the question why the accepted "Types 1-4" list of wind turbine grid-connection options excludes synchronous wind turbines. Perhaps an idea whose time has come?

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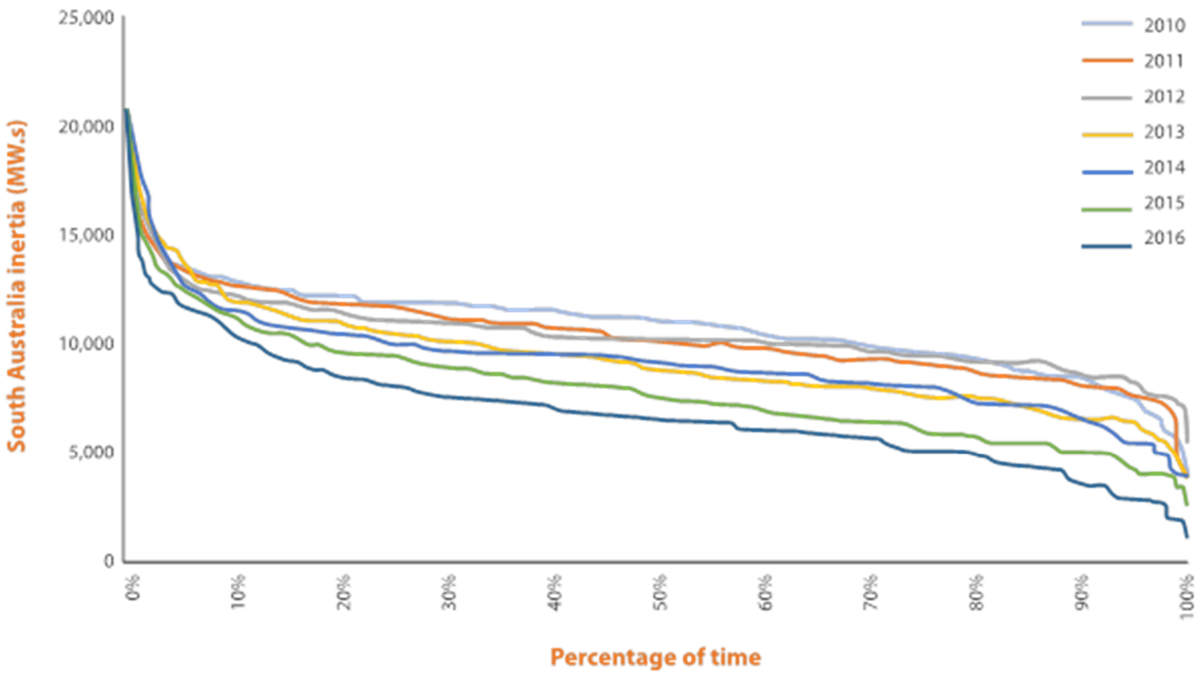

Figure 6. Reducing System Inertia in South Australia – Exceedance Curves