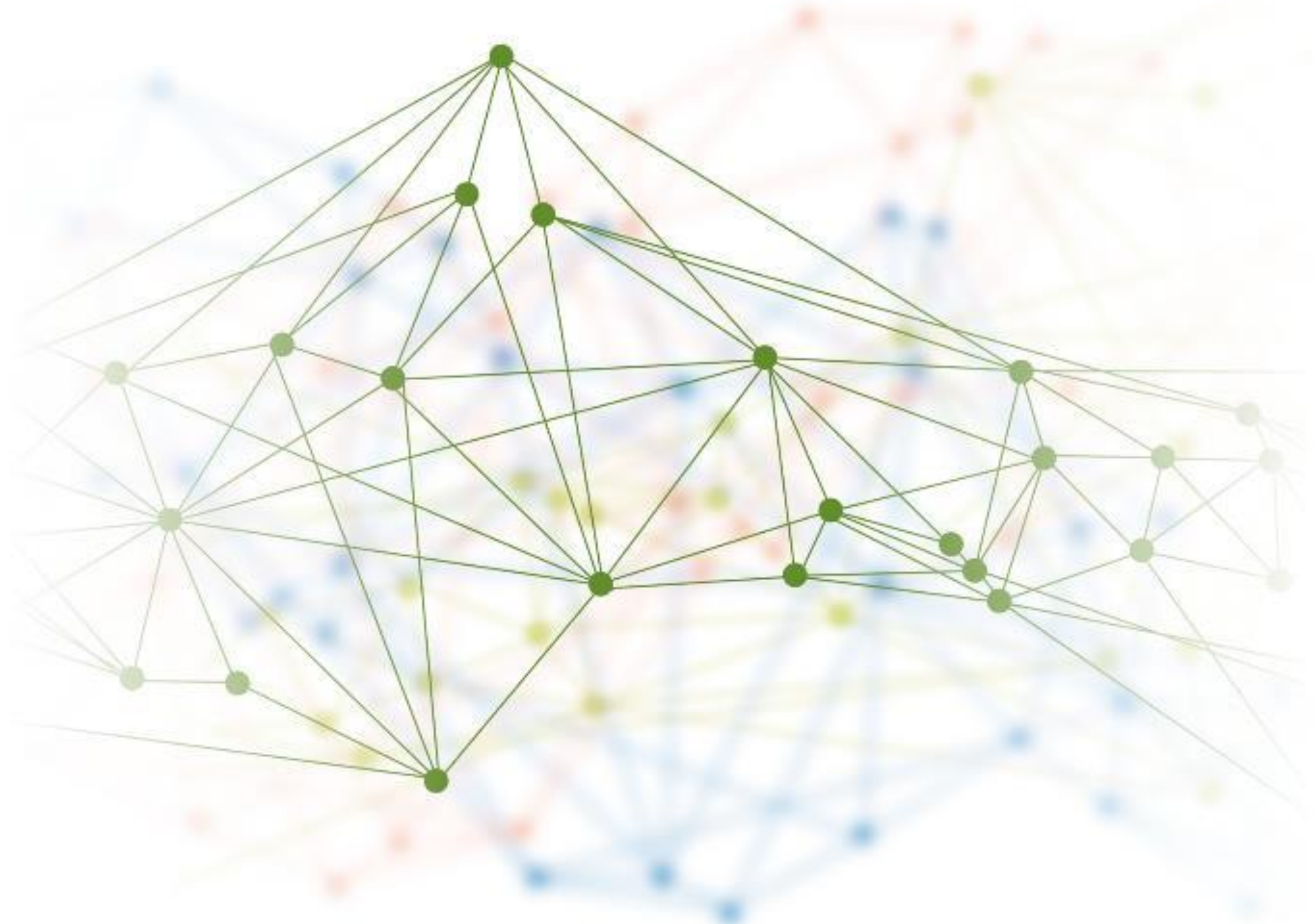
PHOENIX

Report on GB road map for roll out of H-SC



About Report

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Contents

Executive Summary

The requirements for assets and system services to support GB electricity system operation are changing as frequency and voltage management become more complex. Traditional large-scale thermal generation is declining, replaced by distributed generation and investment in low-carbon technologies. This transition creates challenges for system operation:

- Lower system inertia has caused Rate of Change of Frequency (RoCoF) to become a limiting factor and this is affecting how large system infeeds, including interconnectors, are operated.
- Lower short circuit levels can affect the operation of plant (e.g. High-Voltage Direct Current (HVDC) interconnectors) and protection systems.
- New generation sources may be remote from load centres in parts of the transmission network with limited capacity. With less synchronous generation available to support system operation, system voltage and stability constraints are more likely to limit power system transfers.

One of the devices developed to address these challenges is the Hybrid Synchronous Condenser (H-SC). The H-SC developed under the Phoenix project combines the mature technology of a Synchronous Condenser (SC) with the more recent technology of the Static Compensator (STATCOM), with an innovative hybrid control mechanism to maximise the benefits of the SC and STATCOM. Other hybrid arrangements are also possible such as combining an SC with battery storage technology.

The Phoenix Hybrid Synchronous Condenser (H-SC) installed at Neilston 275 kV substation has a rating of 140 MVA and consists of 70 MVA of SC and 70 MVA of STATCOM connected through a single three-winding transformer. The 70 MVA SC can provide a reactive power range of -34 Mvar to +70 Mvar. The SC can provide inertia support to the system and its inertia constant (H) is 1.34 s. The 70 MVA STATCOM can provide a reactive power range of -70 Mvar to +70 Mvar. The total reactive power range of the 140 MVA H-SC is -104 to +140 Mvar. The layout of the H-SC is shown in Figure 1.

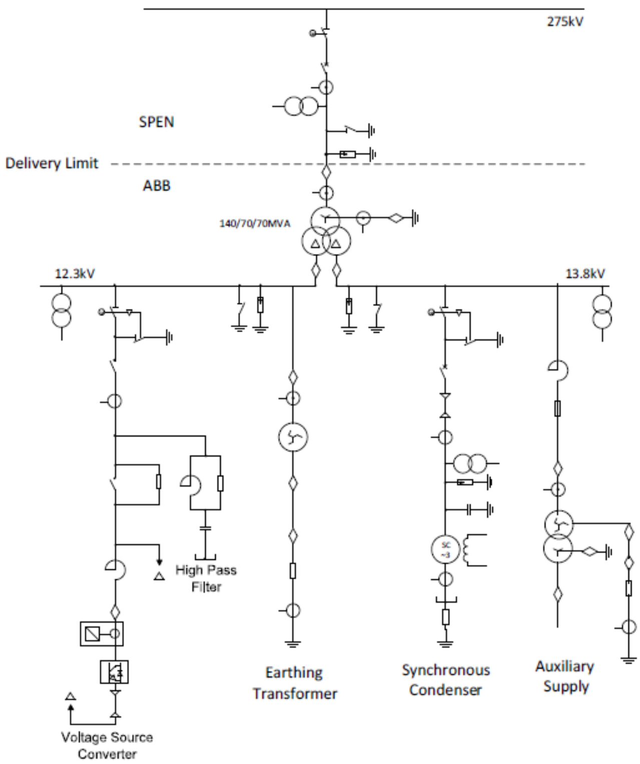


Figure 1: Layout of Hybrid Synchronous Condenser (H-SC) at Neilston

The H-SC technology differs from other technologies currently available as it uses a hybrid (master) control functionality to coordinate and optimise the simultaneous operation of two standalone control systems: namely, the STATCOM branch control system and the SC branch control system. The master control includes functions to co-ordinate voltage control and reactive power sharing, to minimise energy losses, and to speed up the response time of the H-SC.

A technical specification for the H-SC has been established that sets out the recommended minimum requirements for users to comply with when seeking to provide reactive power, inertia and short-circuit infeed services via the connection of a H-SC device [REF 9].

Potential H-SC Benefits

The deployment of H-SC on the GB electricity system could provide the following benefits:

- SC and STATCOM could provide steady state reactive power support and dynamic reactive power support. This would improve the voltage profile and voltage stability of the system.

- The short circuit contribution from the SC could increase fault level and system strength. The increased system strength could improve the operation of Phase Locked Loop (PLL) controllers and the ability of HVDC converters to correctly reference system phase changes. The increased Short Circuit Level (SCL) could help to ensure the correct operation of protection devices.

- The inertia contribution from the SC will improve the system inertia, which could improve the system stability limit and the system frequency response. The higher system inertia could improve the RoCoF values and frequency nadir following any system event and could reduce limits on generation or interconnectors to keep RoCoF and frequency within limits.

- The SCL and steady state and dynamic reactive support from H-SC could also improve the fault ride through capability, power quality (such as harmonics), Transient Over Voltage (TOV) profile and could also assist in the black start restoration approach.

A comparison of H-SC attributes with STATCOM and SC is given in Table 1. H-SC compare favourably to a separate STATCOM or SC in several areas as they can provide a broader range of system benefits by combining the attributes of each of the component elements.

	H-SC	STATCOM	Synchronous Compensator	Comments
Availability	High	High	High	
Losses	Moderate	Low	High	SC are rotating machines with increased losses.
Continuous controllability	Yes	Yes	Yes	
System Inertia Benefits	Moderate	Low	High	
System Strength Benefits	Moderate	Low	High	
Step response	4-5 cycles	<1 cycle	>500 ms	H-SC controlled to provide a faster response than SC.
Harmonic filters	No	No[1]	No	
Over Voltage capability	Moderate	Good	Moderate	
Undervoltage capability	Good	Good	Good	
Investment (USD/kVAR)	100-150	50-100	>150	
O&M Cost	Moderate	Low	High	

Table 1: Comparison between technologies

The studies carried out as part of the Phoenix work have demonstrated that H-SC can provide several benefits to the GB network. H-SC can increase transmission boundary capabilities by improving dynamic voltage capability and by reducing limitations on HVDC circuits. Table 2 summarises potential H-SC benefits on boundary transfers in different GB regions. Further studies have demonstrated that the deployment of SC across the network can improve short circuit levels, protection system performance and reduce RoCoF levels.

Region/Boundary	Summary of H-SC Benefits
Scotland - B6 boundary with single device	One H-SC is insufficient to fully load the Western HVDC Link under all conditions.
Scotland - B6 boundary with multiple devices	Multiple H-SC enable full loading of the Western HVDC Link and improve voltage stability. This provides greater benefit than multiple standalone SC or multiple standalone STATCOM. The multiple H-SC provided higher SCL contribution compared with standalone multiple STATCOM. The multiple SC provided faster dynamic response compared with multiple standalone SC. Hence the multiple H-SC provided greater benefit, with a combination of SCL and improved dynamic response, compared with standalone STATCOM or SC. It could be possible to add standalone SC where more SCL is required and STATCOM where dynamic response is required. This could also provide the similar benefits of multiple H-SC in all locations; however, this combination was not analysed in this project.
North East & West boundaries - multiple devices	STATCOM and H-SC solutions are effective at increasing the boundary transfer capability.
South Coast boundary - multiple devices	STATCOM and H-SC solutions are effective at increasing the boundary transfer capability.

Table 2: Potential H-SC Benefits across GB Regions

[1] The STATCOM may need a small filter to reduce high order harmonics. This filter may also be needed to provide the STATCOM with passivity at certain frequency ranges

Routes to Market for H-SC and SC

Since the Phoenix project was initiated, new GB commercial arrangements to address voltage and system stability requirements have developed. H-SC can already be deployed through existing regulatory and commercial arrangements. These are i) deployment as a regulated asset to meet Transmission Owner (TO) licence requirements, ii) deployment through a Network Options Assessment (NOA) recommendation or other justification driven by an agreed system need, and iii) deployment through the Stability Pathfinder process. These routes to market should enable the ESO to access H-SC and similar solutions at the pace required to meet system changes. The Pathfinder process is expected to inform the definition of more enduring commercial frameworks.

- Network Company Regulated Assets – SC or H-SC could be installed by network companies and remunerated in the same way as other regulated assets such as static reactive compensation equipment. For example, where requirements for SC or H-SC have been identified, TOs could install the assets in areas where SC and H-SC services are required. These assets would be made available to provide voltage, inertia and system strength capability and would reduce the need for NGESO to contract for services.

- NOA Process – Where it would be beneficial to increase transmission boundary capability, the NOA process allows different options to be proposed by TOs and other industry participants, and the “least regrets” option to be identified and recommended by NGESO. For boundaries where voltage performance limits capability, if a SC or H-SC solution is demonstrated to be the best available solution, this can be taken forward by the proposer. At Eccles for example, H-SC have been recommended as solutions to increase Anglo-Scottish transmission boundary capability. Whilst the NOA process provides a means to recommend solutions, it does not provide funding. If a recommended solution is to be taken forward by a TO, funding can be provided through RIIO-T2 mechanisms (including the Incremental Wider Works (IWW) and the Medium Sized Investment Project (MSIP) mechanisms). For other industry parties, the means to fund a recommended option remains unclear. However, the Early Competition Plan being developed by NGESO may provide a means for funding such works.

- Stability Pathfinder – The Phase 1 and 2 commercial tenders have built on the NOA process to allow different solutions to be compared to address identified shortfalls in inertia and short circuit levels. It has already been demonstrated that SC can meet the technical requirements set out for Stability Pathfinder and have been tendered as solutions. Through Stability Pathfinder, NGESO can compare SC and H-SC solutions tendered by a wide range of developers against other solutions and can select those options that are the most cost effective and most suited to meeting the specific requirements. Contracts are then put in place for the most suitable solutions. SC solutions have been successful in achieving contracts through Stability Pathfinder Phase 1 and hybrid solutions including SC are being considered by developers to meet Stability Pathfinder Phase 2 requirements.

The assessment carried out as part of the Phoenix project has shown that H-SC can provide effective solutions to system stability challenges. Particularly, in areas where there are multiple challenges such as a need for increased voltage stability and increased short-circuit level, H-SC provide a cost-effective means to achieve this.

H-SC Development at Neilston – Lessons Learnt

The parallel operation of a SC and STATCOM brings various challenges in equipment, control and system interactions. It is thus important to verify the feasibility of hybrid device operation for future installations in all those respects. The key challenges include:

- Control Interaction: The individual STATCOM and SC control, start stop and transfer sequences can impact on the overall hybrid device performance.
- Control coordination: How master controller can coordinate the control of the two devices (the same or different ratings) with minimised loss and maximising inertia contribution.

- System impact and Dynamics: It is important to verify the impact of the hybrid device on the connected system. Depending on the system strength and device rating the impact would vary. The dynamics of the hybrid device should be validated against the requirements.
- Detailed system studies are needed to verify impacts, and control and system interactions.

During the Phoenix H-SC trial, master controller functions were validated. A function to allocate reactive power between the SC and STATCOM elements performed as planned. A power loss minimisation function also worked though the benefits were not very high for the Phoenix setup.

From the experience of SP Energy Networks and Hitachi Energy in deploying the Phoenix H-SC at Neilston, the following lessons are worth considering.

- Design proposals should incorporate flexibility regarding site layout as changes may be required to match grid requirements.
- Modifications may be required to existing infrastructure such as cable trenches, buildings, drainage, etc.
- Service and earth records may not be accurate and should be investigated in advance of any design.
- Ensure proposals are fully compliant with UK standards. It can be the case that equipment developed for use elsewhere in the world needs some adjustments to meet UK standards.
- Access and safety clearance requirements for O&M should be carefully considered. This includes any unique secondary voltages associated with the H-SC and access requirements including barriers, and access platforms.
- In some cases, depending on soil conditions and geotechnical concerns, the construction of piles below the SC foundation may be required.
- Access to the H-SC switchgear is important to maximise equipment availability. For the Phoenix H-SC at Neilston, an enclosed gas circuit breaker was utilised. In some cases, use of an outdoor circuit breaker may avoid having to shut down the SC during circuit breaker maintenance.

Next Steps

The NIC Phoenix project has demonstrated that H-SC can be an effective solution for improving system voltages, system strength and system inertia. It is likely that SC and H-SC will be further considered by TOs and third party developers to meet future needs.

The development of the NOA and Pathfinder arrangements are providing additional routes to market for SC, H-SC and other hybrid solutions that include SC elements. These options can then be considered alongside other technical solutions for the provision of system services on the GB network. NGESO and wider industry participants will continue to develop the approach to managing voltage and stability in GB including the NOA process and Voltage and Stability Pathfinders.

1. Introduction

This document reports the work to deliver Successful Delivery Reward Criteria (SDRC) 5.4 for the Network Innovation Competition (NIC) Phoenix Project. SDRC 5.4 encompasses a report on a Great Britain (GB) road map for the roll out of Hybrid Synchronous Condensors (H-SC).

The report is based on evidence and learnings gathered by the Phoenix project. It outlines the potential system benefits of the H-SC and the associated deployment routes. It also summaries the key learning from the NIC Phoenix project trial which is a useful reference point in how the H-SC device could be deployed more wider on the GB electricity transmission.

1.1. Key elements of SDRC 5.4

The key elements of this work activity include:

- A review of the system benefits which can potentially be provided by H-SC technology.
- Outlines the routes to market for the deplopyment of the H-SC.
- Considers learning from the NIC Phoenix trail and how this can inform any future roll-out of H-SC devices.

1.2. Report Structure

The remainder of the report is structured as follows:

- Section 2 summarises key aspects the H-SC.
- Section 3 describes the changing GB electricity transmission system requirements.
- Section 4 provides a techanical overview of the H-SC and the potential benefits through the deployment of H-SC. This section also describes the learning from the Neilston trial.
- Section 5 focuses on the practical aspects of H-SC sourcing and installation.
- Section 6 provides a brief overview of the design and functionality of other types of H-SC.
- Section 7 considers what electricity system services might be provided by H-SC includingdiscussion of potential routes to market.
- Section 8 conclusion on the key aspects of any roll out of H-SC on the GB electricity transmission.

2. Hybrid Synchronous Condensor

The changing generation landscape in the GB power network has created challenges related to inertia, short circuit levels, and voltage control. Flexible Alternating Current Transmission Systems (FACTS) have played an ever-increasing role as part of the suite of technology solutions chosen to address the changing power system needs. Static Compensator (STATCOM), Static Var Compensator (SVC) and other dynamic reactive power compensation systems have seen increasing adoption rates globally, while synchronous condenser (SC) systems have experienced a 'renaissance' due to an increasing need for inertia and short circuit reinforcement.

One of the devices developed to address the above-mentioned challenges is the Hybrid Synchronous Condensor (H-SC). An H-SC is the combination of the very mature technology of the synchronous condenser with the more recent technology of the STATCOM.

Figure 2 depicts the simplified single line diagram of an H-SC. It consists of a STATCOM branch with a Voltage Source Converter (VSC) and an SC branch with a Synchronous Condenser. The STATCOM and SC branches can be connected to the same high voltage (HV) bus via a three-winding, three-phase transformer, or via separate two-winding, three-phase transformers. To use a three-winding transformer reduces the cost of the H-SC. If required, two or more VSC can be connected to the VSC bus and/or two or more SC can be connected to the SC bus.

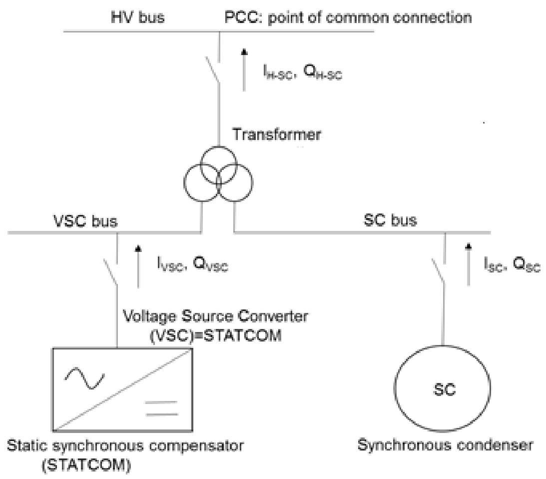


Figure 2: Simplified single line diagram of an H-SC

H-SC have a range of attributes that could meet several different power system challenges. Their SC branches can provide inertia support, overload support, and short-circuit current contribution. The system inertia capability of the SC branches can also be enhanced by adding flywheels to them. The STATCOM branches provide better dynamic voltage support, over-voltage mitigation, power oscillation damping, and power quality enhancement, for example by actively damping harmonics and voltage fluctuations producing flicker. The STATCOM branches can also provide inertia support when they come with batteries or super capacitors.

Synchronous condensers and STATCOM are also complementary technologies that can be combined to take advantage of their strengths and to compensate for their weaknesses. For example, the STATCOM branch of an H-SC can provide very fast voltage support in case of network contingencies and compensate for the slower response of the SC branch, in particular during the post-fault periods, whereas the SC branch can provide short circuit current contribution and compensate for the lower current injection of the STATCOM branch. Synchronous condensers also come with superior overload capabilities as compared to STATCOM. This overload capability can be used to inject reactive power and alleviate very severe voltage dip conditions.

H-SC can be optimised to suit system challenges. For example, the SC or STATCOM branches can be scaled up if certain attributes are more important in an application.

The H-SC technology differs from other technologies currently available as it uses a hybrid (master) control functionality to coordinate and optimize the simultaneous operation of two standalone control systems: namely, the STATCOM branch control system and the SC branch control system. The master control addresses the challenges associated with operation at the same point of common connection (PCC) by:

1. Determining the setpoints required by both technologies for their stable operation.
2. Deciding how to share the reactive power between the two technologies so that the total H-SC losses become as low as possible.
3. Using the faster response of the STATCOM technology to speed up the total H-SC response and improve system performance.
4. Returning the reactive power output of the H-SC to a pre-set steady-state value so that its reactive power capacity to support voltage is held in reserve.
5. Maximising the H-SC contribution to the Inertial Frequency Response (IFR) of the power network.
6. Coordinating Power Oscillation Damping (POD) and Power System Stabilizer (PSS) functions (not included in Phoenix).

The H-SC technology has been successfully demonstrated in the Phoenix project site at Neilston in Scotland, where a STATCOM operates in parallel with an SC via a three-winding power transformer and a hybrid control functionality.

3. Energy Landscape and GB System Requirements

3.1 Changes to GB Electricity Generation and Demand

The Climate Change Act 2008 legally binds the UK to reduce greenhouse gas emissions by at least 80 percent from 1990 levels by 2050. This is the UK's contribution to the Paris Agreement, seeking to hold the increase in global temperatures to less than 2^0C above pre-industrial levels. To meet these targets, one of the actions is to reduce the electricity production from fossil fuels such as coal and to increase the renewable electricity contribution.

National Grid Electricity System Operator (NGESO) has also announced its ambition that, by 2025, electricity system operation would have transformed such that the system can be operated safely and securely at zero carbon. As the UK moves to a low-carbon economy, the GB energy landscape is changing. In the GB Electricity System, the amount of conventional synchronous generation is declining due to the planned closure of coal and nuclear power stations as well as due to the increasing amount of solar and wind power generation being connected to transmission and distribution networks.

NGESO's Future Energy Scenarios (FES) suggest that the operation of synchronous generation will further decrease, and more non-synchronous generation will be installed [REF 1]. The installed low carbon and renewable generation[2] capacity is 54 GW and is expected to increase in the range of 82 GW to 117 GW by 2030 and in 2050 it is expected to be in the range of 140 GW to 248 GW. The forecasted solar and wind capacity in the GB system for the years 2030 and 2050, according to the FES report, is shown in Figure 3 and 4.

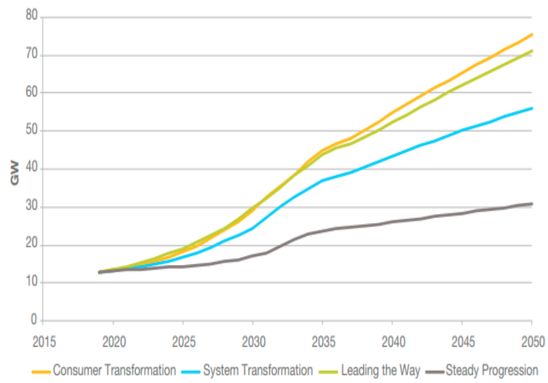


Figure 3: Forecasted Solar Capacity for Different FES Scenarios: Source: [REF 1]

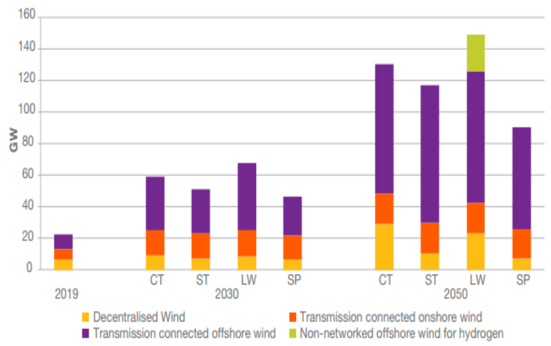


Figure 4: Forecasted Wind Capacity for Different FES Scenarios: Source: [REF 1]

In addition to this, there will be an increase in the amount of interconnector HVDC connections with other countries and an increase in storage technologies in the future years. These increases in interconnectors and storage could further reduce the operation of synchronous generation sources. In the year 2019, the total installed interconnector capacity was 5 GW and this is expected to increase to the region of 16 GW to 22 GW by 2030 and 16 GW to 27 GW by 2050, as shown in Figure 5. In the year 2019, the installed total storage capacity was 4 GW and is expected to increase to the region of 6 GW to 16 GW by 2030 and 25 GW to 60 GW by 2050, as shown in Figure 6.

[2] Includes Carbon Capture Usage and Storage (CCUS), Nuclear, Solar, wind and other renewables

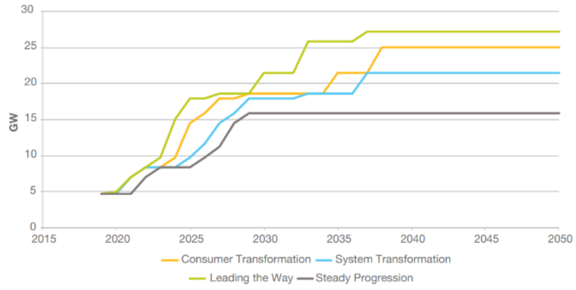


Figure 5: Forecasted Interconnector Capacity for Different FES Scenarios: Source: [REF 1]

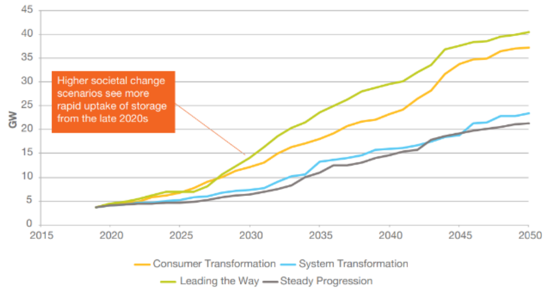


Figure 6: Forecasted Electricity Storage Capacity for Different FES Scenarios: Source: [REF 1]

The increase in storage as well as Electric Vehicles (EV) could also alter demand profiles including the peak and minimum demand levels. This could increase demand ramp rates requiring faster frequency response and more dynamic reactive power support. NGESO's System Operability Framework (SOF) document entitled "Operability Impact of Distributed Storage and Electric vehicles" provides more information and could be accessed from [REF 12].

3.2 The Impacts on GB System Requirements

As the GB system moves to a low carbon electricity system with increased wind and solar generation, as well as an increased amount of storage and interconnectors, more power is coming from non-synchronous generation. This means the amount of synchronous generation running at any time is reduced. The replacement of traditional large-scale thermal generation by distributed generation and low-carbon technologies, creates the following challenges for system operation:

- Reduces the availability of large-scale generation to provide steady state and dynamic voltage control capability and so will reduce the voltage stability of the system

- Reduces the fault level, also known as Short Circuit Level (SCL) of the system, an indicator of system strength. This will impact the operation of HVDC systems, the stable operation of Phase Locked Loops (PLL) in converter-based generation, levels of power quality and the reliable operation of protection. NGESO's System Operability Framework (SOF) document entitled "Impact of declining short circuit levels" could be accessed from [REF 13].

- Significant reduction of synchronous generation also reduces the level of system inertia, which will have an impact on frequency containment, Rate of Change of Frequency (RoCoF) and system stability. Constraints such as fast frequency response services and the Low Frequency Demand Disconnection (LFDD) scheme will come into play when managing the system inertia. NGESO is currently undertaking projects such as the Stability Pathfinder Project to set out the products and services required to maintain the system stability. NGESO's System Operability Framework (SOF) document entitled "Operating a Low Inertia System" can be accessed from [REF 14] and provides more information about challenges on the low inertia system operation.

- With the changing generation profile, there are an increased number and type of providers who can assist, with restoration during a Black Start event [REF 15].

To support the transition to a low carbon electricity system, there is a requirement to both decrease reliance on conventional synchronous generation to stabilise the system and learn to operate with less predictable power generation sources. There are several potential solutions to mitigate these challenges. One of the solutions that could address several effects is to add H-SC and/or SC in the system. In the GB system, there are SC/ H-SC being deployed through Stability Pathfinder and/or RIIO-2 deliverables. Internationally, there are number of SC that have been deployed to address some of the system challenges specified above.

The installation of H-SC on the electricity system could provide the following benefits:

a) SC and STATCOM are both able to provide reactive power support in steady state conditions. For certain system boundaries, the installation of a H-SC or multiple H-SC would provide reactive power support and could potentially increase the boundary transfer capabilities.

b) SC and STATCOM are both able to provide dynamic reactive power capabilities. For particular system boundaries, the installation of a H-SC or multuiple H-SC could provide dynamic reactive support and could improve the voltage stability limit/voltage collapse limit.

c) The amount of fault current contribution by H-SC would increase the Short Circuit Level (SCL) of the system. The increased system SCL could improve the operation of Phase Locked Loop (PLL) controllers and ability of HVDC converters to correctly reference system phase changes. Thus, the increase in SCL could improve the operation of High-Voltage Direct Current (HVDC) links by reducing the likelihood of commutation failure of Current Source Converter (CSC) type HVDC links and could improve the operation of converter-based generators with PLL. This could potentially improve the thermal, voltage and angular stability limits for certain boundaries.

d) The inertia contribution from a H-SC or H-SC could improve the angular stability limit for certain boundaries. The inertia contribution from H-SC could impact the Rate of Change of Frequency (RoCoF) and hence frequency nadir could be improved. As a result, H-SC could reduce the amount of generation which is constrained to meet the RoCoF and maximum infeed loss limit for the given scenario.

e) The SCL and steady state and dynamic reactive support from H-SC could also improve the fault ride through capability, power quality (such as harmonics), Transient Over Voltage (TOV) profile and could also assist in the black start restoration approach.

4. Technical Overview of H-SC

This section provides further detail on the technical requirements for H-SC. In section 4.1 this begins with the high level system technical specification for an H-SC. (Detailed technical specifications for SC and H-SC were produced as deliverables for the Phoenix project [REF 9, 10])

Section 4.2 goes on to explain how the H-SC and control system have been implemented at Neilston and includes details of a number of control system functions that are being trialled in the Neilston H-SC. Finally, Section 4.3 summarises a number of studies that were carried out to investigate the potential value of H-SC and SC on the GB network.

Before the more detailed discussion of technical requirements, a comparison of H-SC attributes with STATCOM and SC is given in Table 3. (The comparison is based on devices with the same overall MVA rating.) The comparison demonstrates that H-SC compare favourably to separate STATCOM or SC in several areas and can provide a broader range of benefits by combining the attributes of each of the component elements.

	H-SC	STATCOM	Synchronous Compensator	Comments
Availability	High	High	High	
Losses	Moderate	Low	High	SC are rotating machines with higher losses.
Continuous controllability	Yes	Yes	Yes	
System Inertia Benefits	Moderate	Low	High	
System Strength Benefits	Moderate	Low	High	
Step response	4-5 cycles	<1 cycle	>500 ms	H-SC controlled to provide a faster response than SC.
Harmonic filters	No	No[3]	No	
Over Voltage capability	Moderate	Good	Moderate	
Undervoltage capability	Good	Good	Good	
Investment (USD/kVAR)	100-150	50-100	>150	
O&M Cost	Moderate	Low	High	

Table 3: Comparison between technologies

4.1. H-SC Technical Specification

The detailed technical specifications for H-SC were produced as part of the deliverables for the Phoenix project [REF 9] and are summarised below. A separate technical specification was also developed for SC and is summarised in Appendix B. For complete guidance on the technical specifications for SC and H-SC, please refer to the detailed specifications document.

1. The H-SC shall be designed for continuous and controllable operation at all system voltages between 0.9 p.u. to 1.1 p.u. and at all system frequencies between 47 Hz to 52 Hz.

[3] The STATCOM may need a small filter to reduce high order harmonics. This filter may also be needed to provide the STATCOM with passivity at certain frequency ranges

2. The H-SC must be capable of operating in either "Voltage Control" mode or "Constant Reactive Power Control" mode with a single operating mode instruction. The facility must be able to switch between voltage control mode and constant reactive power control mode on instruction from the company (system operator) within an agreed time scale of no longer than 2 minutes and changes in operating mode should be achieved without any sudden disturbance to the system via a smooth transition.
   i. The different parts of the Hybrid device should be selectable to different operating modes.
   ii. There should be no control interaction between any of the parts of the device or any undamped oscillations.
   iii. In the voltage control mode, a voltage control slope setting of between 2% and 7% inclusive must be available. The voltage control setpoint should be selectable between 0.95pu to 1.05 pu with a resolution of 0.0025pu.
   iv. In the reactive power control mode, the reactive power output should be controlled to deliver a value of reactive power equivalent to the reactive power setpoint unless acting to address high or low voltage conditions. Under such conditions the voltage control capability should be enabled to contribute to the correction of the voltage during the disturbance. The low and high voltage limits shall be adjustable between 0.93 pu and 1.07 pu with a resolution of 0.005pu.

3. The H-SC shall be capable of continuous operation at any point between the specified reactive capability limits.

4. The SC component of any H-SC device should have a short circuit ratio no lower than 0.5pu.

5. When operating in Voltage Control Mode, as an accuracy measure of the steady state voltage control the hybrid device shall provide continuous steady state control of the voltage at the connection point or other point as agreed with a Setpoint Voltage and Slope characteristic as illustrated in Figure 7. The initial Slope setting will be 4%.

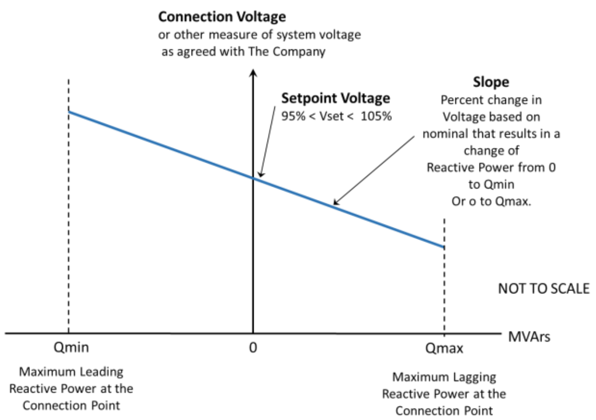


Figure 7: Voltage Control Mode – Setpoint Voltage and Slop Characteristics

6. For an on-load step change in the measured connection point voltage the continuously acting automatic control system shall respond according to the following minimum criteria:
   i. the Reactive Power output response of the device shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAr seconds delivered at any time up to 1 second are at least those that would result from the response shown in Figure 8.

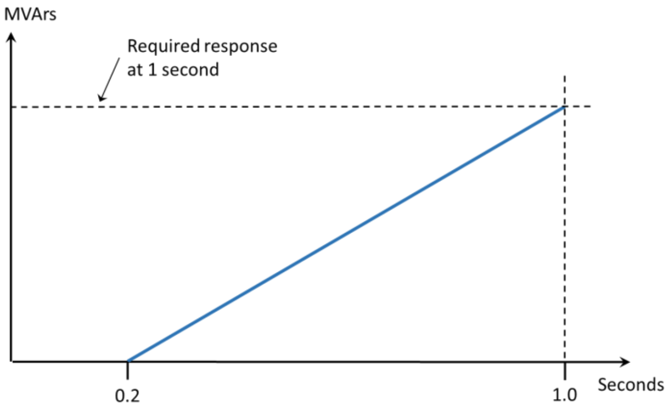


Figure 8: H-SC reactive power output response

ii. the response shall be such that 90% of the change in the Reactive Power output of the H-SC device will be achieved within
  - 2 seconds, where the step is sufficiently large to require a change in the steady state Reactive Power output from its maximum leading value to its maximum lagging value or vice versa and
  - 1 second where the step is sufficiently large to require a change in the steady state Reactive Power output from zero to its maximum leading value or maximum lagging value as required.

iii. the magnitude of the Reactive Power output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.

iv. within 5 seconds from achieving 90% of the response as defined above the peak-to-peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum Reactive Power.

v. following the transient response, the conditions of steady state voltage control shall apply.

7. H-SC should meet the fault ride through requirements where H-SC shall remain stable and connected to the network for system voltages at the HV side of the unit step up transformer
   i. Falling to 0 pu for at least 140ms
   ii. Falling to 0.4pu for at least 300ms

8. H-SC and any of the constituent parts, controls and auxiliaries of the overall device shall remain active and permit delivery of reactive power during any low voltage incident where the measured system voltage remains above 0.2pu. For a voltage measure below this value on any phase any part of the hybrid device is permitted to 'block' the output and must be consistent with the fault ride through requirement.

9. H-SC shall remain stable and connected to the network for instantaneous Transient Overvoltage (ToV) limit of 2 pu, 1.4pu for 0.5s and 1.3 pu for 1s.

10. The H-SC or any of its constituent parts, as required, shall start-up from standstill and synchronise to the system within 15 minutes of receipt of an instruction from the System Operator. The H-SC or any of its constituent parts, as required, shall be fully available to restart no longer than 15 minutes after disconnection from the system following a shutdown instruction[4].

11. H-SC device should achieve an availability of 98%.

4.2. H-SC and Master Control Explained

This section provides the technical details of H-SC and master control functions and its operation and also explains how the technical requirements for the H-SC at Neilston have been achieved. The details of control system for standalone SC and standalone STATCOM are explained in Appendix A.

[4] After the shutdown instruction, a total of 30 minutes to synchronise the H-SC back to the system

H-SC and Master Control

The H-SC system has been designed according to the alternating current (ac) power system characteristics at the point of common connection (PCC). Those characteristics should be specified by the grid operator and include aspects such as system voltage, short circuit levels, expected over-voltages and under-voltages, the maximum rate of change of frequency (df/dt), etc. IEEE Standard 1031-2011 gives an example of the necessary power system characteristics to specify.

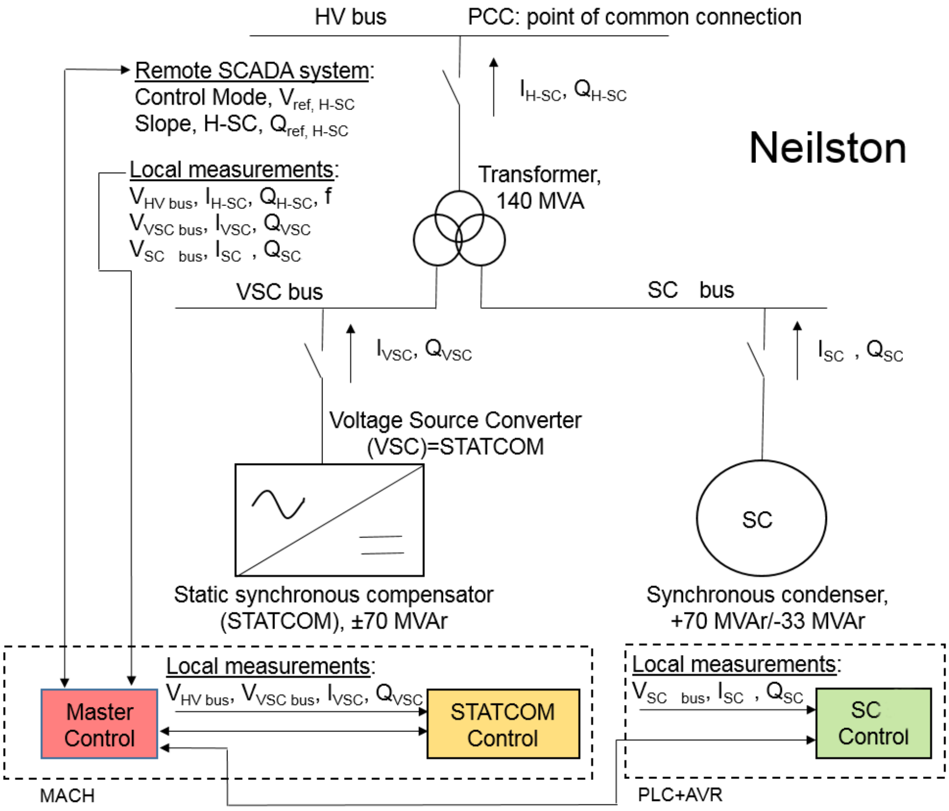


Figure 9 - Simple single-line diagram of the H-SC system

As shown in Figure 9, a ±70 Mvar STATCOM operates in parallel with a +70/-33 Mvar Syncronous Condenser (SC), connected to the HV bus via a three-winding power transformer rated for 140 MVA. The STATCOM, SC and power transformer have been manufactured by Hitachi Energy. The STATCOM utilizes Modular Multi-level Converter (MMC) valve technology, while the synchronous condenser is a 4-pole motor with brushless excitation system and inertia constant of 1.34 s. The synchronous condenser has been designed for installation in a safe area according to IEC 60034-1, 275 kV is the HV bus voltage.

H-SC Control and Operation

SC and STATCOM technologies are traditionally supplied with standalone control systems. The STATCOM control is a MACH® control platform manufactured by Hitachi Energy. The SC control consists of a PLC and an AVR also manufactured by Hitachi Energy.

The SC controls the SC bus voltage ($V_{SC\ bus}$) by using the local measurements I_{SC}, $V_{SC\ bus}$ and Q_{SC} illustrated in Figure 9, whereas the STATCOM controls the HV bus voltage ($V_{HV\ bus}$) by using the local measurements I_{VSC}, $V_{VSC\ bus}$, $V_{HV\ bus}$ and Q_{VSC}.

In addition to the standalone operation of the STATCOM and SC, a hybrid control functionality (Master Control) has been developed inside the MACH® control platform. The developed functionality avoids "control hunting" between the two control systems (STATCOM Control and SC Control), thus allowing the stable, coordinated and efficient operation of both branches simultaneously.

As depicted in Figure 9, Master Control uses all the local measurements mentioned above plus $I_{H\text{-}sc}$, $Q_{H\text{-}sc}$ and the network frequency (f), in addition to the control modes, setpoints ($V_{ref,\ H\text{-}SC}$ and $Q_{ref,\ H\text{-}SC}$), and slope (Slope, H-SC) chosen by the operator for the H-SC system. This information can be obtained remotely via SCADA or locally via the HMI of the MACH® platform, and it is then used to calculate the setpoints and slopes required by the STATCOM and SC controls.

The available control modes in the STATCOM are automatic voltage control (V control) and Mvar control (Q control). In V control the voltage of the HV bus ($V_{HV\ bus}$) is controlled according to the voltage setpoint ($V_{ref,\ VSC}$) and slope (Slope, VSC) chosen by the operator, whereas in Q control the reactive power output at HV bus level is controlled according to the chosen power setpoint ($Q_{ref,\ VSC}$).

The available control modes in the SC are automatic voltage control (V control), Mvar control (Q control) and field current control (Manual control). V and Q controls are similar to those in the STATCOM, but they control the SC bus voltage ($V_{SC\ bus}$) and the reactive power output at SC bus level (Q_{SC}), respectively. In Manual control, the exciter field current is controlled according to the current setpoint chosen by the operator. Manual control is only for commissioning or loss of voltage measurement.

The STATCOM control does not require the transformation of $V_{ref,\ H\text{-}SC}$ and $Q_{ref,\ H\text{-}SC}$ at HV bus level into $V_{ref,\ VSC}$ and $Q_{ref,\ VSC}$ at VSC bus level. In that case, the problem is solved by using the branch current I_{VSC} on the VSC side of the power transformer to regulate the voltage and reactive power output on its high voltage side. However, the SC control requires the transformation of $V_{ref,\ H\text{-}SC}$ and $Q_{ref,\ H\text{-}SC}$ into $V_{ref,\ SC}$ and $Q_{ref,\ SC}$ at SC bus level. Master Control does that transformation by adding the voltage drop across the power transformer and the reactive power losses to $V_{ref,\ H\text{-}SC}$. and $Q_{ref,\ H\text{-}SC}$, respectively.

Therefore, under normal circumstances, the H-SC operating modes will be given by the possible combinations of V and Q control between the STATCOM branch and the SC branch. Table 4 lists the alternatives employed in Phoenix. As indicated by the third column, there are three H-SC operating modes: only STATCOM (SC out of service), only SC (STATCOM out of service) or both STATCOM and SC in service.

The operator can also assign V control or Q control to any of the two branches. As a result, there will be several possible combinations (described as ‘Applications’), as shown in Table 4.

Besides, if the goal of the operator is to provide inertia services without SC MVAr, then the Q setpoint of the SC branch ($Q_{ref,\ SC}$) is set to zero (e.g. in Applications 3, 8 and 9).

Application 7 (both branches in V control) is expected to be the most commonly used mode of operation. In that case, the H-SC system provides inertia with a variable Mvar split to provide automatic voltage control (or V control). Application 6 is expected to be the next most commonly used mode. In that case, the H-SC system provides inertia with a constant Mvar split to provide fixed Mvar Control (or Q control).

Application	Setting	H-SC Operating Mode	STATCOM (VSC)		Synchronous Condenser (SC) System		Setpoints calculated by Master Control
			Control Mode	Setpoint	Control Mode	Setpoint	
01: MVAr only	Constant MVAr	Only STATCOM	Q	$Q_{ref, VSC} \neq 0$ @ HV bus	NA	NA	NA
02: MVAr only	Variable MVAr		V	$V_{ref, VSC}$ @ HV bus	NA	NA	NA
03. Inertia only	NA	Only SC	NA	NA	Q	$Q_{ref, SC} = 0$ @ HV bus	$Q_{ref, SC} = 0$ @ SC bus
04: Inertia with SC MVAr	Constant MVAr		NA	NA	Q	$Q_{ref, SC} \neq 0$ @ HV bus	$Q_{ref, SC} \neq 0$ @ SC bus
05: Inertia with SC MVAr	Variable MVAr		NA	NA	V	$V_{ref, SC}$ @ HV bus	$V_{ref, SC}$ @ SC bus
06: Inertia with MVAr split(1),(2)	Constant MVAr	Both STATCOM and SC	Q	$Q_{ref, VSC} \neq 0$ @ HV bus	Q	$Q_{ref, SC} \neq 0$ @ HV bus	$Q_{ref, SC} \neq 0$ @ SC bus
07: Inertia with MVAr split(1),(2)	Variable MVAr		V	$V_{ref, H\text{-}SC}$ @ HV bus	V	$V_{ref, H\text{-}SC}$ @ HV bus	$V_{ref, SC}$ @ SC bus
08: Inertia with STATCOM MVAr(2)	Constant MVAr		Q	$Q_{ref, VSC} \neq 0$ @ HV bus	Q	$Q_{ref, SC} = 0$ @ HV bus	$Q_{ref, SC} = 0$ @ SC bus
09: Inertia with STATCOM MVAr(2)	Variable MVAr		V	$V_{ref, VSC}$ @ HV bus	Q	$Q_{ref, SC} = 0$ @ HV bus	$Q_{ref, SC} = 0$ @ SC bus
10: Inertia with MVAr split(2)	Variable MVAr		Q	$Q_{ref, VSC} \neq 0$ @ HV bus	V	$V_{ref, SC}$ @ HV bus	$V_{ref, SC}$ @ SC bus
11: Inertia with MVAr split(2)	Variable MVAr		V	$V_{ref, VSC}$ @ HV bus	Q	$Q_{ref, SC} \neq 0$ @ HV bus	$Q_{ref, SC} \neq 0$ @ SC bus
(1) With or without Power Loss Minimization							
(2) With or without Inertia Maximization							

Table 4: H-SC operating models

Master Control comes with several objective functions to achieve its goals. Some are objective functions for optimization, whereas others are simply coordinating functions, control strategies and/or calculation functions. The functions developed by Hitachi Energy are: 1) Coordinated Voltage Control and Reactive Power Sharing, 2) Power Loss Minimisation, 3) Fast Transients Compensation, 4) Inertia Support Maximisation, 5) Losses Calculation and 6) Slow Mvar Control.

Figure 10 depicts the block diagram of Master Control. As shown the input signals are the local voltage, current and power measurements, in addition to control mode, setpoint and slope chosen by the operator for the H-SC system. Other inputs are the on/off signals for the different objective functions and the STATCOM and SC current limits. The outputs are the setpoints (rightmost column in Table 4) and slopes required by the coordinated operation of both control systems.

The operator can also choose different control modes for the branches, according to the applications listed in Table 4**Error! Reference source not found.**, but these have not been depicted in Figure 10 for simplicity. The developed functions for Master Control are described below.

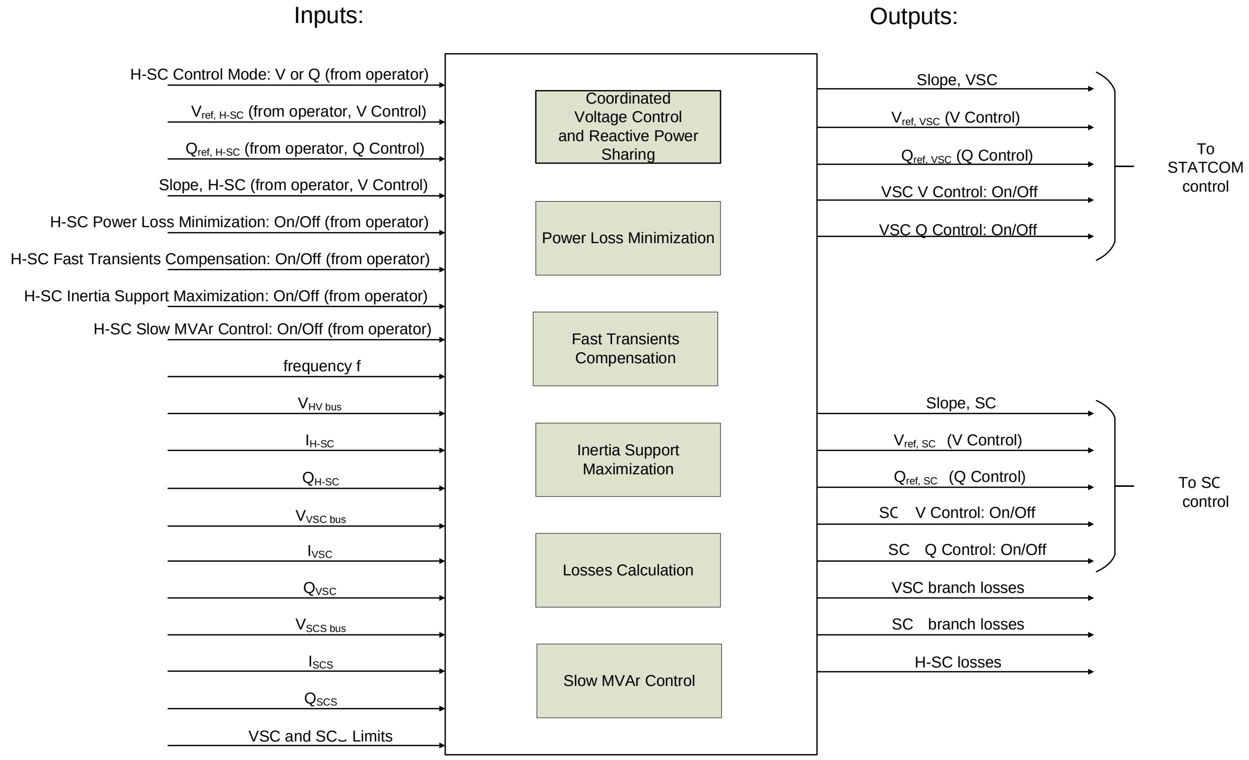


Figure 10 – Block diagram of Master Control

Co-ordinated Voltage Control and Reactive Power Sharing

The main objective of this function is to determine the setpoints required by both control systems for their coordinated and stable operation. For V control, the outputs are voltage setpoints ($V_{ref,\ VSC}$ and $V_{ref,\ SC}$) and slopes (Slope, VSC and Slope, SC), whereas for Q control the outputs are reactive power setpoints ($Q_{ref,\ VSC}$ and $Q_{ref,\ SC}$). In both cases, the output setpoints and slopes are determined as functions of the input setpoints ($V_{ref,\ H\text{-}SC}$ or $Q_{ref,\ H\text{-}SC}$) and slope (Slope, H-SC) chosen by the operator for the HV bus.

To achieve equal reactive power-sharing between STATCOM and SC, this function sets equal slopes for the branches (i.e. Slope, H-SC @140 MVA = Slope, VSC @70 MVA = Slope, SC @70 MVA) when using Application 7 (without Power Loss Minimisation, which is explained in Section 3.2.) in Table 4. The operator can also set different reactive power setpoints per branch (i.e. $Q_{ref,\ VSC}$ □ $Q_{ref,\ SC}$) when using Application 6 (without Power Loss Minimisation) or Application 8 in Table 4, but that option has not been depicted in Figure 10 for simplicity. For the applications listed in Table 4, the operator cannot turn off this function.

Power Loss Minimisation (PLM)

This is an innovative function proposed by Hitachi Energy, and its main objective is to determine how the total reactive power output of the H-SC system should be shared between its two branches so that the total losses are as low as possible. To minimise losses, the losses and their derivatives have been expressed as functions of the branch currents (or branch reactive powers) by using the component ratings and the design data.

The outputs of this function are optimized slopes (in V control, i.e. Application 7 in Table 4) or optimized Q setpoints for both the STATCOM and the SC (in Q control, i.e. Application 6 in Table 4 if the input setpoint is the total reactive power $Q_{ref,\ H\text{-}SC}$). In both cases, the output setpoints and slopes are determined as functions of the input setpoints ($V_{ref,\ H\text{-}SC}$ or $Q_{ref,\ H\text{-}SC}$) and slope (Slope, H-SC) chosen by the operator for the HV bus. The operator can also turn off this function, as shown in Figure 10.

Fast Transients Compensation (FTC)

This is also an innovative function proposed by Hitachi Energy, and its main objective is to speed up the response time of the H-SC system in case of sudden changes in voltage (e.g. due to network disturbances), in particular when using Application 7 in Table 4. The response time of the whole installation can be slowed down by the natural dynamics of the SC, for example immediately after clearing a fault, in addition to the communication delays between the two control systems.

To solve the problem this function adds the SC voltage error to the STATCOM voltage setpoint $V_{ref, VSC}$ while waiting for the SC to catch up. As a result, the response time of the H-SC system goes from the expected SC response of seconds to the expected STATCOM response of milliseconds, thus showing the benefits of a coordinated control between the STATCOM and SC. As shown in Figure 10, the operator can also turn off this function.

Inertia Support Maximisation (ISM)

The main objective of this function is to maximise the H-SC system contribution to the Inertial Frequency Response (IFR) of the power network. The IFR will take place during the first few milliseconds or seconds following the loss of a large power generator or the increase of load. The H-SC system will contribute to the total inertia of the power network from the kinetic energy stored in the SC. This function is triggered by the values of frequency (f) and Rate of Change of Frequency (RoCoF) measured at the PCC. The values (thresholds) for the activation are adjustable by the operator and are expected to be in the interval of 47.5-49.5 Hz and 0.1-3 Hz/s for frequency (f_{th}) and Rate of Change of Frequency ($RoCoF_{th}$), respectively.

The SC and STATCOM generate losses during their operation, and the STATCOM losses will reduce the actual active power contribution of the SC to the grid during the first seconds following the loss of generation. An optimal operation strategy for the H-SC system should then aim to fully utilize the active power contribution from the SC in the expected operating frequency range of the H-SC system (47 – 52 Hz).

To maximise the inertia contribution of the SC when the frequency decreases (47 Hz $\leq f < f_{th}$ and RoCoF $< -RoCoF_{th}$), the IM function simply sets the STATCOM to Q control mode with a fixed reactive power output of 0 Mvar. As soon as the frequency starts to increase, the STATCOM control is released and goes back to the previously chosen control mode (for example V control) and setpoint before the frequency deviation. If the frequency becomes greater than 52 Hz or lower than 47 Hz, then the STATCOM is temporarily blocked. As shown in Figure 10, the operator can also turn off this function.

Losses Calculation

The measurement of the losses of operating STATCOM and Synchronous Condenser Systems is not practical; the main reason is the difficulty with measuring active currents that are much smaller than the xreactive currents of the main circuit. However, the losses are a major part of the operating cost and should be known. As a result, the common practice is to obtain them by calculations.

The objective of this function is to calculate the total losses of the H-SC system during steady-state operating conditions. The total losses of the H-SC system are the sum of the STATCOM losses, the SC losses, the transformer losses, the cooling system losses, and the auxiliary system losses. For a representative number of capacitive and inductive operating points, all the losses mentioned above have been obtained from the component ratings and the design data, and the results have been expressed as functions of the branch currents (or reactive powers) by using quadratic polynomials. The losses are displayed on the HMI.

Slow MVAr Control

The objective of the Slow MVAr Control function is to slowly return the reactive power output of the H-SC system to a preset steady-state value so that its reactive power capacity to support voltage is held in reserve. This higher-level regulator is available when operating the STATCOM in V control (Applications 2, 9 and 11 in Table 4), or when operating the H-SC system in V control with both branches (STATCOM and SC) in service (Application 7 in Table 4). The slow Mvar control is slow compared to the voltage regulators of both branches, and its output is a small addition/subtraction ΔV_{ref} to/from the voltage setpoint $V_{ref, H\text{-}SC}$ of the H-SC system. The output signal ΔV_{ref} is added to the voltage setpoint in such a way that in steady-state the H-SC system remains within a window defined by two limits, one at the capacitive range and one at the inductive range. The operator can also turn off this function.

4.3. Project Phoenix Learnings

In this section some of the learnings through implementation of the Phoenix project are listed.

In general, parallel operation of SC and STATCOM may bring various challenges in equipment, control and system interactions. It is important to verify the feasibility of hybrid device operation for future installations in all those respects. The key challenges include:

1. Control Interaction: This is related to the fact how individual STATCOM and SC control, start stop and transfer sequences can impact on the overall hybrid device performance.

2. Control coordination: How master controller can coordinate the control of the two devices (the same or different ratings) with minimised loss and maximising inertia contribution.

3. System impact and Dynamics: It is important to verify the impact of the hybrid device on the connected system. Depending on the system strength and device rating the impact would vary. The dynamics of the hybrid device should be also validated against the requirements.

4. Detailed system studies are needed to verify impacts, and control and system interactions.

During verification of the live trial in Phoenix, the following conclusions have been made:

1. The H-SC achieved the expected reactive output values in stable manner.

2. The transition between the operating modes is bumpless without introducing any change of the steady state values. After the completion of the mode transition, system settles within few cycles.

3. The speed of STATCOM during dynamic support is as expected and very fast (within 20 ms). In case of dynamic support, it is reasonable that the STATCOM is operated in voltage control mode.

4. The response of SC during setpoint changes is slow due to ramp rate limiters and communication delays, however, the SC responded fast and as expected during the system events. The change in reactive power output and voltage are very small in system events created with reactor switching as the network is very strong.

5. During all unplanned system events e.g., fault, frequency and voltage events, the HSC reacted as expected and provided the active and reactive support during frequency and voltage events respectively.

6. All the master controller functions were validated. The distribution of reactive power, loss minimization in various operation worked as expected.

7. The application of FTC function implies that STATCOM can compensate the slower dynamic response of SC driving H-SC to act much faster. This is validated through the tests in the live trial.

8. PLM contributes to the minimisation of losses of H-SC and it has been shown that its simultaneous use with loss minimisation function (LRM) leads to higher loss minimisation. Although the value of loss reduction was not very high the efficacy of the function is validated in the live trial.

9. The Slow MVAr function changes the steady state reactive output of STATCOM and SC to ensure a larger available headroom for dynamic support. This is validated through the test in the live trial. The gain of the slow MVAr function is increased to avoid continuous STATCOM overload and currently the tuning of the gain is planned for optimal performance.

10. STATCOM has nominal reactive power range of -70 MVAr to +70 MVAr. STATCOM has overload capability to inject reactive power beyond nominal value of 70 MVAr. When STATCOM reaches this overload capability it activates the thermal overload protection. The protection allows the STATCOM to inject overload current for 3 seconds maximum before limiting to 1 p.u. for 3 minutes. After the 3 minutes, if overload capability is still required STATCOM reaches overload limit for 3 seconds maximum and limiting to 1 pu for 3 minutes again. STATCOM overload capability created pulsating behaviour when the STATCOM is overloaded continuously. This is avoided with the use of the slow MVAr function and the change in slow MVAr gain to reduce STATCOM output as discussed above.

11. The change in loss value, with LRM, is not very high for the Phoenix setup. However, the function worked as expected.

12. The inertial contribution of the SC is relatively small for the Neilston device. Larger machine inertias and inertial contributions could be achieved, for example adding a flywheel to the SC. The impact of ISM function is very small in Phoenix. ISM function maximise the inertia contribution by changing either STATCOM control mode, blocking STATCOM or activation of LRM / PLM functions. The changes are decided based on measured frequency and ROCOF. However, this function could be valuable to maximise the inertia contributions in other projects with energy storage or larger inertia source. For example, the function could coordinate the simultaneous injection of active power from both branches (STATCOM and SC) in case of frequency drops. This is not implemented in Phoenix project, but this could be seen as a future scope of ISM function.

13. All the changes in control modes for STATCOM and SC were achieved in stable manner.

14. For verification of the master controller functions, it is important to capture the high-resolution data during the test case and events. In Phoenix, in some cases and events, the data capture with the TFR device did not trigger. This indicates that the trigger level for such data recording device should be selected carefully.

15. In respect of local and remote control, it should be possible to do certain operations locally or remotely including Setpoint changes, Ramp rate limiter changes, Operation mode changes (V/Q), Slope setting changes, Master control function (On/Off), Slow Mvar setting changes, Inertia maximisation setting changes, STATCOM voltage control gain reset, SC setting changes and Start and stop of both and any of the branches**Error! Reference source not found.**. [REF 11]

16. The time response of the SC in standalone mode (with the STATCOM out of service) could be improved by calculating the SC setpoint with feedforward control instead of feedback control. For example, the transformer impedance and the branch current (instead of the voltage measurements) could be used to calculate the voltage error.

17. No major learning on availability and maintenance during the one year live trial stage. There was no preventive maintenance planned during the Live Trial stage and no such maintenance has been done. However, there has been some “corrective maintenance” done with regards to the Lube Oil unit for the SC system, and with regards to the STATCOM IGBT Valves. As for availability the STATCOM and SC as such, these have behaved as expected during the live trial, however, with some issues with the Lube Oil connected to the SC, which has reduced the operational time of the SC-system

4.4. H-SC System Studies

This section summarises the system analysis carried out by NGESO and UoS and the key findings on benefits of H-SC from these analyses. The early sections, sections 3.4.1 and 3.4.2, explain the NGESO study background and the benefits of H-SC in the GB system evaluated through system studies. The later sections, sections 3.4.3 and 3.4.4, explain the UoS study background and the benefits of SC in improving system SCL, protection operation and resilience to loss of generation events.

4.4.1. NGESO Study Analysis on H-SC Benefits

This section summarises the background of the NGESO system studies and the key benefits on H-SC in the GB system, evaluated through system analysis.

NGESO Study Background

To evaluate the benefit of the Phoenix H-SC device, the 2017 Electricity Ten Year Statement (ETYS) transmission network dynamic model prepared by NGESO representing the detailed GB Electricity Transmission Network for different scenarios was used. Future Energy Scenarios (FES) 2018 data published by NGESO was used to set the required generation and demand background to reflect 2019, 2023 and 2027 networks for summer and winter scenarios. This ETYS dynamic model was used to analyse the benefits of a 140 MVA H-SC at Neilston location. The detailed system analysis carried out by NGESO on evaluating the benefit of 140 MVA H-SC at Neilston 275kV substation is reported in SDRC 2.2 [REF 7].

Further analysis has been carried out to evaluate the benefit of higher rated H-SC devices at Neilston location. For this analysis, the ratings were selected as 280 MVA and 420 MVA, double and triple the size of Phoenix device. Analysis has been carried out to evaluate the benefit of multiple H-SC devices in the Scotland region. This analysis has been repeated for different parts of the GB electricity system including the North East and North West region of England & Wales, the South Coast of England & Wales and the South West of England & Wales region. The detailed system analysis on impact on size of H-SC, locations of the device carried out by NGESO is presented in SDRC 2.6 report [REF 8].

The installation of H-SC on the electricity system could provide the following functions:

1. H-SC can provide steady state reactive power support to achieve the target voltage. The master controller in the H-SC is to coordinate and optimise the simultaneous operation of SC and STATCOM and avoids control hunting between two branches.

2. H-SC should be able to operate in “Voltage Control” mode or “Q Control” mode. It should be also possible to change from one mode to another without any unwanted oscillations in the system.

3. Power Loss Minimisation (PLM) function in the master controller helps to achieve the reactive power sharing between each element and at the same time could reduce the amount of power loss incurred by the device. In the Phoenix device, the installed H-SC rating is 140 MVA with 70 MVA SC and 70 MVA STATCOM. With this configuration, the reactive power sharing is almost equal between two branches and the amount of power loss saved by the H-SC is very small. With the different ratings and configurations, the savings could be greater.

4. H-SC can provide dynamic reactive power support to the system. STATCOM can provide very fast dynamic support whereas SC response times will be slower. With the Fast-Transient Compensation (FTC) function, the master controller can speed up the total H-SC response by utilising the faster response of the STATCOM.

For NGESO system analysis, it has been assumed that both SC and STATCOM are operating in “Voltage Control” mode. It has been also assumed that PLM and FTC functions are in service.

In general, the impact of H-SC on the network will depend on:

1. Strength of the network (it would be hard to detect improvement in an already strong network).

2. Amount of reactive power injection of H-SC to the network (small injection of reactive power will not have any significant change in voltage)

3. Amount of active power injection during inertial contribution (small active power injection will not result in any detectable change /improvement in frequency)

4. Loss: The overall loss of the H-SC device should be kept low (< 1.5%)

5. Dynamics: The hybrid device dynamics will play an important role on the system impact. Advanced functions such as FTC can help to speed up the total H-SC response by utilising the faster response of the STATCOM.

NGESO System Analysis Findings

With the assumed network and generation background, the benefits of H-SC device are evaluated through system analysis. The key findings are summarised below.

The benefits of H-SC device in Scotland region are evaluated through boundary transfer analysis and the device contribution in dynamic reactive support, SCL contribution and inertia support are analysed.

1. With the FTC function in service, it is expected that H-SC dynamic response would be faster than the standalone SC and slower than the standalone STATCOM. The increase in response time for

the H-SC, compared with standalone SC, would provide more boundary transfer capabilities where the boundary transfer is limited by voltage stability issues.

2. The Phoenix device installed at Neilston location is rated for 140 MVA (70 MVA SC and 70 MVA STATCOM). With a single device of this rating, the increase in boundary transfer between Scotland and England and Wales is small and an increase in rating of the device increased the boundary transfer. So, the selection of correct size could provide more benefits. From the system studies, it has been found that the optimal size of the H-SC at Neilston location could be about 300 MVA, based on the boundary transfer benefits.

3. From the system studies, it has been found that, for boundaries where voltage stability is an issue, selecting the location where more dynamic reactive support is required increases the benefits from the H-SC. From the system studies, it has been found that locating the H-SC on the eastern side of SPT region could provide more boundary transfer between Scotland and E&W network.

4. The amount of fault current contribution from H-SC would increase the system strength and improve the operation of Line Commutated Converter (LCC) type HVDC operations. In order to achieve these benefits, the selection of locations and suitable rating of H-SC are important factors. By locating H-SC in the western side of the SPT region, SCL in the Hunterston area would be increased to help the operation of Western HVDC.

5. The inertia contribution from SC in the H-SC could improve the Rate of Change of Frequency (RoCoF) and frequency nadir profiles. For the Phoenix H-SC, the inertia contribution is relatively low. For a system, which requires more inertia support, a higher SC rating could be selected or a SC with flywheel could be installed. This could increase the power loss incurred by the device.

6. The SCL and steady state and dynamic reactive power support from H-SC could also improve the fault ride through capability, power quality (Harmonics), Transient Over Voltage (ToV) profiles.

The detailed system analysis carried out by NGESO on evaluating the benefit of 140 MVA H-SC at Neilston 275kV substation is reported in SDRC 2.2 [REF 7]. The detailed system analysis on impact on size of H-SC, locations of the device carried out by NGESO is presented in SDRC 2.6 report [REF 8].

4.4.2. H-SC Locations for Voltage and System Strength Benefits

From the power system analysis carried out by NGESO and reported in “Further Opportunities for H-SC in GB System” (SDRC 2.6), the main regions where SC and H-SC could provide value to the GB transmission system operation over the next five to 10 years include Scotland, the North of England and the South Coast of England. In these areas, there may be scope to install larger SC, STATCOM or H-SC to increase boundary transfers. In addition, H-SC that are located close to LCC (Line Commutated Converter) type HVDC installations can reduce the likelihood of these installations not being able to operate to their full capability due to inadequate system strength.

From the Scotland region studies, with the selected network model and assumed generation and demand background, it has been found that following the closure of nuclear plants, the system SCL in the region reduces. The reduction in SCL reduces the loading level of LCC type HVDC. For such locations, the installation of multiple H-SC devices would increase the system SCL and improve the loading on the HVDC. The number of H-SC devices required to increase the system SCL to the required limit could be optimised by selecting the suitable size and location of the device. The location of H-SC should be close to the point where SCL improvement is required.

In addition to the SCL, H-SC could provide dynamic reactive compensation that would help to increase boundary transfer capability where there are voltage stability issues. The installation of H-SC devices electrically closer to the voltage collapse point would provide more benefits. In certain scenarios, due to the combinations of providing SCL and faster dynamic response, H-SC provides greater improvements to boundary transfer capabilities than standalone STATCOM or standalone SC options.

Similar to Scotland, in the north region of England & Wales (E&W) network, with closure of nuclear generation in the future years, the system SCL and the availability of dynamic reactive compensation will be reduced. For these locations, future boundary transfer capabilities are limited due to the stability issues. The installation of H-SC could improve the boundary transfer capabilities, by locating H-SC where dynamic reactive support and SCL contributions are required.

In the South coast region of E&W, with the increased non-synchronous generation in the area, voltage collapse will be the limiting factor for the future years. The installation of H-SC would increase the dynamic reactive support in the region and help to increase the boundary transfer capability, once thermal overload issues are resolved. With the assumed system background, voltage collapse would be the limiting factor in Southeast Coast area. Locating H-SC where the dynamic reactive support is required would improve the boundary transfer capability.

In its commercial tenders to provide voltage or stability services, NGESO will include locational information. In some cases (e.g. Mersey Voltage Path Finder), a service will be specific to a particular area or location. In other cases, were a GB-wide or regional service is required, the more useful locations for siting assets will be indicated. For example, for Stability Pathfinder Phase 1, a set of substation weightings was published to indicate the likely effectiveness of assets located at these substations in improving voltage and stability.

4.4.3. University of Strathclyde Study on SC Benefits

This section explains the key findings from University of Strathclyde (UoS) studies on evaluating the benefits of SC. The first part of the section explains the study background used by UoS. The second part of this section explains the SC benefits in improving system SCL level. The third prt of this section explains the benefits of SC in improving the protection operation.

University of Strathclyde Study Model Backgrounds

The studies presented in this section were based on a model of the national electricity transmission system of GB which is represented by a 36-bus equivalent network. The model has been developed by National Grid Electricity System Operator in DIgSILENT PowerFactory. Each numbered zone in the model represents a part of the system and consists of a mix of different energy sources and loads. Generators within each zone are represented by static generators and synchronous machines including relevant dynamic controllers. In each zone, the equivalent representation of generation, loads, HVDC interconnectors and transmission lines are connected to 400-kV busbars.

The GB model has been dispatched in a manner to reflect years 2019, 2023 and 2027. NGESO provided data representing GB system (accounting for both generation and demand) for years 2019, 2023 and 2027, which have been converted to the correct format and then imported to the 36-bus model in DIgSILENT PowerFactory.

SCL Contribution

Simulation studies conducted by UoS have investigated the contribution of SC to system short-circuit level. The simulation-based analysis and the corresponding results presented have considered both static and transient simulation environments.

The SCL has been calculated in DIgSILENT PowerFactory using static power flow studies at each number bus using the super-position method (‘complete’ method in PowerFactory short-circuit calculation tool). The short circuit power in MVA (i.e. Sk) and short circuit peak current in kA (i.e. Ip) have been extracted during the SCL assessment. Detailed results and comprehensive analysis of SCL analyse can be found in [REF 2].

To illustrate the benefits of SC units where SCL is reducing, SC units have been placed in Zones 12 and 19. A set of simulation scenarios has been setup to incrementally change the capacity of SC units in Zones 12 and 19 (results for SC installation in additional zones are reported in PHOENIX Milestone 5 [REF 2]). The maximum capacity has been set to 700 MVA with increments of 70 MVA. Figure 11 and Figure 12 illustrate the short circuit power Sk for 12 and 19 respectively. The results present the SCL when SC units with capacities of up to 700 MVA are deployed. It is evident from the graphs that SC can significantly elevate the SCL levels, by approximately four times the rated capacity of the machine. This seems to be extremely important during summer periods when the SCL is significantly low (i.e. to near-zero region). By conducting such a large set of simulations (sensitivity analysis has been conducted for the SCL elevation on other zones and the results are report in PHOENIX Milestone 5 [REF2]), it is concluded that by deploying SC units the SCL can be undoubtedly elevated. However, the selection of a precise rated capacity of those units is anticipated to be based upon other features and metrics, including power system protection performance and commutation failure of HVDC links.

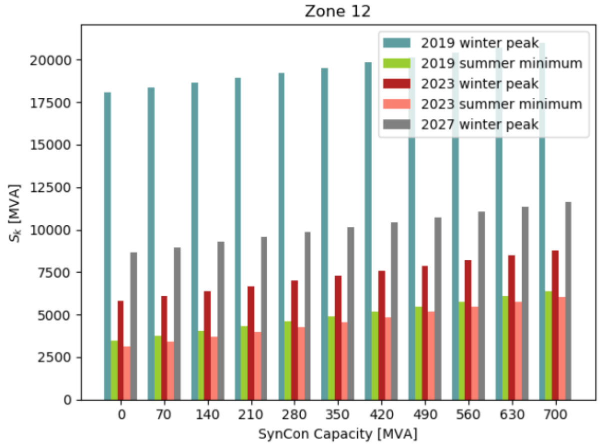


Figure 11: Short circuit power at Zone 12 for different SC capacities and different dispatch scenarios.

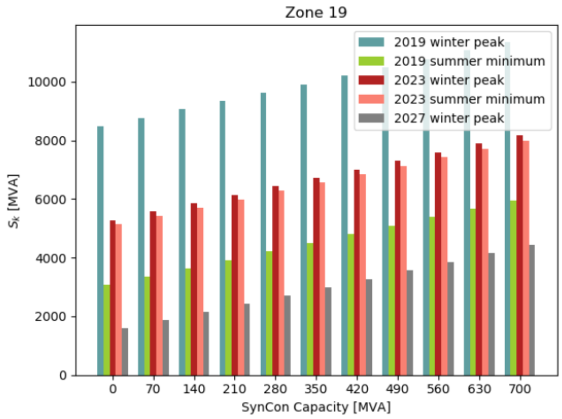


Figure 12: Short circuit power at Zone 19 for different SC capacities and different dispatch.

Impact on Protection

The studies conducted through this simulation environment assessed the performance of distance protection relays in the occurrences of transmission line faults. For the purposes of carrying out transient simulation analysis, a part of a typical transmission network model has been utilised in (the network topology is shown in Figure 13). The network operates at 400 kV and consists of a 100-km transmission line, a grid (represented by a voltage source) and three different generation units accounting for synchronous generator (SG), SC and a wind farm connected via a voltage source converter (VSC).

The SG and SC units are modelled as a standard salient-pole synchronous machine. Three control systems have been integrated which include i) automatic voltage regulator, ii) power system stabiliser and iii) over excitation limiter. In the case of SC unit, the prime mover and governor have been omitted as well (i.e. there is no mechanical input Pm). Wind farms constitute of permanent magnet synchronous generators connected via VSC, which operate under the standard D-Q axis current injection (DQCI) control scheme. A validated dynamic model of a commercially available distance protection relay (i.e. 'MICROMHO - Static Distance Protection Relay') has been utilised in this analysis. Time- domain voltage and current signatures are captured from the generation terminals and imported to the relay for post processing. The studies consider scenarios under different generation mixes starting from 100% synchronous to 100% ICG (Invertor Connected Generation). In the latter setup, SC units under different capacities are deployed to qualify and quantify their impact on transmission line protection in terms of number of successful trips and response time. Detailed analysis of the time-domain fault current signatures of SC and VSC can be found in [REF 3].

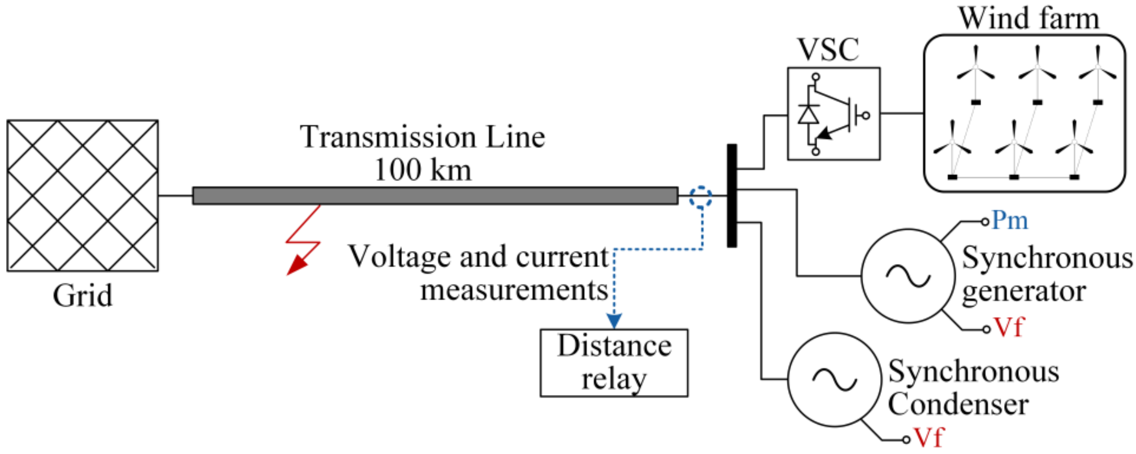


Figure 13: Transmission network illustrating integration of SG, SC and ICG.

To quantify the contribution of SC to the performance of distance protection, a series of simulation test-sets have been conducted for different generation scenarios, fault resistance values, fault positions along the line and fault types. The analysis considered three types of faults within Zone 1 of the protected line: three-phase, phase-phase and single-phase to ground with fault resistances up to 150 Ω. In total, the distance protection relay has been tested under 2,223 different fault scenarios.

The generation scenarios for this analysis are presented in Table 5, where three dominant generation technologies are included (i.e. SG, ICG and SC). These groups subsequently formed nine distinct generation mixes including single technology connections, as well as mixes of two (the base power has been set to S_b = 500 MVA). For all the scenarios an automatic search routine has been developed to iteratively change the position of the fault along the line, fault resistance and fault type.

Scenario	SG	ICG	SC
1	S_b		
2	0.75 S_b	0.25 S_b	
3	0.50 S_b	0.50 S_b	
4	0.25 S_b	0.75 S_b	
5		S_b	
6		S_b	0.05 S_b
7		S_b	0.10 S_b
8		S_b	0.15 S_b
9		S_b	0.20 S_b

Table 5: Portion of generation technologies within a 500 MVA generation mix

Figure 14 depicts the number of successful trips for each of the generation scenario. The percentage of the successful operations has been calculated by dividing the total number of the correct operations by the number of the desired trips for each scenario. The number of the desired trips is based on the definition of the power protection dependability, which is the degree of ability of the protection system to operate correctly for faults within the protected zone. As the proportion of ICG increases, the operation of the relay is compromised. This behaviour is more pronounced at Scenario 5 (i.e. 100% ICG) where the number of successful trips reaches only 20%. However, when SC is deployed in the system (i.e. scenarios 6 to 9), the percentage of successful relay trips increases, reaching values up to 60%. The impact of SC units has been quantified against the response time of the distance protection (response time is defined as the time lapsed between the fault occurrence and the time when the trip signal is initiated). The average response time for all the fault scenarios is depicted in Figure 15. It is evident that the as the penetration of ICG increases, the response time increases. Specifically, when the generation mix consists of 100% SG, the response time is approximately 20 ms (i.e. 1 electrical cycle) while for 100% ICG the response time reaches values approximately up to 70 ms. When SC units are utilised, the average response time starts improving reaching values close to 40 ms, hence improving the speed of protection operation.

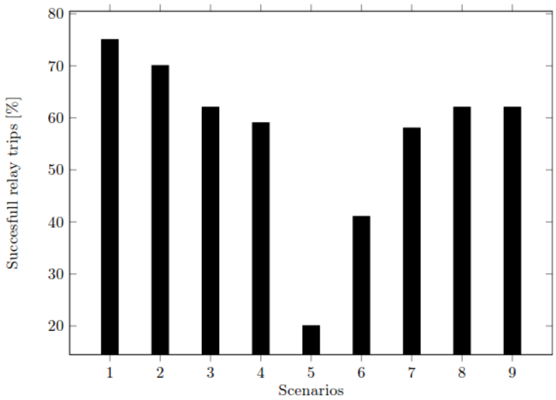


Figure 14: Number of successful trips.

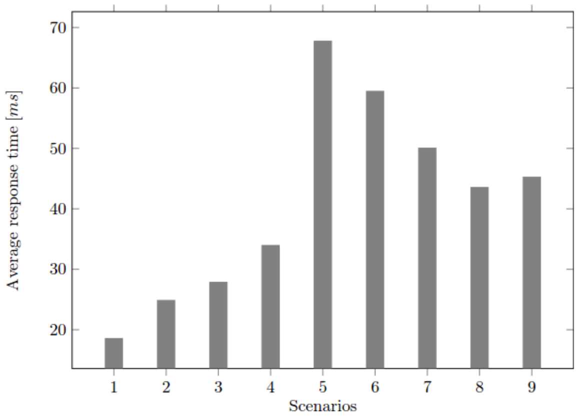


Figure 15: Average response time.

4.4.4. Synchronous Condenser Locations for System Inertia Benefits

The aim of the work described in this section is to investigate the impact of the SC location with respect to the location of loss of generation events.

The studies presented in this section have been conducted with the model background described in the previous section 3.4.3. The GB reduced model has been dispatched to reflect an inertia level of 82 GVAs, which corresponds to a minimum inertia level at solar peak period and is expected to be a credible minimum level of inertia in the GB transmission system in 2025/26.

Studies on system inertia have been conducted considering different loss of non-synchronous generation events as shown in the Table 6.

These locations have been selected in a way to cover a wide geographical spread of the GB network (i.e. north, middle and south). For such Loss of Generator (LoG) events, SC units have been utilised at different locations, including the location of the LoG event as presented in Table 6. Figure 16 illustrate the locations of LoG events and SC deployment for Scenarios 1.

Scenario	Location of LoG event	LoG	SC Location			
1	Zone 1	Solar – 675 MW	Zone 1	Zone 8	Zone 20	Zone 30
2	Zone 6	Solar – 721MW	Zone 6	Zone 1	Zone 20	Zone 30
3	Zone 20	Solar – 400 MW	Zone 20	Zone 1	Zone 8	Zone 30
4	Zone 32	Wind – 441 MW	Zone 32	Zone 1	Zone 8	Zone 25

Table 6: LoG scenarios

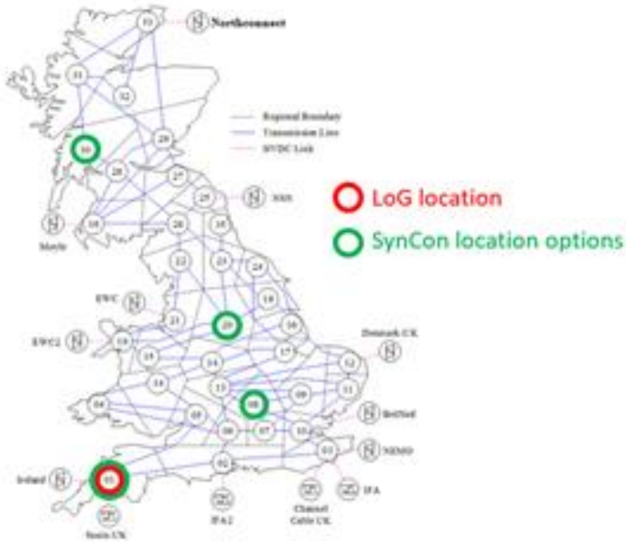


Figure 16: GB transmission network illustrating locations of LoG and SC for Scenario 1.

For each simulation set, frequency and RoCoF traces, as well as the active power from SCunits have been monitored and exported for post-processing. Additionally, minimum values of frequency (i.e. frequency nadir) as well as maximum values of absolute RoCoF traces have been extracted for comparison. With respect to frequency measurement, the average value from frequency traces across all zones has been calculated; this was also utilised for the calculation of RoCoF traces.

Simulation analysis on frequency nadir values indicated it is really challenging to derive any generalisation with respect to optimal SC location and the effectiveness of the frequency nadir containment, which is anticipated. Detailed frequency races and analysis can be found in [REF 4]

The corresponding maximum absolute RoCoF values are captured and presented in Figure 17. As opposed to frequency traces, where no generalisation could be derived, in the case of RoCoF traces, it appears that the least RoCoF values are always generated when SC units are installed at the same location as the LoG event. Such behaviour is possibly stemming from the fact linked to the previous observation – i.e. that the instantaneous active power in four to five times greater when SC is installed at the same location with that of the LoG event. This could potentially indicate 'preferrable' locations of SC installation - for example SC units could be installed to locations where any anticipated LoG could impose higher RoCoF traces, leading to unnecessary activation of RoCoF based protection and control schemes.

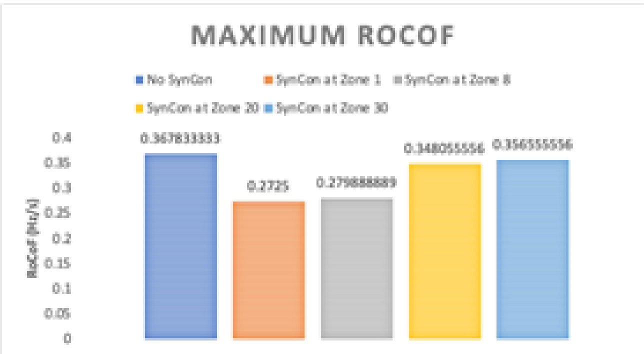


Figure 17: RoCoF values for Scenario 1 (LoG in Zone 1) considering different SC locations.

With respect to the active power exchange with the SCunits, it has been observed that for all scenarios that the SC utilised in the same location as the LoG event, produces the most oscillatory behaviour in the active power of SC (this is very well aligned with the findings reported for Milestone 6 [REF 5]). Additionally, the instantaneous active power output is much larger (i.e. 4 to 5 times higher) compared to the power delivered when SC units were utilised in other zones. This response is very well aligned with the findings reported in [REF 5], with respect to SC capacity allocation.

5. Site and Installation Considerations for H-SC

This section focusses on practical aspects regarding H-SC sourcing and installation. These include site considerations, H-SC procurement and the control and communications that are likely to be required. The content of this section draws on the experience gained by SPT and Hitachi Energy through the installation of the Neilston H-SC.

5.1. Site Considerations

Connection of an H-SC at a transmission substation will normally require a single 275kV or 400kV switchbay. For the 140MVA rated H-SC at Neilston, the site footprint of the H-SC is around 4000m^2 to accommodate equipment including the SC elements, the STATCOM elements, a 3 winding step-up transformer, an earthing transformer, the banking arrangements and auxiliary supplies. For Neilston, these elements are illustrated in Figure 18 in a picture of the pilot installation.

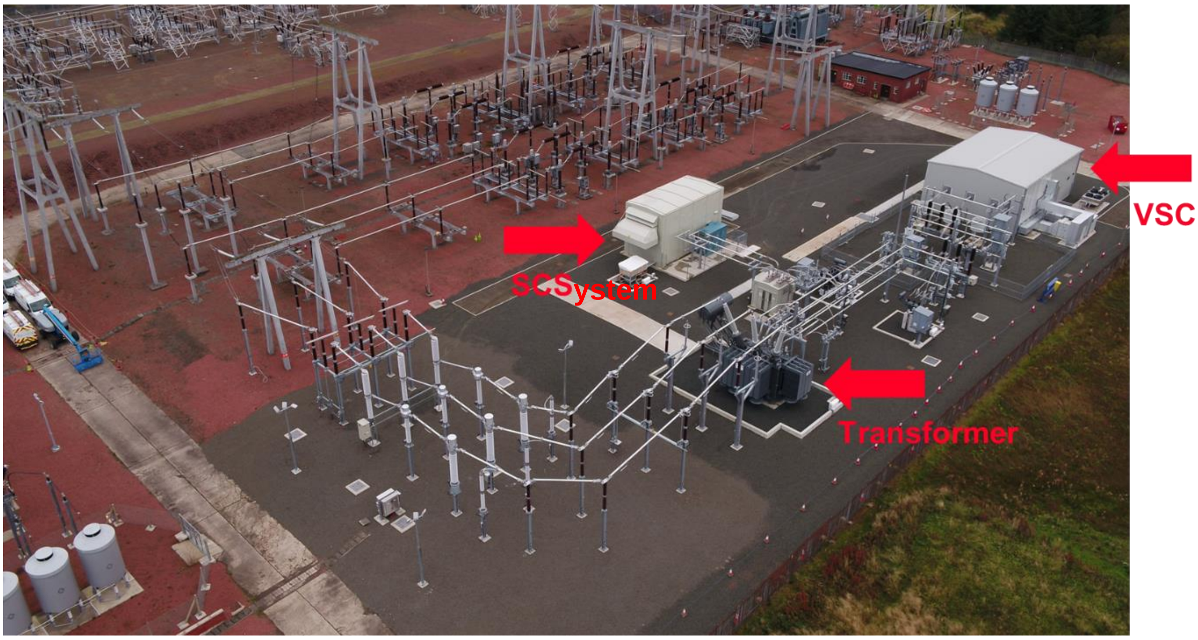


Figure 18: H-SC at Neilston denoted

The total area is about 4000 m^2. On the right-hand side of the site, the STATCOM or VSC is located. The STATCOM building and outdoor phase reactors take approximately 300 m^2. To the left is the synchronous condenser system. The SC building plus its lubrication unit use approximately 150 m^2. At the front we can see the 140-MVA three winding transformer that connects the 2 branches (i.e. the STATCOM branch and the SC branch) to the same Point of Common Coupling (PCC).

For a larger H-SC of 250MVA rating, the STATCOM and SC buildings would be larger than for an H-SC of 140MVA rating. It is likely that the overall site footprint would be increased by around 1000m^2.

In respect of GB planning and environmental aspects, key considerations include the following:

- **Local Planning Requirements**

  Depending on the location and size of the H-SC and associated works, local authority planning permissions may be required to progress the works. The works for the Phoenix H-SC at Neilston were not subject to planning permission as these were contained within the existing substation boundary.

  The need for planning permissions is more likely for installations on greenfield sites and allowance should be made in the project planning process for identifying the need for planning permissions and obtaining these.

  For higher rated H-SC, it may be possible to reduce the site footprint by stacking phases above each other in the STATCOM building rather than placing these side by side as at Neilston. This approach would increase the height of the STATCOM building such that planning permission may be required.

Consideration should also be given to any lighting towers for the H-SC site as, depending on height, these will be subject to planning considerations on brownfield and greenfield sites.

- **<u>Acoustic Noise Considerations</u>**

  Another factor to consider in planning an H-SC installation is the acoustic noise that the H-SC will produce when operating. The level of noise produced will depend on the detailed design and configuration of the H-SC solution. Typically, the components creating the largest noise levels for a H-SC are the Main/Power Transformer and the SC.

  The need to reduce or mitigate noise levels will depend on the location of the H-SC, ambient noise levels locally and the H-SC's proximity to other development including residential dwellings. When considering use of an H-SC, noise data should be obtained early in the planning phase to allow a noise study evaluation and a comparison against current noise levels at local receptors.

  For the Neilston H-SC, a noise impact assessment was carried out at local noise receptors within close proximity to the substation. Then a digital noise propagation model of the substation and surrounding area was created to determine any additional noise impact from the Phoenix H-SC installation. This determined that the Phoenix H-SC required an enclosure to mitigate noise levels due to its relatively remote location and its proximity to local residents.

  The noise propagation model was run for two proposed enclosure designs for the SC. The original proposed enclosure design exceeded the permitted threshold and so a more robust design was proposed and deemed compliant. As a contingency, mitigation measures in the form of additional silencer baffles were available in case the noise levels, once operational, exceeded the permitted limit but a follow up noise assessment demonstrated that further mitigation was not required.

  As mentioned above, the earlier the noise propagation study is carried out the better, but this will rely on the early supply of the supplier's SC/H-SC proposed installation noise data.

  On the Phoenix project, the change in sound requirements following the noise propagation study required the supplier to go from a solution with a difference of 12-13dB(A). This meant that the enclosure had to handle significantly more energy.

  This increased the size of the silencers (longer) increased the pressure drop and required the total enclosure area to double in size. The weight of the whole silencer/filter module trebled with the walls of the enclosure requiring heavier construction to reduce the sound and also support and encapsulate the larger silencer ducts.

- **<u>H-SC Site Electrical Supplies</u>**

  The need for local electricity supplies to support operation of an H-SC should be considered. For the Phoenix H-SC at Neilston, a 150kVA supply is provided from the Phoenix auxiliary transformer, with a backup supply from the local distribution network.

- **<u>H-SC Deployment at Neilston – Lessons Learnt</u>**

  From the experience of Scottish Power Transmission and Hitachi Energy in deploying the Phoenix H-SC at Neilston, the following lessons are also worth considering.

  - Design proposals should incorporate flexibility regarding site layout as changes may be required to match grid requirements.
  - Modifications may be required to existing infrastructure such as cable trenches, buildings, drainage, etc.
  - Service and earth records may not be accurate and should be investigated in advance of any design.
  - Ensure proposals are fully compliant with UK standards. It can be the case that equipment developed for use elsewhere in the world needs some adjustments to meet UK standards.
  - Access and safety clearance requirements for O&M should be carefully considered. This includes any unique secondary voltages associated with the H-SC and access requirements including barriers, and access platforms.
  - Depending on soil conditions and geotechnical concerns, the construction of piles below the SC foundation may be required.

- Access to the H-SC switchgear is important to maximise equipment availability. For the Phoenix H-SC at Neilston, an enclosed gas circuit breaker was utilised. In some cases, use of an outdoor circuit breaker may avoid having to shut down the SC during circuit breaker maintenance.

5.2. SC and H-SC Procurement

Hitachi Energy and a number of other electricity transmission equipment manufacturers are already able to provide SC and a number of companies have supplied SC in other parts of the world in recent years.

The H-SC at Neilston was supplied and installed by Hitachi Energy. As well as Hitachi Energy, other companies are likely to develop the capability to supply and install this type of equipment if there is an ongoing requirement.

The lead-time from contract placement to energisation of the H-SC at Neilston was around 18 months. Commissioning of the H-SC at Neilston required a further 6 months though this programme was lengthened by COVID-19 restrictions. The timescales for supply and commissioning are likely to be similar for larger H-SC devices.

5.3. Control and Communications Requirements

In normal operation, the H-SC at Neilston would be set up such that both the SC and STATCOM elements would be in Voltage Control mode and would respond automatically to network changes. If changes to the mode of H-SC operation were required (e.g. a change to voltage setpoint), the change would be communicated by NGESO to SPT's network control centre and the H-SC settings would be adjusted remotely by SPT.

Some learning points form the Neilston installation in relation to site control of the H-SC include:

- It would have been useful to implement remote access to the OWS (Operator Workstation) both for SPEN and Hitachi Energy. This would have facilitated the retrieval of Transient Fault Recorder (TFR) data and lists of events. Besides, this would have facilitated the update of the control system software and the correction of problems such as that of the reactor thermal overload protection.
- It would have been useful to implement remote trigger of the TFR functionality for pre-selected disturbances. This would have facilitated the process of checking the performance of the H-SC in such cases.
- It would have been useful to have synchronisation between SPEN and MACH data. This would have facilitated the correlation between SPEN TFRs and MACH TFRs.
- Control panel spec and solution – Ensure a clear understanding of how the system would be operated from the control room and of any infrastructure and hardware requirements.
- Ensure the specifications for communication interface between H-SC and substation control room and existing substation control room is reviewed as part of the scope.
- Ensure specification includes for suitable training (classroom and practical) for both operations and control room staff.

6. Other H-SC Design Perspectives

Other than the aforementioned H-SC design that is combining a SC with a STATCOM, there are other variants have been studied and/or deployed in power systems. The section provides a brief overview of the design and functionality of other types of H-SC, for the sake of inspiration for future development.

6.1. Variants of deployment of SC in the field

6.1.1. Standalone Synchronous Condenser

Standalone synchronous condensers (SC) have been deployed by transmission system operators worldwide since 2010, following the policy of decommissioning of the traditional coal fired power plants. In Denmark, three synchronous condensers were installed in the period from 2013-2014 (Bjæverskov 2013, Herslev 2014, Fraugde 2014), with the aim of enhancing the short circuit power, dynamic reactive power support, and operation of HVDCs. Similar situation in California, with the retirement of nuclear power plants in the system, several condensers have been added to the system through new installations or refurbishing of the retired generator units to restore voltage regulation and short circuit power. Texas has also adopted SC to enhance the wind power transferability from the wind rich area to the rest of the system. Research on the benefit of standalone SC has been extensively investigated in the Danish project "Synchronous condenser applications in low inertia systems (SCAPP)" carried by DTU. In general, standalone SC is a mature technology with proven benefits to the system operation. (Further information on the use of SC more widely, are provided in Commercial Deliverable SDRC 2.3 "International Review".)

6.1.2. Hybrid Variants

To enhance the frequency regulation and inertia response of standalone SC, new variants have been proposed in the recent years. Besides the hybrid concept realized in Phoenix project, two additional variants have been proposed. One variant is SC plus energy storage such as battery energy storage system (BESS) or supercapacitor that is investigated in Phoenix. In addition to this, direct coupling of Flywheel into SC has been another option and has been deployed in real system.

Synchronous condenser plus battery energy storage system (SC + BESS)

In this solution, the system includes SC, BESS and a coordinated control for SC and BESS. The response of BESS can be achieved by using either grid following (GFL) or grid forming (GFM) mode (ENTSO-E, 2020) for different inertial and dynamic reactive power responses. For example, a swing equation-based inertial response can be implemented in SC+BESS in GFL mode by estimating the rate of change of frequency and computing an active-power setpoint target to provide inertial power similar to a synchronous machine. While the inertia response achieved in GFM is similar to the response from synchronous generator but does not require any frequency measurement.

There are MW level commercial GFM options available from manufacturers (SMA, n.d.) (Energy H. , 2021). The inertia support by means of GFL converter could pose system security challenges when the short circuit level is low, as GFL converter employs Phase Locked Loop (PLL) to measure the phase and frequency. On the other hand GFC BESS can provide tunable and high inertia with properties similar to a synchronous machine and furthermore it can contribute to short circuit level and can operate under low short circuit power (ESO, 2021).

Owing to high overload capability an SC is complementary to the BESS that has limited capability, and SC has voltage source characteristics regardless of operational conditions.

Voltage support

Several functions can be developed under this service that is similar to SC+STATCOM,

- Automatic voltage control and reactive power control capability.
- Fault ride-through function.
- Fast transient response: This function serves to compensate a slower response of the SC by using the faster BESS. The scenarios for which this function is relevant include voltage regulation and

post-fault voltage recovery. The function effectively reduces the HSC response time to be equivalent to the BESS response (less than 100 ms).

- Equal reactive power sharing: The SC and BESS will generate the same level of reactive power for reference voltage change or the grid voltage change by having the same droop settings.

Frequency Support

For SC+BESS, the frequency support is provided by BESS alone. The technology itself is mature and has been demonstrated worldwide. For example, multiple MW BESS based on GFM control has been installed in Australia (Aurecon, NOVEMBER 2019) (ELectranet, 2021) to provide fast frequency reserve. The following functions can be incorporated,

- Droop control: BESS provides conventional droop control for frequency disturbances and the function is the same for the two differing control strategies.
- ROCOF function: This function represents a synthetic inertia capability of BESS, where the active power change is proportional to the Rate of Change of Frequency (RoCoF). This function is a part of GFL strategy. The GFM BESS provides an instantaneous response that is similar to a synchronous machine.

It is worth noting that for BESS, sharing of total storage between inertial and frequency services with storage used for other purposes needs to be carefully considered. The application of short-term storage devices such as supercapacitor is also a viable option for providing inertial and frequency support functionality (Energy, 2020).

Synchronous Condenser Plus Flywheel (SC + Flywheel)

The SC mechanically coupled with flywheel can significantly boost the inertial constant (from 1-2 s to 10 s typical). Such a combination is beneficial and technology ready, and tender has been awarded for such a combination in Stability Pathfinder – Phase 1 to increase inertia (stored energy) across Great Britain (nationalgridESO, 2020). The SC+Flywheel option is now also available as a packaged solution (Energy H. , HItachi Energy synchronous condenser packages, 2021).

There is a difference in inertia response among SC+BESS and SC+Flywheel. The inertial response from a SC+Flywheel combination is compared to the hybrid solutions of SC+BESS (GFL) and SC+BESS (GFM). The SC+Flywheel exhibits oscillatory behavior, and a large damper winding may be needed to provide a damped response. However, there are constraints in providing large mechanical damping. The inertial power response from SC+BESS is well damped, and depending on the DC power source's capability, both the damping and inertia can be further tuned. The frequency support through BESS storage in both GFL and GFM modes can further increase the frequency nadir during large system contingencies.

In general, services that can be achieved by SC + Flywheel and SC+BESS include the following facets as summarised in Table 7.

Technology	Inertia/Fast Freq. Response	Volt./Curr. Characteristic	Short-Circuit Current	Response Time
SS or SC + Flywheel	1 - 3 s inertia constant from SC. Adding Flywheel, the number can be extended to above 10s. Instantaneous Response	High overloading capability Physical limitations for the inductive mode, close to 0.5 pu of rated current	3 - 5 pu of the rated current at sub transient time scale**	Seconds for post-fault settling time and reference voltage change
BESS Grid Following	No intrinsic inertia Droop control Possibility of providing synthetic inertia	Full rated reactive current for cap. and ind. mode Possible instability due to cascaded control loops and PLL	Constrained by the overcurrent limiter, typical values 1.1 - 1.3 pu	> 1 cycles
BESS Grid Forming	Inertia response like SGs Fast frequency response similar to SM Possibility of providing synthetic inertia	Full rated reactive current for cap. and ind. mode. Typical overload 1.1 - 1.3 pu	Requires current limiting strategy once the commanded current exceeds max. value	> 0.5 cycles
SC + BESS Grid Following	1 - 3 s inertia constant from SC. Instantaneous response + droop control. Possibility of providing synthetic inertia	High overloading capability Less than 1 pu of inductive current due to the SC limitations Possible instability due to cascaded control loops and PLL for BESS	>4 pu for SC, 1.1-1.3pu for BESS. Final value depends on the rating composition.	Improved response for post-fault settling time and reference voltage change due to the compensation of SC's response by BESS
SC + BESS Grid Forming	>3s inertia constant Instantaneous response +fast freq. response, similar to SM Possibility of so-called synthetic inertia	High overload capability Less than 1 pu of inductive current due to the SC's limitations (close to 0.75 pu)	>4 pu for SC, 1.1-1.3pu for BESS. Final value depends on the rating composition. BESS requires current limiting strategy once the commanded current exceeds max. value	Improved response for post-fault settling time and reference voltage change due to the compensation of SC's response by BESS

Table 7: SC + BESS Services

6.2. Synchronous Condenser vs Battery Energy Storage Systems

Simulation studies conducted by UoS have been conducted to investigate the impact and quantify the contribution of SC and Battery Energy Storage Systems (BESS) to system inertia.

The studies presented in this report are based on a model of the national electricity transmission system of GB which is represented by a 36-bus equivalent network, as explained in Section 3.4. The GB model has been dispatched to reflect an inertia level of 82 GVAs, which corresponds to a minimum inertia level at solar peak period and is expected to be a credible minimum level of inertia in the GB transmission system in 2025/26.

A loss of generation (LoG) event (675 MW of non-synchronous generation) has been triggered to drive frequency to reach a nadir of 49.2 Hz. SC and BESS units with different capacities and control settings have been put forward to investigate their contribution. Simulation results revealed the following:

Simulation results revealed the following:

- Active power output from SC units connected in close vicinity to the location of the LoG event, is highly oscillatory. On the contrary, as the total SC capacity is concentrated far away from the location of the LoG event, the SC active power output is smoother. Effectively, the placing a SC unit at the location of the LoG event, can introduce an oscillatory behaviour.

- By connecting a total of 4 GVA SC units (which corresponds to 5 GVAs considering 1.25 s inertia constant), the maximum infeed loss can be increased by 50 MW, considering a 49.2 Hz frequency nadir limit (refer to Figure 19).

- Active power output from BESS units is not affected significantly by their geographical allocation. Considering a 100 MW BESS unit and a 675 MW LoG event, different frequency droop characteristics had different impact on the frequency nadir. Specifically, for frequency droop settings 0.016 p.u., 0.02 p.u. and 0.04 p.u., the frequency nadir is improved by 0.08 Hz, 0.06 Hz and 0.03 respectively.

- Considering a maximum infeed loss limit, it has been found that by connecting 100 MW BESS unit with frequency droop setting at 0.016 p.u., the maximum infeed loss can be increased by 50 MW, considering a 49.2 Hz frequency nadir limit

- By combining SC and BESS units the frequency nadir (i.e. 4 GVA of SC and 100 MW of BESS) can be elevated by approximately 0.15 Hz and the maximum infeed loss can be increased by 100 MW, considering a 49.2 Hz frequency nadir limit (refer to Figure 20).

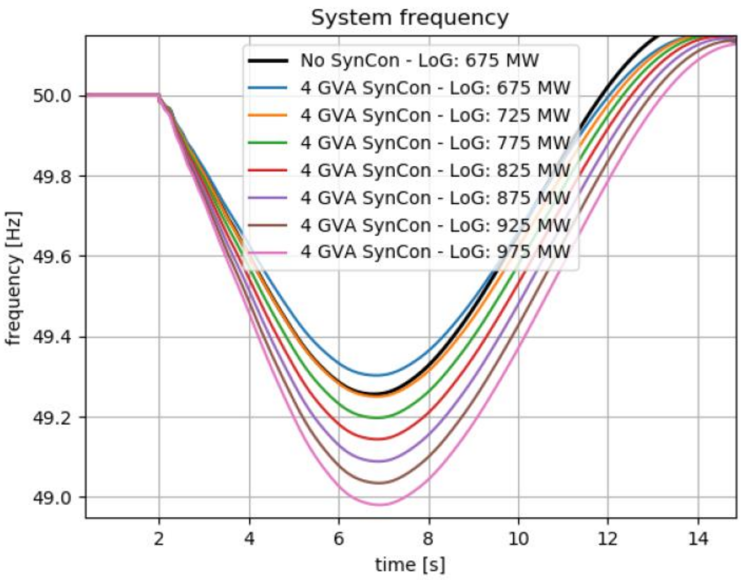


Figure 19: Frequency traces for different LoG capacities

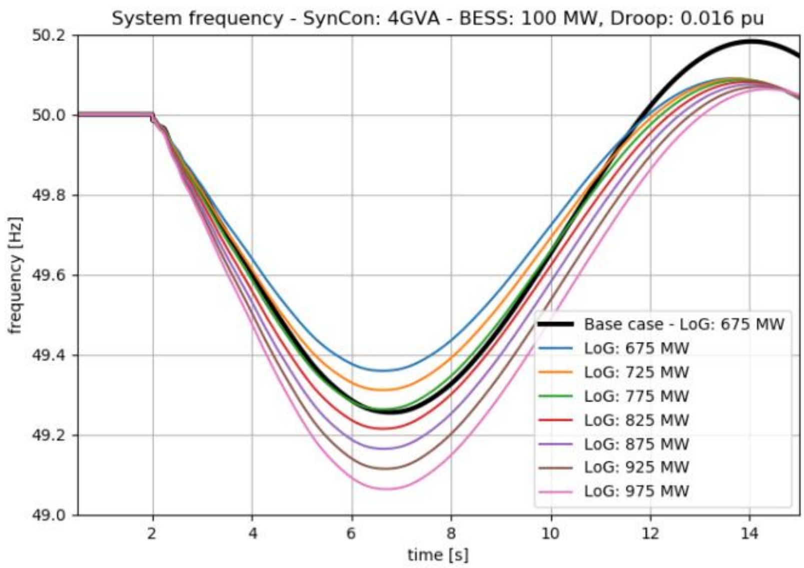


Figure 20: Frequency traces for different LoG capacities combining both SC and BESS units

6.3. Enhanced Frequency Control Capability Scheme

Simulation studies conducted by UoS have been conducted to investigate the impact and quantify the contribution of SC units and the Enhanced Frequency Control Capability (EFCC) scheme to system inertia.

The studies presented in this report are based on a model of the national electricity transmission system of GB which is represented by a 36-bus equivalent network. Studies on system inertia have been conducted with a loss of generation (LoG) event (approximately 675 MW of non-synchronous generation) triggered to drive frequency to reach a nadir of 49.2 Hz. SC units totalling 4 GVA and the EFCC scheme under different configurations have been put forward to investigate their contribution. Considering a frequency nadir of 49.2 Hz, it was found that different LoG events can be sustained by different combinations of the EFCC scheme and SC units, as follows and illustrated in Figure 21:

- LoG: 675 MW, without EFCC resources deployed and SC untis
- LoG: 725 MW with 5% of EFCC resources deployed and without SC units
- LoG: 775 MW, with 10% of EFCC resources deployed and without SC units
- LoG: 775 MW, with 5% of EFCC resources deployed and with SC units (see example Figure 21)
- LoG: 825 MW, with 10% of EFCC resources deployed and with SC units
- LoG: 925 MW, with 25% of EFCC resources deployed and without SC units
- LoG: 975 MW, with 25% of EFCC resources deployed and with SC units

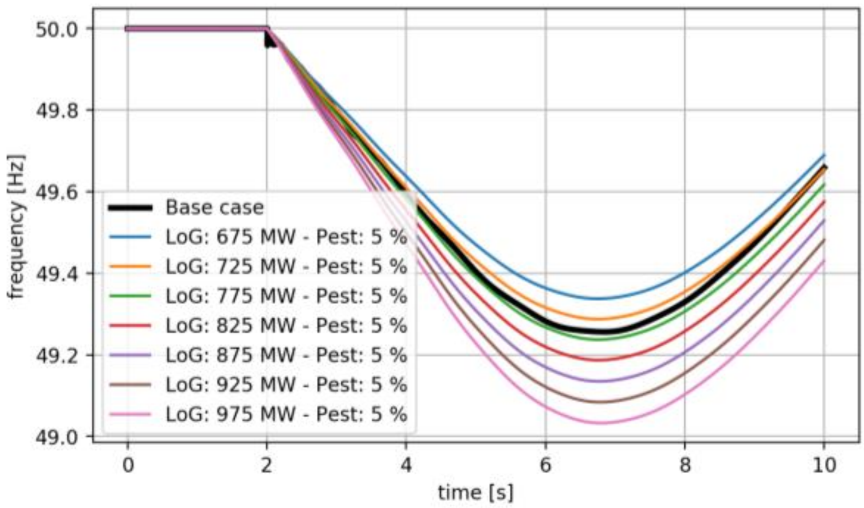


Figure 21: Frequency traces for different LoG capacities considering 5% of EFCC resources deployed.

Further sensitivity analysis indicated that SC units can bring certain savings to the active power required from synchronous generators and the EFCC scheme. These results highlight that the capacity of the EFCC scheme and SC units need to be carefully selected to achieve satisfactory frequency control performance. Detailed analysis on the quantification of SC benefits in coordination with the EFCC scheme can be found in [REF 6].

7. Owner Perspective

This section considers what ongoing grid system services might be provided by H-SC including discussion of potential routes to market. Practical considerations for potential H-SC developers including indicative costs and development challenges are outlined.

7.1. Grid System Services

SC and H-SC can provide voltage and system stability services to electricity networks. The use of these services on the GB electricity transmission network is described below.

Voltage Management and Market Arrangement

Reactive power services are used by NGESO to ensure acceptable voltage levels. Voltage is managed by maintaining a balance between elements on the system which absorb reactive power (decreasing voltage) or generate reactive power (increasing voltage). Voltage management is carried out on a regional basis with the requirements provided through a combination of network assets and balancing services. Network assets for reactive power are installed by network companies to comply with the system security standards and these provide much of the reactive power requirements. Balancing services are used to fill the gap when network assets are not available or when system requirements are higher.

NGESO can already procure reactive power generation and absorption through the Obligatory Reactive Power Service (ORPS) though this can only be used where providers are running to provide real power. As patterns of generation and demand change, there are fewer ORPS providers at times when they are needed (e.g. during periods of low active power demand when conventional thermal plant is less likely to run). This has caused increasing levels of voltage constraints when there is not enough reactive power available regionally.

To help manage voltage levels on a zero-carbon network, NGESO has defined service requirements and is seeking alternative solutions. This includes the use of voltage pathfinder projects which apply a NOA type approach to regional voltage challenges. The early voltage pathfinders (Mersey and Pennines) have identified the reactive power requirements for system operation to meet current and future requirements in particular areas. Through these pathfinders, commercial services are being sought to operate alongside regulated network assets.

Inertia and System Strength Management and Market Arrangements

Transmission system stability has previously been dependent on synchronous generation operating on the network. To enable operation with a significantly lower level of synchronous generation, there is work underway to update standards, to better monitor requirements, to identify new sources of stability and to introduce new markets to procure the services required.

System standards are being updated to ensure they are appropriate for a system with less synchronous generation. Revised Loss of Mains protection requirements will reduce the volume of generation at risk of disconnecting in response to a large infeed loss or an electrical fault on the system. This will enable operation with lower levels of inertia and will reduce the actions and costs to manage this constraint. By addressing Loss of Mains limitations, faster frequency response services will become key to containing frequency before frequency limits are reached.

To better understand system stability, real-time systems to monitor the inertia of the GB transmission system are being built and tested. These solutions will measure the combined inertia-like effects of conventional synchronous generation, power electronic converted generation (such as wind and solar) and passive load. One solution is non-intrusive, continuously monitoring and using machine learning to forecast the inertia up to 24 hours ahead. Another solution includes one of the world's largest ultracapacitors to 'inject power' into the grid, while measurement units directly measure the response, enabling the full system inertia to be established. Ultimately, these systems will measure system inertia in real-time to optimise real-time operation and service procurement.

New sources of stability capability and new markets to procure capability are being introduced through the Stability Pathfinders and through the development of a future GB Grid Forming market. The Stability Pathfinders allow NGESO to outline stability requirements, seek feedback on proposals and feasible solutions, and run tenders to determine the most economical solution. Through Stability Pathfinder phase 1, NGESO have awarded 12 contracts to 5 providers to secure 12.5 GVAs of inertia until 31st March 2026. All solutions in phase 1 are synchronous compensators. Through Stability Pathfinder phase 2, specific locational requirements for SCL and inertia in Scotland are being addressed while opening the service to a range of new technologies and this approach will be developed to address needs in other areas of the network.

The pathfinder process is informing updates to the NOA methodology to ensure an enduring approach for procuring voltage and stability solutions. By reviewing requirements for stability alongside the requirements for voltage, areas where these requirements may be combined will be identified.

7.2. Potential SC & H-SC Routes to Market

SC or H-SC have been considered for deployment in GB using three different approaches as outlined below:

1. Network Company Regulated Assets – SC or H-SC could be installed by network companies and remunerated in the same way as other regulated assets such as static reactive compensation equipment. For example, where requirements for SC or H-SC have been identified, TOs could install the assets in areas where SC and H-SC services are required. These assets would be made available to provide voltage, inertia and system strength capability and would reduce the need for NGESO to contract for services. As an example, as part of its RIIO-T2 business plan, SPT proposed the installation of an H-SC solution at Eccles to increase the Anglo-Scottish boundary capability and, in the longer term, to help maintain system strength without Torness generation. RIIO-T2 funding for the Eccles H-SC solution has been allowed.

2. NOA Process – Where it would be beneficial to increase transmission boundary capability, the NOA process allows different options to be proposed by TOs and other industry participants, and the “least regrets” option to be identified and recommended by NGESO. For boundaries where voltage performance limits capability, if a SC or H-SC solution is demonstrated to be the best available solution, this can be taken forward by the proposer. As an example, as part of the 2020 and 2021 NOA processes, the Eccles H-SC solution was assessed and recommended for installation by 2026. Whilst the NOA process provides a means to recommend solutions, it does not provide funding. If a recommended solution is to be taken forward by a TO, funding can be provided through RIIO-T2 mechanisms (including the Incremental Wider Works (IWW) and the Medium Sized Investment Project (MSIP) mechanisms). For other industry parties, the means to fund a recommended option remains unclear. However, the Early Competition Plan being developed by NGESO may provide a means for funding such works.

3. Stability Pathfinder – The Phase 1 and 2 commercial tenders have built on the NOA process to allow different solutions to be compared to address identified shortfalls in inertia and short circuit levels. It has already been demonstrated that SC can meet the technical requirements set out for Stability Pathfinder and have been tendered as solutions. Through Stability Pathfinder, NGESO can compare SC and H-SC solutions tendered by a wide range of developers against other solutions and can select those options that are the most cost effective and most suited to meeting the specific requirements. Contracts are then put in place for the most suitable solutions. As part of the Phase 1 Stability Pathfinder, new SC are being installed at sites at Keith and at Lister Drive by Statkraft UK Limited. Uniper UK are building two new synchronous compensation units at Grain and repurposing redundant steam generators at Killingholme. In addition, Welsh Power is building a synchronous condenser at Rassau, which is supplied by Siemens-Energy. In addition, as part of Stability Pathfinder 2 hybrid-SC solutions are being considered by developers.

4. Short term Stability Market - Stability has traditionally been available as a ‘by-product’ through market dispatch of power supply. NGESO aims to create long- and short-term markets for stability to be provided by a range of technologies.

5. Voltage pathfinder – The voltage pathfinder has contracted for solutions to provide reactive power in the Mersey area from 2024 and is currently seeking solutions to assist in the Pennines region which covers West Yorkshire and North East England.

6. Reactive Reform – NGESO is working with industry to better understand how future reactive needs could be accessed which could include new services or opening current services to a range of new technologies.

Comparing with other technologies

In assessing options to provide additional transmission boundary capability or to meet Stability Pathfinder requirements, NGESO will compare SC and H-SC solutions to other solutions offered by service providers. As well as SC and H-SC, other solutions are being developed to provide the voltage and stability capability that has previously been provided by synchronous generation. These solutions include energy storage systems such as batteries, and Grid Forming Converter (GFC) technologies that would enable Direct Current (DC) or other asynchronous power sources to be used to mimic synchronous generators.

The suitability and cost-effectiveness of SC and H-SC compared to other technical solutions can be assessed by potential service providers. Some indicative costs to support an assessment are discussed further in section 6.3.

As SC and H-SC can provide a range of services, they are likely to be most effective where a range of voltage, inertia and system strength services are being sought.

7.3. Equipment Costs & Site Development Considerations

In assessing whether a SC or H-SC should be proposed to meet a NOA boundary requirement or to provide a Stability Pathfinder service, several cost and practical development aspects need to be considered. These are outlined in the following sub-sections.

Typical SC & H-SC Costs

In section 3.3, the typical size of SC or H-SC installation was identified as around 250 to 300 MVA. For a 250 MVA rated SC, the costs to procure and install the equipment is likely to be in the range £21m to £27m depending on a number of factors including site conditions and installation costs. For a 250 MVA rated H-SC, meaning a 125 MVA SC and a 125 MVA STATCOM, these costs would be greater and are likely to be in the range £26m to £32m.

As for running costs, as a rule of thumb, the no load losses for a H-SC device, will be between 50-60% when compared to a SC for same total MVA rating. This should be taken into consideration when calculating the total cost of ownership.

The costs to maintain equipment and potentially upgrade control systems over the asset lifetime should also be considered when assessing the use of SC or H-SC. For a 280 MVA rated SC, typical maintenance costs could be around £0.05m per annum over a 40 year life. In addition, a control system upgrade after 20 years could cost around £0.4m. For a similar rated H-SC, the maintenance costs are likely to be slightly higher at around £0.06m per annum and control system upgrades after 20 years could cost around £0.7m.

When an H-SC is compared to a SC and a STATCOM, there is no planned or foreseen need of any specific additional maintenance for the H-SC compared to the SC and the STATCOM individually.

As well as the costs to build and maintain SC and H-SC, service providers would also need to consider other ongoing costs including losses and network charges. The different elements of these costs will depend on the service provider type and whether SC and H-SC are defined as generation or demand. For example, if a Third Party where to provide a transmission connected solution and this was treated as a generation asset, then the provider would need to consider Transmission Network Use of System (TNUOS) charges, Balancing System Use of System (BSUOS) charges and the costs of the equipment's energy losses.

In assessing the suitability of an SC or H-SC alongside other potential solutions, service providers should also consider how long the service is likely to be required for. SC and H-SC are long-life assets and could provide services over a 20 to 40 year asset life. This should be considered in assessing whether a solution is appropriate to meet a NOA or Stability Pathfinder requirement. The funding mechanisms for Third Party solutions to meet NOA requirements have yet to be finalised and so it is possible that funding could be aligned to the expected life of the asset. For the Stability Pathfinder Phase 1 and Phase 2 requirements, the expected contract periods are up to 5 years and up to 12 years respectively, so consideration needs to be given to the asset's use at the end of the contract period and what residual value it would have.

Development Aspects

In considering the location of SC or H-SC, several aspects should be considered. Firstly, the electrical connection of the device to a transmission substation will be required. This transmission substation will need to be suitably located if the SC or H-SC is to be effective in providing services.

Once the connection substation is identified, a number of other aspects will bear on the practicality and costs of an SC or H-SC solution. These aspects are summarised in the following table.

Development Aspect	For SC and H-SC
Substation connection	To achieve the connection of the SC or H-SC to a local transmission substation, local connections comprising HV switchgear and underground cable, overhead line or Gas Insulated trunking will need to be designed and installed. Normally the SC or H-SC developer will own these electrical connections from the SC or H-SC to the Point of Connection (PoC). From the PoC to the transmission substation including the HV switch bay at the transmission substation, normally owned by transmission owner. The ownership boundary for assets will normally be at the point where the HV substation switch bays meets the PoC. There are often complications when connecting to an existing substation. For example, modifications may be required to existing infrastructure such as cable trenches, buildings, drainage, etc. More generally, the local service and earth records for a local connection route may not be accurate and should be investigated in advance of any design. Depending on soil conditions and geotechnical concerns, the construction of piles below the SC foundation may be required.
Equipment size and footprint	For the 140 MVA rated H-SC at Neilston, the site footprint is around 4000 m^2 to accommodate equipment including the SC elements, the STATCOM elements, a 3 winding step-up transformer, an earthing transformer, the banking arrangements and auxiliary supplies. For a larger H-SC of 250 MVA rating, the site footprint would be increased to around 65 x 75 m, giving a footprint of 5000 m^2.
Local planning requirements	Depending on the particular location and size of the SC or H-SC and associated works, local authority planning permissions may be required to progress the works. The works for the Phoenix H-SC at Neilston were not subject to planning permission as these were contained within the existing substation boundary. The need for planning permissions is more likely for installations on greenfield sites and allowance should be made in project planning for identifying the need for planning permissions and obtaining these. Consideration should also be given to any lighting towers for the site as, depending on height, these will be subject to planning considerations on brownfield and greenfield sites.
Acoustic noise	An H-SC or SC will produce acoustic noise when operating. Typically, the components creating the largest noise levels for a H-SC are the Main/Power Transformer and the SC. The level of noise produced will depend on the detailed design and configuration of the SC or H-SC solution. The need to reduce or mitigate noise levels will depend on the location of the SC or H-SC, ambient noise

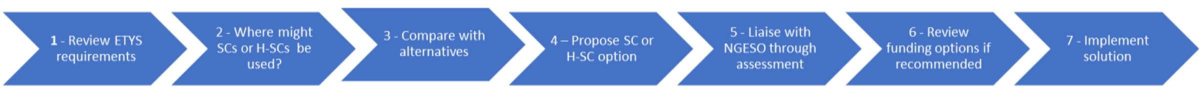
	levels locally and the proximity to other development including residential dwellings. When considering an H-SC or SC, noise data should be obtained early in the planning phase to allow a noise study evaluation and a comparison against current noise levels at local receptors. For the Neilston H-SC, a noise impact assessment was carried out at local noise receptors close to the substation. A digital noise propagation model of the substation and surrounding area was created to determine any additional noise impact from the Phoenix H-SC installation. This determined that a substantial reduction to noise levels was required due to relatively remote location of the Phoenix H-SC and its proximity to local residents. Ultimately, a robust noise enclosure was included for the SC element and this increased the size and weight of the SC installation. Overall, the SC enclosure area doubled in size.
Site electrical supplies	The need for local electricity supplies to support operation of an H-SC or SC should be considered. Generally, two independent supplies are required. For the Phoenix H-SC at Neilston, a 150 kVA supply is provided from the Phoenix auxiliary transformer, with a backup supply from the local distribution network.
Other factors	Ensure proposals are fully compliant with UK standards. It can be the case that equipment developed for use elsewhere in the world needs some adjustments to meet UK standards. Design proposals should incorporate flexibility regarding site layout as changes may be required to match grid requirements. Access and safety clearances to the SC or H-SC should be carefully considered for O&M. This includes any unique secondary voltages associated with the SC or H-SC and access requirements including barriers, and access platforms. Access to the SC or H-SC and its switchgear is important to maximise equipment availability. For the Phoenix H-SC at Neilston, an enclosed gas circuit breaker was utilised. In some cases, use of an outdoor circuit breaker might avoid having to shut down the SC during circuit breaker maintenance.

7.4. How can I offer services to the ESO?

Potential H-SC Services

Section 6.1 outlines the system services that SC and H-SC can provide and the potential routes to market for service providers. These include services to support voltage, system strength and system inertia. At present, these services are sought by NGESO through the NOA process and through the Stability Pathfinders.

To offer H-SC services for evaluation through the NOA process, service providers should follow these steps:



Step 1 – The Electricity Ten Year Statement (ETYS) is published by NGESO in November each year. The ETYS provides details of future boundary power transfer requirements and the boundary limitations that would prevent these transfers being achieved.

Step 2 – Some transmission boundaries are likely to have voltage limitations. Those boundaries where SC or H-SC might address limitations and increase power transfers can be identified.

Step 3 – SC and H-SC can be compared with other technical options to determine if they are likely to be an effective solution. The nature of the voltage problem, steady state or transient, and the expected duration of the boundary limitation may help determine whether SC or H-SC are economic and effective solutions.

Step 4 – If an SC or H-SC solution would be cost-effective in addressing a boundary limitation, this can be proposed to NGESO. Details of how the proposal should be made will be available on the NGESO website. (For example the 2020 NOA included an Interested Persons' options process whereby non-network parties could propose options for further assessment.)

Step 5 – As part of the NOA process, NGESO will compare the different options that have been proposed to address a boundary limitation. Further information on proposed SC or H-SC solutions may be sought.

Step 6 – If the proposed SC or H-SC solution is recommended to be taken forward, funding options for the solution would be considered.

Step 7 – The proposed SC or H-SC option should be further developed and installed as per the agreed timescales. This will involve obtaining a connection agreement with NGESO and the appropriate TO and commissioning of the solution onto the transmission network.

The Stability Pathfinder requirements are being developed and published by NGESO on a regional basis. Each pathfinder will include an invitation to tender (ITT) detailing the commercial requirements of the particular service and indicating what technical solutions are likely to be effective. To offer H-SC services to meet Stability Pathfinder requirements, service providers should follow these steps:

Step 1 – Review the technical specification and locational needs. Requirements would be published by NGESO on the stability requirements at specific locations. This will help potential providers to determine whether to express an interest in participating in the tender.

Step 2 – The capability of SC or H-SC to meet the technical requirements should be assessed by prospective service providers. The proposed contract terms for the Stability Pathfinder service should be reviewed.

Step 3 – SC and H-SC can be compared with other possible technical solutions to determine if they are likely to be an effective means of meeting the requirements. If the proposed Stability Pathfinder service rewards voltage, inertia and system infeed services, then it is more likely that SC or H-SC will provide effective solutions.

Step 4 - Carry out any technical studies and submissions.

Step 5 - Review the invitation to tender.

Step 6 - If eligible, and if an SC or H-SC based solution can be provided cost-effectively, submit a tender for the proposed solution(s).

Step 7 – NGESO will carry out an assessment of the tenders received and notify the successful tenderers. If successful, the contract terms would be finalised and agreed. The provider would commence detailed development of its solution(s).

Step 8 – To implement the solution, the proposed SC or H-SC option should be installed as per the agreed timescales. This will involve obtaining a connection agreement with NGESO and the appropriate TO and commissioning the solution onto the transmission network.

Connection, Commissioning and Service Provision

If a service provider is engaging with the NOA process or with the Stability Pathfinder process to agree provision of a SC or H-SC solutions, further steps will be required to connect the SC or H-SC to the transmission network, to commission the equipment and to provide services on an ongoing basis.

Connection Process

Connection of an SC or H-SC to the GB transmission network will involve liaising with the NGESO and the relevant TO(s) to assess the impacts of connecting the SC or H-SC at a particular transmission substation. If the connection is feasible with costs and timescales that are acceptable to the service provider, then the provider would enter into a connection agreement with NGESO. Given the limitations of existing substations and given that other parties may also be seeking to connect locally, the connection to some substations will be more complex and could take longer to complete. For the Stability Pathfinder process, it may be that some indication of suitable connection sites will be provided as part of the Invitation to Tender.

Asset Commissioning

Ahead of asset operation and the provision of services to NGESO, the SC or H-SC based solution would be tested, commissioned and accepted onto the GB network. This ensures that the assets are safe to connect to the transmission system, that they will operate effectively across the range of conditions they are likely to encounter, and that they are capable of providing the agreed commercial services in line with the technical and performance requirements defined in a bilateral connection agreement.

Ongoing Service Provision

Under the stability pathfinder contracts, units are paid for the periods where they declare themselves as available for SCL and/or inertia, with a separate payment for reactive power delivered. Solutions are required to be available for at least a minimum period of time with a failure to meet this resulting in a rebate due to NGESO. No separate payment is made when units are instructed to deliver a service.

Where units are available, they may be instructed by NGESO to synchronise to the network and to deliver SCL and inertia. A separate instruction may be issued for voltage support.

As part of the connection agreement, units are required to install dynamic system monitoring equipment which provides access to data on the performance of units. This can be especially useful in the event of system events to better understand how units responded.

8. Conclusions

The requirements for assets and system services to support GB electricity system operation are changing as energy balancing including frequency and voltage management becomes more complex. The H-SC device has been developed and trialled through Phoenix to address these electricity system challenges, by combining SC and STATCOM, and by controlling the hybrid device with an innovative hybrid control mechanism.

The H-SC uses a hybrid (master) control system to coordinate and optimise the simultaneous operation of two standalone control systems: namely, the STATCOM branch control system and the SC branch control system. The master control includes functions to co-ordinate voltage control and reactive power sharing, to minimise energy losses, and to speed up the response time of the H-SC.

Neilston Trial: H-SC Effectiveness and Further Considerations

The Neilston trial has provided evidence that the H-SC has the potential of being an additional tool to manage increasing voltage and stability challenges on the GB system. It has demonstrated the capability to provide steady state reactive power, post fault voltage support and stability services. During the trial, the H-SC achieved the expected reactive output values in a stable manner. For unplanned system events, the H-SC reacted as expected and provided support. Going forward, the H-SC can provide the following system benefits as the GB grid transitions to net zero carbon operation:

- Steady state reactive power support and dynamic reactive power support, which could improve voltage profiles and voltage stability.
- The short circuit contribution from the SC could improve the SCL of the system, increasing the system strength.
- The inertia contribution from the SC will improve the system inertia, that could improve the system stability limit and the system frequency response.

The trial has also highlighted that there are challenges to achieving parallel operation of SC and STATCOM. Detailed system studies are needed to verify impacts on control and system interactions:

- Control Interaction: The individual STATCOM and SC control, start stop and transfer sequences can impact on the overall hybrid device performance.
- Control coordination: Careful design is needed to ensure that the hybrid controller can coordinate the control of the two devices (the same or different ratings) with minimised loss and maximizing inertia contribution.
- System impact and dynamics: It is important to verify the impact of the hybrid device on the connected system. Depending on the system strength and device rating, the impact would vary. The dynamics of the hybrid device should be also validated against the requirements.

H-SC Master Control Functions (NGESO Perspective)

With the Phoenix device configuration of equal size of STATCOM and SC, the amount of power loss savings with PLM function is negligible / insignificant. The Phoenix device has the LRM function that would block STATCOM when the reactive power output from STATCOM is closer to 0 MVAr, to save the power loss incurred by the STATCOM. The power loss reduction due to LRM function could be low, as the power loss incurred by STATCOM is generally low and it only works when STATCOM output is closer to 0 MVAr. With the different configuration such as higher rating of STATCOM could provide more power loss savings with PLM and LRM functions.

Inertia Support Maximisation (ISM) function developed in the Phoenix project to block or de-block STATCOM to improve the frequency. The power consumed by STATCOM device is very small with 70 MVA STATCOM in the Phoenix device. Hence ISM function does not provide additional inertial support and this function has not been tested in the trials. The inertial contribution from the H-SC could be improved by having flywheel attached to SC or having Battery Energy Storage System (BESS) instead of STATCOM.

The FTC function developed in the Phoenix device could help to achieve faster dynamic response, by exploiting the STATCOM's fast response to compensate for the slower response from the SC.

At the time of this report, SC response time is not yet proven. This needs to be studied further as the dynamic response of the SC would have impact on the boundary transfer capability studies carried out in SDRC 2.4 and SDRC 2.6.

STATCOM reaches overload capability even in steady state condition. When it reaches overload capability, it stays for 3 seconds, then it goes back to nominal reactive power range (70 MVAr) for the next 3 minutes. This behaviour introduces unnecessary oscillations even in steady state condition.

The slow Q control function developed in the master control could help to avoid this unwanted oscillation by limiting the reactive power output from STATCOM to be within 70 MVAr. At the time of writing this report, gain setting requirements for slow Q control being tested and not proven. In the way forward, H-SC devices should be designed to avoid unwanted oscillations caused by cycling in and out of STATCOM overloading capability.

Among all the different functions developed in the Phoenix device, FTC and LRM functions could provide more benefits than other functions.

Phoenix device has been tested for different modes of operations:

1. H-SC in voltage control mode (SC and STATCOM in V control mode)
2. H-SC in Q control mode (SC and STATCOM in Q control mode)
3. SC in V control mode and STATCOM in Q control mode
4. STATCOM in V control mode, SC in Q Control mode
5. Only STATCOM (either V or Q control mode)
6. Only SC (either V or Q control mode)

To achieve dynamic reactive support, SCL contribution and inertial support, keeping both STATCOM and SC in operation and both in voltage control mode would be most preferred mode of operation.

Wider System Benefits

As H-SC can provide a range of services, they are likely to be most effective where a range of voltage, inertia and system strength services are being sought. There are locations on the GB network (e.g. north of the Anglo-Scottish B6 boundary) where the combination of voltage support and fault infeed can be particularly effective. The wider studies of GB network requirements indicate that H-SC may be valuable in other parts of the GB network including the North East and North West of England and the South Coast of England.

In supporting GB network operations, the effectiveness of H-SC will depend on:

- Strength of the network (it would be hard to detect improvement in an already strong network).
- Amount of reactive power injection of H-SC to the network (small injection of reactive power will not have any significant change in voltage)
- Amount of active power injection during inertial contribution (small active power injection will not result in any detectable change /improvement in frequency)
- The overall loss of the HSC device should be kept low (< 1.5%)
- Dynamics: The hybrid device dynamics will play an important role on the system impact. Advanced functions such as FTC can help to speed up the total H-SC response by utilising the faster response of the STATCOM.

Route to Market

H-SC can be deployed through existing regulatory and commercial arrangements. These arrangements include i) deployment as a regulated asset to meet Transmission Owner (TO) licence requirements, ii) deployment through NOA recommendation, and iii) deployment through the Stability Pathfinder process or other mechanisms that emerge based on the findings of the Pathfinder. These routes to market should enable NGESO to access H-SC and similar solutions at the pace required to meet system changes such that no further bespoke commercial framework is required to enable H-SC use.

In assessing system requirements for NOA or for tendered commercial services, NGESO will compare the H-SC device to other solutions offered by service providers. As well as H-SC comprising STATCOM and SC, other solutions are being developed to provide voltage and stability capability. These solutions include energy storage systems such as batteries and Grid Forming Converter (GFC) technologies. Other hybrid solutions are also being developed such as the combination of SC and battery storage.

NGESO has recently launched a Stability Market Design Network Innovation Allowance (NIA) project. The development of a stability market could offer NGESO a route to access stability services through an open, transparent and competitive market. The possibility of developing a short-term stability market is also being investigated as well as the optimal mix between long and short-term procurement.

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Appendix A – STATCOM and SC Control

1. STATCOM Control

<u>Automatic Control</u>

The voltage control system is a closed-loop system with control of the positive-sequence voltage at the HV bus. A simplified block diagram is shown in Figure A1. The voltage regulator is required to be fast enough to counteract voltage variations and disturbances, but also retain an adequate stability margin.

The reference voltage, which is fed into the control, is calculated by adding four terms:

- The voltage reference V_{ref}
- The sum of the VSC and filter currents which is multiplied by the slope. Note that this term is subtracted:

$$-\,\text{slope} \cdot \left(i_{\text{VSC}} + i_{\text{filt}}\right)$$

- The additional reference voltage signal from the slow MVAr control, ΔV_{ref}
- The additional signal from the fast transients compensation function, e_{sc}

The total voltage reference is limited by V_{max} and V_{min} before it is compared with the measured voltage V_{resp}. The resulting error signal ε is fed into the PI regulator. The regulator output is the system current reference.

Finally, the VSC current reference is created by removing the filter size.

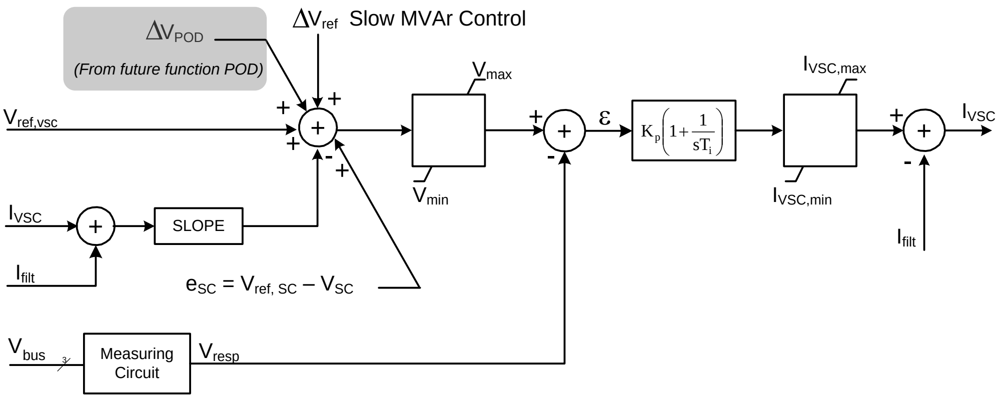

Figure A1 - Voltage regulator block diagram in automatic voltage control mode, STATCOM

Since the voltage control mode operates in a closed-loop, it is not possible to operate the STATCOM in automatic mode if the voltage response signal (V_{resp}) is lost. If the voltage measurement is lost, the control will FREEZE by setting to zero the voltage error (ε), with a time delay of 25ms, and will not change back to auto control model until the problem is fixed.

The desired voltage reference is set from the OWS and limited to the range defined in the Main Component Design, where the STATCOM operational area is defined. The slope, i.e. the allowed error between the desired voltage reference and the measured voltage for every 1 p.u. current, is adjustable between 2 – 10% on the capacitive side and 2 – 10% on the inductive side, based on rating, and is set from the OWS. The setting of the slope is limited between 2 – 10% by the control system, so that the operator cannot input any value outside of that range.

The master control can also set the STATCOM voltage reference and slope, in addition to the slow MVAr control ΔV_{ref} signal and the fast transients compensation e_{sc} signal.

Manual Control (MVAr Control)

In manual mode, the STATCOM operates with open-loop control. The desired reactive power output is set manually from the Operator Work Station (OWS) and the STATCOM provides the corresponding output current. The specified reactive power output is a function of the measured voltage on the primary side of the transformer.

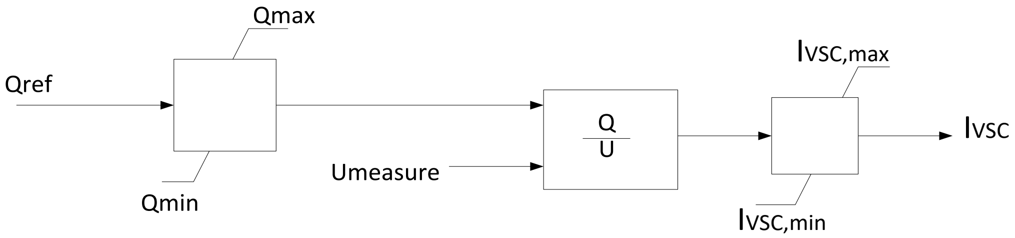

Figure A2 - Simplified regulator block diagram for the manual control mode, STATCOM

The Q_{ref} value is ramped to the desired value with a ramp rate, which can be set from the (OWS. During the start-up sequence of the STATCOM in Manual Control mode, before the control functions are deblocked, the manual reference is set to zero. In this way, the STATCOM will always start with zero MVAr output. The operator then adjusts the output to the desired level.

In Manual Control mode, the voltage reference follows the actual line voltage including slope correction, whereas at STATCOM start-up and in Automatic Voltage Control mode, Q_{ref} follows the reactive power calculated from the voltage regulator. Therefore, transients in the STATCOM output are avoided at transition from one control mode to the other. There will not be any change in the output when changing control mode.

The manual control mode operation will only allow the STATCOM to be controlled within the limits of the rated output.

The master control can also set the STATCOM Q_{ref} value.

Figure A2 is a simplified regulator block diagram for the STATCOM in the Manual Control mode.

Gain Supervisor

Changes in the power system configuration, e.g. trip of lines and generation units, may initiate oscillations in the STATCOM reactive power output. The oscillations are caused by a voltage regulator gain which is too high in relation to the network-short-circuit impedance. For this reason, the control system is equipped with a gain supervision function to ensure stability in the closed-loop voltage control during severe network conditions.

After 3 swings of the controlled quantity, in this case the voltage regulator output in Figure A1, i.e. the VSC current reference, the Gain Supervisor lowers the relative gain by a suitable factor. The suitable factor is calculated as of the peak to peak value of the detected oscillation. If another oscillation is detected, then the function will decrease again the relative gain up to a value which is 5 % of the nominal gain.

An indication of reduced gain is sent to the OWS. The voltage regulator gain can be manually reset from the OWS.

Power Oscillation Damping (POD) – future control function

Power Oscillation Damping is provided by modulation of the voltage reference in dependence of a measured quantity in the transmission system. The selected input signal is typically active power flow or frequency deviation. The preferred signal depends on

- Observability
- Controllability
- Location of the STATCOM in the transmission system

The output of the POD is the voltage modulation ΔV_{POD}, which will be added to the STATCOM voltage regulator (in Figure A1). The ΔV_{POD} is limited, and at severe system disturbances, the limits will always be hit. Therefore, the STATCOM initially operates in a bang-bang mode. The operation may change to a linear operation mode when the oscillation amplitude decreases.

It is extremely important that the POD modulation system is well-behaved with respect to large-signal system disturbances in order to successfully damp oscillations at critical events. Specifically, the phase shift between the measured quantity and the derived voltage modulation signal must be preserved when the limiting function is applied.

Note that this function is not in the current scope of Phoenix project, and could be a future application if needed by the customer.

2. SC Control

The SC is controlled by Hitachi Energy's UNITROL 1020. UNITROL 1020 is an automatic voltage regulator (AVR) of the latest design for synchronous generators and synchronous motors. The unit contains the most advanced microprocessor technology together with IGBT semiconductor technology. UNITROL 1020 operations are affected through a practical and simple-to-operate panel on the unit. Figure A3. shows a simplified diagram of the interconnection between UNITROL 1020, the synchronous machine and its exciter.

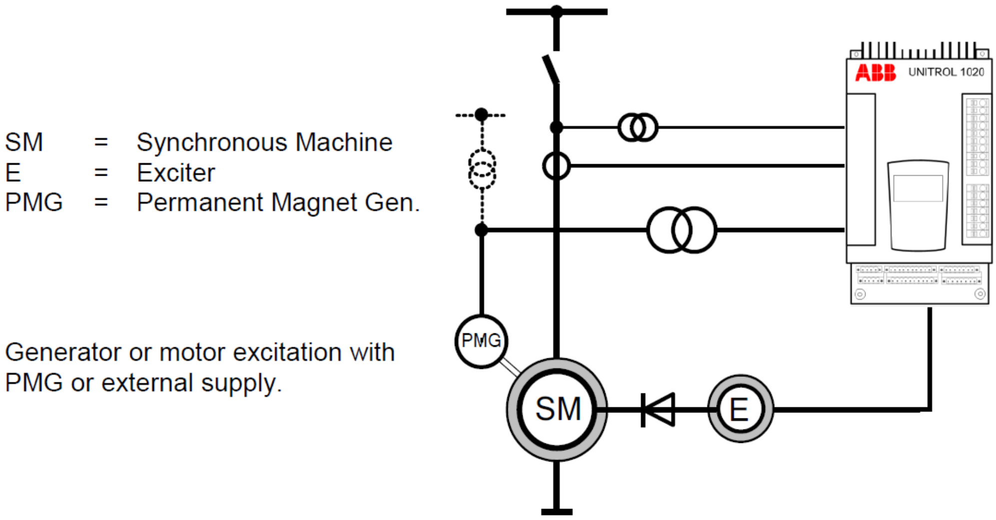

Figure A3 - Simplified diagram of interconnection between UNITROL 1020 and SC

For Phoenix the SC control system has the following control modes:

i. Automatic Voltage Regulation (Auto)
ii. Manual Control
iii. VAr Regulation (constant MVAr mode)

UNITROL 1020 communicates with the MACH system, where the Master Control is located.

Automatic Voltage Regulation (Auto)

Figure A4 depicts a simplified block diagram of the SC Excitation Control System. As shown, the AVR (UNITROL 1020) and exciter (GLC 600A) models are based on IEEE's model AC8B[5].**Error! Reference source not found.** for static voltage regulators and brushless excitation systems.

[5] IEEE Standard 421.5-2005, IEEE Recommended Practice for Excitation System Models for Power System Stability Studies

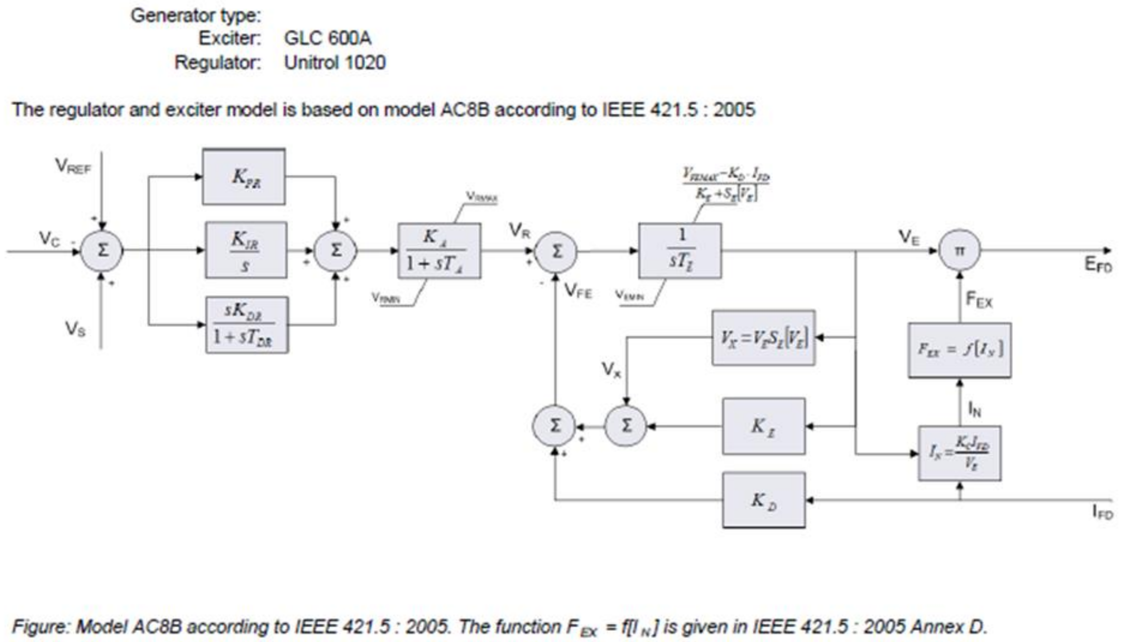

Figure A4

Automatic Voltage Regulation (AUTO) is a closed loop control mode that regulates the voltage of the synchronous machine at the 13.8 kV bus. It uses a PID controller whose inputs are the SC terminal voltage error (SC voltage reference V_{REF} – SC terminal voltage V_C) and the stabilizing voltage V_S from a PSS (Power System Stabilizer). V_R is the voltage regulator output (or exciter field voltage) after enforcing the voltage limits V_{RMAX} and V_{RMIN}.

The exciter model is a block diagram whose inputs are V_R and the SC field current I_{FD}. The output of the exciter model is the SC field voltage E_{FD}. In the exciter model V_R is compared with a signal V_{FE} proportional to I_{FD}. V_{FE} is derived from the summation of the exciter output voltage V_E multiplied by $K_E+S_E[V_E]$ (where $S_E[V_E]$ represents saturation effects) and I_{FD} multiplied by the demagnetization term K_D, as explained in the IEEE Standard 421.5-2005.

Although not depicted, the SC terminal current and a droop coefficient (slope) are also used to allow voltage compensation/droop with respect to the SC terminal voltage V_C. In addition, the system is provided with voltage and current limiters, which have not been depicted for simplicity. Lists with AVR and AC8B model parameters are in the Excitation Transfer Model [6] **Error! Reference source not found.**.

The master control calculates the SC voltage reference V_{REF} as of the voltage reference $V_{ref\text{-}H\text{-}SC}$ set for the HV bus, either for only SC operation or for coordinated operation SC-STATCOM, In addition, the master control adds the slow MVAr control ΔV_{ref} signal to the SC voltage reference V_{REF} in case of coordinated operation SC-STATCOM.

<u>Manual Control (Exciter Field Current Regulation)</u>

The exciter field current is regulated and no limiters are active while in this control mode. Manual Control is mainly for commissioning and testing purposes. However, if the voltage measurement is lost, then the AVR will automatically switch to Manual Control in order to maintain the SC operation. Manual Control is a closed loop control mode where the voltage regulator output V_R comes from a PI controller whose input is the exciter field current error.

This control mode is used mainly for commissioning purposes and it is not required for this application, yet it will be available for the operator via UNITROL 1020's HMI.

<u>VAr Regulation</u>

This control mode allows regulation of the reactive power output of the synchronous machine. The VAr setpoint is normalized at 1 p.u. terminal voltage of the machine. VAr Regulation is a closed

[6] 3BSY200419-HTP, Excitation Transfer Model, 2018-03-12.

loop control mode where the voltage regulator output V_R comes from a PID controller whose input is the reactive power error at SC terminals. UNITROL 1020 can also use this PID controller for Power Factor (PF) Regulation. However, due to the synchronous machine being used as a synchronous condenser, PF Regulation is not required for this application. Therefore, neither the operator nor Hitachi Energy personnel will have access to the PF Regulation control mode.

<u>Limiters</u>

Table A1 lists the limiter functions in UNITROL 1020 that have been enabled for this application including their objectives.

Limiters
V/Hz: V/Hz Limiter (to reduce voltage set-point in case of under-frequency)
SP Min: Minimum Voltage Set-Point Limiter
SP Max: Maximum Voltage Set-Point Limiter
Max Ie: Maximum Exciter Current Limiter
Max UM: Maximum Machine Voltage Limiter
Max IM: Maximum Machine Current Limiter ("IMmax_ind" or "IMmax_cap" applies depending on the reactive power flow direction)

Table A1 – SC Limiter Factors

<u>Power System Stability – future control function</u>

UNITROL 1020 comes with a PSS (Power System Stabilizer) model. This model can represent type PSS2A/2B/2C Power System Stabilizers according to IEEE Std. 421.5. The main objective of the PSS is to provide damping of low frequency oscillations (up to 2 Hz), either from local synchronous machines or large transmission networks. The damping is achieved by adding a stabilizing signal V_S to the voltage regulator of the existing excitation system, as shown in Figure A4.

Figure A5 depicts the block diagram of UNITROL 1020's PSS model. As depicted, input signals and blocks to use are configurable, and the dual input allows the stabilizing signal to be proportional to speed (or measured frequency), electrical power or a combination of speed and electrical power.

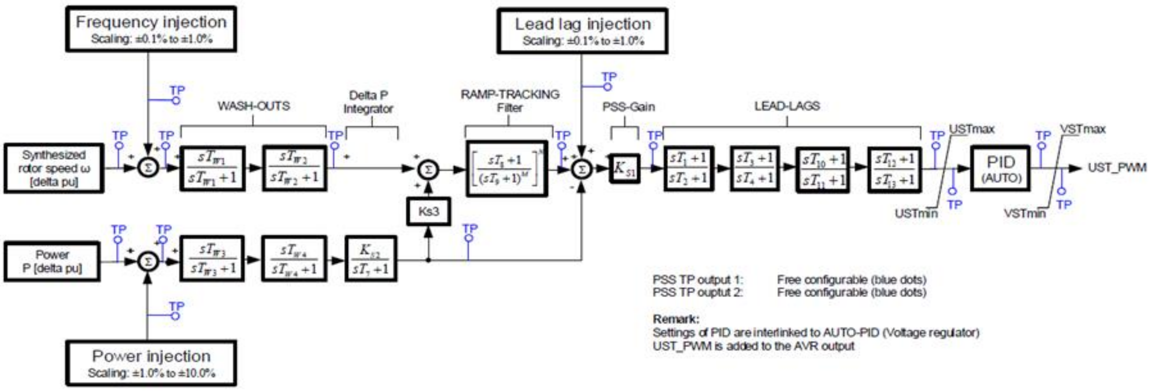

Figure A5 - Type PSS2A/2B/2C Power System Stabilizer model in UNITROL 1020C

A more detailed information of the safety instructions, description of the product, installation, commissioning and operation, and maintenance and troubleshooting of the UNITROL 1020 can be found in the UNITROL® 1020 User Manual.

Note that this function will not be used in Phoenix. However, it could be a future application if needed by the customer.

Appendix B – SC Technical Specifications

Detailed technical specifications for SC were produced under the Phoenix project [REF 10] and the key specifications are summarised in this Appendix. For the complete guidance on the technical specifications for SC, please refer to the detailed specifications document.

SC Technical Specifications

1. The SC shall be designed for a continuous and controllable operation at all system voltages between 0.9 p.u. to 1.1 p.u. and at all system frequencies between 47 Hz to 52 Hz.

2. The SC must be capable of operating in either "Voltage Control" mode or "Constant Reactive Power Control" mode with a single operating mode instruction. The facility must be able to switch between voltage control mode and constant reactive power control mode on instruction from the ESO within an agreed time scale of no longer than 2 minutes and changes in operating mode should be achieved without any sudden disturbance to the system via a smooth transition.

3. When selected to reactive power control mode the reactive power output should be controlled to deliver a value of reactive power equivalent to the reactive power setpoint. This reactive power setpoint and reactive power delivery can be at the local terminals of the synchronous condenser or at an alternative system measurement point advised by the Company.

4. The SC shall be capable of continuous operation at any point between the specified reactive capability limits.

5. The SC should have a short circuit ratio no lower than 0.5pu.

6. Excitation system shall include an excitation source (Exciter) and a continuously acting Automatic Voltage Regulator (AVR) and meet the following performance requirements.
   a. When operating in Voltage Control Mode, an accuracy measure of the steady state voltage control the Automatic Voltage Regulator shall limit the change in the synchronous condenser terminal voltage to a drop not exceeding 0.5% of its rated terminal voltage when the plant's output is gradually changed from zero to its reactive power limits.
   b. For a step change from 90% to 100% of the synchronous condenser terminal voltage when on open circuit the Excitation System response shall have a damped oscillatory characteristic. For this characteristic, the time for the synchronous condenser terminal voltage to first reach 100% shall be less than 600ms. The plant settling time within 5% of the voltage change shall less than 3 seconds.
   c. To ensure adequate synchronising power is maintained when the synchronous condenser is exposed to large voltage disturbance, the exciter shall be capable of providing its lower and upper ceiling voltages to the plant field in a time not exceeding the value specified. This will normally be not less than 50ms and not greater than 300ms. The achievable lower and upper ceiling voltages may be dependent on the voltage disturbance.
   d. The exciter shall be capable of achieving an excitation system on load positive ceiling voltage of no less than a value specified that will be:
      i. not less than 2pu.
      ii. normally no greater than 3pu.
      iii. exceptionally up to 4pu.

      of rated field voltage when responding to a sudden drop in voltage of 10 percent or more at the synchronous condenser terminals.

   e. If a static exciter is employed, the field voltage should be capable of attaining the negative ceiling level specified after the removal of the step disturbance. Where a specific value is not provided the value will be 80% of the positive ceiling value in (d). The exciter shall be capable of maintaining free firing when the synchronous condenser terminal voltage is depressed to a level between 20% to 30% rated terminal voltage. The exciter shall be capable of attaining a positive ceiling voltage not less than 80% of the excitation system on load positive ceiling voltage upon recovery of the synchronous condenser terminal voltage to 80% of rated terminal voltage following fault clearance. The requirement to provide a separate power source for the exciter if required for system reasons will be specified.

7. Synchronous Condensers excitation system shall include an Under-Excitation Limiter control function to prevent the Automatic Voltage Regulator reducing the plant excitation to a level which would endanger synchronous stability.

8. The Over-Excitation Limiter setting for SC shall ensure the excitation is not limited to less than the maximum value that can be achieved whilst ensuring the Synchronous Condenser is operating within its design limits.

9. The SC shall start-up from standstill and synchronise to the system within 15 minutes of receipt of an instruction from the System Operator. The SC shall be fully available to restart no longer than 15 minutes after disconnection from the system following a shutdown instruction.

10. SC should meet the fault ride through requirements where H-SC shall remain stable and connected to the network for system voltages at the HV side of the unit step up transformer
    a. Falling to 0 pu for at least 140ms
    b. Falling to 0.4pu for at least 300ms

11. A synchronous condenser and any of the critical constituent parts, controls and auxiliaries of the overall device shall remain active and permit delivery of reactive power during any low voltage incident where the measured system voltage remains above 0.2pu. For a voltage measure below this value on any phase the device is permitted to ‘block’ the output.

12. SC shall remain stable and connected to the network for instantaneous Transient Overvoltage (ToV) limit of 2 pu, 1.4pu for 0.5s and 1.3 pu for 1s.