SP ENERGY NETWORKS
ScottishPower Group

Phoenix Project
Innovation Testing and Demonstration Webinar

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PHOENIX

20th July 2021 – Session 1

Introduction from SP Energy Networks – Michael Walsh

Welcome to Our 2021 Phoenix Stakeholder Event

Introduction

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- Schedule overview

Event Agenda

Part 1, 09:00-12:00

- 09:00-09:20 Introduction from SP Energy Networks – Michael Walsh
- 09:20-10:50 6-Month Live Trial Update from ABB – Ritwik Majumder
- 10:50-11:00 Interval
- 11:00-12:00 Update on Boundary Analysis Studies from NGESO – Jay Ramachandran

- Schedule overview

Event Agenda

Part 2, 12:30-15:00

- 12:30-13:10 Update on Studies from Denmark Technical University – Guangya Yang
- 13:10-13:50 Update on Studies from University of Strathclyde – Dimitrios Tzelepis
- 13:50-14:00 Interval
- 14:00-14:30 Update on Commercial Reports – John West
- 14:30-15.00 Final Q&A Session and Closing Remarks – John West & Michael Walsh

Housekeeping

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- Please switch off **cameras** and **microphones.**

- During the presentation, please type any questions into the **chat box** on MS Teams, the moderator will control the Q&A. Questions relating to points of clarification will be raised during the presentations, the remainder will be answered at the end of the presentation.

- If you have any questions after that project partners presentation, please send them via Sli.do, we will endeavour to answer them at the final Q&A session at 14:30. Any questions missed we will answer and email out to attendees alongside the slide pack.

- There will be regular refreshment breaks during the event for participants.

Phoenix overview

Phoenix is demonstrating the design, deployment and operation of the world's first Hybrid Synchronous Compensator (H-SC) at transmission network. An H-SC is the combination of a static condenser (STATCOM) and a Synchronous Condenser improving the system inertia and voltage stability. This implementation is expected to increase the UK transmission B6 boundary power transfer capacity from by 45 MW to 98 MW. This will allow additional Distributed Energy Resources to be connected and flow through the network.

Timescale:
2017 – 2021

Funding:
£17.0m through Ofgem NIC mechanism

Benefit:
£66m and 150,817 tCO_2 (2050)

Key achievements to-date:

- Developed technical and functional specs for H-SC
- Designed, manufactured, installed and commissioned H-SC
- 12 month Live Trial is underway, following a phased energization of the main components at Neilston 275kV Substation.

Key upcoming activities (3 months):

- H-SC live trial performance monitoring
- Cost benefit analysis validation and rollout strategy development

Phoenix Project Video

Video link:

IBERDROLA – Stop (youtube.com)

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Delivering During Lockdown

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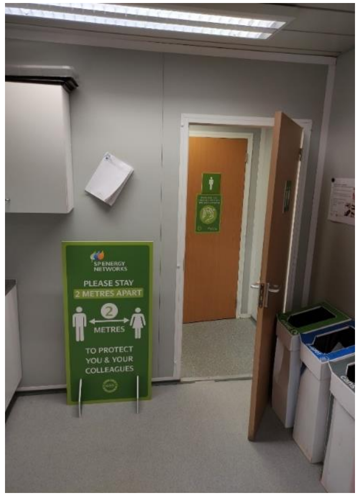

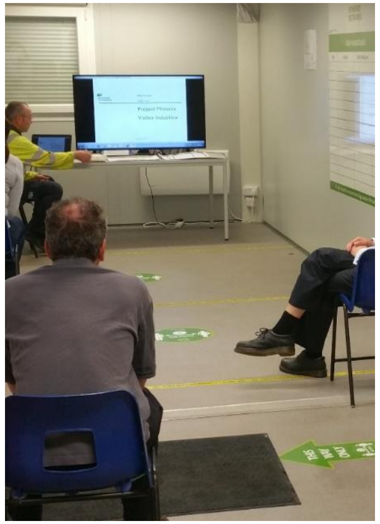

Throughout the Covid-19 pandemic and lockdown, the Phoenix project continued pressing on with the site team adhering to social distancing and having fewer operatives on site. Although there have been some challenges relating to furloughed subcontractors, we have adapted to allow energization of the H-SC and commencement of the Live Trial in October 2020.

DISTANCING
Ensure safe social distancing controls are maintained within the workplace

HYGIENE
Maintain good hygiene controls (hands & equipment)

FACE COVERINGS
Wear a face covering when moving around the workplace

SYMPTOMS
Don't come into the workplace if you, or any of your household, have any C-19 symptoms

COVID-19

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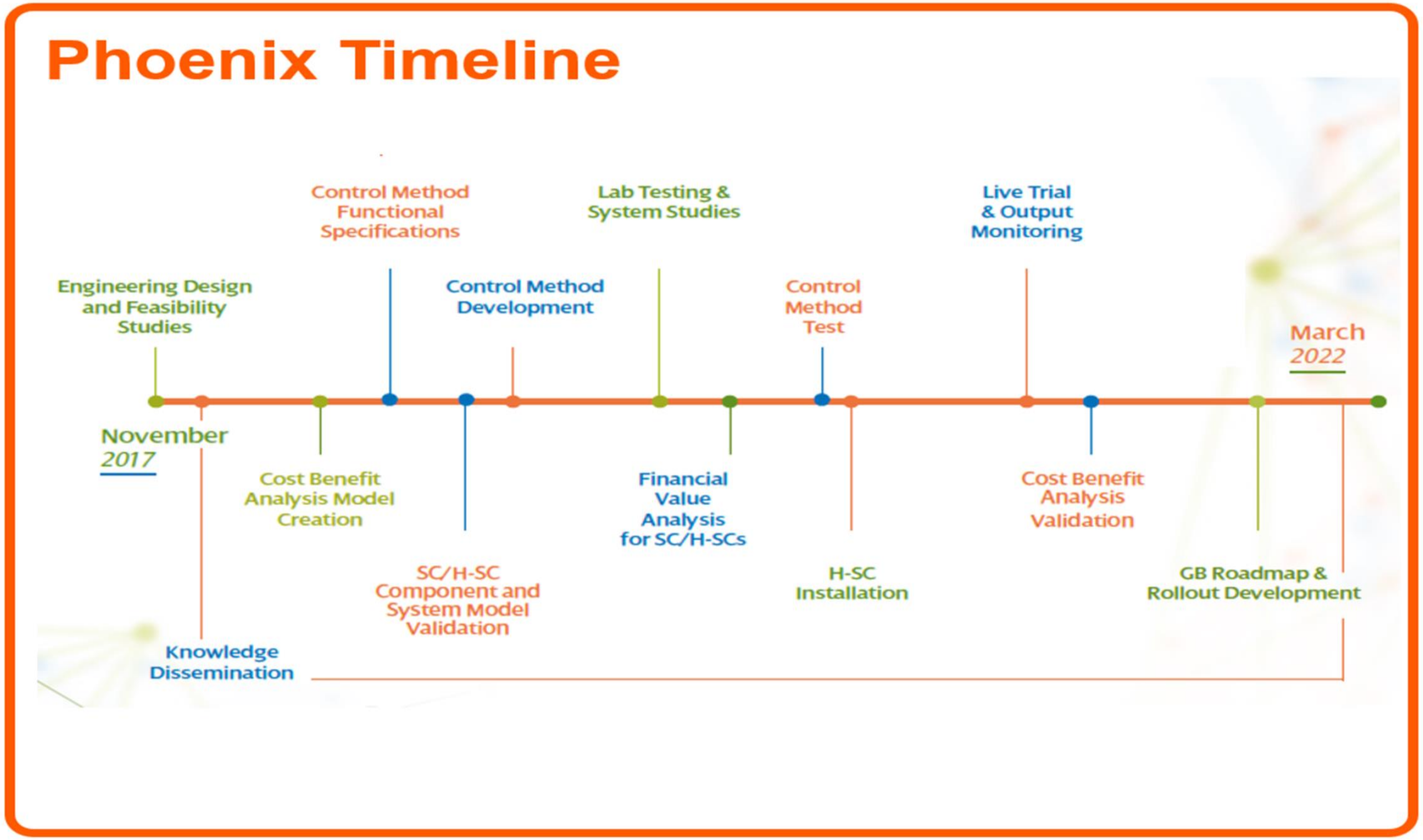
Progress Update

Commenced the live trial of the Phoenix Project, world's first H-SC IN October 2020

During the 12 months Live Trial, we are following a programme of Live Trial test scenarios and mode changes. These tests will be used to verify the H-SC master controller's performance, control of the hybrid devices and will allow the captured data and learnings to be analysed and validated against the Project Partner Phoenix System Studies which you will hear more about later

These study results will be compared with real data collected during the live trial and will be used for the Cost Benefit Analysis works where we will begin to understand the commercial value and mechanisms to incentivise the roll out of this technology.

Phoenix Overview



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HITACHI ABB PHOENIX

Live Trial Update from ABB – Ritwik Majumder

Agenda

Transition from thermal to renewable power stations

Phoenix solution and benefits

Live trial scope and plan

Live Trial Plan timeline

Data monitoring

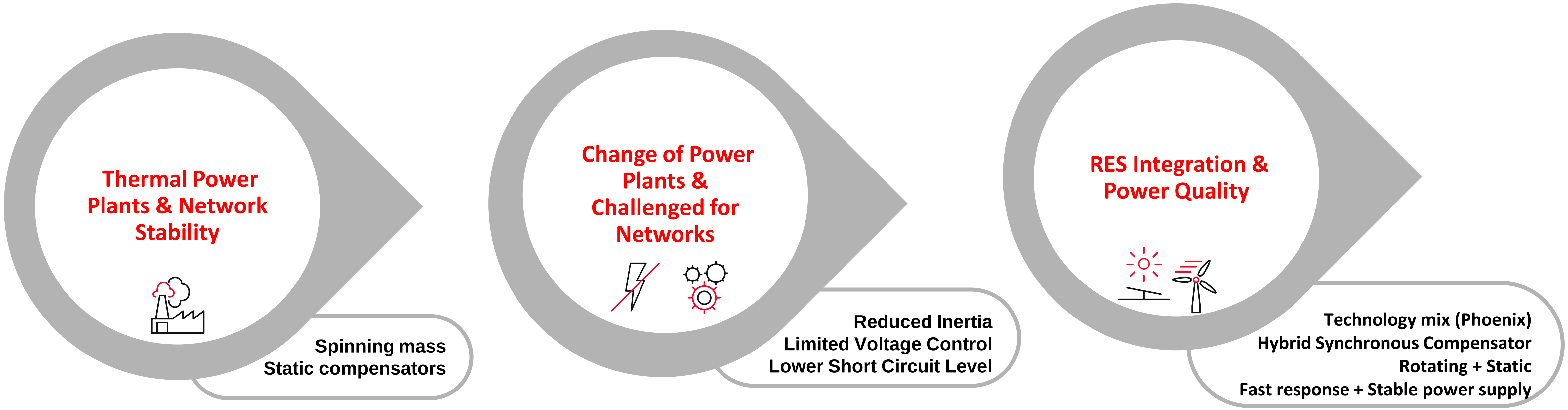
Operational modes and test cases
- Hybrid operation of STATCOM and SC
- Only STATCOM in service
- Only SC in service

Unplanned events

Voltage profile and reference

Conclusions

Transition from Thermal to Renewable Power Stations



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Phoenix Solution and Benefits

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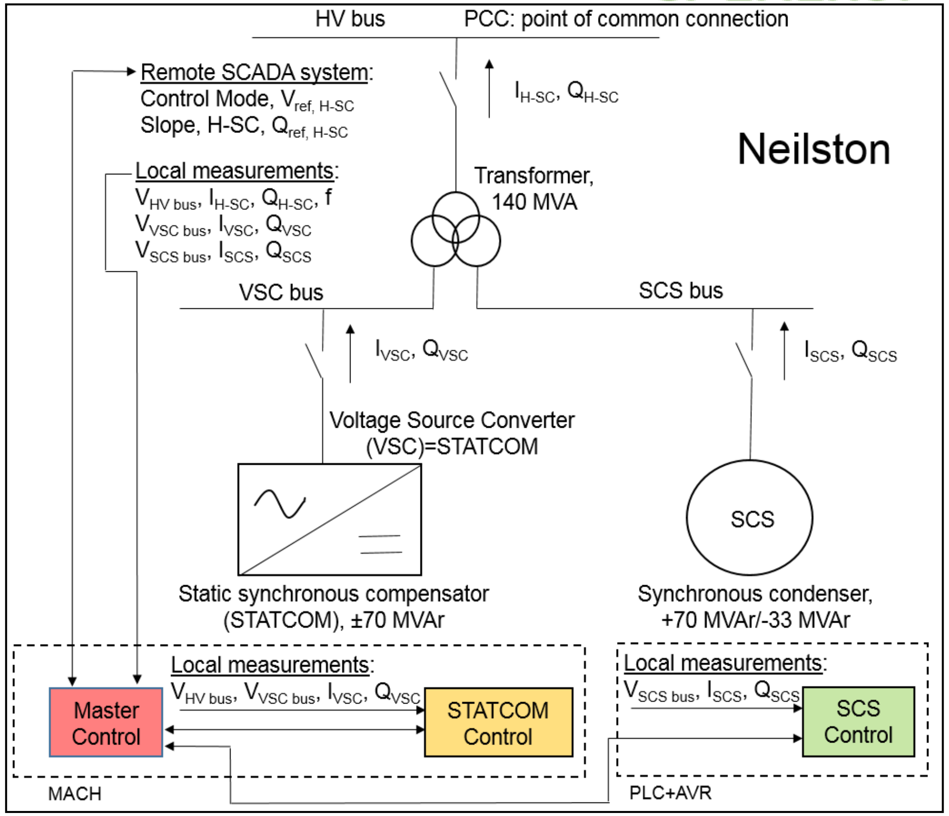
Hybrid Synchronous Compensator

- Sustainable Design
- Innovative Technology Mix (STATCOM + SC)
- Dynamic Voltage Control, Inertia, Short Circuit Level
- Enhhanced system stability
- Aid in maintaining power quality of the network
- Reduced operating costs
- Higher RES penetration



Coordinated Voltage Control and Reactive Power Sharing	Power Loss Minimization	Fast Transients Compensation	Slow MVAr Control	Loss Reduction Mode (STATCOM)	Inertia Support Maximization

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Coordinated Voltage Control and Reactive Power Sharing

Calculation of setpoints required by both control systems.

(For Automatic control, the voltage reference and for Manual Control reactive power reference)

Power Loss Minimization

Calculation of optimized slopes (in automatic mode) or optimized Q setpoints (in manual mode) for both STATCOM and SC, to minimize H-SC loss

Fast Transients Compensation

Speed up of the response time of H-SC Automatic Voltage Control with both branches-adding voltage error from SC to the voltage reference of STATCOM

Slow MVAr Control

In automatic control mode, slow MVAr control output is added to the voltage reference signal in such a way that in steady-state H-SC will remain within a window defined by two limits

Loss Reduction Mode

Reduction of the switching losses for STATCOM. When STATCOM output is 0 MVAr for a certain time, (min 1 s) STATCOM is released when voltage is outside bandwidth and will not repeat within 10 min

Inertia Support Maximization

Maximization of H-SC inertial contribution. STATCOM is set to manual control with zero reactive power output. When frequency is back, STATCOM is released

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Live Trial Plan Timeline

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Mode 1: STATCOM and SC in V control mode	2nd Nov – 4th Dec 2020
Mode 2: STATCOM and SC in VAr control mode	4th Dec – 23rd Dec 2020
Mode 5: Only STATCOM	3rd Feb – 2nd Mar 2021
Mode 3: STATCOM in V control mode and SC in Var control mode	24th Mar - 9th Apr 2021
Mode 4: STATCOM in VAr control mode and SC in V control mode	17th Apr – 2nd May 2021
Mode 6: Only SC	2nd – 23rd May 2021
Master Controller - additional tests	23rd May – 20th June 2021

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Live Trial Scope & Plan

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Scope of Live Trial Plan: assess the combined operation of the STATCOM and SCS technologies, in addition to the performance of the developed hybrid control functionality (Master Control).

- Change in voltage and reactive power setpoint
- Line switching, open/close bus tie
- Trip of a generation unit or load
- Remote or local fault

Setpoint

Network Structure

Power Imbalance

Fault

Operational modes definition	Data files	Results analysis
Test performance description	On-site data acquisition	STATCOM & SC response analysis
Time planning	Files in TFR/TREND format	Understanding of H-SC response to unplanned events
	Control of received data	Monthly reporting
		Weekly update meetings

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High Resolution data

- Voltage at HSC bus
- Reactive power output at HSC bus
- Voltage and reactive power output from SC and STATCOM
- Active power injection from HSC, SC and STATCOM

Low Resolution data

- Reactive power output at HSC bus
- Terminal voltage at HSC bus
- Losses
- Harmonic injection into the grid
- Temperature and vibrations
- Alarms

High Resolution data

- Dynamic voltage support event
- Overload event
- Reactive power absorption event, over voltage event
- Reactive power injection events, under voltage event
- Fault current contribution events
- Inertia support event
- Power oscillation damping event
- Closing H-SC breaker
- Closing of SC breaker and STATCOM power switch
- Gain supervision events
- Other network disturbance

Low Resolution data

Reactive power output
- Terminal voltage
- Losses
- Harmonic injection into the grid
- Temperature and vibrations
- Alarms
- Number of forced outages per year and annual availability

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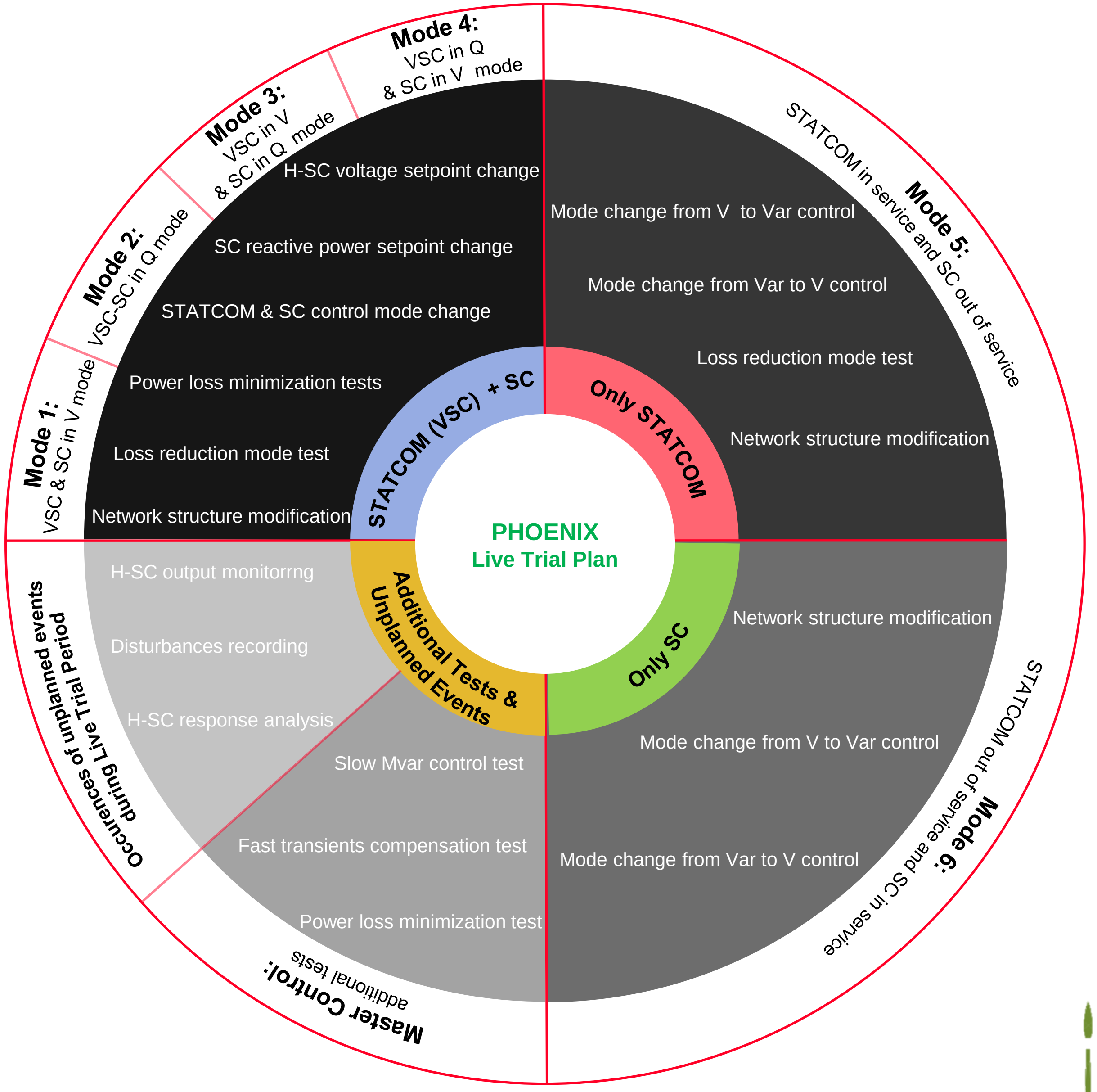
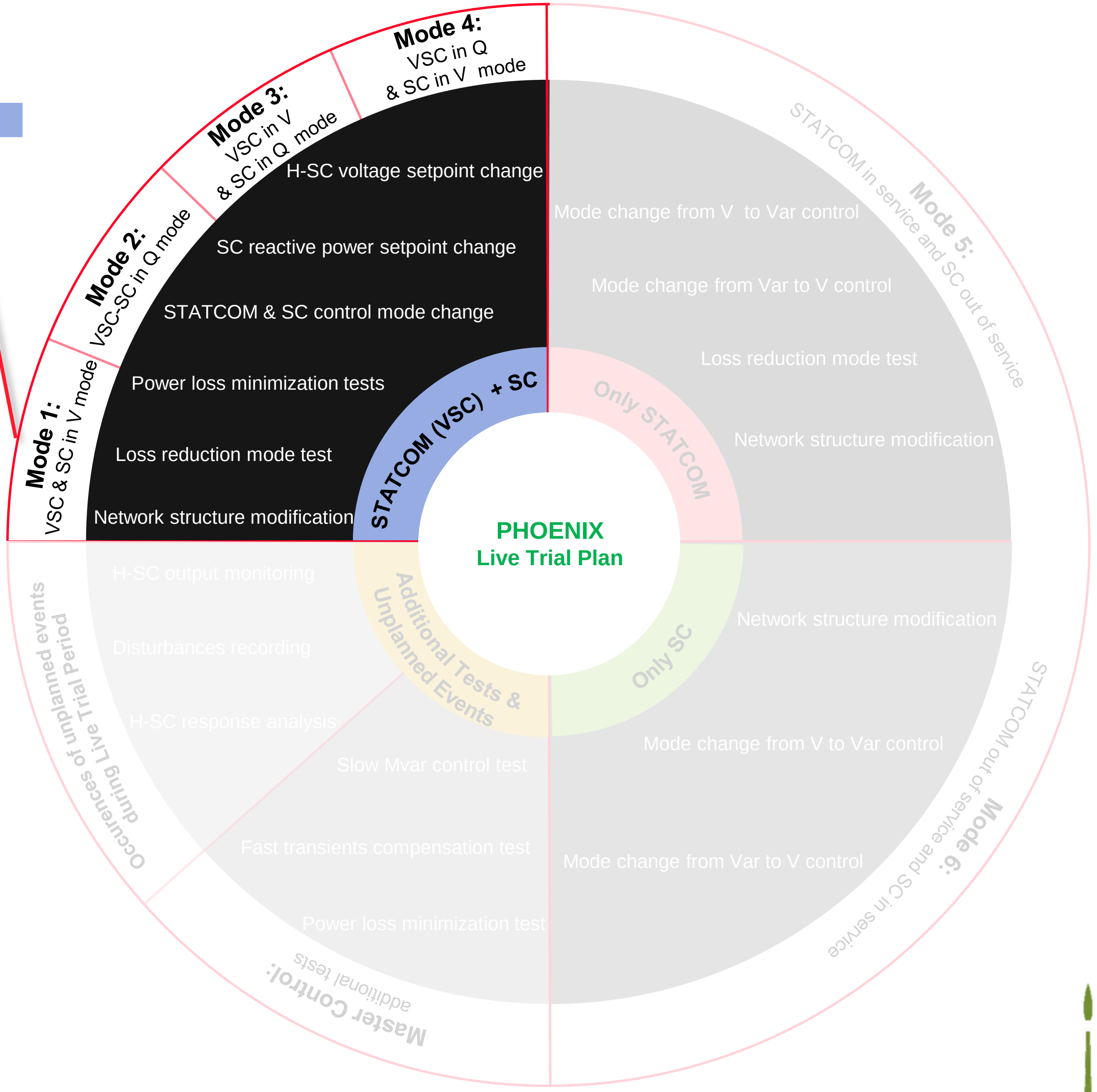
Live Trial Plan

Operational Modes and Tested Cases



Hybrid Operation of STATCOM and SC

- **Case 1: Change H-SC voltage setpoint down**
- Case 2: Change H-SC voltage setpoint up
- Case 3: Change control mode-STATCOM
- Case 4: Change control mode-SC
- Case 5: Loss Reduction Mode (LRM-ON) test
- Case 6: Loss Reduction Mode (LRM-OFF) test



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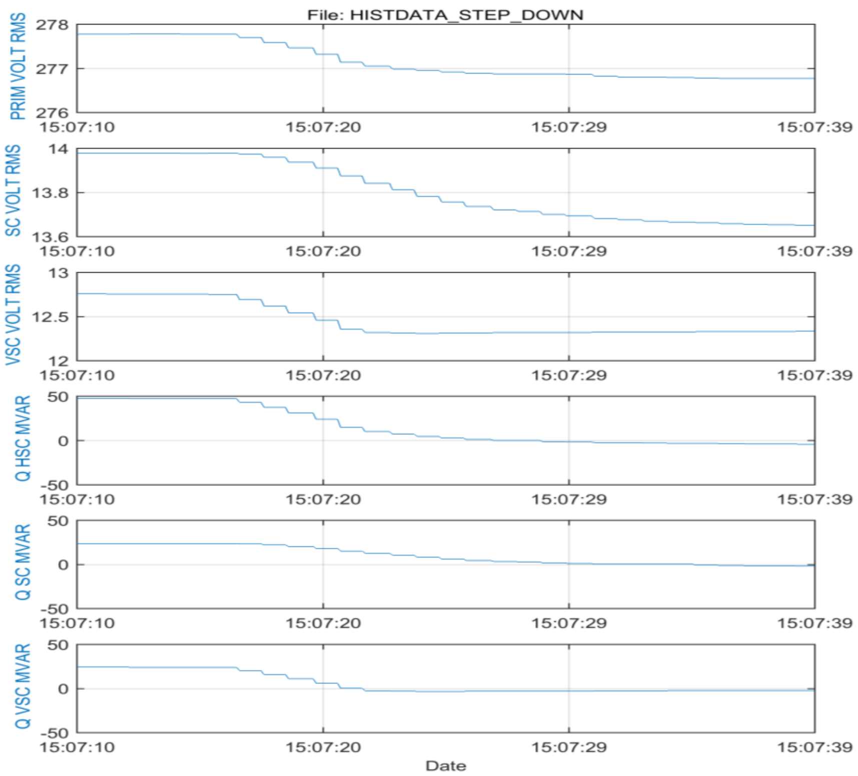
Mode 1 / Case 1: Change voltage setpoint down (2nd November 2020- 15:07)

STATCOM V control
SC V control
Vref 1 to 0.98 pu



1 | Voltage at HV side is decreased due to voltage setpoint change

2 | SC response is relatively slower compared to STATCOM due to higher time constant

3 | Voltage on STATCOM and SC side is decreased due to the voltage setpoint change

4 | Voltage at HV side reaches a new steady state value approximately 20 seconds after the change

5 | STATCOM & SC have equal sharing of reactive power due to their identical slopes

6 | After the change, H-SC reactive power output is decreased to approximately 0 MVAr

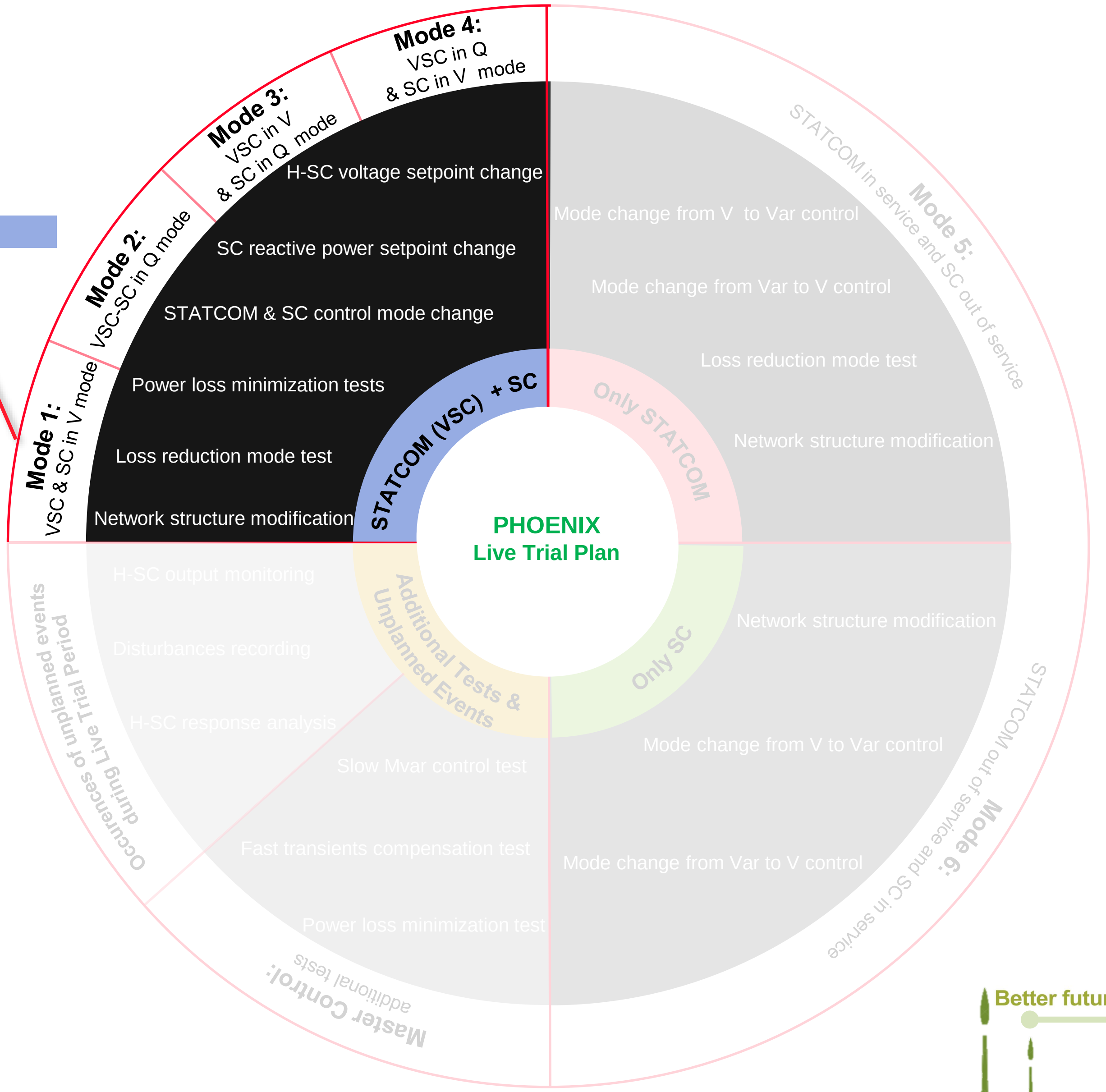
- ✓ STATCOM and SC respond to voltage setpoint change as expected.
- ✓ H-SC has a stable operation during the performance of the test.
- ✓ The step time is around 10-12 s and the main delay comes from the communication of the setpoint and ramp rate limiter (More tests are planned to validate SC response time without these limitations)

Hybrid Operation of STATCOM and SC

- Case 1: Change voltage setpoint down
- Case 2: Change voltage setpoint up
- Case 3: Change control mode-STATCOM
- Case 4: Change control mode-SC
- **Case 5: Loss Reduction Mode (LRM-ON) test**
- Case 6: Loss Reduction Mode (LRM-OFF) test

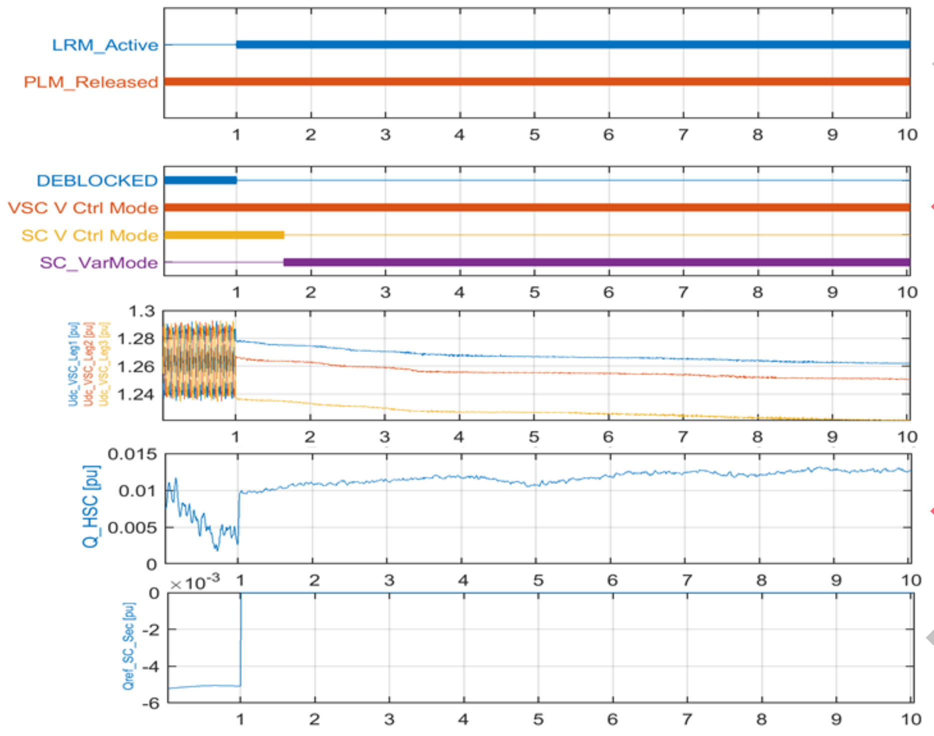
Loss reduction mode :

- ✓ Reduce the switching losses for STATCOM, by blocking the VSC, when reactive power output of the STATCOM is within a specified area around 0 MVAr for a certain time
- ✓ Only in Automatic Voltage Control (i.e. not in Manual Control).



STATCOM V control
SC V control
Vref set to make Q=0
LRM ON

Mode 1 / Case 5: Loss Reduction Mode (LRM-ON) test (21st November 2020 - 13:12)



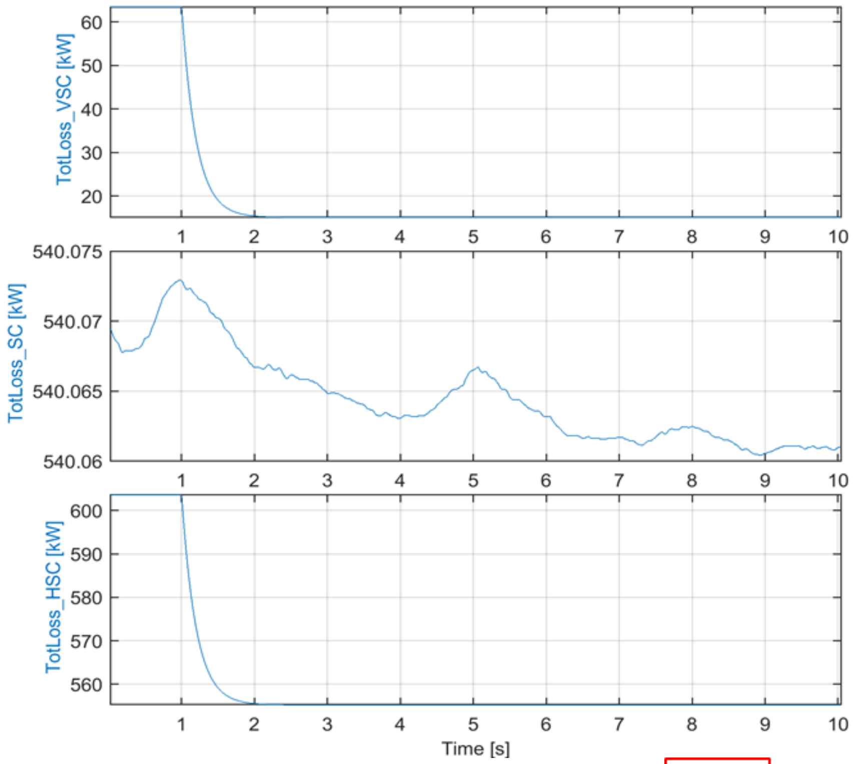
1 Both LRM & PLM are ON after 1 s

2 STATCOM & SC operate in V control mode
STATCOM is blocked at 1 s

3 The voltage at STATCOM side is decreased

4 H-SC reactive power output is equal to 0

5 SC reactive power reference is set to 0
SC starts operating VAr control mode.

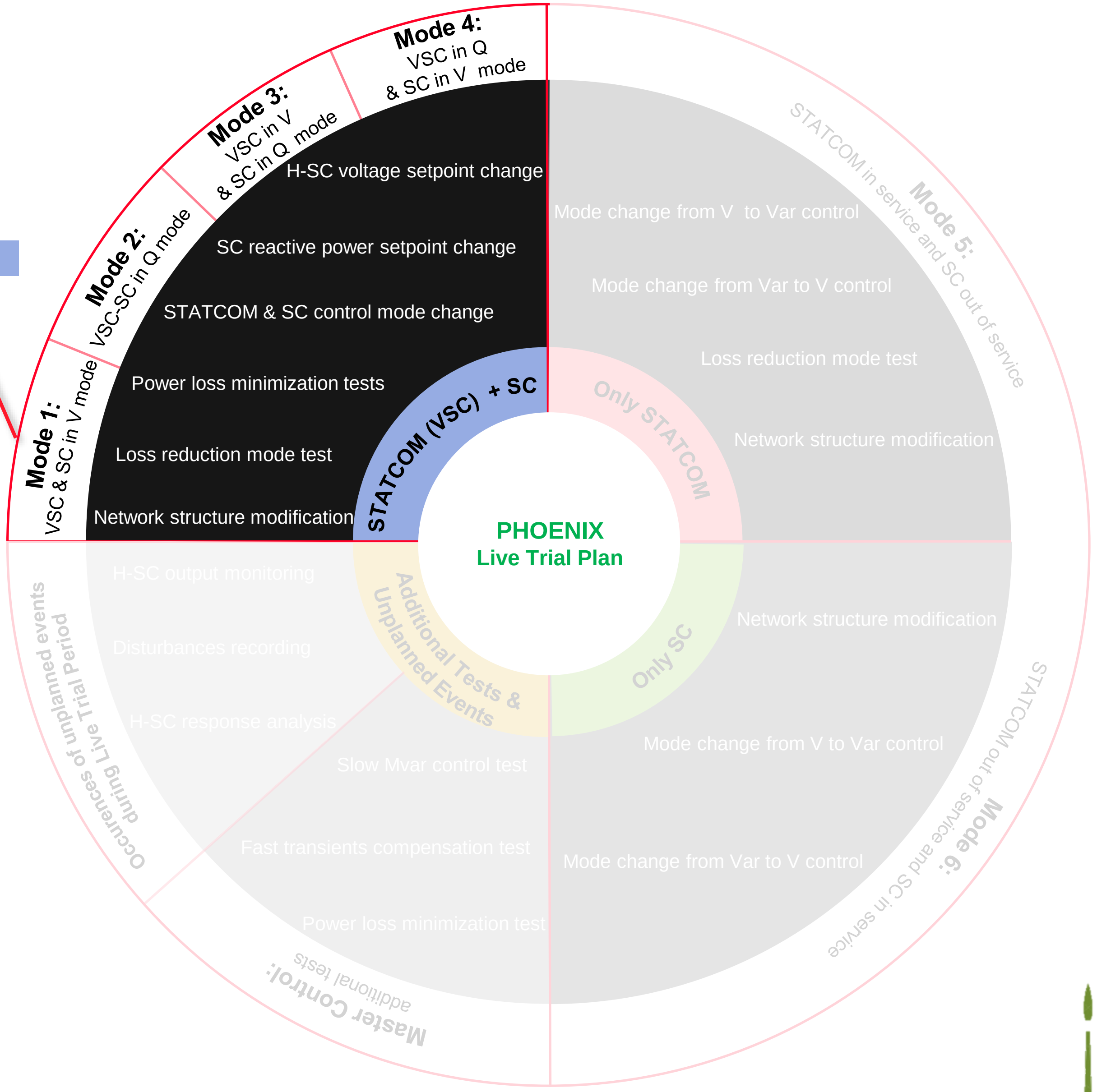


- ✓ The H-SC master control functions PLM and LRM performed as expected.
- ✓ H-SC losses are reduced with the PLM and LRM functions.

Power losses are reduced/minimized

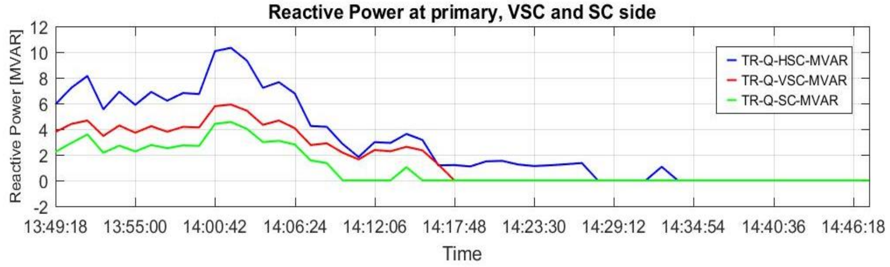
Hybrid Operation of STATCOM and SC

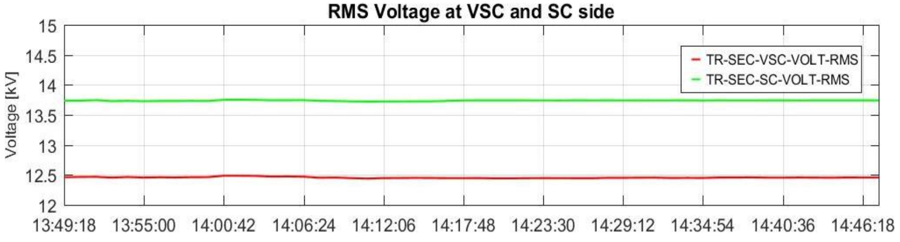
- Case 1: Change voltage setpoint down
- Case 2: Change voltage setpoint up
- Case 3: Change control mode-STATCOM
- Case 4: Change control mode-SC
- Case 5: Loss Reduction Mode (LRM-ON) test
- **Case 6: Loss Reduction Mode (LRM-OFF) test**

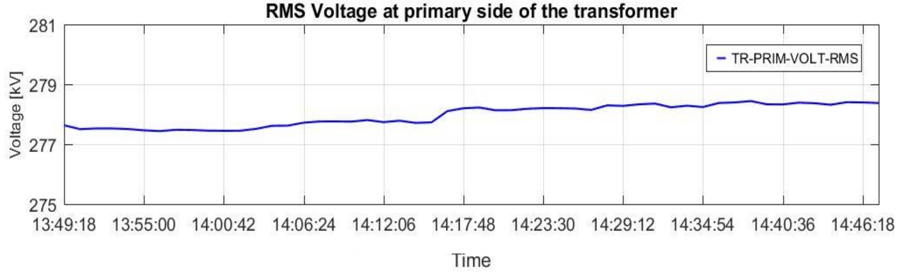


STATCOM V control
SC V control
Vref set to make Q=0
LRM OFF

Mode 1 / Case 6: Loss Reduction Mode (LRM-OFF) test (21st November 2020- 14:28)



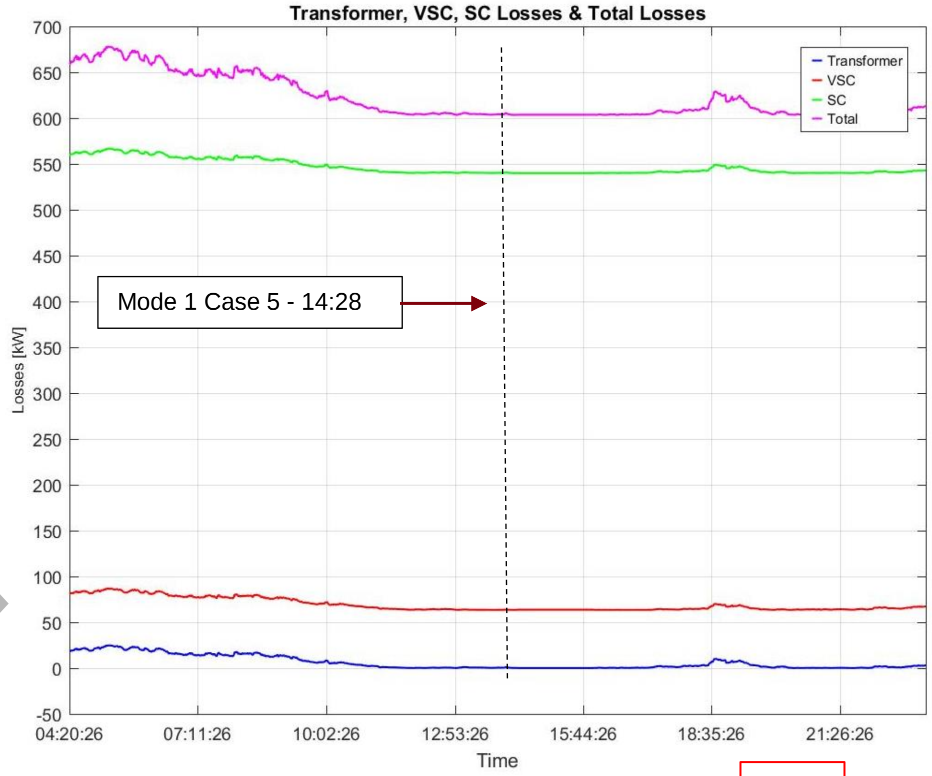




1 H-SC reactive power output becomes equal to 0 MVAr around 14:28

2 VSC & SC losses are stabilized at 63 kW and 540 kW

3 The total losses of the VSC, SC and transformer are 603 kW.



- ✓ The deactivation of LRM in Mode 1 Case 6 resulted in higher total losses compared to Case 5.
- ✓ H-SC has a stable operation during the performance of the test.

Loss in SC+STATCOM

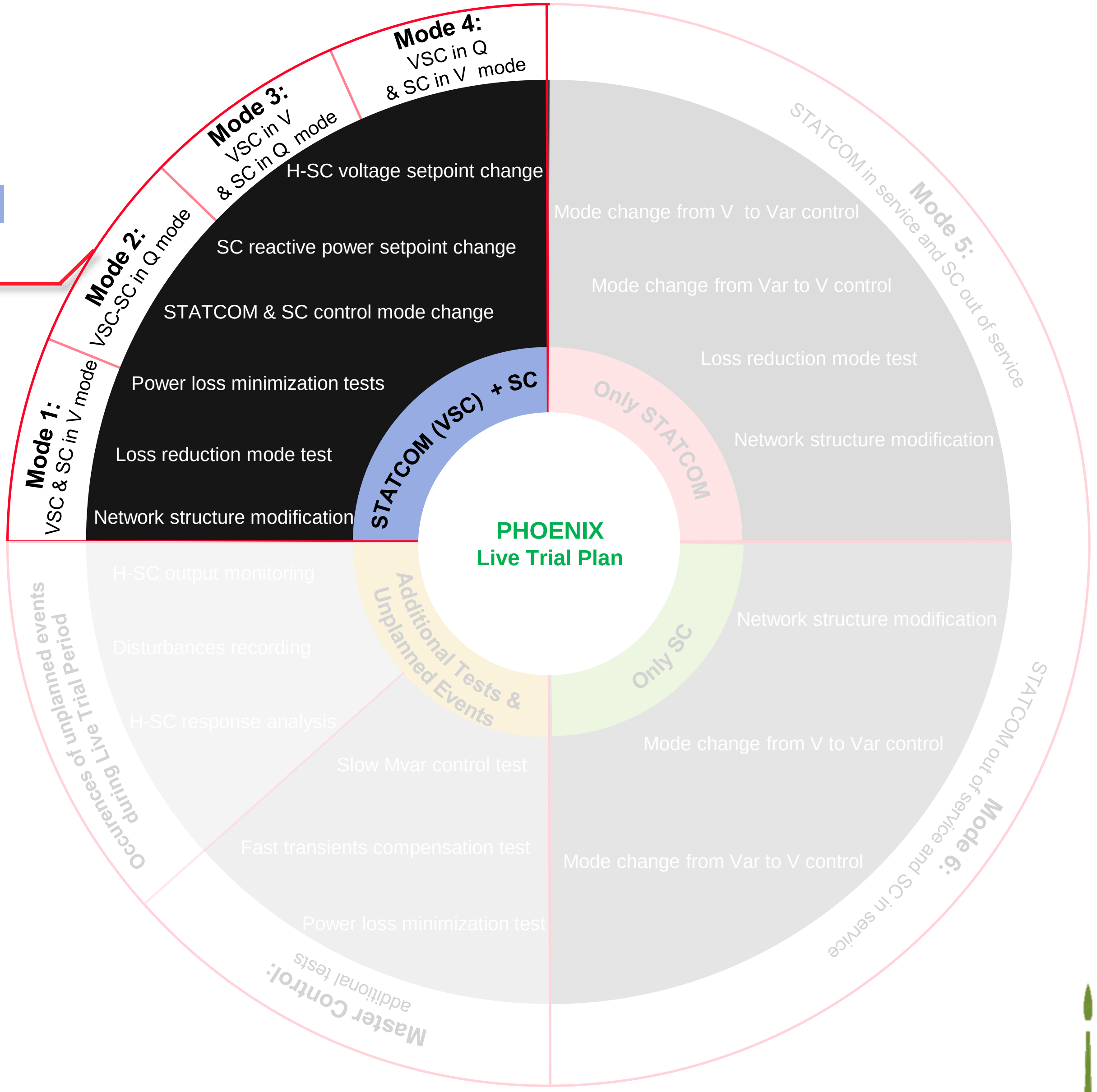
1. **Case 6 :LRM OFF - 600 kW**
2. **Case5 : LRM ON - 545 kW**

Hybrid Operation of STATCOM and SC

- **Case 1: PLM test 1 under Var control mode**
- Case 2: PLM test 2 under Var control mode
- Case 4: Change operation mode-STATCOM

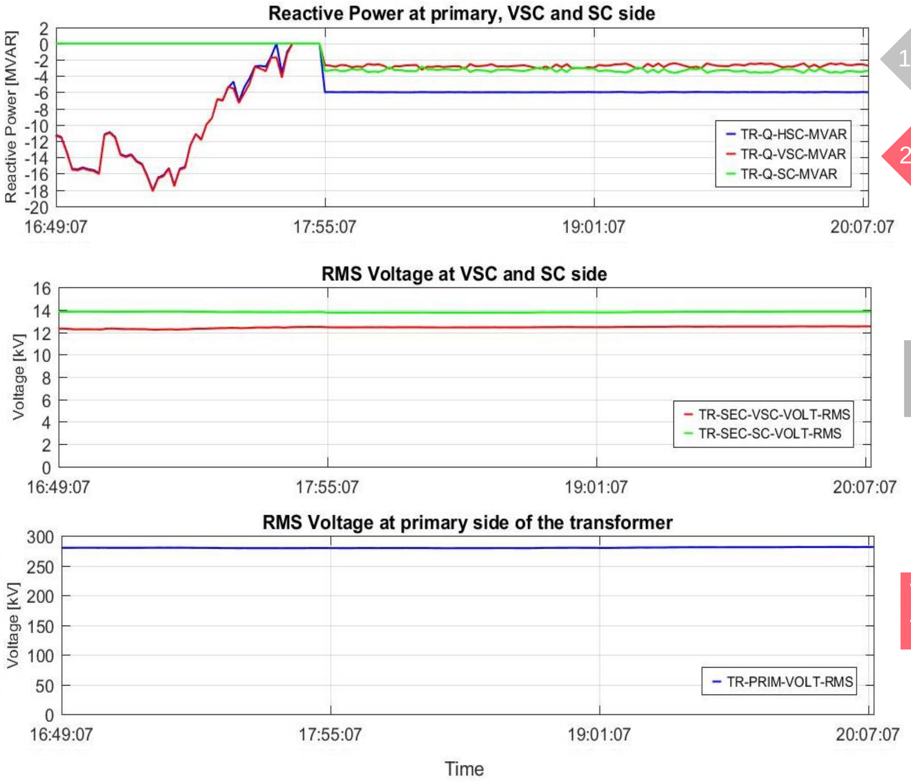
Power Loss Minimization (PLM)

Calculation of optimized slopes (in automatic mode) or optimized Q setpoints (in manual mode) for both the STATCOM and the SC, so that the total losses of the H-SC become the minimum possible



STATCOM Q control
SC Q control
Qref =6 MVAr
PLM ON

Mode 2 / Case 1: PLM test 1 under Var control mode (4th December 2020 – 17:55)

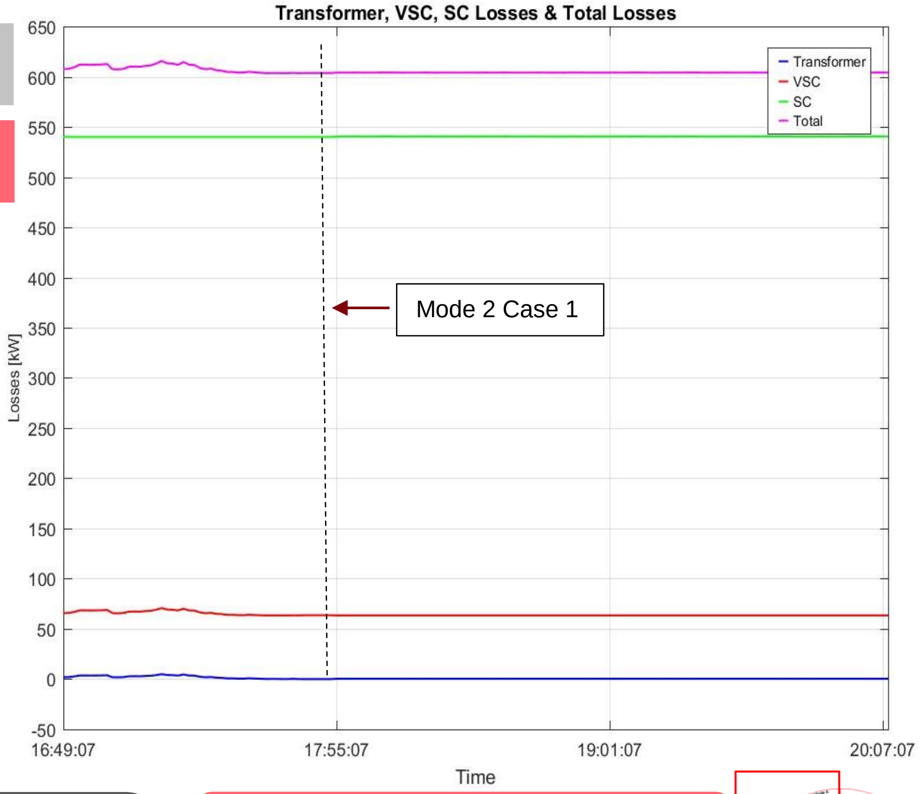


1 STATCOM & SC operate in VAr control mode

2 At 17:53, STATCOM & SC Q reference is changed and PLM is ON

3 STATCOM and SC losses are minimized at 63,4 kW and 540 kW

4 The total losses of STATCOM, SC and transformer are 604 kW



- ✓ The PLM function is verified with equal distribution of reactive power .
- ✓ The aim was to set non-zero reference for STATCOM reactive power output and zero SC before turning on PLM in order to investigate the impact of the power loss minimization.
- ✓ H-SC has a stable operation during the performance of the test.

Total Loss
1. **PLM ON- 604 kW**
2. **PLM OFF -616 kW**

Hybrid Operation of STATCOM and SC

- **Case 1: Change voltage setpoint of H-SC**
- Case 2: Change reactive power setpoint of SC

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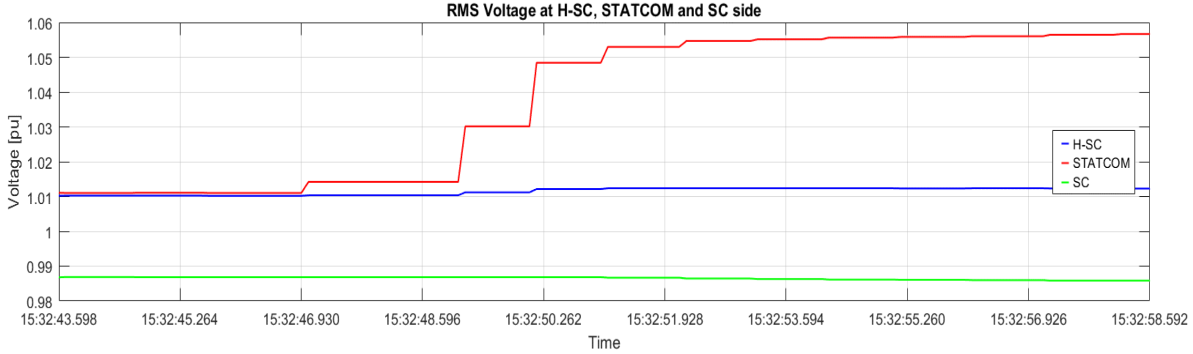
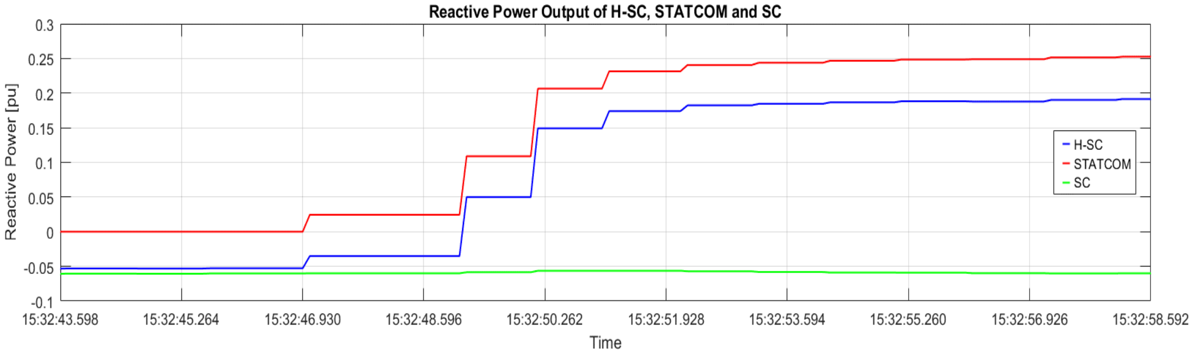
Mode 3 / Case 1: Change voltage setpoint of H-SC (25th March 2021, 15:32)





STATCOM V control
SC Q control
Vref = 1,01 pu

1. At 15:32, H-SC voltage setpoint is set equal to 1,02 pu
2. STATCOM voltage ramps up from 1,01 pu to 1,055 pu within 5 s
3. STATCOM reactive power peaks at 0,25 pu (35 MVAr)
4. SC operating in VAr control stays closed to its initial steady state

- ✓ The test verifies a well performed change of the voltage setpoint at H-SC side
- ✓ H-SC has a stable operation during the performance of the test

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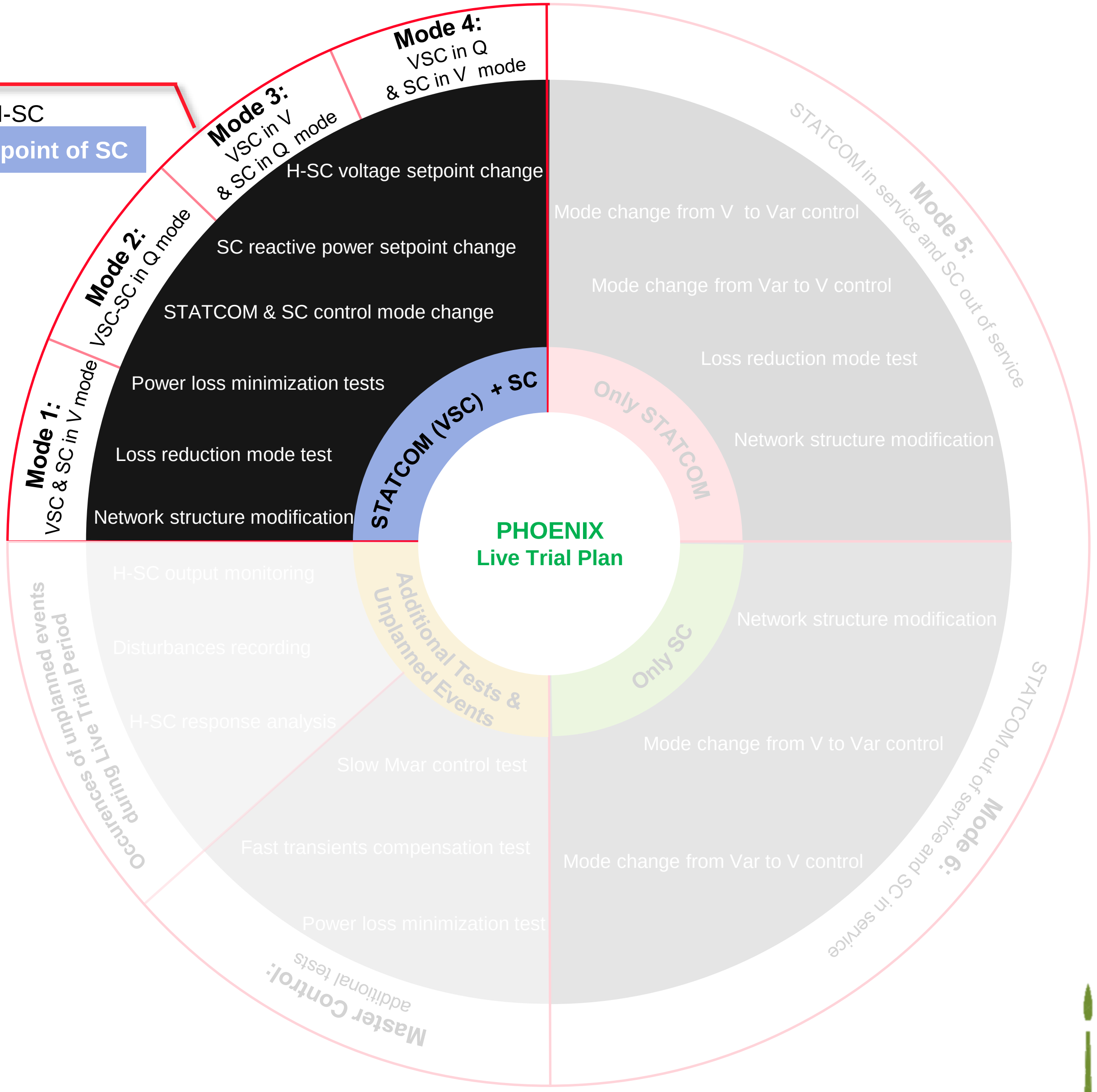
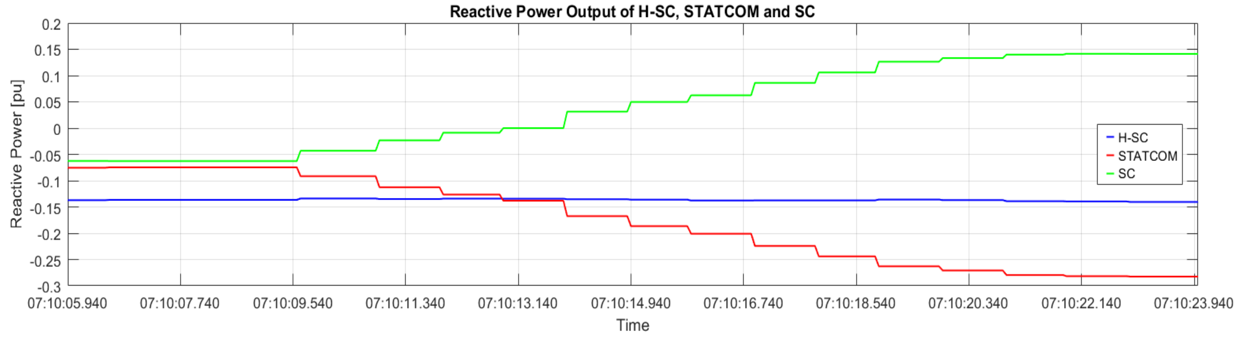
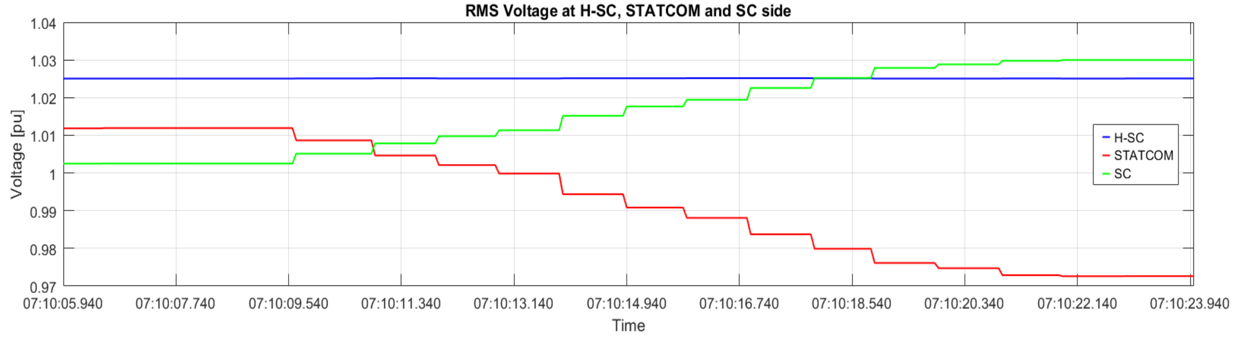
Hybrid Operation of STATCOM and SC

- Case 1: Change voltage setpoint of H-SC
- **Case 2: Change reactive power setpoint of SC**



Mode 3 / Case 2: Change reactive power setpoint of SC (27th March 2021, 07:10)



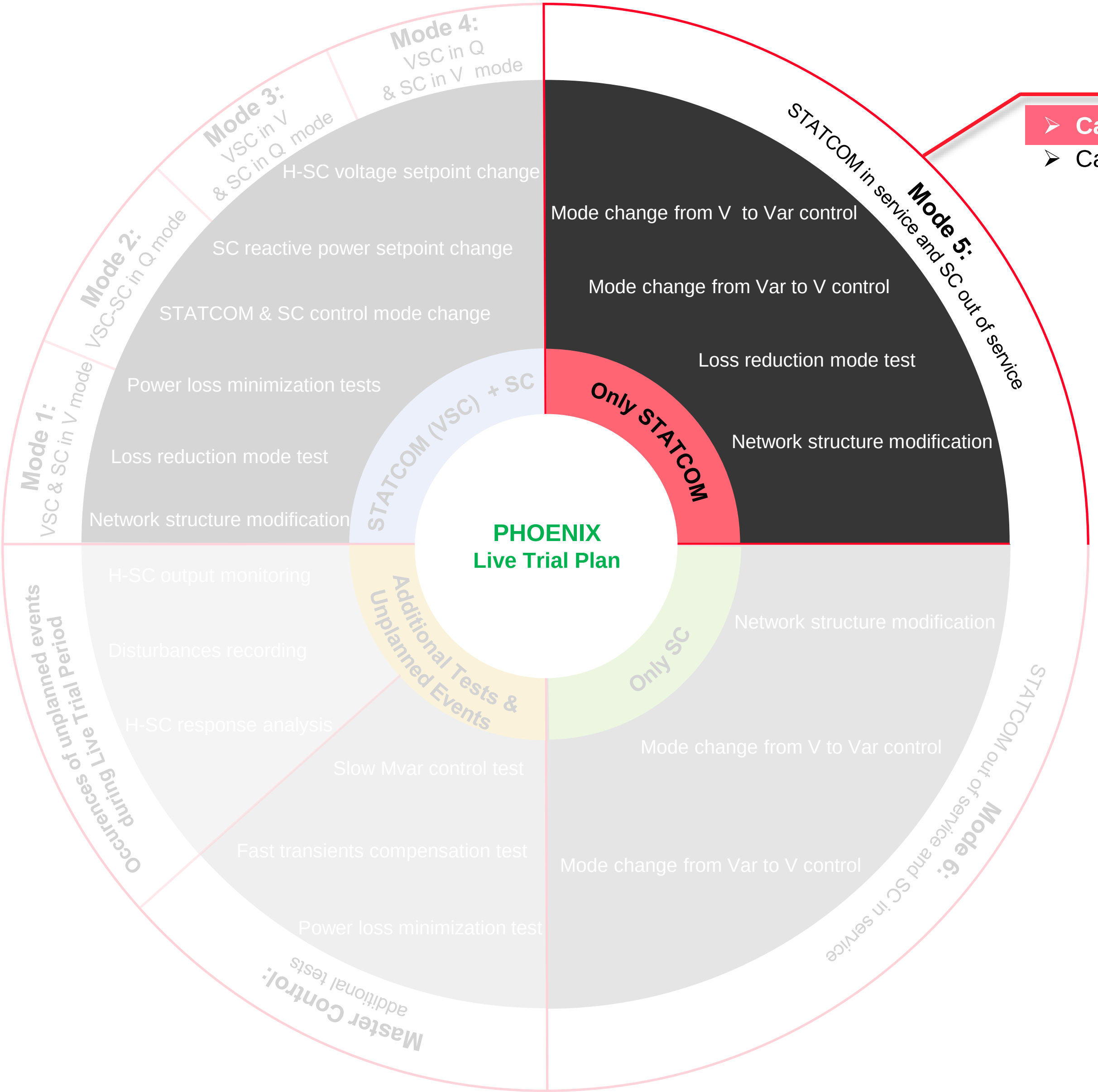


1. **At 07:10, SC reactive power setpoint is set equal to 0,143 pu (20 MVAr)**
2. **Within 13 s, SC reactive power ramps up from the inductive to capacitive area reaching 0.148pu**
3. **STATCOM voltage decreases to keep the set value stable**

STATCOM V control
SC Q control

- ✓ The test verifies a well performed change of SC reactive power setpoint
- ✓ H-SC has a stable operation during the performance of the test

Only STATCOM in Service

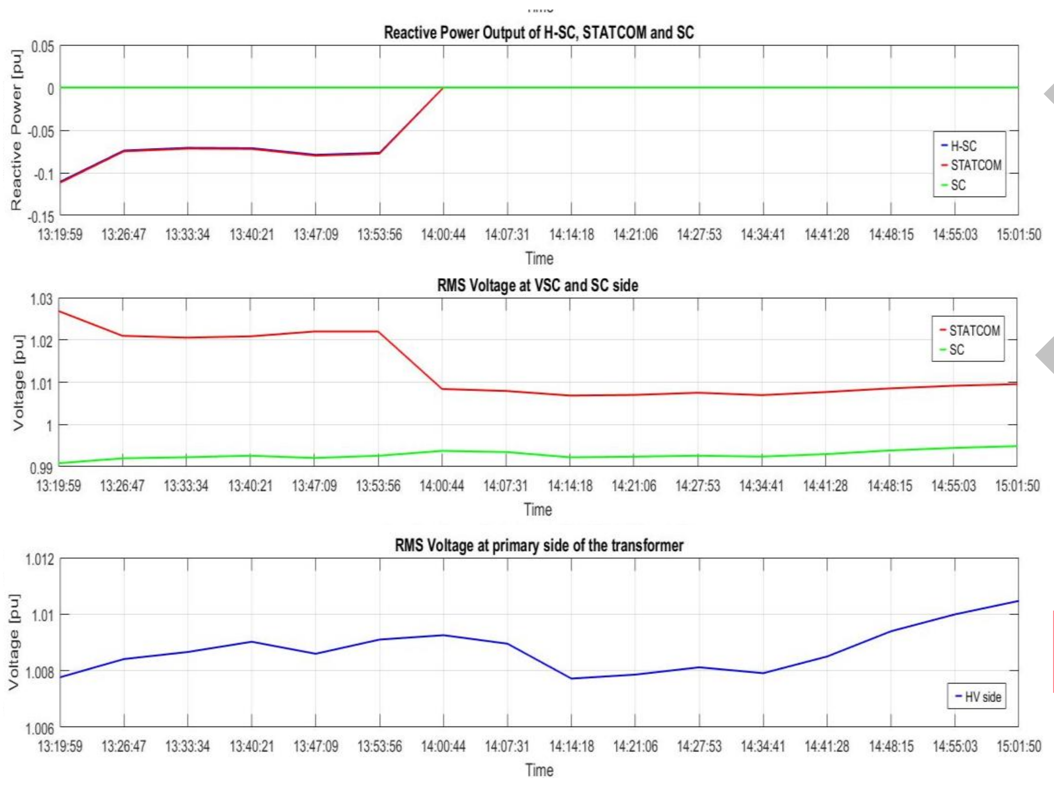


- **Case1: STATCOM mode change from V to Var control**
- Case2: STATCOM mode change from Var to V control

Only STATCOM in Service

STATCOM V to Q control
Vref =1 pu
Qref=0 MVAr

Mode 5 / Case 1: mode change from V to VAr control (3rd February – 13:54)

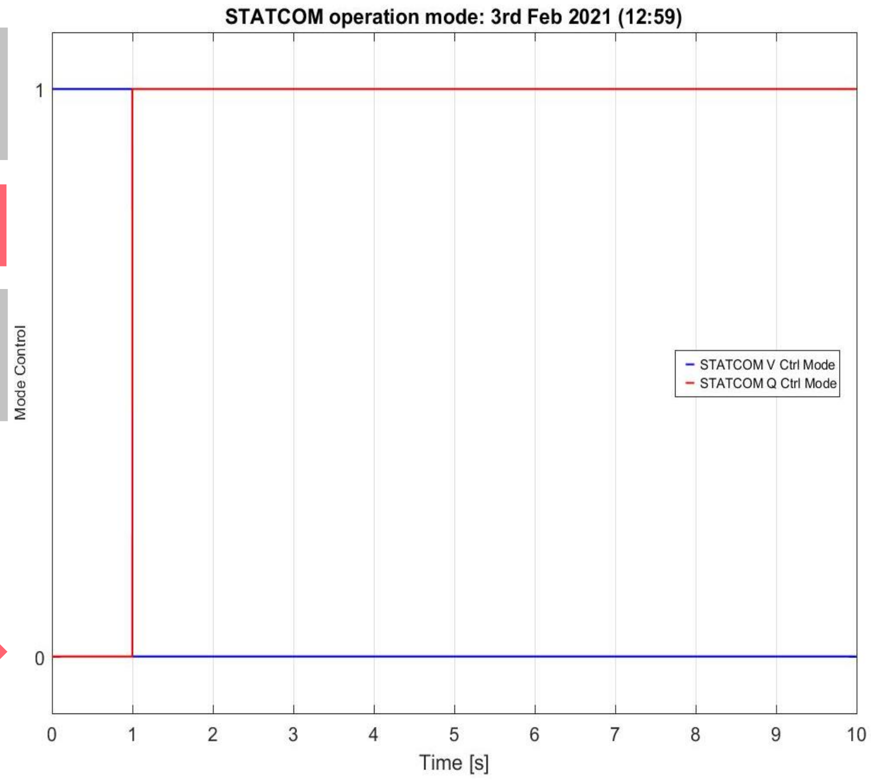


1 At 13:54, the operation mode of STATCOM is changed from V to VAr control mode

2 The new Q setpoint is equal to 0

3 Before 13:54, STATCOM injects reactive power, as the voltage at its side in pu is higher than the voltage in pu at H-SC side

TFR data shows the change of STATCOM control mode 4



- ✓ The test verifies the correct performance of the mode change.
- ✓ H-SC has a stable operation during the change.

Only SC in Service

- **Case1: Change of SC operation mode from V to VAr control**
- Case2: Change of SC operation mode from VAr to V control
- Case3: Change of network structure with SC in V control mode

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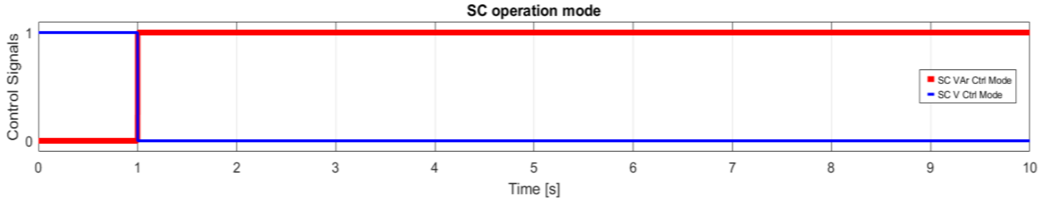
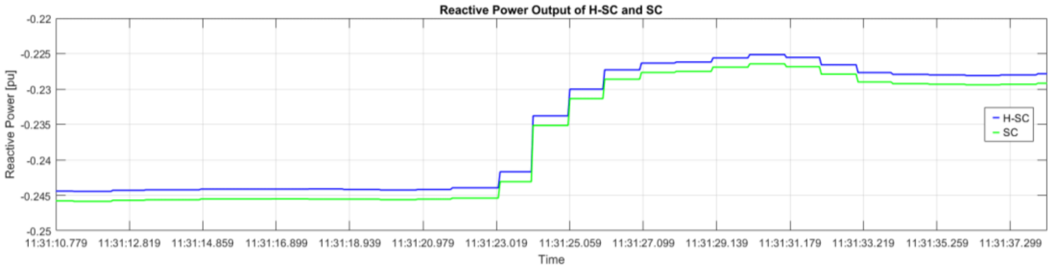
Mode 6 / Case 1: change of SC operation mode from V to VAr control (11th May – 11:31)





SC V to Q control
Vref =1.01 pu
Qref=32 MVAr

1. At 1 s SC operation mode changes from voltage to reactive power control
2. The voltage reference for H-SC is always the same and equal to 1,01 pu
3. The voltage on SC side stays closed to 0,97 pu
4. H-SC reactive power setpoint changes at (11:31:22) to 31,9 MVAr, inductive (-0,228 pu) and it is reached 90% of the final value within 3-4s
5. SC operating in VAr control mode absorbs lower reactive power equal to -0,226 pu (31,64 MVAr inductive)

- ✓ The test verifies the correct performance of the mode change.
- ✓ H-SC has a stable operation during the change.
- ✓ SC reaches 90% of the final value in reactive power within 3-4 s

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Only SC in Service

- Case1: Change of SC operation mode from V to VAr control
- Case2: Change of SC operation mode from VAr to V control
- **Case3: Change of network structure with SC in V control mode**

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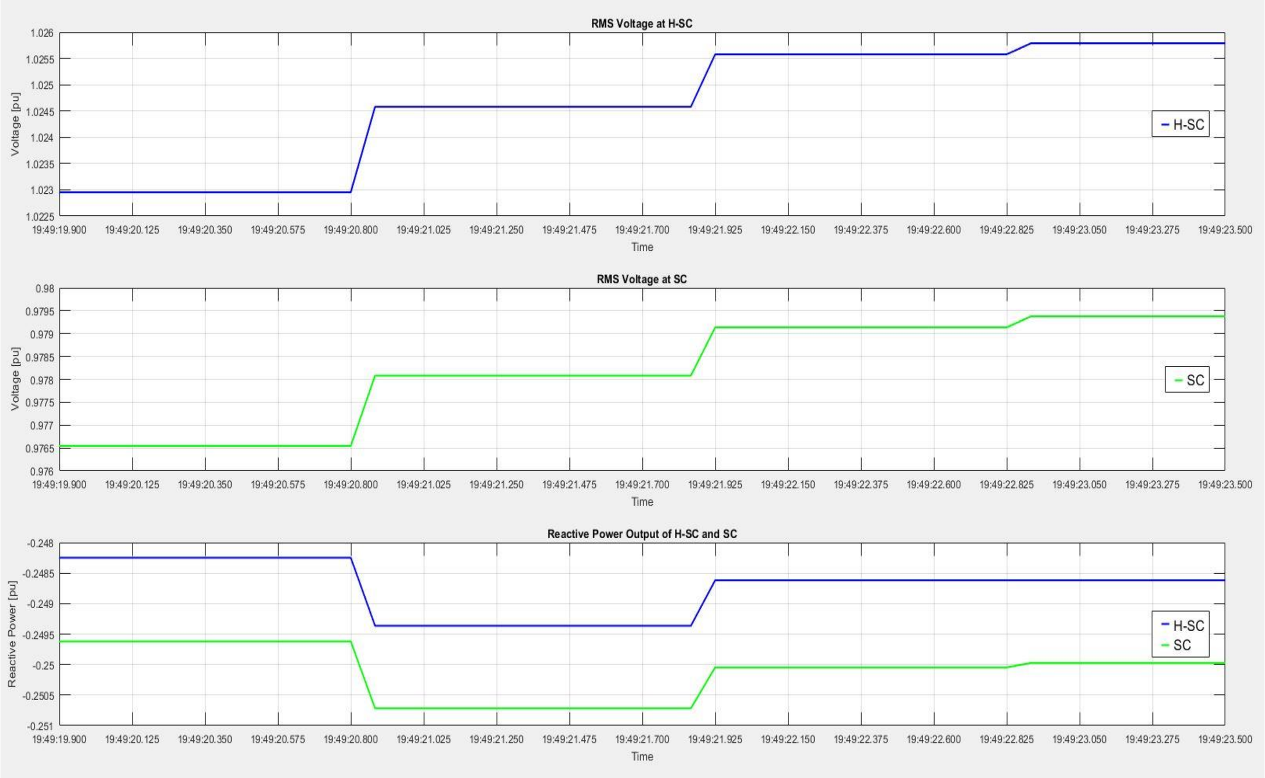
Mode 6 / Case 3: Change of network structure with SC in V control mode (14th May – 19:49)



1 The voltage at H-SC side increases from 1,023 pu to approximately 1,0256 pu in 2 s

SC V control
Network change

2 As a response, SC absorbs slightly higher reactive power

3 SC reactive power output is stabilized at 35 MVAr (-0,25 pu)

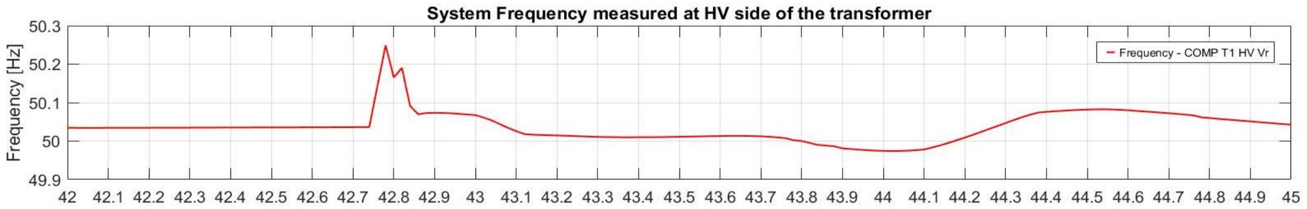
- ✓ The test verifies the correct performance of the SC.
- ✓ H-SC has a stable operation during the change.

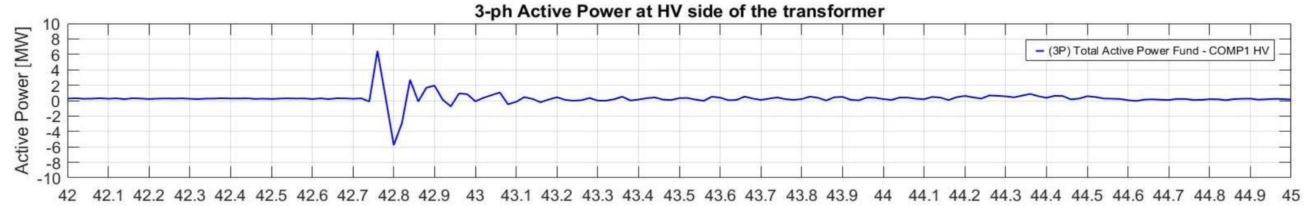
Unplanned Events

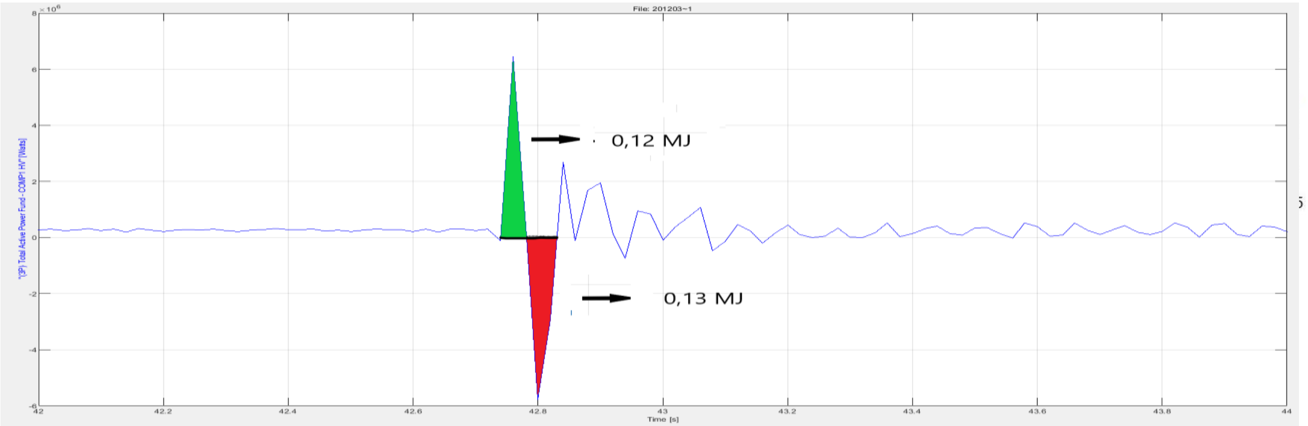
- **HVDC link Response due to external fault**
- 275 kV Fault (East Scotland)
- 132kV Network Fault
- Shunt Reactor switched OUT
- Trip & DAR of a circuit in north Scotland

HVDC link response due to external fault (3rd December - 09:06) – Only STATCOM in service

STATCOM Q control
Frequency event







1 STATCOM is in service during the unplanned event

2 System frequency disturbance occurs due to external fault

3 Active power is injected from STATCOM, and its peak is around 5 ms

4 STATCOM absorbs positive energy that is dissipated during the negative swing of the frequency

- ✓ An HVDC link response due to external fault leads to a frequency disturbance.
- ✓ H-SC responds as expected to the disturbance.

Unplanned Events

- HVDC link Response due to external fault
- 275 kV Fault (East Scotland)
- 132 kV Network Fault
- **Shunt Reactor switched OUT**
- Trip & DAR of a circuit in north Scotland

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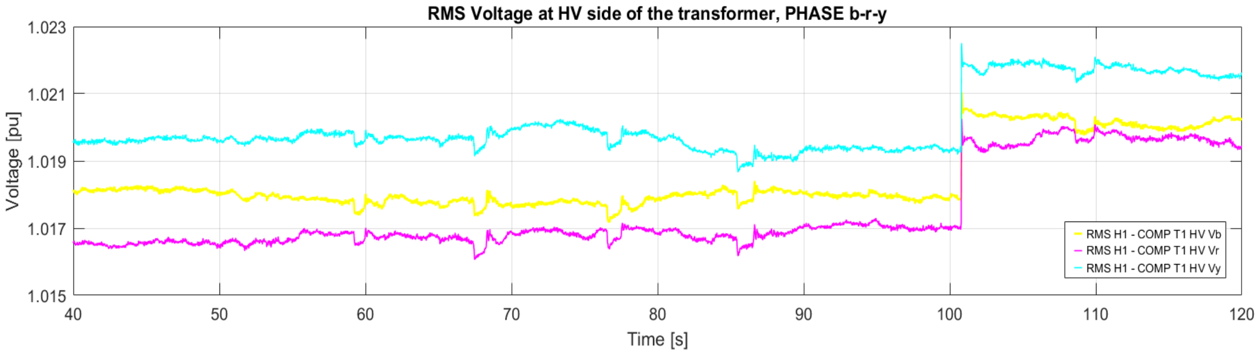
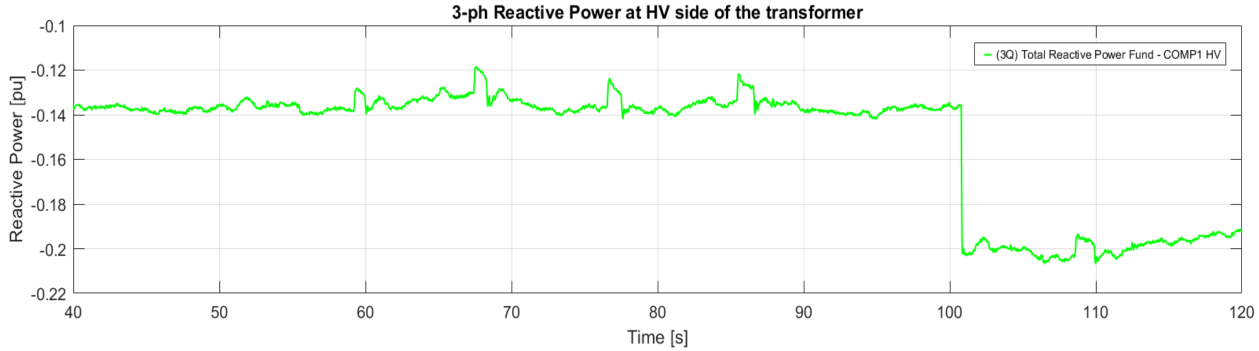
Shunt Reactor switched OUT (9th February, 11:34) – Only STATCOM in service

STATCOM V control
Vref=1.02 pu
Reactor switched OUT



1 The phase to ground voltages on the HV side of the transformer step up



2 This implies an increase of the inductive reactive power of H-SC

3 STATCOM is in voltage control mode

- ✓ A switching event of shunt reactor causes a voltage step at H-SC side.
- ✓ H-SC responds as expected to the disturbance.

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Unplanned Events

- HVDC link Response due to external fault
- 275 kV Fault (East Scotland)
- 132 kV Network Fault
- Shunt Reactor switched OUT
- **Trip & DAR of a circuit in north Scotland**

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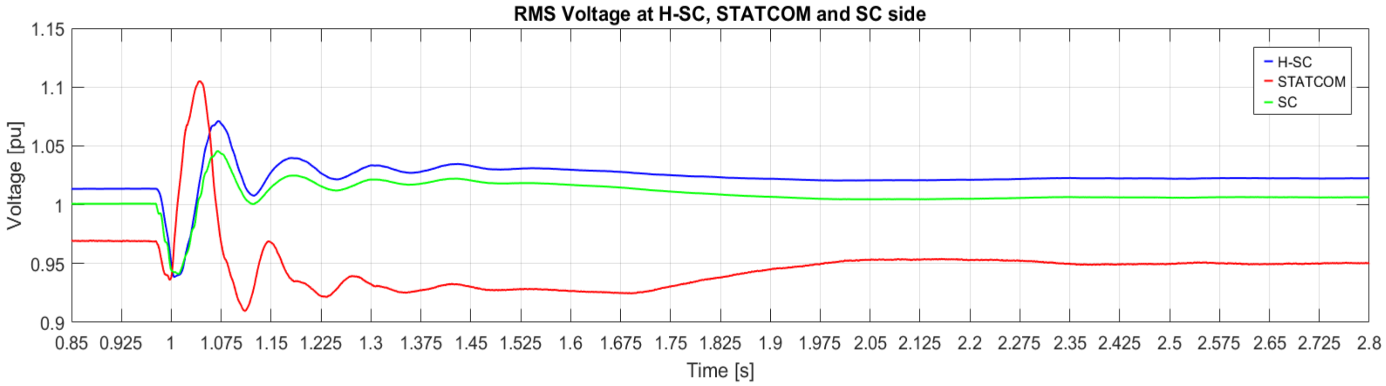
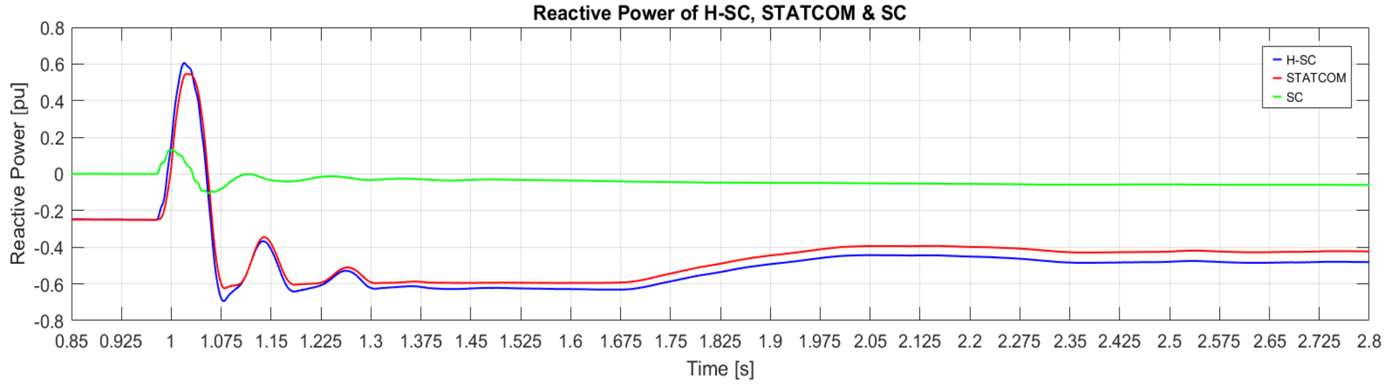
Trip & DAR of a circuit in north Scotland causing 800MW loss (4th Apr, 22:13) – Full H-SC in service.





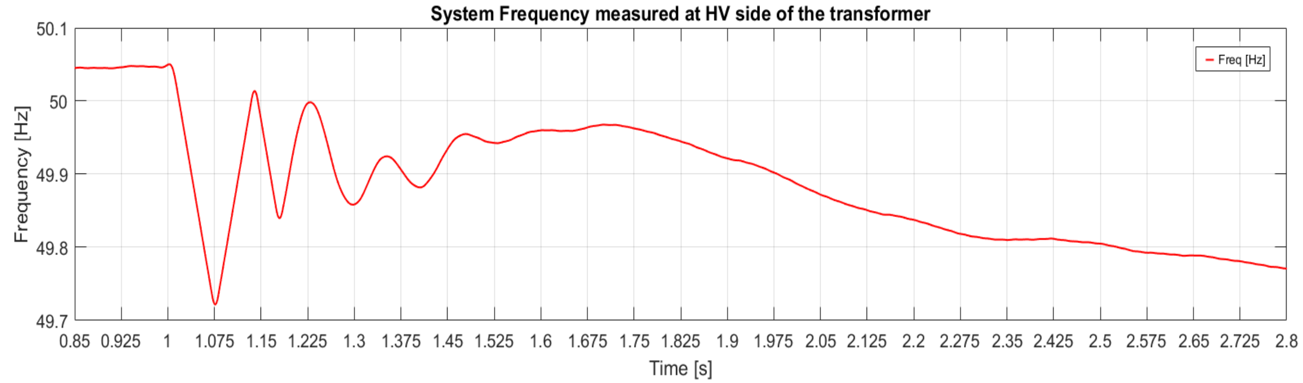
1 A voltage drop at primary side is observed due to the trip

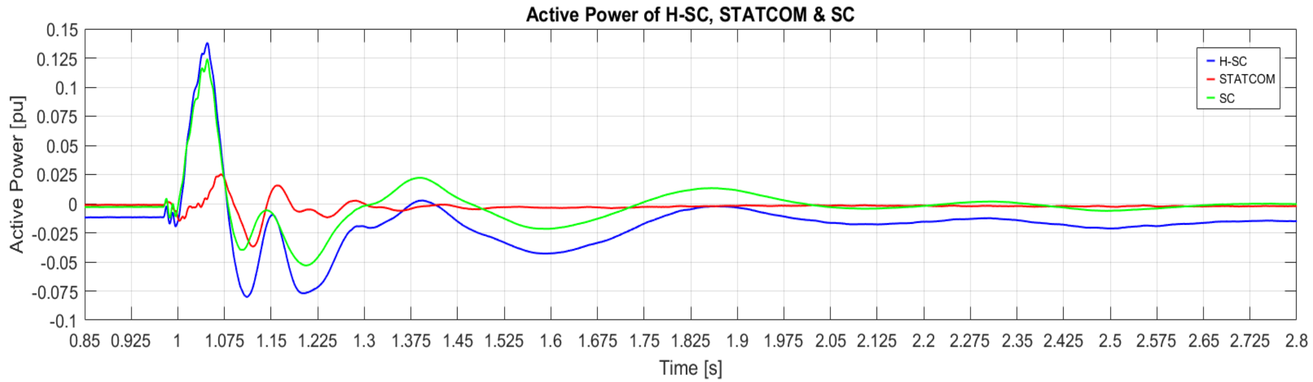
STATCOM V control
SC Q control
Vref= 1.0
Qref= 0

2 As a response, H-SC injects reactive power to the grid

✓ As a response to the voltage drop, H-SC injects reactive power to the grid.

Trip & DAR of a circuit in north Scotland causing 800MW loss (4th Apr, 22:13) – Full H-SC in service.





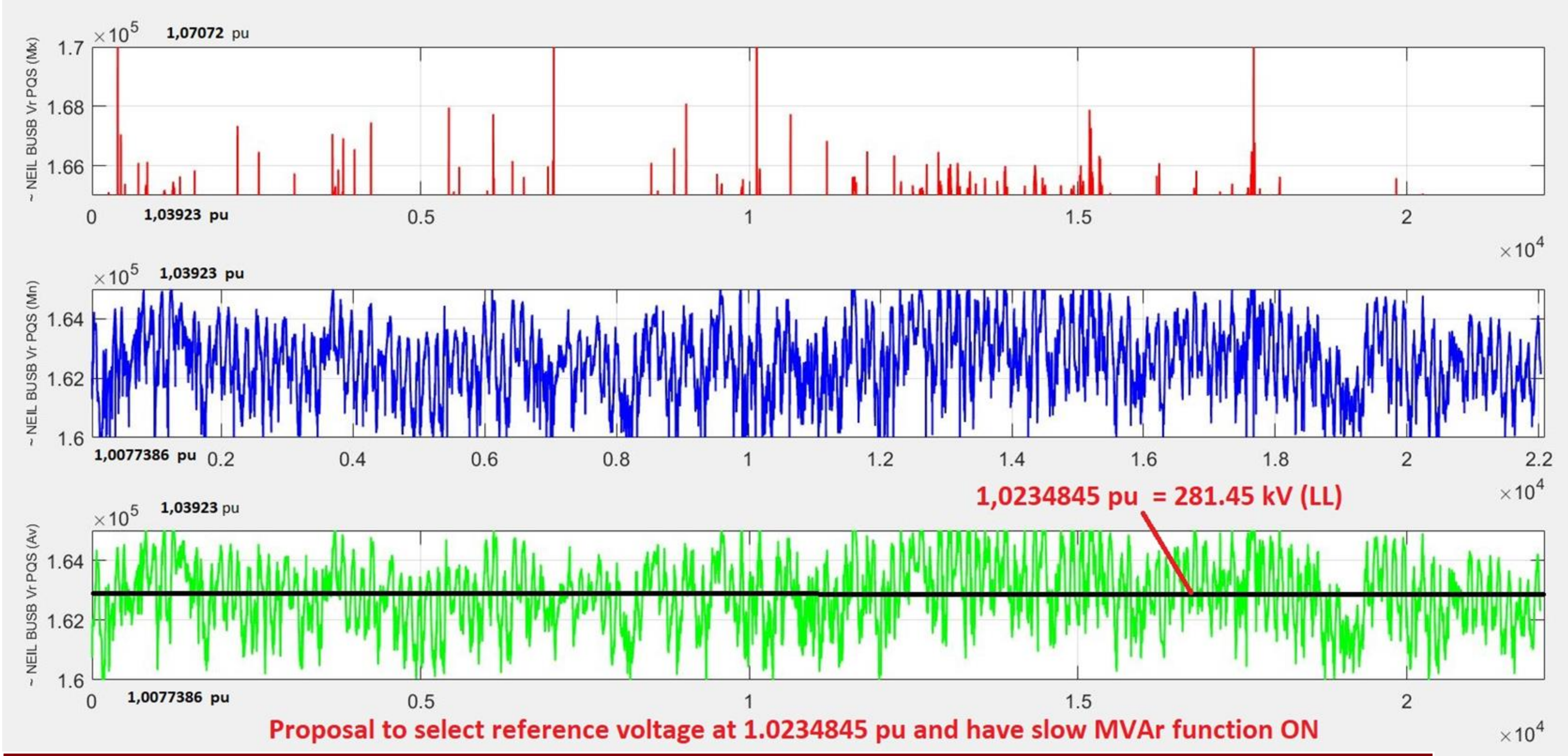
1 Frequency drop at primary side is observed due to the trip

STATCOM V control
SC Q control
Vref= 1.0
Qref= 0

2 As a response, H-SC injects active power to the grid

✓ As a response to frequency drop , SC supports with maximum inertial output (17.8 MW of 19.5 MW peak reached in 40 ms)

Voltage Profile and Reference



The voltage profile is investigated for a longer time span to identify HSC voltage setpoints

Conclusions

Setpoint and Change and Control Mode Verification

- HSC achieved the expected values in stable manner
- Speed of STATCOM control as expected and good
- SC response is slow during setpoint change due to communication delay and ramp rate limiter
- SC response in unplanned events are much faster compared to set point changes and more validations are planned

Unplanned Events

- HSC responded as expected and contributed with reactive support
- Active power injection from STATCOM in frequency event

Verification of Master Controller

- All master controller functions are verified
- The distribution of reactive power, loss minimization in various operation worked as expected

TFR and additional tests

- TFR setting has been adapted to capture setpoint change and control mode change
- In some cases, TFR data has not been captured
- More test cases with only SC mode and master controller verification

Collaboration and Reporting

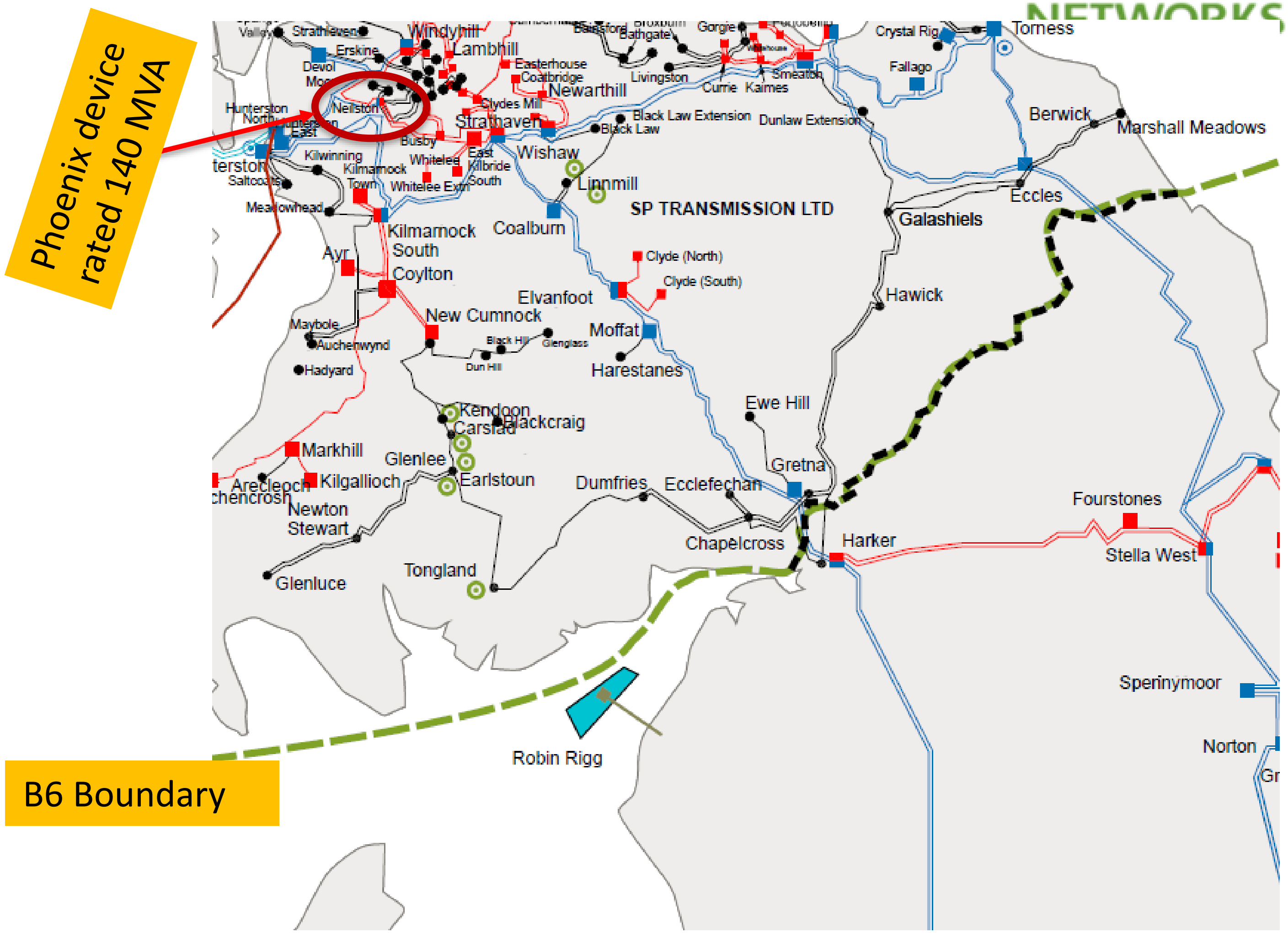
- Weekly Meeting with SPEN and Monthly meeting including National Grid
- Monthly report with test cases and unplanned events
- Biannual and Annual report with summarizing live trial

Interval – 10 minutes

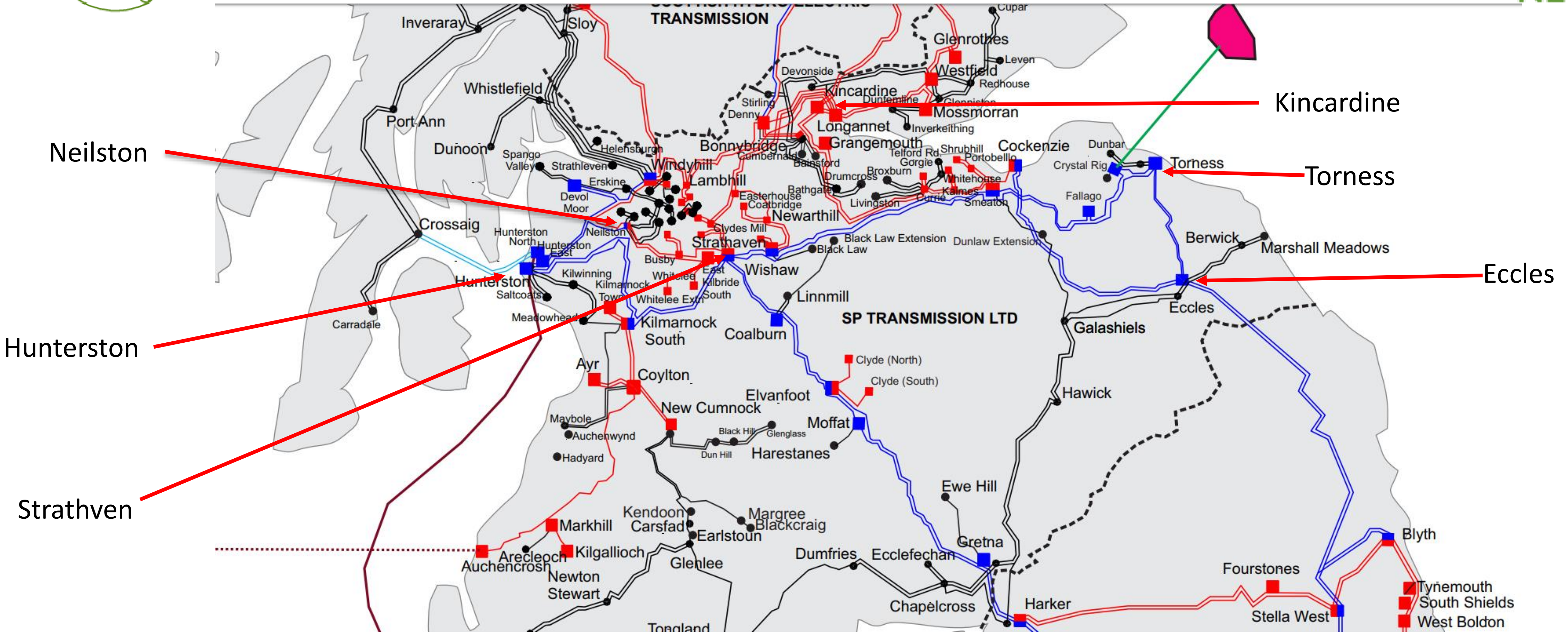
National Grid – Jay Ramachandran

B6 Boundary Analysis – Single Device at Neilston Location

- B6 boundary analysis has been carried out using 2017 ETYS model
- Generation and demand background is based on FES 2018 scenarios
- Analysis carried out for 2019, 2023 and 2027 network background
- Analysis carried out for the following options:
    - Synchronous Condenser (140 MVA)
    - STATCOM (140 MVA)
    - SC and STATCOM without hybrid (70 MVA SC and 70 MVA STATCOM)
    - Hybrid Synchronous Compensator (70 MVA SC and 70 MVA STATCOM)
- There are several NOA options that have been proposed in recent years but are not included in the analysis
- The analysis has been repeated assuming 280 MVA and 420 MVA devices



- B6 boundary transfer is limited due to voltage collapse limit
- STATCOM provides more boundary transfer benefit than other options, as fast dynamic reactive support available from STATCOM.
- H-SC provides same level of benefit as SC and STATCOM together (without master control).
- H-SC is more economical as a lower number of transformers are used compared with SC and STATCOM together (without master control) option.
- H-SC response time is better than SC only option.
- The most economic size, for this case, is about 280 MVA (for an H-SC, 140 MVA SC and 140 MVA STATCOM).
    - Analysis has been repeated for 280 MVA and 420 MVA rating
- The economic benefit is much higher in the years 2024 to 2029 (After Hunterston closure, before eastern HVDCs installed)



In addition to Neilston location, the above five locations are assumed to have Phoenix device installed.

Key Findings from Multiple Devices in SPT Region

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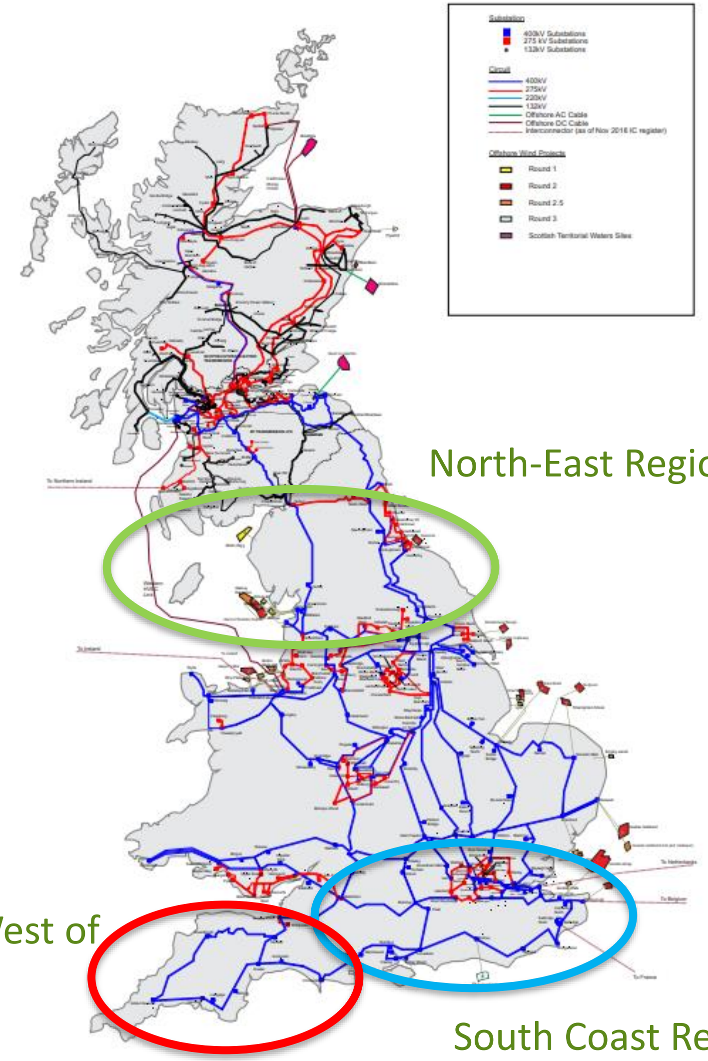
- After Hunterston closure, system SCL decreases and WHVDC loading is reduced.
- With single device at Neilston, SCL contribution from SC is not enough to load WHVDC to full rating
- Installing SC at selected 6 locations in SPT region, increases the system SCL and enough to load WHVDC to full rating.
    - 280 MVA rating SC are sufficient to load WHVDC to full rating in year 2023
    - For 2027 summer period, 420 MVA SC are required
    - Please note that 3 SC in the west side and 3 SC at eastern side is selected in this analysis.
- Addition of H-SC also increases the system SCL and hence improves the WHVDC loading.
- In certain scenarios, H-SC at 6 locations could provide slightly more benefit than SC
    - WHVDC can be loaded fully and H-SC in eastern side could provide faster response than SC
- Addition of STATCOM provides 1p.u. of fault current and hence there is no change in the loading of WHVDC with STATCOM only option.

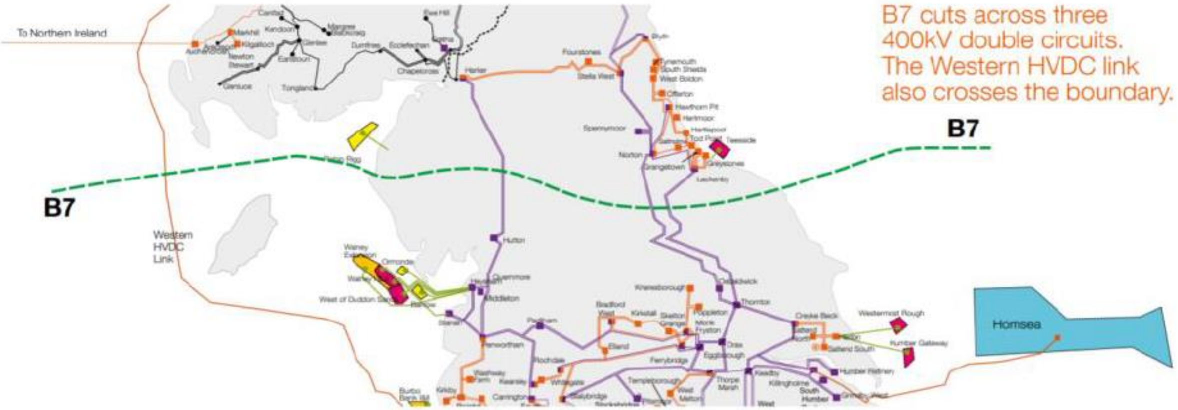
Other GB Locations

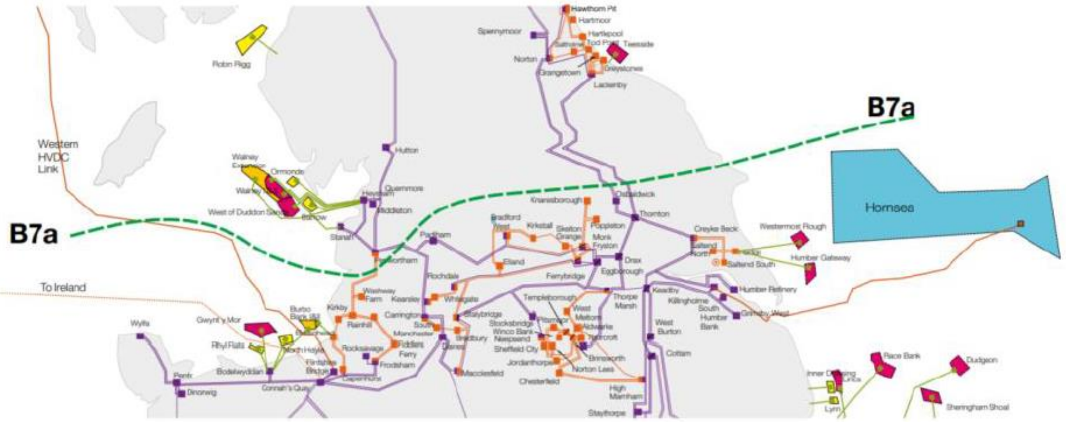


North-East Region

South West of
E&W

South Coast Region



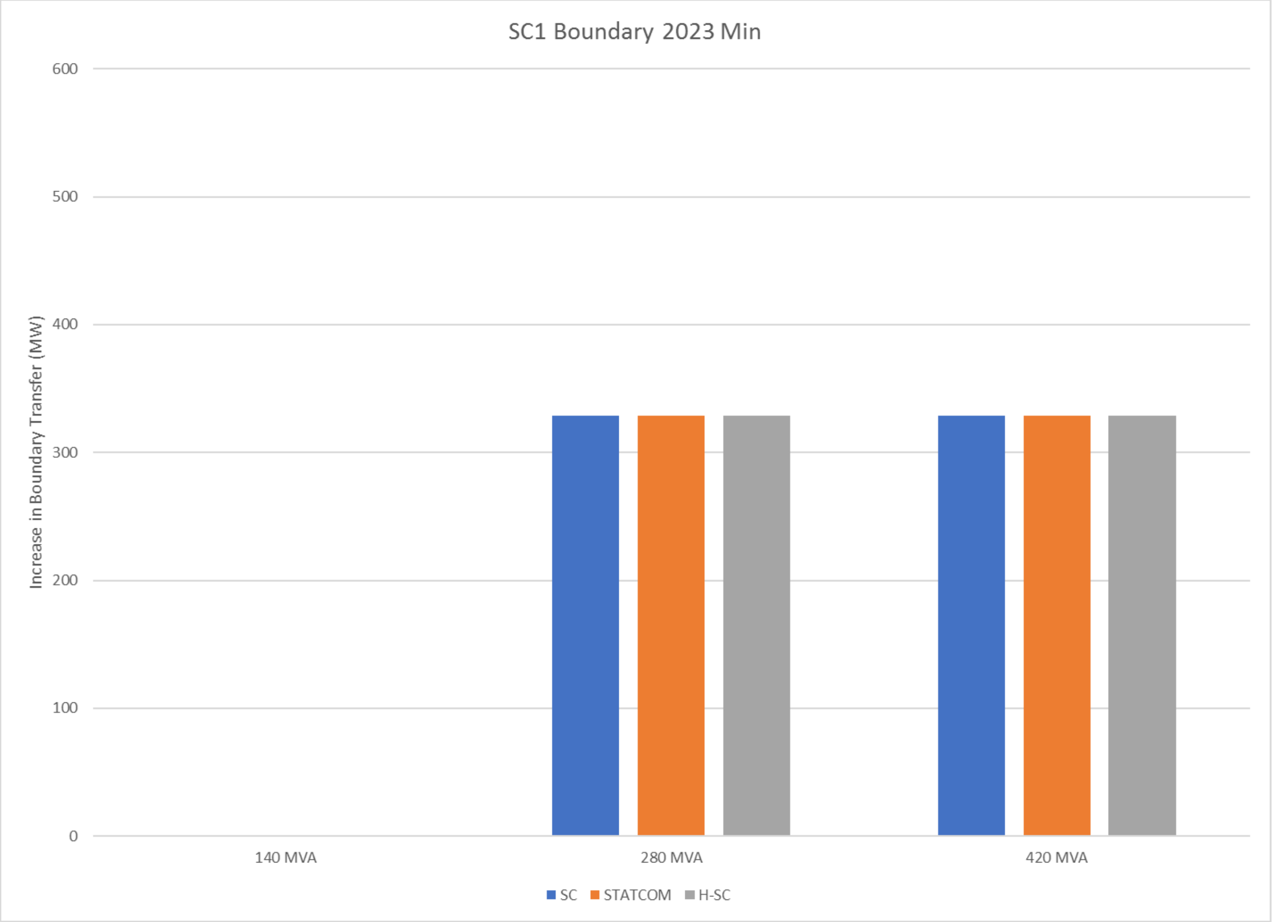


- For North East and North West regions, analysed boundaries B7 and B7a in the region
    - Study background assumptions are the same as in the SPT region analysis
- Assuming STATCOM/SC/H-SC at five different locations in North of E&W region- Heysham, Hartlepool, Spennymoor, Norton and Penwortham
- These locations were selected based on the steady state analysis results and future generation closures
    - This is independent of B6 boundary analysis (no SC/STATCOM/H-SC devices in SPT region)
- For the summer 2023 scenario, B7a has thermal loading as the limiting factor.
- For other scenarios (2023 & 2027), B7 and B7a boundaries have stability as the limiting factor.
- With five H-SCs, B7 boundary transfer could be increased by 40 MW to 460 MW, depending upon the size of the device and scenario.
- With five H-SCs, B7a boundary transfer could be increased by 40 MW to 527 MW, depending upon the size of the device and scenario.

SC1 Boundary

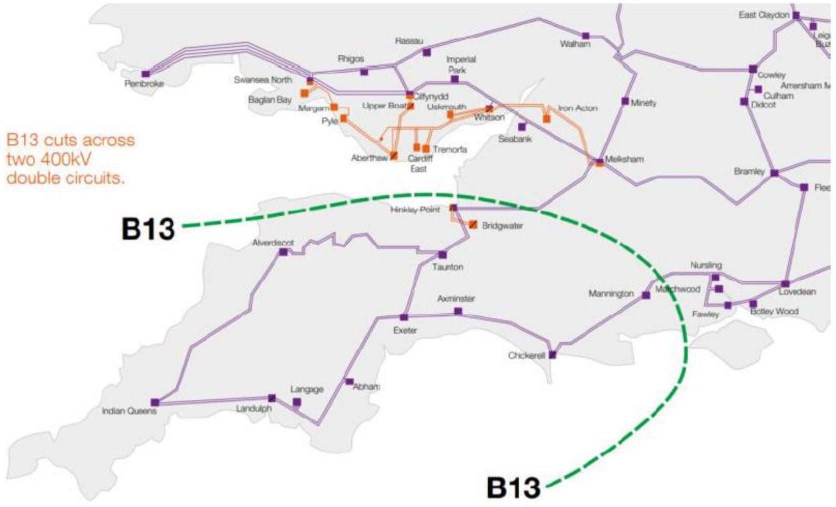
- Assumed 5 different locations in the boundary has devices (SC/STATCOM/H-SC).
- Alverdiscot, Bramley, Dungeness, Exeter, Nursling locations in South Coast boundary are selected.

SC1 Boundary Transfer



- Stability limit is due to the constraint in South-East coast.
- With the addition of 280 MVA, 420 MVA, stability limit increases.
- Beyond this limit, thermal overload is the limiting factor.
- Thermal overload limit is addressed then SC/STATCOM/H-SC options provide further benefit to increase the stability limit.

B13 Boundary



- B13 boundary is limited by thermal overloading, mainly in the DNO networks.
- When thermal loading is addressed, depending upon the solution to address thermal over loading, voltage in the region become limiting factor.
- Then installation of devices could provide additional boundary transfer benefit.

Summary

Region (Boundary)	Summary of H-SC Benefits
Scotland (B6 with single device at Neilston)	A single H-SC device provides better boundary transfer capability than a standalone SC. A standalone STATCOM provides greater benefit than a single H-SC. A single H-SC device (with rating up to 420 MVA) provides insufficient SCL to enable full loading of the Western HVDC, with the assumed generation and network condition.
Scotland / B6 with multiple devices	As multiple H-SCs can enable full loading of the Western HVDC and improve voltage stability, this solution provides greater benefit than multiple standalone STATCOM option. In certain scenarios, multiple H-SCs can provide better boundary transfer capability than multiple standalone SCs. This is due to the faster dynamic response from H-SCs than standalone SCs.
North East & North West (B7 & B7a) with multiple devices	H-SC based solutions are effective at increasing the boundary transfer capability. In certain scenarios, in particular for 2027 networks, the boundary transfer benefit is limited due to transient stability issues in the Scotland region. It could be possible to further increase the boundary transfer if H-SCs are installed in both Scotland and the North of England & Wales.
South Coast (SC1) with multiple devices	H-SC based solutions are effective at increasing the boundary transfer capability, once thermal overload issues are resolved.

Conclusion

- H-SC has response time with Fast Transient Compensation (FTC) is better than SC, slower than STATCOM.
- With a single device, for a boundary with voltage collapse limit, STATCOM provides more benefit than H-SC.
    - H-SC provides more benefit than SC
- For region where existing CSC type HVDC operations limited by SCL, multiple STATCOM provide less benefit than multiple SC and H-SC.
- With the multiple H-SC in this region, SCL could be increased to load CSC HVDC to full rating, H-SC provides more benefit than SC (due to faster response).
- In addition to SCL contribution, H-SC also provides inertia to the system. Hence the benefit from H-SC could be more compared with the STATCOM alone option.
- H-SC could also improve residual voltage, fault ride through capability, power quality (harmonics) and restoration capability
- H-SC is more economical than SC and STATCOM together option (without master control) as only one transformer is used in H-SC.

Interval – 30 minutes

Returning at 12:30 for Session 2

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ScottishPower Group

PHOENIX

SP ENERGY NETWORKS

Phoenix Project
Innovation Testing and Demonstration Webinar

20th July 2021 – Session 2

University of Strathclyde - Dimitrios Tzelepis

Agenda

- Introduction
- Modelling
- Simulation results
- Conclusions
- Publications

Introduction to the Studies

1. Short Circuit Level:

   a) Static SCL analysis

   b) Impact on protection performance

2. System Inertia:

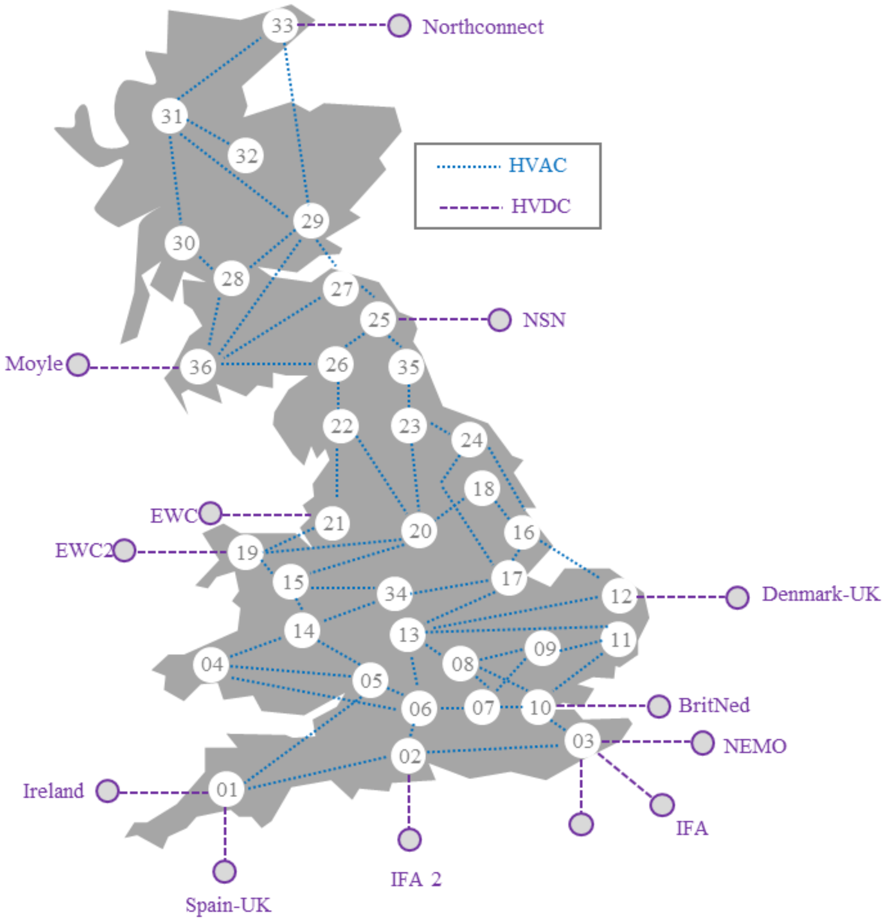
   a) SynCon & BESS scheme

   b) SynCon & EFCC scheme

Studies conducted by UoS considered mainly **SynCon** (standalone) units as the main scope was focused on system inertia and short-circuit level analysis

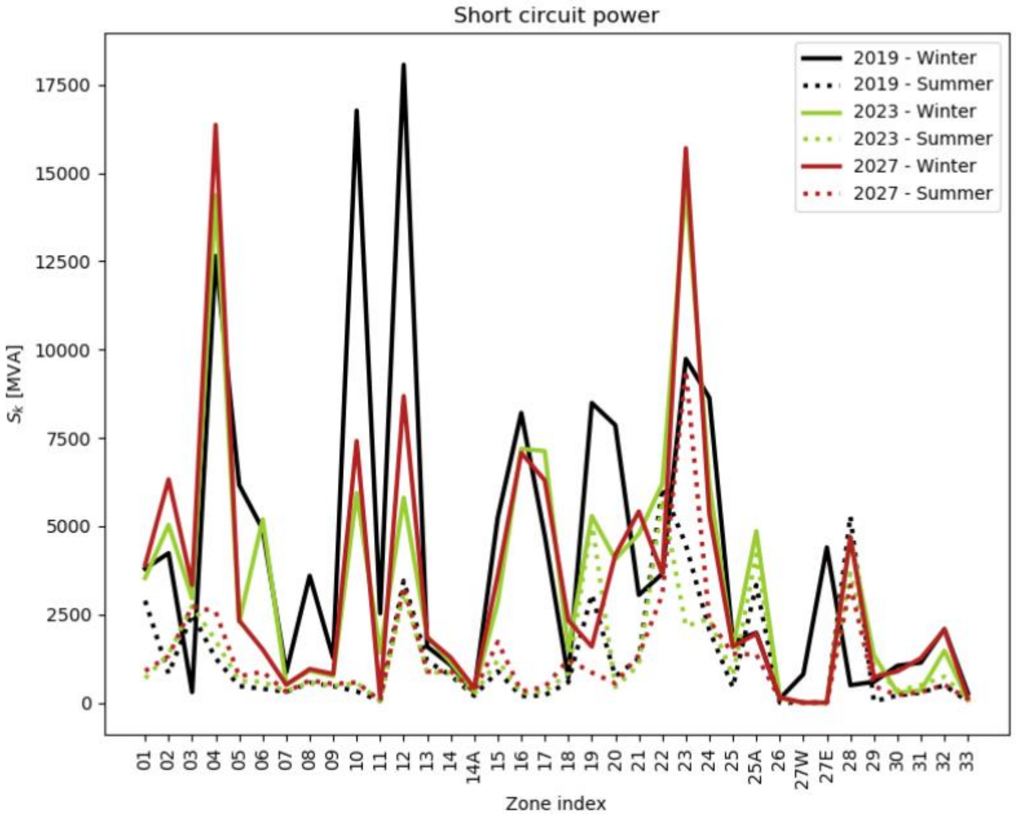
The hybrid H-SC unit was studied mainly on steady state conditions

GB Network Model

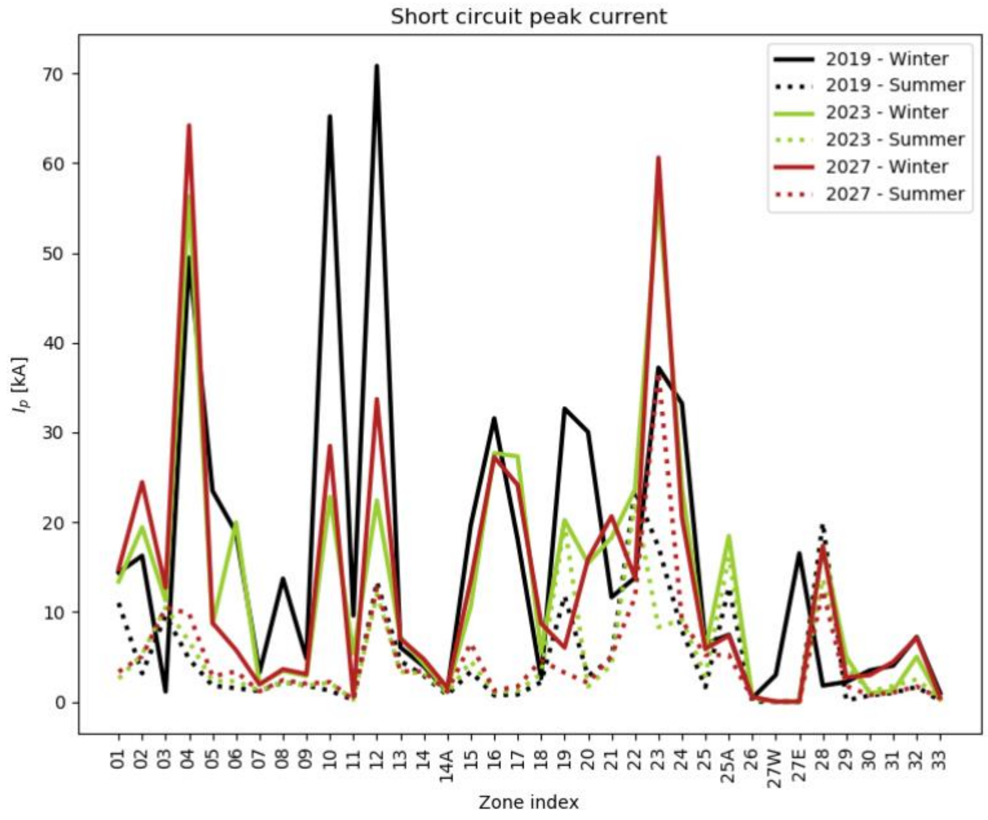


- The system studies have been conducted using the RMS simulation tools in DIgSILENT PowerFactory.
- The model used for the studies is a 36-zone equivalent of the GB transmission network.
- Each numbered zone in the model represents a part of the system and consists of a mix of different energy sources and loads. Generators within each zone are represented by static generators
- and synchronous machines including relevant dynamic controllers. In each zone, generation, loads, HVDC interconnectors and transmission lines are connected to 400 kV busbars.
- In most studies 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.

Static SCL Analysis

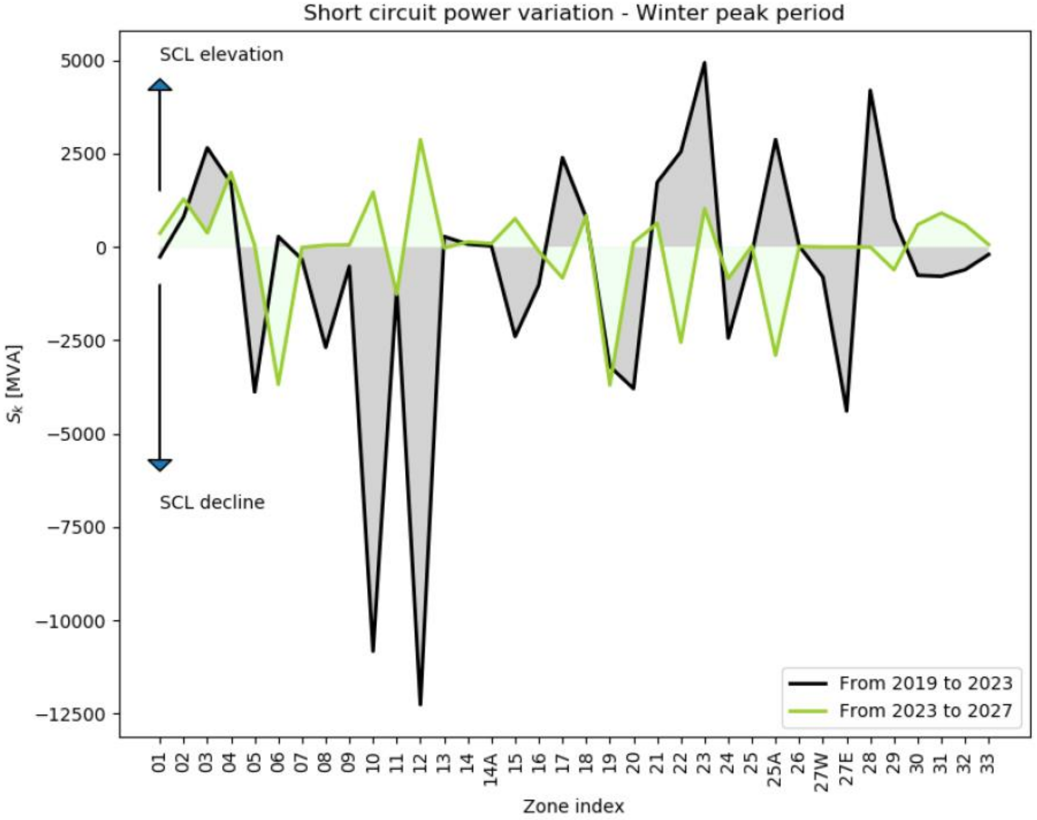


Short circuit level at different zones for different dispatch scenarios.

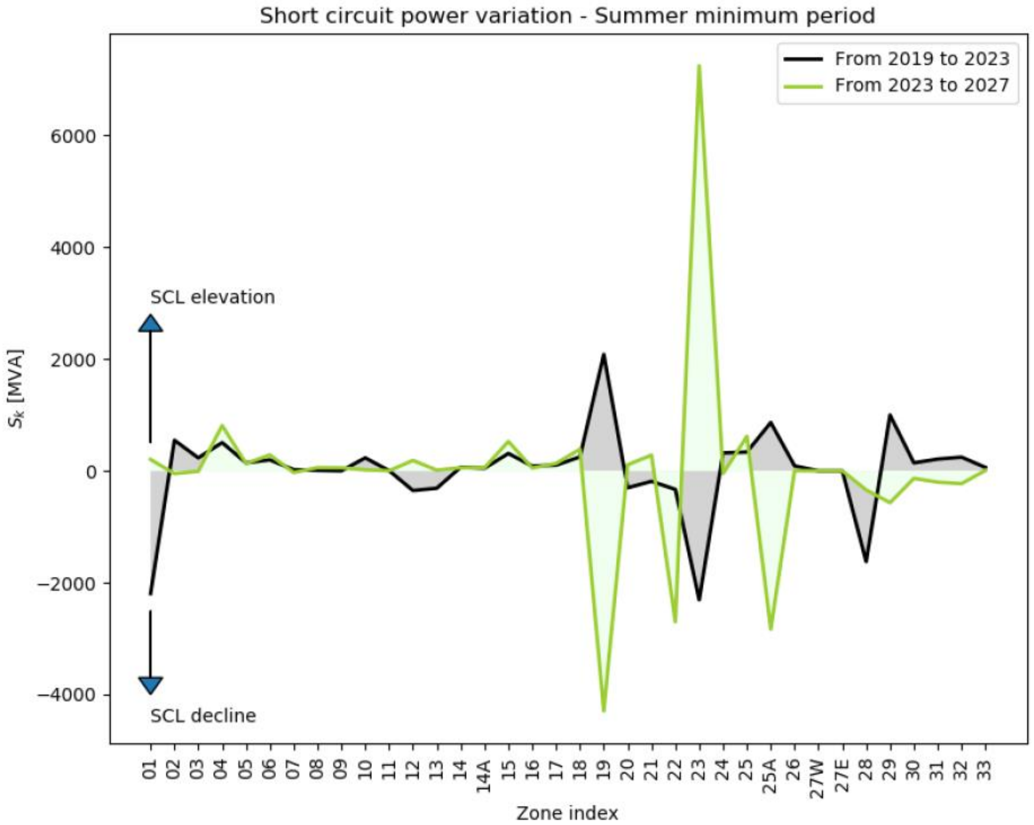


Short circuit peak current at different zones for different dispatch scenarios.

Static SCL Analysis



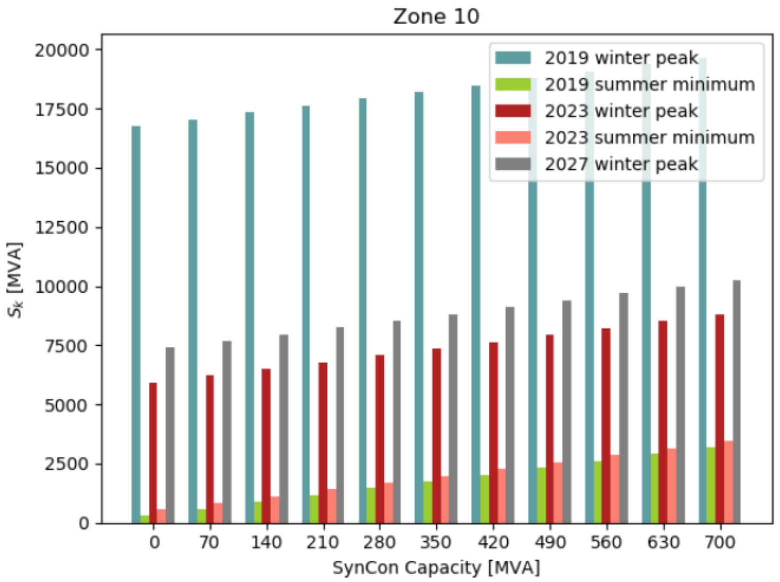
Short circuit level change from 2019 to 2023 and 2023 to 2017 for winter peak period.



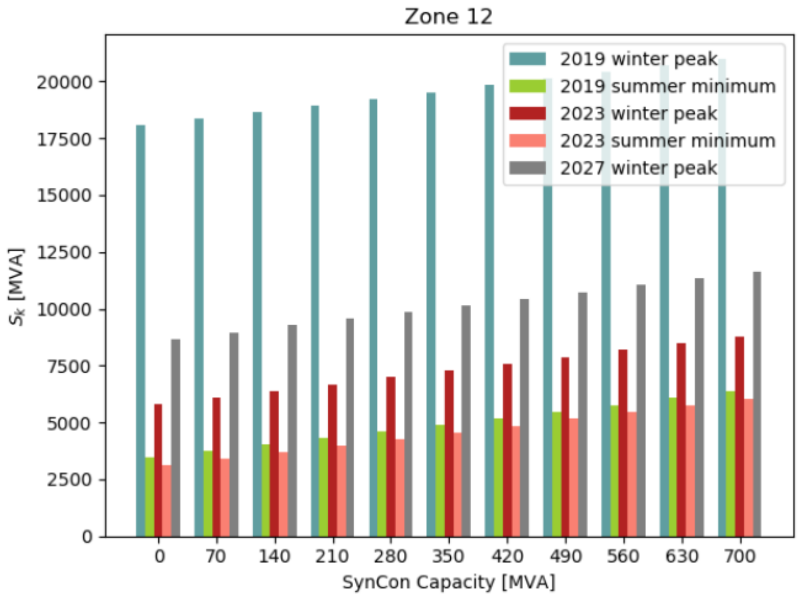
Short circuit level change from 2019 to 2023 and 2023 to 2017 for summer minimum7 period.

Static SCL Analysis

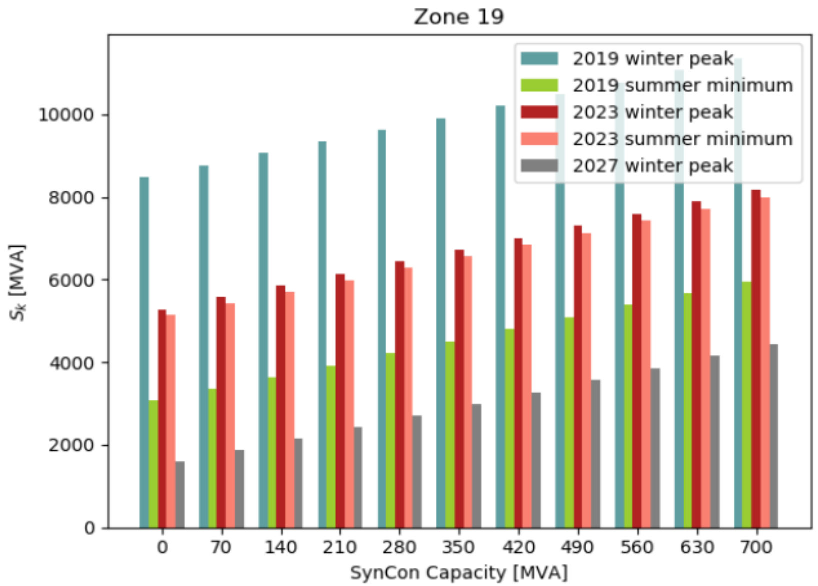
The analysis it has been highlighted that Zones 10, 12 and 19 will be subject to large SCL decline in future energy scenarios (i.e. years 2023 and 2027).



Short circuit power at Zone 10 for different SynCon capacities and different dispatch scenarios.

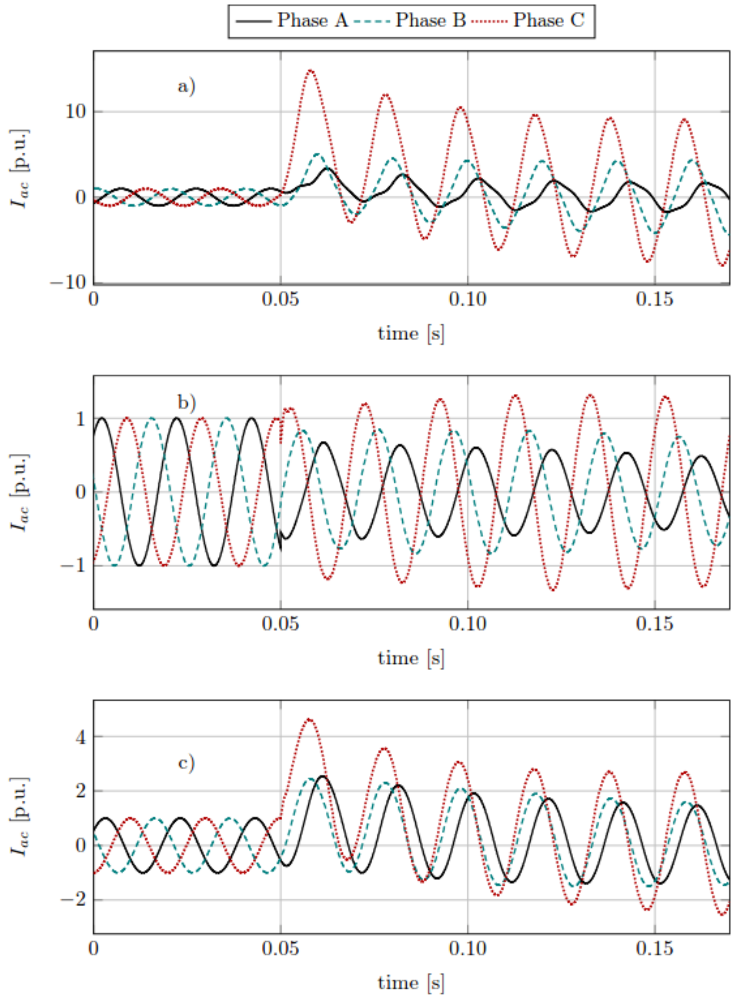


Short circuit power at Zone 12 for different SynCon capacities and different dispatch scenarios.

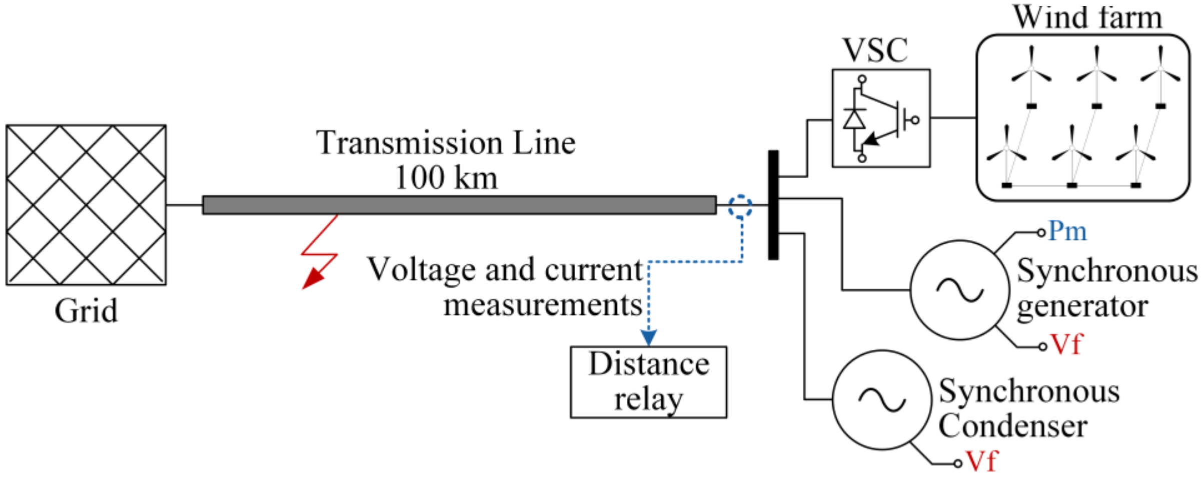


Short circuit power at Zone 19 for different SynCon capacities and different dispatch.

Transient SCL Analysis



Fault current signatures for three-phase transmission line faults for different generation mixes: a) 100% SG, b) 100% ICG, c) 100% ICG + 20% SynCon.



Transmission network illustrating integration of SGs, SynCons and ICG.

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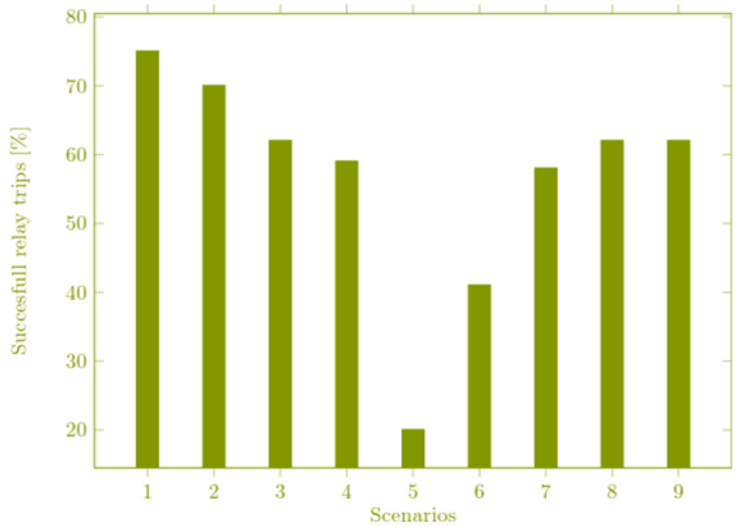
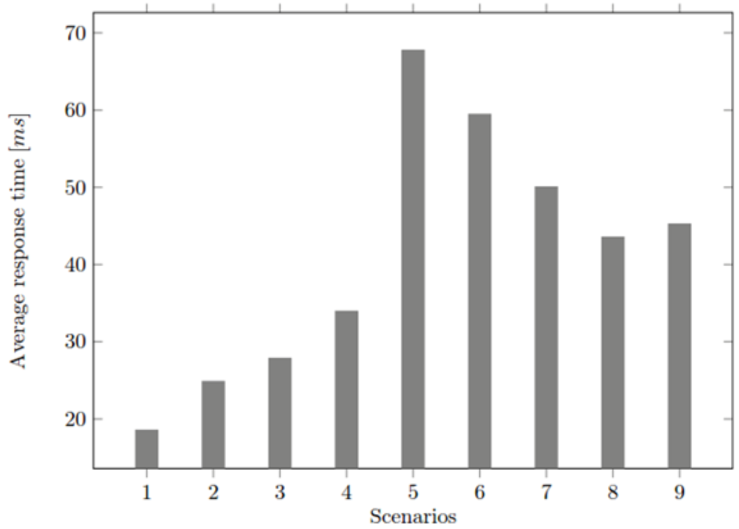
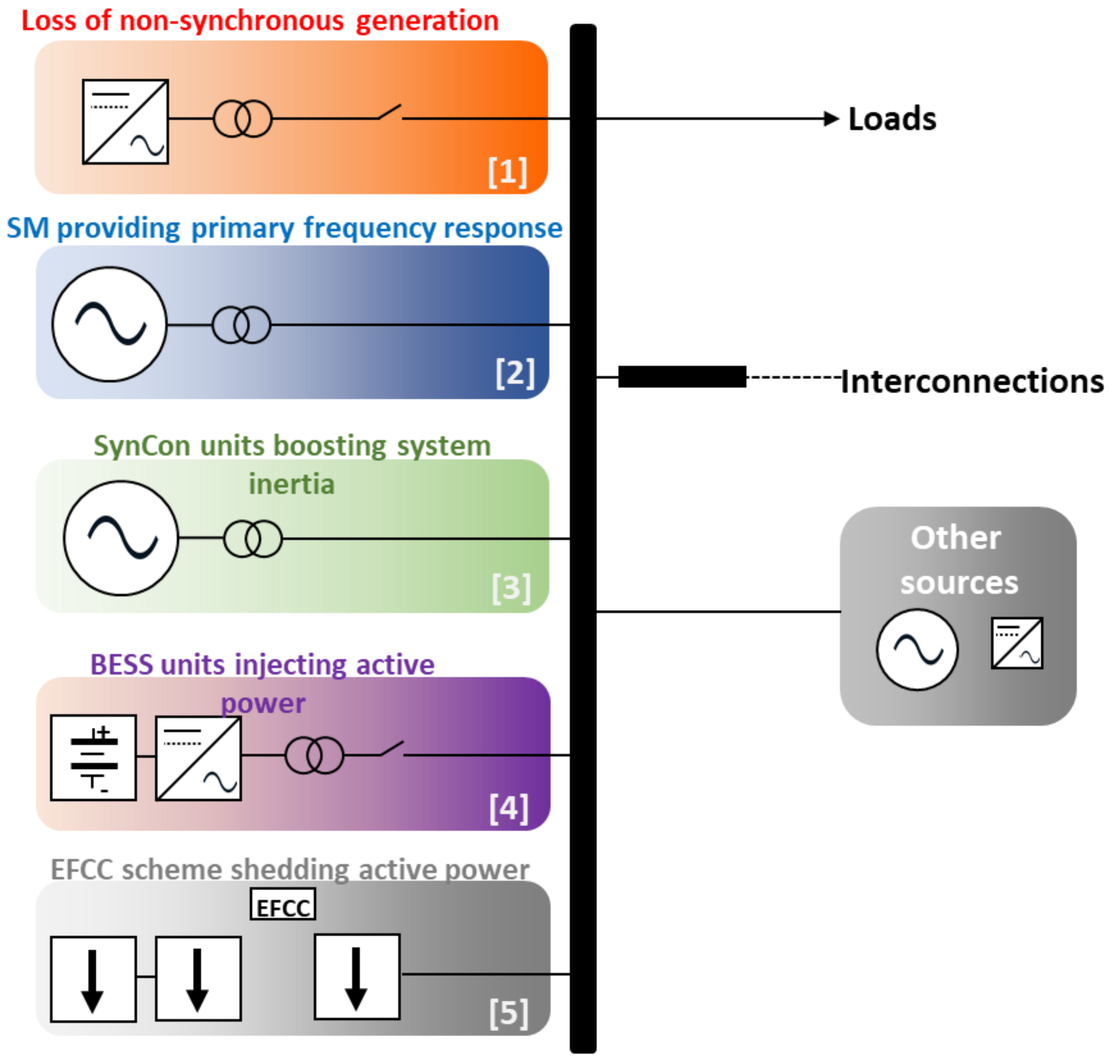
Transient SCL Analysis

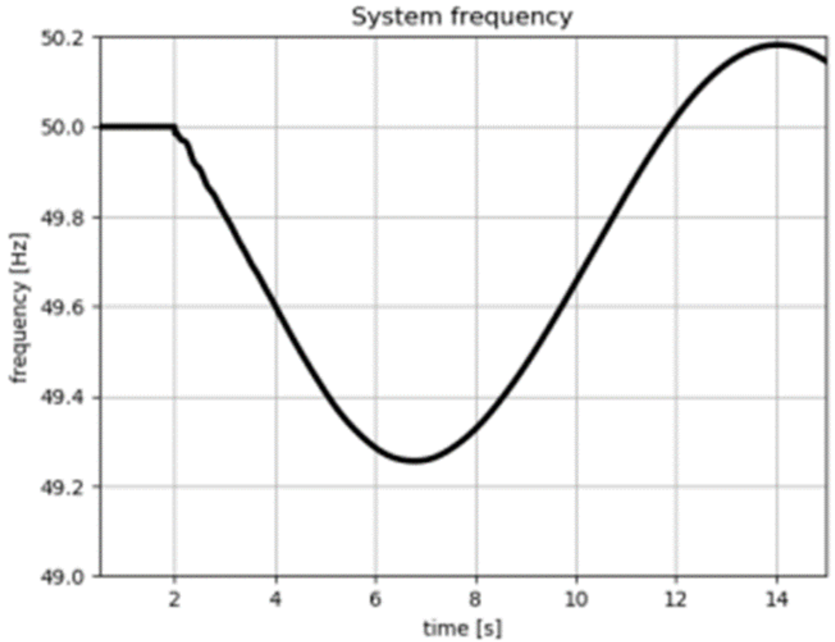


Scenario	SG	ICG	SynCon
1	S_b		
2	$0.75\ S_b$	$0.25\ S_b$	
3	$0.50\ S_b$	$0.50\ S_b$	
4	$0.25\ S_b$	$0.75\ S_b$	
5		S_b	
6		S_b	$0.05\ S_b$
7		S_b	$0.10\ S_b$
8		S_b	$0.15\ S_b$
9		S_b	$0.20\ S_b$



System Inertia – Base Case

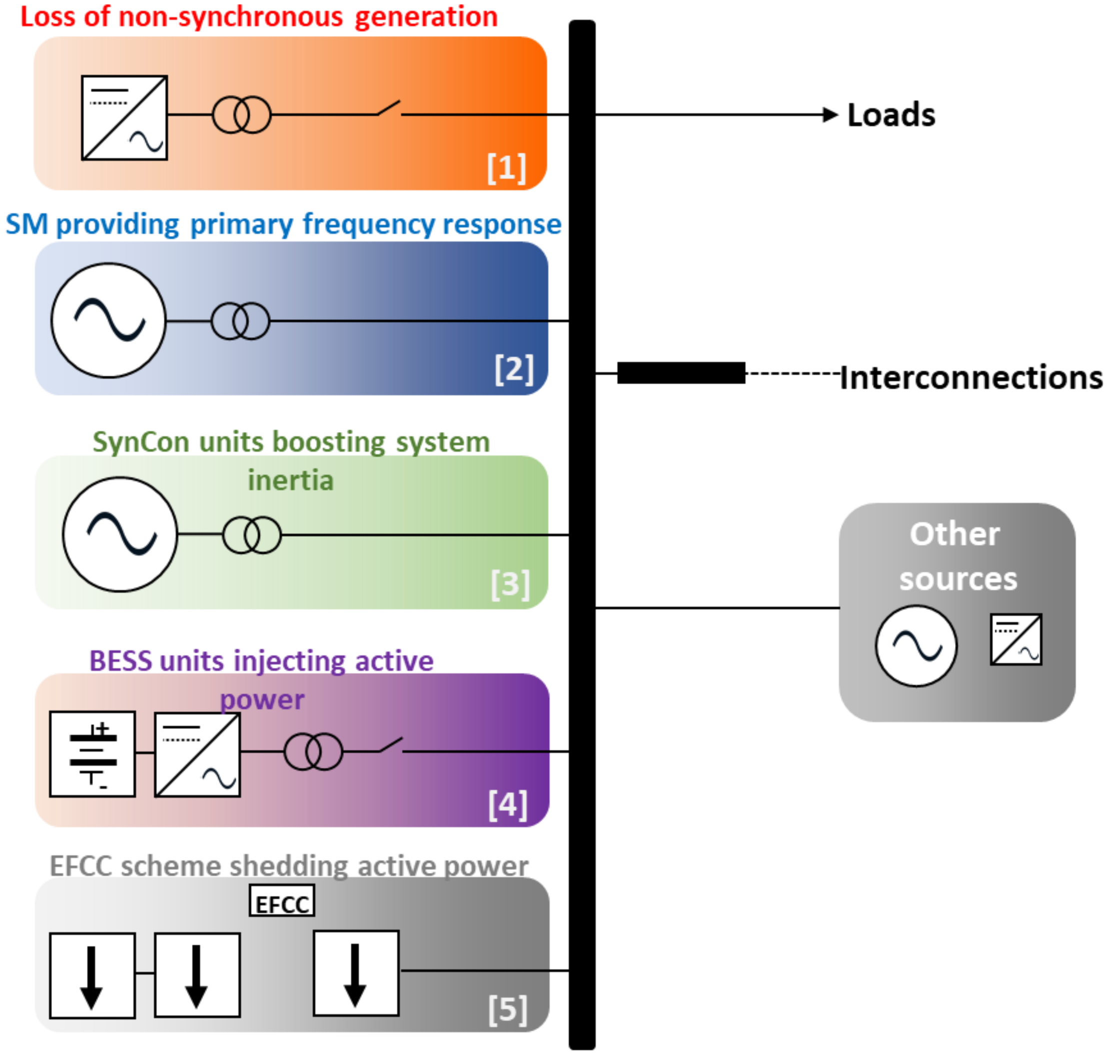




[1] Loss of non-synchronous generation (i.e. inverter connected) is initiated to force the frequency drop to approximately 49.2 Hz. This has been achieved by disconnecting 675 MW of inverter- connected wind resources at Zone 01.

[2] Synchronous generators with reserve capacity and appropriate governors in place will provide primary frequency response and restore frequency (this corresponds to the response required to keep the frequency within 49.2 Hz).

System Inertia – Base Case



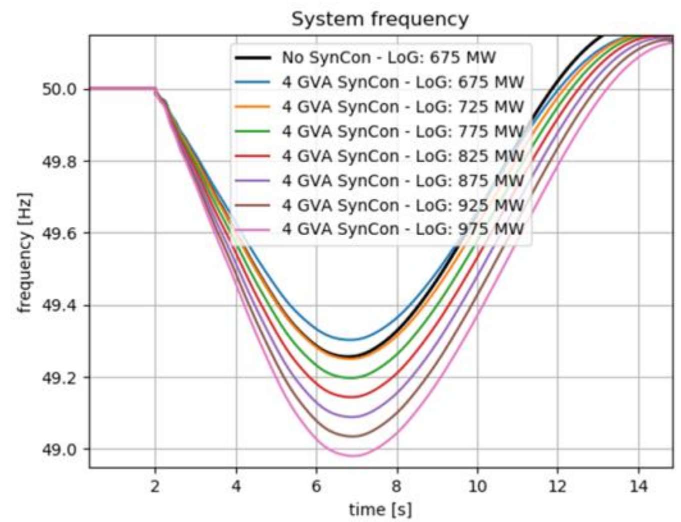
[3] SynCon units will naturally respond to system frequency deviations, contributing to power system inertia.

[4] BESS units will respond to system frequency deviations as defined by their frequency droop characteristics, thus injecting active power to the system and therefore contributing to frequency stability.

[5] The EFCC scheme will respond to system frequency deviations as defined by the estimation factor $Pest$ (i.e. factor to control the amount of the EFCC response to be dispatched during frequency deviations).

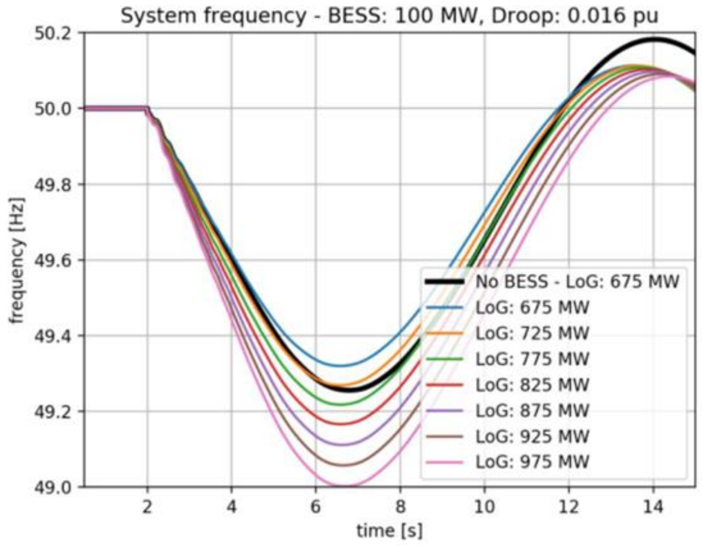
System Inertia – SynCon & BESS

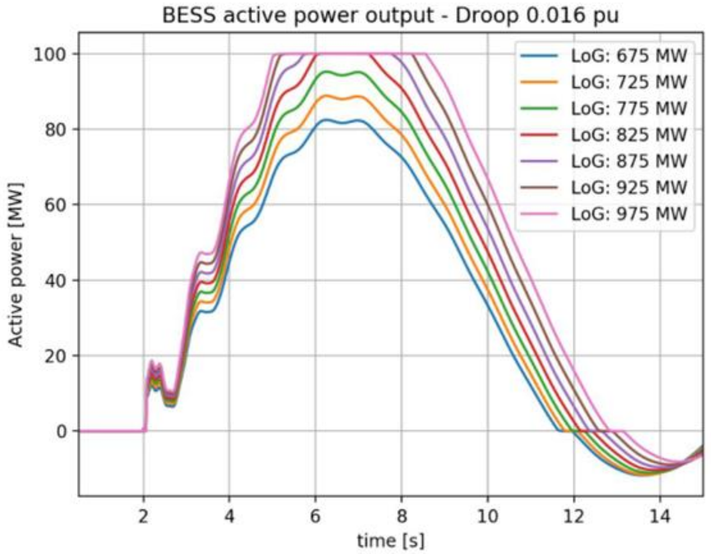
By connecting a total of 4 GVA SynCon units (which corresponds to 5 GVAs considering 1.25 s inertia constant), the maximum infeed loss can be increased by 50 MW, considering a 49.2 Hz frequency nadir limit.



Considering a 100 MW BESS unit and a 675 MW LoG event, different frequency droop characteristics had different impact on the frequency nadir:

- 0.016 p.u. → 0.08 Hz
- 0.020 p.u. → 0.06 Hz
- 0.040 p.u. → 0.03 Hz

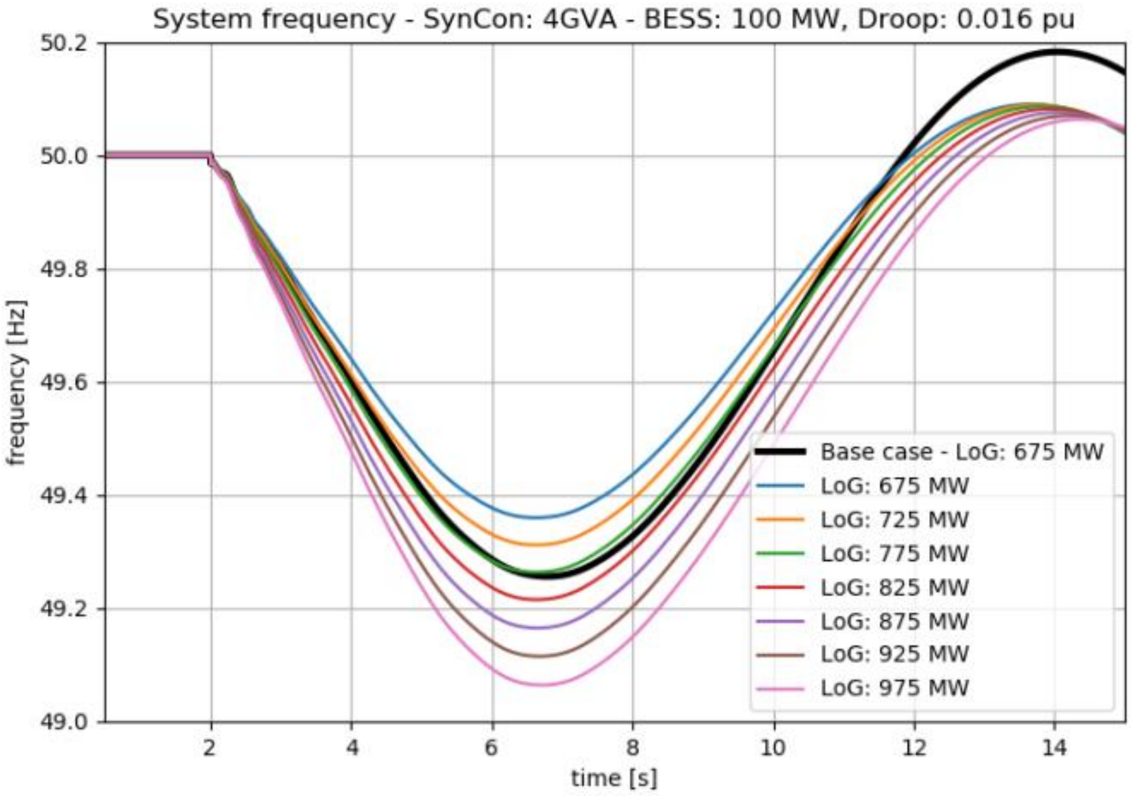




System Inertia – SynCon & BESS

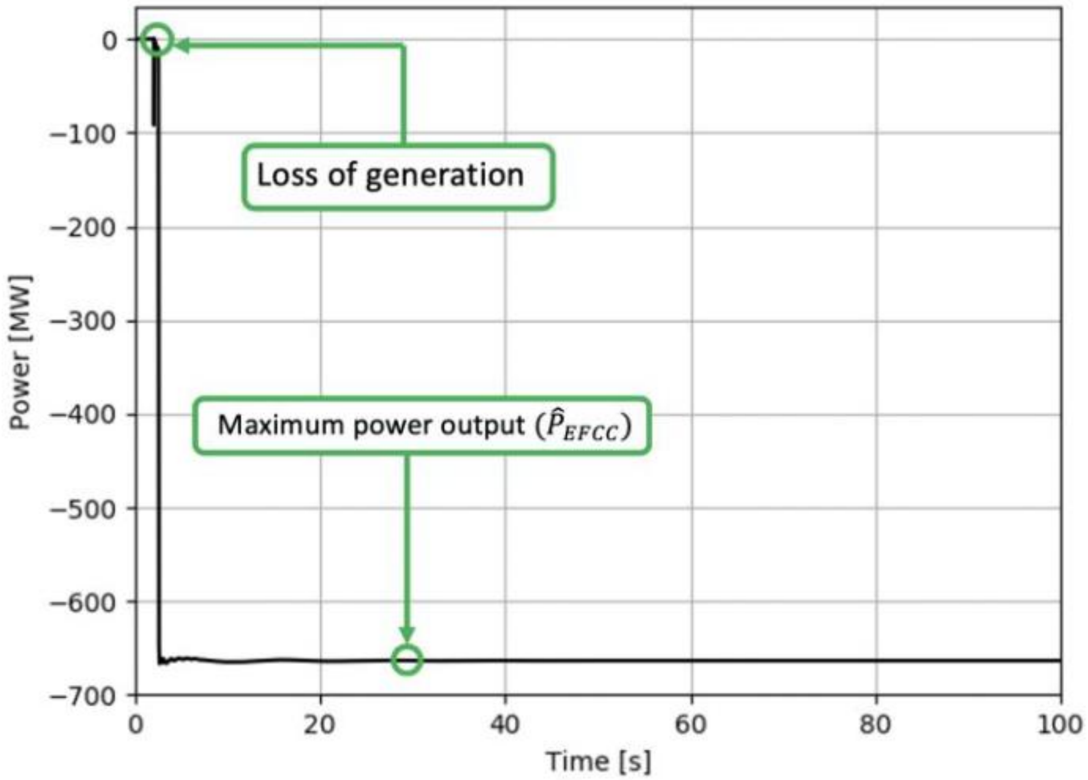
Considering a maximum infeed loss limit, it has been found that by connecting 100 MW BESS unit with frequency droop setting at 0.016 p.u., the maximum infeed loss can be increased by 50 MW, considering a 49.2 Hz frequency nadir limit

By combining SynCon and BESS units the frequency nadir (i.e. 4 GVA of SynCon 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 2).



Frequency traces for different LoG capacities combining both SynCon and BESS units.

System Inertia – SynCon & EFCC



Typical EFCC response to an LoG event

EFCC scheme estimates the LoG capacity based on frequency and RoCoF traces and coordinates responses from loads and/or generators.

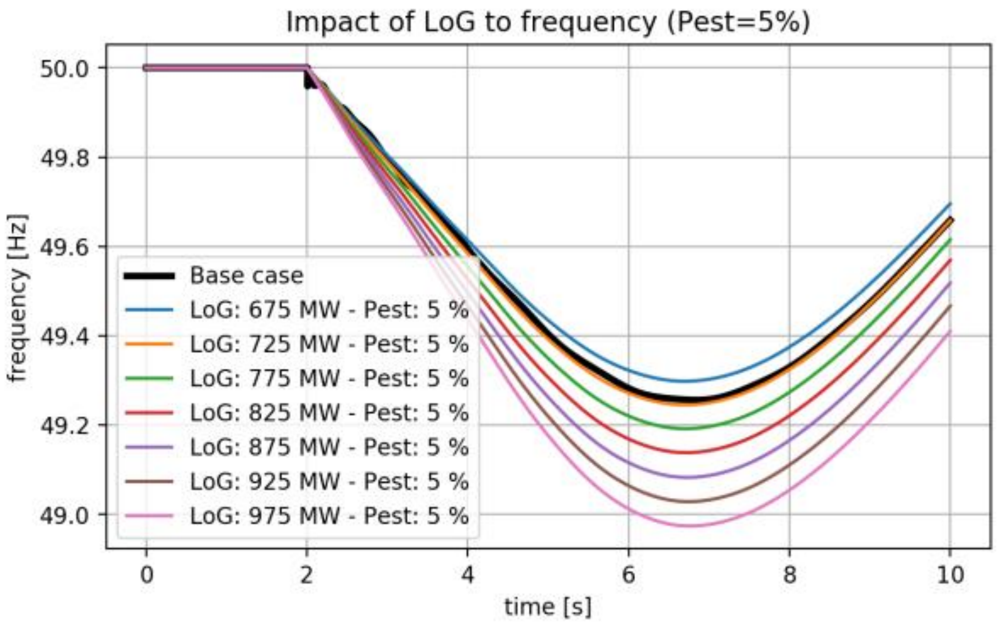
The output can be set as a fraction of the estimated LoG capacity.

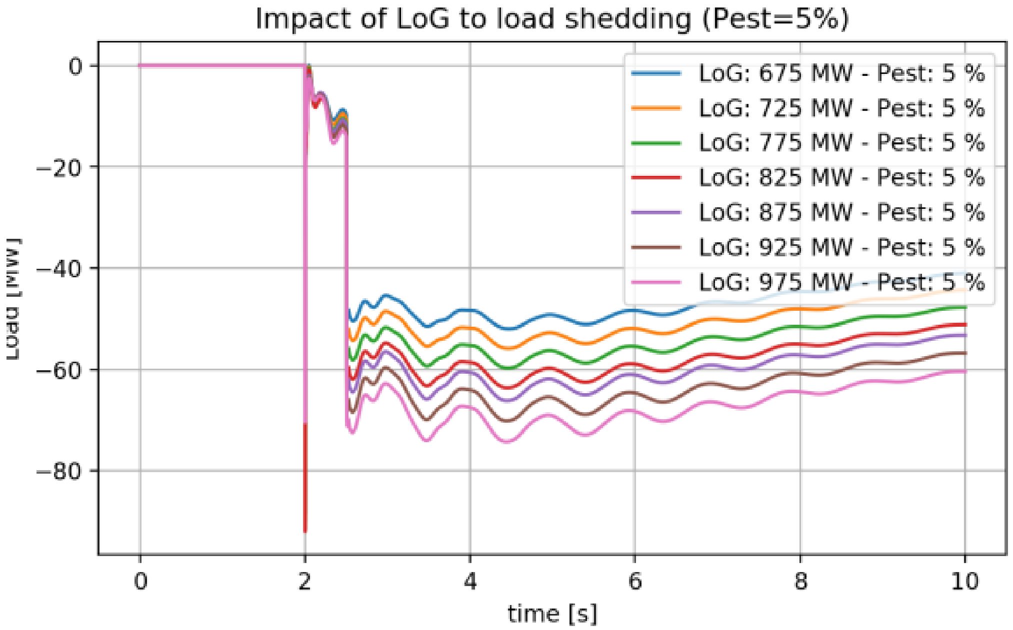
$$P_{EFCC} = P_{LOG} \cdot p_{est}$$

System Inertia – SynCon & EFCC

The studies considered LoG events, starting from 675 MW (i.e. base case) to 975 MW with increments of 50 MW. The studies have been conducted considering the two following scenarios:

Scenario I: EFCC scheme ON, SynCon OFF
Scenario II: EFCC scheme ON, SynCon ON





System Inertia – SynCon & EFCC

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Considering a frequency nadir of 49.2 Hz, it was found that different LoG events can be sustained by different combinations of EFCC scheme and SynCon units, as follows:

- LoG: 675 MW, without EFCC and SynCon untis
- LoG: 725 MW with 5% of EFCC and without SynCon units
- LoG: 775 MW, with 10% of EFCC 10and without SynCon units
- LoG: 775 MW, with 5% of EFCC and with SynCon units
- LoG: 825 MW, with 10% of EFCC and with SynCon units
- LoG: 925 MW, with 25% of EFCC and without SynCon units
- LoG: 975 MW, with 25% of EFCC and with SynCon units

The capacity of the EFCC scheme and SynCon units need to be carefully selected in order to achieve satisfactory frequency control performance.

Conclusions

Studies presented in this report have demonstrated that the deployment and operational control of SynCon GB transmission system can bring advantages to the system with respect to

- SCL elevation
- Performance of power systems protection
- System inertia: Maximum infeed loss in considering a frequency nadir of 49.2 Hz

Publications

'Impact of Synchronous Condensers on Transmission Line Protection in Scenarios with High Penetration of Renewable Energy Sources'
D. Tzelepis, E. Tsotsopoulou, A. Dysko, V. Nikolaidis, V. Papaspiliotopoulos, Q. Hong, C. Booth
IET – Developments in Power System Protection (DPSP), March 2020
DOI: 10.1049/cp.2020.0095

'Enhancing Short-Circuit Level and Dynamic Reactive Power Exchange in GB Transmission Networks under Low Inertia Scenarios'
D. Tzelepis, Q. Hong, C. Booth, P. Papadopoulos, J. Ramachandran, G. Yang
International Conference on Smart Energy Systems and Technologies (SEST), September 2019
DOI: 10.1109/SEST.2019.8849020

'Provision of Voltage Ancillary Services through Enhanced TSO-DSO Interaction and Aggregated Distributed Energy Resources'
Oulis-Rousis, **D. Tzelepis**, Y. Pipelzadeh, G. Strbac, C. D. Booth and T. Green,
IEEE Transactions on Sustainable Energy,
DOI: 10.1109/TSTE.2020.3024278

'Impact of system strength and HVDC control strategies on distance protection performance'
D. Liu, Q. Hong, A. Dysko, **D. Tzelepis**, G. Yang, C. Booth, I. Cowan, B. Ponnalagan
IET - Renewable Power Generation International Conference, March 2020
DOI: (Pending)

Thank you

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ScottishPower Group

DTU

PHOENIX

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Technical University of Denmark- Guangya Yang

DTU activities and progress

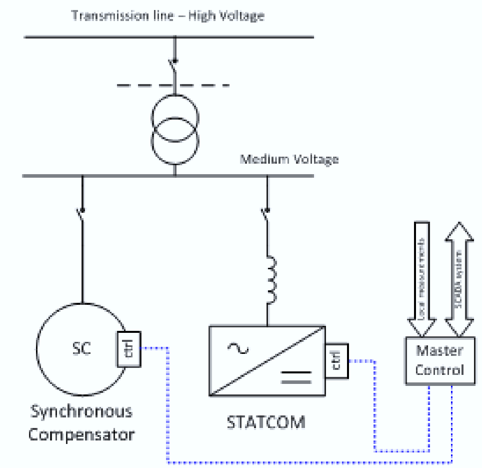
Phoenix project (2016-2021)

- ❑ Looks at a hybrid synchronous condensers design
  - ○ SynCon + STATCOM full-scale installation and field test (70 MVA SC + 70 MVA STATCOM)
  - ○ GB system wise inertia and voltage support studies
- ❑ DTU is working on the variant 4. H-SC (SynCon + BESS)

SCAPP project (2014-2018)

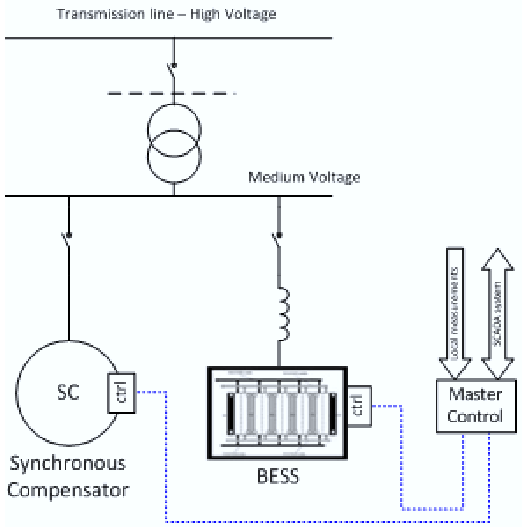
- ❑ Synchronous condenser applications in low inertia systems (www.scapp.dk)
  - ○ Standalone synchronous condenser

2. H-SC SC + STATCOM



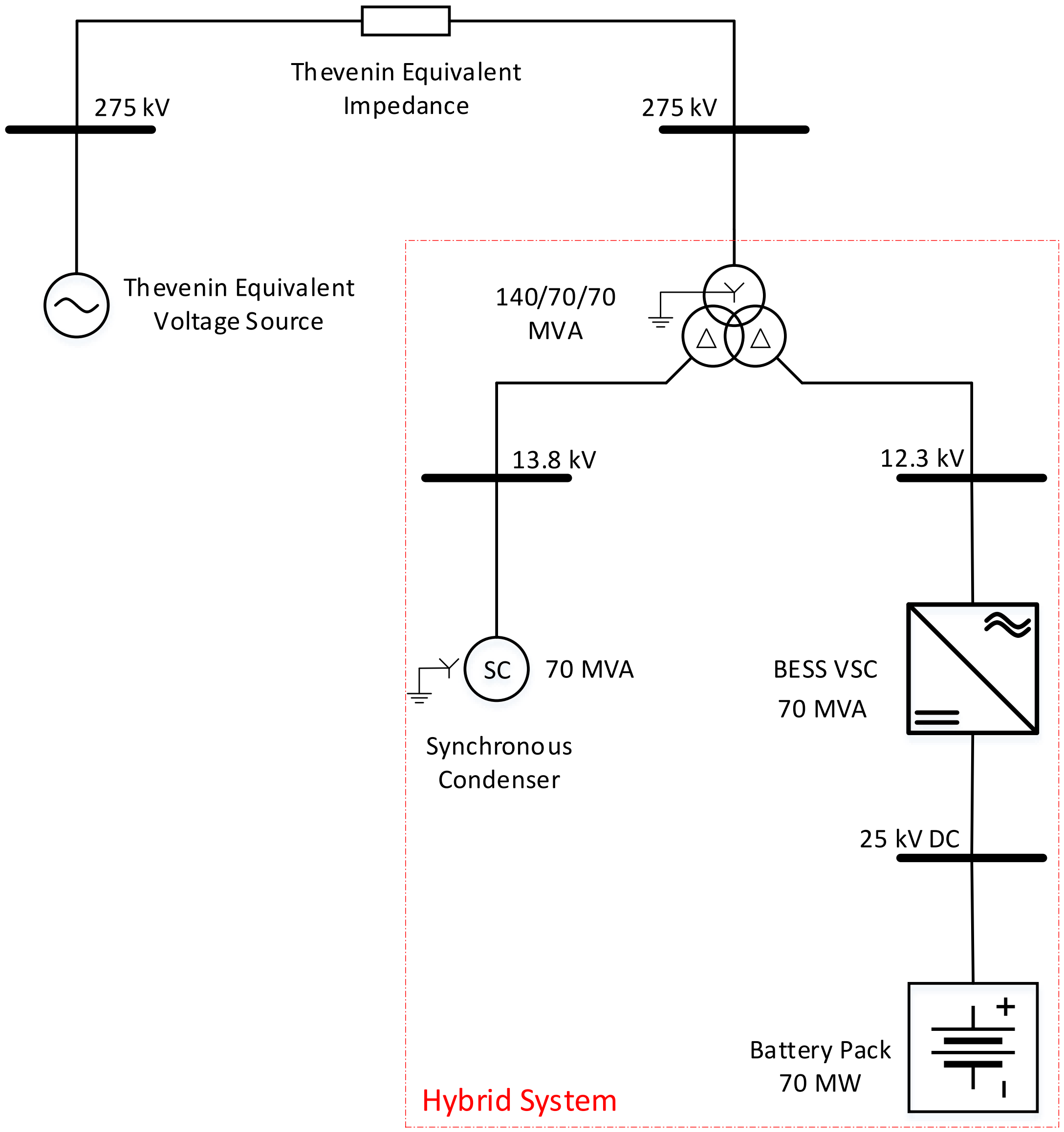
- Design, develop, simulate and deploy on live system hybrid-coordinated control mechanisms
- Maximise strengths of both technologies minimise weaknesses

4. H-SC SC + Battery Energy Storage System (BESS)



- Simple extension from variant 2 moving from DC-capacitors in pure STATCOM to battery energy storage system.
- The component models for this variant will developed and simulated in Phoenix research studies

Simulated H-SC



- ❑ **SC modelled in power factory validated against ABB's PSCAD model.**
- ❑ **Basic design follows the Phoenix SynCon + STATCOM system.**
- ❑ **Master controller controls both components.**

Simulation Setup

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Hybrid system of BESS and SC	Battery Pack Model	Synchronous condenser model	Master controller functionality
✓Rating is the same as Phoenix system ✓Connected by a 3-winding transformer ✓Master controller controls both components based on SC+STATCOM	✓Equivalent Circuit ✓Grid following control ✓Frequency Control: Droop and RoCoF ✓QV droop, Q control ✓Fault ride through based on UK grid codes	✓Excitation limiters ✓Automatic voltage control, QV droop, Q control	✓Inertia maximization ✓Reactive power sharing ✓QV droop, Q control ✓Fast transient response ✓Manual battery charging/discharging, POD)

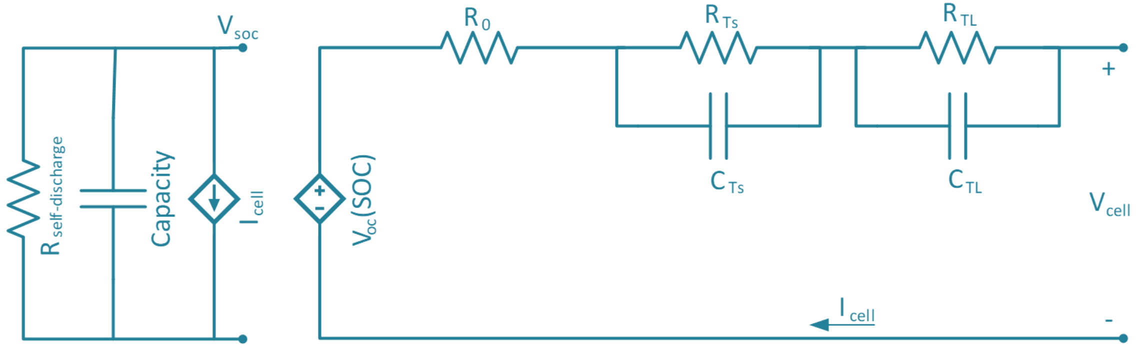
Battery Pack Model

Battery modelled as an electrical equivalent.

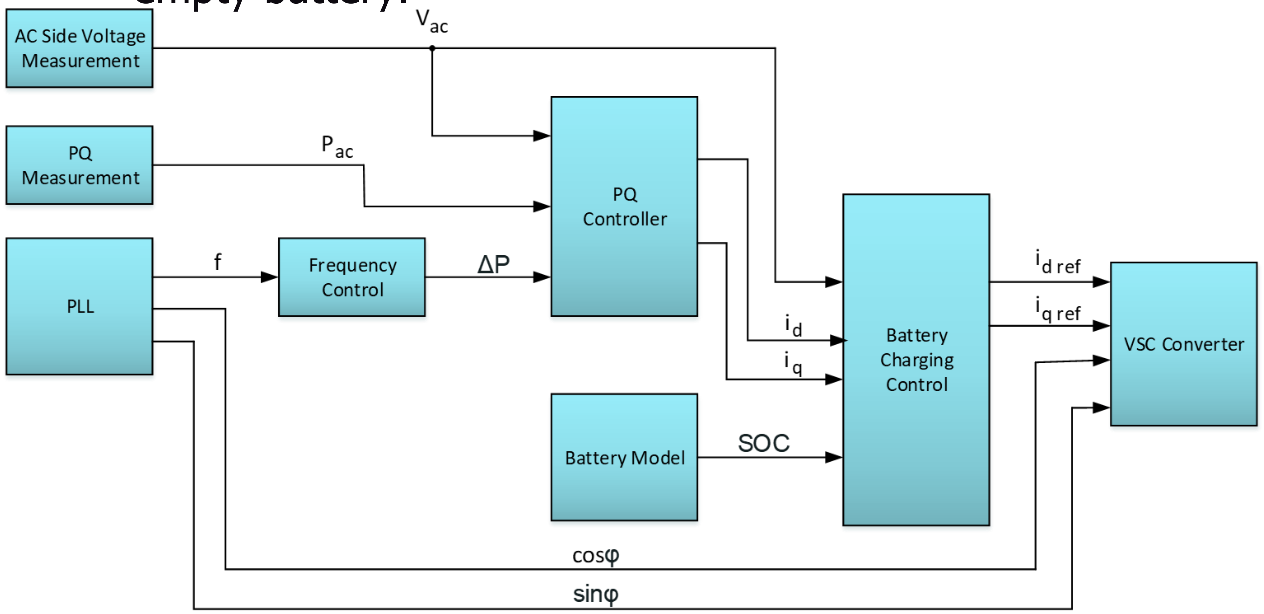
- ❑Chemical processes represented by RC circuits.
- ❑Circuit parameters are functions of the SOC
- ❑Lithium based battery pack
- ❑Speed of the BESS response dependent solely on the speed of the control system.

VSC control functions

- ❑Grid following control/grid forming control
- ❑Grid following control functions: automatic voltage control, VAR control, droop and RoCoF based frequency control, fault-ride-through capability according to the grid codes.
- ❑Charging current limit at high SOC (constant voltage charging). Gradual power cut-off for full and empty battery.

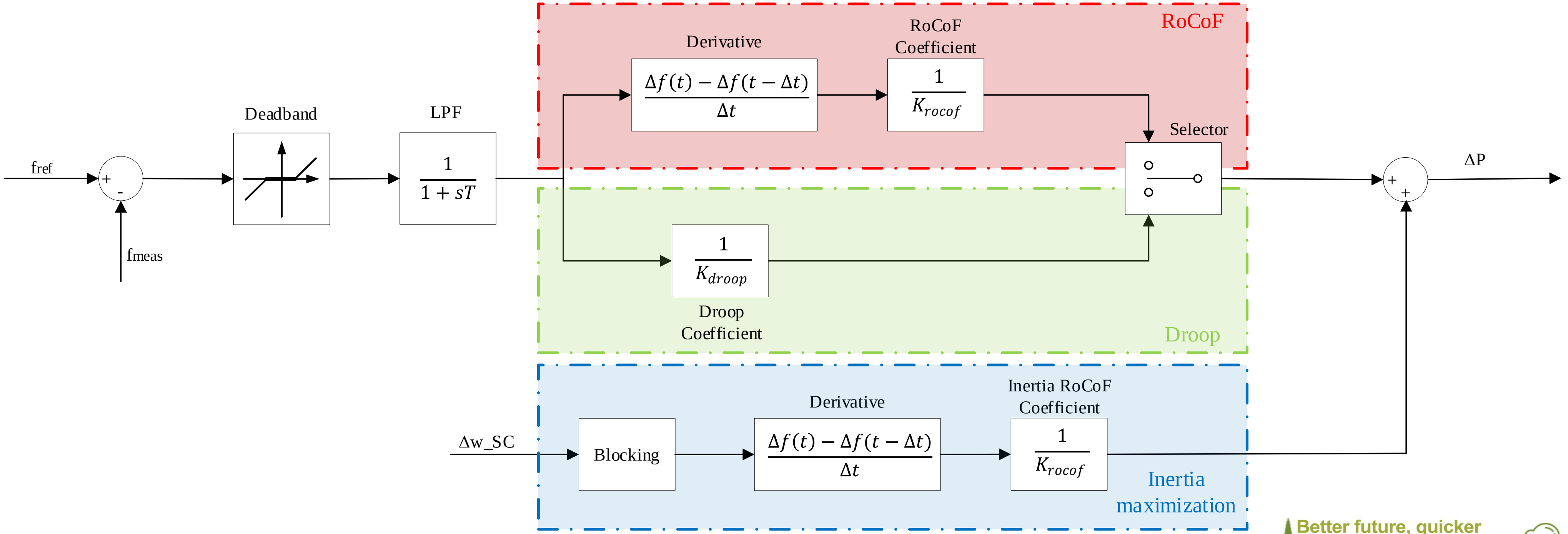


Battery equivalent circuit model

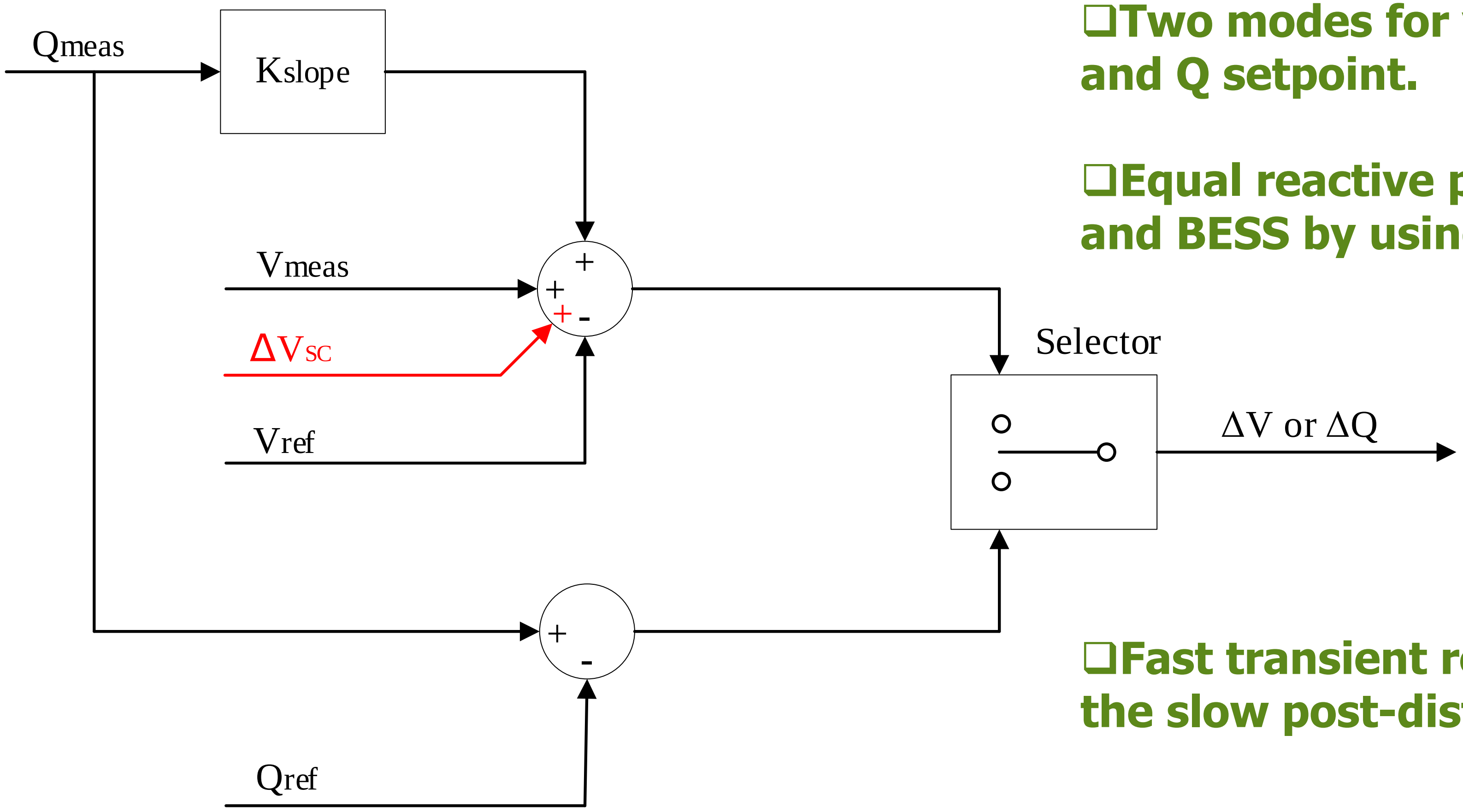


Droop, ROCOF and Inertia Control

- Possible to change the control strategy or use both droop and RoCoF
- Inertial maximization is a separate function.
- Use SC speed or active power as signal to enhance inertia response
- Adjustable RoCoF calculation time window.
- High gradient changes prevented by using a low pass filter.



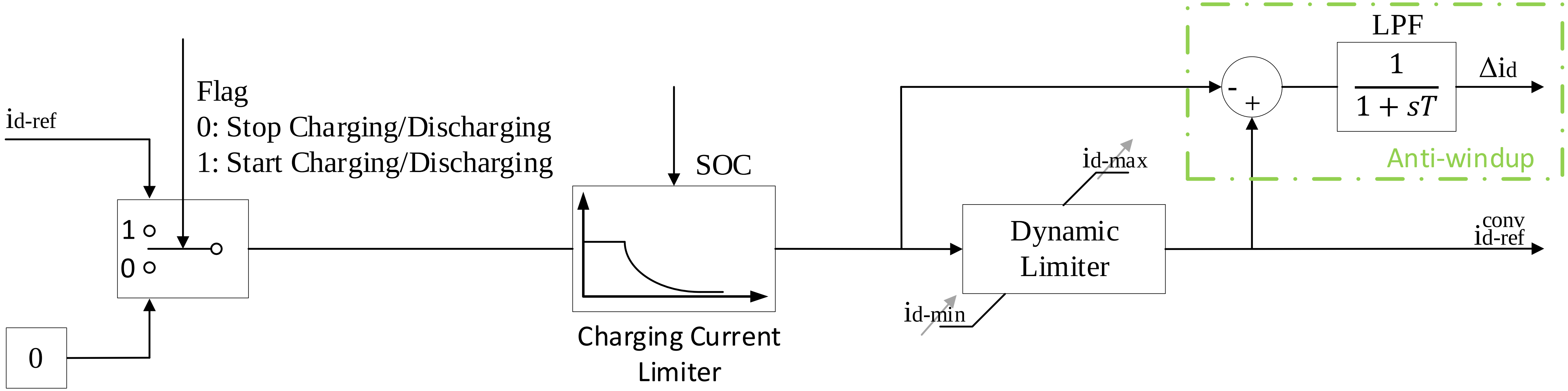
Automatic Volt/Var Control



- ❑Two modes for voltage support, Q/V droop and Q setpoint.
- ❑Equal reactive power sharing between SC and BESS by using the same slope.
- ❑Fast transient response, compensating for the slow post-disturbance recovery of SC

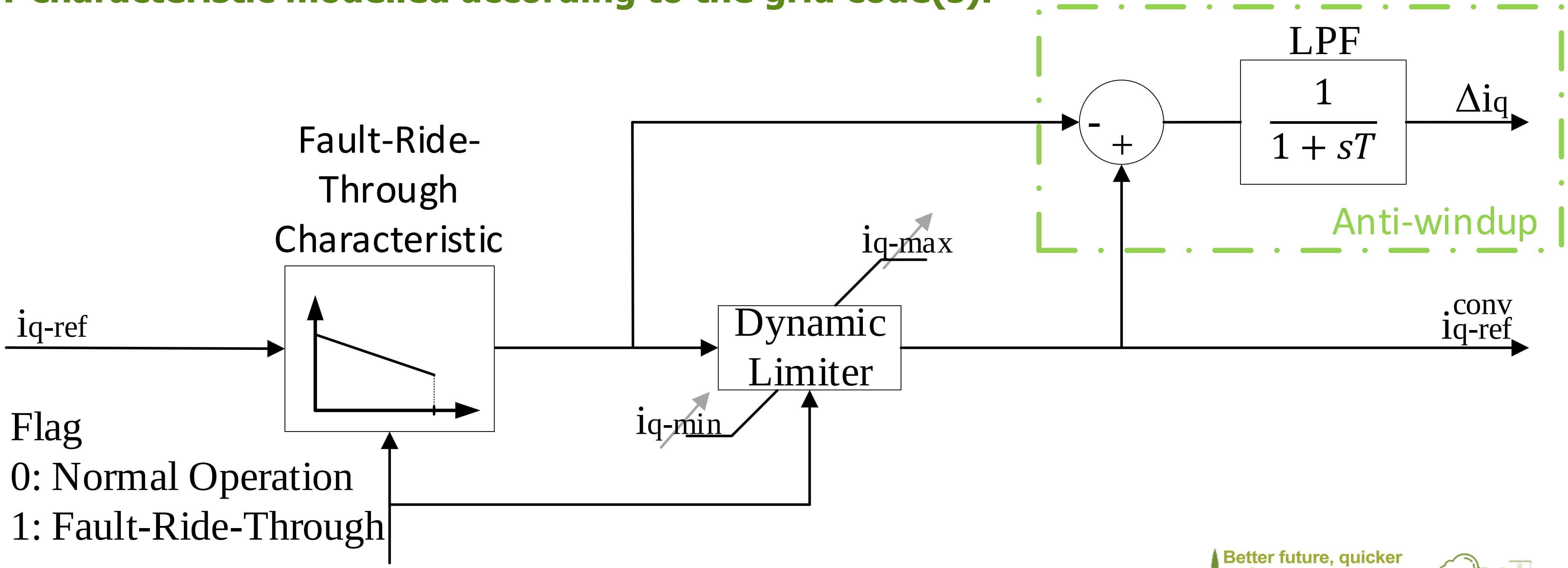
I_d Current Limiter

- Charging current limitation at high SOC (SOC > 80%, constant voltage charging).
- Dynamic limiter operates based on the active or reactive power injection preference.
- Anti-windup loop added to ensure controlled transition between operating states.



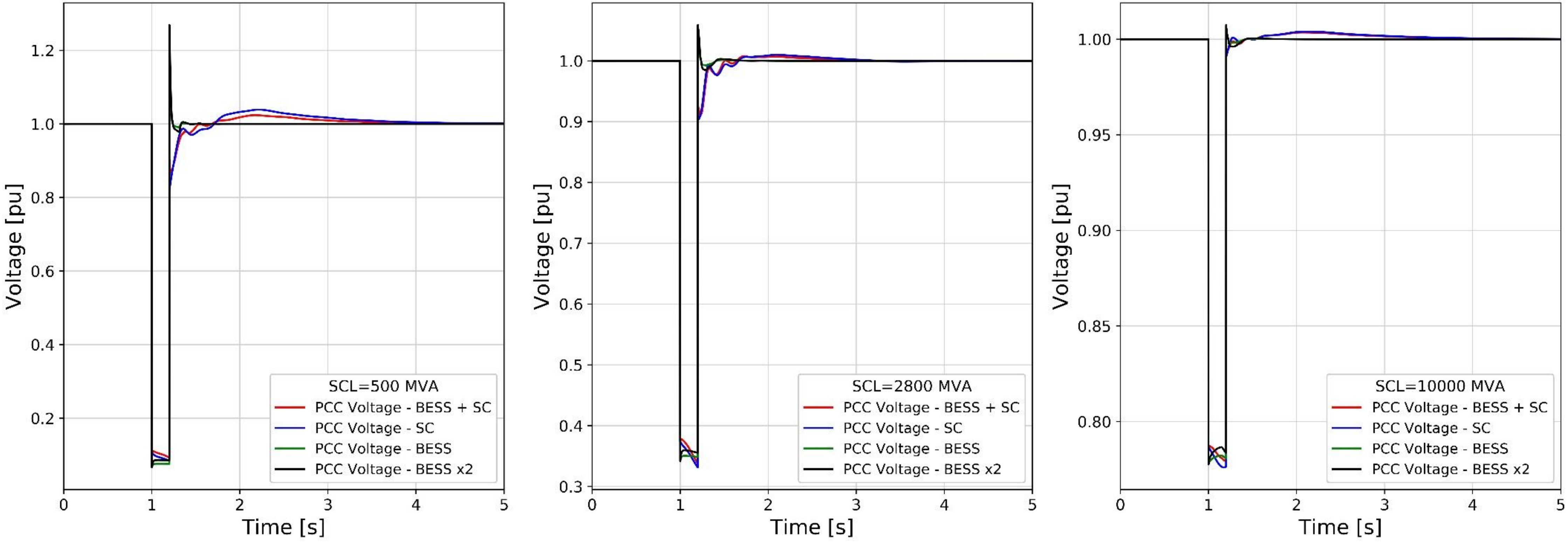
I_q Current Limiter

- Fault-ride-through (FRT) and dynamic current limiter
- FRT strategy activated once the voltage drops below 0.9 pu.
- FRT characteristic modelled according to the grid code(s).



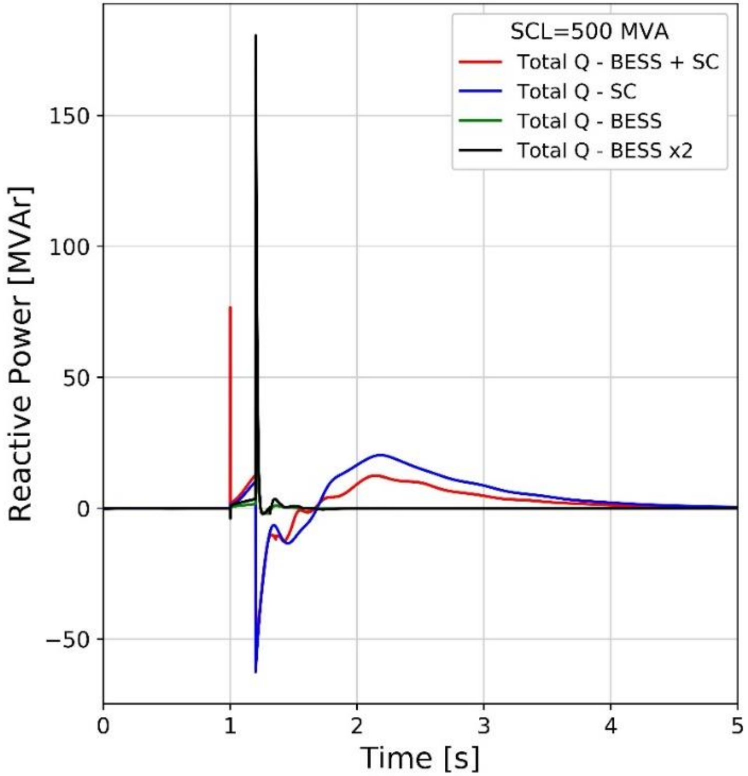
Dynamic Reactive Power Support (BESS in grid following control)

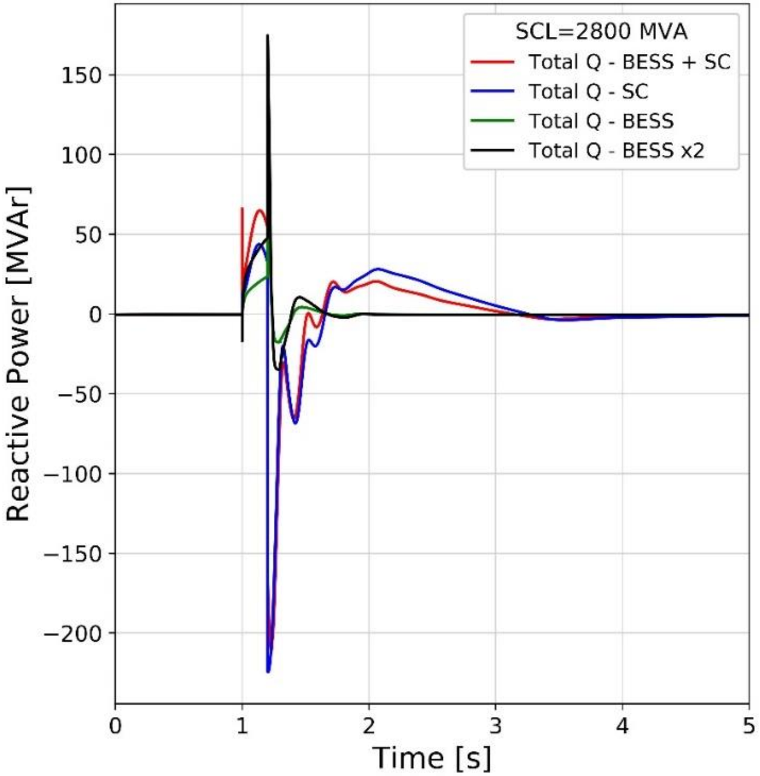
- 3 Phase Short Circuit, 200ms fault, 10 Ohm Resistance
- 3 short circuit levels, 4 combination of devices
- **BESS provides faster voltage regulation**

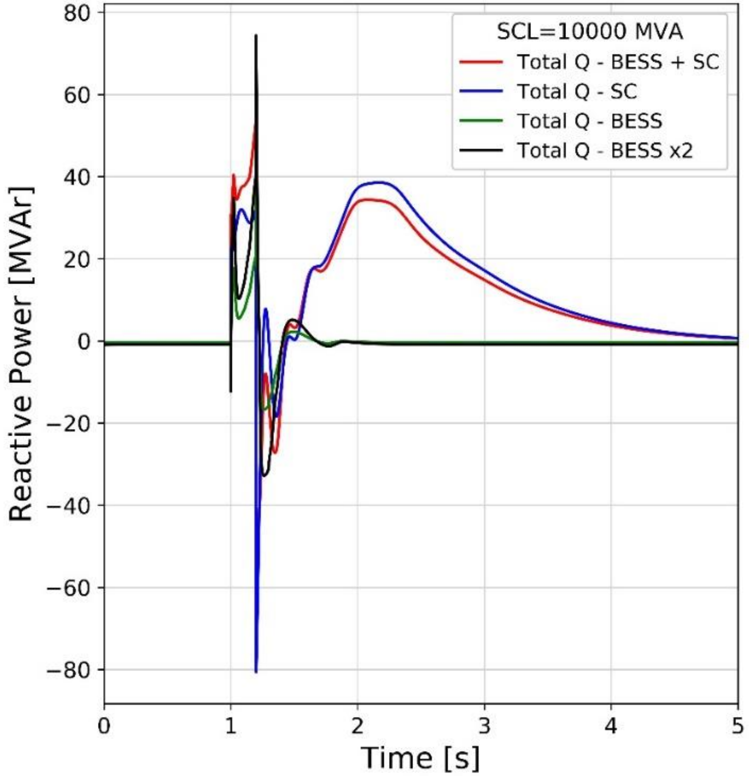


Reactive Power Output (BESS in grid following control)

- 3 Phase Short Circuit, 200ms fault, 10 Ohm Resistance
- 3 short circuit levels, 4 combination of devices
- **BESS provides faster reactive power response than SC. BESS+SC provides better all-rounded performance.**

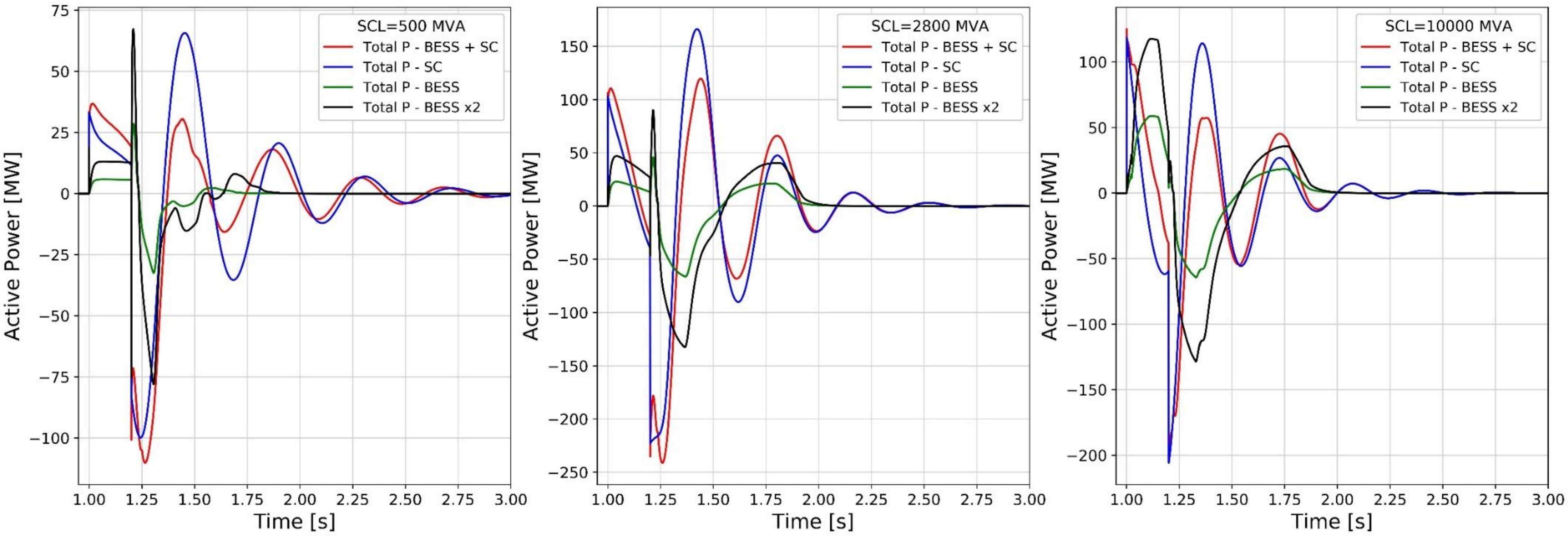






Active Power Output (BESS in grid following control)

- ❑BESS provides more active power response than SC, but SC provides better inertial response. BESS+SC provides better all-rounded performance.



System Voltage Step Change (Terminal voltage change)

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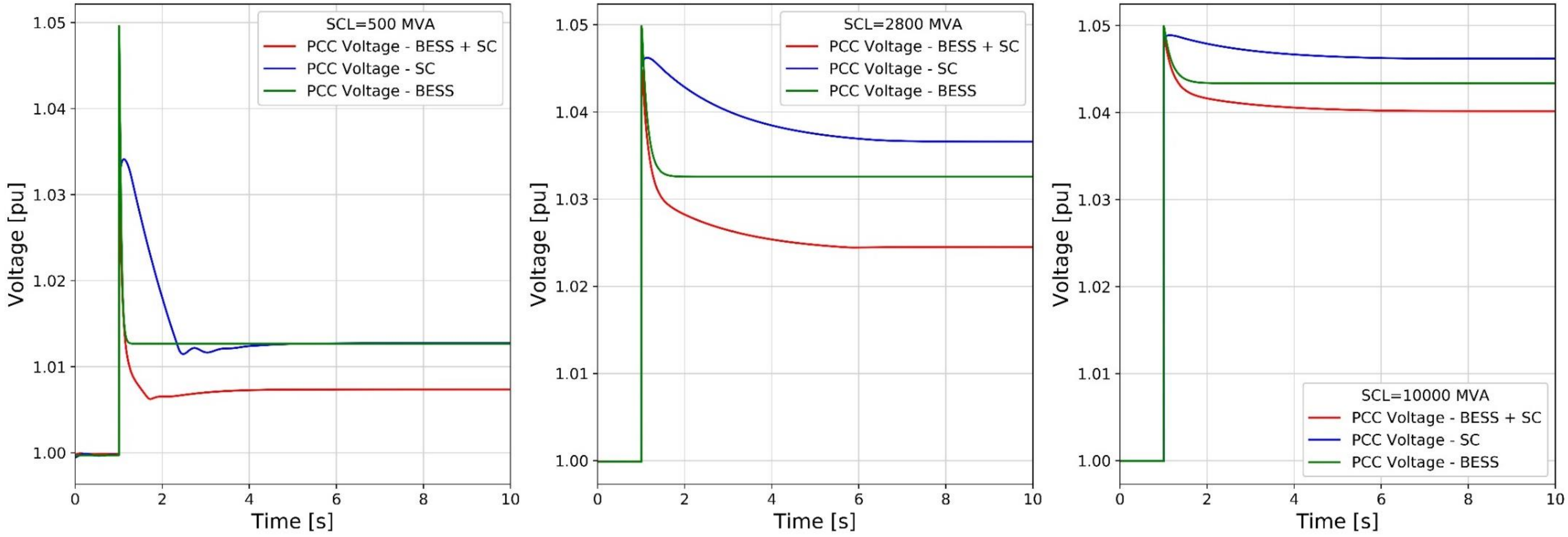
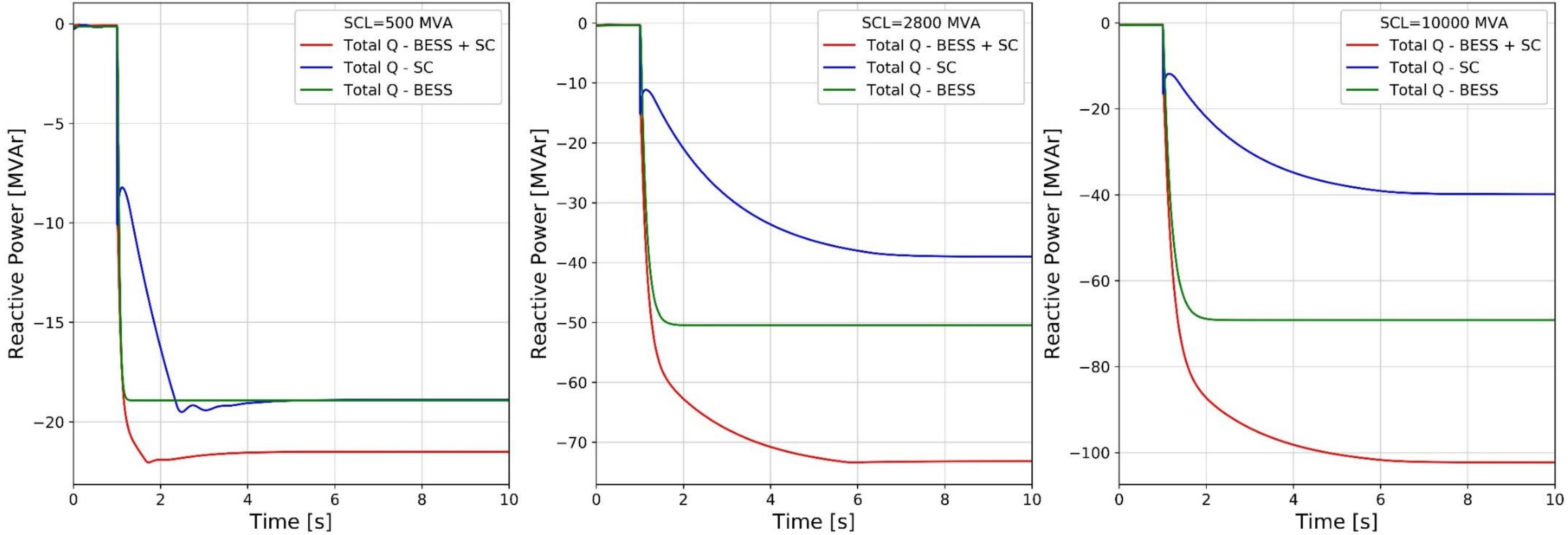
❑System voltage jumps from 1 to 1.05 pu, BESS in grid following control

❑**BESS can better regulate the local voltage than SC because of better –Q limit when short circuit power is higher (2800MVA, 10000MVA)**



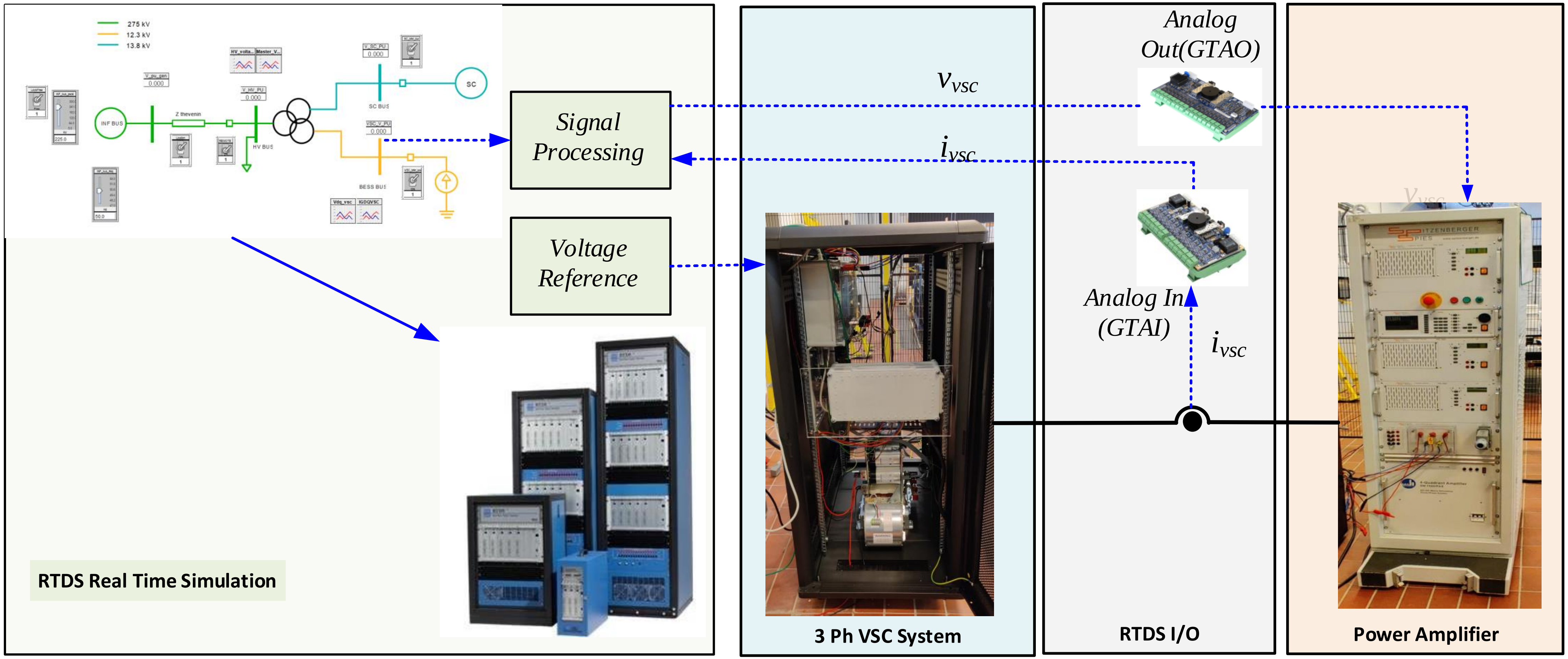
System Voltage Step Change (Reactive power result)

- System voltage jumps from 1 to 1.05 pu, BESS in grid following control
- **Below figures show the reactive power output from SC, BESS, and BESS+SC in three short circuit levels. The responses verify the results of the previous slide.**



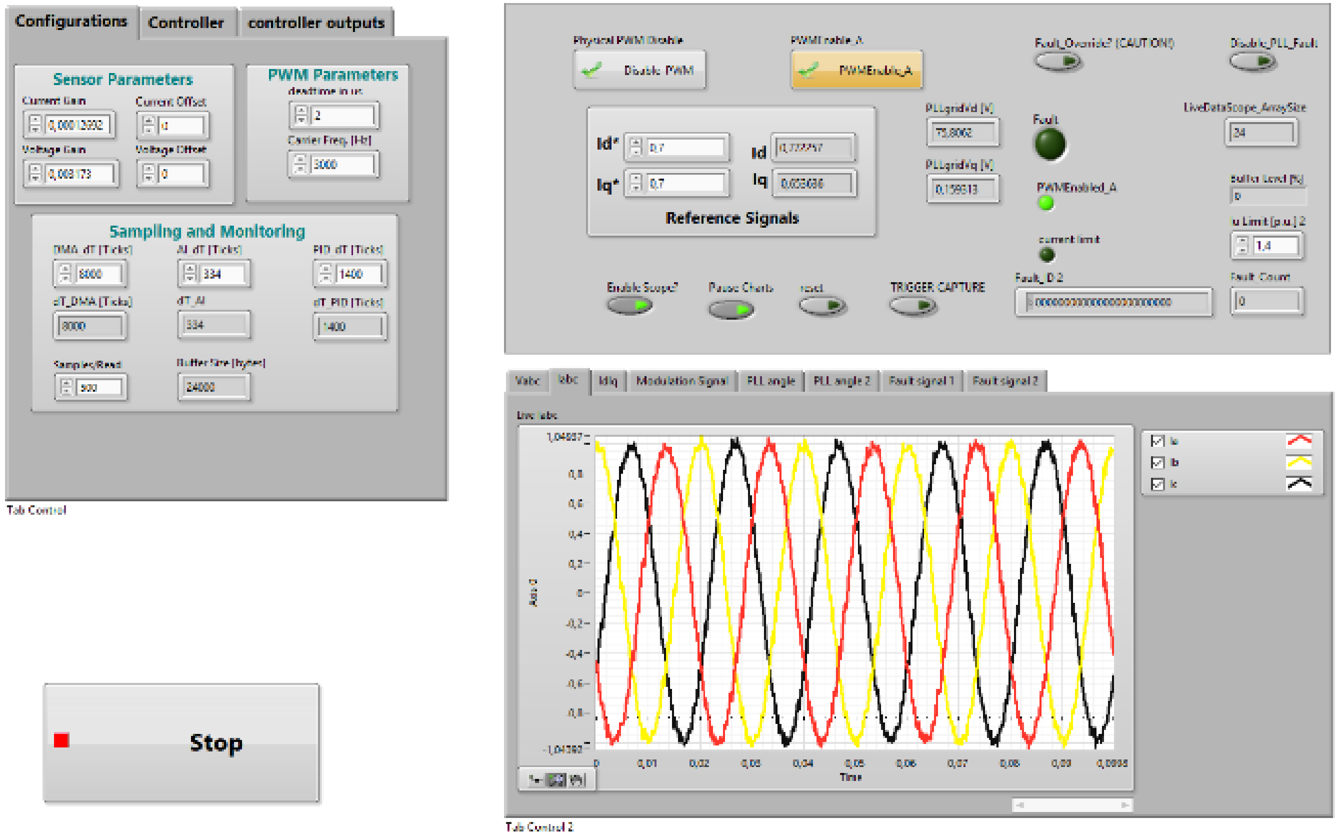
Power Hardware-In-the-Loop Platform

Objective is to validate the proposed control methods and analysis for H-SC (Grid following, Grid Forming, SC+Flywheel)

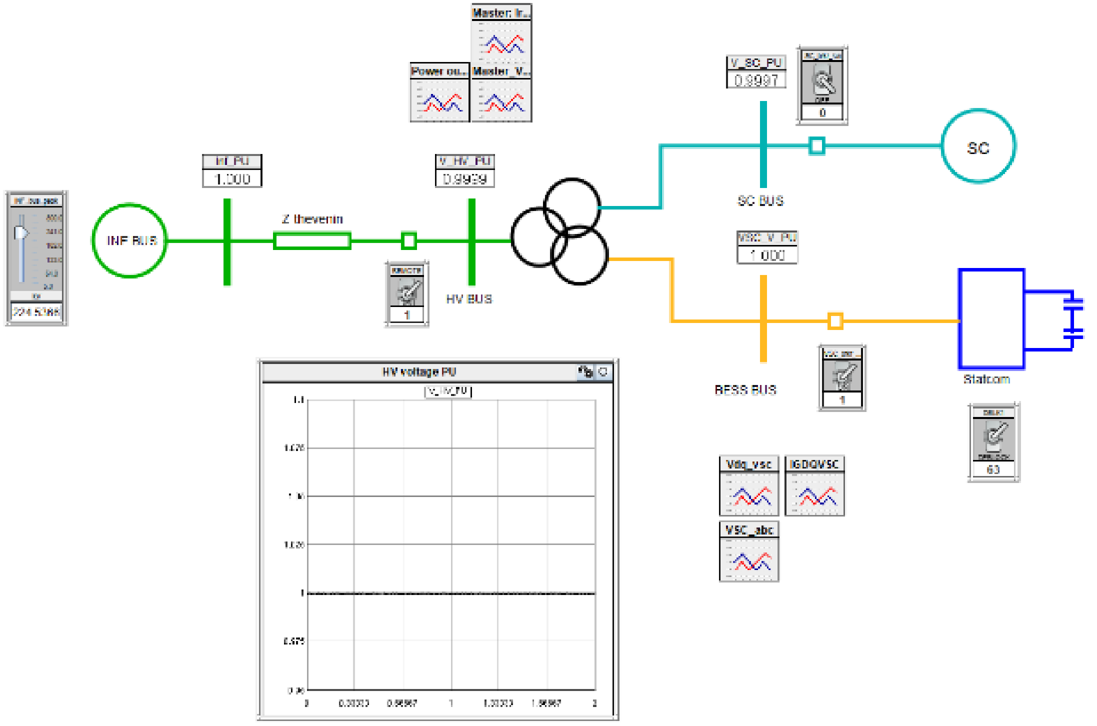


Model Interfaces

The converter control is modelled in Labview. The converter is connected to RTDS



LabVIEW GUI



RSCAD Runtime interface

SC + BESS (BESS in grid following control)

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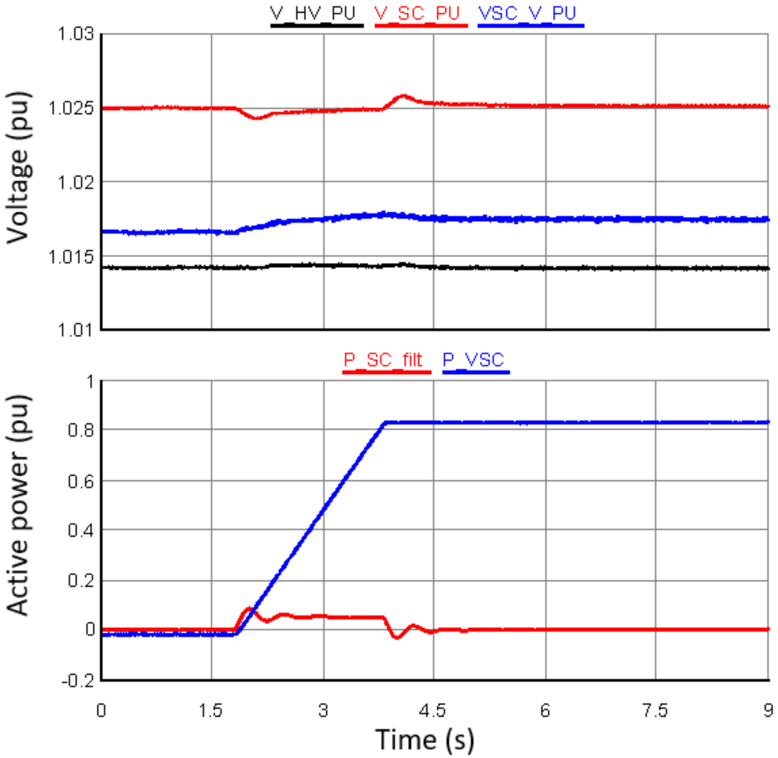
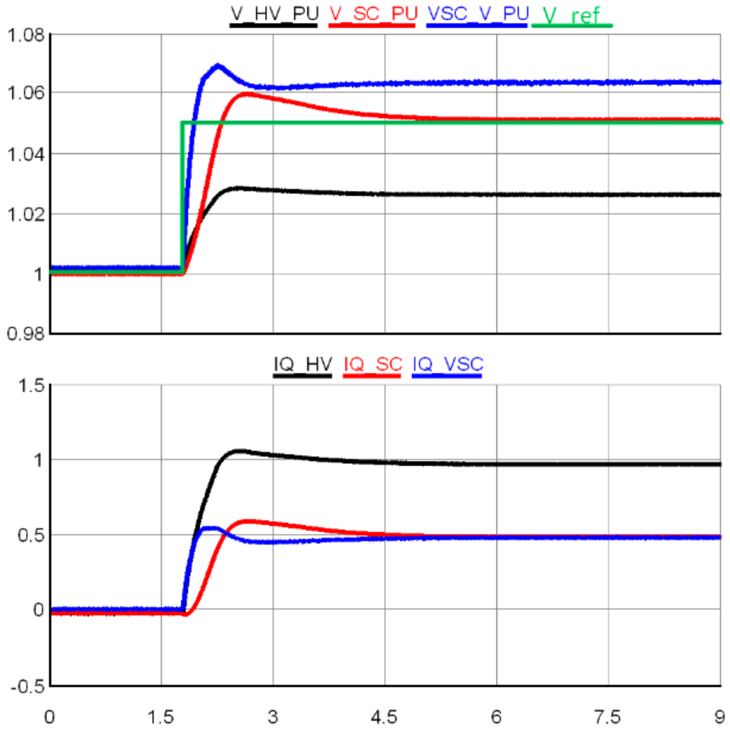
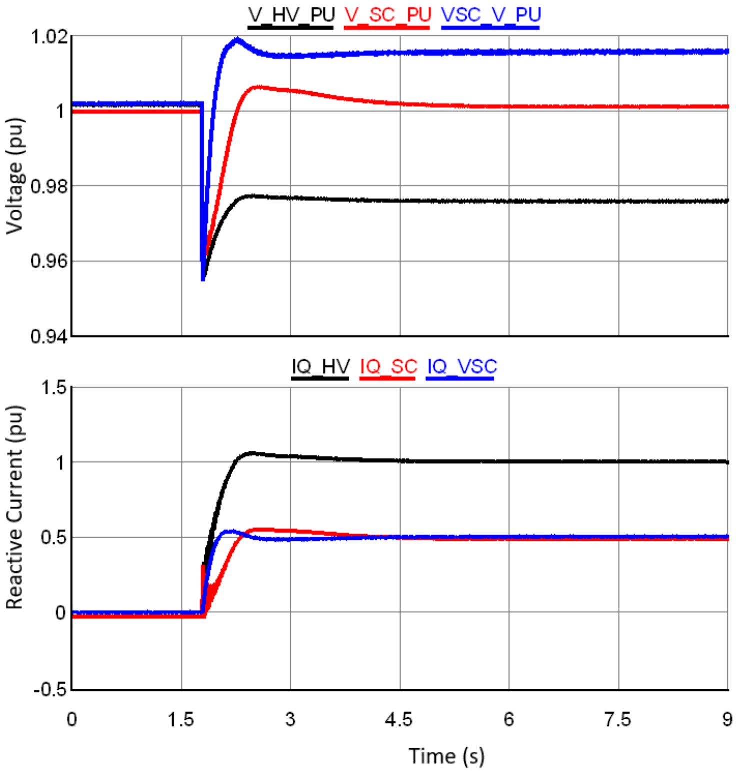
- ❑Objective to verify the simulated response with scaled down VSC hardware
- ❑The responses for all the events were found to be with the simulated responses



Active power response for Thevenin voltage frequency drop with ROCOF 1 Hz/sec



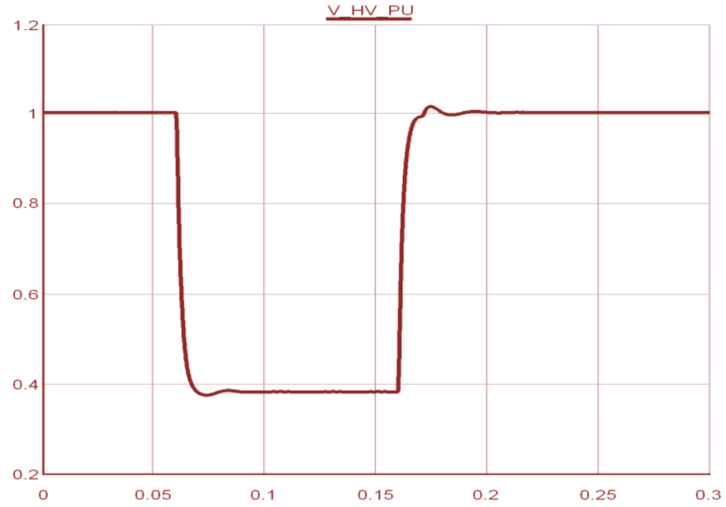
Voltage Reference step change 0.05 pu SCL=2800 MVA, Slope=5%



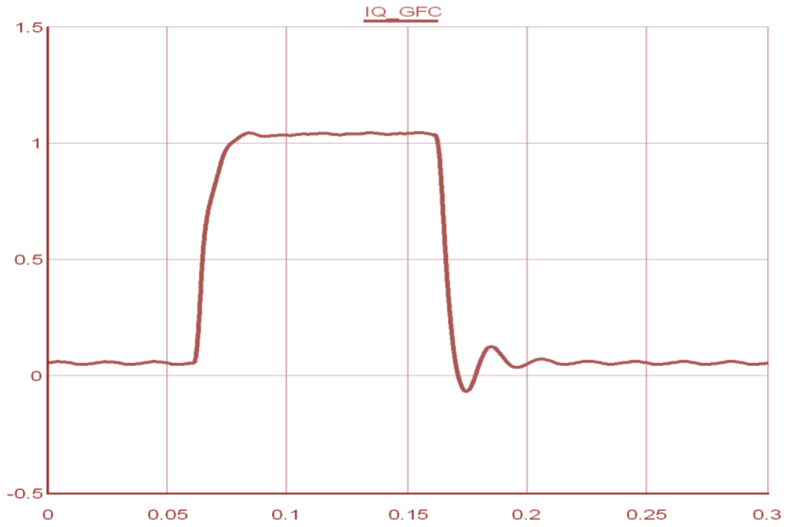
Reactive current injected for a Thevenin voltage drop to 0.95 pu SCL=2800 MVA, , Slope=5%

BESS in Grid Forming Control with Fast Acting Current Limiters

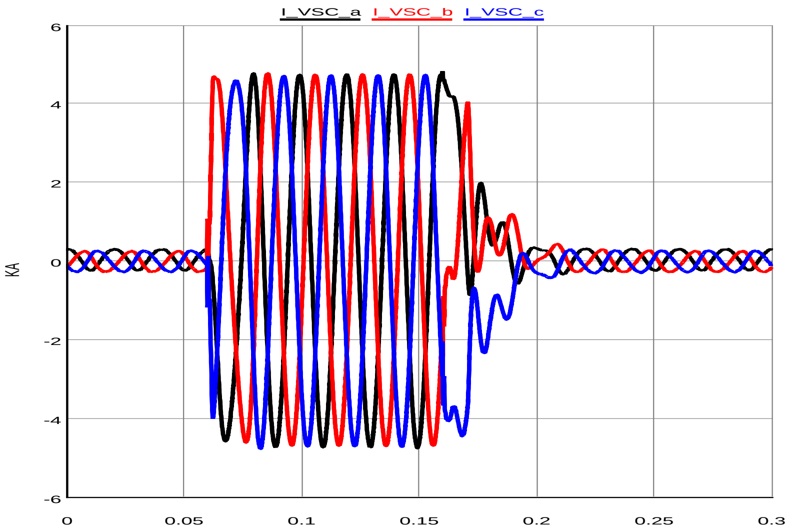
- ❑Challenging to ensure the protection due to sensitive electronics in VSC
- ❑Need fast acting limiter, however, can lead to transient instability



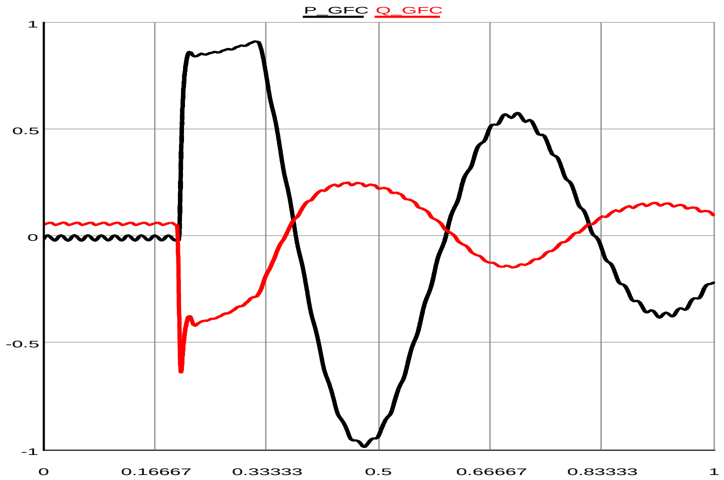
Voltage at HV side of transformer



Reactive current response from GFC



3 phase current GFC

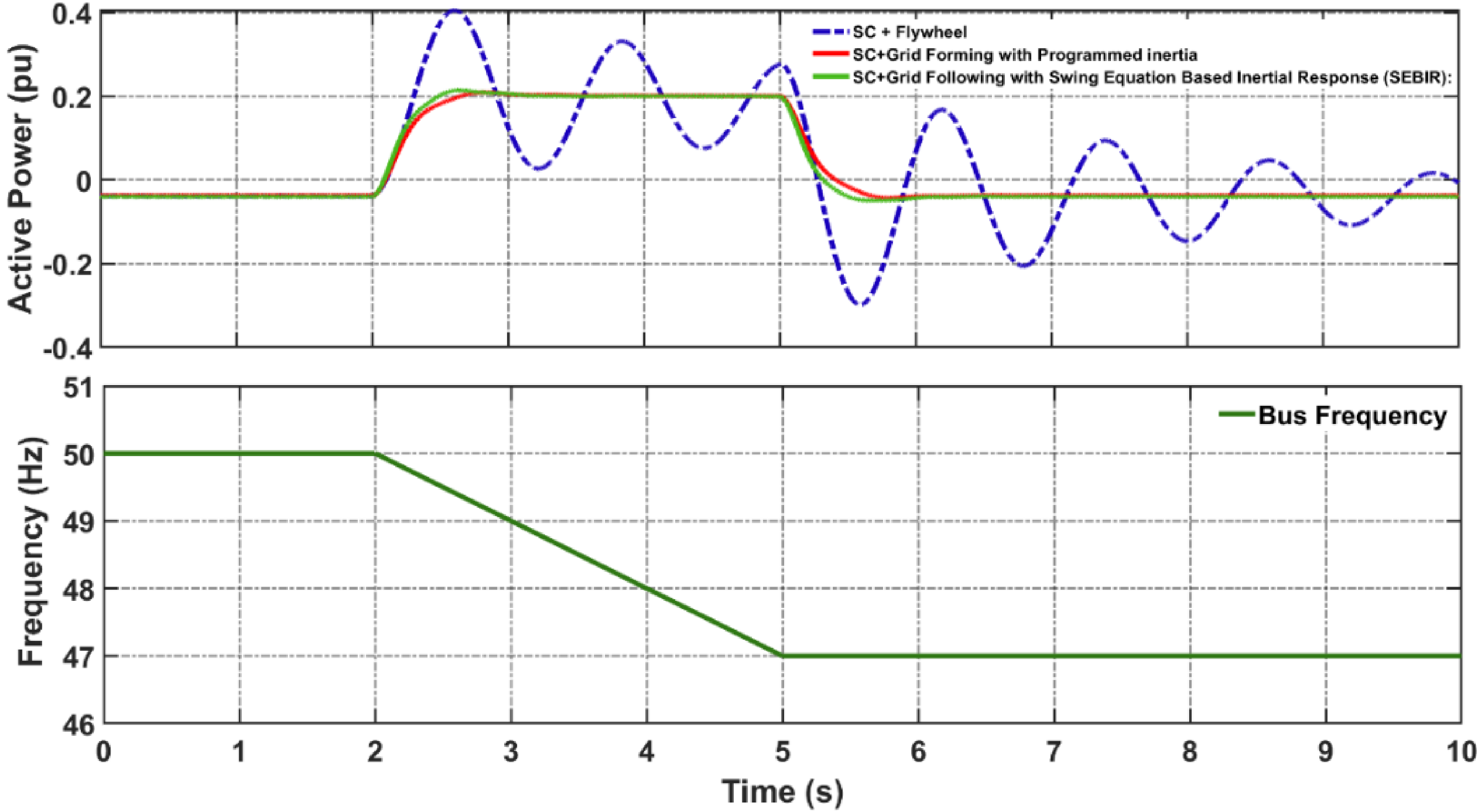


Limiter activation during phase shift

Better future, quicker...

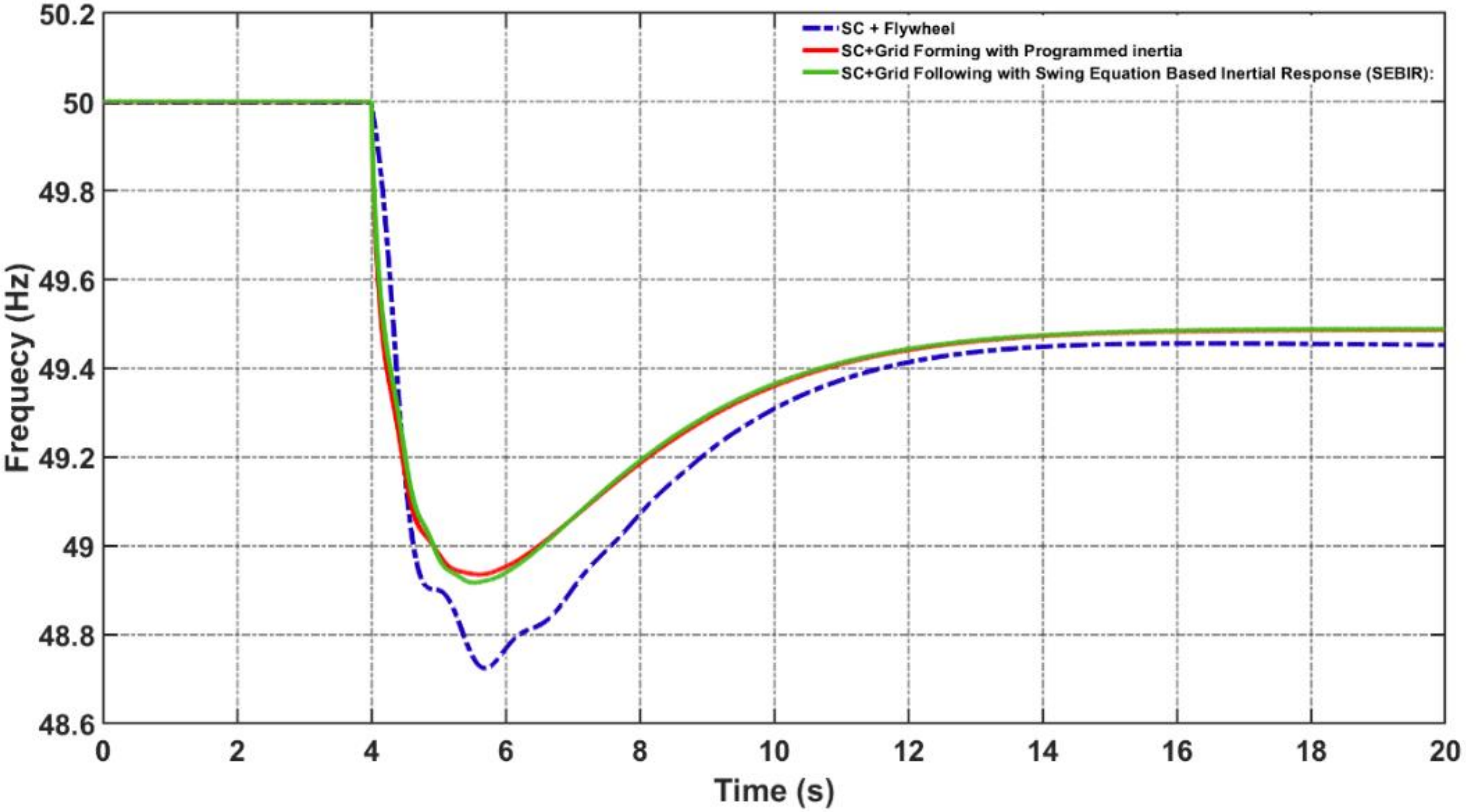
Inertial Responses Comparison (3 variants)

❑H-SC (Grid following, Grid Forming, SC+Flywheel)



ROCOF response 1Hz/s

Frequency Regulation Comparison (3 variants)



System frequency response under load event

H-SC Power Oscillation Damping Function

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- An implementation evaluated on an existing known problem with three underdamped/critically damped torsional interaction modes
- Torsional oscillation damping control is developed based on the measurement of voltage and current at the PCC of the involved synchronous generators.
- Using active and reactive power control of H-SC to provide damping to the system. Estimation of levels of power needed for effective damping .
- Adaptive power oscillation damping for local and interarea oscillations based on the active power measurement at PCC can be achieved.

Overview of Completed Work

Synchronous condenser model in PowerFactory

BESS model based on the RC circuit equivalent

Hybrid Synchronous Condenser System (HSC) model

Comparative study between grid-forming and grid-supporting control strategies

Power Oscillation Damping (POD) using HSC

Conclusion of H-SC Using Grid-Forming and Grid-Supporting Controls

SC adds robustness due to significant overloading capability, both in terms of short-circuit levels and voltage support.

Basically, an instantaneous response from the grid-forming converter.

Converter based technology have a step like response for large disturbances due to current limiters.

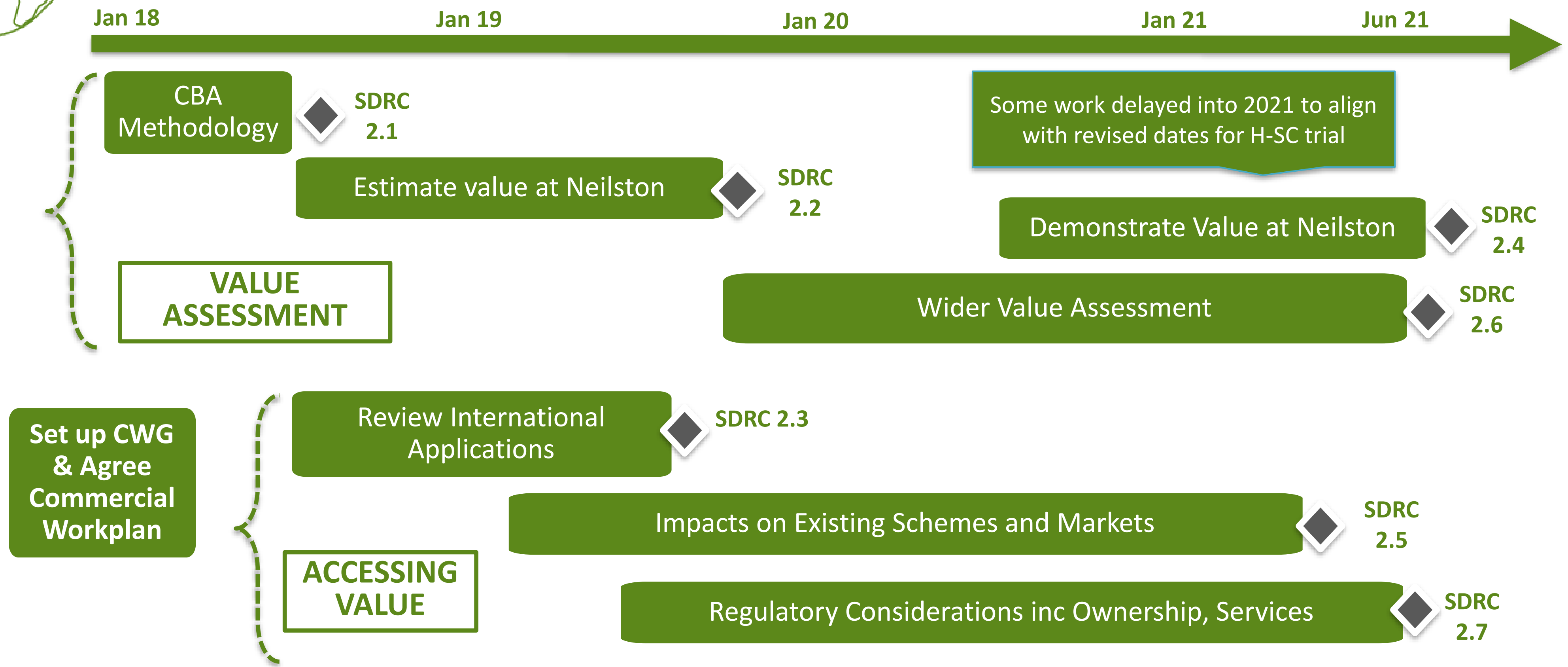
The slow SC post-fault response can be compensated by the converter.

The most balanced solution is the HSC with grid-forming capabilities -> very fast response and in many ways similar to a synchronous machine. Main difficulty in implementation is current limiting.

Interval – 10 minutes

Commercial Reports – John West

Recap of Commercial Work



Cost Benefit Assessment (SDRC 2.1, 2.2 & 2.6)
Validation from trial (SDRC 2.4)
International Review (SDRC 2.3).
Commercial Impacts (SDRC 2.5 & 2.7)

Work supported by industry Commercial Working Group

Through **SDRC 2.2**, a 140 MVA H-SC was shown to provide more value at Neilston than an SC or STATCOM by increasing boundary capability.

Anglo-Scottish Boundary Benefits (MW)	
Network	H-SC
2023 Winter	90
2023 Summer	45
2027 Winter	98
2027 Summer	65
Estimated benefits for 2019 FES (£m range)	
Scenario	H-SC
CE	73 - 86
CR	53 - 66
TD	54 - 67
SP	40 - 53

Through **SDRC 2.6**, SCs, STATCOMs and H-SCs were assessed for other GB cases.

Region/Boundary	Summary of H-SC Benefits
Scotland - B6 boundary with single device	One H-SC is insufficient to fully load the Western HVDC cable under all conditions.
Scotland - B6 boundary with multiple devices	Multiple H-SCs enable full loading of the Western HVDC cable and improve voltage stability. This provides greater benefit than SCs or STATCOMs.
North East & West boundaries - multiple devices	Both the STATCOM & H-SC solutions are effective at increasing the boundary transfer capability.
South Coast boundary - multiple devices	STATCOM and H-SC based solutions are effective at increasing the boundary transfer capability.

Through their ability to provide voltage support, inertia & fault infeed, H-SCs could support the GB network in a number of ways.

International Review (SDRC 2.3) – New SCs

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Area	New SC Case	Date	Rationale	Commercial
Denmark	3 SC's at Bjaeverskov, Fraugde & Herslev	2014- 15	System strength	Tendered, TSO Owned
Germany	SC at Bergheinfeld	2015	System strength	TSO Owned
Germany	SC at Oberottmarshausen	2018	Not known	TSO Owned
Italy, Sardinia	2 SCs at Codrongianos	2014	System strength & inertia	TSO Owned
USA, California	8 SCs at Talega, Miguel, San Luis Rey, Santiago & San Onofre	2015 - 18	System strength, inertia & voltage	ISO identify need, TO owned
USA, Texas	2 SC's at Alibates & Tule Canyon substations	2018	System strength (power transfers)	ISO identify need, TO owned
Australia, Victoria	1 SC to be installed with Solar Farm at Kiamal	2019	System strength	Connection Requirements
South Australia	4 SC's to be installed in Davenport 275kV area	2020	System strength, system inertia	ISO identify need, TO owned

- 22 new SCs installed/being installed (at late 2019)
- Also, 9 gen units converted to SC operation

1) Different approaches are being used internationally to support networks with increasing levels of inverter connected generation.
2) SCs used widely. Voltage support and system strength are the primary reasons.
3) SCs can be provided quickly (conversions <12 months, new SCs <24 months).
4) SC ratings tend to be in range 150 to 250MVAr. Designs often specific to local challenges.
5) There are no preferred commercial arrangements. SC's are typically installed by TSOs following processes to assess solutions, but generation developers are also installing SCs.

GB Markets for Voltage & Stability Services

Voltage Management:

- Managed regionally. Generators & other assets absorb/generate reactive power.
- Network assets (capacitors, reactors) have met much of the need with commercial services used to meet shortfalls.
- Reactive Power is procured through the ORPS (Obligatory Reactive Power Service), which must be provided by all generators with a Mandatory Services Agreement. (ORPS can only be used if the provider is running to provide real power.)
- ORPS provider availability has reduced.
- NGESO have piloted **Voltage Pathfinder** projects (e.g. Mersey, Pennines) to test commercial solutions in areas. Further regions are being prioritised with input from transmission & distribution owners.

Inertia & System Strength:

To manage transition to a system with less synchronous generation, work includes:

- Updates to standards including “Loss of Mains” protection requirements & SQSS.
- Inertia Modelling & Measurement to better predict operational requirements.
- Identifying new sources of stability from technologies including Phoenix & non-synch sources (Grid Forming capability).
- New market mechanisms to procure capability including **Stability Pathfinder**.
- Stability Pathfinder phase 1 (Jan 2020) awarded tenders for 12.5GVAs of inertia until March 2026. Phase 2 is underway to meet requirements in Scotland until 2030.
- The development of a future GB Grid Forming market.

Commercial Impacts of SC / H-SCs (SDRC 2.5)

With the support of the Commercial Working Group, impacts on GB balancing schemes and markets were considered in SDRC 2.5.

Conclusions on H-SC benefits:

- H-SCs can provide effective solutions where different attributes are needed (e.g. voltage response & fault infeed). They add to the options currently available.
- As yet, the studies and Neilston trial haven’t demonstrated particular benefits to suggest H-SCs should be deployed widely ahead of other solutions.

Conclusions on “routes to market” for H-SCs and SCs:

- SCs / H-SCs can be deployed through the NOA process and Pathfinders to meet voltage and stability requirements. Additional mechanisms are not needed.
- GB’s developing commercial arrangements enable different technologies to be used. SC / H-SC use should not detrimentally affect existing schemes and service providers.
- Adjustments to commercial arrangements are considered in SDRC 2.7 report.

Regulatory Considerations for Roll-Out (SDRC 2.7)

Pro’s and Con’s of the current approaches to deploying SCs / H-SCs were considered:

Approach	Main +ves	Main -ves	Conclusions
As TO regulated assets	• Wider benefits of SCs / H-SCs are available to ESO. • Can be deployed quickly. • May be connected where works are straightforward.	• Others don’t compete to provide this capability. • Assets may not be needed if conditions change. • No firm availability.	• Clarity needed on SC classification. • May reduce future opportunities for competition in service provision. • Look to firm up asset availability. • Could set ceiling price for tendered services.
Through NOA process	• Solutions are efficient as long term costs & benefits of options are compared. • There are mechanisms to fund TO solutions.	• Boundary assessments don’t factor in other benefits. • NOA recommendations may change year to year. • No Third Party funding.	• Further develop use of Interested Persons’ Options process. • Follow through work to establish funding for Third Party solutions.
Through Stability Pathfinder	• Different types of solution can be compared. • Third Parties can compete. • Contract periods can be matched to requirements. • Availability is contracted.	• Need for new connections may limit solutions. • Possible conflicts for NetCos. • Asset lives are likely to be longer than contract periods. • Some generators not eligible.	• Improve info to mitigate perceived conflicts. • Compare all proposals on equivalent basis. (E.g. losses, availability & levels of performance). • Consider remunerating TOs and Third Party providers on the same basis.

Other approaches to deployment have also been considered:

- by connectees to meet local compliance criteria
- through Early Competition Arrangements
- by TOs where commercial services are not cost-effective

Closing Remarks & Q&A Session

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University of Strathclyde Engineering

ABB

nationalgridESO

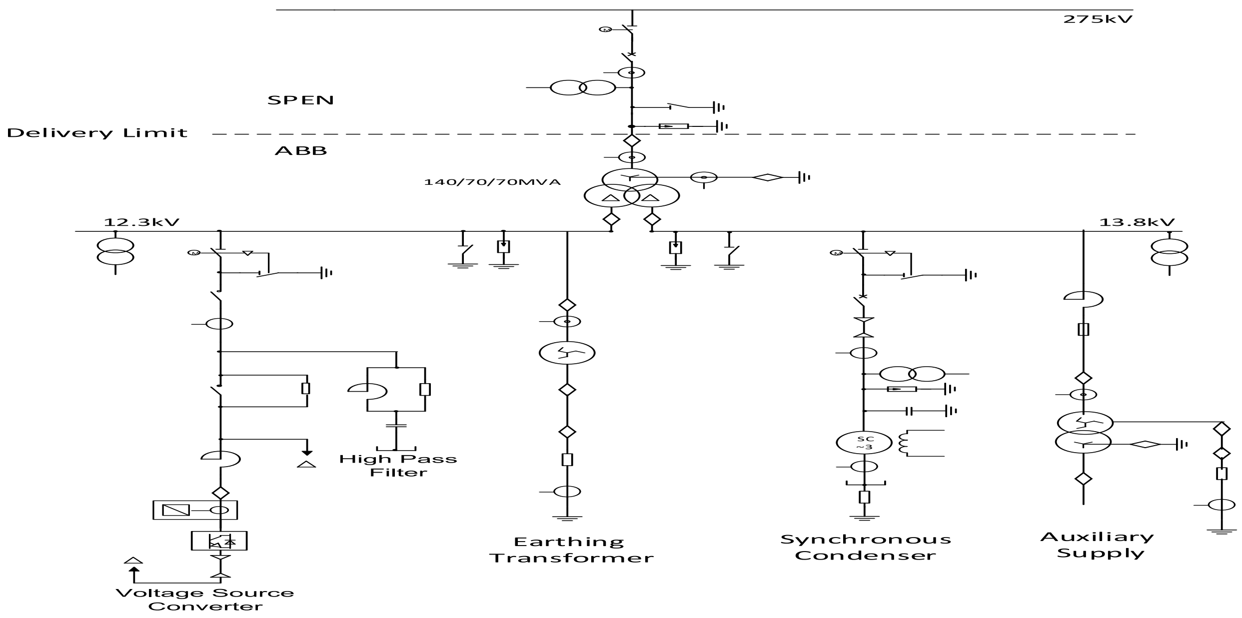
DTU

Q&A Session

Questions for ABB

Q - Is there an OLTC in the Step-Up Transformer? in case of affirmative answer, where is the control of the voltage control of the OLTC? Thanks

A - There is no OTLC. The transformer configuration with earthing transformer is show in figure.



Q&A Session

Questions for ABB

Q - What are the key areas still to test?

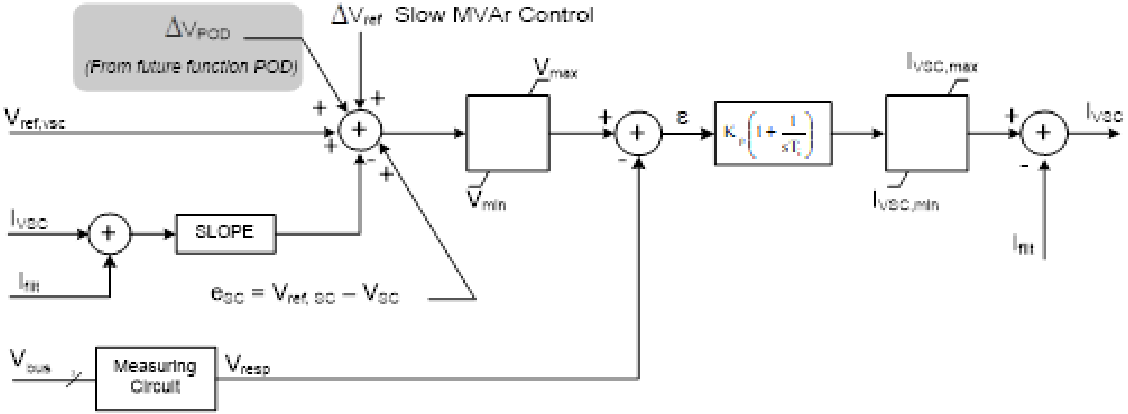
A - The dynamic response of the SC. These are included in repeat test cases

Q - Is the project compliant with the Grid Code?

A – As this is the world's first example of a H-SC in service there was no existing grid code requirements. National grid adapted the existing grid code for H-SC to define requirement.

Q - one question for me was around how you are using the synch comp error on voltage and angle measurement to inform the STATCOM control- could you expand on that unless other presentations cover that?

A - The error in SC voltage controls added in STATCOM voltage control loop as shown in Figure.



Q&A Session

Questions for ABB

***Q* - What would be the maximum short circuit contribution of the SC?**
A - The fault current varies between 4-7 pu depending on the machine. With 5 pu of fault current, a 70 MVA machine will provide 350 MVA short circuit contribution.
Q - ABB presentation; extra controls (POD-perhaps other GB-GFC?) could enhance device performance-do you see any benefits in having those controls in your analysis?
A - Yes definitely. Power oscillation damping (POD) was out of scope, but this can be done with our solution. The function will also help in grid stability
Q - Why is there a 3 winding transformer used to connect AC and BESS, and not a 2-winding transformer like shown on your first slide?
A - The three winding transformer is used to reduce cost as otherwise you would require 2 transformers for the different SC and STATCOM supplies - 12.3kV for STATCOM and 13.8kV for the SC. The challenges related to winding impedances are solved. This is also compact solution with one PCC at primary side.

Q&A Session

Questions for NGESO

Q - Is the project compliant with the Grid Code?

A - As this is the world's first example of a H-SC in service there was no existing grid code requirements in place. NGESO defined the technical requirements for the Phoenix H-SC. As ABB mentioned in the presentation, still more tests are planned to be carried out as part of the live trial to validate the response time of SC. Following this, we will be able to confirm that the device meets all the technical requirements and device specifications.

Q - When choosing sites for H-SC in the NE, NW and South Coast, how were these locations chosen? Are they optimised?

A - H-SC locations are based on the voltage issues, closure of existing generator (mainly nuclear) locations. It is not optimised locations, rather these locations are chosen to evaluate the benefit of H-SC.

Q - When comparing H-SC, SC and Statcom you say which is the best. Is this based on the relative costs (capex and opex) or assuming the same MVA capacity?

A - The analysis is based on the same MVA capacity for each option and is assessed against the system benefits (i.e. increase in boundary capabilities)

Q&A Session

Questions for NGESO

Q - What will be the need of SCL, once the Stability Pathfinder Phase-2, is in place? And there will be need of all this H-SC in south?
A - Stability Pathfinder phase 2 defined the SCL requirement in Scotland based on 2030 network background. With the changing energy background, with the increasing non-synchronous generations (or further declining synchronous generation) there may be a requirement of more SCL. If there is a requirement of inertia and dynamic reactive support, H-SC could be one of the options to meet such needs across the GB network.
Q - when you have 5-6 HSC devices; do we see any value in wide area control across them?
A - NGESO did not carry out any wide area control studies such as Power Oscillation Damping (POD), across multiple H-SCs in the system. DTU presented their findings on POD in the system.

Q&A Session

Questions for NGESO

Q - Have you reviewed the H-SC capability in comparison to the phase 2 stability pathfinder specification? (appreciate that came later than Phoenix)-can it help?
A - Phoenix device would be able to meet the Stability Pathfinder specifications.

Q - What do you think is the outlook for H-SC need post 2035 in Scotland?
A - As answered in Q4, with the further declining synchronous generations, beyond 2030 the requirement of SCL, inertia, Dynamic reactive support (and other benefits such as fault ride through capability, power quality and restoration capabilities) could be met by H-SC in Scotland. Given the changing energy landscape and the associated uncertainty Phoenix studies have focused on the period up to 2030 only, beyond this point studies have not been done.

Q&A Session

Questions for Technical University of Denmark

Q - How the grid forming control is implemented for BESS?
A – Please find the way of implementation from the paper here: https://arxiv.org/abs/2106.13555
The control without inner loop where the design is given from the paper https://arxiv.org/abs/2106.10048.

Q - A stable current limiting strategy is possible with grid forming converter. Is there any special challenge due to HSC?
A – There is no special challenge for HSC given the current hybrid control strategy from the combability perspective. Given the grid forming strategy the voltage source characteristic will be clearer that would make the converter system stable under weak grid conditions, especially when the SC is out for service.

Q - your GFC simulations disagree with actual practical experience of the control in action. suspect some misunderstandings in your modelling- pls send paper link.
A - Please find the link to the papers here: https://arxiv.org/abs/2106.13555.
We would very much like to hear your feedback.

Q&A Session

Questions for Technical University of Denmark

Q - I do not follow why a GFC- which is effectively a voltage source behind an impedance- would ever be "out of phase" or "not tracking" residual volts.

A – This is because of the active power loop control. For a sudden phase jump, say the grid phase angle has a step change in the forward direction, the power from the grid forming converter should be higher because the phase of the internal voltage vector is still keeping the same position so there will be wider phase difference between the controlled voltage phase and the grid phase. As we know the wider phase will lead to larger active power flow. However, because the exist of current limiter, the power will not reach the natural level but regulated at a low level of 1.1 pu typically or even reduce it due to the control strategy. Then the power control loop would lose the ability to maintain the active power that will lead to further separation of the phase between the internal control loop and the external grid. In this case, if the power reference is not adjusted quickly, the operating point will move to an unstable region.

It can also be explained as the following: When disturbance happens, the active and reactive power increases with a larger delta between 2 voltage sources (ref to active and reactive power transfer equations). A current limit based on virtual impedance works in principle similar to increasing the reactance between the two voltage sources i.e., increasing the denominator of the power transfer equation between the voltage sources. At a larger phase jump at higher dispatch active power (ref power), an increase in virtual reactance to limit the current can offset the expected increase in active power output and could also reduce the active power output further. In this case, if the power reference is not adjusted quickly, the operating point will move to an unstable region.

Q&A Session

Questions for Market Specialist

Q - Could you please explain your comment the asset may not be needed if the condition changes in your last slide.

A - This comment recognises that if SCs or H-SCs are deployed as TO regulated assets, they are likely to be remunerated over a regulatory asset life of 20 to 40 years. Over this period of time, network conditions may change, perhaps due to new generation being developed, and the SCs or H-SCs may no longer be as useful at the location where have been deployed.

Often the benefits obtained in the early period after deployment will make the SC or H-SC investment worthwhile in any case. The ability to relocate assets can also offset the longer-term risk that they are not as useful in a particular location.