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First Interim Report

Upgrading Energy Regulations for Energy Regulatory Commission of the Philippines

Report for the Energy Transition Partnership

ED 15884 | Issue number 2 | Date 28/04/2022

Ricardo Confidentia

Customer:

Energy Transition Partnership (ETP) and Energy Regulatory Commission (ERC)

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Date:

28 April 2022

Ricardo Energy & Environment reference

Ref: ED 15884 Issue 2

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Executive Summary

The Energy Transition Partnership (ETP) awarded Ricardo Energy and Environment the project study Upgrading Energy Regulations for the Energy Regulatory Commission (ERC) of the Philippines. The project held the inception meeting on 23 December 2021 and submitted the final Inception Report on 31 January 2022.

As specified in the project contract, this First Interim Report updates ETP and ERC on the first progress of our activities. The objective of this report is to present the preliminary analysis and results as well as seek feedback and guidance from ERC and ETP as we continue with our planned activities to achieve specific task goals and deliver anticipated project outputs.

Our preliminary results and analysis are presented in the following sections. The table below presents project activities and timelines. This is to provide an overview on the progress of our activities with respect with the overall project timeline.

Project Activity and Timelines

Number	Project Activity Description	Activity Duration specified in the Terms of Reference	Timeline
Task 1	Project Inception	-	17–23 Dec 2021
Task 2	Data Collection	-	3–31 Jan 2022
Task 3	Analysis, Capacity Building and Proposed Changes		3 Jan – 18 Sep 2022
Task 3.1	Revisiting the existing technical, operating and performance standards for renewable energy generators	6 months	3 Jan–19 Jun 2022
Task 3.2	Rules and Regulations for Ancillary Services Responsive with Variable Renewable Energy Technology	6 months	31 Jan–17 Jul 2022
Task 3.3	Rules and Regulations for Smart Grid Facilities	6 months	14 Feb–31 Jul 2022
Task 3.4	Revisions and Amendments on the Existing Philippine Small Grid Guidelines	6 months	28 Feb–14 Aug 2022
Task 3.5	Sustainable Energy Initiatives for Smarter and Greener City	6 months	7 Mar–28 Aug 2022
Task 3.6	Procurement of Consultancy Services for the Promulgation of the Distribution Systems Loss Cap	6 months	28 Mar–18 Sep 2022
Task 3.7	Strategic Review of the Regulatory Framework	12 months	3 Jan–18 Sep 2022
Task 4	Public Consultations	-	30 May–18 Sep 2022
Task 5	Finalisation, Presentation and Reporting	-	17 Jan–20 Nov 2022
	Inception Report		17 Jan 2022
	First Interim Report [1]		28 Feb 2022 Proposed to be moved to 31 March 2022
	Second Interim Report		1 Aug 2022
	Draft Final Report		1 Oct 2022
	Final Report		17 Nov 2022

[1] Ricardo proposes to move the submission of the First Interim Report to 31 March 2022 as the project started in January 2022. Minimal progress will be achieved until the end of February given that the first month of activities will be devoted to data collection.

Ricardo Engagements with ERC

Based on the Draft Inception Report, Ricardo communicated to all task focal points of ERC on 16 January 2022, introducing Ricardo's team responsible for each task, and sending them Ricardo's listing of data required for each task.

- Task 1
  - ERC focal point acknowledged receipt of our email on 19 January 2022.
  - On 27th January, the Team forwarded 2 documents for modifications
  - These documents are ERC Resolution No. 13, Series of 2021 entitled "A Resolution Adopting the Rules for the Monitoring of Variable Renewable Energy (VRE) Generating Facilities Performance". Attached also is ERC Resolution No. 9, Series of 2012 "A Resolution adopting the Rules and Procedures to Govern the Monitoring of Compliance of Grid User to the Philippine Grid Code".
  - Recommendations for modifications will be done after the webinar.
- Task 2
  - The team responded on 17 January 2022 and forwarded 2 documents for reference.
  - These documents are the Ancillary Service Procurement Plan (ASPP) approved in year 2006 and Ancillary Service-Recovery Mechanism (AS-RCM).
- Task 3
  - The team acknowledge receipt of our email on 17 January 2022.
  - On 10 February 2022, the team sent 2 documents: resolution for the distribution planning manual of PUs and ECs (Annex of Resolution 26).
- Task 4
  - The team replied on 17 January 2022 and sent the following documents: Philippine Small Grid Guidelines (PSGG); PDC, Philippine Small Grid Dispatch Protocol and DOE's DCs related to the Small Grid operations.
- Task 5
  - The Team replied on 19 January 2022 and informed Ricardo that they are compiling the requested information.
- Task 6
  - The Team replied on 19 January 2022 and sent the following document: ERC Resolution containing the methodology, the incentive mechanism, and the required data from DUs for the SL cap review.
  - The Team also sent on 23 March 2022 the previous consultant's presentation material containing their approach and methodology in estimating the distribution loss cap.
  - Ricardo sent its proposed methodology and data request on 4 April 2022. The Team replied on 18 April 2022 informing Ricardo that data are being collected and will be sent by end of April.
- Task 7
  - The Team responded on 20 January 2022 and sent a list containing all RE issuances of ERC.

Ricardo's Recommendations and ERC's Response

The period 1 January to 31 March 2022 corresponds to data collection and Ricardo's preliminary analysis related to project tasks.

Ricardo's preliminary analysis and recommendations are reported in this Interim Report. The analysis and recommendations were not shared with ERC before the submission of this report. The intention is to organise webinars for each task after the submission of the Interim Report.

A webinar for Task 1 is being organised in early May 2022. This webinar will present Ricardo's preliminary analysis, results and recommendations to ERC related to the upgrading of the national grid code and distribution grid code. The preparation of this activity and the outcomes will be reported separately.

A series of webinars are being planned according to the timeline submitted in the Inception Report.

Challenges and Success Stories

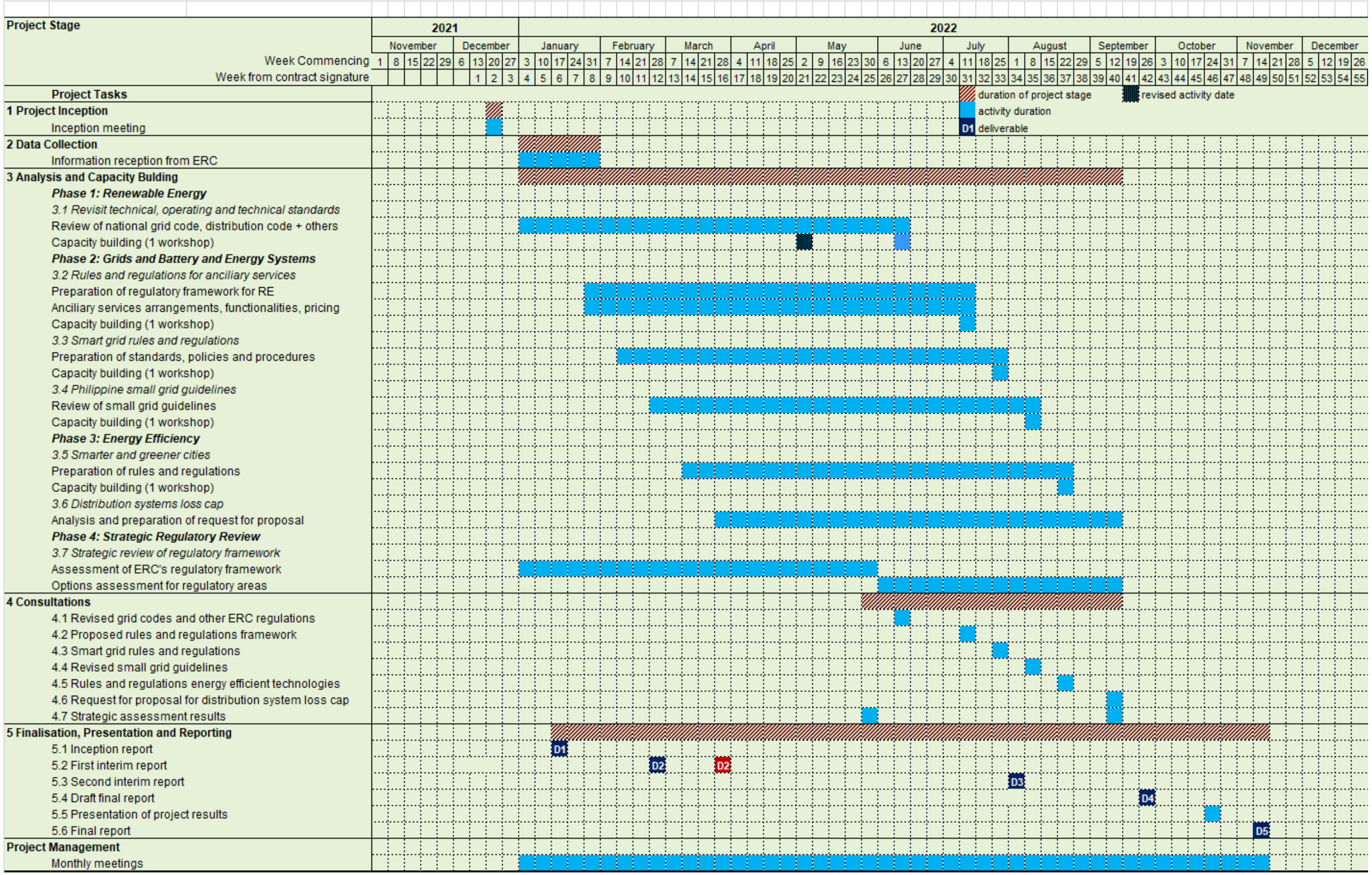
The lack of face-to-face meeting due to COVID-19 pandemic travel restrictions initially appears to be a barrier in effective engagement with ERC. Our constant communications with ERC however have apparently overcome this potential barrier.

Response to Comments

Comments	Response
Page 1 **I** feel for reporting to ETP, Sections 2-8 would be better placed as an Annex items with a summary report sitting on top, listing work done, workshops held, proposals made, next steps etc Also, there is no updated work plan as per the contract requirement.	For this report, we added the Executive Summary covering the points mentioned in the comment while the rest remains key chapters of the report. We added the Results-Based Monitoring Framework as Chapter 1. We added the workplan under the Executive Summary section.
Page 6 How was the list of benchmarks chosen/determined? Was there a standard?	We selected USA as this is 60 Hz system (IEEE, FERC and NERC) similar to the Philippines. We included Europe, ACER the UK and South Africa as these countries/regions have been recently updated their regulations related to VRE.
Page 26 How are recommendations being delivered to ERC? What is the ERC response to such questions? Whilst this report looks good, a summary report with outcomes would be more useful for ETP evaluation.	This report is a progress report covering the analysis based on international practices. The recommendations will be delivered through webinars. We arrange the webinars by project task. Task 1 webinar is scheduled on May 6, 2022.

Table 1. Updated Project Workplan

We will adhere to our original workplan as shown in the Gantt Chart below. We initially plan to have our webinars starting from July but with the recent progress that we have, we have moved the webinar for Task 1 in early May 2022.



1 Results-Based Monitoring Framework

The results-based monitoring framework submitted in the Inception Report – Issue 1 was revised in the Issue 2 of the Inception Report. At this stage, the Framework remains the same, as shown in Table 1.

Table 2. Results-based Monitoring Framework

ETP Results	Project Output(s)	Indicators	Targets	Data Source and Means of Verification
Impact	The Philippines transitions towards modern energy systems that simultaneously ensure economic growth, energy security and environmental sustainability	**IN Im-01** - Climate action plans with respect to climate agreement targets and commitments	The current Philippines's NDC is compatible with 2°C goal. The target is to make the plan compatible with 1.5°C goal.	Revised action plans and NDCs.
		IN Im-02 - GHG Emissions avoided or reduced – estimates of fossil fuel mix replaced in % (Coal, Natural Gas, Oil) GHG emissions intensity	The NDC targets the energy sector emissions reduction of 525.59 MTCO2eq between 2020 and 2040. The Philippine Energy Plan 2020-2040 aims to increase the energy sector emissions reduction to 1,039.44 MTCO2eq during the same period. The Philippine Energy Plan 2020-2040 aims to reduce the GHG intensity from 6.8 tCO2eq per million PhP of GDP in 2020 to 4.9 tCO2eq per million of GDP in 2040.	Power sector statistics and plans
		IN Im-03 - Average Air Quality Index (AQI) improved thus impact of pollution on health minimized		
		IN Im-04 - Green Jobs in low-carbon industries added	The Philippine Energy Plan 2020-2040 plans to add 845,208 green jobs between 2020 and 2040.	Power sector statistics and plans
Long-term Outcome	Increased deployment of renewable energy and energy efficiency	**IN LTO-01** - %share of renewable energy in the total final energy consumption (TFEC)	The Philippine Energy Plan 2020-2040 aims to increase the share of RE in total power generation mix from 21.26% to 50.13% in 2040. In terms of share from TFEC, from 22% in 2020 to 26% in 2040 (renewable electricity only, excluding biomass).	Power sector statistics and plans
		IN LTO-02 - %share of renewable energy in the total primary energy supply (TPES)	In terms of share from TPES, from 20 % in 2020 to 26% in 2040 (renewable electricity only excluding biomass)	Power sector statistics and plans
		IN LTO-03 - Additional RE (non-combustible) installed capacity (GWh)		
		IN LTO-04 - Energy Intensity (Efficiency)	The ASEAN targets energy intensity reduction of 25% in 2030 and 45% in 2035 from 2005 level. Energy intensity in	Power sector statistics and plans

			2020 reached 3.2 toe per million Php which is around 26% lower than that of 2005. The Philippine Energy Plan 2020-2040 projects the energy intensity to decline by around 52% in 2035 and 56% in 2040 from 2005 level.	
Intermediate Outcome 1. Strengthened RE and EE policy enabling environment				
Short-Term Outcome 1.1 National RE and EE policies, regulations, standards, and energy plans reflect a clear commitment to Energy Transition agenda and integrated into sectoral plans to contribute to the achievement of Paris Agreement	Updated regulations to ensure achievement of RE and EE targets stipulated in the Government's NDC	**IN 1.1-03**: Integration of RE technologies • 2 Grid Codes updated (National and Distribution) • **x** number of resolution, rules and regulations updated Ancillary services • 1 updated rules and regulations Smart grid facilities • 1 updated rules and regulations Small grids • 1 amended Philippine small grid guidelines Energy efficiency • 1 draft rules and regulation on energy efficiency	At least 6 grid codes and rules and regulations updated/amended	List of submitted Codes, resolutions, rules and regulations to ERC Board for approval
Short-Term Outcome 1.2 National Fiscal policies, regulations, and Investment policies have undergone reforms to create an Investment Climate that is conducive to investment flow into RE/EE and improves its energy transition readiness for capital and investments				
Short-Term Outcome 1.3 Energy transition agenda is centrally led and coordinated effectively at a National-level agency/institution that is tasked to champion the cause with right level of authority	Strategic overview of ERC's regulatory framework to ascertain its pertinence and pursuit of a low carbon energy system, low carbon economy, and the Government's NDC	**IN 1.3-01:** Strategic assessment of ERC framework and options assessment for regulatory areas where ERC can further align its regulations with the Philippine climate goals	Strengthened ERC with comprehensive outlook on RE and EE.	ETP coordination activities
Intermediate Outcome 2. Increased flow of public and private investments to RE and EE projects in the power and end-user sectors				
Short-Term Outcome 2.1 National budgets indicate a resolve to maximize RE/EE capacity by allocating increased amount of public funds and attracting FDI in the RE/EE sector				
Short-Term Outcome 2.2 De-risked project finance is accessible via financial institutions generating a pipeline of large-scale RE/EE projects				
Intermediate Outcome 3. Increasing the amount of RE integrated in smarter grids				
Short-Term Outcome 3.1				

National energy strategy and sectoral plans involve evidence-based planning for an improved national-smart-grid system along with related infrastructure and innovative technologies				
Intermediate Outcome 4. Increased development of and accessibility to RE/EE knowledge				
Short-Term Outcome 4.1 Stakeholders (relevant Government entities, Public sector companies, Financial institutions, Private entities, Academia, and Consumers) involved in the RE/EE value chain, are knowledgeable and better informed to advance the energy transition agenda	Capacity developed at ERC and key stakeholders on RE, battery storage, ancillary services, and EE	**IN 4.1-01:** 1 study on EE (system loss caps analysis)	At least 1 study on EE	Implementation report and attendance sheets
		IN 4.1-02: 5 seminars for ERC and 5 regulation drafting consultations for ERC and its key stakeholders	5 seminars and 5 regulation drafting consultations.	Implementation report

2 Task 3.1: Revisiting the existing technical, operating and performance standards for renewable energy generators

2.1 Introduction

The Philippine Grid Code - 2016 Edition (PGC) and Distribution Grid Code 2017 Edition (DGC) generator connection conditions are reviewed and compared to one another.

Generator in the context of this report includes both synchronously and non-synchronously connected power plants and power plant modules. Internationally the generator connection conditions are sorted into categories and the categories are dependent on plant size and voltage level. Unfortunately, there is currently no consistency between codes on the category sizes. The main reason is the impact of size is dependent on the size of the interconnection.

The Philippine codes are also compared to DOE Department Circulars and WEMS rules.

The grid code connection requirements are benchmarked against:

1. IEEE 1547-2018 standard for embedded generation,
2. FERC Order 2003a and pro forma Large Generator Interconnection Agreement,
3. NERC Reliability Standards for the Bulk Electric Systems of North America, Updated June 28, 2021,
4. ACER - Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators. This code specifies the generator connection requirements for Europe, Nordic and Ireland.
5. Great Britain – The Grid Code, 4 September 2019.
6. South African Grid Code sections:
    a. Network Code version 10,
    b. Grid Connection Code for Renewable Power Plants (RPPs) Connected to the Electricity Transmission System (TS) or the Distribution System (DS) in South Africa version 3.0, and
    c. Grid Connection Code for Battery Energy Storage Facilities (BESF) Connected to the Electricity Transmission System (TS) or the Distribution System (DS) in South Africa version 5.2.

The key focus of this review is where we have observed different requirements between the PGC and DGC and where these codes deviate from international practice. The main sections reviewed are:

1. Generator and Power Plant size
2. Fault ride through
3. Fast fault current injection
4. Reactive Power and Voltage Control
5. Real Power and Frequency Control
6. BESS

2.2 General observations

2.2.1 Grid code sections

Europe and Great Britain have moved away from specific grid code sections for each technology and now have requirements for synchronously connected and non-synchronously connected (inverter) generators. This makes managing the grid code easier and there's not misalignment between technologies.

The question for Philippines is whether this is desired or possible?

2.2.2 Introduction of new grid code requirements

Most codes are clear that new requirements only apply to new generators. Europe will give new requirements a year to come into force to ensure generators being built have time to comply. Without such clauses grid code changes become difficult to implement as they impact exiting generators. With technology moving so fast it is important that the latest good international practice is followed.

2.3 Generator and Power Plant size

This section provides a comparison of the different sizes used for categorising the requirements for generators connected to the transmission and distribution system.

2.3.1 Philippines Grid Code

The PGC only mentions Large Generating Plant but does not define an actual size. The code does mention the definition of Large Generating Plant is the same as in the DGC.

2.3.2 Philippines Distribution Grid Code

The classification of embedded generating plants in the DGC is defined in the Table below.

Table 3. DGC definition

Category	Installed Capacity and Characteristics
Large Conventional	Conventional Embedded Generating Plant with an aggregated Installed Capacity of 10 MW or more.
Large VRE	VRE Embedded Generating Plant with an aggregated Installed Capacity of 10 MW or more.
Medium	Conventional or VRE Embedded Generating Plants with Installed Capacity larger than 1 MW which do not qualify as Large Embedded Generating Plant.
Intermediate	Conventional or VRE Embedded Generating Plants with Installed Capacity larger than 100 kW and equal to or less than 1 MW; and Conventional Embedded Generating Plants with Installed Capacity lower or equal to 100 kW connected to MV networks.
Small	Embedded Generating Plant with Installed Capacity larger than 10 kW and equal to or less than 100 kW connected to LV networks.
Micro	Embedded Generating Plants with Installed Capacity lower or equal to 10 kW connected to LV networks.

2.3.3 NERC Reliability Standards

Although not specifically stated the NERC standards seem to apply to:

- Generators and synchronous condensers ≥ 20 MVA, or
- Aggregate plant/Facility ≥ 75 MVA.

2.3.4 FERC Order 2003a and pro forma Large Generator Interconnection Agreement

FERC Order 2003a and pro forma Large Generator Interconnection Agreement applies to electric generating facilities having a capacity of more than 20 megawatts.

2.3.5 IEEE 1547-2018 requirements

IEEE 1547-2018 does not specify the MW / MVA level for each of the categories for fault ride through and voltage control. Instead in expects each interconnection to decide the levels based on the impact of embedded generator in the network. It does state that for the USA NERC Reliability Standards apply to transmission connected generators.

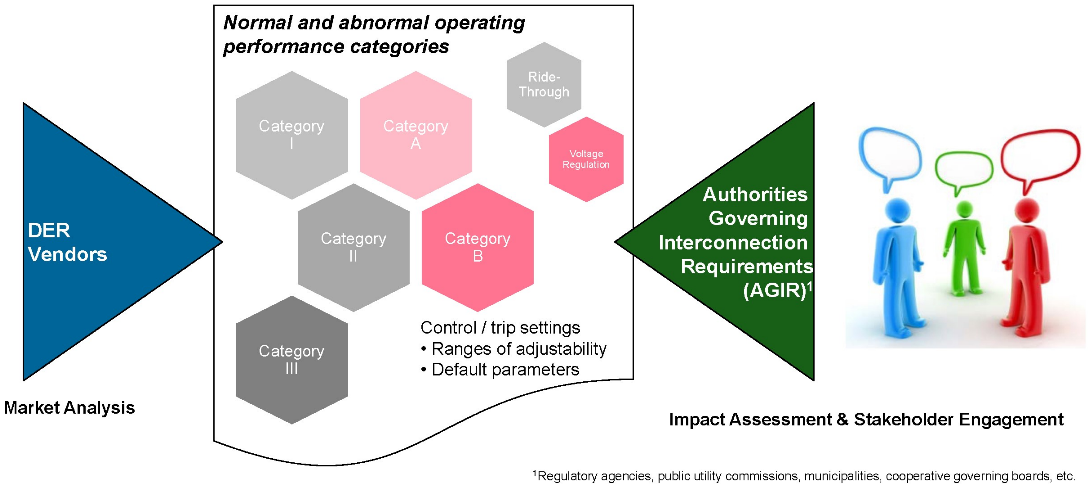


Figure 21. IEEE 1547-2018 High-level overview of performance-based category approach

2.3.6 Ireland Grid Code

The Irish limit for maximum capacity threshold from which a power- generating module is:

- Type A < 0.1 MW,
- Type B ≥ 0.1 MW,
- Type C ≥ 5 MW, and
- Type D ≥ 10 MW.

2.3.7 Great Britain Grid Code

The Great Britain limit for maximum capacity threshold from which a power- generating module is:

- Type A < 1 MW,
- Type B ≥ 1 MW,
- Type C ≥ 50 MW, and
- Type D ≥ 75 MW.

2.3.8 South African Grid Code

The South African limit for maximum capacity threshold for renewable power plants is:

- Category A1 < 13.8 kVA,
- Category A2 ≥ 13.8 kVA,
- Category A3 ≥ 100 kVA,
- Category B ≥ 1 MVA, and
- Category C ≥ 20 MVA.

The South African network code has a table defining which requirements are applicable. The first few rows non hydro plants are shown in the table below.

Table 4. South African Grid code requirement for hydro

Grid code requirement	*Units* other than hydro (MVA rating)					
	<20	20 to <100	100 to <200	200 to <300	300 - <800	>=800
GCR1 Protection:						
Network Backup protection	Yes	Yes	Yes	Yes	Yes	Yes
Loss of field	-	Depends on IPS Requirements	Yes	Yes	Yes	Yes
Pole slipping	-	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements
Trip to house load	-	-	Depends on IPS Requirements	Depends on IPS Requirements	Yes	Yes
Gen trfr backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
HV breaker fail	Yes	Yes	Yes	Yes	Yes	Yes

The categories for Battery Energy Storage Facilities (BESF) in South Africa is shown in the Table below.

Table 5. South African Grid code categories of battery energy storage facilities

Category	Rated power of *BESF*		
A	>0	to	< 1 MW
A1	>0	to	≤ 13.8 kW
A2	>13.8 kW	to	<100 kW
A3	≥100 kW	to	<1 MW
B	≥1 MW	to	<20 MW
B1	≥1 MW	to	<5 MW
B2	≥5 MW	to	<20 MW
C	≥20 MW	-	-
Note: For a category A *BESF* connected to multi-phase supplies (two- or three-phase connection at the *POC*), the difference in installed capacity between phases may not exceed 4.6 kW per phase			

2.3.9 Recommendations for defining plant size

The Philippines PGC and DGC have used 10 MW as the threshold for a large generator. This aligns with the Irish code requirements.

The USA and South African codes have set the large generator at ≥ 20 MW which could be considered for the Philippines.

The PGC could be clearer that the code applies to all generators connected to the transmission system and clearly define a larger generator as being ≥ 10 MW so the reader doesn't have to look in the DGC.

2.4 Reactive Power and Voltage Control

2.4.1 Introduction

Reactive power capabilities and voltage control requirements are important to define in the grid code. Reactive power / voltage control is required at a local level and its key that the generator support voltage control at the connection point.

2.4.2 Philippines Grid Code

The PGC has different requirements for wind farms and solar farms. Wind farms are required to provide reactive capability as shown in the figure below. PV must provide Reactive Power capability, at its Connection Point, within the limits of Power Factor 0.95 lagging and 0.95 leading. There is no minimum limit.

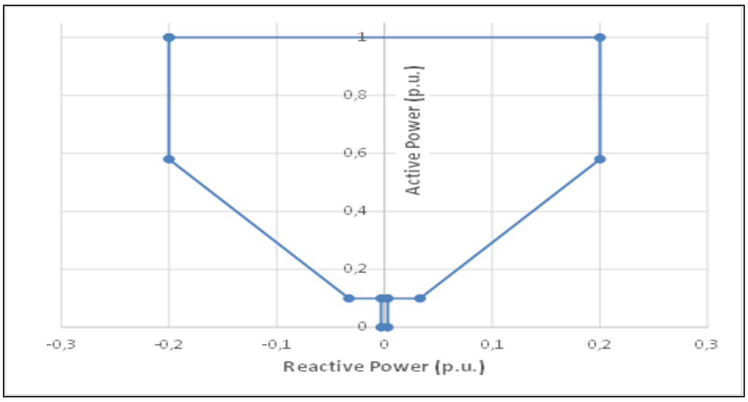


Figure 22. PGC reactive power capability for large wind farms

2.4.3 Philippines Distribution Grid Code

The DGC requires large variable renewable energy power plants to provide the same reactive power capability as defined for large wind farm in the PGC (shown in the above figure).

2.4.4 IEEE 1547-2018 requirements

2.4.4.1 Reactive power capabilities

Category A and category B must provide the reactive capability as shown in the figures below. Note that full reactive power is required when power is > 0.2 of rated power.

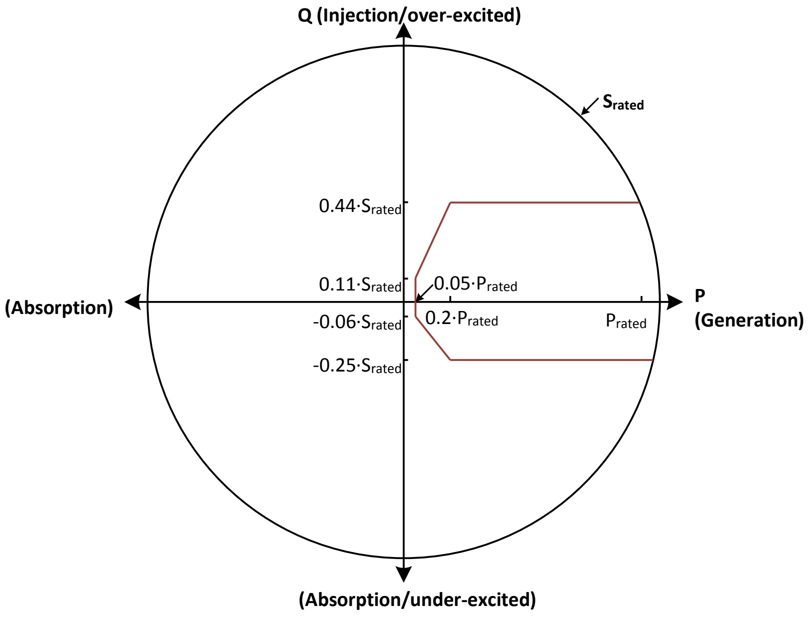


Figure 23. IEEE 1547-1018 category A reactive power capability requirements

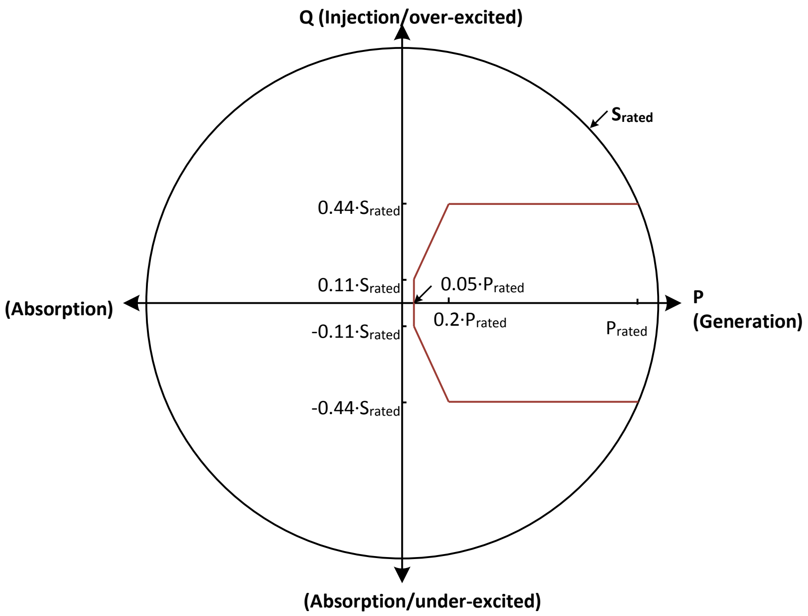


Figure 24. IEEE 1547-1018 category B reactive power capability requirements

2.4.4.2 Voltage control requirements characteristic

The curve of reactive production for various voltage levels is to be defined by the relevant distribution network owner. Figure 25 shows the typical curve with a dead band and slope. Figures below show the IEEE 1547-2018 reactive power and voltage requirements for generators. The allowable dead band voltage-reactive power is 0.05 pu for category A and Vref ± 0.02 for category B.

Maximum reactive power must be provided when the voltage deviation is 0.1 pu for category A and Vref ± 0.08 for category B.

The response is to be settable between 1s and 90 s. Default vale for category B is proposed to be 5s.

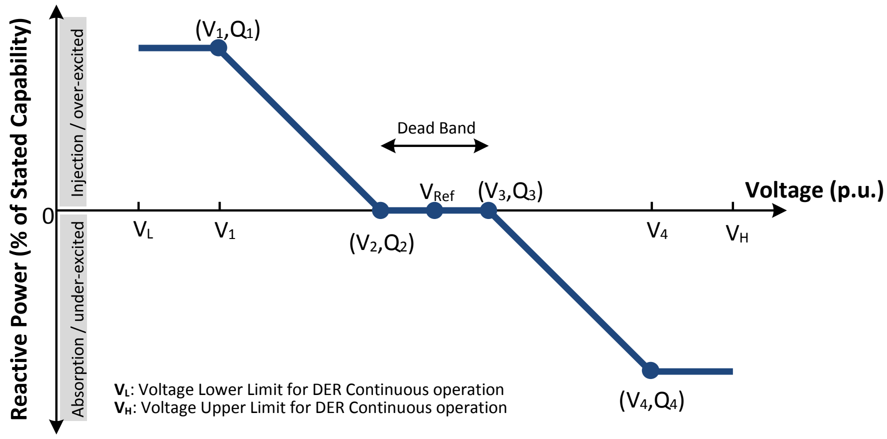


Figure 25. IEEE 1547-1018 voltage-reactive power requirements

2.4.4.3 Active power reactive power characteristic

When in this mode, the generator actively controls the reactive power output as a function of the active power output. The maximum the response time is proposed to be 10 s.

The default setting is a dead band of 0.5 pu of rated power, full reactive production at 0.2 pu of rated power and full reactive absorption at rated power.

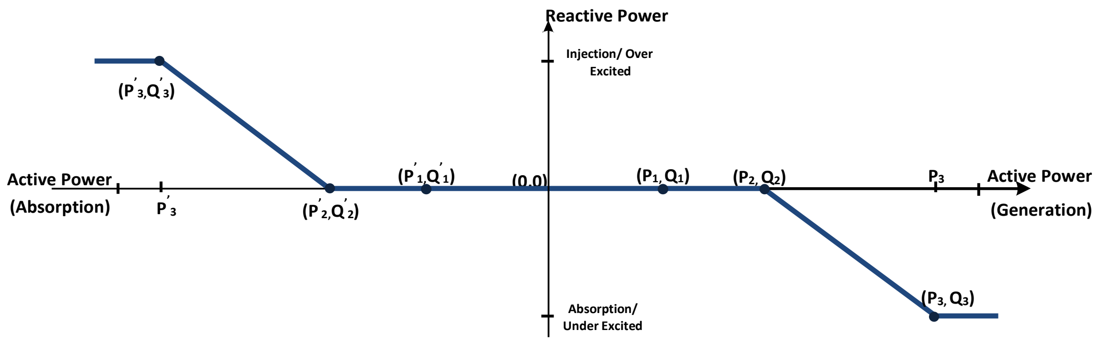


Figure 26 IEEE 1547-2018 active power reactive characteristic

2.4.5 FERC Order 2003a and pro forma Large Generator Interconnection Agreement

2.4.5.1 Reactive power capabilities

Synchronous must provide a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging.

Non-synchronous must provide composite power delivery at continuous rated power output at the high side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging. Reactive power can be provided by power electronics and / or switchable capacitors.

2.4.5.2 Voltage control capabilities

Large generators must be able to receive a voltage schedule. Voltage regulators must be able to control the voltage according to the prescribed schedule and to the specifications of the system operator.

2.4.6 Ireland Grid Code

2.4.6.1 Reactive power capabilities

Ireland requires all generators > 5 MW to have reactive power capability according to Figure 27.

Synchronous generator inner loop must have a Q/P_{max} range of 1.08 and maximum steady state voltage range of 0.218 pu. The requirement is from minimum stable generation to maximum generation.

Non-synchronous generator inner loop must have a Q/P_{max} range of 0.66 and maximum steady state voltage range of 0.218 pu. The requirements below maximum generation are defined in Figure 28. Note the full reactive range must be provided down to 12% of maximum power.

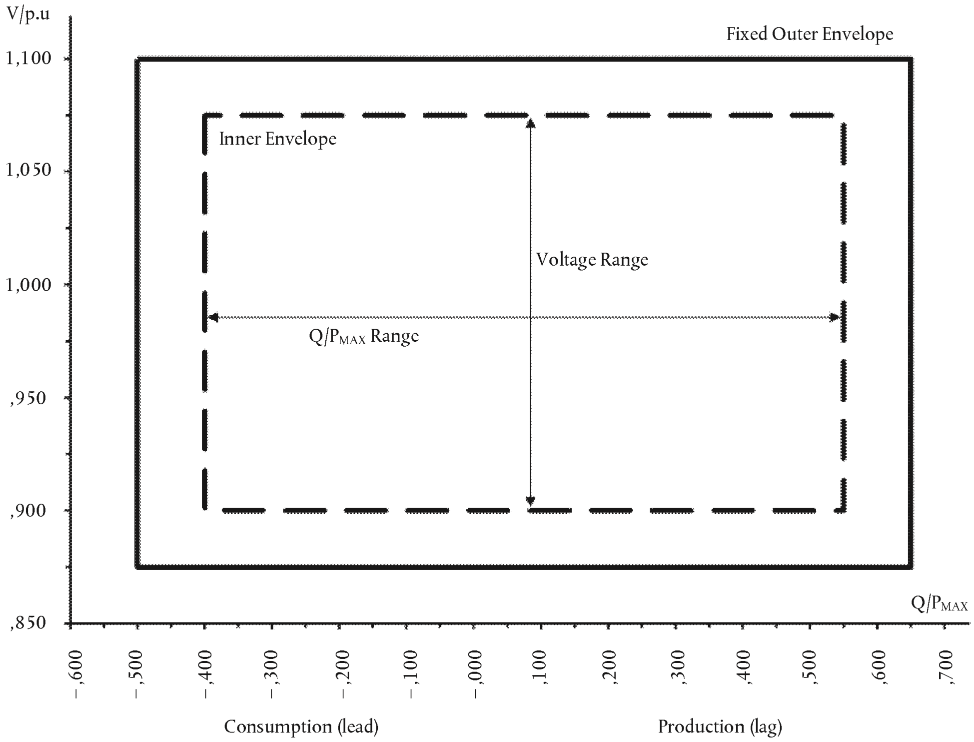


Figure 27 Ireland Grid Code V-Q/Pmax reactive power capabilities for synchronous generators > 5 MW

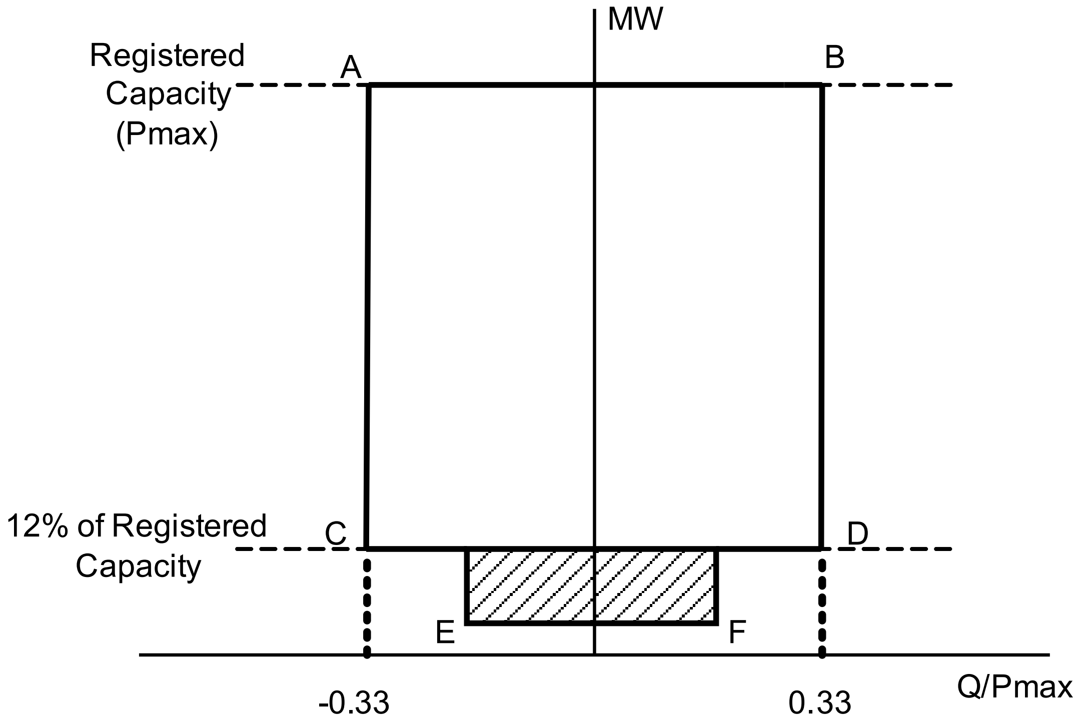


Figure 28 Ireland Grid Code - minimum real power / reactive power capability of non-synchronous generator

2.4.6.2 Voltage control capabilities

Generators shall be capable of providing reactive power automatically by either voltage control mode, reactive power control mode or power factor control mode. Times to control and quality for control are provided for in the grid code.

2.4.7 Great Britain Grid Code

2.4.7.1 Reactive power capabilities

Great Britain requires all generators > 50 MW to have reactive power capability according to Figure 29.

Synchronous generator ≥ 50 MW inner loop must have a Q/P_{max} range of 0.95 and maximum steady state voltage range of 0.225 pu.

Non-synchronous generator ≥ 5 MW inner loop must have a Q/P_{max} range of 0.66 and maximum steady state voltage range of 0.225 pu. The requirements below maximum generation are defined in Figure 29. Note the full reactive range must be provided down to 20% of maximum power.

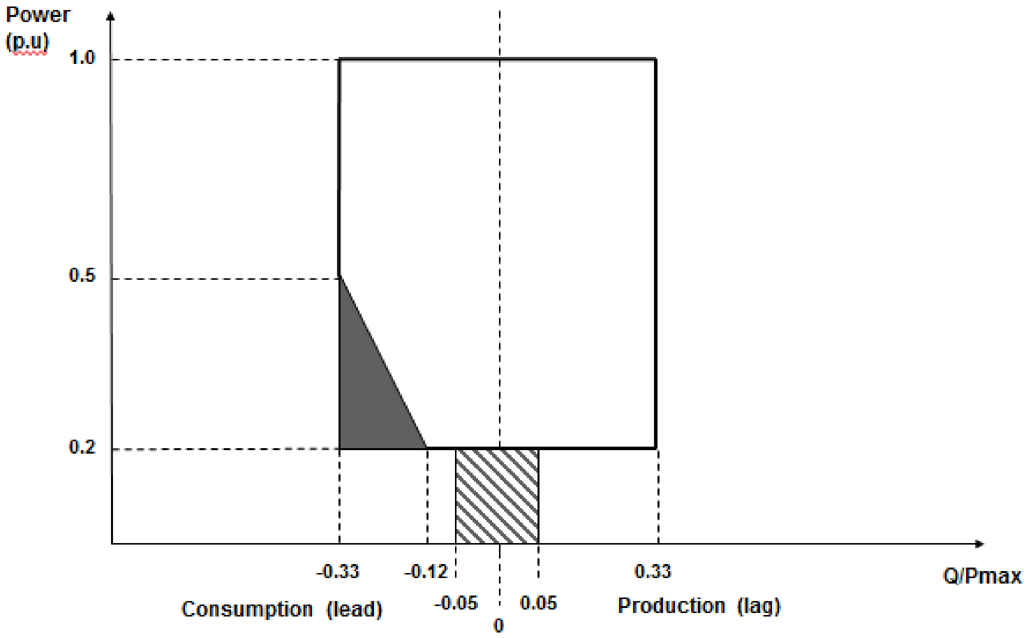


Figure 29 Great Britain - minimum real power/reactive power capability of non-synchronous generator

2.4.7.2 Voltage control capabilities

Generators shall be capable of providing reactive power automatically by either voltage control mode, reactive power control mode or power factor control mode. Times to control and quality for control are provided for in the grid code.

The voltage control range is specified in the code for non-synchronous power plants ≥ 50 MW is shown in the Figure 210.

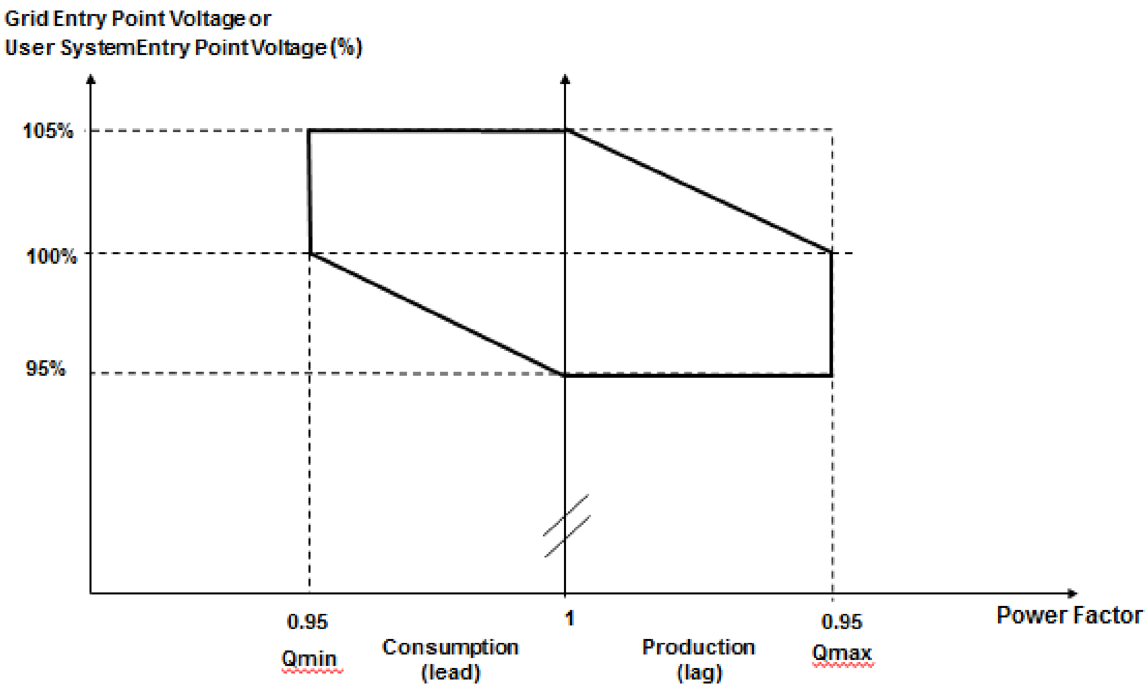


Figure 210 Great Britain grid code voltage control range for non-synchronous power plants ≥ 50 MW

2.4.8 South African Grid Code

2.4.8.1 Reactive power capabilities

The South African codes reactive power requirements for renewable generators ≥ 1 MVA (1 MW for battery energy storage systems) to be as shown in Figure 211. Note that the reactive power capabilities for BESS in the South African Code are not correct. BESS can offer reactive power over the full range from full power consumption to full power production.

Non-synchronous generator ≥ 1 MVA must have a Q/P_{max} range of ±0.228, equivalent to 0.975 leading and 0.975 lagging.

Non-synchronous generator ≥ 20 MVA must have a Q/P_{max} range of ±0.33, equivalent to 0.975 leading and 0.975 lagging.

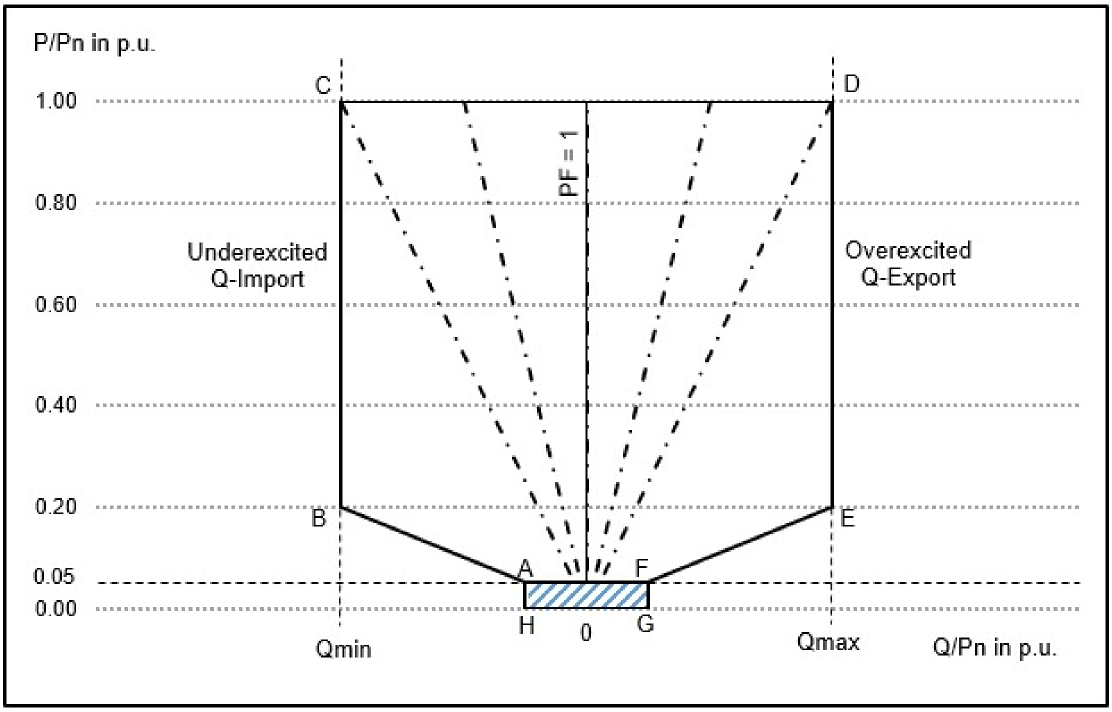


Figure 211 South African grid code renewable power plants reactive power capability requirements ≥ 1 MVA

2.4.8.2 Voltage control capabilities

The South African codes reactive power requirements for renewable generators ≥ 1 MVA (1 MW for battery energy storage systems) to be as shown in Figure 212.

Table 6: South African Grid Code automatic reactive power and voltage control functions for all renewable generators and battery energy storage facilities of category A3, B and C

Function	A1	A2	A3	B1	B2	C
Power factor control	-	-				
Reactive power control	-	-	-			

Voltage control	-	-	-			
Remote control capability	-	-				

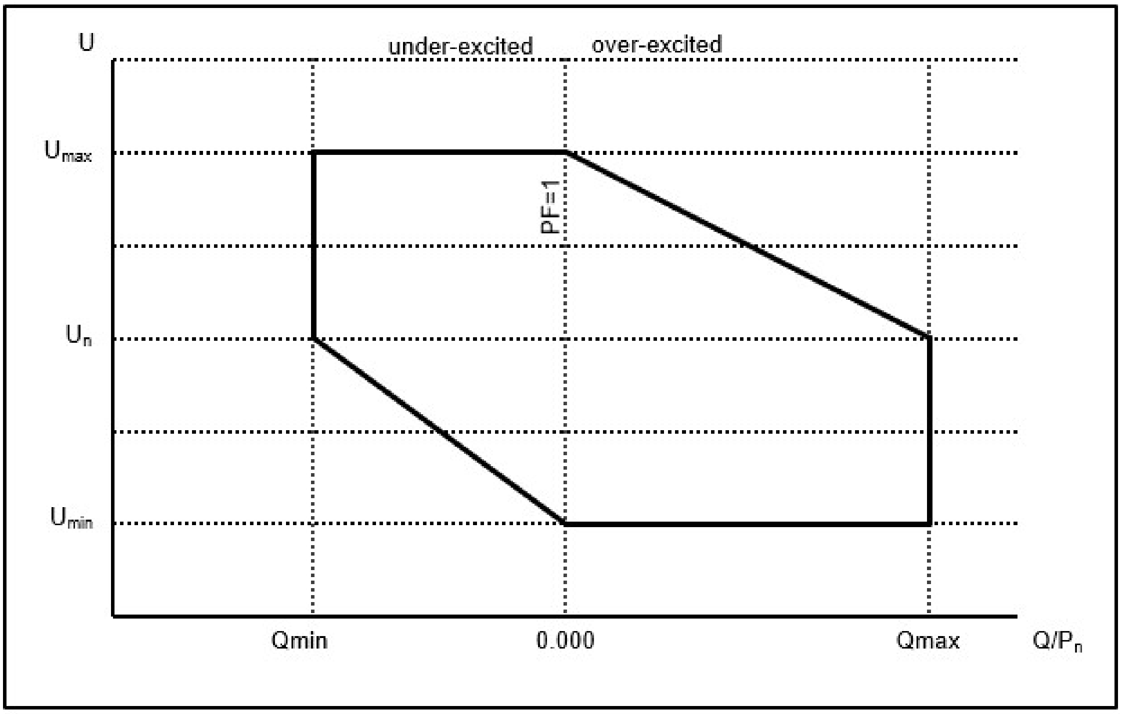


Figure 212 South African grid code voltage control range for renewable power plants ≥ 1 MVA

2.4.9 Recommendations for specifying reactive power capability and voltage control requirements

The PGC and DGC are lenient on non-synchronously connected generators when it comes to providing reactive support at low power outputs.

It is proposed that full reactive power capability be provided from 0.2pu of rated power for all new large generators to ensure adequate voltage control.

The South African grid code conditions are quite recent and reactive power and voltage control is required from 1 MW. The lower level could be considered for Philippines.

2.5 Fault ride through

2.5.1 Introduction

When wind turbines and PV were initially introduced there were no requirements for fault ride through. Inverters switched off when the reference voltage went too low. The result was a loss of significant generation in Ireland, Great Britain and Denmark. Grid codes were then adapted to ensure that non-synchronous connections provide sufficient reactive power to keep a reference voltage (and frequency) when there is a fault. Fault ride through capability has since become a standard practice.

Embedded generation at a low voltage level requirements are typically less stringent as the impact of the loss of generation does not have a significant impact on the interconnected system.

2.5.2 Philippines Grid Code

The PGC requires synchronous generators to ride through three phase faults and unbalanced faults but no details provided. Figure 213 provides the fault ride through capability for wind turbines and Figure 214 for PV.

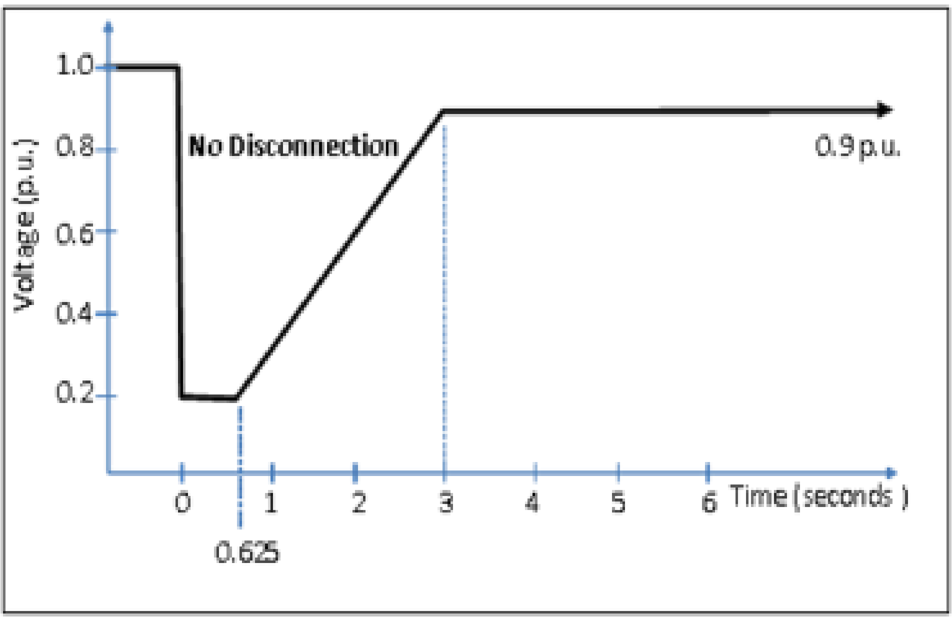


Figure 213 Wind turbine fault ride through capability

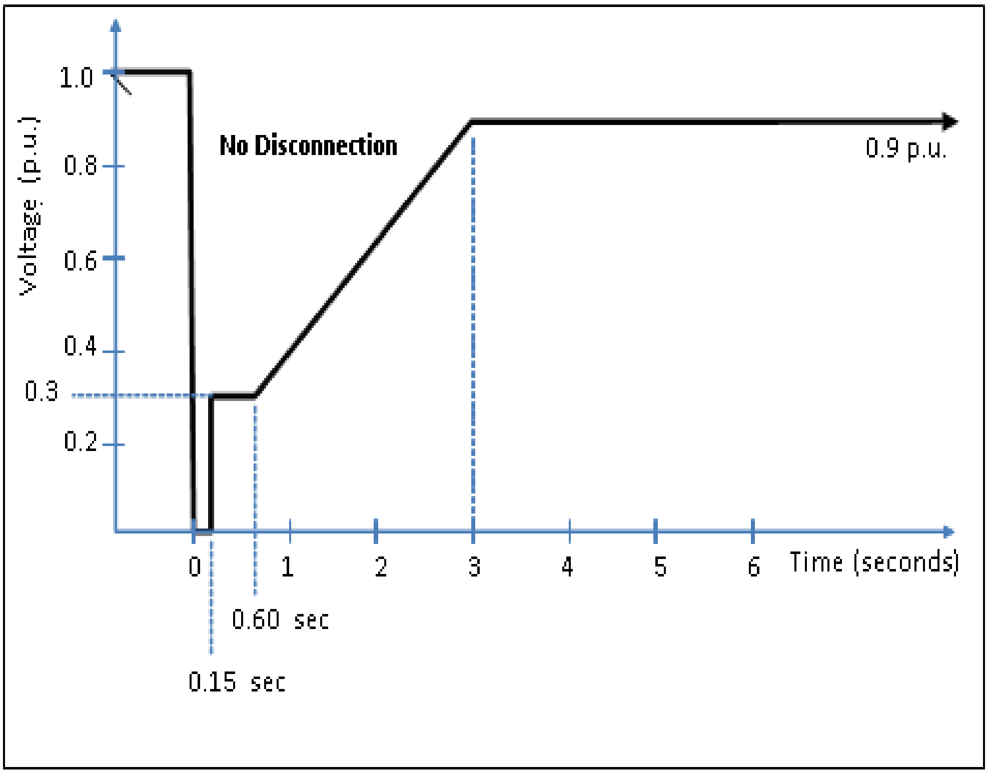


Figure 214 Large PV fault ride through capability

2.5.3 Philippines Distribution Grid Code

The DGC fault ride through capability for large VRE is almost the same as the PGC PV requirements Figure 215.

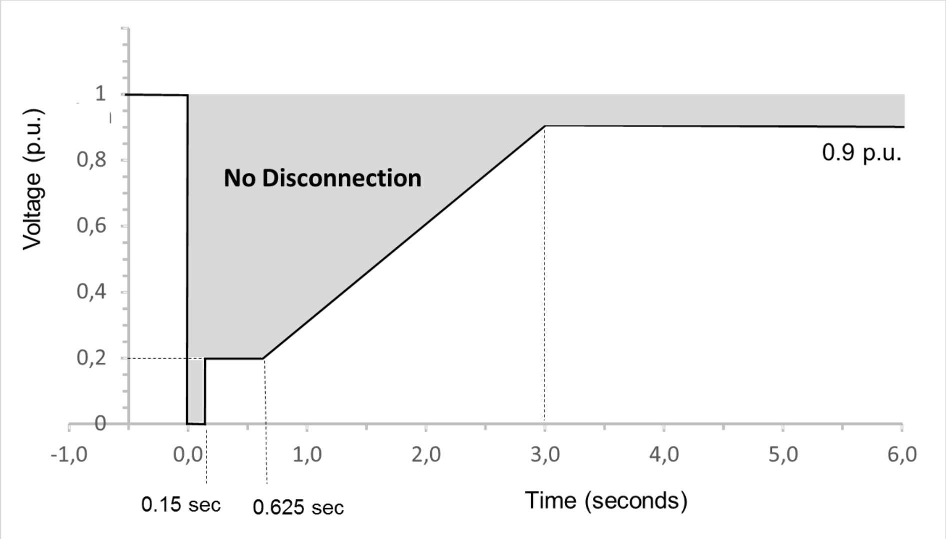


Figure 215. DGC Large, medium and intermediate VRE fault ride through capability

The Small or Micro Embedded Generating Plant shall be able to withstand Voltage Sag or Overvoltage at the Connection Point without disconnection, produced by fault or disturbances in the network, which magnitude and duration profiles are within the following limits (Table 25).

Table 7. DGC Voltage sag limits

Voltage Range (% of Base Voltage)	Time
(V < 50	0.16
50 ≤ V < 90	2.00
90 ≤ V ≤ 110	Normal Operating Range
110 < V < 120	1.00
V ≥ 120	0.16

2.5.4 NERC Reliability Standards

The voltage ride through duration curve for all power plants in ERCOT ≥20 MW is shown in the Figure 216.

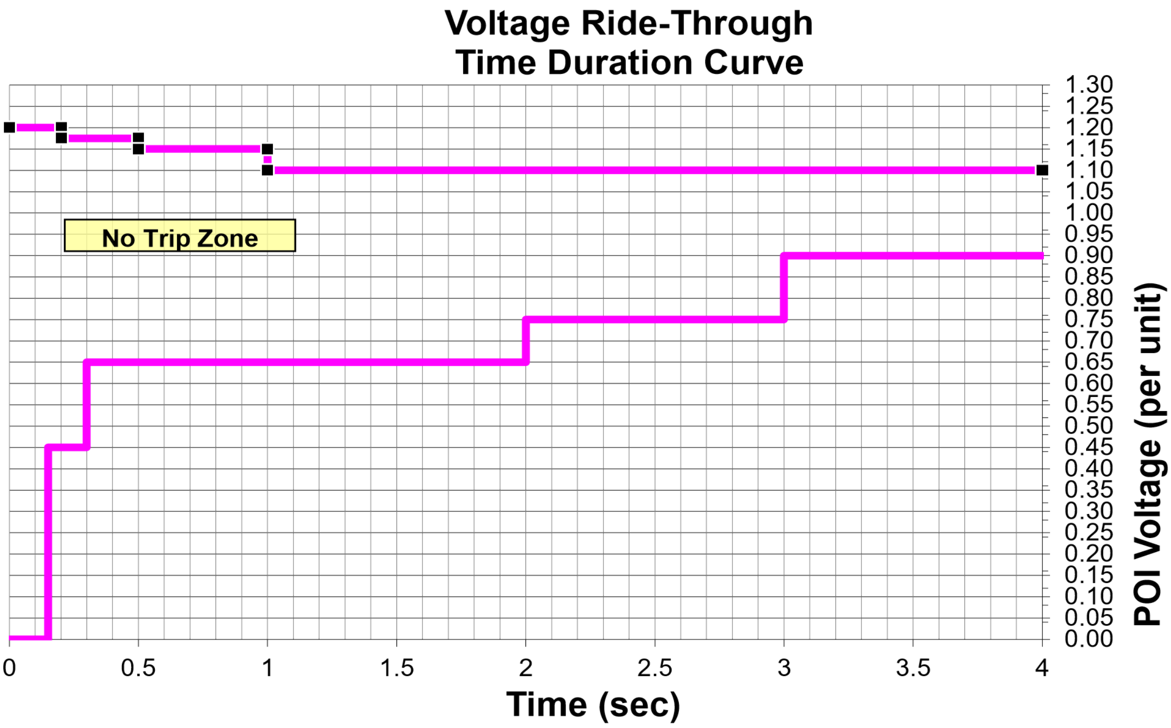


Figure 216 NERC Reliability Standards - ERCOT fault ride through requirements

2.5.5 IEEE 1547-2018 requirements

The IEEE 1547-2018 fault ride through requirements for categories I, II and III are shown in the figures below. Note that none of the embedded generator's fault ride through categories is required to run through a fault at their point of connection (which would result in a zero voltage). The lowest voltage for category 3 is 0.5 pu. It can be calculated how far the fault needs to be before the plant will potentially trip.

If the voltage is outside the curve the generator must trip.

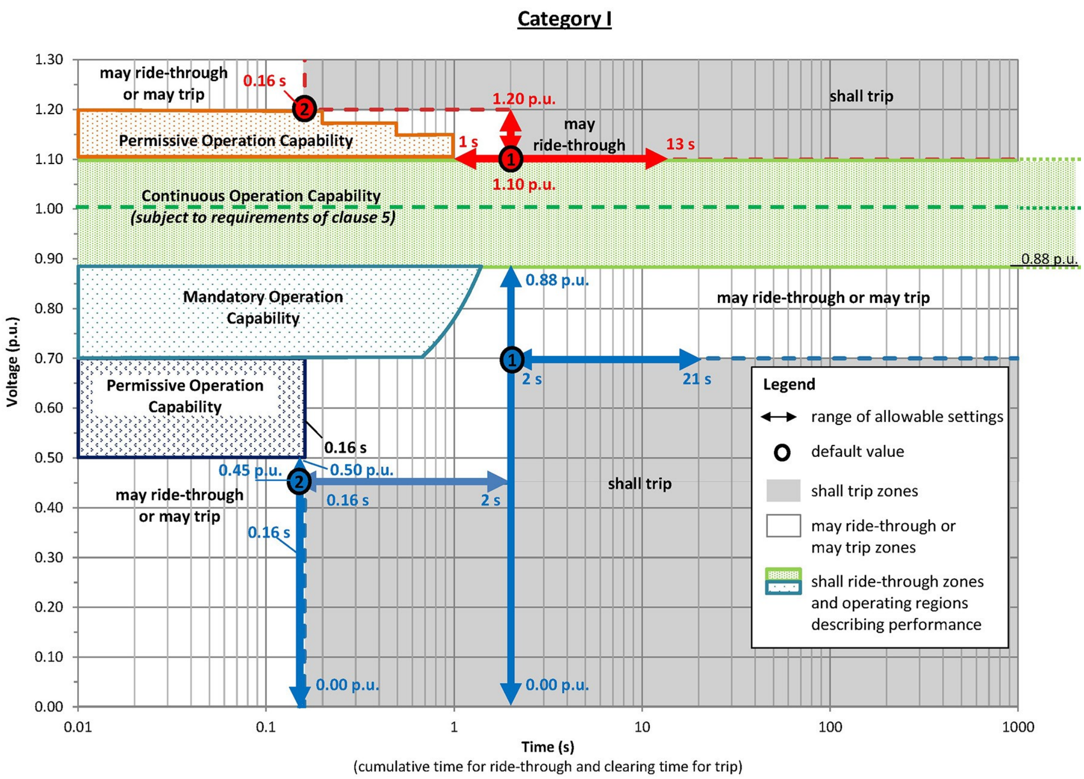


Figure 217 IEEE 1547-2018 category I voltage ride through

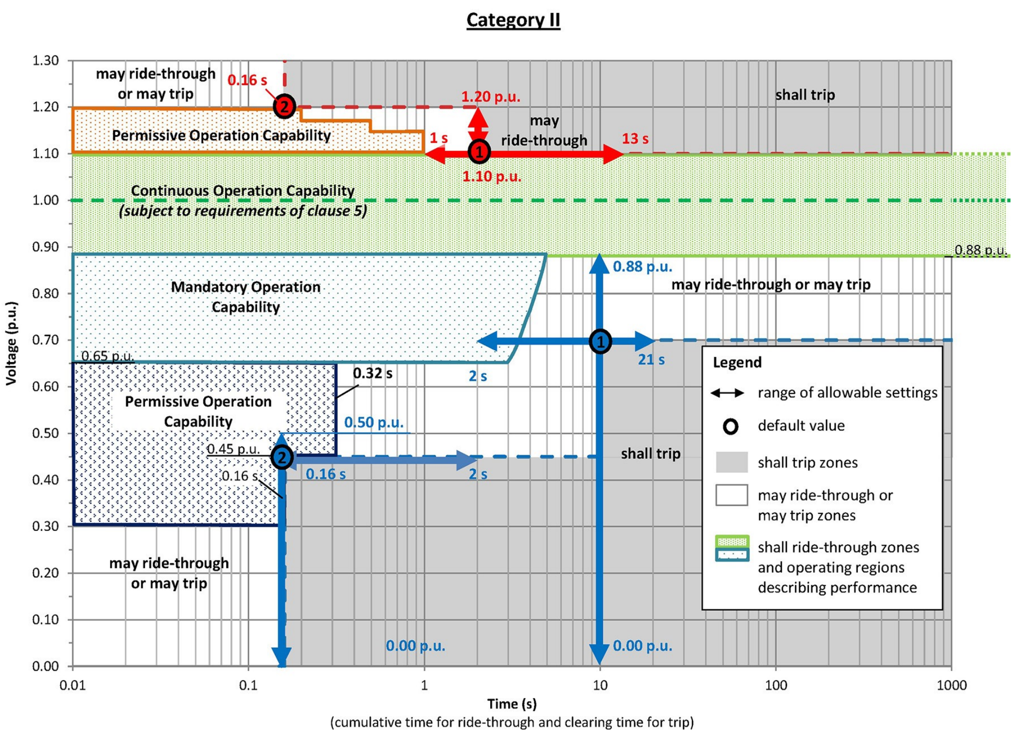


Figure 218 IEEE 1547-2018 category II voltage ride through

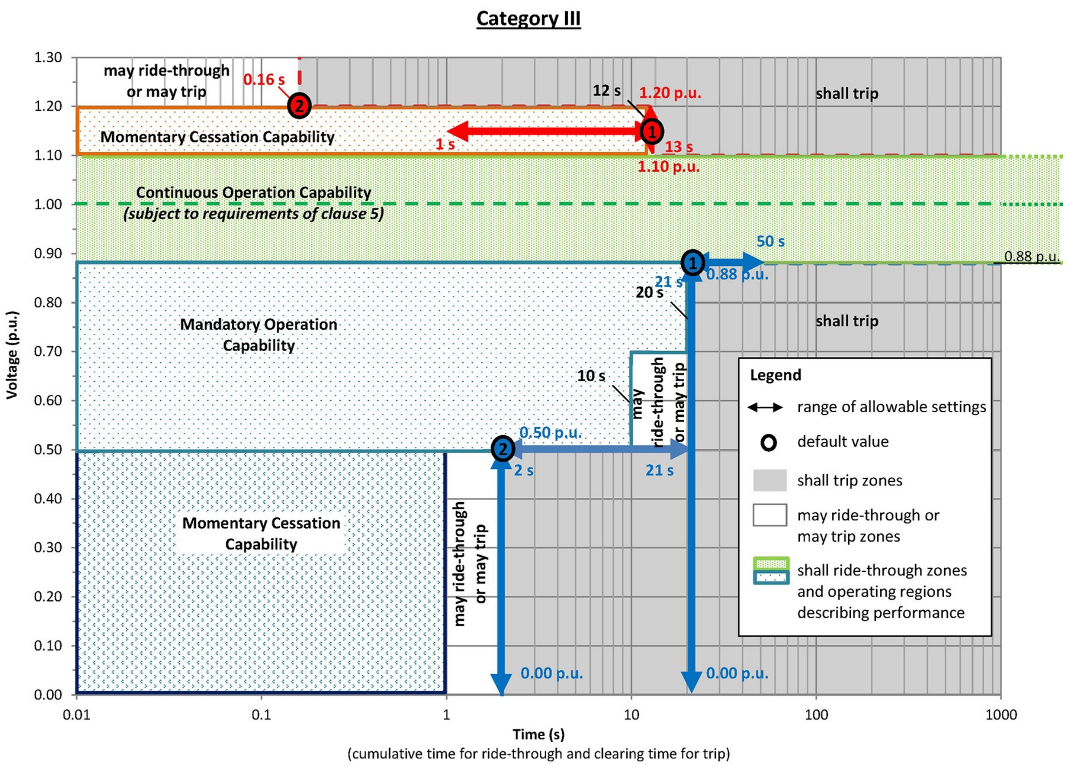


Figure 219 IEEE 1547-2018 category III voltage ride through

2.5.6 Ireland Grid Code

The Irish code requires the fault ride through as specified in figure and table below.

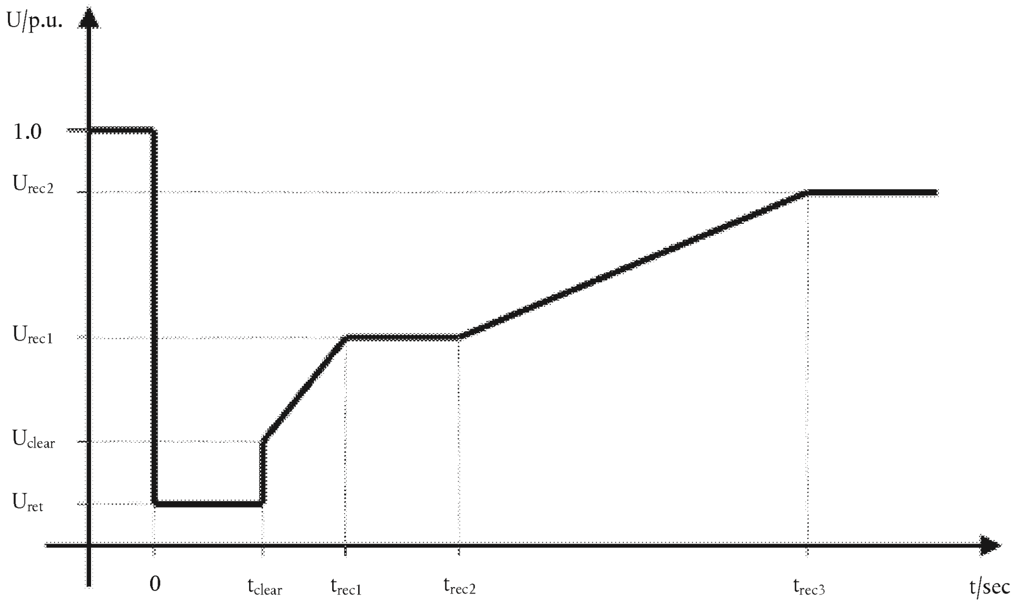


Figure 220. Ireland Grid Code fault ride through curve

Table 8. Ireland Grid Code parameters for fault-ride-through capability of synchronous generator

Voltage parameters	Time parameters (seconds)

	(pu)		
U_{ret}:	0,05-0,3	t_{clear}:	0,14-0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	0,7-0,9	t_{rec1}:	tclear
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}-0,7
U_{rec2}:	0,85-0,9 and ≥ U_{clear}	t_{rec3}:	t_{rec2}-1,5

Table 3.2

Table 9. Ireland Grid Code parameters for fault-ride-through capability of non-synchronous generator

	Voltage parameters (pu)		Time parameters (seconds)
U_{ret}:	0,05-0,15	t_{clear}:	0,14-0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	U_{ret}-0,15	t_{rec1}:	tclear
U_{rec1}:	U_{clear}	t_{rec2}:	trec1
U_{rec2}:	0,85	t_{rec3}:	1,5-3,0

2.5.7 Great Britain Grid Code

Great Britain's fault through requirements for generators connected to the transmission system changed from 1 April 2005. Figure 221shows the requirements before 1 April 2005 and Figure 222 the new requirements for generators built after 1 April 2005.

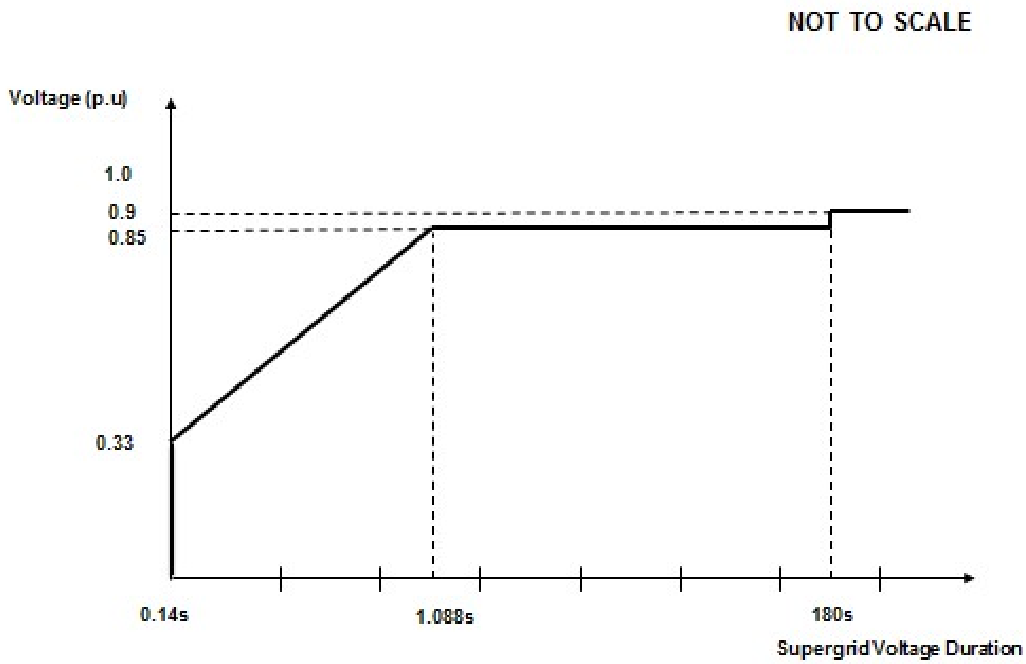


Figure 221 GB Grid Code fault through requirements for generators connected to the transmission system before 1 April 2005

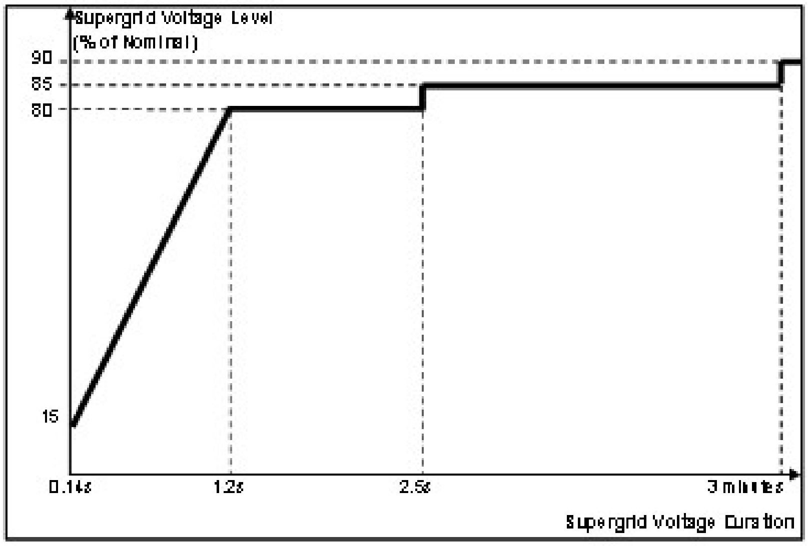


Figure 222 GB Grid Code fault through requirements for generators connected to the transmission system from 1 April 2005

2.5.8 South Africa Grid Code

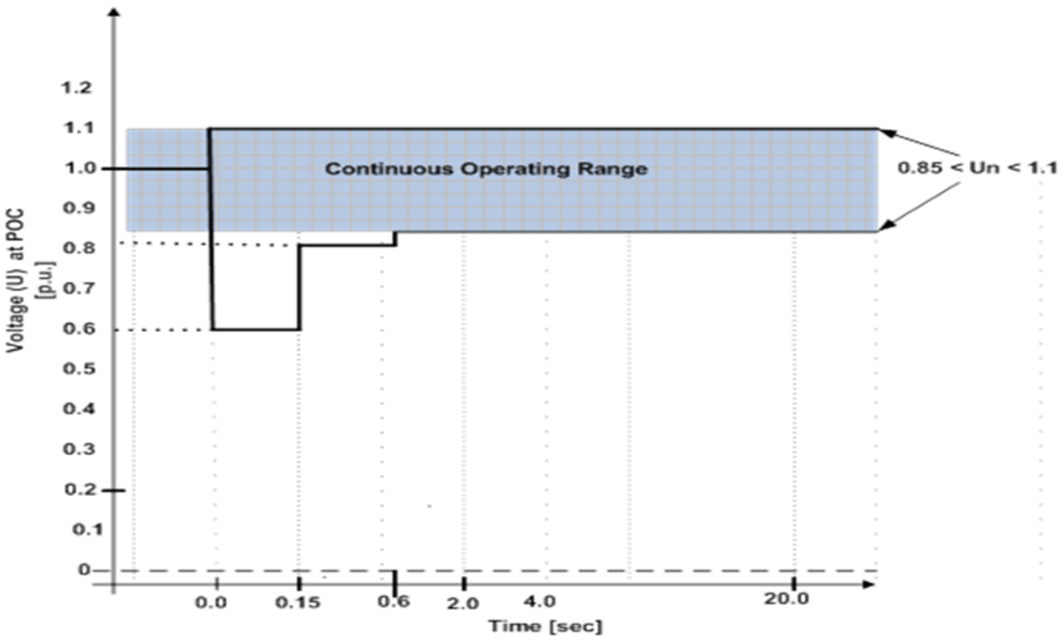


Figure 223 South Africa Grid Code fault ride through requirements for generators < 100 kVA

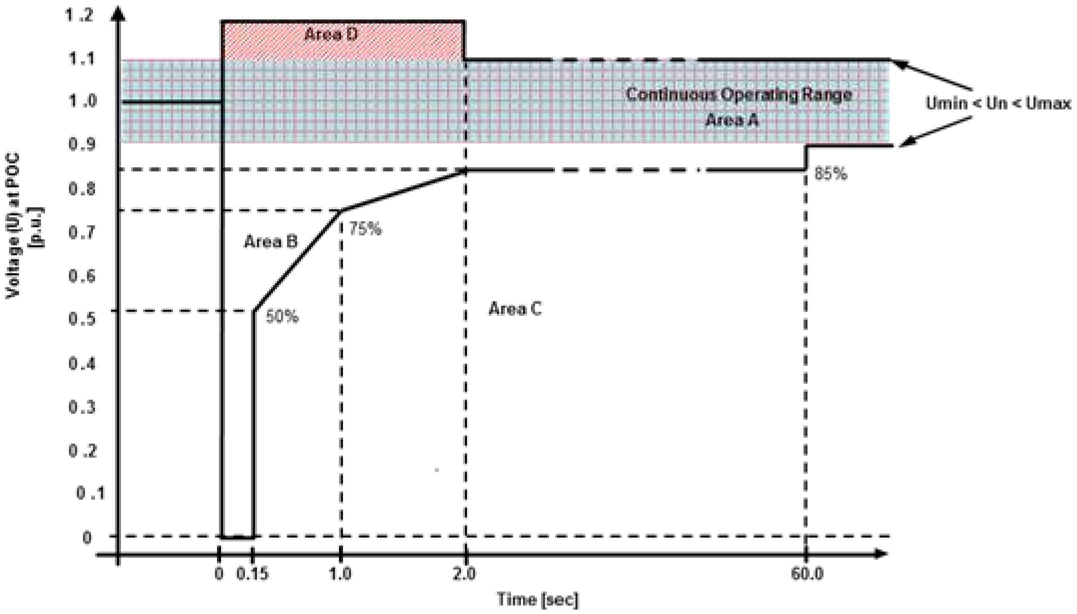


Figure 224 South Africa Grid Code faut ride through requirements for synchronous generators ≥ 100 kVA

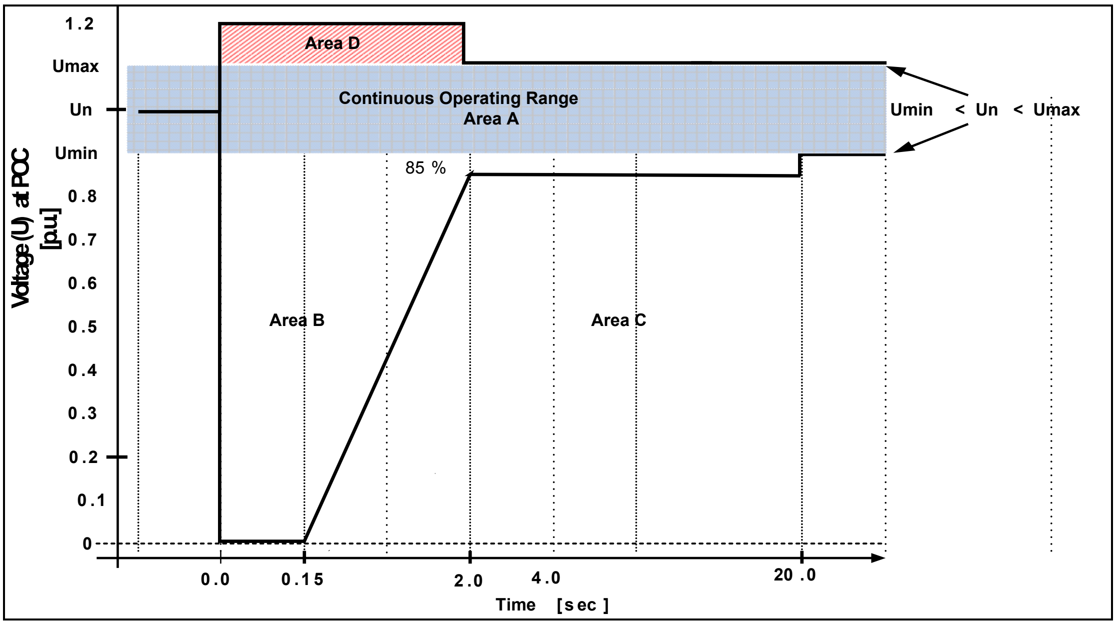


Figure 225 South Africa Grid Code faut ride through requirements for non-synchronous generators ≥ 100 kVA

2.5.9 Recommendations for specifying fault ride through capability

The fault ride through capabilities for small and micro embedded generators is aligned to IEEE 1547-2018 requirements.

The fault ride through capabilities requirements for large, small and intermediate embedded VRE generators and large PV in the PGC are the same. The fault ride through requirements are aligned to internal practice. Wind turbines requirements in the PGC are lenient. It is proposed that the requirements for large wind turbines in the PGC be the same as for large VRE in the DGC for all new wind turbines.

2.6 Fast fault current injection

2.6.1 Introduction

Fast fault current injection is the current injected by a non-synchronously generator or device during and after a voltage deviation caused by an electrical fault with the aim of identifying a fault by network protection systems at the initial stage of the fault, supporting system voltage retention at a later stage of the fault and system voltage restoration after fault clearance[1]. Fast fault current injection is limited to the maximum rating of the inverter whereas synchronous generator's fault currents exceed the maximum current by 3-fold or more. The extra overcurrent assists the protection to clear the faults near to the synchronous generator' with overcurrent relays.

2.6.2 Philippines Grid Code

The PGC requires fast fault current injection from wind turbines as shown in Figure 226 and PV are required to provide fault current injection but this is not specified to the same detail as for wind turbines.

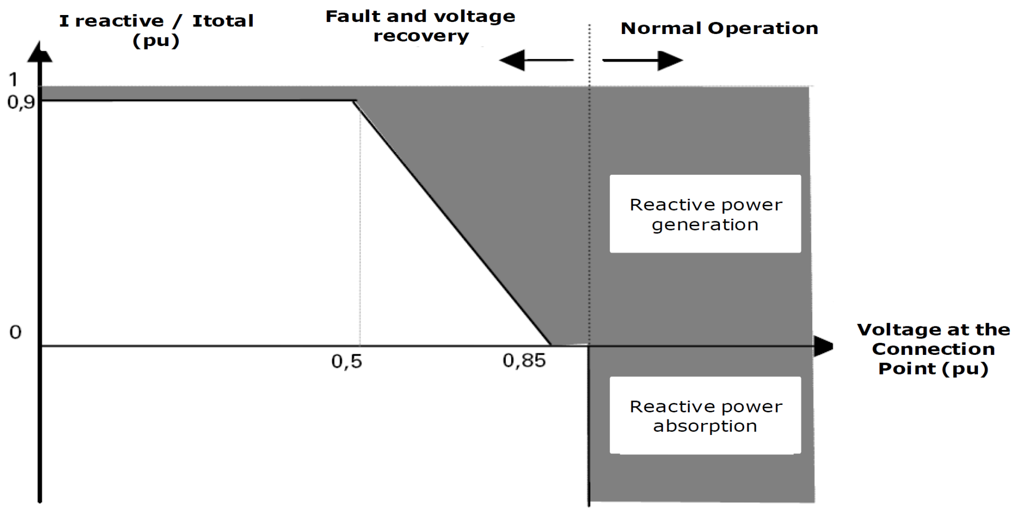


Figure 226 PGC fault current injection for wind turbines

2.6.3 Philippines Distribution Grid Code

The DGC requirements for fast fault current injection for large, small and intermediate embedded VRE is the same as the PGC requirements for wind farms.

2.6.4 Ireland Grid Code

Non-synchronous generator will be capable of activating the supply of fast fault current for three phase faults by either by:

- ensuring the supply of the fast fault current at the connection point, or
- measuring voltage deviations at the terminals of the individual units of the non-synchronously generator and providing a fast fault current at the terminals of these units;

[1] EU code - network code on requirements for grid connection of generators, April 2016

Double and single phase faults fast current injection requirements is to be agreed with the system operator

System operator shall specify the post-fault active power recovery that the non-synchronously generator should be capable of providing.

2.6.5 Great Britain Grid Code

Non-synchronous generator will be capable of activating the supply of fast fault current for three phase faults according to the cure below.

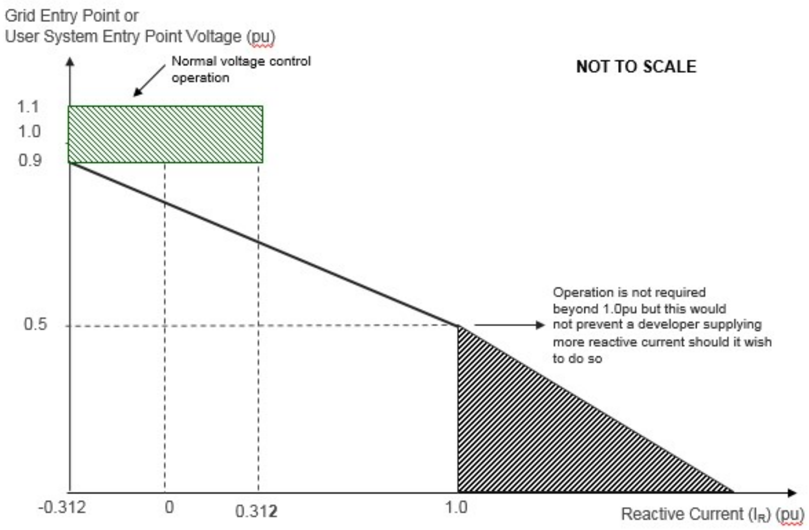


Figure 227. GB Grid Code fault current injection

2.6.6 South Africa Grid Code

Non-synchronous generator ≥ 1 MVA will be capable of activating the supply of fast fault current for three phase faults according to the cure below.

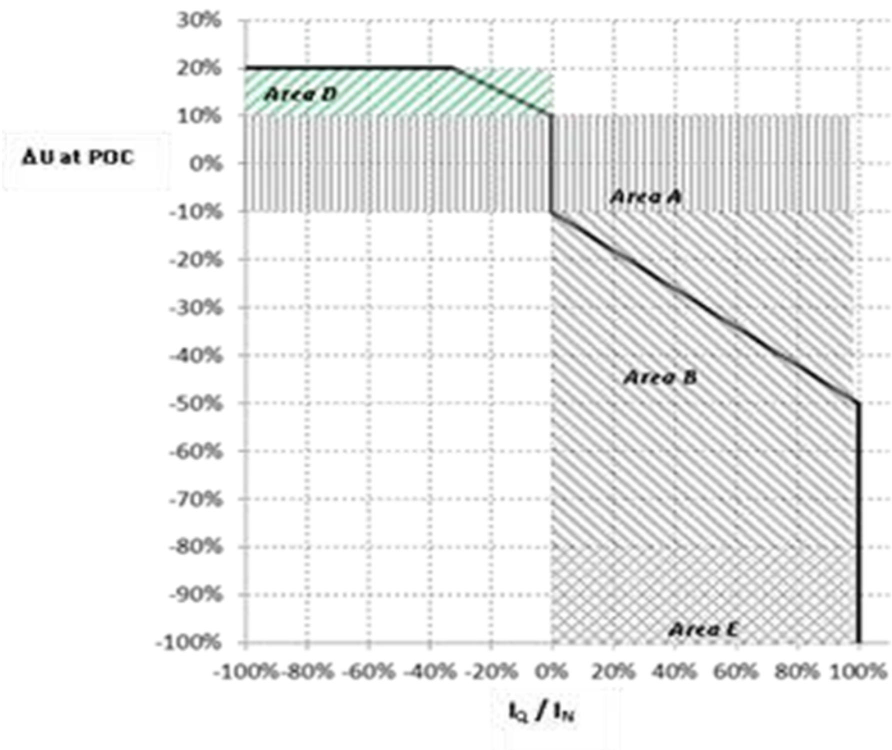


Figure 228. SA Grid Code fault current injection

2.6.7 Recommendations for specifying fast fault current injection capability

The PGC and DGC are aligned and in line with international practice. The cross referencing in the DGC needs to be checked as it refers to section 4.6.6.2 but should also refer to 4.6.6.1. Both sections are applicable and need to be read in conjunction with one another.

2.7 Real Power and Frequency Control

2.7.1 Introduction

Grid codes specify the frequency ranges which generators must be able to tolerate. As frequency is common to an interconnection the requirement for all generators is typically the same.

Frequency rate of change has started to become an issue in interconnections with high penetration of non-synchronous generators. These generators do not provide inertia and as a result the frequency rate of change increases for the same reference incident. If the rate of change is too high then synchronous generators will start to pole slip and trip, and non-synchronous generators can lose the reference frequency and stop producing power on the network. The fast frequency rate of change can be mitigated by increasing the inertia by keeping more synchronous generators online or by having fast frequency response (1second range) from BESS and / or demand response.

2.7.2 Philippines Grid Code

The PGC requires that the synchronous generators shall be capable of continuously supplying its active power output, within the frequency range of 59.4 to 60.6 Hz. Continuous range for wind turbines is 59.7 to 60.3 Hz and PV is 58.2 – 61.8 Hz.

Any decrease of power output occurring in the frequency range of 59.4 to 57.6 Hz shall not be more than the required proportionate value of the frequency decay for synchronous generators

In case the frequency momentarily rises to 62.4 Hz or falls to 57.6Hz, all synchronous generators, shall remain in synchronism with the Grid for at least five (5) seconds.

Wind turbines and PV shall be capable to operate, for at least 5 minutes, in case of increase in frequency within the range of greater than 61.8 and 62.4 Hz; and for at least 60 minutes, in case of a decrease in frequency within the range of 57.6 and 58.2 Hz, in both cases provided the Voltage at the Connection Point is within ±10% of the nominal value. For wind turbines the requirements is to remain connected < 58.2 Hz for 5 s and > 61.8 Hz for as long as possible.

The PGC is unclear whether primary and secondary frequency response is a mandatory and paid as ancillary service or not. The ancillary services regulations clearly state how generators are selected and compensated for primary and secondary frequency response (as a combined service).

Large wind turbines and PV have to provide mandatory primary frequency control when the frequency goes above 61 Hz. The droop is equivalent to a 5% droop.

In case the System Frequency exceeds 61 Hz, the Active Power control system should reduce the Active Power previously generated following the formula below:

$$\Delta P = 45 \cdot P_m \cdot \left(\frac{61.0 - f_n}{60} \right)$$

Where:

ΔP: is the variation in Active Power output that should be achieved

P_m: is the Active Power output before this control is activated

f_n: is the network Frequency

In case the System Frequency drops below 59.0 Hz the Active Power control system should change to free Active Power production mode, generating the maximum possible Active Power output, compatible with the Availability of the primary resource.

2.7.3 Philippines Distribution Grid Code

The DGC requires that the large embedded synchronous and non- synchronous generators shall be capable of continuously supplying its active power output, within the frequency range of 59.7 to 60.3 Hz.

Any decrease of power output occurring in the frequency range of 59.4 to 57.6 Hz shall not be more than the required proportionate value of the frequency decay for synchronous generators

In case the frequency momentarily rises to 62.4 Hz or falls to 57.6Hz, all synchronous, shall remain in synchronism with the Grid for at least five (5) seconds. Non- synchronous generators requirements are to remain connected < 58.2 Hz for 5 s and > 61.8 Hz for as long as possible.

Large embedded synchronous and non- synchronous generators shall be capable to operate, for at least 5 minutes, in case of increase in frequency within the range of greater than 61.8 and 62.4 Hz; and for at least 60 minutes, in case of a decrease in frequency within the range of 57.6 and 58.2 Hz, in both cases provided the Voltage at the Connection Point is within ±10% of the nominal value.

Large Conventional Embedded Generating Unit shall remain Synchronized during a rate of change of Frequency of values up to and including ±1 Hz per second measured as a rolling average over 500 milliseconds.

Large, medium and intermediate VRE have to provide mandatory primary frequency control when the frequency goes above 61 Hz. The droop is equivalent to 5% droop.

In case the System Frequency exceeds 61 Hz, the Active Power control system should reduce the Active Power previously generated following the formula below:

$$\Delta P = 45 \cdot P_m \cdot \left(\frac{61.0 - f_n}{60} \right)$$

Where:

ΔP: is the variation in Active Power output that should be achieved

P_m: is the Active Power output before this control is activated

f_n: is the network Frequency

In case the System Frequency drops below 59.0 Hz the Active Power control system on large VRE should change to free Active Power production mode, generating the maximum possible Active Power output, compatible with the Availability of the primary resource.

2.7.4 NERC Reliability Standards

The off-frequency capability for generators per frequency incident is defined for each interconnection in Northern America. Specifically note the tight continuous operating range in Northern America. Each of these interconnections are large and therefore can control the frequency within this continuous range.

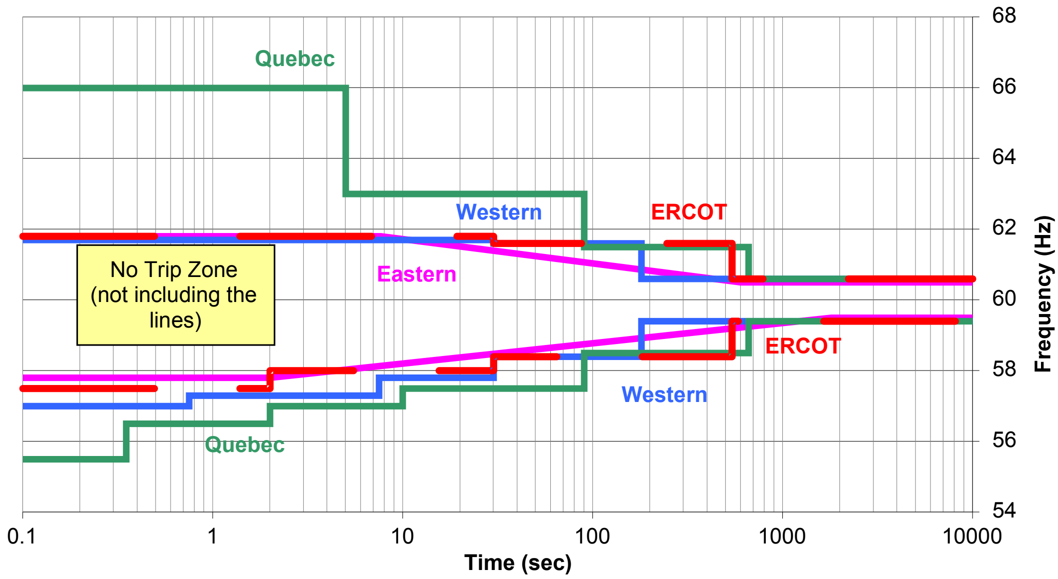


Figure 229 NERC Reliability Standard PRC-042-2 frequency capability requirements for generators

2.7.5 IEEE 1547-2018 requirements

2.7.5.1 Voltage - active power characteristic

IEEE 1547-2018 proposes that active power started to be limited when voltage exceeds 1.06 pu and fully limited when voltage reaches 1.1 pu. Note that the curve also applies to storage where the minimum generation is negative. The default setting is no active power production. In effect the battery can be set to be fully importing when the voltage is at 1.1 pu.

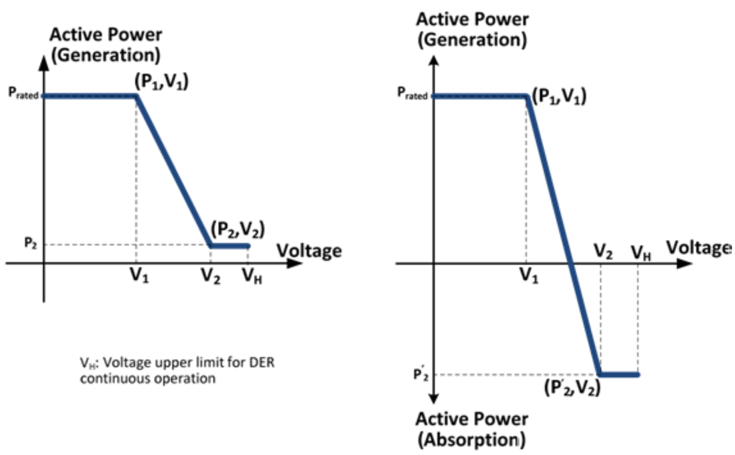


Figure 230 IEEE 1547-2018 voltage - active power characteristic

2.7.5.2 Frequency minimum requirements

The default trip settings for embedded generators are:

1. >62 Hz for longer than 0.16s,
2. >61.2 Hz for longer than 300s,
3. Continuous operation 58.2 Hz to 61.2 Hz,
4. <58.5 Hz for longer than 300s, and
5. <56.5 Hz for longer than 0.16s.

2.7.5.3 Frequency – Rate of Change of Frequency

Rate of Change of Frequency is to be measured over 100ms. Minimum requirements to remain connected are:

1. Category I <0.5 Hz/s,
2. Category II <2.0 Hz/s, and
3. Category I <3.0 Hz/s.

2.7.5.4 Frequency - active power characteristic

The potential frequency support is shown for a generator starting at three different loadings. Note the dead band for the USA is 0.036 mHz. The default droop is 5%.

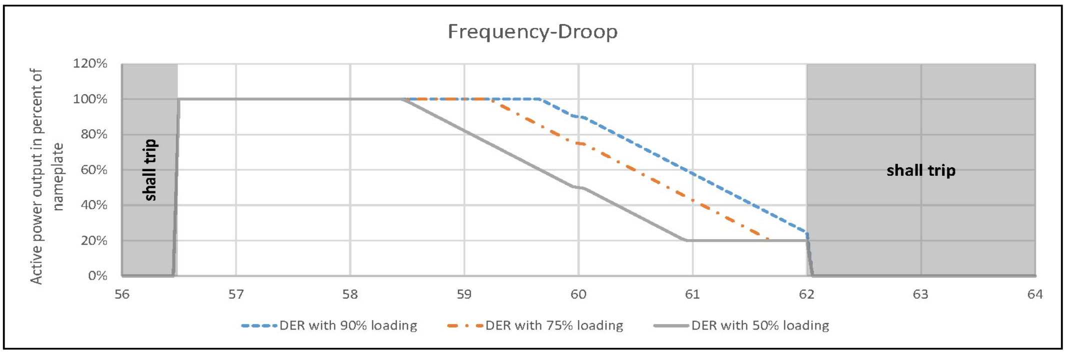


Figure 231 IEEE 1547-2018 active power frequency characteristic

2.7.5.5 Combined active power characteristic

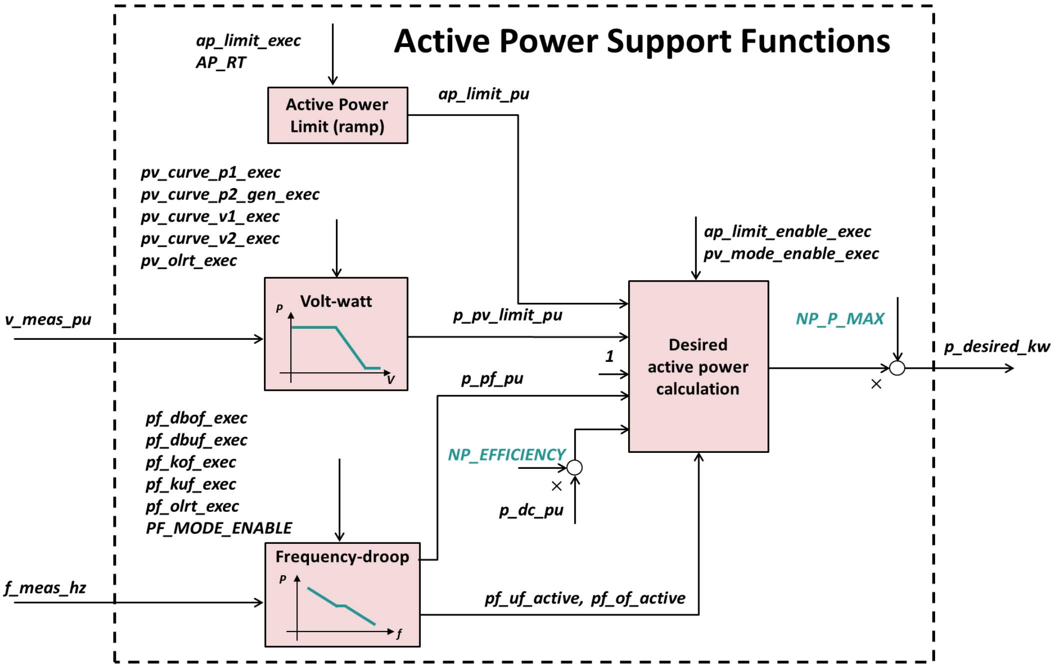


Figure 232 IEEE 1547-2018 combined active power characteristic[2]

Table 10. **Volt-watt function variable list**

[2] EPRI, IEEE 1547-2018 DER Model, Version 1.0, 3002021694, December 2021

Variable type	Variable name	Description
Input variable	*v_meas_pu*	Applicable voltage for volt-var and volt-watt calculation
	pv_curve_p1_exec	Volt-watt Curve Point P1 Setting (*PV_CURVE_P1*) signal after execution delay
	pv_curve_v1_exec	Volt-watt Curve Point V1 Setting (*PV_CURVE_V1*) signal after execution delay
	pv_curve_p2_gen_exec	Volt-watt Curve Point P2 Setting (*PV_CURVE_P2_GEN*) signal after execution delay
	pv_curve_v2_exec	Volt-watt Curve Point V2 Setting (*PV_CURVE_V2*) signal after execution delay
	pv_olrt_exec	Volt-watt open loop response time setting (*PV_OLRT*) signal after execution delay
Input variable	*f_meas_hz*	DER frequency measurement in Hertz, from model input
	PF_MODE_ENABLE	Frequency-Active power mode enable
	pf_dbof_exec	Over frequency deadband offset from nominal frequency signal (*PF_DBOF*) after execution delay
	pf_dbuf_exec	Under frequency deadband offset from nominal frequency signal (*PF_DBUF*) after execution delay
	pf_kof_exec	Over frequency slope signal *(PF_KOF)* after execution delay
	pf_kuf_exec	Under frequency slope signal *(PF_KUF)* after execution delay
	pf_olrt_exec	Frequency-Active power open-loop response time signal *(PF_OLRT)* after execution delay
	p_dc_pu	DER available DC power in pu

2.7.6 Ireland Grid Code

Minimum time periods for which a power-generating module has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network.

Table 11. Ireland frequency range and minimum time period

Synchronous area	Frequency range	Time period for operation
Ireland and Northern Ireland	47,5 Hz-48,5 Hz	90 minutes

	48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than 90 minutes
	49,0 Hz-51,0 Hz	Unlimited
	51,0 Hz-51,5 Hz	90 minutes

2.7.7 Great Britain Gride Code

Minimum time periods for which a power-generating module has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network.

Table 12. Great Britain frequency range and minimum time period

Synchronous area	Frequency range	Time period for operation
Great Britain	47,0 Hz-47,5 Hz	20 seconds
	47,5 Hz-48,5 Hz	90 minutes
	48,5 Hz-49,0 Hz	To be specified by each TSO, but not less than 90 minutes
	49,0 Hz-51,0 Hz	Unlimited
	51,0 Hz-51,5 Hz	90 minutes
	51,5 Hz-52,0 Hz	15 minutes

All generators must respond to an increase in System Frequency above 50.4Hz leading to a reduction in Active Power. The Active Power output should decrease at a minimum rate of 2 per cent of output per 0.1 Hz deviation of System Frequency above 50.4 Hz. This is equivalent to a maximum droop of 10%.

Generators are to be capable of withstanding without tripping a rate of change of Frequency up to and including 1 Hz per second as measured over a rolling 500 milliseconds period. Voltage dips may cause localised rate of change of frequency values in excess of 1 Hz per second for short periods, and in these cases, the requirements for fault ride through supersedes this requirement.

2.7.8 South Africa Grid Code

The mandatory frequency capability curve for all non-hydro generators in South Africa is shown in Figure 233. No frequency tripping is allowed within the curve. Hydro generators have a much wider range. All generators not contracted for primary frequency control serves shall also have a mandatory frequency control curve as shown in Figure 234. The response down on thermal generators is limited to 15% from current generation level and all other plant must go to minimum generation is 10 s.

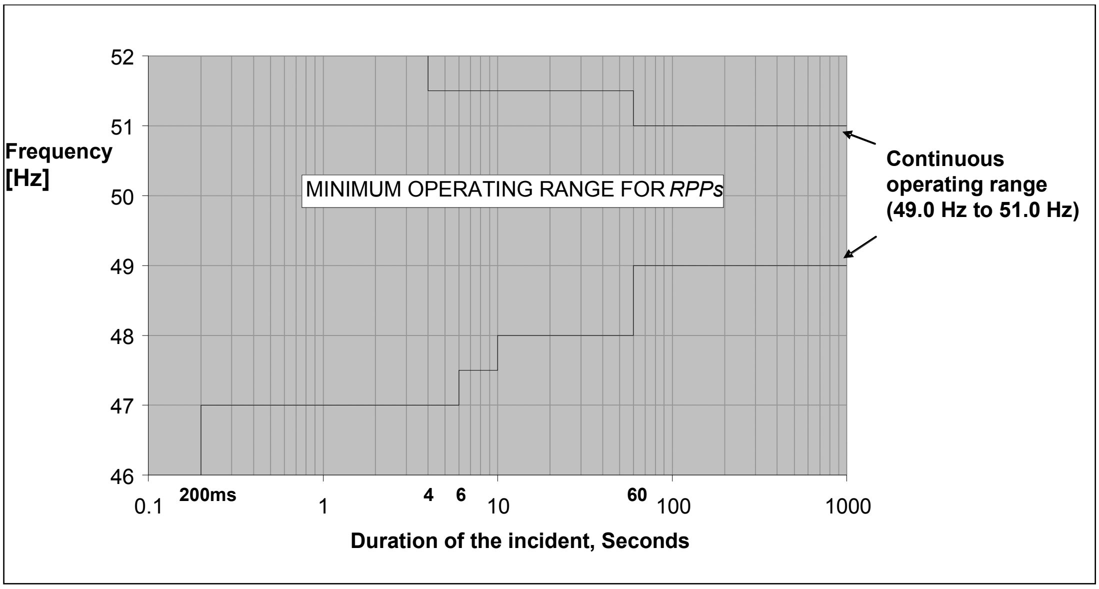


Figure 233 SA Grid Code mandatory frequency capability requirements for all non-hydro generators

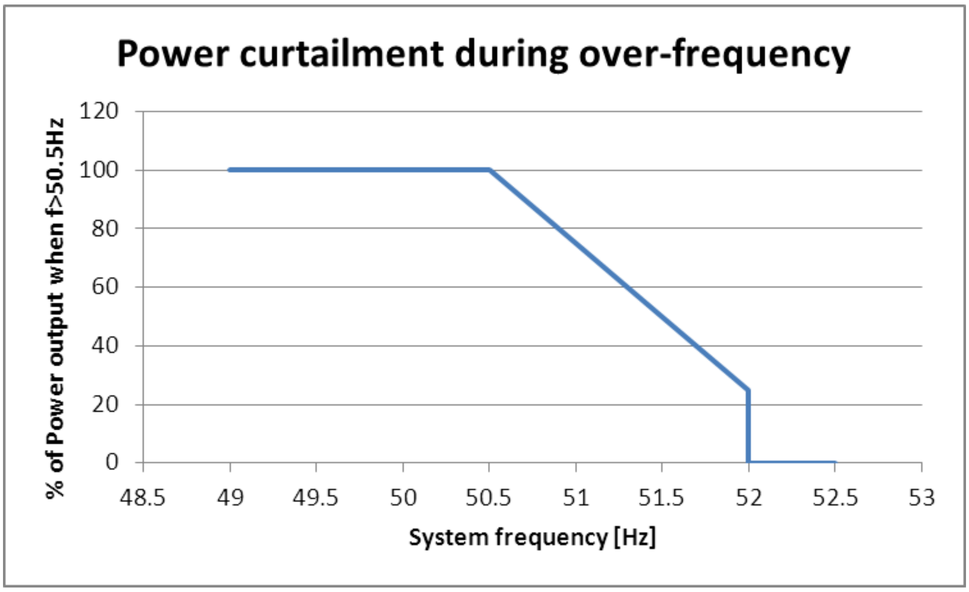


Figure 234 SA Grid Code over frequency mandatory frequency control requirements for all generators

2.7.9 Recommendations for specifying frequency capability and frequency control requirements

The PGC and DGC requirements for frequency tolerance are reasonably aligned with each other and with the practice in the USA. However, the continuous frequency range is very small for the Philippines for synchronous generators. The steady state frequency in each interconnection is common and system operator has to thus control to the frequency to the tightest requirement.

IEC standards and international practice is that synchronous generators should be designed to able to continuously tolerate up to ±2% change in frequency.

The continuous range could easily be extended to a continuous range of ±2% of nominal frequency or 58.8 Hz to 61.2 Hz for a 60 Hz system.

The PGC and DGC mandatory high frequency response starts at 61 Hz. Most systems start the mandatory response much earlier and this could be adjusted to start at 60.6 Hz (1% deviation).

2.8 BESS

2.8.1 Introduction

Battery Energy Storage requirements in grid codes is quite new and not many codes have put in specific requirements. The South African Grid Code is one of the few codes with specific requirements for battery storage.

2.8.2 South Africa Grid Code

The Grid Connection Code for Battery Energy Storage Facilities (BESF) Connected to the Electricity Transmission System (TS) or the Distribution System (DS) in South Africa version 5.2 has recently been developed and promulgated. The code is the same as for non-synchronous connections in the renewable code except primary frequency control (up and down) is mandatory for all BESS > 20 MW.

There are significant omissions specifically:

1. Reactive power and voltage control don't include the fact that this service can be provided from full consumption to full production
2. Fast frequency control (or inertia) is not required. This is a key future service that BESS can provide
3. There is no black start or islanding requirements which could be a key service for BESS to provide

2.8.3 Conclusion

The development of the PGC and DGC codes to include BESS will be done under this assignment. The key requirements will be based on our experience as there are very few grid codes to reference.

3 Task 3.2: Rules and Regulations for Ancillary Services Responsive with Variable Renewable Energy Technology

3.1 Introduction

The Ancillary Services Procurement Plan Requirements in Philippines is compared to PGC and DGC connection requirements, DOE Department Circulars and WEMS market rules.

Ancillary service requirements in the USA, Ireland, Great Britain and South Africa are provided to benchmark against the Philippine Ancillary Services Procurement Plan Requirements.

Summary and provisional recommendations are made.

3.2 Ancillary Services Procurement Plan Requirements in Philippines

This section is a summary of the Ancillary Service Procurement Plan and comparing this to PGC and DGC connection requirements, DOE Department Circulars and WEMS market rules.

3.2.1 Operating Reserves

The Ancillary Services Procurement Plan and the WEMS market rules have not been updated with the PGC 2016 operating reserve requirements.

3.2.1.1 Regulation Reserve

The regulation reserve in the Ancillary Services Procurement Plan is a combination of primary and secondary reserve. The primary frequency response must be 5 seconds with a sustained time 25 seconds. The secondary component must respond within 25 seconds. Although not stated this response is probably in response to AGC commands to raise or lower (or a setpoint change).

Total regulation reserve must be 4% of demand.

3.2.1.2 Contingency Reserve

Contingency reserve has a primary frequency response requirement but no time frames. Full activation time is 10 minutes and sustain time of 30 minutes. Generators must be synchronised and demand can also participate. Activation is via manual instructions from the System Operator. Contingency Reserve must be at least the maximum capacity among the following: the largest synchronized generating unit or a transmission element or the power import from a circuit interconnection.

3.2.1.3 Dispatchable Reserve Service

Synchronised capacity and demand participants that are not scheduled for Regulating Reserve or Contingency Reserve and generators that can synchronise in 15 minutes. Response time is 30 minutes. Maximum capacity among the following: the second largest synchronized generating unit or a transmission element or the power import from a circuit interconnection.

3.2.2 Reactive Power Support Service

Reactive Power Support Service is the capability of a generating unit to supply Reactive Power to, or absorb Reactive Power from, the Grid in order to maintain the bus voltage within five percent (5%) of its nominal voltage. A generator is considered to be providing Reactive Power Support if it operates outside the range of 0.85 lagging and 0.90 leading Power Factor but within its Reactive Capability Curve.

3.2.3 Black Start Service

The need for Black Start Ancillary Service arises when an event or significant incident will result in a partial or total system blackout. Black Start is the ability of a generating unit, without assistance from the Grid or other external power supply, to recover from a shutdown condition to an operating condition in order to energize the Grid and assist other generating units to start. Black Start plants must be able to be put on-line and ready to extend power within thirty (30) minutes upon receipt of a dispatch instruction and must be capable of sustained operation for at least 12 hours.

3.3 Ancillary services procurement internationally

This section reviews the ancillary service requirements and procurement in various international countries including USA, Great Britain, Ireland and South Africa.

3.3.1 USA ancillary services

The USA section focuses on PJM as being the typical example for ancillary services. ISO NE, California ISO, Mid-west, ERCOT and NY ISO follow similar guidelines in their approach to ancillary services. The remaining sections of the USA are still vertically integrated and little information is provided on ancillary service arrangements.

3.3.1.1 Ancillary service definitions

Ancillary services help balance the transmission system as it moves electricity from generating sources to ultimate consumers. PJM operates several markets for ancillary services[3], namely:

1. Synchronized Reserve Market
2. Non-Synchronized Reserve Market
3. Day-Ahead Scheduling Reserve Market
4. Regulation Market – units under AGC to meet NERC control area performance requirements
5. Black start

Synchronized Reserve

Synchronized reserve is the capability of a generation resource and demand resource to increase in energy output or load reduction achievable by the generation resource and demand resource within a continuous 10-minute period.

Non-Synchronized Reserve

Non-synchronized reserve is the capability of a generation resource to increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

Day-ahead Scheduling Reserves

Day-ahead scheduling reserves are reserves that can be activated thirty-minutes. The reserve can be provided by both synchronised and non-synchronised resources.

Regulation

Regulation is a resource that can receive automatic instructions (under AGC). A resource capable of automatic energy dispatch that is also providing regulation shall have its energy dispatch range reduced by at least twice the amount of the regulation provided with consideration of the regulation limits of that resource.

Black Start

Black start unit must be able to provide the following:

[3] PJM website https://www.pjm.com/markets-and-operations/ancillary-services.aspx.

1) A Black Start Unit must be able to close its output circuit breaker to a dead (deenergized) bus within the time specified in the PJM Manuals.
2) A Black Start Unit must be capable of maintaining frequency and voltage under varying load.
3) A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

3.3.1.2 Procurement of ancillary services

PJM[4] has an 'Ancillary Services Optimiser' (ASO) which performs the joint optimisation function of Energy, Reserves and Regulation in the dispatch run. The main functions of ASO are the clearing and commitment of all Regulation resources and inflexible Reserve resources for a one-hour time period. The ASO case is executed one (1) hour prior to the beginning of an operating hour and is normally solved and approved up to thirty (30) minutes prior to the operating hour. Upon case approval, the assignments are posted in the markets system. In the event the ASO case is not approved, previous assignments are effective into the next hour. The ASO engine uses the hourly offers for Energy, Reserves and Regulation that are effective at the target time for each case solution. ASO does not calculate market clearing prices.

Figure 31 has the annual average regulation reserve prices in the USA which is showing an overall average of US$15 / MWh. Table 31shows the price of BESS providing regulation reserve is decreasing as the cost of BESS is coming down every year. Note that the share of batteries providing regulation reserve is significant. Spinning reserve prices vary between 4 – 8 US$/MWh for most system operators for most of the year. EPRI[5] notes that energy storage, demand response, and distributed energy resources are all technologies that are newly participating in USA markets. These resources can provide the majority of the services with high quality and can be used by the system operators to increase competition and reduce overall costs.

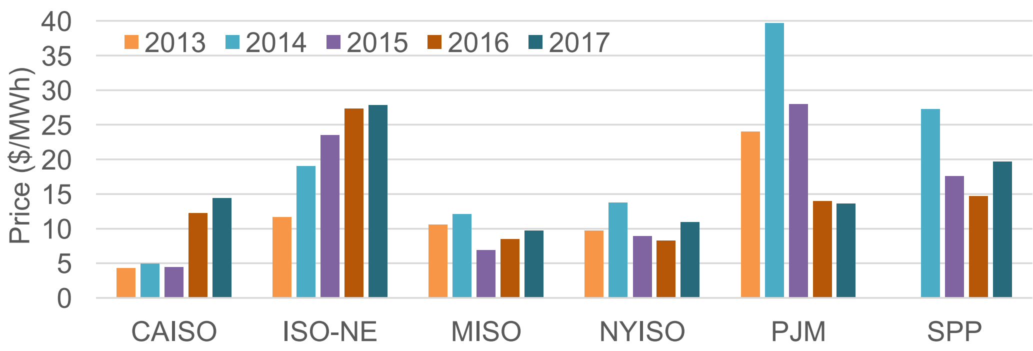


Figure 31 Average Regulation Reserve Prices in the USA[6]

Table 13 **Battery revenues and market shares in the PJM Regulation market, 2014-2017**[7]

Year	Avg. Battery revenue ($/MW of regulation provided)	Battery share of settled regulation revenues (%)
2014	36.78	16.0

[4] PJM Manual 11: Energy & Ancillary Services Market Operations, Revision: 118, Effective Date: March 1, 2022
[5] EPRI, Ancillary Services in the United States, technical report 3002015670, June 2019
[6] EPRI, Ancillary Services in the United States, technical report 3002015670, June 2019
[7] EPRI, Ancillary Services in the United States, technical report 3002015670, June 2019

2015	27.07	27.6
2016	15.39	41.0
2017	13.70	46.5

Black start is procured via bilateral contracts. The formulas to calculate the costs for a black start unit is defined by FERC or filling cost components in a spreadsheet provided by PJM. Allowable black start costs are capital costs, fixed operating costs, variable operating costs, training costs and fuel storage costs. Black start facilities must be tested once a year and the test is compensated for under the variable cost component.

Reactive power is currently compensated by the system operators in the USA using a cost methodology developed by use the FERC-approved "AEP methodology" or payments based on settlements[8]. The current compensation methodology used in the USA is summarised in Table 32.

Table 14 Reactive power compensation methodologies in the USA

Entity	Compensation Methodology
ISO-NE	Both capability and provision payments. Capability payment based on settlement using AEP methodology. Provision includes cost of energy consumed and produced and lost opportunity costs in the energy markets.
NYISO	Both capability and provision payments. Capability payment based on settlement. Provision payments includes cost of energy consumed and produced and lost opportunity costs in the energy markets. Compensation may differ by resource type.
PJM	Both capability and provision payments. Fixed costs calculated using the "AEP methodology" and filed with FERC. Provision payments include cost of energy consumed and produced and lost opportunity costs in the energy markets. Compensation may differ by resource type.
MISO	Capability payment based on "AEP methodology". Qualified resources seeking compensation for reactive service must file with the Commission to justify its cost-based revenue requirements.
SPP	Provision payments. SPP charges a reactive compensation rate which is multiplied by the monthly amount of reactive power provided by a qualifying generator outside of the standard range to calculate monthly payments.
ERCOT	Provision payments of lost opportunity costs in the energy markets.

[8] EPRI, Ancillary Services in the United States, technical report 3002015670, June 2019

CAISO	Provision payments based on LMP or RMR contract.

3.3.1.3 USA PJM – renewables in a dynamic market9

Secondary frequency services using wind farm and battery storage

PJM has a grid scale energy storage system project, Laurel Mountain, with a 98 MW wind farm and a 32 MW (8 MWh) storage battery designed to provide secondary frequency control (called regulation in the USA). This provides both 32 MW of positive regulation and 32 MW of negative regulation (Figure 32).

The potential exists for this to become the future for wind farms to provide a service, specifically as the cost of batteries is decreasing and for wind and solar farms the inverter is already installed.

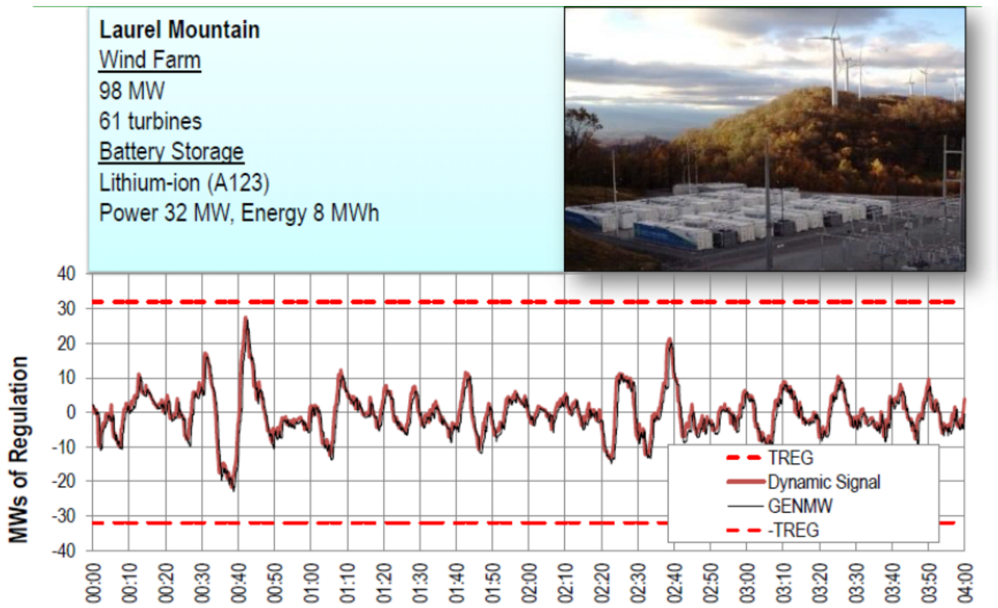


Figure 32 Laurel Farm regulation capability

3.3.2 Great Britain Ancillary Services

3.3.2.1 Ancillary service definitions

Great Britain has the following ancillary services:

1. Operating reserve including
    a. Frequency Containment Reserve
    b. Frequency Regulation Reserve
    c. Replacement Reserve
2. Reactive power and voltage control
3. Black start

3.3.2.2 Reactive power and voltage control

Reactive power within the grid code requirements is not compensated. Enhanced reactive power service is for generators who can provide reactive power over and above the grid code and obligatory reactive power service requirements. Enhanced reactive power service is compensated.

[9] Enduring Investment in Reliable Resources, Adam Keech, PJM, Cigre tutorial, 20113.

National grid is exploring potential solutions to reform the reactive power services which will help to address the challenges Great Britain are facing with system voltage control. The proposals are in the consultation phase and it's too early to include in this report.

3.3.2.3 Black start

Great Britain has a few black start facilities but with the move to zero carbon emissions National Grid is working on the Distributed ReStart project with industry partners[10]. It's a world-first initiative that's harnessing the rapid growth of distributed energy resources (DERs) – including renewables – and making it possible for them to deliver a new kind of grid restoration capability.

The Ofgem-funded project takes a 'bottom up' approach to black start. Instead of creating individual islands of thermally-generated power to reconnect Britain's transmission network after a blackout, the whole process starts with distributed energy – those smaller generators connected in much greater numbers to the regional distribution networks.

These DERs create clusters of power which scale up through the regional networks, gradually restoring grid power through the high-voltage transmission lines. It's an exciting prospect and one which is in tune with the country's net zero targets. In a near-future where Distributed ReStart has replaced our black start strategy, we could see renewable generation alone meet our grid restoration needs – whether it's from hydro power, biomass or intermittent generators like wind and solar.

3.3.2.4 Operating reserves

The operating reserve requirement are of interest as Great Britain has significant VRE. Operating reserves are defined as follows:

1) Frequency Containment Reserve (FCR) – primary frequency control

   Due to the higher volatility of the reference incident, the FCR is calculated on a continuous basis which does not make the probabilistic approach viable and only the Reference Incident shall apply.

2) Frequency Regulation Reserve (FCR) – secondary frequency control

   For FRR only the deterministic approach is applied due to the volatility of the systems. Furthermore, the RR Capacity shall be dimensioned not only as support to FRR but also to FCR activation.

3) Replacement Reserve (RR) also called Short Term Operating Reserve (STOR)

   The level of operating reserve for the next 4 hours requirement is derived from a statistical analysis of generation output losses across conventional plant and demand forecast error. This is set at a level such that there is a less than 0.3% (or 1 in 365) chance of being unable to maintain security of supply from approximately 4 hours ahead of real time. It includes regulating reserve, reserve for response and STOR (Short Term Operating Reserve) and is referred to in combination as operating reserve.

   These are defined as follows:

   - Basic Reserve: Reserve for demand forecast error and conventional generation loss[11] ;
   - Reserve for Response: Reserve carried in order to carry sufficient response holding for largest in-feed loss; and
   - Reserve for Wind: Additional reserve required to manage variability of wind output[12].

[10] National Grid website, https://www.nationalgrideso.com/news/black-start-bottom-rethinking-our-most-important-back-plan
[11] Electricity System: Assessment of Future Challenges – Summary, DECC, August 2012

The necessity to increase the operating reserve, as shown in Figure 4-1, is mainly driven by two key reasons:

- The anticipated connection of larger generation assets will increase the normal in-feed loss risk from 1000MW to 1320MW and the largest credible in-feed loss risk from 1320MW to 1800MW; and
- With wind capacity increasing as a proportion of the GB generation portfolio, it is important to ensure that there is enough flexibility to meet the variability.

Figure 33 shows the required levels of operating reserve for three scenarios of wind load factor, i.e. 0%, 30% and 100% up to 2025. It can be seen that wind integration has a significant impact on the reserve requirement.

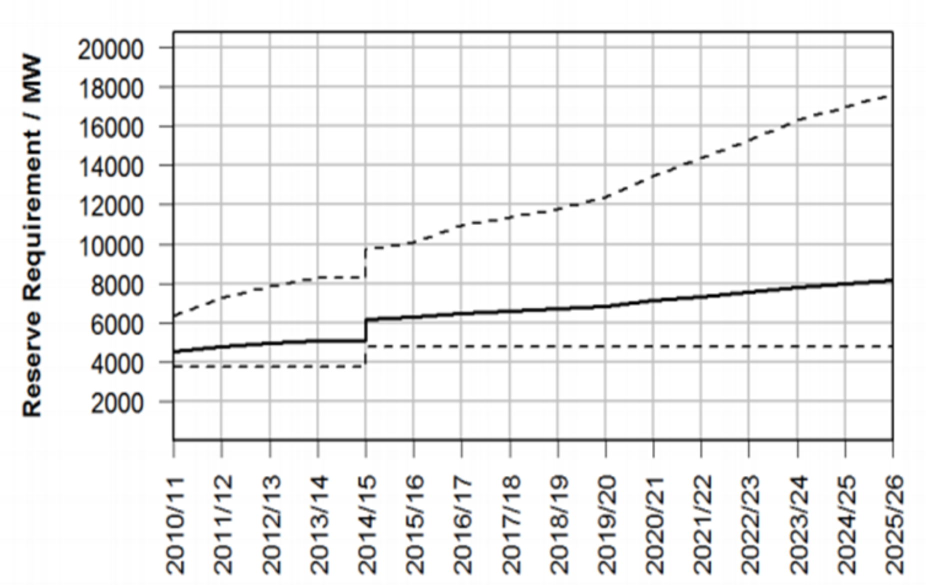


Figure 33 Operating reserve requirement for Gone Green Scenario (solid line is 30% wind load factor, bottom dashed line 0% wind load factor and top dashed line 100% wind load factor) [13]

Figure 34 shows a scenario modelled by National Grid which assumes demand for January 2010 and wind output scaled to predicted 2021 capacity. This shows the volatility of the reserve required for wind generation. Therefore, the two trends that are driving the increase in reserve requirement are increase in variable generation and the increase in the in-feed loss limit.

[12] Understanding the Balancing Challenge, for the Department of Energy and Climate Change, August 2012, Imperial College/NERA
[13] National Grid, Operating the Electricity Transmission Networks in 2020 – Update June 2011

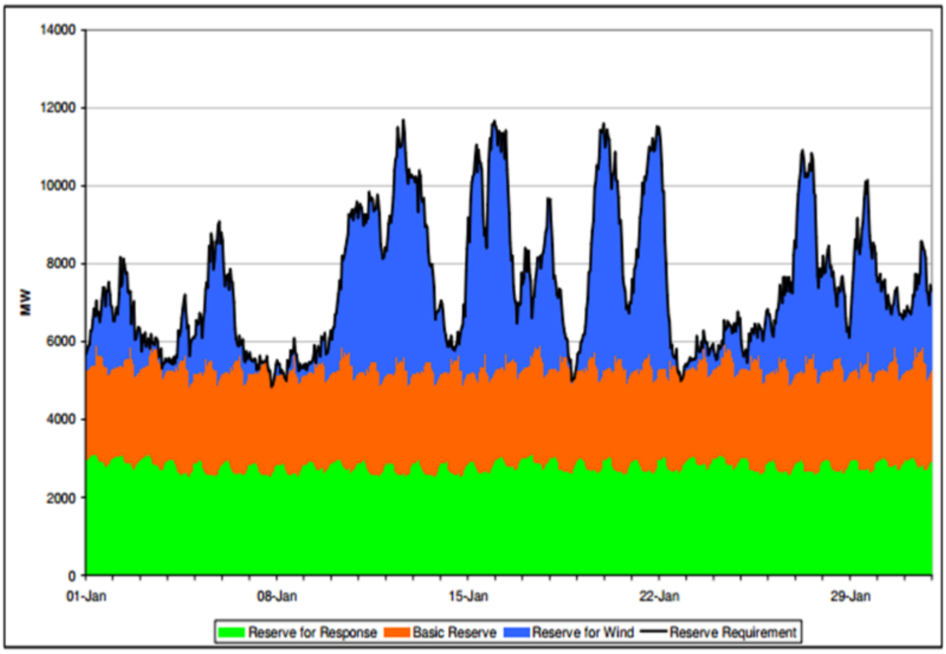


Figure 34 Volatility in operating reserve requirement in 2020[4]

Due to the higher volatility of the Reference Incident with varying power flowing from wind power plants and DC import from GB, the FCR is calculated on a continuous basis which does not make the probabilistic approach viable and only the Reference Incident shall apply.

FRR is dimensioned to exactly cover the Reference Incident which is the largest single infeed at the time. So after 90 seconds following a loss of power the FCR response's additional MWs become FRR. The use of the same reserve for both FCR and FRR means that for the Reference Incident FRR cannot restore FCR and the TSO must rely on Replacement Reserves to restore the FCR to the required level.

3.3.2.5 Procurement of ancillary services

Great Britain runs annual auctions to procure all ancillary services. There are discussions of making the auctions longer to ensure the development of new ancillary service options.

3.3.3 Ireland Ancillary Services

3.3.3.1 Ireland inertia and rate of change of frequency

The inertia of the Irish system is predicted to decline with increasing non-synchronous wind penetration as shown in Figure 35. Studies have shown that the inertia needs to be above 25,000MWs otherwise the rate of frequency change will exceed 0.5 Hz/s.

The duration curve shows the predicted 30% of the time the inertia will be below 25,000MWs in 2020.

In 2011, EirGrid and SONI identified opportunities for mitigation strategies to address the expected reduction in system inertia. These included:

- Remove or reconfigure RoCoF protection from windfarms;
- Improve (or confirm) the capability of generators to remain synchronised for higher RoCoF (i.e. greater than 0.5 Hz/s);
- Improve speed and magnitude of reserve response;
- Reduce minimum stable generation levels of synchronous generation; and

- Develop new, alternative sources of synchronous inertia (e.g. flywheels).

Since the report was written, the RoCoF limit to remain synchronised has been increased to 1 Hz/s in the Irish grid code.

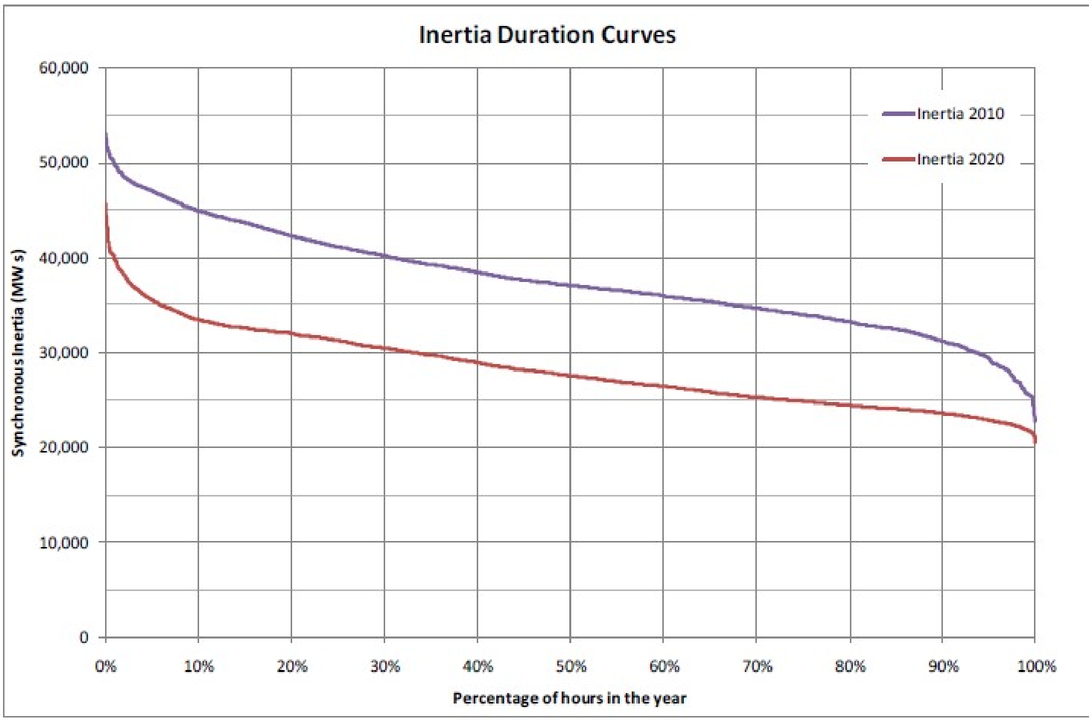


Figure 35: Inertia Duration Curves for the Irish System (Source: EirGrid)

Research performed by Ricardo for the Irish Energy Regulator, the Commission for Energy Regulation (CER), showed that a RoCoF of 1 Hz/s measured over 500 ms can be tolerated by Irish consumers and generators alike[14]. The change from the previously determined 0.5 Hz/s to 1 Hz/s will significantly assist the Irish system operator, EirGrid, along with a range of other technical enablers in achieving the mandated 40% renewable electricity target by 2020 for Ireland (75% non-synchronous instantaneous penetration)[15,16]. Power plants in Ireland are in the process of checking for compliance before the abovementioned grid code change becomes final and binding. Simplified dynamic studies[17] determined that frequency changes of greater than 1 Hz/s (as measured over a 500 ms sliding window) can result in pole slip to combined cycle gas turbines and other thermal generators (as summarised in Table 33).

The CER has required all generators to prove compliance to ROCOF of 1 Hz/s and at the time of writing, all high-priority conventional generators have tested for compliance while most medium-priority and low-priority generators are ahead of schedule. Protection setting changes were required on wind farms and these are over 80% complete[18].

[14] DNV GL Energy Advisory (for EirGrid plc), "RoCoF Alternative Solutions Technology Assessment: High level assessment of frequency measurement and FFR type technologies and the relation with the present status for the reliable detection of high RoCoF events in a adequate time frame," 2015.
[15] The EirGrid Group, "The DS3 Programme Delivering a Secure, Sustainable Electricity System; Shaping the Power System for the Future;"
[16] EirGrid, "All Island Tso Facilitation of Renewables Studies," 2010.
[17] PPA Energy and TNEI Services Ltd, "Rate of Change of Frequency (ROCOF) Review of TSO and Generator Submissions Final Report," 2013.
[18] DNV KEMA, "RoCoF, An independent analysis on the ability of Generators to ride through Rate of Change of Frequency values up to 2Hz/s," 2013.

Table 15: Summary of transient stability analysis

Generator Type	Unit Size (MW)	Stable during RoCoF event?		
		0.5 Hz/s	1.0 Hz/s	2.0 Hz/s
CCGT Single-shaft	400	Y	Y*	N
CCGT Dual-shaft	260	Y	Y*	N
CCGT Dual-shaft	140	Y	Y*	N
Steam Thermal (Reheat)	300	Y	Y*	N**
Steam Thermal (Once Through)	150	Y	Y*	N
Steam Thermal (Fluidised Bed peat)	150	Y	Y*	N
OCGT	50	Y	Y*	Y*
Salient-pole Hydro	30	Y	Y	Y

Key: Y is used to indicate stable operation
Y* is used where a pole slip is only observed for a 0.93 leading power factor operating mode
N is used when a pole slip is also observed for power factors of unity and/or 0.85 lag
N** is used when no pole slip is observed for power factors of unity and/or 0.85 lag, but negative power generation is detected.

The largest cause of RoCoF is not due to loss of the largest unit but is due to transmission and distribution faults near to wind farms. The power output of the wind farm from a system perspective reduces to zero and this reduction is greater than loss of a single contingency. The mitigation is to ensure the wind farm's output recovers as quickly as possible once the fault is cleared.

3.3.3.2 Ancillary service definitions

Ireland has introduced DS3 services to replace ancillary services with enhanced ancillary services to ensure reliability of the network with significant VRE.

Overview of DS3 Services

In the Republic of Ireland and Northern Ireland the TSOs have introduced seven new services to assist in the real time balancing of the network. The key is that these services will be compensated for by the TSOs. This is a different approach than that suggested by European Networks where the service provision is tending to be mandatory.

The DS3 services are based on a scenario of 40% renewable penetration by 2020 and could be achieved as follows:

- 5200MW installed wind on the Ireland and Northern Ireland power system; and
- operational policies equivalent to a System Non-Synchronous Penetration (SNSP) limit of 75%;

This would result in the level of wind energy curtailment being less than 5%.

The following new DS3 services and existing products already available are:

New products

- Synchronous Inertial Response (SIR),
- Fast Post-fault Active Power Recovery (FPFAPR),

- Dynamic Reactive Response (DR),
- Fast Frequency Response (FFR), and
- Ramping Margin (RM1, RM3 and RM8).

Existing products

- Operating Reserves: POR, SOR, TOR1 &TOR2,
- Replacement Reserve – minor modification implemented, and
- Steady-state reactive power – modification implemented.

The services can be divided into two distinct categories: Services that are for enhanced frequency control and services for enhanced voltage control. The main purpose for the enhanced voltage control services is to keep wind power plants producing power and thus these services are provided here as a complete picture of how operating reserves are interrelated with voltage control services in Ireland.

Frequency Control Services

Ireland has a very high wind penetration and intends on growing this to 40% of energy requirements. Ireland is not synchronously connected to any other system. The result is that the measured rate of frequency change is increasing and changes greater than 1 Hz/s are not uncommon.

Frequency control services time frames and overlaps are best described in Figure 36 below.

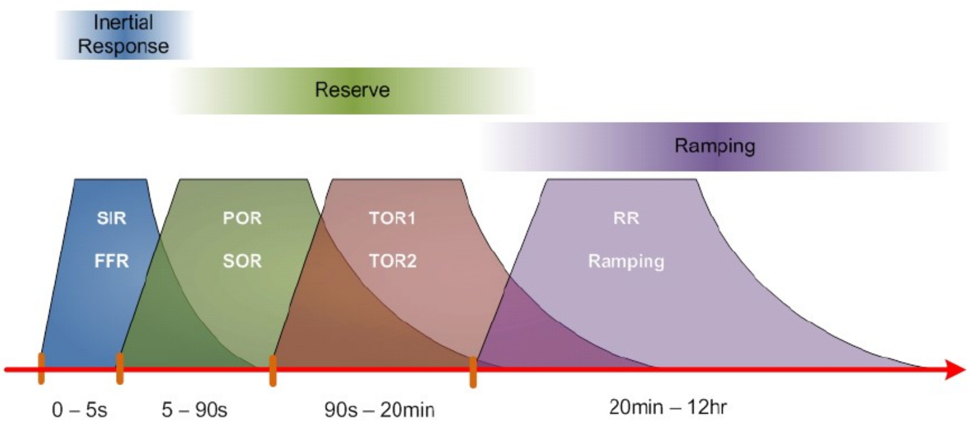


Figure 36: Frequency Control System Services (source EirGrid[1])

Potential areas for wind turbines to participate are:

Synchronous Inertia Response (SIR) – This uses the inertia of the wind turbine to provide power to the network when there is a rapid change in frequency. The inertia is a small amount of power that is provided for a few seconds as the frequency falls as shown in Figure 37.

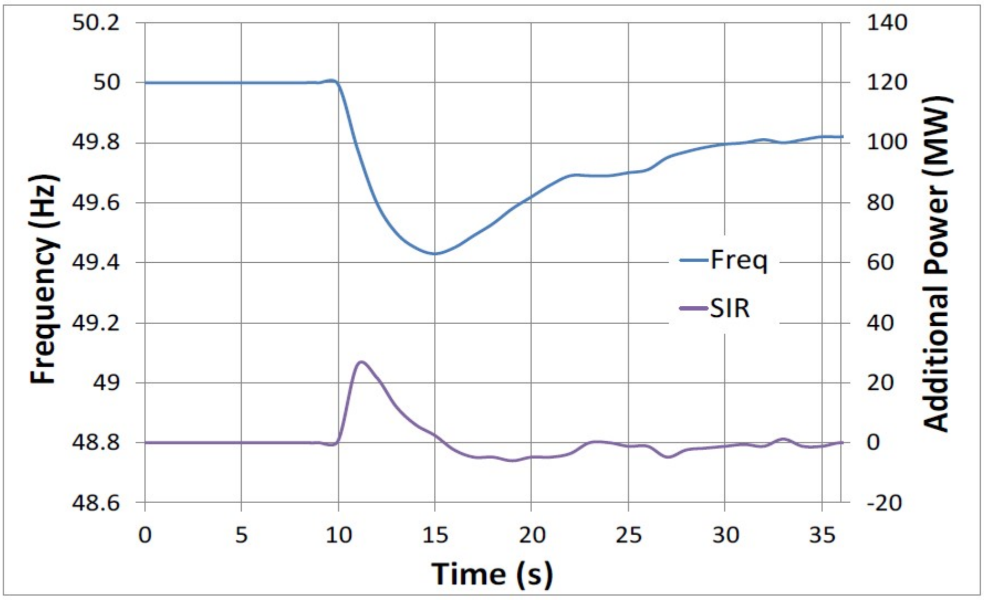


Figure 37: Illustration of Synchronous Inertia Response (source EirGrid)

Fast Frequency Response (FFR) – This involves providing extra power into the network for 2 – 10 seconds. The power drop-off after 10 seconds must be less than the power provided in the 2 – 10 seconds timeframe, shown in Figure 38. This response can be provided by a wind farm by drawing down on the inertial energy and it is recognised that energy drawn in the first 10 seconds will mean there is a power drop off after 10 seconds.

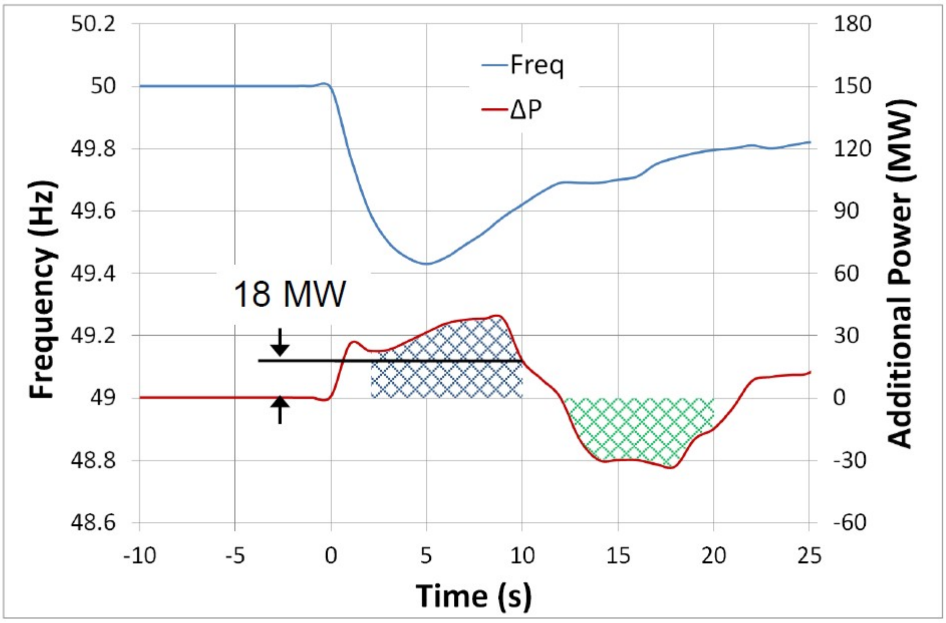


Figure 38: Fast Frequency Response (source EirGrid)

Remaining Frequency Services (POR, SOR, RM1, RM3 and RM8) – these involve providing power from 10 seconds after the incident. Wind farms can realistically only provide this response if the wind farm has been curtailed. This also applies to the other services.

Voltage Control services/ Fault Ride Through capability

Voltage Control and in particular Fault Ride Through capability in Ireland is a key problem. There are fewer and fewer synchronous units online that have a significant capability to decrease system reactive power and provide very fast voltage support. The same trend has been noted in GB. Reactive power and voltage control requirements from wind farms are going to be ongoing requirements as more and more wind farms are added.

The Ireland DS3 system services programme proposes two new Fault Ride Through system services as follows:

Fast Post Fault Active Power Recovery (FPFAPR)

Power plants that can recover their power output quickly following a disturbance assist in maintaining frequency. The faults can be either distribution- or transmission-induced - the key is that if the fault is cleared within 900 ms and the power from the plant is restored to 90% of pre fault value within a further 250 ms then frequency excursions will be minimised, as shown in Figure 39. It is likely that this requirement can be achieved through a software modification on the wind farm.

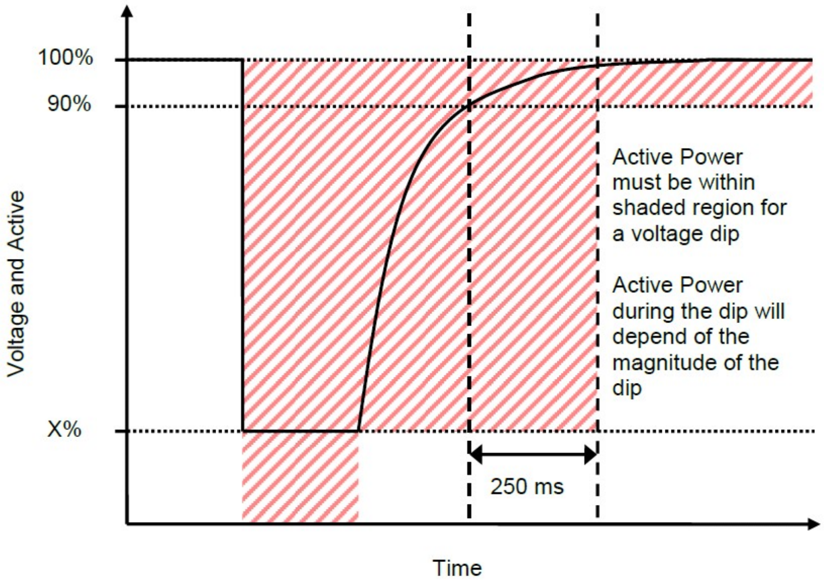


Figure 39: Fast Post Fault Active Power Recovery (source EirGrid)

Dynamic Reactive Response

Dynamic Reactive Response is the ability of non synchronous power plants to deliver reactive current response to voltage dips in excess of 30% of nominal voltage. The current response has to have a rise time of less than 40ms and settling time of 300 ms, as shown in Figure 310.

This service is targeted at wind farms and is a grid code requirement which will be compensated for by the TSO.

In order to prove the service is being provided the service provider will require high quality phasor measurement units to be installed. This will probably be also required for large wind farms as part of the innovation drive by National Grid to get better network visibility.

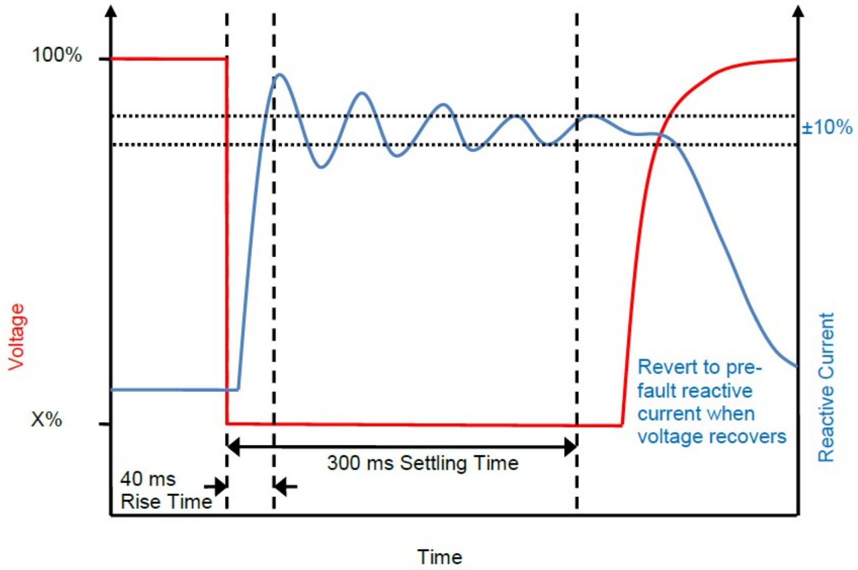


Figure 310: Dynamic Reactive Response Service (source EirGrid)

3.3.3.3 Procurement of ancillary services

The compensation methodology for DS3 services is based on the value of the service rather than the costs. A key issue with this approach is that the value of the service changes over time.

The contract period will be 5 years to stabilise the uncertainty of the value approach. After the 5-year period the TSO could contract with another 'cheaper' service provider. This move is intended to try to create an opportunity for innovation in the industry.

3.3.4 South Africa Ancillary Services

3.3.4.1 Ancillary service definitions

The ancillary services in South Africa were initially defined based on the NERC proposed ancillary services in 2000 and the following services were defined[19]:

1) Regulation and Load Following
2) Operating Reserves
3) Energy Imbalance (Constrained Generation)
4) Real Power Transmission Losses
5) Reactive Power Supply and Voltage Control from Generation Sources
6) System Black Start Capability
7) Network Stability from Generation Sources

The number of ancillary services has recently been reduced to:

1) Operating Reserves which includes:
    a. Instantaneous reserve – 10 second activation primary frequency reserve (direct frequency control)
    b. Regulation reserve – secondary frequency control reserve (under AGC)
    c. Ten-minute reserve – restoration of instantaneous and regulation reserve following a single incident
    d. Supplemental reserve – can be activated in 2-5 hours to restore ten-minute reserve following a large incident or load forecast error
    e. Emergency reserve – activation a few hours a year

[19] Chown G.A. and Willis J.A., Ancillary Services in Eskom, Cigre Regional Conference, Somerset West, South Africa, October 2001.

2) Black Start and Islanding – units > 100 MW that cannot start in 2 hours must have the facility to island the unit. Ancillary service pays for testing of facilities and costs incurred when service activated
3) Reactive Power and Voltage Control – mainly payments for synchronous condenser operation
4) Constrained Generation – both constrained down and constrained up

The minimum Regulating Reserve requirements are still specified by the system operators Ancillary Services Technical Requirements for 2019/20 – 2023/24 and the requirements are stated below[20]: The technical requirements come from a study on the impact of VRE done for Eskom by Fraunhofer IWES[21].

Table 16. South Africa regulating reserve requirement

Reserve	Period	2019/20 MW	2020/21 MW	2021/22 MW	2022/23 MW	2023/24 MW
Regulating up	Summer (Pk/off pk)	450	450	470	500	520
	Winter (Pk/off pk)	550	550	570	600	620
Regulating down	Summer (Pk/off pk)	450	450	470	500	520
	Winter (Pk/off pk)	550	550	570	600	620

3.3.4.2 Procurement and charging for ancillary services

The procurement of Black Start and Islanding, Reactive Power and Voltage Control, and Constrained Generation are annually negotiated bilateral contracts with generators. Constrained generation is based on known constraints. If a generator (without an annual constrained contract) is constrained down in the day-ahead energy market or in real time, they are paid a loss of profit payment. The loss of profit payment is the difference between their offer price and the market clearing price.

Primary frequency control services are contracted bilaterally with demand side participants. These participants provide around 50% of the primary frequency control requirement.

Supplemental reserve is contracted bilaterally with demand side participants and open cycle gas turbines.

The rest of the reserve requirements are purchased in the day-ahead market and co-optimised with energy in a fully constrained 'PJM style' market clearing algorithm.

Each participant is paid an availability payment, usage payment and a loss of profit. The loss of profit payment is made is if the generator is constrained down in order to provide operating reserve when the market is cleared.

[20] Eskom System Operator, Ancillary Services Technical Requirements for 2019/20 – 2023/24 Ref No. : 342-466, http://www.nersa.org.za/Admin/Document/Editor/file/Consultations/Electricity/Notices/6Ancillary%20Services%20Technical%20Requirements%20for%202018_19%20-%202022_23%20(1).pdf

[21] Wind and Solar PV Resource Aggregation Study for South Africa – Fraunhofer IWES November 20

Eskom, the main utility in South Africa started to charge for ancillary services, through a reliability charge in 2000. The ancillary services budget for the year ahead was calculated and these charges including system operator costs were charged to generators and consumers through a reliability charge. Generators and consumers each had to pay 50% of the ancillary services charge and the c/kWh was determined from the budgeted energy for the year ahead. The international trader was treated as a generator when importing and a load when exporting and charges were determined at each international connector. The international trader charged as a control area service charge as a fixed monthly charge to countries that are within the Eskom Control Area which includes Botswana, Eswatini, Lesotho, Mozambique and Namibia. The control area service definition came from SAPP operating guidelines.

Eskom has recently changed the reliability charge to an ancillary service charge which does not include system operator charges.

The 2019/20 budget has decreased to USD 60 million[22] resulting in Eskom now charging an ancillary service charge of 0.026 USc/kWh to consumers connected at 132 kV and above.

It is noted that the above budget does not include regulation reserve services even though these are the key services to balance VRE. It is presumed that these services are provided by generator to Eskom for no cost.

In an ongoing project with Eskom Generation, it has been calculated that regulation reserve of 600 MW up and 600 MW down costs Eskom between US$ 40m and US$ 65m per annum. If the current coal fired power plants provide regulation reserve the overall cost of dispatch increases by US$ 130 per annum.

BESS systems can provide regulation reserve and a study done for South Africa, shows a battery size of 600 MW / 1800 MWh will be able to provide regulation reserve 100% of the time.

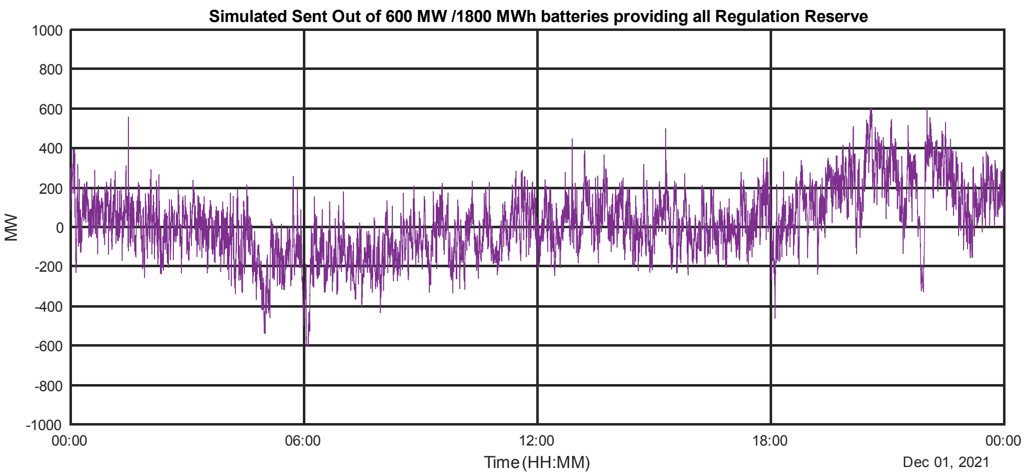


Figure 311 Simulated power out from a 600 MW 1800 MWh battery providing Regulation Reserve

The estimated annualised costs for providing secondary frequency reserve, using a conservative cost of US$ 275 /kWh, is US$ 65m per annum or US$ 12 / MWh. Figure 311 shows that the BESS system can also provide 400 MW of primary frequency reserve (or fast frequency reserve) for most of the day and thus BESS can provide both secondary frequency and primary frequency reserve. Additionally, BESS can provide a source for black start and reactive power over the full range 100% of the time. This makes this a viable economic solution.

[22] Eskom Revenue Application, Multi-Year Price Determination (MYPD 4), FY2019/20 - 2021/22, September 2018, http://www.nersa.org.za/Admin/Document/Editor/file/Consultations/Electricity/Notices/3Transmission_MYPD%204%20Sept%202018.pdf

3.4 Future Ancillary Services in Philippines

The ancillary services procurement plan should be updated to the latest grid code ancillary service requirements.

The following changes are proposed:

3.4.1 Separation of regulation reserve to primary and secondary frequency reserve

The regulation reserve in the Ancillary Services Procurement Plan needs to be separated to primary frequency and secondary frequency reserve. Noting:

1) Primary frequency reserve should be dedicated to arresting the frequency following a contingency. This is international practice in most interconnections.
2) The suppliers of primary frequency and secondary frequency reserve suppliers are different. Demand side and BESS are potential providers of primary frequency reserve and international experience has shown that these options can provide primary reserve cheaper than traditional power plants. Demand side and BESS providing primary frequency reserve further means the existing power plants do not need be backed off from their most economic solution and thus this reduces the system marginal price.
3) EPRI report TR 107270 V4[23] calculates that thermal power plants providing only secondary frequency control (and not primary frequency control) marginal costs are reduced by 0.5%.

3.4.2 Secondary frequency reserve requirement

Secondary frequency reserve requirement in the ancillary services procurement plan is currently 4% of the peak demand.

Internationally the secondary reserve requirements are now calculated dynamically to include wind and solar PV intermittency. Some interconnections even change their secondary frequency reserve requirements based on current wind and solar PV outputs. Depending on the dispersity of wind the total wind minute to minutes output can vary 5 - 20%. Solar PV individual power plants power dips as large as 80% in seconds due to clouds and the total system effect depends on the environment. In South Africa most solar PV is in semi desert area and the minute-to-minute variability due to cloud cover is negligible.

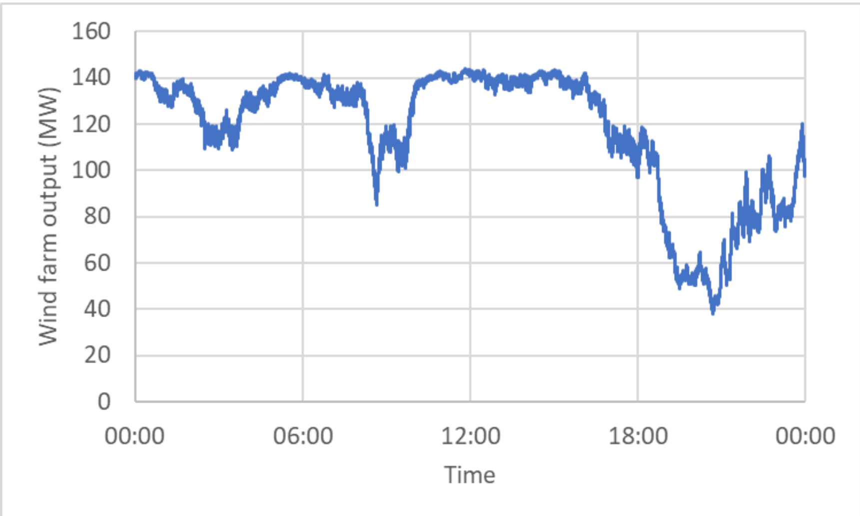


Figure 312 Second to second power output of a 150 MW wind farm in South Africa

[23] TR_107270_V4_Cost of Providing Ancillary Services from Power Plants_ Operating Reserve _ Spinning.pdf

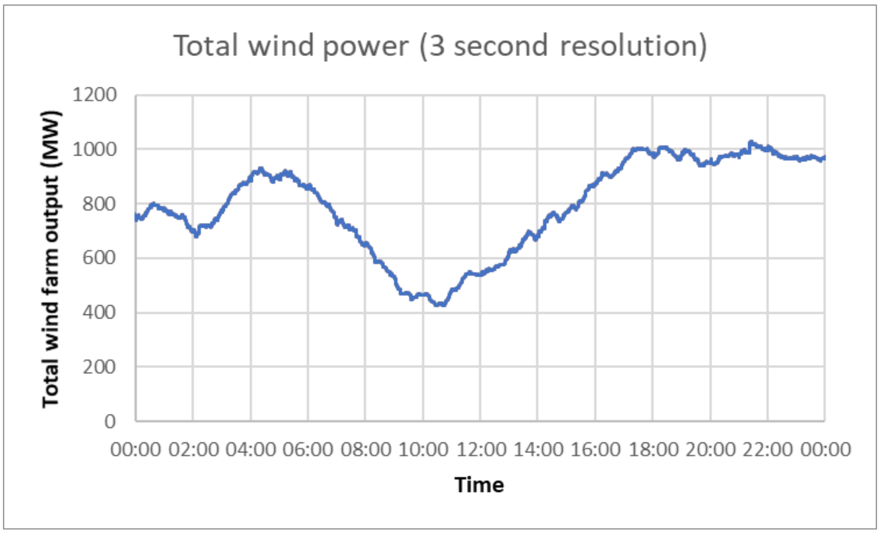


Figure 313 Minute to minute total wind power in Finland

3.4.3 Introduction of 3-5 hour ahead operating reserve

Many interconnections have introduced 3-5 hour ahead operating reserve specifically to cater for VRE load forecasts errors. This is to ensure there is sufficient operating reserve should the day be cloudier than predicted on the previous day or if the overall wind power is less.

The Northern Ireland system operator (SONI) day-ahead hourly wind forecast accuracy is within ±10% for 90% of the time in 2018. The forecast is within ±20% for 95% of the time.

Individual wind farms in South Africa have to provide a day-ahead forecast by 10 am for the following day. There is currently 1500 MW of wind farms in the country. The total forecast error for all wind farms in South Africa over the last three years is ±10% for 80% of the time and ±20% for 98% of the time.

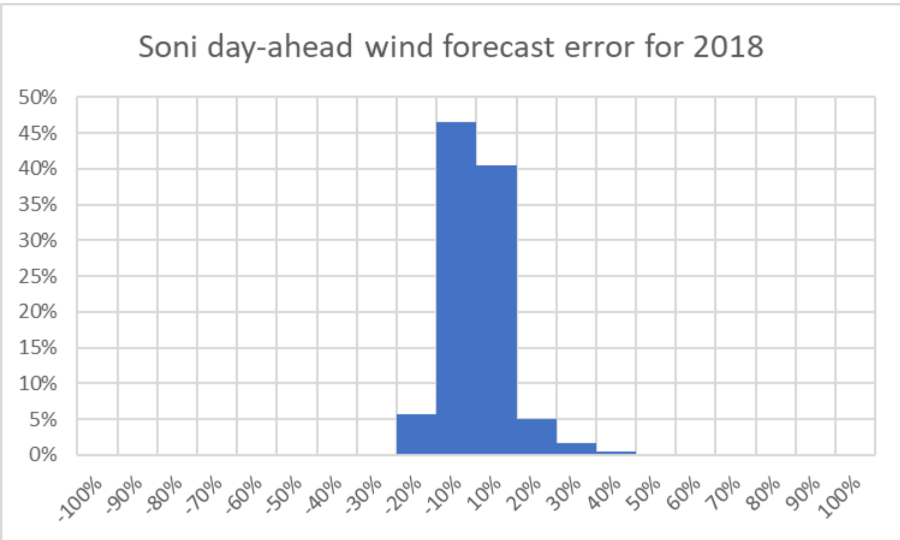


Figure 314 SONI day-ahead hourly wind forecast error for 2018

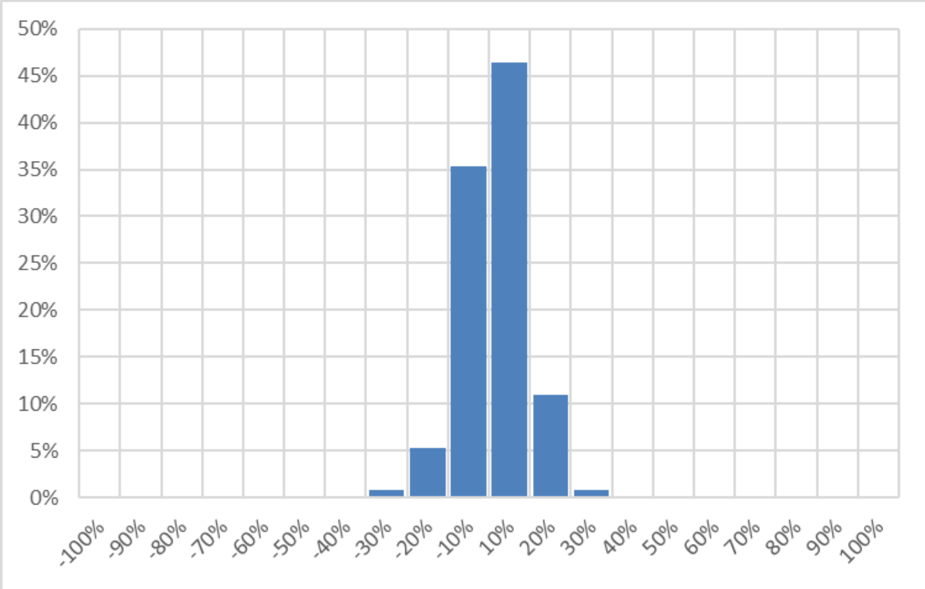


Figure 315 Total day-ahead hourly wind forecast error in South Africa

3.4.4 Introduction of inertia / fast frequency reserve

The on the system inertia provided by synchronously connected generators and induction motors. With increasing non-synchronous penetration the total inertia of the system declines. The rate of change of frequency is directly proportional to the size of the disturbance and inversely proportional to the inertia.

The inertia requirements for each network in the Philippines have to be defined to ensure system security of supply. This is a three step process:-

1. Determine what level of Rate of Change of Frequency (RoCoF) is acceptable
2. Determine contingency size for each network in the Philippines
3. Calculate minimum inertia requirements for each network in the Philippines

Once the inertia requirements are known then the requirements for fast frequency response and inertia can be calculated and procured.

Inertia can be increased by having more units on-line at minimum generation, running units in synchronous condenser operation, and wind farms providing synthetic inertia.

Fast frequency reserve which can react within 1 second is an alternative to adding inertia. Fast increase in power counter acts the loss in power reducing the overall disturbance size.

Sources of fast frequency response are:

1) Demand side disconnection which can be disconnected in 200 ms using under frequency relays. Europe system operator unsuccessfully proposed that all thermal storage devices are automatically switched off for 10 minutes. South African thermal storage devices are already providing 400 MW of primary frequency reserve ancillary services and could be reprogramed to provide fast frequency response.
2) BESS which can respond in under 1 second. Note BESS can go from full power import (charging) to full power export (discharging) in under a second. This can be done for a few minutes without overheating the batteries.
3) Non synchronously connected wind and solar PV that is below their instantaneous maximum can increase their power to instantaneous maximum in under 1 second. Ireland is using this very successfully and on 8 February 2022 operated the interconnection with 95% non-synchronous penetration for a few hours Figure 316.

4) Electric vehicles that are charging can provide fast frequency response in under a second. The amount of response will be limited to the inverters size and distribution network where it is connected to.
5) HVDC connections between two synchronous areas can provide fast frequency response in under a second. The amount of response has to be limited so there is no negative impact to the interconnection the power is drawn from.

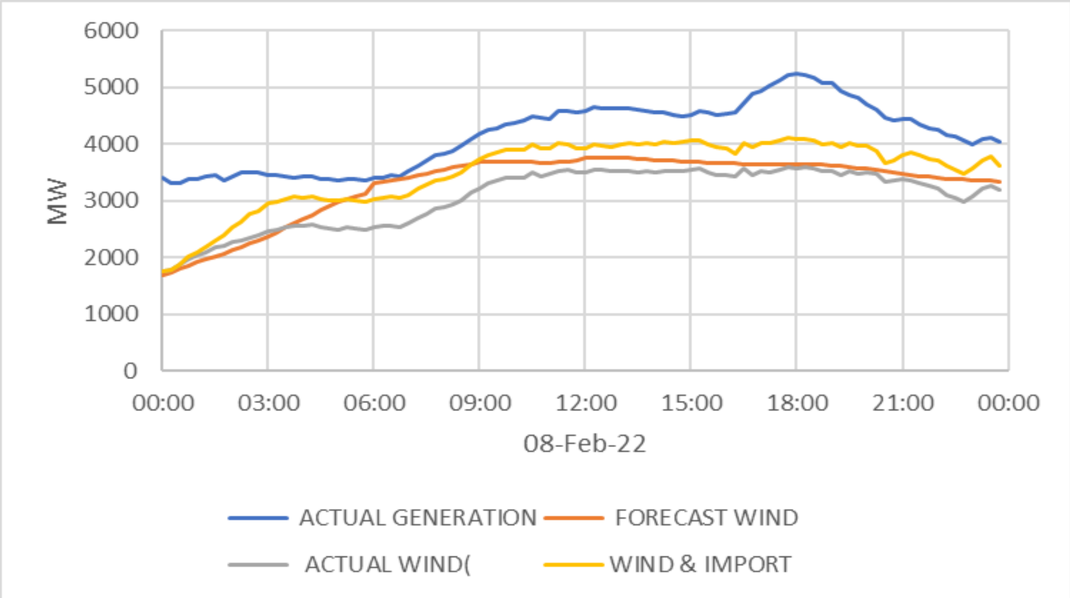


Figure 316 Ireland total generation, wind power and HVDC imports for 8 Feb 2022

3.4.5 Introduction of long-term steady state reactive and dynamic power procurement as an ancillary service

Reactive power and voltage control is required to control the local steady state voltage. The provision of sufficient reactive power to control the voltage has traditionally been the responsibility of the transmission and distribution network service provide. With the increase in VRE there are new voltage control excursions that need controlling as power flows change from minute to minute. The grid code requires VRE power plants to assist with voltage control but there might still be some requirements to control the voltage to meet targeted steady state voltage levels.

Inverters with voltage source converters (using IGBTs) can provide dynamic voltage control over an above the grid code requirements. If these inverters have BESS then the reactive power and voltage control range can be extended and the inverter can provide the full reactive power range regardless of real power output.

If steady state and/or dynamic reactive power and voltage control is required beyond the grid code requirements, then this should be compensated as an ancillary service. There should be a clear ancillary services framework to ensure all new proposed wind and solar PV factor in the additional revenue. The key is to ensure the power plant is incentivise at the design stage to provide the extra steady state and/or dynamic reactive power and voltage control.

3.4.6 Introduction of demand-side islanding and black start ancillary services

The Philippine Department of Energy Department Circulation DC2020-02-0003 provides a framework for the Philippine Electric Power Industry and roadmap for distribution utilities. Part of the framework is the development of distribution islanding technologies and self-healing grids. BESS with frequency forming inverters can control an island and black start other generators as part of the restoration of the grid.

If BESS are a part of the Philippine restoration plan, then the facilities must be tested regularly in accordance with the grid code. The costs for testing black start and islanding capability that is a part of the restoration plan (plus the fixed and variable costs including training staff) should be paid as an ancillary service.

4 Task 3.3 Rules and Regulations for Smart Grid Facilities

4.1 Introduction

The modern consumer is more engaged with the electricity sector. Consumers are aware of the low costs of installing PV and more consumers are discovering the advantages of installing batteries to improve their own power quality – specifically to avoid interruptions and dips.

Currently only consumers who can afford PV and batteries are seen to be a part of this market but it is foreseen that soon there will be companies offering PV systems with batteries on rental agreements.

The other driver is the introduction of electric vehicles which have the possibility of being active participants in the electricity market – either by themselves or through third party traders. Electric vehicles also bring challenges for example consumers might want to charge the vehicles at the same time and this needs to be manged through smart grid technologies to prevent the local network from being over loaded.

The installation of batteries even at the consumer level can enhance system security. All inverters with batteries already protect the customer and keep essential power to selected circuits. These inverters also are already pre-programmed with the ability to assist with network frequency and voltage control. It is key that these settings are set correctly for the particular installation.

1.1 Philippine Electric Power Industry framework and roadmap for distribution utilities

The modern consumer will want to be engaged in the electricity trading and it is essential regulations are in place to ensure reliability and security of supply are maintained.

The Philippine Department of Energy Department Circulation DC2020-02-0003 provides a framework for the Philippine Electric Power Industry and roadmap for distribution utilities.

The vision is that the Philippines will reach a level of smart grid development by 2040 that will be capable of the following:

1) Self-healing grid
2) Full customer choice
3) Full implementation of retail competition and open access, renewable portfolio standards, green energy option and net metering
4) Optimised energy storage systems (ESS) , energy management systems (EMS) and distributed energy resources (DERs)
5) Virtual power plant integration
6) Islanding
7) Demand response, demand-side and peak management
8) Smart homes and cities

The framework and infrastructure is to comprises of:

1) Smart power generation including DERs, hybrid systems, ESS and flexible generation. The smart power generation shall gradually be integrated into the electricity market to improve competition in market thereby improving efficiency, reliability and flexibility of power grid operations.
2) Transmission modernisation and improvement including:
    a. wide area monitoring and control
    b. regional frequency and voltage stability control
    c. full transmission automation
    d. Island-to-gird interconnection

The smart distribution utility roadmap has four levels for implementation, namely:

1) Level 0 – distribution utilities that have no smart grid plans yet
2) Level 1 – distribution utilities that have initiated installation of reclosers, sectionalisers, load break switches, fault circuit indicators, SCADA and/or GIS
3) Level 2 – distribution utilities that have initiated installation of remote voltage regulators and other devices
4) Level 3 – distribution utilities that have initiated installation of smart distribution and substation automation advanced distribution management system (ADMS) and/or Fault location, isolation and service restoration (FLISR)
5) Level 4 – distribution utilities that have initiated the implementation of smart distribution automation and smart substation automation.

The Philippines smart distribution utility roadmap is shown in Figure 41. The roadmap will guide the smart grid regulations to be developed.

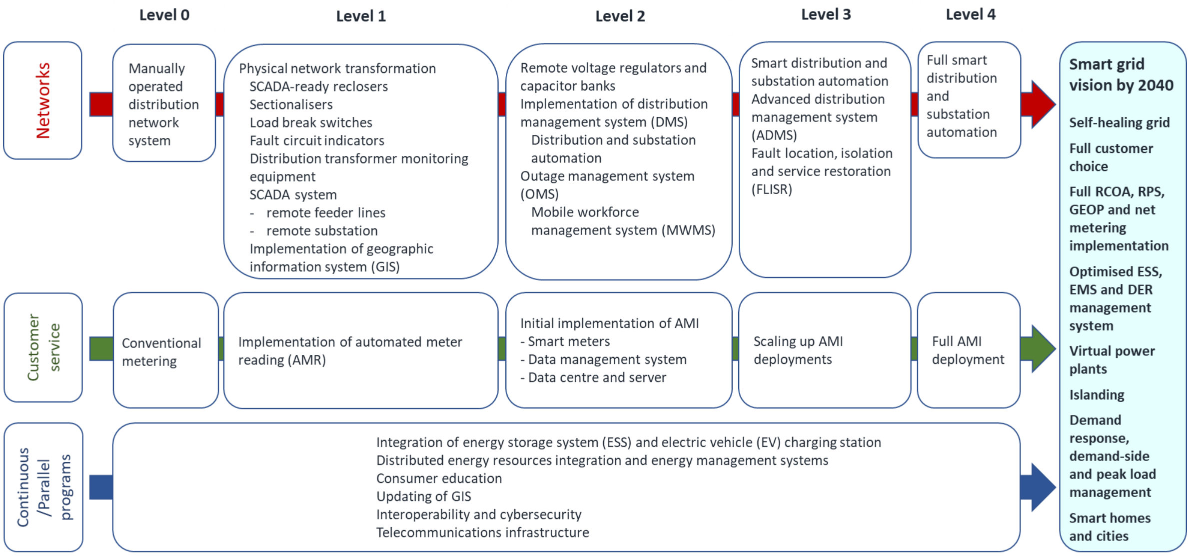


Figure 41 Philippines smart distribution utility roadmap

4.2 Existing smart products

The capabilities of conventional embedded generators and inverters are such that they can provide frequency and voltage control services, this includes:

1. Energy market
2. Ancillary services including:
   a. High primary frequency control in addition to the mandatory requirements in the grid code
   b. Low frequency control for conventional embedded generators, inverters with BESS and where the PV power has been limited
   c. Voltage and reactive power control for conventional embedded generators and inverters with BESS
3. Balancing services for conventional embedded generators and inverters with BESS

The smart grid regulations have to enable embedded generators to provide these services, enable participation in the electricity markets and where appropriate receive compensation through the ancillary services and energy market.

4.3 New smart products

There are many new smart products being discussed in the industry. UK is launching many new ancillary service 'type' products to allow for constructive and meaningful engagement by embedded generator and demand side participants.

Inverters that use voltage source convertors (IGBTs) can provide frequency and voltage control and commonly called frequency forming inverter.

Any embedded generator / demand side participant with a frequency forming inverter and BESS can provide ancillary numerous services, including:

1. Fast frequency control / inertia – BESS can respond within 1 s to fast frequency changes
2. Dynamic voltage control – inverter with BESS can function as a static reactive power compensator (STATCOM)
3. Fast fault current injection for fast post fault voltage recovery
4. Island formation – inverter with BESS can control both voltage and frequency.

There is also much discussion with the introduction of EV's on the potential to optimise and protect the grid.

Such examples are:

1. Optimising charging of the EV when prices are low
2. Energy arbitrage – discharging EV battery back into the grid when prices are high

In the UK, there is the expectation that virtual power plants or data aggregators will have many vehicles under their control and can optimise the vehicles charging. The idea is that a car owner will communicate when the car will be needed and the minimum expected charge. The virtual power station will use the battery to get the best deal for themselves. If an owner wants a fast charge, then this will come at a premium price.

4.4 Smart communication

The National Institute of Standards and Technology (NIST) in the USA has published the possible future for the communications standards and communication pathways to allow for full demand side participation and Distributed Energy Resources (DER).

The three areas are they the report focuses on are:

- Grid operations and economics,
- Cybersecurity, and
- Standards testing & certification.

4.4.1 Grid Operations and Economics

New smart devices, such as inverters, can (or need to) communicate to the grid operators for the provision of Energy, Ancillary Services and Balancing. Similarly, the interface to the market operator is required or embedded generators to participate in future electricity markets. In this regard, the NIST report notes that the use of open standards to achieve interoperability is key to optimising utility operations as new devices, systems, equipment, and technologies are increasingly used within the context of an aging electric grid.

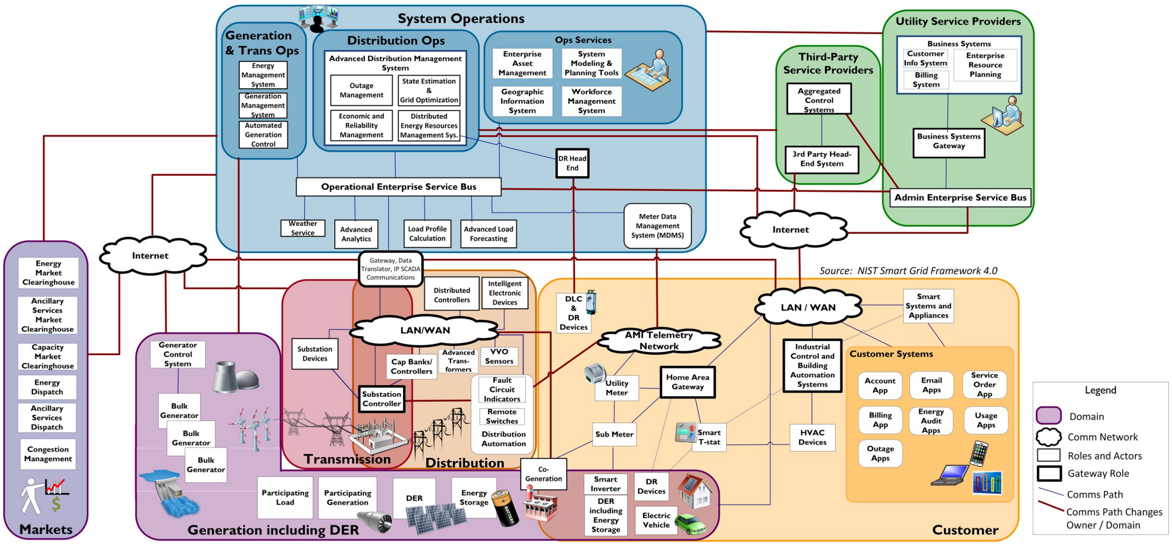


Figure 42 High-DER communication pathways possible future scenario[24]

The report also notes that an inverter communicating via any one of three communications protocols (IEEE P2030.5, IEEE 1815, or Modbus) can conform to the IEEE 1547-2018 standard. Communications via the IEC 61850 also conforms to IEEE 1547-2018.

The regulations for enabling smart grids in the Philippines need to ensure these standard protocols are used for communicating between the embedded generator or demand side participant to the market and grid operator.

4.4.2 Cyber security

Cyber security is a key consideration for the implementation of significant embedded generation. The use of the internet is commonplace for recording embedded generator outputs, monitoring plant availability and changing settings / parameters. The communication with system operator and distribution operator has internationally moved to IEC 61850 -103 protocol. The IEC 61850 -103 protocol uses IP technology and has the possibility to be compromised.

Concerns from regulators and system operators are:

1. Can a single cyber-attack trip significant generation?
2. Can the settings in the control system be compromised causing loss of security of supply?
3. Can protection settings be changed which could lead to damage of equipment or an unsafe condition?
4. Can significant generation be held ransom causing load shedding or worse?

And the list of concerns continues to grow.

The National Institute of Standards and Technology (NIST) in the USA has published the following cyber security management functions:

1. Identify and manage cyber security risks to systems, assets, data, and capabilities
2. Protect to limit the impact of a potential cybersecurity event
3. Detect to timely discovery of cybersecurity events
4. Respond to contain the impact of a potential cybersecurity event
5. Recover to timely recovery to normal operations to reduce the impact of a cybersecurity event

IEC has identified three axis of cyber security as shown in Figure 313[25] The axis focus on process,

[24] NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 4.0, https://doi.org/10.6028/NIST.SP.1108r4
[25] IEC, Cyber Security, iec_2021_cyber_security_a4_en_lr_0.pdf

action and technical. The appropriate IEC standards are listed to ensure compliance which are also applicable to embedded generators and form a part of the smart grid security management process.

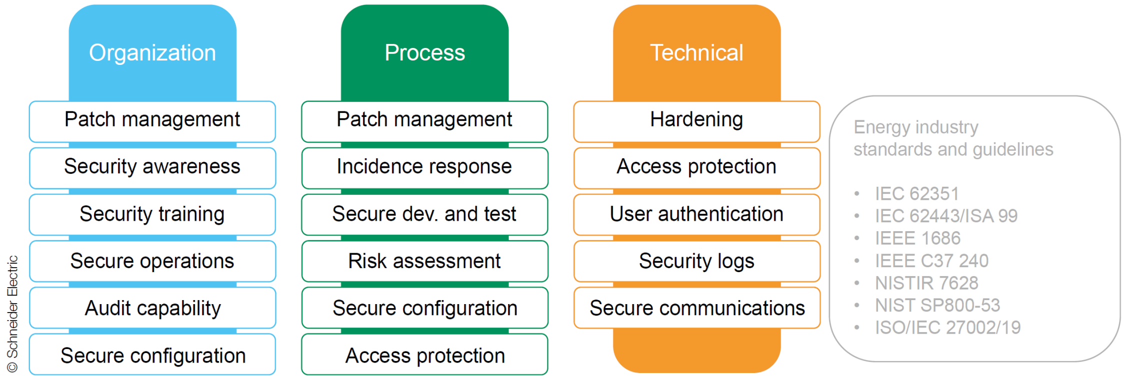


Figure 43 IEC – Three axis of cyber security

NERC reliability standards have a chapter devoted to Critical Infrastructure Protection (CIP) and defines the responsibilities for generators, consumers, system operators and transmission companies to access, detect, prevent and recover from cyber security attacks. Whilst this is for the bulk electric system it does emphasise the criticality of protecting the electrical system and with significant embedded generation and storage will soon include these devices.

4.4.3 Standards testing & certification

Testing and certification programs provide common processes that are used to demonstrate conformance with a standard. The value of certification programs increases as the number of devices grows through economies of scale for both manufacturers and test program operators. As the range of technologies and their uses continue to evolve, grid operations become commensurately more complex. Certification programs, therefore, become essential to ensure the reliable performance of grid components in this increasingly dynamic environment[26].

NIST Framework and Roadmap for Smart Grid Interoperability Standards notes that all stakeholders benefit from testing and certification, noting:

1. Customers benefit by ensuring standards and performance requirements are implemented appropriately and consistently across purchased equipment, which eases integration of new products and services with existing infrastructure and operations.
2. Manufacturers and Vendors benefit from the establishment of clear performance requirements, which reduces implementation costs for new standards. Testing and certification programs ensure product certification occurs in a neutral environment and creates a level playing field for participants, which can facilitate market access and reduce entry barriers for all — including new entrants.
3. Regulators benefit because interoperability testing and certification maximizes the benefits of new grid technology investments they approve through regulatory proceedings

Testing and certification requirements are to be included in the smart grid regulations. What needs to be agreed is who in the Philippines will be responsible for testing and issuing of certificates or will it be acceptable for international companies to provide compliance to international standards?

[26] NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 4.0, https://doi.org/10.6028/NIST.SP.1108r4

Maybe it will be a combination of international compliance and some local testing to ensure local Philippine requirements are met.

There is also a requirement that a qualified person sign-off the embedded generation installation. This requires electricians (or other appointed person) to be trained in the setting up, testing, signing off the installation and issuing of the compliance certificate. The compliance certificate must be provided to the distribution company and who else?

4.5 Draft smart grid regulations proposed

The draft regulations are proposed to cover the requirements for embedded generators to participate in the electricity market including ancillary services and balancing.

The electricity market participation can be in one or more of the following market platforms:

1. Energy market
2. Ancillary services including:
    a. High primary frequency control in addition to the mandatory requirements in the grid code
    b. Low frequency control for conventional embedded generators, inverters with BESS and where the PV power has been limited
    c. Voltage and reactive power control for conventional embedded generators and inverters with BESS
3. Balancing services for conventional embedded generators and inverters with BESS

The regulations will also allow for the introduction of future smart grid services such as

1. Fast frequency control / inertia – BESS can respond within 1 s to fast frequency changes
2. Dynamic voltage control – inverter with BESS can function as a static reactive power compensator (STATCOM)
3. Fast fault current injection for fast post fault voltage recovery
4. Island formation – inverter with BESS can control both voltage and frequency.

The smart grid regulations are also proposed to include requirements that are not in the grid code, including:

1. Communication requirements to system operator and market operator
2. Cyber security requirements
3. Testing and certification

The Philippine Department of Energy Department Circulation DC2020-02-0003 Electric Power Industry framework and roadmap for distribution utilities will guide the development of the regulations.

5 Task 3.4 Revisions and Amendments on the Existing Philippine Small Grid Guidelines

5.1 Philippine Small Grid Guidelines Resolution No 15 Series of 2013

The existing Philippine Small Grid Guidelines Resolution No 15 Series of 2013 and are comprehensive for the connection of conventional synchronous generators to a small grid. The guidelines are silent on the connection of VRE (wind, solar PV) and BESS.

The objectives of the Philippine Small Grid Guidelines are to:

1) Set a standard for Small Grid Operations;
2) Describe the planning and operational responsibility of all Small Grid Users;
3) Facilitate the monitoring of compliance with these Guidelines at the operations
4) Ensure that the Small Grid will be operated in a safe and efficient manner;
5) Ensure that the basic rules for connection to the Small Grid or to a Small Grid User System are fair and non-discriminatory for all Small Grid Users;
6) Specify the operating states, operating criteria and protection scheme that will ensure the safety, reliability, security and efficiency of the Small Grid.

The Philippine Small Grid Guidelines cover a range of topics including:

1) Performance standards for small grid and generators specifically:
    a. Frequency variations
    b. Voltage variations
    c. Voltage unbalance
    d. Reliability standards
    e. Reliability reports and performance targets
2) Safety standards for small grid and generators specifically:
    a. Compliance to Philippine Electrical Code (PEC) Part 1 and Part
    b. Compliance to Philippine Occupational Safety and Health Standards (OSHS)
    c. Submission of Safety Records and Reports
3) Small grid technical, design and operational criteria, including
    a. Frequency variations
    b. Voltage unbalance
    c. Grounding requirements
    d. Equipment standards
    e. Maintenance standards
4) Procedures for small grid connection or modification, including
    a. Connection agreement
    b. Amended connection agreement
    c. Processing of application
    d. Submissions prior to the commissioning date
    e. Commissioning of equipment and physical connection
5) Requirements for generators, including:
    a. Generating unit power output capability
    b. Frequency withstand capability
    c. Unbalance loading withstand capability
    d. Speed governing system capability
    e. Excitation control system capability
    f. Black start capability
    g. Fast start capability
    h. Protection requirements, coordination and arrangements
    i. Transformer connection and grounding

6) Requirements for distributor and other small grid users, including:
    a. Connection point requirements
    b. Protection arrangements
    c. Transformer connection and grounding
    d. Underfrequency relays for automatic load dropping
7) Communication equipment requirements and methods, including:
    a. Communication systems for monitoring and control
    b. Methods of transmitting dispatch instructions
    c. Contents of dispatch instructions
    d. Acknowledgement of dispatch instructions
8) Fixed asset boundary document requirements
9) Electrical diagram requirements
10) Connection point drawing requirements
11) Small grid data registration
12) Small grid planning, including:
    a. Small grid planning studies
    b. Standard planning data requirements
    c. Detailed data planning requirements
13) Small grid operation, including:
    a. Small grid operating states, operating criteria and protection
    b. Operational responsibilities
    c. Operation notices and report
    d. Operating and maintenance programs
    e. Frequency and voltage control
    f. Emergency procedures including islanding, black start and restoration
    g. Safety coordination
    h. System tests
    i. Generating unit capability tests
    j. Site and equipment identification and labelling
14) Scheduling and dispatch, including:
    a. Scheduling and dispatch responsibilities
    b. Responsibilities of other grid users
    c. Dispatch principles, scheduling and implementation
15) Metering
    a. Metering requirements
    b. Metering equipment standards
    c. Metering equipment testing and maintenance
    d. Metering reading and meter data
16) Small grid transitory provisions
    a. Transitional compliance plans

The Philippine Small Grid Guidelines Resolution No 15 Series of 2013 are a combination of a grid code, connection agreement and connection process all captured in one document.

Some concerns are:

1) The document is only a guideline and not binding on generators and users
2) The guideline applies to all generators regardless of size
3) The guideline does not have all the requirements captured in the Philippine Distribution Code, specifically:
    a. Fault ride through requirements
    b. Harmonic emission levels

5.2 Philippine Small Grid Dispatch Protocol Resolution No. 15 Series of 2014

The purpose of the Philippine Small Grid Dispatch Protocol Resolution No. 15 Series of 2014 is to:

1) Implement those sections of the Philippine Small Grid Code which involves normal and emergency operations of the small grid
2) Establish relevant information that would be necessary for the system operator to prepare week ahead and day ahead schedule
3) Describe the operational activities such as scheduling and dispatch procedures to be adopted in operating the small grid
4) Describe the operational procedures and responsibilities of the small grid user
5) Describe the small grid monitoring and communication facilities

The protocol was amended in to specifically mandate that TRANSO to be the small grid system operator for small grids having:

1) More than one distribution utility utilising a high voltage line to transmit power generated by more than one generating company.
2) Only one distribution utility utilising a high voltage line to transmit power generated by more than one generating company.
3) Only one distribution utility utilising its medium voltage line to transmit power generated by more than one generating company.

The distribution utility remains system operator for small grids having only one distribution utility utilising its medium voltage line to transmit power generated by only one generating company.

The protocol describes the activities of the small grid owner, the generator and distribution utilities. The concern is there is no limit on generator size, so all generators are required to provide its capability and availability, follow dispatch instructions and emergency instructions. All generators have to submit a quarterly report on its operation to the DOE and ERC. These requirements are impractical and probably unnecessary for small scale wind, solar PV and BESS. A size limitation will need to be agreed.

The dispatch protocol will also require strengthening to include wind and solar forecasting, managing reserve levels, short circuit levels monitoring and maintaining inertia / fast frequency control.

5.3 VRE and BESS in Small Grids

5.3.1 VRE with BESS are economically viable solutions

Homer energy[27] provided a study on the economic value of VRE with batteries for a diesel system. The study showed an optimal ‘knee' point around 80%. VRE with batteries can provide a cheaper solution than diesel generation for small grids where the VRE and batteries are sized for a typical day. The remaining 20% of the time the diesel generators run. The analysis showed that the diesel generators are required for days when there is no wind or solar. To move to 100% VRE and batteries requires the VRE and batteries installation to be three times the 80% optimal limit. The graph is for a typical small grid but the optimal point will move depending on the variability of daily yields.

[27] Homer energy white paper on energy storage

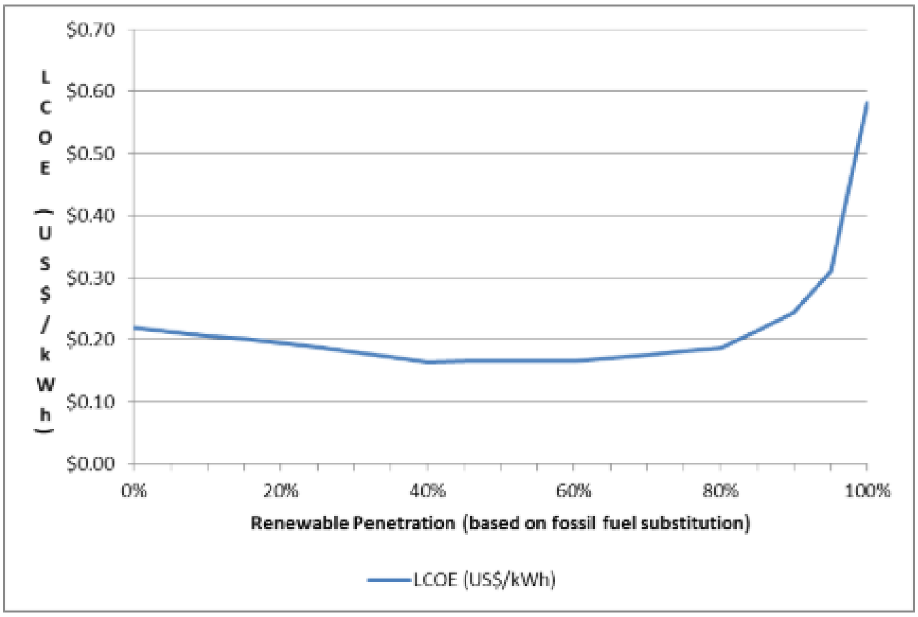


Figure 51. LCOE and renewable energy penetration

5.3.2 Voltage Source Inverters with BESS and or VRE can provide frequency and voltage control without synchronous generation

Voltage Source Inverters have the ability provide sub second frequency, static and dynamic voltage control without assistance from conventional synchronous generation. The response is fast enough to provide sufficient inertia but some networks generators are operated in synchronous condenser operation (SCO). When in SCO mode of operation, the generator is connected to network without the turbine connected (or when the turbine is spinning on air). SCO mode consumes a small amount of power but provides high fault currents, inertia, static and dynamic voltage control.

The concerns with operating only with voltage source inverters is the fact that the inverters can only inject fault current of 100% of inverter rating whereas conventional generators provide 300% of rated current. Over current relays can easily identify a fault and isolate the fault quickly.

5.3.3 Harbledown Island – Canada

Harbledown Island has a microgrid that generates a significant portion of its electricity from 120 kilowatts (kW) of solar PV and a 125 kW energy storage inverter paired with 440 kilowatt hours (kWh) of energy storage. Renewable energy developer Hakai Energy built the system while Ageto Energy designed the microgrid and its controls. The Ageto ARC microgrid controller manages the system, which includes three generators[28].

The significant observation from the chart below is that the microgrid has sufficient batteries to be able to switch the synchronous generators. When the generators are switched off the inverter controls the frequency and voltage and can perform these functions when the batteries have sufficient charge. The inverters can also cope with the variability of the PV output at the same time as controlling the instantaneous demand. The inverters provide reactive power and voltage control over the full range of the inverter from full import to full export.

The generators are automatically switched on by the Ageto ARC microgrid controller when the batteries discharge to 25% and switch the generators off when the batteries are charged to 25%.

[28] https://microgridnews.com/microgrid-brings-quiet-and-cost-reductions-to-canadian-native-community/

The result is that the generators only had to provide 169 kWh (~28%) of the total load of 604 kWh for the day.

The regulation for small grids needs to recognise the functionality of inverters supported by BESS.

Figure 52. Microgrid Controller

5.3.4 St. Paul, Alaska

In 1999, Northern Power Systems installed a high-penetration, no-storage hybrid power system that maximised the island's abundant wind resource. The primary components of the plant included a 225-kW Vestas V27 wind turbine, two 150-kW Volvo diesel engine generators, a synchronous condenser, a 6,000 gallon insulated hot water tank, and a microprocessor-based control system capable of providing fully automatic plant operation[29].

The primary electrical load for the facility averages about 69.6 kW, but the system also supplies the primary space heating for the facility with excess power from the generators and thermal energy from the diesel plant.

The 500 kW TDX Power system in St. Paul, Alaska, operates for weeks at a time in the winter with just the wind turbines but with no diesel power or energy storage. A dump load controller provides all the power quality and frequency control required to maintain system stability[30].

5.4 International regulations and standards

5.4.1 IEC TS 62257 series – recommendations for renewable energy and hybrid systems for rural electrification

IEC has published a comprehensive set of standards for renewable energy and hybrid systems for rural electrification.

The series consists of 22 publications covering wind, solar PV, energy storage and micro power controls systems.

[29] https://www.nrel.gov/docs/fy09osti/44523.pdf
[30] https://www.homerenergy.com/pdf/High_Penetrations_of_Renewable_Energy_for_Island_Grids.pdf

1) IEC TS 62257-1:2015 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 1: General introduction to IEC 62257 series and rural electrification
2) IEC TS 62257-2:2015 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 2: From requirements to a range of electrification systems
3) IEC TS 62257-3:2015 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 3: Project development and management
4) IEC TS 62257-4:2015 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 4: System selection and design
5) IEC TS 62257-5:2015 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 5: Protection against electrical hazards
6) IEC TS 62257-6:2015 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 6: Acceptance, operation, maintenance and replacement
7) IEC TS 62257-7:2017 RLV - Recommendations for renewable energy and hybrid systems for rural electrification - Part 7: Generators
8) IEC TS 62257-7-1:2010 - Recommendations for small renewable energy and hybrid systems for rural electrification - Part 7-1: Generators - Photovoltaic generators
9) IEC TS 62257-7-2:2022 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 7-2: Generator set - Off-grid wind turbines
10) IEC TS 62257-7-3:2018 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 7-3: Generator set - Selection of generator sets for rural electrification systems
11) IEC TS 62257-7-4:2019 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 7-4: Generators - Integration of solar with other forms of power generation within hybrid power systems
12) IEC TS 62257-8-1:2018 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 8-1: Selection of batteries and battery management systems for stand-alone electrification systems - Specific case of automotive flooded lead-acid batteries available in developing countries
13) IEC TS 62257-9-1:2016 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 9-1: Integrated systems - Micropower systems
14) IEC TS 62257-9-2:2016 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 9-2: Integrated systems - Microgrids
15) IEC TS 62257-9-3:2016 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 9-3: Integrated systems - User interface
16) IEC TS 62257-9-4:2016 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 9-4: Integrated systems - User installation
17) IEC TS 62257-9-5:2018 RLV - Recommendations for renewable energy and hybrid systems for rural electrification - Part 9-5: Integrated systems - Laboratory evaluation of stand-alone renewable energy products for rural electrification
18) IEC TS 62257-9-6:2019 RLV - Renewable energy and hybrid systems for rural electrification - Part 9-6: Integrated systems - Recommendations for selection of Photovoltaic Individual Electrification Systems (PV-IES)
19) IEC TS 62257-9-7:2019 - Renewable energy and hybrid systems for rural electrification - Part 9-7: Recommendations for selection of inverters
20) IEC TS 62257-9-8:2020 - Renewable energy and hybrid systems for rural electrification - Part 9-8: Integrated systems - Requirements for stand-alone renewable energy products with power ratings less than or equal to 350 W
21) IEC PAS 62257-10:2017 - Recommendations for renewable energy and hybrid systems for rural electrification - Part 10: Silicon solar module visual inspection guide
22) IEC TS 62257-12-1:2020 RLV - Recommendations for renewable energy and hybrid systems for rural electrification - Part 12-1: Laboratory evaluation of lamps and lighting appliances for off-grid electricity systems

5.4.2 Republic of Mozambique

The Republic of Mozambique has just released Decree No. 93/2021, of 10 December which is to strengthen the current legal framework for the energy sector, by regulating supply activities for access to energy in off-grid zones, with a view to increasing the productive use of energy for universal access to this resource and the consequent socio-development of the nation. The regulation establishes the principles and rules applicable to supply activities for access to energy in off-grid zones, with regards to mini-grids up to 10 MW and energy services.

The regulation key features are:

1) Concessions for mini grids are to go out to public tender and the concession will be for 30 years
2) Mini-grids are classified according to the following categories:
    a. category 1: mini-grid with installed capacity between 1,001 MW – 10 MW;
    b. category 2: mini-grid with installed capacity between 151kW – 1 MW;
    c. category 3: mini-grid with installed capacity up to 150 kW.
3) Technical-financial studies, including financial plan and business model, are required
4) Concessions are to be validated by the Energy Regulator, including:
    a. Approve the submission forms
    b. Verify certification of equipment
    c. Managing and supervising installation
5) A detailed list of the contents of the concession agreement, including:
    a. Energy source, capacity and technology
    b. Rules for suspension, modifications and termination
    c. Schedule for execution of the project
    d. Rights and obligations
    e. Applicable tariffs, prices and fees
    f. Environment licensing
6) Operation and maintenance of the mini grid, including Plan, design, finance, build, possess, insure, operate, maintain, manage and subcontract the operation of the respective electrical installations
7) Concessionaire must comply with the principles and standards of quality, safety and reliability in relation to electrical energy supply activities
8) The consumer is responsible to pay fees for goods and services provided
9) The tariff principles are defined in the regulation
10) Complaints and dispute resolution process

5.4.3 Gambia

The Gambian Standards Bureau has adopted the full set of IEC 62257 series. The introduction notes that rural electrification is one of the predominant policy actions designed to increase the wellbeing of rural populations together with access to clean water, improved healthcare, education, personal advancement and economic development. Several strategies can be adopted to implement rural electrification. Rural electrification can be completed through connection to a national or regional electrification grid. The IEC 62257 series applies to cases where the grid is too far away (too costly) or the individual demand centres are too small to make grid access economic, where autonomous power systems may be used to supply these services. This series IEC 62257 provides technical specifications to different players involved in rural electrification projects (such as project developers, project implementers, installers, etc.) for the setting up of renewable energy and hybrid systems with AC voltage below 500 V, DC voltage below 750 V and power below 100 kVA.

5.4.4 Tanzania

Tanzania Standard is in the process of adopting the International Standard IEC 62257-9-8:2020 Renewable energy and hybrid systems for rural electrification - Part 9-8: Integrated systems - Requirements for stand-alone renewable energy products with power ratings less than or equal to 350 W which has been prepared by the International Electrotechnical Commission.

5.4.5 Recommendations for Revisions and Amendments on the Existing Philippine Small Grid Guidelines

The Existing Philippine Small Grid Guidelines are comprehensive but do not include VRE or BESS.

The following two items are of concern:

1) The Existing Philippine Small Grid Guidelines have some typical 'grid code' compliance requirements but these do not include all the requirements. This needs to be clarified in the guidelines. In essence the relevant grid code takes precedence.
2) The guidelines seem to apply to all power plants regardless of size. The requirements will be able to be met by home PV and BESS systems.

There are two options to include VRE and BESS:

1) Update the existing Philippine Small Grid Guidelines, or
2) Adopt the IEC TS 62257 series which has a comprehensive recommendation for renewable energy and hybrid systems for rural electrification.

These two options are to be discussed with stakeholders.

6 Task 3.5: Sustainable Energy Initiatives for Smarter and Greener City

6.1 Energy Efficiency and Conservation Act of 2019

The Energy Efficiency and Conservation Act of 2019 has declared the policy of the State to:

a) Institutionalise energy efficiency and conservation as a national way of life geared towards the efficient and judicious utilisation of energy by formulating, developing, and implementing energy efficiency and conservation plans and programs to secure sufficiency and stability of energy supply in the country to cushion the impact of high prices of imported fuels to local markets and protect the environment in support of the economic and social development goals of the country;
b) Promote and encourage the development and utilisation of efficient renewable energy technologies and systems to ensure optimal use and sustainability of the country's energy resources;
c) Reinforce related laws and other statutory provisions for a comprehensive approach to energy efficiency, conservation, sufficiency, and sustainability in the country; and
d) Ensure a market-driven approach to energy efficiency, conservation, sufficiency, and sustainability in the country.

The scope of the Energy Efficiency and Conservation Act of 2019 is to establish a framework for introducing and institutionalising fundamental policies on energy efficiency and conservation, including the promotion of efficient and judicious utilisation of energy, increase in the utilisation of energy efficiency and renewable energy technologies, and the delineation of responsibilities among various government agencies and private entities.

The Department of Energy is the lead agency in the implementation of the Energy Efficiency and Conservation Act and is responsible for the planning, formulation, development, implementation, enforcement, and monitoring of energy management policies and other related energy efficiency and conservation plans and programs.

The Energy Efficiency and Conservation Act calls for the formation of Energy Service Companies who must have the capability to perform:

1) Energy audits;
2) Design engineering;
3) Providing or arranging project financing;
4) Construction management;
5) Operations and maintenance of energy efficient technologies; and
6) Verifying energy savings.

The Act categorises designated establishments to be initially as follows:

1) Type 1 designated establishments are those with an annual energy consumption of 500,000 kilowatt-hours(kWh) to 4,000,000 kWh for the previous year; and
2) Type 2 designated establishments are those with an annual energy consumption of more than 4,000,000 kWh for the previous year.

Type 1 and Type 2 establishments are required to:

1) Have energy management systems in compliance with ISO 50001
2) Have energy efficiency programs
3) Have annual energy efficiency targets
4) Perform an energy audit once every three years
5) Report annually to the Department of Energy

The Department of Energy, with the assistance of the Energy Regulatory Commission and the Philippine Economic Zone Authority, is responsible to implement a Demand Side Management program for the electric power industry for the reduction of energy consumption through effective load management resulting to the decrease of power demand and the migration of power demand from peak to off-peak periods or such measures undertaken by distribution utilities to encourage end users to properly manage their loads to achieve efficiency in the utilisation of fixed infrastructures in the systems.

The Energy Utilisation Management Bureau (EUMB) under the DOE is hereby reorganised as follows:

1) Alternative Fuels and Energy Technology Division whose functions shall include:
    a. Formulating policies, plans, and programs related to alternative fuels and new and advanced energy technologies' development towards socially and environmentally responsive and effective utilisation of energy resources; and
    b. Developing and managing the alternative fuels and energy technology program;
2) Energy Efficiency and Conservation Program Management and Technology Promotion Division whose functions shall include:
    a. Evaluating energy efficiency and conservation technologies;
    b. Promoting the increased utilisation of energy efficient products;
    c. Preparing all reports for submission to other government agencies as required by law; and
    d. Developing a comprehensive information, education, and communication strategy for public awareness on energy efficiency programs and energy efficient products;
3) Energy Efficiency and Conservation Public Sector Management Division whose functions shall include:
    a. Coordinating with the local government units and the National Energy Efficiency and Conservation Coordinating Officer to ensure consistency with the National Energy Efficiency and Conservation Plan;
    b. Providing technical assistance to local government units and other government agencies;
    c. Enhancing, expanding, and developing the Government Energy Management Program; and
    d. Providing technical support to the Inter-Agency Energy Efficiency and Conservation Committee and acting as its Secretariat;
4) Energy Efficiency and Conservation Performance Regulation and Enforcement Division whose functions shall include:
    a. Spearheading the creation of the National Energy Efficiency and Conservation Coordinating Officer in accordance with the provisions of this Act;
    b. Formulating, developing, and updating the minimum energy performance, energy labelling, and other programs indicated herein: and
    c. Enforcing the programs under this Act and its implementing rules and regulations, such as the minimum energy performance and energy labelling.

6.2 Regulations developed from the Energy Efficiency and Conservation Act of 2019

We are aware of the following regulations that have been developed as required by the Energy Efficiency and Conservation Act of 2019:

1) Department Circular N0 DC2019-11-0014 Implementing Rules and Regulation of Energy Efficiency and Conservation Act. The regulation establishes a framework for introducing and institutionalising fundamental policies on energy efficiency and conservation, including the promotion of efficient and judicious utilisation of energy, increase in the utilisation of energy efficiency and renewable energy technologies, and the delineation of responsibilities among various government agencies and private entities.

2) Department Circular N0 DC2020-06-0015 Prescribing the Guidelines of the Philippine Energy Labelling Program for Compliance of Importers, Manufacturers and Dealers of Electrical Appliances and other Energy Consuming Products.
3) Department Circular N0 DC2020-06-0015 Prescribing the Minimum Energy Performance for Products Covered by the Philippine Energy Labelling Program for Compliance of Importers, Manufacturers and Dealers of Electrical Appliances and other Energy Consuming Products.
4) Department of the Interior and Local Government, Memorandum Circular No 2020-082. Guidelines in Implementing Republic Act No 11285 or the "Energy Efficiency and Conservation Act" and its Implementing Rules and Regulations.

6.3 Time of use tariffs and consumer market exposure in Philippines

MERALCO's (the Utility) has introduced time-of-use tariffs to expose demand-based customers to market prices to get energy efficiency, providing ancillary service and moving demand out of peak hours.

MERALCO have the Peak-Off Peak (POP) program as illustrated in Figure 61.

Peak and Off-peak hours

TIME PERIOD	PEAK	OFF-PEAK
Monday to Saturday	8 am to 9 pm (13 hours)	9 pm to 8 am (11 hours)
Sunday	6 pm to 8 pm (2 hours)	8 pm to 6 pm (22 hours)

Seasonal POP rates*

TIME PERIOD	POP RATE (PEAK)	NON-POP RATE (PEAK)	POP RATE (OFF-PEAK)	NON-POP RATE (OFF-PEAK)
Dry (Jan-Jun)	7.48	5.69	3.55	5.69
Wet (Jul-Dec)	7.28	5.57	3.55	5.57

*With approval from ERC

Figure 61. MERALCO peak-off peak program

MERALCO also has demand-based (kW) tariffs, only non-residential consumers with an average demand of 5kW and higher are billed with the demand charge in addition to the energy (kWh) charge.

Contestable customers of the distribution utility that are under a supply agreement with Retail Electricity Suppliers (RES) will have their own exposures to the peak demand pricing depending on their agreement with the RES and the interconnection agreement with the distribution utility.

6.4 Interruptible Load Programme in Philippines

An Interruptible Load Program (ILP) was promulgated under ERC Resolution No. 8 Series of 2010 and amended by Resolution No. 8 Series of 2013, No. 5 Series of 2015, and No. 3 Series of 2019. which also can be considered as some form of demand response.

ILP is a voluntary, demand-side management program that allows customers to operate their generating sets and collectively reduce electricity drawn from the grid when power interruptions are imminent to ration limited power supply:

1) Open to non-contestable customers, contestable customers, locators in economic and freeport zones, and directly connected customers
2) Prioritises customers with large loads and requests them to 'de-load' when NGCP issues a Red Alert notice

After notification and confirmation of a reduction the energy reduced is confirmed by MERALCO and consumer is compensated for kWhs reduced. The compensation rate is determined from the marginal costs of operating a diesel generator.

6.5 International Experience in Energy Efficiency

International experience in energy efficiency is in numerous areas and specifically:

1) Legislating energy efficient devices including standards and labelling, as indeed we have MEPS and labelling for aircons, refrigerators, TV sets, lighting products (8 products), and passenger cars and commercial vehicles, and at least labelling for other household appliances.
2) Subsidising solar hot water heaters, CFL's, heat pumps etc.
3) Energy efficient buildings
4) Time of use tariffs
5) Enabling demand side participation in ancillary services
6) Enabling demand side participation in the energy market

The first three items have been implemented in the Philippines and so this report is not going to cover these areas.

6.5.1 Time of use tariffs

The Philippines already has implemented time-of-use tariffs. However, internationally with the increase of embedded solar PV the time-of-use tariff are being adjusted to fit the new profile. The energy prices start to fall in the middle of the day and the consumers are being encouraged to consume energy in the middle of the day.

Time-of-use tariff encourages customers to store energy from embedded wind and solar when the price is low and release the energy at higher prices. Too large a difference between high and low prices can cause energy arbitrage where the customer can make a profit by charging at low prices and discharging at higher price.

6.5.2 Enabling demand side participation in ancillary services

Task 3.2 has shown that there is a large potential for demand side participation in ancillary services. In many countries there is active participation by demand side entities, specifically the consumers with storage.

6.5.3 Enabling demand side participation in the energy market

Many countries allow for active participation in the energy market by consumers and in some market structures this is mandatory.

The uptake by consumers in participating in energy markets is small due to many reasons. One of the key reasons is regulated tariffs where the price the consumer pays is fixed and for domestic consumers subsidised. There is no financial incentive to actively trade electricity.

The second reason is consumers don't have time to put in bids every day and the effort is not worth any potential savings. This could be overcome by the introduction of traders (aggregators) who represent multiple consumers.

Distribution owners in the UK are concerned that the mandating of electric vehicles will cause network overloads on their system. Specifically, all vehicles get to work at the same time and want to 'fast' charge their vehicle so it's ready should they have a to drive somewhere. UK is looking at real time pricing and traders that will offer incentives to vehicle owners to not charge their vehicles in 'peak' times. These peaks will vary through the day depending on the requirements of all vehicles. There is even discussion of allowing the trader to discharge your vehicle at high prices and then recharge when the price is low.

EPRI research report on Power System Flexibility Challenges and Opportunities notes that consumers will drive increased power system flexibility as they shift from passive buyers to active users, and as they install solar PV panels, and purchase plug-in electric vehicles, appliances, and equipment that enable them to more active consumers is more variable load, requiring a flexible system to respond.

The drive towards low- and zero-net energy buildings using PV can reduce load but can also lead to local concentrations of highly variable load when local load does not correspond to local generation (for example, when PV output is reduced due to cloud cover). This can also lead to sharper peak demand (i.e., decreased load factor) and a more variable customer load shape as traditional loads (for example, HVAC and lighting) are replaced by "behavioural loads" (for example, plug-in electric vehicles and consumer computing).

These trends call for increased flexibility in two areas. First, increased local flexibility is needed at the distribution and generation level. Second, utilities need organisational flexibility due to changing customer expectations of utility services. These expectations include increased flexibility/ choice; increased availability of information, connectivity, and control at shorter time scales; and additional services such as PV.

6.6 Recommendations for Sustainable Energy Initiatives for Smarter and Greener City

It's our understanding that the regulations for defining the Minimum Energy Performance, Labelling, Energy Monitoring and Reporting as required by the Energy Efficiency and Conservation Act of 2019 is already promulgated or in the process of being promulgated.

The proposed regulations for Task 3.5 - Sustainable Energy Initiatives for Smarter and Greener City are:

1) Regulations to enable participation by demand in the energy and ancillary services market commonly known as Demand Market Participation (DMP). The DMP initiative will review the current market rules and regulations to understand how more meaningful participation can be enabled by DMP with the goal of being more energy efficient and demand shifting out of peak periods.
2) Regulations on exposing more demand side participants to at least declare their physical position in the day-ahead market. This will reduce the burden on the system operator to forecast the outputs from demands, especially when consumers have embedded VRE.
3) Regulations for embedded generation who can export surplus energy onto the grid and specifically customers with energy storage who can provide excess when required by the system.

7 Task 3.6: Distribution System Loss Cap for Distribution Efficiency

7.1 Introduction

As a background for this task, ERC has introduced a system loss limit to distribution utilities to lower the electricity costs of consumers and improve the efficiency of distribution utilities as mandated by the Electric Power Industry Reform Act (EPIRA).

The terms of reference of this project specified the Consultant to prepare the terms of reference and request for proposal documents for consultancy services for the promulgation of the distribution utility loss cap.

During the Inception meeting, ERC informed us (Ricardo) to calculate for the new system loss cap target for 2022 in this task. ERC will share their methodology, past analysis and data as well as provide new data to Ricardo as a basis for determining the new system loss cap limit.

ERC provided Ricardo the following information:

- Resolution 10, Series of 2018: A Resolution Clarifying the System Loss Calculation and Providing the Effectivity of the Rules for Setting the Distribution System Loss Cap – last 17 January 2022.
- Slide Presentation: Proposed Rules for Setting the Distribution System Loss Cap and Establishing Performance Incentive Scheme for Distribution Efficiency – last 23 March 2022.
- ERC however informed us (Ricardo EE) that the data and the electronic file of the previous study used in Resolution 10, Series of 2018 are not available.

Resolution 10, Series of 2018 stipulates the following:

- Distribution Loss Cap for Electric Cooperatives
  - 2021: Cluster 1 (12.00%), Cluster 2 (10.25%), and Cluster 3 (9.00%)
  - 2022 onwards: Cluster 1 (12.00%), Cluster 2 (10.25%), and Cluster 3 (8.25%)
- Distribution Loss Cap for Distribution Utilities
  - 2021: 5.5%
  - 2022: 4.75

7.2 Reported Actual Feeder Losses

We understood that each distribution utility is required to submit feeder technical loss, non-technical loss, and sub transmission and substation losses to ERC yearly. With these data from ERC, we will group the EC's according to clusters specified in the above resolution and analyse the data interquartile range of each type of system loss as well as the total system loss. We will also analyse how these values evolve overtime since the implementation of Resolution 10, Series of 2018.

7.3 Predicted Feeder Losses

We will compare the analysed actual feeder losses above with the predicted feeder losses. We will use the methodology employed in estimating the predicted feeder losses in Resolution 10, Series 2018.

The feeder loss cap in kWh will be estimated using the following equation:

where,

- Energy Sales $_{HV}$ – energy sales to HV customer (in kWh)
- Energy Sales $_{LV}$ – energy sales to LV customers and Residential Customers (in kWh)
- Length $_{secline}$ - total secondary line lengths (in km)
- Demand $_{peak, MW}$ - peak demand (in MW)

We will use the regression coefficients specified in Resolution 10, as shown in the Figure below, to estimate the feeder loss. We will estimate the feeder technical loss for each DU and analyse the range (interquartile range) of values for each cluster of DUs. We expect that ERC will provide us the sales data (HV and LV), network length and peak demand for each DU over the past 3-5 years.

$$TL_{feeder} \approx A_1 \times EnergySales_{HV} + A_2 \times EnergySales_{LV} + A_3 \times Length_{SecLine} + A_4 \times Demand_{Peak,MW}$$

Group ID	A1	A2	A3	A4
Off-Grid DU	0.03124	0.02102	0.01922	0.01707
EC Group A	0.04653	0.03906	0.00742	0.01315
EC Group B	0.03352	0.02583	0.02934	0.00936
EC Group C	0.01163	0.02469	0.01603	0.01107
EC Group D	0.03058	0.03352	0.01870	0.00809
EC Group E	0.02707	0.03653	0.00787	0.00950
EC Group F	0.00943	0.03048	0.02150	0.00507
EC Group G	0.02707	0.02016	0.05179	0.00608
Private DU	0.00943*	0.02016*	0.00742*	0.00507*

*in the absence of feeder data, this coefficient is the minimum within the column

Figure 71. Coefficients for estimating feeder technical losses

7.4 Distribution System Loss Cap

From the above results (analysis of actual system losses) and predicted system losses, we will assess and determine which appropriate target that could be pursued by ERC for distribution system loss cap.

8 Task 3.7: Strategic Review of the Regulatory Framework

This task will cover 2 levels of analysis:

i. Assessment of the regulatory framework of ERC in view of the Philippine NDC and low carbon economy goals
ii. Options assessment for regulatory areas where ERC can further align its regulations with the Philippine climate goals

Data collection and analysis and international best practice review are on-going.

- ERC's regulatory framework currently focuses on renewable energies (Table 81 and Table 82)
- No framework has been issued with respect to energy efficiency and demand-side management, hydrogen, and coal and natural gas phase-out programmes.

A SWOT-PESTLE analysis is under preparation.

Table 17. ERC resolutions related to renewable energies

Resolution Number	Title	Promulgation Year
Resolution No. 16, Series of 2010	Resolution Adopting the Feed-in Tariff Rules	2010
Resolution N0. 10, Series of 2012	Resolution Approving the Feed-in Tariff Rates	2012
Resolution No. 15, Series of 2012	Resolution Adopting the Position of the Commission on the Issues Paper Published on 02 April 2012 and the Corresponding Amendments to the Feed-in Tariff Rules	2012
Resolution No. 9, Series of 2013	A Resolution Adopting the Rules Enabling the Net-Metering Program for Renewable Energy	2013
Resolution No. 24, Series of 2013	A Resolution Adopting the Guidelines on the Collection of the Feed-In Tariff Allowance (Fit-All) and the Disbursement of the Fit-All Fund	2013
Resolution No. 7, Series of 2014	A Resolution Adopting the Rules to Govern the Availment and Disbursement of Cash Incentive to Renewable Energy (RE) Developers Operating in Missionary Areas	2014
Resolution No. 18, Series of 2014	A Resolution Approving the Templates for the Renewable Energy Payment Agreement (REPA) and the Renewable Energy Supply Agreement (RESA)	2014
Resolution No. 6, Series of 2015	Resolution Adopting the New Solar Feed-In Tariff (FIT) Rate	2015
Resolution No. 14, Series of 2015	Resolution Adopting The Wind Feed-In Tariff (Wind-FIT2) Rate	2015
Resolution No. 02, Series of 2016	A Resolution Clarifying the Issuance of Certificates of Compliance (COCs) in Favor of Generation Companies for their Renewable Energy (RE) Power Plants	2016
Resolution No. 1, Series of 2017	Resolution Setting the Degressed Feed-in Tariff Rates for Run-of-River Hydro and Biomass, as Provided in Section 2.11 of the Feed-in Tariff Rules (FIT Rules)	2017
Resolution No. 06, Series of 2019	A Resolution Adopting the Amendments to the Rules Enabling the Net-Metering Program for Renewable Energy	2019
Resolution No. 05, Series of 2020	A Resolution Clarifying ERC Resolution No. 06, Series of 2019, entitled "A Resolution Adopting the Amendments to the Rules Enabling the Net-Metering Program for Renewable Energy"	2020
Resolution No. 06, Series of 2020	A Resolution Approving the Adjustment to the Feed-in Tariff (FIT)	2020
Resolution No. 06, Series of 2021	In the Matter of Adoption of the Amendments to Resolution No. 10, Series of 2012, Entitled "A Resolution Approving the Feed - In Tariff (FIT) Rates", Particularly for Run - Of - River Hydropower (ROR Hydro) and Biomass Fit Rates, as Necessitated by the Review and Re-Adjustment of the FOF Hydro and Biomass Fit Rates Since the Installation Target for Wind Technology Has Been Extended by the Department of Energy (DOE)	2021
Resolution No. 08, Series of 2021	A Resolution Adopting the Rules for the Green Energy Option Program (GEOP)	2021

Table 18. ERC decisions related to renewable energies

Case Number	Title	Decision Date	Promulgation Date	Promulgation Year
2011-006 RM	In the Matter of the Petition to Initiate Rule-Making for the Adoption of the Feed-in Tariff for Electricity Generated from Biomass, Ocean, Run-of-Rive Hydropower, Solar, and Wind Energy Resources	27-Jul-12	28-Aug-12	2012
2011-060 RC	In the Matter of the Adoption of the Feed-in Tariff (FIT) Pursuant to to the Feed-in Tariff Rules Specific to the Existing Renewable Energy Plants, with Prayer for Provisional Authority	30-Jun-14	18-Nov-14	2014
2014-004 RM	In the Matter of the Adoption of the Amendments to Resolution No. 10, Series of 2012, a Resolution Approving the Feed-In Tariff (FIT) Rates, as Necessitated by the New Installation Target for Solar Energy Generation Set by the Department of Energy (DOE)	27-Mar-15	28-Apr-15	2015
2014-109 RC	In the Matter of the Application for the Approval of the Feed-in Tariff Allowance for Calendar Year 2014 and 2015 Pursuant to the Guidelines for the Collection of the Feed-in Tariff Allowance and Disbursement of the Feed-in Tariff Allowance Fund, with Prayer for Provisional Authority	29-Sep-15	10-Dec-15	2015
2014-185 RC	In the Matter of the Adoption of the Feed-in Tariff (FIT) Pursuant to to the Feed-in Tariff Rules Specific to the Existing Renewable Energy Plants	23-Jun-20	10-Jul-20	2020
2015-002 RM	In the Matter of the Adoption of the Amendments to Resolution No. 10, Series of 2012, Entitled "A Resolution Approving the Feed-In Tariff (FIT) Rates" (FIT Rules), Particularly for Wind FIT Rates, as Necessitated by the Review and Re-adjustment of the Wind FIT Since the Installation Target for Wind Technology has already been Achieved	6-Oct-15	23-Nov-15	2015
2015-216 RC	In the Matter of the Application for the Approval of the Feed-in Tariff Allowance (FIT-All) for Calendar Year 2016 Pursuant to the Guidelines for the Collection of the Feed-in Tariff Allowance and Disbursement of the Feed-in Tariff Allowance Fund, with Prayer for Provisional Authority	9-May-17	18-May-17	2017
2016-192 RC	In the Matter of the Application for the Approval of the Feed-in Tariff Allowance for Calendar Year 2017 Pursuant to the Guidelines for the Collection of the Feed-in Tariff Allowance and Disbursement of the Feed-in Tariff Allowance Fund, with Prayer for Provisional Authority	27-Feb-18	11-May-18	2018
2016-142 RC	In the Matter of the Application for Approval of the Memorandum of Agreement Between Manila Electric Company and Montalban Methane Power Corporation, with Prayer for Provisional Authority	5-Nov-19	30-Jun-20	2020
2017-079 RC	In the Matter of the Application for the Approval of the Feed-in Tariff Allowance for Calendar Year 2018 Pursuant to the Guidelines for the Collection of the Feed-in Tariff Allowance and Disbursement of the Feed-in Tariff Allowance Fund, with Prayer for Provisional Authority	12-Mar-19	4-Apr-19	2019
2018-085 RC	In the Matter of the Application for the Approval of the Feed-in Tariff Allowance for Calendar Year 2019 Pursuant to the Guidelines for the Collection of the Feed-in Tariff Allowance and Disbursement of the Feed-in Tariff Allowance Fund, with Prayer for Provisional Authority	28-Oct-19	28-Jan-20	2020
2019-056 RC	In the Matter of the Application for the Approval of the Feed-in Tariff Allowance for Calendar Year 2020 Pursuant to the Guidelines for the Collection of the Feed-in Tariff Allowance and Disbursement of the Feed-in Tariff Allowance Fund, with Prayer for Provisional Authority	23-Nov-20	29-Dec-20	2020
2018-007RM	In the Matter of Adoption of the Amendments to Resolution No. 10, Series of 2012, Entitled "A Resolution Approving the Feed - In Tariff (FIT) Rates", Particularly for Run - Of - River Hydropower (ROR Hydro) and Biomass Fit Rates, as Necessitated by the Review and Re-Adjustment of the FOF Hydro and Biomass Fit Rates Since the Installation Target for Wind Technology Has Been Extended by the Department of Energy (DOE)	23-Nov-20		2021

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