PHOENIX

International Review

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Report History

Date	Issue	Status
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11th May 2019	Version 2	Draft document for Phoenix NGESO & project team review
28th May 2019	Version 3	Draft document with National Grid ESO comments.
31st May 2019	Version 4	Final draft document.
17th September 2019	Version 5	Final document with Commercial Working Group input.
30th October 2019	Version 6	Final document with SPEN comments.

Contents

1. Introduction

This document reports the international review work to deliver Successful Delivery Reward Criterion (SDRC) 2.3 for the Phoenix project.

1.1. SDRC 2.3 and Interim Deliverables

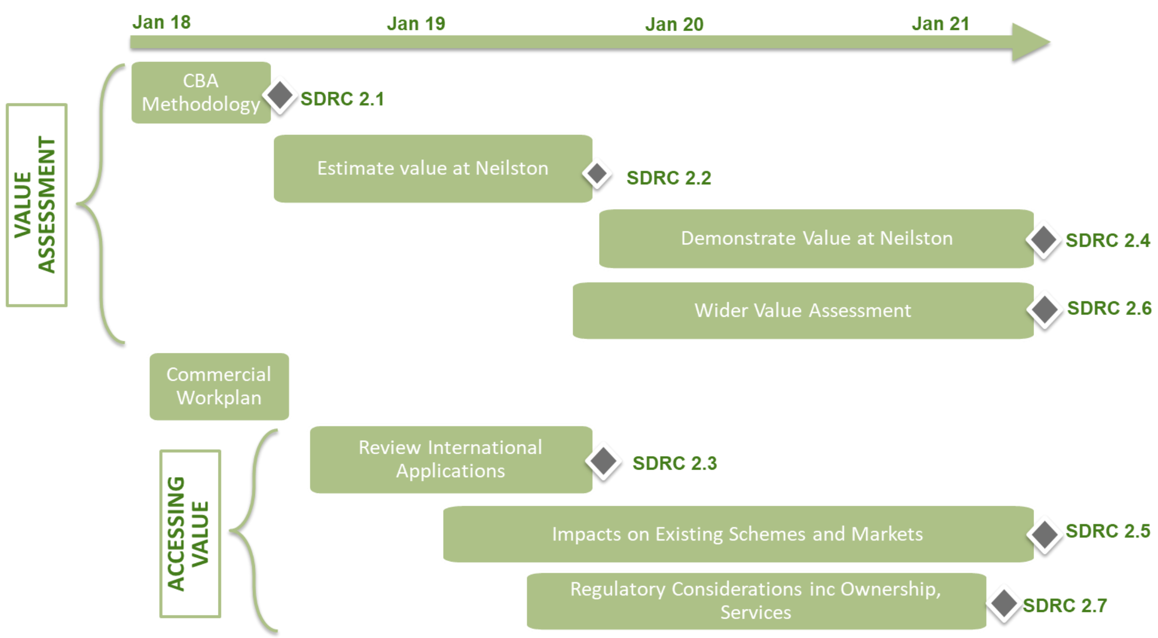
The international review work on the Phoenix project is intended to consider and learn from how similar challenges to those faced in Great Britain (GB) are being addressed in other parts of the world. This includes consideration of other transmission networks with high levels of renewable generation sources including networks where synchronous compensation is being installed. This will inform the wider commercial work being carried out during the Phoenix project.

Whilst there are no Hybrid Synchronous Compensators (HSC's) in service in GB or internationally, aspects of the commercial work can be informed by looking at countries such as Denmark, Germany, Iceland, Ireland, Italy, the United States of America (USA) and Australia where there are increasing levels of renewable generation being connected to transmission and distribution networks.

Given the challenges of reduced system strength, some of the electricity transmission networks in these countries are already utilising synchronous compensation to provide system benefits that were previously provided by synchronous generation. There are recent examples of synchronous condensers (SC's) being installed in Denmark, Germany, Italy and in the United States of America (USA). There are also proposals to install SC's in Australia.

The international work culminates in delivery of milestone SDRC 2.3. How this work fits with other elements of the commercial work is illustrated in Figure 1.

Figure 1 Main Phases of Commercial Work in Phoenix Project



In developing the wider Commercial Work Plan for Phoenix, the interim milestones in Table 1 were established for SDRC 2.3.

Table 1 Interim Milestones for Review of International Applications

Milestones	Completion Date
Agree Scoping of International Assessment - Agree international applications to be reviewed and detailed scoping of assessment.	September 2018
Reviews with TSOs & Regulators - Set up and complete interviews with relevant TSOs and Regulators.	January 2019
Review with CWG - Review initial conclusions of international applications work with Commercial Working Group.	March 2019
Draft Report for SDRC 2.3 – Report drafted by Market Specialist and reviewed by National Grid.	May 2019
Final Report for SDRC 2.3 – Issue final report taking account of stakeholder comments.	October 2019

2. Elements of International Review

2.1. Approach to Review

Other parts of the world are facing similar challenges to GB with the increasing use of inverter connected renewable generation and reducing system strength and inertia.

The Phoenix project is understood to be the first implementation of a Hybrid Synchronous Compensator (HSC). As direct international comparisons with other HSC's cannot therefore be carried out, this review focusses on how similar challenges are being addressed in other transmission networks and the use of synchronous condensers (SC's) internationally. Increasingly, these devices are being installed to provide system stability services that were previously provided by synchronous generators.

SC's were relatively widely installed and used through the 20th century for voltage support and power factor correction. At sites where generation would be expensive or difficult to operate, SC's were often used to provide reactive power to compensate for large inductive loads such as induction motors. From the 1980's, they have been less widely used as alternative reactive power control devices including SVC's and STATCOM's became more widely available. These alternatives were generally less expensive to install and maintain, and had better availability.

As the operation of synchronous generators in GB is reducing with more inverter connected generation being connected to networks, containing system frequency within limits, system strength and stability are becoming greater challenges. The benefits that SC's offer compared to other reactive power control devices include the stored kinetic energy and the short circuit infeed. As a result, SC's are being increasingly used by electricity utilities ahead of other reactive power control devices [1] [2].

Since 2012, in areas where synchronous generators have become particularly scarce, or more expensive to operate, SC's have started to be used to provide improved system strength. In some cases, SC's have been provided by adapting existing generation plant that is no longer economic to operate. Some of these cases (e.g. in Denmark, Germany and the USA) are covered in section 3 of this report. In other cases, new "off the shelf" SC's have been installed and utilised. These are more straightforward to install, control and maintain compared to earlier SC devices. Two pole machines are common and larger air-cooled SC's are now available with static excitation and starting systems. These modern control systems can provide much faster start up and much faster response to dynamic system events than was possible with earlier SC's [3]. Some of the new SC installations (e.g. in Denmark, Germany, Italy, the USA and Australia) are further detailed in section 3.

Focus of Review

As the use of STATCOM's to help manage voltage stability is widespread in GB and internationally, this review focusses on the increasing use of SC's to provide wider system strength. Further, the review has not examined cases where SC's have been installed along with high voltage direct current (HVDC) systems to help ensure stable operation of HVDC links.

Such a case is the transmission system in Manitoba, Canada, where much of load is supplied from remote hydro generation. In July 2018, Manitoba Hydro commissioned a 1400 km HVDC link to increase the security of load centres around Winnipeg that are supplied by remote hydro-electric generation. At its Riel converter station near Winnipeg, four 250 MVAr SC's were installed. Whilst these will help stabilise the power system local to Winnipeg, they are largely to support the HVDC convertors. In GB, SC's have not yet been used to date to support HVDC systems. For example, the Western HVDC link between Hunterston in Scotland and Deeside in North Wales began operation in December 2017 but did not include SC's as the local system was sufficiently strong to support operation of the link. (Appendix A includes further information on the wider use of SC's.)

The focus of the review has been on areas with similar system challenges to GB. In such areas, the particular challenges, the approach, benefits and market arrangements have been reviewed where possible. This was achieved through literature review, interviews with relevant Transmission System Operators (TSOs), Original Equipment Manufacturers (OEMs) and subsequent analysis.

This work has been supported by project partners and the Phoenix project Commercial Working Group (CWG). Project partners that have provided input have included ABB and DTU. CWG members that have provided input have included Siemens, Statkraft, SSE Renewables, the Energy Networks Association (ENA) and the Energy Systems Catapult.

2.2. Scope and Structure of Review

The following areas have been considered:

- **Denmark** - where a generator was converted for SC operation in 2013 and where three SC's have been installed since 2014 to provide system strength with lower levels of synchronous generators.
- **Germany** - where an existing generator was converted for SC operation in 2012 and where two SC's have been installed since 2014 to provide system strength and voltage management.
- **Italy** - where two SC's were installed on Sardinia in 2014 to enable the increased operation of renewable generation sources.
- **California** - where existing generating units were converted for SC operation in 2012 and where eight SC's have been installed since 2015 to provide system strength.
- **Ohio** – where five existing generating units were converted for SC operation over the period 2013-2016 to help provide voltage security.
- **Texas** - where two SC's were installed in the Panhandle area during 2018 to enable the increased operation of renewable generation sources and increased transfers of power to load centres.
- **Australia** - where SC's are being installed to help enable the connection of renewable generation sources, and to improve transmission system strength.
- **Iceland** - where there is a high level of renewable generation in service on an island network that is relatively small compared to GB.
- **Ireland** - where increasing volumes of wind farms are being connected and operation with higher levels of renewable generation is being sought.

Typically, the assessments have explored:

- What are the system characteristics and challenges in other transmission areas outside GB?
- What solutions have been implemented in other areas?
- How is the SC (or alternative solution) used?
- What are operational experiences to date? Have SC's enabled wider benefits for local networks and markets (e.g. increased opportunities for renewables)?
- What commercial and ownership arrangements are being utilised?

2.3. Outputs of International Work

The output of this work will contribute to other areas of the Phoenix commercial work stream. Operational experience to date will be important and the international experience will inform work on the forthcoming commercial deliverables SDRC 2.5 (Impacts on Existing Markets) and SDRC 2.7 (Ownership & Commercial Arrangements).

3. Areas Reviewed

This section summarises reviews for a number of international areas.

In the main, SC's might be installed for voltage support, to improve system strength and/or system inertia. Voltage support involves the production of or absorption of reactive power to maintain system voltages within acceptable limits as the demands on the system changes over time. Simple definitions of system strength and system inertia are given below.

System Strength enables a power system to withstand changes in generation output and load levels while maintaining stable voltage levels. In stronger systems, the voltage stiffness of the network is greater such that the voltage will change less as current changes.

System strength tends to be measured by the three-phase fault level, expressed in megavolt-amperes (MVA). At locations where the ratio of the fault level to the capacity of a connected generator is low (i.e low Short Circuit Ratio), there is greater likelihood that the generator will be unstable in operation. Improving system strength helps networks by improving resilience during power system disturbances, reducing system voltage fluctuations and ensuring that protection systems operate correctly.

System strength can be improved in several ways including the operation of synchronous generators, improved transmission inter-connectivity (e.g. additional lines), some types of voltage control equipment and SC's.

System Inertia enables a power system to withstand changes in generation and load while maintaining stable system frequency.

It tends to be measured in megawatt seconds (MWs). In a system with high levels of inertia, the rate of change of frequency (RoCoF) is less for a sudden change in load or generation.

Inertia is generally provided by large rotating electrical machines, including synchronous generators, motors and SC's. In some cases, the impact of reduced system inertia can be addressed by fast acting frequency control services.

Nine international areas are covered in sub-sections 3.1 to 3.9 below.

3.1. Denmark

Summary

Existing generation plant owned by Dong Energy was converted to SC operation in 2013. Subsequently, three new SC's were installed on the Danish network in 2015 and continue to be in operation.

Electricity System in Denmark

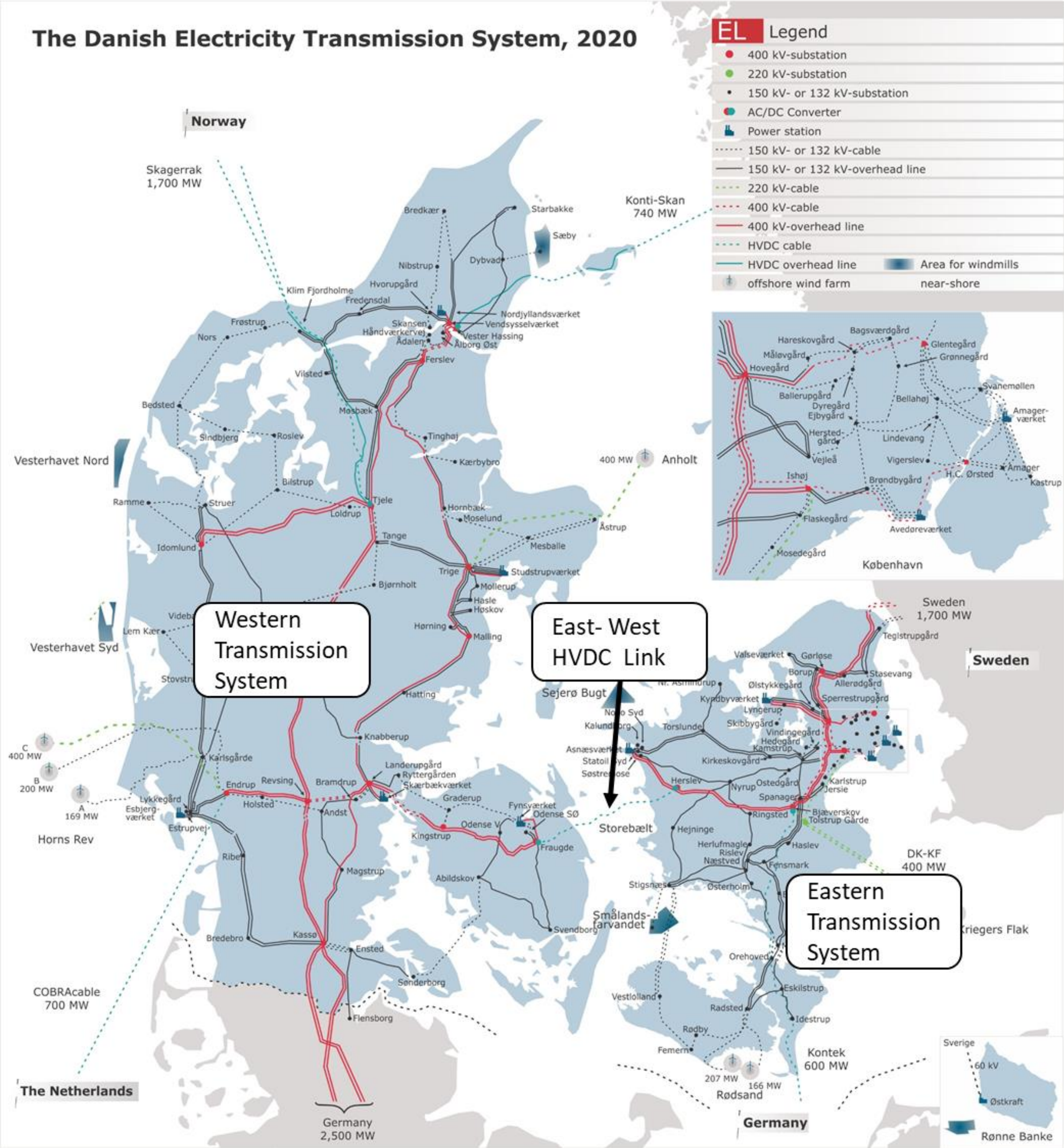
Total electricity demand in Denmark is around 33TWHr per annum. (This compares to GB electricity demand of 330TWHr in 2018.) The Danish electricity transmission network is illustrated in Figure 2 [4] and comprises an eastern transmission system serving the areas of Greater Copenhagen and Zealand (total demand around 13TWHr in 2017) [5] and a western transmission system serving North Jutland, Central Jutland and Southern Denmark (total demand around 20TWHr in 2017) [5].

The eastern transmission system in Denmark is synchronous with the Nordic synchronous network and the western system is synchronous with the continental European system. The eastern and western systems are linked by an HVDC interconnector.

The transmission system in Denmark is owned and operated by Energinet. Energinet is an independent public enterprise owned by the Danish Ministry of Climate and Energy.

In Denmark, renewable energy has been increasing rapidly over the last 10 years. Since 2009, the share of wind and solar energy relative to total Danish electricity consumption has increased from 19.4% to 43.5% [6]. In the same period the share of wind and solar energy in GB has increased from around 2% to over 20% [7].

Figure 2 Diagram of Danish Transmission System [4]



Characteristics of Danish Network

With the connection and operation of increasing levels of wind powered generation, problems were encountered with system strength on the Danish network from around 2011 as the levels of synchronous generation connected to the electricity transmission network were dropping.

Energinet was working to operational criteria that included a “must run” requirement for a number of synchronous generators to maintain system strength. From 2011, the costs of “must run” generation increased. In 2011, these costs exceeded M€25 and, in 2012, they increased to over M€40 [8]. In addition, the “must run” generators displaced renewable plant. (This position has similarities with GB where increasing system service costs have been incurred to address voltage and frequency issues arising from lower levels of synchronous generation.) As Energinet’s “must run” requirement got harder to meet with economically dispatched generation, more effective solutions were sought.

Solutions Considered for Danish Network

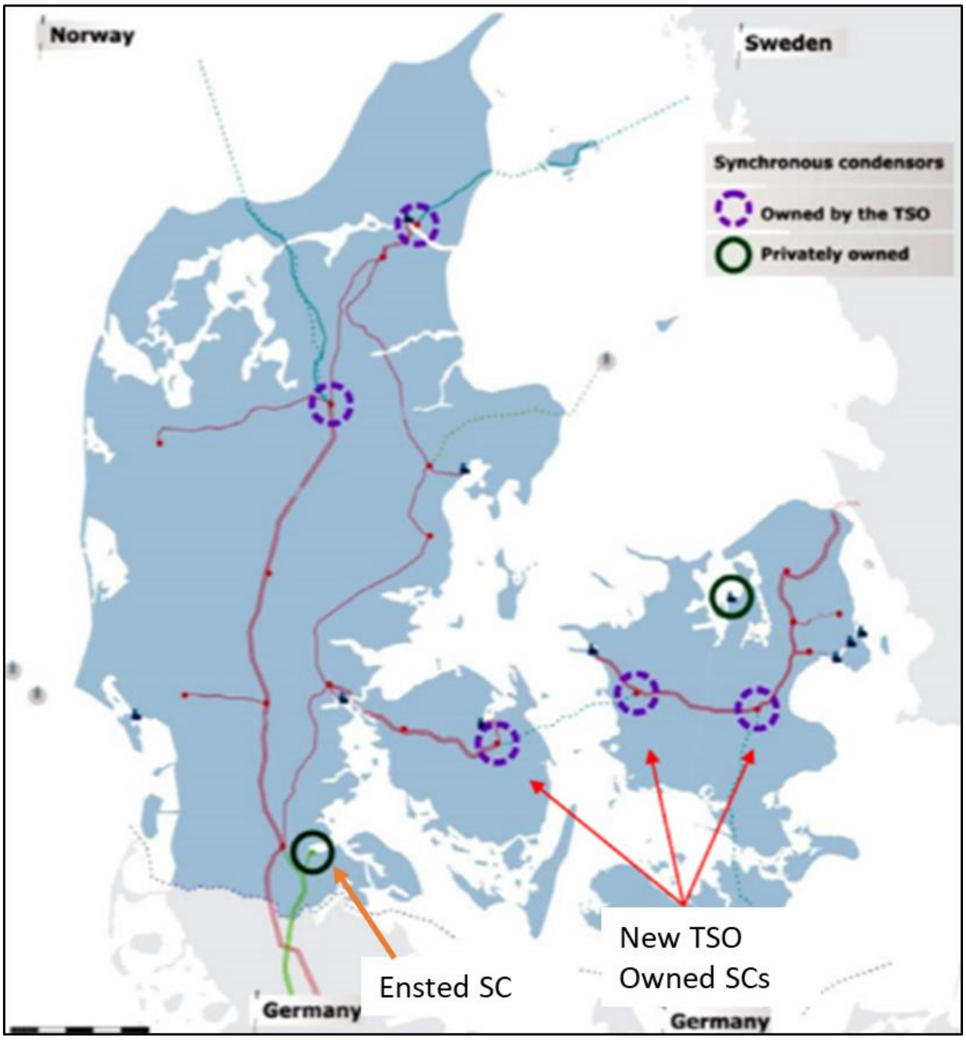
After the need for more cost effective support to the transmission network was identified, different options were considered. As well as new SC's, other potential solutions included the conversion of moth-balled generation plant to SC operation. Support from distribution-connected resources was also considered. However, protection arrangements for the Danish network mean that it is feasible that parts of the distribution network would be islanded from time to time.

Following an approach to Dong Energy, mothballed Dong Energy generation plant at Ensted was converted to SC operation in 2013. The 626MW rated Unit 3 generator at Ensted was converted in only a few months to provide reactive power in the range -350 to +800MVAr [9]. The conversion appears to have been successful and the Ensted synchronous compensator was providing services for much of the period up to 2015 when it was taken out of service.

Energinet also carried out a business case to assess the value of further SC's on the Danish network. This demonstrated that new SC's would be more economic when compared to continuing to operate generating plants out of merit to provide services. Following a tender process to determine who would own and operate SC's, it was determined that Energinet would procure and own three new SC's.

The three SC's were installed by Siemens in 2014 and 2015 [10] at Bjaeverskov, Fraugde and Herslev substations. The locations are shown on Figure 3. Each of the new SC's is rated at -150MVAr to +215MVAr of reactive power and each can deliver around 900MVA of fault infeed. (2 other TSO owned SC's were already operating on the Danish network. These had been installed in 1965 and in 1976 to support HVDC interconnectors.)

Figure 3 Location of Synchronous Condensers on Danish Transmission System (2015)



Use of Synchronous Condensers

Energinet report that the SC’s significantly reduce the number and duration of ”must-run” requests for conventional thermal generation through their short circuit level contribution, their dynamic and continuous voltage regulation and their fault-ride-through capability [8].

The three new SC’s run when insufficient levels of synchronous generation are operating. This has become increasingly frequent. When levels of synchronous generation drop, then SC units are scheduled to run by Energinet. As well as providing system strength, the units also provide voltage support for off-shore windfarms with long sub-sea cable connection circuits. Until recently, these windfarms could connect without the need to provide reactive compensation.

As the new SC’s are being operated more often, they are increasingly being used as part of Energinet’s voltage management strategy. Coarse voltage control can be provided through switched compensation devices that are installed on the network and the SC’s are used to provide fine tuning of voltage on top of this as levels of generation and demand fluctuate.

The SC’s also provide post fault voltage support. Two of the units can be started up and synchronised within 10 minutes and the third unit within 15 minutes.

Energinet have confirmed that the SC’s have been very reliable to date. They tend to run most of the time with stop/start operations avoided as these incur additional wear on the machines. Losses are up to 2.2MW for each SC when they are operating. As with other transmission grid losses, the costs of these losses are included in the TSO tariffs which are charged largely to load customers [11].

Commercial Arrangements

Having identified that an economic solution for the Danish network would be to install three SC’s, public tenders were carried out for market participants to own and operate the SC’s and deliver non-synchronous ancillary services to Energinet. This process was conducted in collaboration with Danish government and the Danish Energy Regulatory Authority (DERA).

There were two tenders, one for the first SC and then a second for the two further SC’s. Tenders were based on a 5 year contract (the maximum period allowed by the Danish regulator). Only one bid was received in the first tender and this was more expensive than a TSO owned SC option. No bids were received in the second tender. It is not clear why there was limited participation in the tender process but the level of investment and the tender period may not have been favourable to market solutions.

The three SC’s are owned and operated by Energinet. Energinet is both System Operator and Transmission Owner for the Danish electricity network though there is separation of these functions. There is also increasing debate within the Danish electricity industry on organisational arrangements.

The three SC’s are treated as other static transmission assets (e.g. shunt reactors) and are remunerated in a similar way. Until recently, this meant that Energinet was allowed to set its annual transmission charges to recover its yearly costs including the costs of funding investments such as the SC’s. (Regulation in Denmark has been unusual with this annual approach to cost recovery. This changed in 2018 with the introduction of a new system whereby DERA will set Energinet’s revenue for a number of years and allow limited adjustments in the regulatory period. An investment framework based on long-term development plans has also been established to enable greater transparency.)

More generally in Denmark, existing synchronous generator operators were unhappy about the provision of services for free. Compensation models have been considered to provide some payment for synchronous generation services, but this has recently been rejected by DERA.

Stakeholders have also lobbied the Danish Government and DERA to introduce legislation so that Energinet has to identify (and pay for) its ancillary service needs. These needs would include inertia, short circuit power and voltage regulation. However, it is likely be some time before the new ancillary service regime is up and running. Distribution stakeholders are also lobbying that they could provide transmission and wider network services going forward.

3.2. Germany

Summary

Existing generation plant owned by RWE was converted to SC operation in 2012. Subsequently, in 2015, a new 250MVAr SC was installed on the TenneT transmission network. In 2018, Amprion installed a SC on its transmission network.

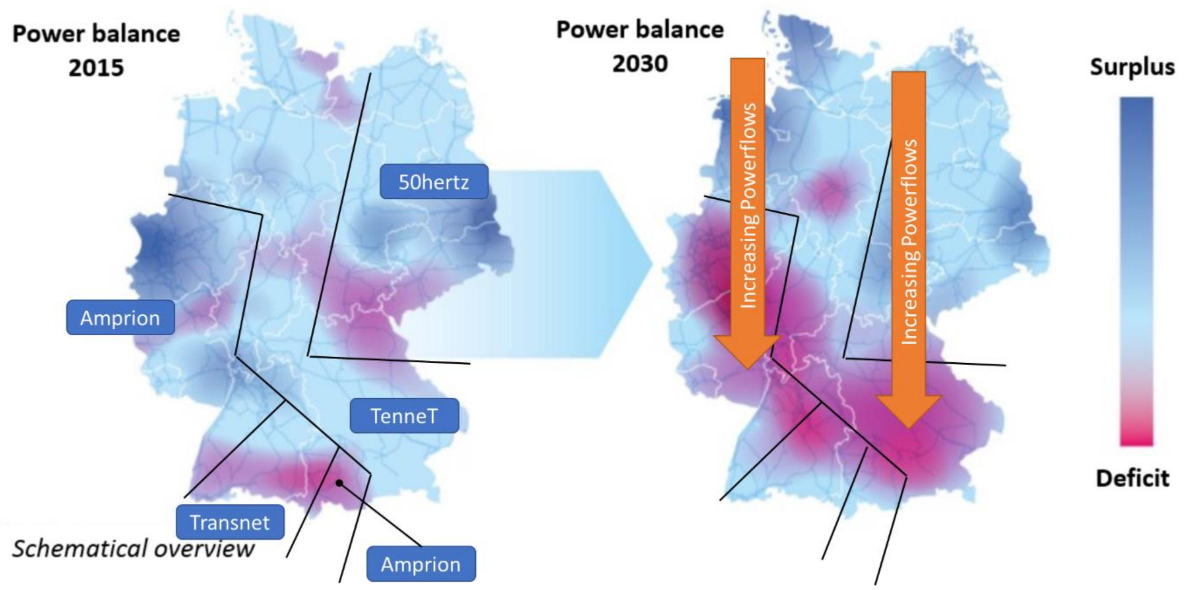
Electricity System Structure in Germany

Total electricity demand in Germany is around 600TWHr per annum, around twice the GB level in 2018. The German electricity transmission network is an extensive system which is part of the larger synchronous continental European system. There are imports and exports to neighbouring countries.

The transmission system in Germany is owned and operated by four TSOs. The service areas for these TSOs are illustrated on Figure 4. The TSOs are 50hertz, Amprion, TenneT and TransnetBW.

- 50hertz operates in the north and east of Germany and is majority owned by Elia, the Belgian TSO.
- Amprion operates in the west and south of Germany and is largely owned by institutional investors.
- TenneT operates in the north and southeast of Germany and is owned by the Dutch Ministry of Finance.
- TransnetBW operates the transmission system in the German state of Baden-Württemberg in in the southwest of Germany. TransnetBW is a subsidiary of the ENBW group.

Figure 4 Schematic Illustrating TSO areas & Powerflows [12] **(Based on Amprion Diagram)**



Electricity production in Germany has changed significantly over the last 15 years such that Germany is one of the world's largest producers of electricity from renewable sources. In 2003, renewable electricity production in Germany amounted to around 46TWHrs (7% of total electricity produced) and largely comprised on-shore wind, hydro and biomass generation. By 2017, the AGEB Energy Balances Group reported that renewable electricity production had increased to 216TWHrs (33% of the total electricity produced) and that this also included significant levels of off-shore wind and solar powered generation [13]. (This proportion is similar in GB. By 2017, renewable electricity production in the UK had increased to almost 99TWHrs or 29% of the total electricity produced [7].)

Germany has further ambitions to increase its levels of renewable generation. In early 2018, the new German government set a new target for renewable sources to provide 65 percent of German electricity consumption by 2030.

Alongside this commitment to renewables, Germany is phasing out its nuclear generation plant by 2022. In 2017, nuclear generation sources still provided almost 12% of Germany's electricity.

Characteristics of German Network

In Germany, as noted above, there have already been large-scale increases in electricity production from renewable energy sources including on-shore and off-shore wind farms and solar generation over the last 15 years. Together with the ongoing programme of nuclear power station closures, the characteristics of the German electricity transmission and the challenges faced by its transmission system operators are changing greatly.

As illustrated in Figure 4, much of the energy surplus is in the north of the Germany where there are more substantial on-shore and off-shore wind resources. Power transfers from north to south Germany have increased and will need to increase further if renewable energy targets are to be met. Whilst there are proposals to substantially increase north-south transmission capacity by 2025 through the installation of new transmission infrastructure including 4 new HVDC lines, it is possible that these reinforcements will be delayed through legal challenges to planning and installation.

With increasing and more variable power transfers and closing nuclear generation, there are increasing challenges to achieving power transfers and maintaining local system stability. Part of the solution in Germany has been to consider the installation of SC's.

Solutions Considered for German Network

The first SC solution implemented to support system stability in Germany was the conversion of RWE's Biblis nuclear power plant. Biblis comprised two pressurized water reactors with outputs of 1200MW (unit A) and 1300MW (unit B) respectively. In line with Germany's nuclear energy moratorium, unit A was disconnected from the grid in March 2011.

With the increasing levels of renewables and the shutdown of nuclear power plants in southern Germany, Amprion, the regional TSO, faced major challenges. To help stabilise the network, the Biblis A unit was converted to a SC. The conversion was successfully carried out and Biblis A was able to provide a reactive capability of -450 to +850MVAr. SC operation of Biblis A started during 2012 [9]. As with the conversion of Ensted generation in Denmark, the conversion of Biblis A was completed quickly to provide support to the transmission network.

A further key power station closure was the Grafenrheinfeld nuclear generating station in central Germany. This was due to be closed in 2015. The regional TSO, TenneT, identified that system support was needed locally and contracted with Alstom to install a -175MVAr to +250MVAr SC at Bergrheinfeld substation in Bavaria in 2015.

A further SC has been commissioned by Amprion in 2018 at Oberottmarshausen near Munich in southern Germany. This SC is noted in ENTSO-E's 2018 Ten Year Network Development Plan (TYNDP) [14]. In September 2018, Siemens and Amprion reported that the SC had been commissioned. (In press releases about the installation, the SC is also referred to as a rotating phase shifter.) Further details about this device have not been obtained as yet.

Use of Synchronous Condensers

Following the conversion of Biblis A to SC operation in 2012, it was reported to be still operating in 2016 [9] but subsequent information on its operation and performance has not been obtained.

Following installation of the SC at Bergrheinfeld in December 2015, this SC continues to operate. It is understood that it has performed as expected. TenneT are carrying further work to upgrade its network in the Bergrheinfeld area.

Commercial and Ownership Arrangements

The nuclear generator at Biblis was converted to SC operation by Siemens and continued to be owned by RWE. It is understood that Amprion contracted directly with RWE for services from the SC. It is not known if the how this contract is structured.

The SC at Bergrheinfeld substation is owned and operated by the regional TSO TenneT. Likewise, the SC at Oberottmarshausen is owned by the regional TSO Amprion.

3.3. Italy, Sardinia

Summary

Two 250MVAr SC's were installed on the Sardinian network in 2014.

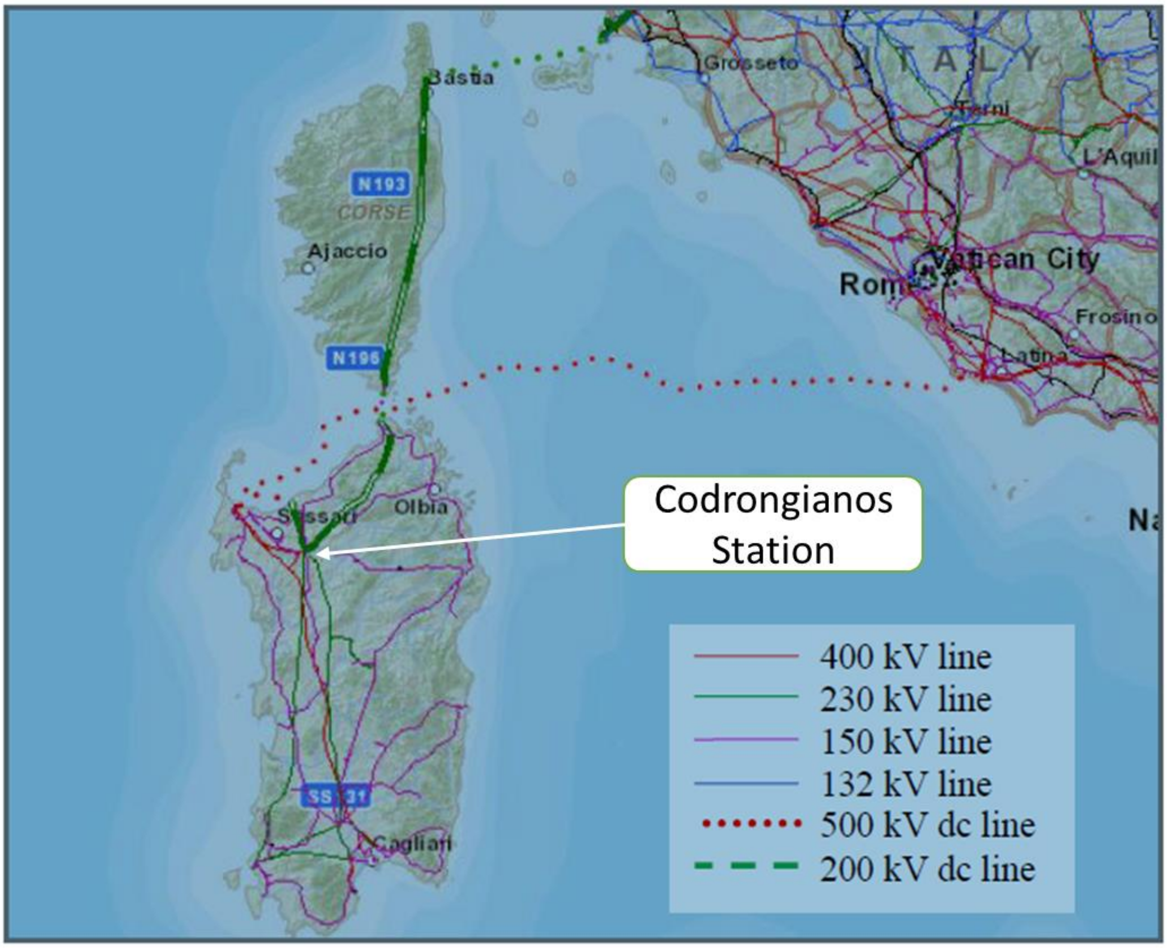
Electricity System in Sardinia and Characteristics of Sardinian Network

The electricity transmission network in Sardinia is part of the Italian transmission network and is owned and operated by TERNA. It meets a peak demand of around 1.5GW. The network has an AC connection to the nearby island of Corsica, and HVDC connections to Corsica and to continental Italy as illustrated in Figure 5.

With increasing levels of renewable generation on Sardinia including wind (≈1GW) and solar (≈0.7GW), there are times when renewable generation is sufficient to supply demand on the island. Other generation on Sardinia includes coal and oil-fired plant. There is limited gas-fired plant as there is no natural gas network on Sardinia.

Whilst the electricity system on Sardinia is much smaller than the GB system, there are some similar characteristics to the GB system in that more expensive synchronous generation was having to be operated to provide adequate inertia and short circuit infeed for stable operation of the LCC (Line Commutated Converter) HVDC links.

Figure 5 HV/EHV Transmission Network in Sardinia [15]



Solutions Considered for Sardinian Network

To enable increased renewable generation development and operation on Sardinia, TERNA compared a number of reactive power support devices and identified synchronous condensers as its preferred solution due to their ability to provide short circuit power and inertia [15].

TERNA subsequently installed two SC's at Codrongianos substation on Sardinia in 2014. These were manufactured by Ansaldo Energia. Integration of the SC's with the network was provided by ABB [16]. Each SC was rated at +250 /-125 MVAr and they were designed to provide relatively high short circuit infeed and inertia. The most significant parameter was short circuit infeed with the SC's designed to provide over 2500MVA infeed in total to the network at Codrongianos. To provide this short circuit infeed, the SC's were specified to have a sub-transient reactance (Xd'') of 10.1% and the step-up transformers were specified with a rating of 330MVA and a short circuit impedance of 12.5% [15].)

TERNA chose to install two separate SC's rather than a larger device as the capability of air-cooled synchronous machines was limited.

With the SC's in service, the higher short circuit levels reduce the need for existing coal or oil fired synchronous generation to be in service when more renewable generation is available.

Commercial Arrangements

The SC's are owned and operated by TERNA.

3.4. California - USA

Summary

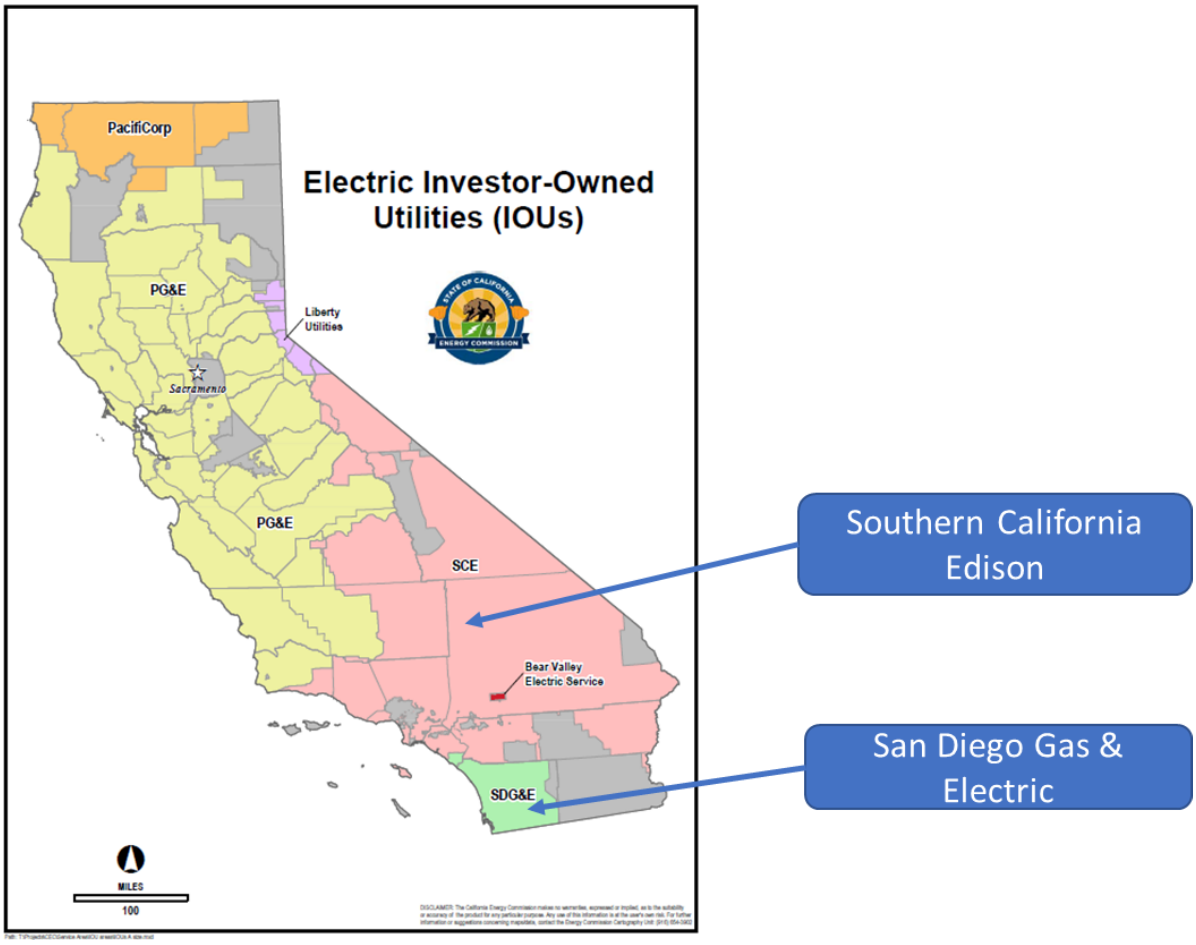
With increasing levels of renewables and reduced operation of fossil fuel and nuclear generation plant on the Californian system, SC's have been installed to provide voltage support and more stable operation. To date, seven SC's have been installed in Southern California by San Diego Gas & Electric (SDG&E) and a single SC has been installed by Southern California Edison (SCE). Existing generation at Huntington Beach had previously been converted to SC operation in 2012.

Electricity System Structure in California

Total electricity demand in California is around 290TWHr per annum. This is similar to the level of electricity demand in GB. In terms of electricity production, California has historically relied on natural gas, nuclear and hydro-electric resources supplemented by imports from other states.

The California Independent System Operator (CAISO) operates the transmission network across much of California and in a part of Nevada serving around 30 million consumers. Total electricity demand from the system operated by CAISO is around 230TWHr per annum. The electricity network in the CAISO area is owned and managed by a number of investor owned and publicly owned utilities. The larger investor owned utilities are illustrated on Figure 6. The investor owned utilities include SDG&E and SCE.

Figure 6 Investor Owned Electricity Utilities in California [17]



SDG&E and SCE are regulated public utilities. SDG&E provides energy services to around 3.6 million people in the San Diego and southern Orange counties in Southern California. SCE provides energy services to around 15 million people in central, southern and coastal areas of Southern California.

Characteristics of Californian Network

California has plentiful natural resources and a progressive policy in respect of support for renewable energy. In 2002, the Renewables Portfolio Standard (RPS) was established by the state government. The RPS includes targets for the proportion of electricity retail sales to be met by renewable resources. Initially, the requirement was for 20% of electricity to be met by renewable sources by 2017. Subsequently, further RPS requirements have been legislated. In 2011 a 33% target was set to be achieved by 2020 and in 2015 a 50% target was set to be achieved by 2030.

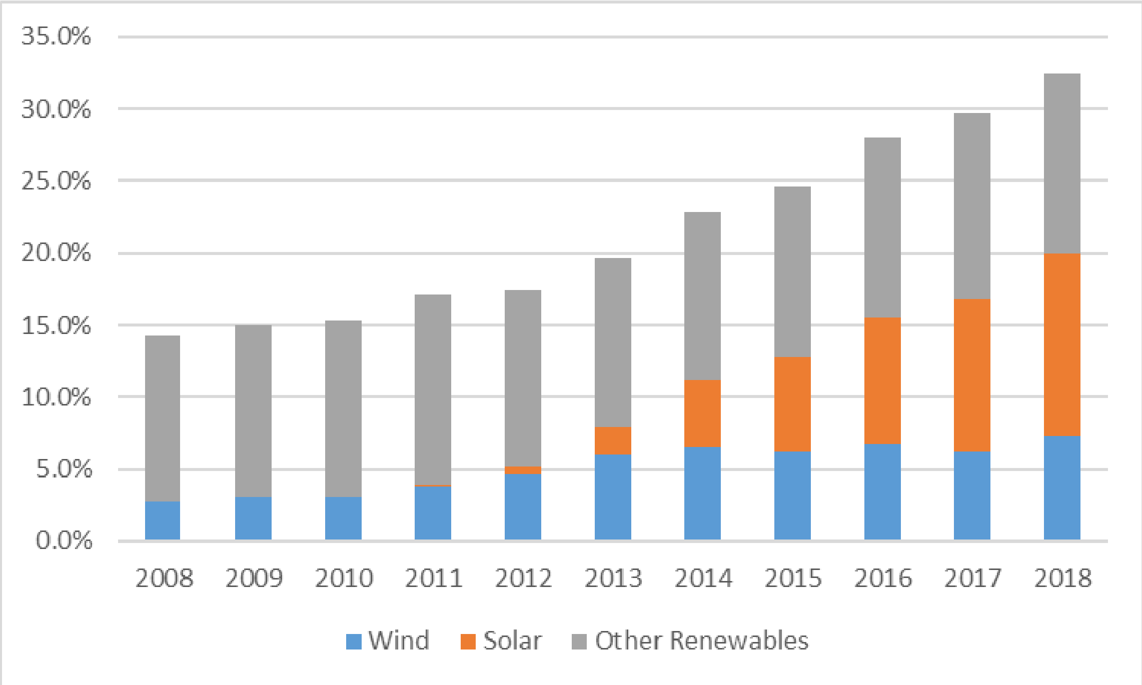
The RPS is administered by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). Progress against the RPS targets has been good. For example, in its November 2017 report on the RPS [18], the CPUC reported that an interim target of 25% target had been met, and that utilities were on track to meet or exceed the target of 33% renewable energy by 2020. It was also reported that the investor owned utilities were projecting to outperform the 2020 target and reach 50% renewable energy use by 2020.

In 2018, the RPS targets were further updated to increase the level of renewable energy to 60% by 2030 and to require all California's electricity to come from carbon-free resources by 2045.

Many measures have been put in place to support renewable electricity use in California. These include roof top solar PV programmes and incentives for the flexible use of energy by consumers. Additionally many large-scale wind farms have been developed since 2002 and large-scale solar farms have been developed since 2012.

As illustrated in Figure 7, total renewable energy consumption as a percentage of total energy production in California has increased from around 14% in 2008 to over 32% in 2018. (These figures exclude large hydro-electric resources.) Figures from CAISO's website on installed renewable resources indicate that in May 2019, installed solar PV capacity was 11.9GW and installed wind capacity was 6.7GW.

Figure 7 Annual Renewable Electricity Production as % of Total Production in California [19]



Note – "Other Renewables" comprise Geothermal, Biomass and Small Hydro generation.

With increasing levels of renewables and incentives for flexible operation in California, there is less scope for nuclear generation. Significantly, the San Onofre nuclear plant stopped generating in 2013 after problems were detected with replacement steam generators. In June 2016, it was announced that the remaining Californian nuclear generating station at Diablo Canyon would close by 2025. It was reported [20] that the two 1100MW pressurised water reactors at Diablo Canyon would no longer be economic given the developing energy regime in California. The CPUC agreed to a closure plan for Diablo Canyon in January 2018.

SC Solutions Considered for Californian Network – Huntington Beach

With the unexpected closure of the San Onofre nuclear generation station, CAISO recognised that there would be voltage management problems locally and approached AES to convert units 3 and 4 at its recently closed Huntington Beach generating station to SC operation. Each of these units had been rated at around 225MW. The Huntington Beach conversion was completed quickly and successfully and the SC's were commissioned in June 2013.

CAISO put in place "must run" contracts with AES for the Huntington Beach SC's and these contracts were subsequently extended through to 2017. However, the SC's were no longer required by CAISO after December 2017 largely due to the installation of new SC's by SGD&E and by SCE [21]

SC Solutions Considered for Californian Network – SDG&E

To help support its 230kV transmission network in southern California with increasing levels of renewables, CAISO identified the need for reactive support in the SDG&E service area through its Transmission Planning Process. SDG&E subsequently proposed the installation of SC's and commissioned Siemens to install seven SC's to provide voltage support, inertia and short circuit support. These SC's were installed at four sites across the SDG&E service area over the period 2015 to 2018 [22].

The first two of SDG&E's seven SC's were installed at Talega in 2015. Each SC was rated to provide -120 to +225 MVAr of reactive power.

Two further SC's rated to 225MVAr were installed at SDG&E's Miguel substation in Bonita in early 2017 and 2 similarly rated devices were installed at Oceanside, California at SDG&E's San Luis Rey substation during late 2017.

A seventh 225MVAr SC was installed for SDG&E at San Onofre. This was completed in October 2018.

SC Solutions Considered for Californian Network – SCE

A 225MVAr SC has been installed at Santiago substation in Southern California. This was planned for operation in 2017.

Use of Synchronous Condensers in Southern California

Whilst the Huntington Beach SC's are no longer in operation, all of the new SC's taken forward in the SDG&E and SCE service areas have been commissioned and form part of the transmission system planned and operated by CAISO.

In an October 2018 paper "Talega SynCon - Power Grid Support for Renewable-based Systems" [23] phaser measurement unit (PMU) data is reviewed to show that the Talega SC's provided valuable voltage and short circuit support during two system incidents.

In one of these incidents in August 2016, around 1200MW of PV generation was lost in the Southern California area. The PMU results show that the Talega SC's acted to improve system RoCoF and to support voltage locally immediately following the generation loss. In the second incident, the PMU data demonstrated that the Talega SC's were effective in supporting the local network voltage following a transmission line trip.

Commercial Arrangements

The transmission planning and procurement process for transmission reinforcement in the CAISO area is a three stage process which takes place over two year cycles [24]:

- In the first stage, a study plan is agreed taking account of government policy and latest forecasts such as electricity demand. This stage draws heavily on CPUC and CEC inputs.
- In the second stage, reliability and economic studies are carried out by CAISO to determine a transmission plan with recommended projects. This considers transmission proposals from utilities and also identifies any larger projects that may be required.
- In the third stage, larger projects (typically >200kV) are opened up for competition. CAISO compares proposals and selects an approved project sponsor to build and own each project. (CAISO maintains a list of approved project sponsors. These are typically transmission owners in the CAISO area but also include competitive organisations such as Nextera Energy Transmission.)

The new SC's were installed to meet requirements identified through this process and are owned by the transmission companies SDG&E and SCE.

3.5. Ohio - USA

Summary

Existing coal-fired generation at Eastlake near Cleveland in northern Ohio was converted to SC operation over the period 2013–2016 to provide voltage support to the local area following the closure of coal-fired generation plant.

Electricity System in Ohio and Characteristics of Network

The electricity system in Ohio is part of a regional network operated by PJM (Pennsylvania-New Jersey Maryland Interconnection), a Regional Transmission Organisation (RTO). This network is part of the wider North American Eastern Interconnection. PJM's area covers all, or parts of, 13 US states including Ohio. It had a total demand of over 800TWHrs in 2018 with a peak demand of over 165GW [25]. This level of demand is around 2.5 times the size of the GB electricity demand in 2018.

There are a number of transmission zones in the PJM area including the ATSI (American Transmission Systems Inc) area. ATSI is a subsidiary of First Energy and covers much of northern Ohio including Cleveland. The PJM transmission areas are illustrated in Figure 8 [26].

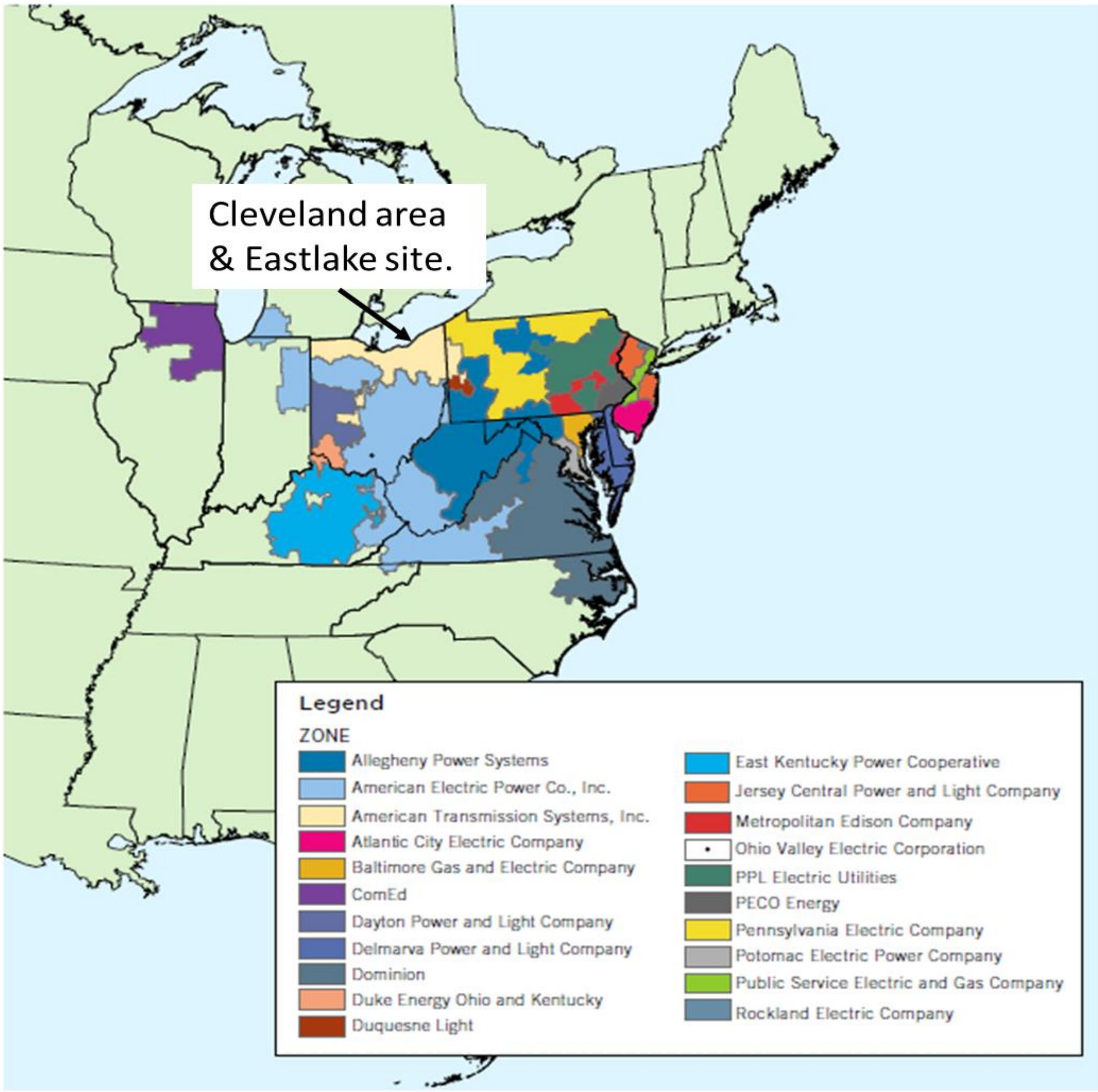
Traditionally, states in the PJM area including Ohio have relied heavily on coal for electricity supply. In 2012, coal-fired generation accounted for over 42% of the generation connected to the PJM network. At that time, the other main generation sources were natural gas and nuclear. Wind and solar power renewables amounted to less than 0.5% of generation capacity.

Coal and gas continue to be major industries in the PJM area. In 2016, Ohio was the third largest coal consuming state in the USA after Texas and Indiana with 90% of the coal consumed used for electricity generation despite more stringent environmental legislation including the Mercury and Air Toxics Standards (MATS) that were introduced in 2011. More widely in PJM's area, relatively low cost shale gas has led to increased gas fired generation over the last 5 years. Renewable generation has grown but much more slowly compared to other areas of the USA [27]. By 2018, renewable generation accounted for only 6% of the generation capacity connected to the PJM network, a figure much lower than most other US states. In Ohio, some larger wind farms had been commissioned, but just over 2% of net electricity use in 2017 was met by renewable sources [28].

From 2012, as a result of the environmental regulations on air pollution including MATS, generation companies began to close older generation capacity rather than retrofit stations with equipment to clean up emissions. In January 2012. First Energy Generation announced the closure of a number of coal-fired power stations along the shores of Lake Erie in northern Ohio including its Eastlake power station comprising 5 generating units (1233MW total) and its Lake Shore power station (245MW) [29]. These stations had been operating as peaking generation but were important in supporting the Cleveland area.

In a paper dated May 2012 [30] PJM identified that the Lake Erie generation closures would require significant transmission upgrades to resolve thermal and voltage problems in and around Cleveland.

Figure 8 Transmission Zones in the PJM Area including ATSI [26]



Solutions Considered for Network

After assessment of the planned generation closures, PJM identified that the 5 units at Eastlake and the single unit at Lake Shore should be converted to SC's at a cost of around $20m per machine. Initially Eastlake units 4 and 5 would to be converted to SC operation. PJM determined that the other 3 Eastlake units and the Lake Shore unit should continue to operate as "Reliability Must Run" (RMR) units until reinforcement to support the Cleveland area had been completed. (RMR units are generating units that are to be retired but continue to be needed to ensure system reliability. Typically, RMR units are requested to remain operational until transmission upgrades have been completed.) Through the RMR process, PJM facilitated regulated payments to First Energy Generation. These payments required the approval of the US Federal Energy Regulatory Commission (FERC).

Conversion of Eastlake unit 5, a 345kV connected generator, took just over 12 months and was completed in May 2013. The SC was rated to +560/-206MVAr. The conversion of Eastlake unit 4, a 138kV connected generator, was completed in January 2014. This SC was rated to +268/-140MVAr. The conversions required the transfer of assets from First Energy Generation to ATSI so that they could be treated as transmission assets.

With the first two SC's in service, and the completion of other transmission and distribution works, PJM identified that the remaining Eastlake and Lake Shore generation would no longer be required as RMR units after September 2014. The 3 units at Eastlake (units 1,2 and 3) would continue to be converted to SC's when they ceased generation. The generating unit at Lake Shore would not be converted to SC operation due to the higher costs of doing this. Instead, a new SVC would be installed.

During 2015 and early 2016, the conversion of units 1, 2 and 3 at Eastlake was completed to provide 3 further SC's each rated to +124/-80MVAr.

PJM and ATSI decided to convert Eastlake generation to SC's as part of a diversified approach to ensuring reliability in northeast Ohio. As well as the SC's, other transmission reinforcement was carried out including SVC's, capacitor banks and transmission line upgrades. The conversion of the Eastlake plant to SC's provided reactive support close to the Cleveland load centre and enabled reliance on local generation to be removed quickly.

With 5 generating units at Eastlake, there was greater flexibility to take forward a solution based on the conversion of existing generation to SC's. There was scope to convert two units to SC's whilst retaining other units to support the local network in the short term. Conversions could be completed quickly as much of the equipment was already in place and additional space was not required.

Use of Synchronous Condensers

The SC's at Eastlake continue to operate. In April 2018 [31] it was reported that the Eastlake SC's continue to provide between +1200 and -600 MVAR of dynamic reactive support to the Cleveland area. It was also reported that the SC's have performed well since going into service.

Commercial Arrangements

The Eastlake generating units were converted to SC's to address immediate problems following the closure of generation in the Cleveland area. Conversion provided a quick and straightforward means of providing dynamic voltage support without local generation.

Following closure of the generation at Eastlake, ownership of the relevant generation unit assets was transferred from First Energy Generation to ATSI. This transaction was approved by FERC in July 2012. The SC's are owned by ATSI and their costs are recovered as regulated transmission assets.

3.6. Texas - USA

Summary

Two SC's were commissioned in the Panhandle area of Texas in 2018 to increase the capability of the transmission system to transfer power generated by renewable sources towards population centres in the centre and east of Texas. The installation of further SC's is being considered.

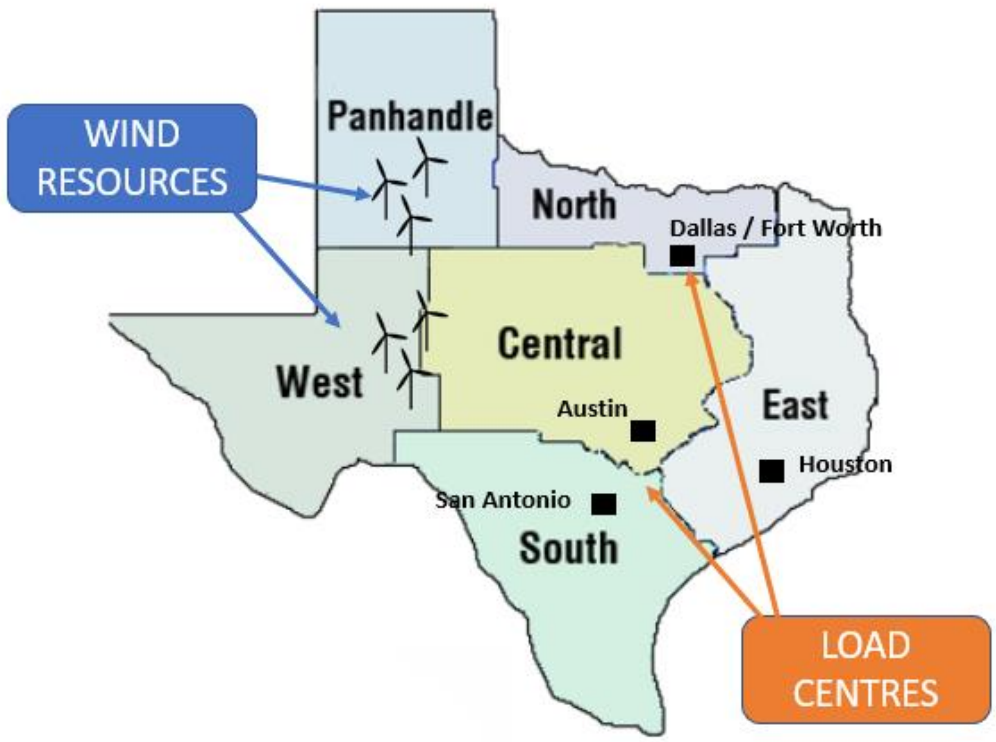
Electricity System in Texas and Characteristics of Texan Network

Much of Texas is served by a synchronous electricity system operated by the Electric Reliability Council of Texas (ERCOT), the Regional Transmission Organisation (RTO) and independent system operator (ISO). The ERCOT system is operated separately from the two other synchronous electricity systems that serve the eastern and western states that make up continental USA. The ERCOT system has a peak demand of 73GW and covers around 75% of the Texas land area (around 200,000 square miles). Total annual demand supplied through the ERCOT system in 2016 was around 350TWHr. This is similar to the level of demand supplied through the GB network.

Five transmission and distribution utilities (TDUs) operate in the ERCOT area. These TDUs include AEP Texas, CenterPoint Energy, Oncor, Sharyland Utilities and Texas-New Mexico Power. They are responsible for maintaining and operating local transmission and distribution assets and they are regulated by the Public Utility Commission of Texas (PUCT) to provide services within their service territories.

Whilst Texas is rich in fossil fuel resources, it was recognised in the early 2000's that there was huge potential to utilise renewable generation sources, particularly wind, in more remote parts of the state such as West Texas and the Panhandle area. However, as illustrated in Figure 9, these areas are located hundreds of miles from the main load centres such as Houston, Dallas-Fort Worth, San Antonio and Austin. Additionally, the transmission networks in West Texas and Panhandle areas were not well developed as existing fossil fuel generation was largely located in other areas.

Figure 9 Renewable Resources & Load Centres in Texas



Solutions Considered for Texan Network

In 2005, the Texas State Legislature introduced the Competitive Renewable Energy Zones (CREZ) programme to enable wind resources in remote areas of the state to be utilised. A few years later, the PUCT approved a $5 billion plan for the CREZ to provide around 3,500 miles of new transmission lines and upgrades to transfer power from areas with high renewable resources to load centres.

The transmission line works related to the CREZ were largely completed in 2013. A major part of the CREZ works extended transmission infrastructure into the Panhandle area. This new transmission infrastructure comprised a 345kV transmission line loop that was built and owned by Sharyland Utilities.

Over 75% of the installed and planned wind generation was located in the Panhandle and West Texas regions. For the Panhandle area, the uptake of wind farm development exceeded the capability of transmission network initially provided through the CREZ works and it was recognised by ERCOT that further transmission reinforcement would be needed.

ERCOT initiated a Panhandle area Renewable Energy Zone (PREZ) study which identified that increased system strength would be needed to improve voltage stability and further increase the levels of renewable power transported from renewable sources away from the Panhandle area.

Through 2014 and 2015, ERCOT worked on the PREZ study with other market participants in its Regional Planning Group to evaluate options for increased transmission capacity and system strength. Proposals included options presented by different transmission utilities. These included the further extension of the Sharyland Utilities system, the installation of new SC’s and the conversion and installation of retired generator units to operate as SC’s.

In late 2015, ERCOT recommended works including a further transmission line upgrade in the Panhandle area and the installation of two new SC’s on Sharyland’s 345kV Panhandle transmission system at Alibates and Tule Canyon substations. ERCOT designated Sharyland Utilities to install the SC’s and the two 175MVAr rated SC’s were brought into service in March and April 2018.

The SC’s at Alibates and Tule Canyon were included as part of the PREZ reinforcements as they increased the short circuit level in the Panhandle area and, along with the additional transmission line capacity, they improved the system’s capability to maintain angular and voltage stability with increased power transfers away from the Panhandle area towards load centres.

Current Position on ERCOT Network

The SC’s installed in the Panhandle area are part of a wider set of transmission investments and operational measures to improve system strength. ERCOT had previously introduced requirements for all generators including renewables to provide reactive power and it is also putting in place new ancillary services to support its network. These include a Responsive Reserve Service which utilises both generator and load resources. For the Panhandle area, ERCOT uses the concept of “Weighted Short Circuit Ratio” (WSCR) as a measure to help ensure generator and system controllers function correctly. It also checks voltage stability limits as part of its real time system operation [32].

With further scope to increase wind generation, the addition of a third 175MVAr rated SC at Windmill substation has also been proposed in the Sharyland Utilities area [33]. This would further increase the capability of the local network to transfer power to load centres. The current status of this proposal is not clear.

The CREZ and PREZ related works have greatly increased the provision of energy by renewable sources. During 2016 for example, over 15% of energy use was met by wind generation [32]. This level is similar to the UK where just over 14% of electricity generated was provided by renewable wind or solar sources during 2016.

By September 2018, over 21GW of wind generation had been connected to the ERCOT system and a further 12GW of wind generation had connection agreements in place to connect by 2020 [34] On some occasions, wind energy was providing over 50% of the total load.

Solar generation connected to the ERCOT system is also increasing. In September 2018, around 1.5GW of solar generation had been installed and a further 2.5GW of generation had connection agreements in place to connect by 2020 [34].

Use of Synchronous Condensers

The SC’s at Alibates and Tule Canyon were installed in 2018. No data is publicly available to help assess the effectiveness of the SC’s.

Commercial Arrangements

The SC’s on the Panhandle transmission system were installed following a process of economic assessment of transmission reinforcement options co-ordinated by ERCOT. As part of this process, Sharyland Utilities’ proposed solution was compared to options put forward by other transmission companies. The installed SC’s are owned by the transmission utility Sharyland Utilities.

3.7. Australia

Summary

SC's are being installed, or are being considered for installation, on the electricity transmission network in south east Australia. In some cases, these SC's are associated with the connection of large renewable generation developments. In other cases, transmission companies such as TransGrid and ElectraNet are considering the use of SC's to improve system strength and increase power transfers.

Three examples of SC use in Australia are detailed below. The first of these is the installation of a SC at Kiamal in Victoria to support the connection of a large solar farm. The second example is 4 SC's that are to be installed on the South Australia transmission network to improve local system strength and inertia. The third example outlines the use of existing hydro and gas generation as synchronous condensers to support the Tasmanian power system.

The Network in East and South East Australia

The transmission network in Eastern and Southern Australia is a 5000 km long system interconnecting 5 states – Queensland, New South Wales, Victoria, South Australia and Tasmania. This overall network is referred to as the National Electricity Market (NEM). The NEM serves a number of concentrated load centres that are distant from each other. It has developed around the supply of these load centres from fossil fuel generation resources. This has resulted in a system that can be operated as a single market and is strongly interconnected within regional load centres. However, the interconnections between regional load centres are not as well developed such that some parts of the NEM are relatively weakly connected to the remainder of the transmission network.

The annual electricity demand supplied via the NEM is around 200TWHr, around two-thirds of the GB annual demand level. The total generation on the NEM is over 54GW [35]. Australian Government statistics indicate that for the 5 NEM states, around 79% of electricity generated in 2018 was provided by coal, oil or gas-fired generators. Renewable electricity generation in Australia is increasing and for the NEM states, this amounted to 21% including biomass and hydro generation sources. Wind and solar electricity generation was almost 12% in 2018 [36].

The NEM is operated by the Australian Energy Market Operator (AEMO). As well as electricity and gas market functions, AEMO is responsible for NEM system operations and for national transmission planning. As well as AEMO, there are five transmission network service providers (TNSPs) that manage the transmission networks in each of the 5 states covered by the NEM. These TNSPs include TransGrid in New South Wales, ElectraNet in South Australia and TasNetworks on the island of Tasmania. The TNSPs own and operate the regional transmission networks and look after the delivery of network connections and reinforcements.

Characteristics of the NEM

The better renewable generation resources in Eastern and Southern Australia are remote from load centres and tend to be at the periphery of the existing transmission network. With the increasing development of renewable generation, particularly wind and solar resources, available connection capacity has been become scarce.

AEMO has a central role in supporting the connection of new renewable resources. For example, AEMO has published an Integrated System Plan for the NEM [37]. This identifies a number of renewable energy zones where new renewable generation could be more effectively connected. For many of these zones, new transmission capacity would need to be provided to transport power towards demand centres.

For new generation developments seeking connection to the NEM, AEMO's role includes the following:

- AEMO will consider wider reinforcement of the network to provide additional capacity for increased network flows. Such investment would only be taken forward if there are benefits to the broader market. This process is subject to rigorous economic assessment and consultation (referred to as a Regulatory Investment Test – Transmission). If reinforcement is agreed, this could take several years to complete.

- AEMO also sets requirements for system strength in different parts of the Australian network so that the market can continue to operate effectively. When new generation projects seek connection from a local service provider, AEMO will determine that system strength is maintained and identify if remediation is needed to accommodate the new generation. AEMO have put in place System Strength Guidelines in line with the National Electricity Rules (NER). In practice these place a “do no harm” requirement on new generation such that it must put in place remedial measures to maintain system strength.

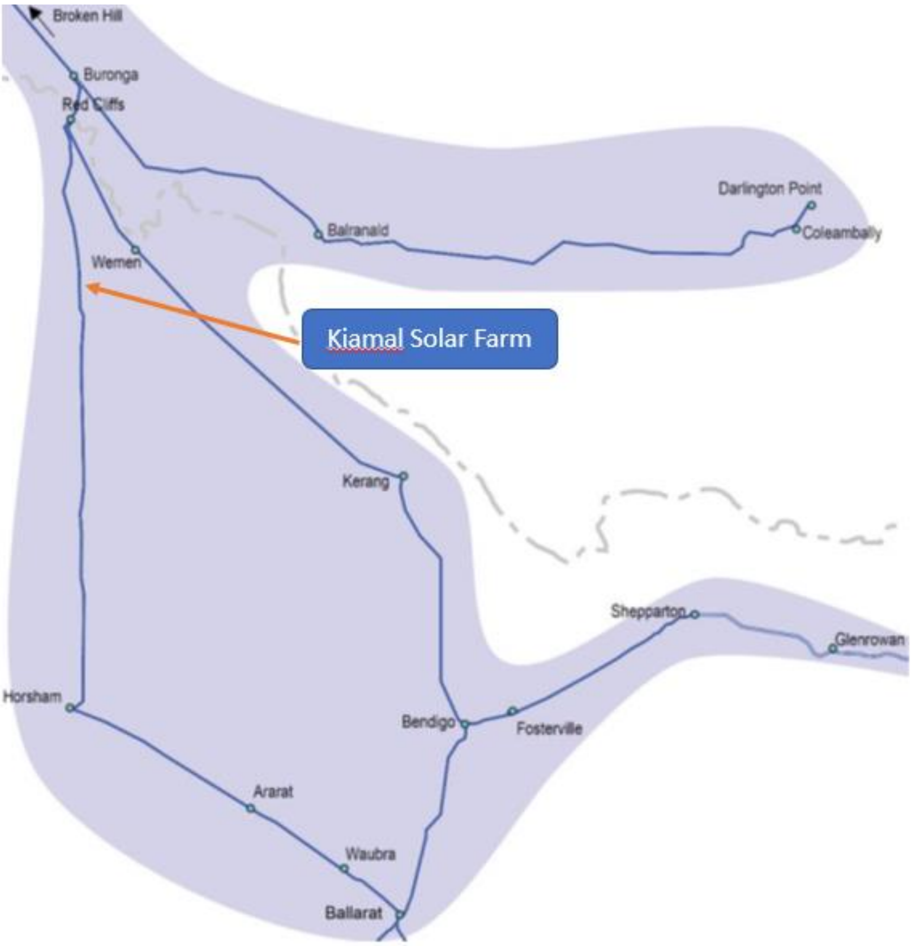
Given the relatively weak interconnections between parts of the NEM, AEMO also plans for parts of the network to become separated from the remainder of the NEM, and operate as islanded sub-networks. For example, the TransGrid transmission network in South Australia is linked to the remainder of the NEM by one 275kV AC double circuit and one HVDC link towards Victoria. With this level of transmission connection, the likelihood of the South Australia network being separated and islanded is considered to be high [38]. To enable islanded operation, AEMO identify minimum levels of inertia for each region to ensure continued operation in the event of network separation.

Example 1 - Connection of the Kiamal Solar Farm in Victoria

Kiamal is a large solar farm being developed by Total Eren in North West Victoria. The first phase is over 200MW. In this part of Victoria, there are significant network challenges. There has been already been large-scale development of wind and solar generation encouraged by local government who are keen to have resources developed locally. As at December 2018, ongoing wind farm development included 4-5 larger projects of around 500MW in total and ongoing solar development included 4-5 larger projects of around 500W in total. As there is limited electricity demand locally, much of the power to be generated by these renewable resources will be exported south east towards Melbourne.

This part of Victoria is served by the Western Victoria Transmission network which includes a 220kV transmission loop. This network is illustrated in Figure 10.

Figure 10 Western Victoria Transmission Network



With the development of the new wind and solar generation, parts of this network have reached their capacity. The connection of further renewable resources such as the Kiamal solar farm will exceed the capability of the local transmission network such that restrictions affecting generation will be required. These restrictions include thermal constraints on parts of the network in Western Victoria such as the Ballarat to Horsham transmission line where there are high levels of wind generation. In North-West Victoria, system strength is a limitation and AEMO has warned that constraints are likely. (The local issues in Western and North West Victoria are further explained in an information sheet published by AEMO covering connection to the Western Victoria Transmission network [39].)

One way in which new renewable generation can meet system strength requirements as part of a new connection is to install a SC. This is identified in AEMO's System Strength Guidelines [40] as a means of providing remediation for low system strength. In its information sheet for the Western Victoria Transmission network [39], AEMO identify that "The relatively low system strength in North-West Victoria may result in additional constraints, and works may be required to ensure the stable operation of additional generation. These works may include installation of synchronous condensers or other plant to raise fault levels."

To help its generation project be progressed, Total Eren have worked with TransGrid, the local Network Service Provider and AEMO to satisfy connection requirements including the requirement to maintain system strength. Total Eren have included a large SC as part of its development. This is being supplied by Siemens, rated to 190MVAr and will be capable of providing more than 700MVA of fault infeed. The SC will be sufficiently large to support the second phase of the Kiamal solar farm that will increase the total generation capacity to 450MW [41].

Other Generation Connections where SC's are being considered

Information is not readily available to identify a comprehensive list of all renewable generation developments in Eastern and Southern Australia where SC's are being considered as part of the connection arrangements. However, ABB have advised that SC's are being considered for the 175MW Finley Solar Farm being connected to the TransGrid network in New South Wales and for the 275MW Darlington Point Solar Farm also being connected in New South Wales.

Another solar farm considering the inclusion of SC's is the Yarrabee Solar Project being developed by Reach Solar Energy. This is planned to have a capacity of 900MW with a first stage of 300MW.

Commercial Arrangements

The SC at Kiamal will be owned by the renewable project developer, Total Eren. Likewise, the other SC installations at Finley Park, Darlington Point and Yarrabee would be owned by the renewable generation project owners.

There are markets in place for Frequency Control Ancillary Services (FCAS) and Network Support & Control Ancillary Services (NSCAS). These are operated by AEMO and include services for voltage control and transient stability for which SC is likely to be well suited. It is not clear if the Kiamal or other SC's will be able to compete in these markets.

Where SC's are installed as part of renewable generation developments, they may also be able to offer a system stability service that would enable other generators to connect and operate in locally constrained transmission areas.

Example 2 – Proposed Installation of SC's by ElectraNet in Southern Australia

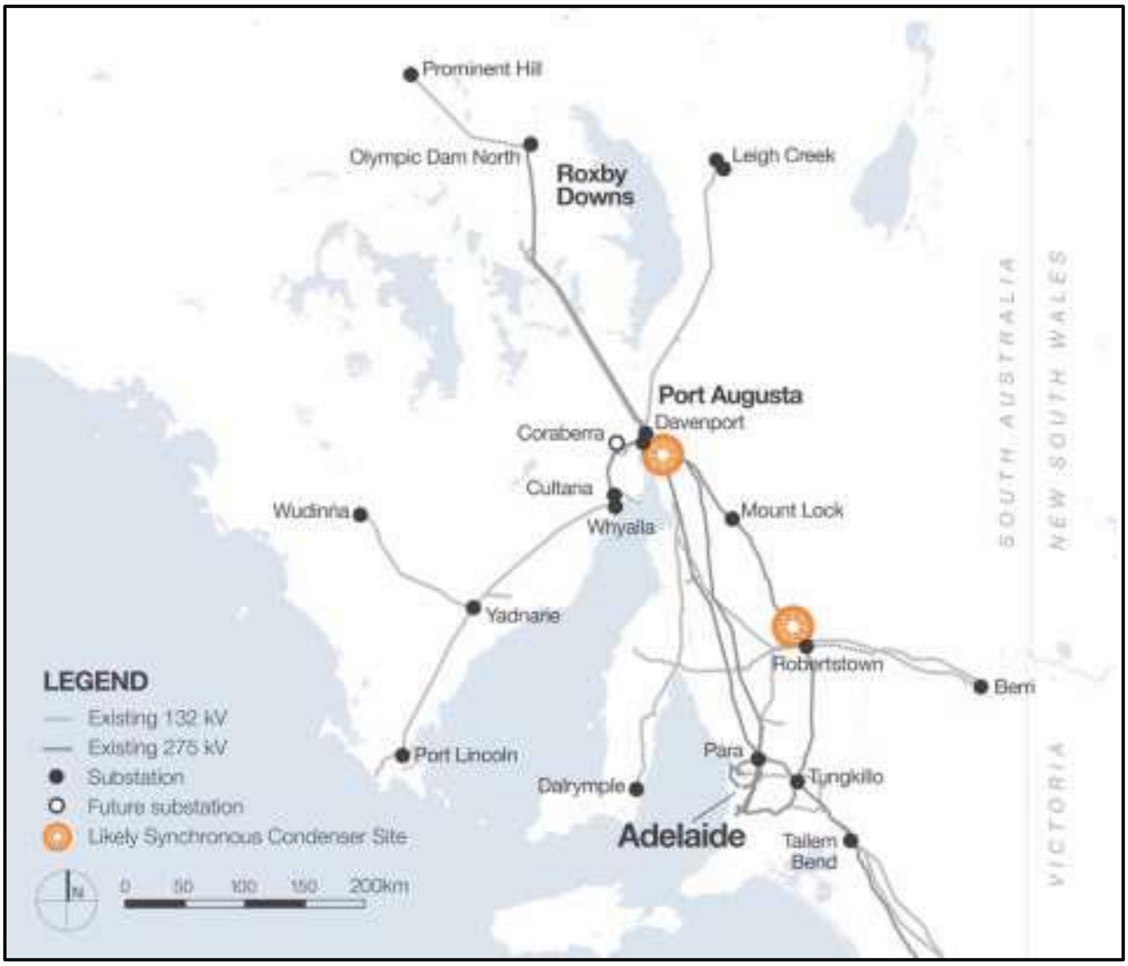
In its Integrated System Plan published in July 2018 [37], AEMO identify the need to install synchronous condensers in Southern Australia to provide system strength and increase system inertia. Given the identification of a fault level shortfall under the system strength framework, the Southern Australia transmission company ElectraNet proposed the installation of 4 SC's in its service area. This proposal is well progressed with sites identified and installation planned during 2020.

AEMO had previously identified need for additional system strength in the Davenport 275kV area. To ensure adequate system strength locally, AEMO has been directing the operation of synchronous generation. It has also set constraints on the operation of renewable generation locally.

ElectraNet opted to develop a solution to the shortfall under the provisions in the system strength framework. In its economic assessment [42], ElectraNet identify that compared to contracting with existing gas-fired generators, the installation of up to 4 SC's is a more efficient and lower cost solution. ElectraNet carried out its economic assessment over a 10 year timeframe given the level of uncertainty beyond this period. Each of the SC's would provide around 575MVA of fault infeed.

ElectraNet proposed the earliest possible connection of the SC's as the costs of generation direction by AEMO are increasing. It notes in its evaluation report [42] that other solutions are not available in the short term to address system strength. Other solutions have been considered such as network reinforcement and the conversion of existing generation to SC operation, but these are not considered to be as effective as installing new SC's. It is proposing the provision of two SC's by mid-2020 and the provision of two further SC's by end-2020.

Figure 11 Installation Sites of SC's (From ElectraNet Economic Assessment [42]**)**



Whilst system strength was the initial reason given for installing the SC's, in its economic report, ElectraNet recognised that the SC's will also enable the minimum threshold level of system inertia for system operation in Southern Australia to be maintained going forward. This involves the installation of higher inertia machines at a relatively small incremental cost compared to the total SC costs. (In its economic evaluation report, ElectraNet identified that the SC's might be fitted with flywheels to provide sufficient inertia capability. Additional costs of circa $5m across the 4 SC's are noted [42]. This represents about 3% of the overall project cost estimate.)

In its 2018 National Transmission Network Development Plan [43] published in December 2018, AEMO identified a shortfall in level of inertia available in South Australia to ensure its ability to operate as an transmission island in the event of separation from the remainder of the NEM. AEMO projects a typical level of inertia in 2023/24 of 1900MWs compared to a secure operating level of 6000MWs. As a result, AEMO declared an inertia shortfall for the area and recommended that ElectraNet should address this through the installation of high inertia SC's and/or contracts with synchronous generation and contracts for fast frequency response services from storage and non-synchronous generation.

Commercial Arrangements for ElectraNet SC's

Following identification of a system need by AEMO, ElectraNet have evaluated solutions and proposed the installation of SC's as a solution to system strength and inertia shortfalls in Southern Australia. It also lodged a request with the Australian Energy Regulator (AER) that it should be funded for investment in the SC's. ElectraNet submitted a further detailed project application in June 2019 to AER [44]. Through this application, ElectraNet proposed it would install and own 4 high inertia SC's at a total cost of $185m and have increased regulatory allowance over its regulatory period.

In August 2019, the AER reached a final decision on ElectraNet's proposal and approved that the project should proceed [45]. This decision took account of AEMO's technical advice that high inertia SC's should be installed. The MVAr rating of each SC's has not been published but it likely to be in the range 150-175MVAr. Each of the SC's would provide 575MVA of short circuit infeed at 275kV and 1100MWs of inertia contribution.

In its final decision on Electranet's project, AER also determined that the SC's would have an asset life of 40 years for regulatory depreciation purposes.

Example 3 – The use of SC's to support the Tasmanian Power System

The Tasmanian power system supplies a maximum demand of around 1800MW. As of 2016, There was a variety of generation on the island including hydro (≈2300MW), gas-fired (≈400MW), wind (≈300MW) and solar (≈100MW) [46]. There is also an HVDC interconnector to the transmission network in Victoria. This is referred to as the Basslink interconnector and it has a capability of 478 MW import (to Tasmania) and 630 MW export.

The TNSP (transmission network service provider) for Tasmania is TasNetworks. Much of the hydro and wind generation on Tasmania is owned and operated by Hydro Tasmania, an enterprise owned by the Tasmanian government. Planning and operation of the Tasmanian electricity system by AEMO and TasNetworks must take consideration of contingencies which are relatively large compared to the size of the system. These include the potential loss of the Basslink interconnector, the loss of a 208MW Combined Cycle Gas Turbine and the loss of a 230MW load block [46].

Minimum demand on Tasmania is around 900MW. In periods of lower demand, when wind generation is operating and when the Basslink interconnector is importing power to Tasmania, there is limited scope for gas-fired or hydro generation to provide system strength and system inertia to the Tasmanian network. To address this, and to limit the curtailment of generation output including renewables, Hydro Tasmania upgraded several of its hydro generators so that they can operate as SC's. These upgrades have enabled around 1470MWs of additional inertia on the Tasmanian system. Hydro Tasmania also modified three OCGTs in the north of Tasmania to operate as SC's. These provide additional fault level support for the George Town area where the Basslink interconnector converter station is sited.

As of 2016, much of the costs of using the SC's to provide system strength and inertia services to the Tasmanian system was being borne by Hydro Tasmania as formal contracts or system services were not in place with TasNetworks or AEMO [46].

3.8. Iceland

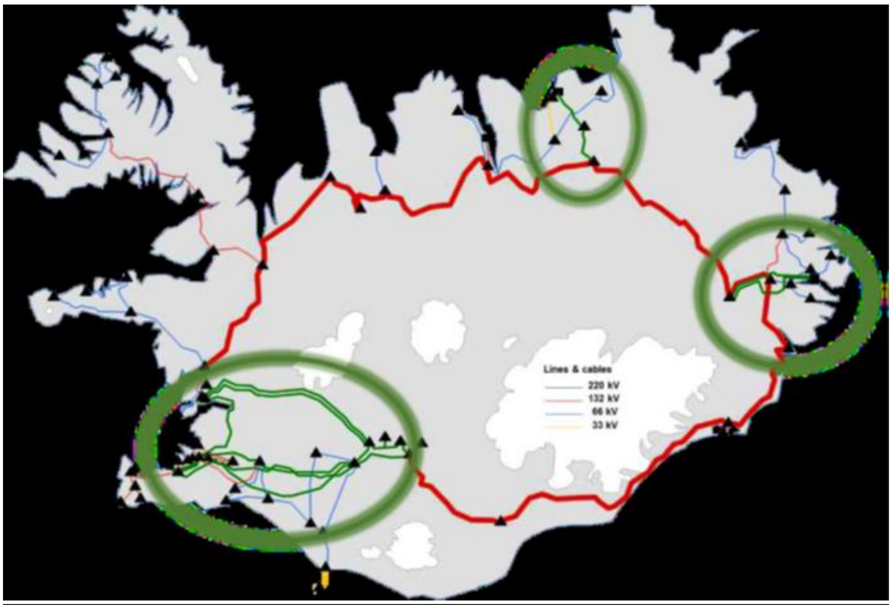
Summary

Iceland has an island transmission network with a large level of renewable generation. Approaches to managing the network might provide insight for the GB network.

Electricity System in Iceland and Characteristics of Icelandic Network

The Icelandic transmission system serves around 2.2GW of demand and is operated by Landsnet. There are several large demands including smelters, fish processing plant and data centres. Generation on Iceland largely comprises hydro and geothermal sources such that energy costs are relatively low. There are three main network areas where load and generation are concentrated with 220kV transmission infrastructure to serve demand. There is also a 132kV ring around the island. As an island system, some of the challenges faced by Landsnet in managing system frequency and stability have parallels in GB. This is illustrated on Figure 12 extracted from the Horizon 2020 Migrate project report for deliverable 2.4 of the Migrate project [47].

Figure 12 Icelandic System Showing Main 220kV Centres of Inertia and the 132kV Ring



Low inertia is not a major challenge to operating the Landsnet network as much of the generation is synchronously connected. Renewable sources including hydro and geothermal generation are synchronised to the grid and overall system strength is not a major problem.

However, with distinct demand and generation centres in different parts of the island, there are challenges in maintaining frequency and angular stability when larger loads are lost. For example, if a large load is lost, differences in RoCoF occur such that the system is susceptible to splitting.

Demand is increasing across Iceland, in part through the connection of data centres. Over time, further wind generation may be connected but not to the extent that non-synchronous generation sources will dominate.

Solutions Considered for Icelandic Network

Landsnet have not pursued network asset based solutions to address its system challenges but is attempting to make use of the flexibility that generators and larger demands can provide.

It is pursuing a smart grid solution based on wide area monitoring of its network and, when needed, utilising fast response from generation and demand to manage stability. Ideally, Landsnet would avoid system splits through generator and demand response, but, if the system does split, it will look to retain operation in the separate parts through fast control of the demand and generation resources.

Further details of the Landsnet wide area monitoring solution are included in a Landsnet presentation made at a dissemination event for National Grid ESO's, Enhanced Frequency Control Capability (EFFC) project in February 2016 [48].

Use of Synchronous Condensers

No SC's are in use or planned on the Icelandic system. For the Westfjords region, which is connected by a radial network, there may be some value in connecting a SC (or HSC) to help maintain local stability in the event of the 132kV circuit into the area being lost. However, there are some generators and larger loads in the Westfjords area and solutions utilising these resources may also be feasible.

Commercial Arrangements

The smart grid solution relies on larger demands and generation providing response. As yet, there isn't a commercial market in place for these services. Many of the larger electricity users on Iceland have been willing to support the smart grid solution for the wider benefits that it brings in providing cost effective network operation and security.

Given the nature of the Icelandic network, Landsnet are not able to connect large customers in some areas. Additionally, when new generation and demand does connect, Landsnet have been making the provision of response services a condition of connection.

Recently, users are starting to question the non-commercial approach to response provision and Landsnet are starting to consider commercial models.

There are different possible arrangements for managing the use of demand and generation resources on the Landsnet system. Possible approaches include the introduction of commercial services, obligations on connectees and industry self-regulation. Self-regulation would rely on system users recognising that their participation provides a more resilient system and that the introduction of other solutions (or market arrangements) would increase costs.

In the event that equipment such as an HSC or SC was to be installed, it is likely that this would be owned by Landsnet.

3.9. Ireland

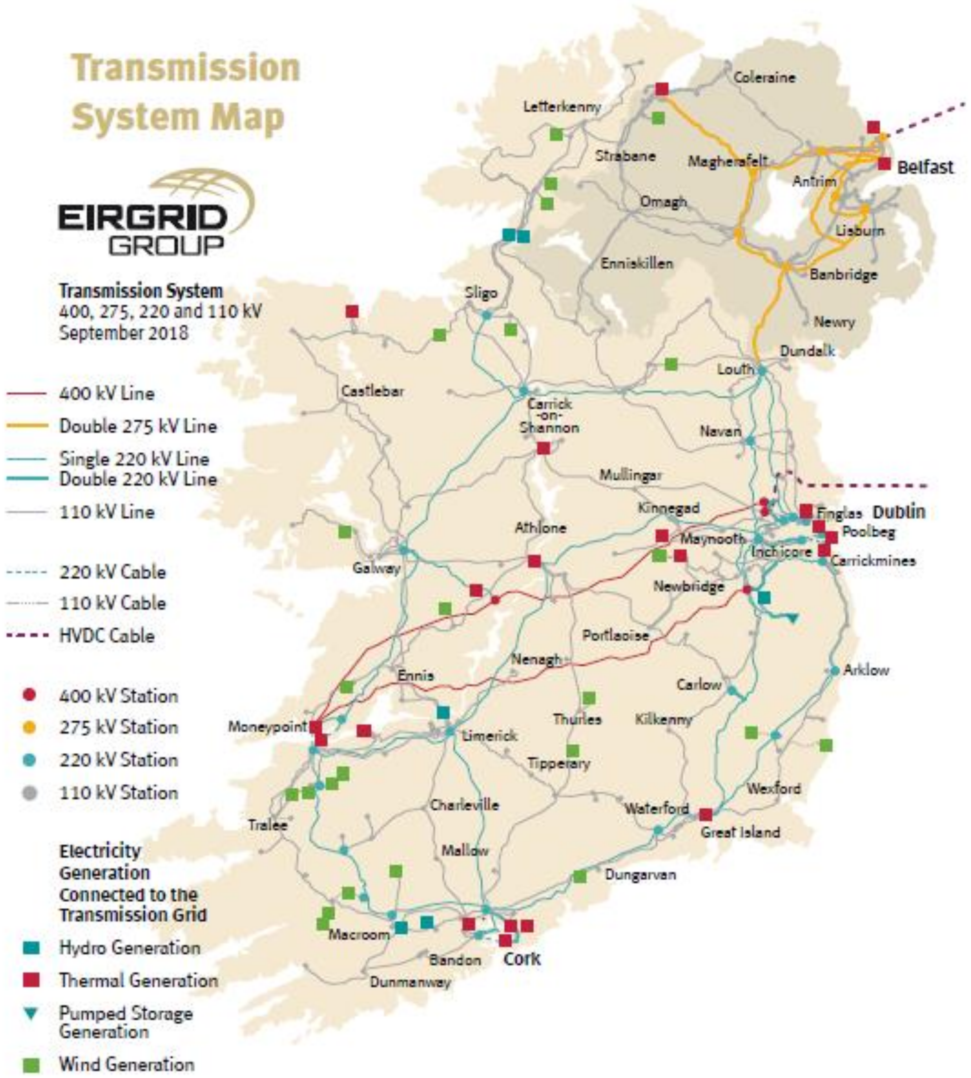
Summary

Ireland has an island transmission network with increasing levels of renewable generation. Approaches to managing the network might provide insight for the GB network.

Electricity System in Ireland and Characteristics of Irish Network

The electricity system in the island of Ireland operates as a synchronous system across the state of Ireland and Northern Ireland. EirGrid is the system operator in Ireland and SONI is the system operator in Northern Ireland. Both EirGrid and SONI are part of the state owned EirGrid Group. The networks operated by EirGrid and SONI are illustrated on Figure 13.

Figure 13 EirGrid Transmission System Map [49]



The total annual electricity demand across the whole island of Ireland is around 38TWhrs with a peak demand of around 7GW [50]. There are around 15GW of generation connected across the island of Ireland including 5.5GW of generation from renewable energy sources. The bulk of this renewable generation is wind generation.

In both Ireland and Northern Ireland, there are ambitious targets to provide increasing levels of renewable energy from renewable sources. The Irish Government has set a target of 40% electricity being provided by renewable sources by 2020. Similarly, in Northern Ireland, there is a target that 40% of electricity should come from renewable sources by 2020.

A challenge to the operation of renewable generation in Ireland is the maximum level of non-synchronous generation that can operate at any time. This is characterised by the System Non-Synchronous Penetration (SNSP) level and, up until recently, to maintain stable operation, the maximum SNSP was restricted to 50%. To achieve its targets for 40% of electricity provision by renewables, EirGrid and SONI are aiming to increase the maximum SNSP level to 75% by 2020.

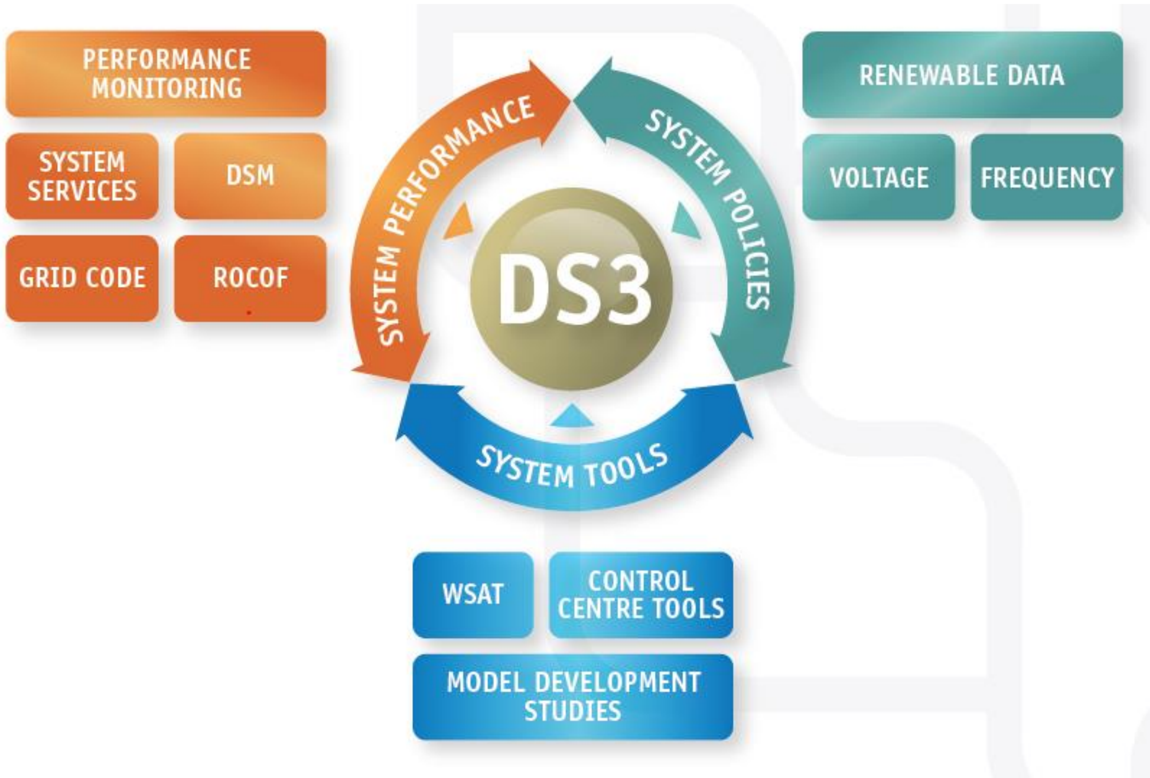
Solutions Considered for Irish Network

To help meet renewable targets, multiple approaches are being utilised in Ireland. These include a programme of investment in new network capability, particularly to provide better connectivity to areas of Ireland where there are higher levels of renewable resources such as the west and south of Ireland. As yet, SC's are not part of this investment programme.

A second approach is the 'Delivering a Secure Sustainable Electricity System' (DS3) work programme. The DS3 programme looks to achieve secure operation with very high levels of renewables on the grid whilst maintaining stable system frequency and voltage and minimising the curtailment of renewable electricity sources. To this end the DS3 programme is implementing a range of measures aimed at achieving the 75% SNSP level.

The DS3 programme contains three main work areas: system performance, system policies and system tools. These are illustrated in Figure 14 below.

Figure 14 "The Three Pillars of DS3" [51]



The system policies are intended to support frequency control and voltage control in situations with higher levels of renewable generation operating on the system. These should help increase the maximum SNSP level to 75%.

The system tools are intended to provide improved forecasting, improved system monitoring and improved assessment of system stability in real time.

The system performance part of DS3 aims to provide certainty around plant performance capability, ensure that plant is developed to align with the long-term operational needs of the power system and to identify and incentivise the necessary System Services to operate a secure power system with a significant level of renewables. These System Services are the ancillary services that are required for the continuous, secure operation of the power system such as frequency response and reactive power.

As part of the DS3 approach, the System Services are focussed towards better performance and greater flexibility. Fourteen System Service products have been identified and these are contracted using either a regulated tariff or an auction procurement mechanism.

The 14 services identified as part of the DS3 programme are listed on Table 2 below. These include services that might be delivered by SC's or HSC's.

To date, the different elements of the DS3 programme have been successful and in April 2018, Eirgrid announced that an interim target of 65% SNSP had been achieved [52].

Table 2 DS3 System Services [53]

Service Name	Unit of Payment	Short Description
Synchronous Inertial Response	MWs^{2}h	(Stored kinetic energy)*(SIR Factor – 15)
Fast Frequency Response	MWh	MW delivered between 2 and 10 seconds
Primary Operating Reserve	MWh	MW delivered between 5 and 15 seconds
Secondary Operating Reserve	MWh	MW delivered between 15 to 90 seconds
Tertiary Operating Reserve 1	MWh	MW delivered between 90 seconds to 5 minutes
Tertiary Operating Reserve 2	MWh	MW delivered between 5 minutes to 20 minutes
Replacement Reserve – Synchronised	MWh	MW delivered between 20 minutes to 1 hour
Replacement Reserve – Desynchronised	MWh	MW delivered between 20 minutes to 1 hour
Ramping Margin 1	MWh	The increased MW output that can be delivered with a good degree of certainty for the given time horizon.
Ramping Margin 3	MWh	
Ramping Margin 8	MWh	
Fast Post Fault Active Power Recovery	MWh	Active power (MW) >90% within 250ms of voltage >90%
Steady State Reactive Power	Mvarh	(Mvar capability)*(% of capacity that Mvar capability is achievable)
Dynamic Reactive Response	MWh	MVAr capability during large (>30%) voltage dips

Commercial Arrangements

In Ireland, Eirgrid and SONI have not focussed on transmission system reinforcement to improve system strength and system inertia. Instead, limits have been set for the levels of renewables that can operate at a particular time and a longer term plan is being followed to increase this level so that the renewable targets set by government can be delivered.

Part of the approach in Ireland has been to define a set of system services to support the system operation at higher SNSP levels. This does not preclude the installation of SC's or HSC's to provide these services. It does encourage developers to bring forward solutions based on the expected payments for the services going forward.

4. Comparison of Larger Transmission Areas with GB

Table 3 summarises characteristics from seven larger areas that have been considered in this report. High level information for the GB system is also included to enable comparisons. The approximate levels of electricity produced by wind and solar renewable sources are included as it is the increasing operation of these sources that tends to impact system strength and system inertia.

Across the seven areas, there are several with similar system challenges to GB and increasing levels of wind and solar energy production. In areas where targets for renewable energy use have been set, multiple approaches are being used to help increase renewable energy use including the installation of SC's. In these areas, there are different market and regulatory structures including TSO models, the US ISO model and the Australian NEM model with AEMO setting levels for system strength and inertia, and generation developers and transmission providers taking forward works to meet these levels.

Table 3 Summary of Larger Areas Included in Report

Area	Annual Electricity Demand & Renewable Electricity Production [A]	System Characteristics and Challenges [B]	Market Structures & Transmission Planning Processes	Approaches to Renewables Integration & SC Use to Date
Denmark	Demand ≈ 33TWHr ≈43% wind & solar electricity in 2018	Low system strength with high levels of wind & solar.	TSO has SO & TO roles TSO drives planning process.	New plant compliance, transmission reinforcements, generator contracts. 1 generator conversion to SC, 3 new SC's installed.
Germany	Demand ≈ 600TWHr ≈24% wind & solar electricity in 2018	Nuclear plant, closures , remote renewable sources	4 x TSOs in Germany. TSOs drive planning process.	New plant compliance, transmission reinforcements, generator contracts. 1 generator conversion to SC, 2 new SC's installed.
California (CAISO Area)	Demand ≈ 230TWHr ≈20% wind & solar electricity in 2018	With aggressive renewable targets, there have been fossil fuel and nuclear plant closures.	ISO Model. ISO (CAISO) coordinates planning across market area with multiple transmission owners.	New plant compliance, transmission reinforcements, generator contracts. 2 generator unit conversions, 2 new SC's installed.
Ohio (PJM Area)	PJM Demand ≈ 800TWHr ≈2.5% renewable electricity in Ohio in 2018	High levels of coal and relatively inexpensive shale gas. Local voltage management with generation closures.	ISO Model. ISO (PJM) coordinates planning across market area with multiple transmission owners.	Limited integration of renewables to date. 5 generator unit conversions.
Texas (ERCOT Area)	Demand ≈ 350TWHr ≈15% wind electricity in 2018 (solar < 1%)	Major wind sources are remote from load centres.	ISO Model. ISO (ERCOT) coordinates planning across market area with multiple transmission owners.	Large-scale transmission reinforcement, new plant compliance, new system services. 2 new SC's to date.
Australia (NEM)	Demand ≈ 200TWHr ≈12% wind & solar electricity in 2018	Renewable resources are remote from load centres. Some parts of NEM are weakly connected such that system strength and inertia are low.	Single Market Operator (AEMO) with multiple TNSPs. AEMO sets requirements for strength and inertia. TNSPs propose solutions subject to regulatory tests.	New plant compliance, and large-scale transmission reinforcements. Multiple SC's being installed by developers of new renewable generation. 4 TNSP provided SC's.
Ireland	Demand ≈ 38TWHr ≈25% wind electricity in 2017 (solar < 1%)	Low system strength and inertia without fossil fuel plant.	SOs (EirGrid & SONI) co-ordinate network reinforcement and requirements for services.	Transmission reinforcement. System services based solutions open to all.
GB	Demand ≈ 330TWHr ≈21% wind & solar electricity in 2018	Reducing system strength and inertia leading to increased system operating costs.	Separate SO & TOs. SO identifies need for larger reinforcements and requirements for services.	New plant compliance, transmission reinforcement and new system services.

Notes:

A Figures are comparable but not always for 2018. Renewable electricity production figures are the percentage of renewable electricity produced over one year. At many times through the year, much higher %ages of renewables will be operating.

B Systems Characteristics and Challenges are based on the material collated for this report and do not represent the full challenges within the service areas.

5. Conclusions of Review

Sections 3 and 4 have considered areas where there are similar challenges to those faced in GB due to the closure of synchronous generation and operation with increased levels of renewable generation. Seven of these areas were chosen on the basis that information was available on recently installed, or proposed, synchronous condensers (SC's). These areas are Denmark, Germany, Italy, California, Ohio, Texas and Australia. The other two areas, Iceland and Ireland, were included on the basis that they have smaller island based synchronous systems with increasing levels of renewable generation.

A summary of recently installed and proposed SC's is given Table 4 below. These include the conversion of 9 existing generation units across 4 sites and the installation of 22 new SC's.

The main conclusions of the international review are as follows:

1. **There is no single or standard approach to addressing system strength or inertia challenges** - Where there are increasing levels of inverter connected renewable generation, different approaches have been employed to support transmission networks. Often these approaches include the use of SC's but not always. In Ireland for example, whilst transmission investment is being taken forward, this does not yet include SC's.

2. **SC's are being used in different geographic areas and in areas with different market structures –** SC's are being used to address voltage management and system strength challenges in Europe, the US and Australia. They have also been assessed and preferred as a solution in areas where TSO's drive electricity infrastructure planning and where ISO's have a key role in taking forward transmission reinforcements.

3. **SC's can be provided quickly in comparison to other transmission solutions** – The conversion of generators or the installation of new SC's provide a relatively quick way to provide voltage support and improve system strength. This has been important where synchronous generation has been closed, or where significant costs was being incurred though the continued operation of synchronous generation. Other options such as SVC's or STATCOM's can support local voltage but SC's also provide increased fault infeed and system inertia. Following a decision to progress, generator conversions to SC's have been achieved in 6-12 months and new SC's have been installed in around 24 months. Typically SC's are installed without the need for major transmission works such as new overhead lines or substations.

4. **Generator conversions to SC's have taken place where system support is needed most urgently** - In four cases where existing generation has been converted to SC operation, this has been done to help address imminent transmission system problems including the need for increased system strength and dynamic voltage support. In three of the four generator conversions, the SC's have been owned by the generation company and bilateral commercial arrangements have been put in place to cover the generation company costs. In the fourth case, the generator owned assets were transferred to the local transmission company. In all four cases, it appears that the conversion was successful. In two cases, the SC's have provided a short term solution ahead of other works.

5. **Where new SC's are installed at transmission voltages, voltage support and system strength are the primary reasons** - A number of new synchronous condensers have been installed over the last 5 to 6 years. In the main, these have been installed to improve system voltage and system strength. In a few cases, system inertia has also been cited as a reason for the SC installation.

6. **The MVAr rating of new SC's connected to transmission networks tend to be similar** - Typically the rating of new SC's connected to transmission networks is in the range 150 to 250MVAr.

7. **SC designs are often very specific to local system challenges** - In some cases, the design of the SC's has been very specific. For example, SC's in Sardinia were designed to provide greater levels of short circuit infeed (and so have a low value of Xd''). It is proposed to design SC's in South Australia to provide increased inertia (and so have a high value of inertia constant H in MWs/MVA).

8. **So far, new SC's are tending to be owned by TSOs** – Where "off the shelf" SC's are installed, these are generally being owned by the transmission network companies. As with other transmission reinforcements, the need for the SC's is being tested through local planning processes. Competitive mechanisms for the provision of the SC's are developing (e.g. California).

A number of SC's have been used internationally to support transmission systems with reducing levels of synchronous generation. The local context, system requirements and commercial arrangements are diverse across the examples that have been reviewed. Whilst they don't indicate a clear direction for commercial and regulatory arrangements in GB, in the event that the Phoenix value assessment demonstrates a strong case for H-SC or SC installation in GB, the examples provide valuable insight into potential approaches.

Table 4 Synchronous Condensers Installed Since 2012

Area	Synchronous Condenser Case	In Service / Planned	Technical Characteristics	Owner	Reason for Installation	Commercial / Ownership
Denmark	Conversion of Ensted Unit 1	2013	-350 to 800MVAr reactive power	Dong Energy (TSO Energinet)	System strength	Bilaterally Contracted
Denmark	3 SC's at Bjaeverskov, Fraugde & Herslev substations	2014-2015	3 x -150 to 215MVAr reactive power, 3 x 900MVA short circuit infeed	Energinet	System strength	Tendered, TSO Owned
Germany	Conversion of Biblis Unit A	2012	-450 to 850MVAr reactive power	RWE (TSO Amprion)	System strength	Bilaterally Contracted
Germany	1 SC at Bergheinfeld substation	2015	-175 to 250MVAr reactive power	TenneT	System strength	TSO Owned
Germany	1 SC at Oberottmarshausen substation	2018	Not known	Amprion	Not known	TSO Owned
Italy, Sardinia	2 SC's at Codrongianos substation	2014	2 x -125 to 250MVAr reactive power, 2500MVA short circuit infeed	TERNA	System strength, System inertia	TSO Owned
USA, California	Conversion of generators at Huntington Beach	2013	2x225MW units converted to SC operation	AES (ISO CAISO)	Voltage support	Bilaterally Contracted
USA, California	7 SC's at Talega, Miguel, San Luis Rey & San Onofre substations	2015 - 2018	7 x -120 to 225MVAr reactive power	San Diego Gas & Electric	System strength, System inertia & voltage support	ISO identify need, TO owned
USA, California	1 SC at Santiago substation	2017	-120 to 225MVAr reactive power	Southern California Edison	System strength, System inertia & voltage support	ISO identify need, TO owned
USA, Ohio	Conversion of generators at Eastlake	2013 - 2016	5 units providing -600 to 1200MVAr reactive power	ATSI (First Energy)	Voltage support	ISO identify need, TO owned. (Generator assets were transferred to TSO)
USA, Texas	2 SC's at Alibates & Tule Canyon substations	2018	2 x 175MVAr rated	Sharyland Utilities	System strength (to enable power transfers)	ISO identify need, TSO owned
Australia, Victoria	1 SC to be installed with Solar Farm at Kiamal	2019	190MVAr unit >600MVA short circuit infeed	Total Eren (TransGrid area)	System strength	Connection Requirements
Australia, South Australia	4 SC's to be installed in Davenport 275kV area	2020	575 MVA short circuit infeed, 1100 MWs inertia per SC	ElectraNet	System strength, system inertia	ISO identify need, TO owned

Note: Appendix A1 includes an overview of new SC numbers including HVDC and other applications.

Appendix A – Market for Synchronous Condensers

This appendix provides an overview of the wider international use of SC's by indicating the numbers of larger SC's that have been installed in recent years. (This does not include power stations that have been converted for SC operation.)

As well as SC's installed to increase transmission system strength (the focus of this report), SC's have also been installed for other reasons including HVDC link support, to provide more robust power supplies to mining projects, and for power factor correction of industrial loads.

- HVDC Link Support – SC's are sometimes installed to support the operation of line commutated convertor (LCC) based HVDC converter stations. LCC's generally utilise thyristors for switching and require a strong synchronous AC voltage source to ensure successful operation. Increasingly, voltage source convertor (VSC) based HVDC converter stations utilising insulated gate bipolar transistor (IGBT) technology are being installed. IGBT currents can be switched on and off independent of the AC voltage and so VSC links are more flexible and robust as they do not rely on AC system strength. Nevertheless, LCC type links continue to be installed as they are able to carry higher levels of power which is often the key determinant for HVDC applications. Recent examples where SC's have been installed to support LCC type HVDC links include the 2000MW Nelson River link in Canada where 4 SC's were installed at the receiving end substation and the 900MW Labrador – Newfoundland link where 3 SC's were installed at the receiving end substation.

- Mining Projects – Large mining operations are often located in remote areas and rely on long transmission lines for power supply. As mines have large non-linear and process critical loads such as mills, SC's can be installed to help maintain voltage levels and power quality. Examples include 4 x 20MVA SC's at the Antapaccay and Las Bambas copper mines in Peru and 2 x 70MVA SC's at Lolwezi convertor station to support supplies to copper mines in the Democratic Republic of Congo.

- Industrial Load Power Factor Correction – SC's are often used to control power factors and provide robustness against voltage dips for large industrial loads such as compressors, fans and pumps. Typically, these SC's are smaller in rating than those used at transmission voltages with ratings ranging from a few hundreds of kVA to several MVA.

The OEM's providing larger SCs include ABB, Siemens, GE, Voith Group, Mitsibushi, WEG, Eaton and BRUSH. Information for each of these OEM's has been reviewed. Along with available utility information, this provides a comprehensive picture for larger SC's in most parts of the world. In many areas (e.g. India), hydro stations are used to provide SC capability.

Information on SC's in China is less accessible although the State Grid Corporation of China's Corporate Social Responsibility Reports indicate that the installation of several SC's is underway. These include larger 300MVA rated SC's for use at UHV transmission voltages. Table A1 indicates the levels of SC's installed in different parts of the world over the period 2014–2020.

Table A1 Indicative Numbers of Larger SC's Installed Internationally over 2014-2020

Region	SC's 2014-20	Commentary for Period 2014-2020
Europe	10	As well as SC's to improve system strength in Denmark, Germany and Italy, SC's were installed to support the NorNed HVDC interconnector and to support an AC interconnector from Sicily to Malta.
North America	19	SC's were installed to improve system strength in California and Texas. In the USA, SC's were installed to support windfarm connections in Maine and Wyoming. In Canada, SC's were installed to support LCC type HVDC links.
South America	14	SC's were installed in Brazil by Voith and WEG to support the transfer of power from hydro-electric sources to load centres. SC's were also installed to support mining operations.
Asia	10+	SC's have been installed in China and Korea to support HVDC link operation.
Australia	5	No new SC's have been installed until the Kiamal windfarm SC in Victoria and the Electralink SC's in South Australia.
Africa	0	Existing SC's that support mining operations have been refurbished.

On average, around 8-10 larger SC's have been installed each year over the 2014-2020 period suggesting a market value of around £200-300m per annum for larger SC's. Commercially available market reviews suggest that the total size of the SC's market (including smaller units) is around $500m per annum with the majority of sales in Europe and North America.

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