EXPLANATORY DOCUMENT RFG

Connection of generators to the transmission grid
Requirements for Generators (RfG)

Please note: This translation of the original Danish text is for informational purposes only and is not a substitute for the official Danish text. The English text is not legally binding and offers no interpretation on the Danish text. In case of in-consistency, the Danish version applies.

ENERGINET
Elsystemansvar

Revision history

SECTION	CHANGE	REV	DATE
Alle		0	10-08-2020
4 4.4 4.2.2.5 4.3.1 4.4.8 4.4.9	Subheadings added to a large number of subsections. Section 4.4 Voltage stability moved forward and is now section 4.2. Table with base values for pu voltage added. Clarification of Uc, normal operating voltage, and the requirements in which it is used. Clarification of Pn and Pmax. Clarification of requirements for reactive power control, Q/Pn. Response time corrected from 2 to 5 s, cf. RfG requirements. FRT requirements specified for facilities connected below 110 kV Heading added. Downward regulation function in connection with high winds clarified. Ramp rates clarified	1	16-06-2021

General information about Rev 1:
Only significant clarifications/changes are noted in the revision history. Clarifications are indicated in the sections containing the text “Clarification May 2021”.

Contents

List of figures and tables

1. Introduction

Energinet prepared this explanatory document in order to create an overview of the provisions for connecting generators to the transmission grid. The explanatory document is a new initiative from Energinet. Feedback and suggestions for improvements are welcome and can be sent to teamtilslutning@energinet.dk (technical issues) or svar.netregler@energinet.dk (regulatory issues). As this explanatory document applies to facilities connected to the transmission grid, only requirements for type D power-generating facilities[1] are included. This explanatory document does not cover requirements for the provision of ancillary services.

The explanatory document concerns Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators (the Regulation):

In the explanatory document, direct requirements from the Regulation are combined with the requirements that Energinet have registered with and obtained approval of from the Danish Utility Regulator, and the descriptions in the Regulation regarding preparation and options have been removed.

Along with the requirements from the Regulation, requirements in Technical regulation 3.2.7 on voltage quality for power-generating facilities to be connected to the transmission grid, also apply. The requirements for voltage quality are not included here, as these requirements are not divided into different sources in the same way.

The explanatory document uses footnotes to indicate the article of the Regulation on which the subsection in question is based, for example this note[2].

Section 2, Basis, describes the legal basis for this explanatory document.

Section 3, Validity, specifies which power-generating facility are covered by the explanatory document, as well as the relationship between the rules and the geographical location. These two sections are short, general descriptions.

Section 4, Technical, describes the specific technical requirements for the facilities. This section is aimed at specialists in the field.

Section 5, Process for connection, describes the overall steps for grid connection.

Section 6, Simulation and test, describes how to document conformity with the specified requirements.

Section 7, Derogations, describes how facility owners can apply for a derogation from the requirements of the Regulation.

2. Basis

This document is based on the following:

- COMMISSION REGULATION (EU) 2016/631 of 14 April 2016, establishing a network code on requirements for grid connection of generators

[1] Point (d) of Article 5(2)

[2] This note is only an example

(Danish title: KOMMISSIONENS FORORDNING (EU) 2016/631 af 14. april 2016, om fastsættelse af netregler om krav for produktionsanlæg).

- Energinet's registered requirements of 17 May 2018, approved by the Danish Utility Regulator on 24 September 2018.

3. Validity

This explanatory document provides an overview of the requirements for new transmission-connected power-generating facilities, as well as requirements if changes are made to them.

This explanatory document does not apply to facilities connected to the distribution grid.

The explanatory document also applies to existing facilities (facilities which have not previously been governed by requirements under the Regulation) when facilities are changed. This is assessed in the following process steps:

- The facility owner must inform Energinet that the facility owner plans to modernise and/or replace equipment which may result in changes to the technical properties and characteristics of the facility.

- Based on the facility owner's description, Energinet must assess whether modernisation and/or replacement of equipment is of such a scope that it requires a significant change to the connection agreement, and the change in the facility is therefore covered by the requirements of the Regulation.

- Energinet deem that the following technical areas may give rise to a significant change to the connection agreement:
  - Frequency stability
  - Robustness
  - System management
  - Voltage stability
  - Restoration of the system
  - General requirements.

- If Energinet deem that a change is necessary, Energinet must initially send an indicative assessment of the need to amend the connection agreement to the Danish Utility Regulator, after which the Danish Utility Regulator will decide whether to amend the connection agreement.

- The Danish Utility Regulator will decide whether the Regulation must be followed for the existing facility.

As Denmark is located in two synchronous areas, different values will be stated for a number of requirements. In the Regulation and in the explanatory document, the designations CE (for Continental Europe) and N (for Nordic) are used for the two synchronous areas. DK1 is in CE and covers Jutland/Funen and DK2 is in N and covers Zealand and the islands of Denmark.

In cases of doubt, the rules set out in the Regulation and the requirements registered with the Danish Utility Regulator apply.

4. Technical

This section refers to relevant articles of the Regulation. A note has been added every time the text refers to a new article in the Regulation.

A number of requirements apply to all facility types, while some requirements are divided into the following facility types:

SPG: Synchronous power-generating facility (synchronous generators)
PPM: Power park module (everything except synchronous generators)

4.1 Frequency stability

[3] The concept of frequency stability contains a number of sub-concepts:

FSM: Normal range
LFSM-U: Underfrequency
LFSM-O: Overfrequency
ROCOF: Rapid frequency changes.

The concepts are presented in the figures below with the relevant frequency ranges.

CE (DK1):

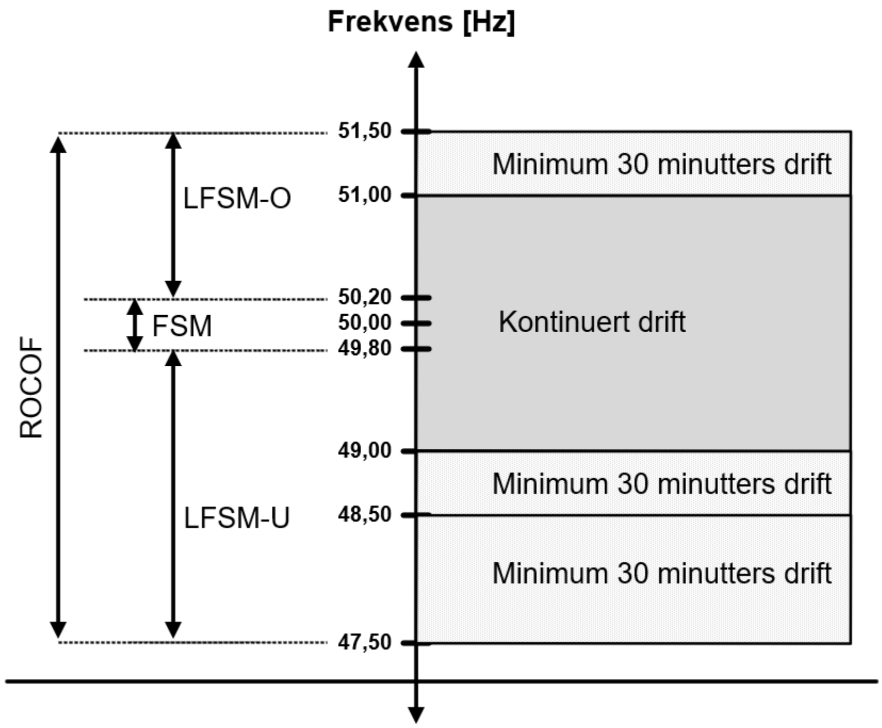

Figure 1 Concepts relating to frequency stability in the Continental Europe synchronous area.

Translations of above Danish text
Frekvens [Hz]: Frequency [Hz]
Minimum 30 minutters drift: Minimum 30 minutes of operation
Kontinuert drift: Continuous operation

[3] Point (i) of Article 13(1)(a)

N (DK2):

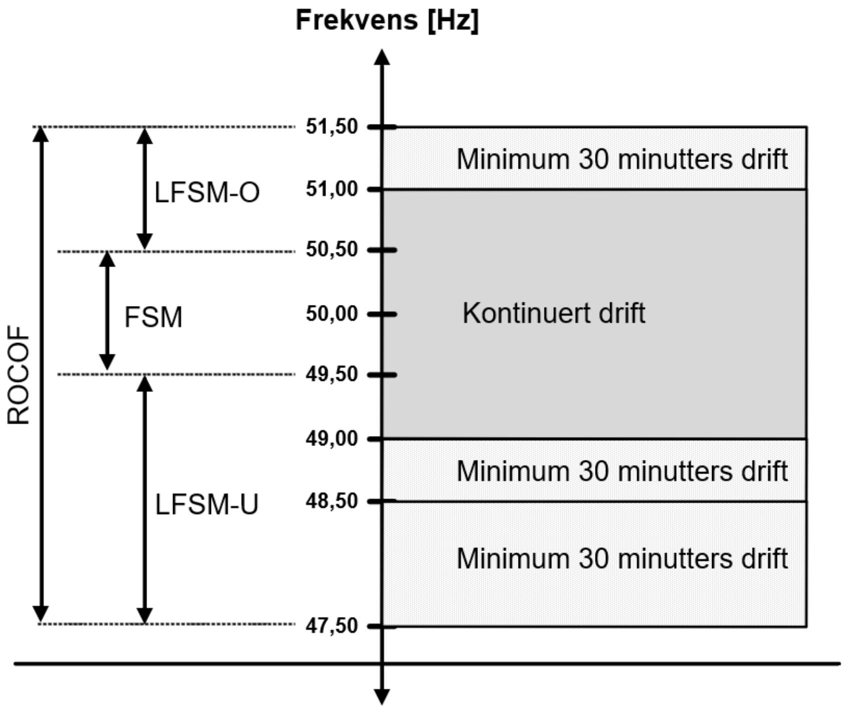

Figure 2 Concepts relating to frequency stability in the Nordic synchronous area.

Translations of above Danish text
Frekvens [Hz]: Frequency [Hz]
Minimum 30 minutters drift: Minimum 30 minutes of operation
Kontinuert drift: Continuous operation

Power-generating facilities must be able to remain connected to the grid and maintain operation within the frequency ranges and time periods shown in the right-hand column in the figures above and described in table 1 below.

Frequency range (Hz):	CE:	N:
47.5-48.5	30 minutes	30 minutes
48.5-49.0	30 minutes	30 minutes
49.0-51.0	Unlimited	Unlimited
51.0-51.5	30 minutes	30 minutes

Table 1 Minimum operating times in frequency ranges.

This means at least 30 minutes in the 48.5 Hz to 49 Hz frequency range and 30 minutes in the 47.5 Hz to 48.5 Hz frequency range. However, the total operating time below 49 Hz may not exceed 60 minutes.

[4]The power-generating facility must be able to maintain constant generation (active power) regardless of frequency changes in the FSM range.

[4] Article 13(3)

[5]The permitted reduction in active power with decreasing frequency relative to maximum capacity is described as a percentage reduction:

- 6% of P_n per Hz, starting at 49.0 Hz – shown as follows:

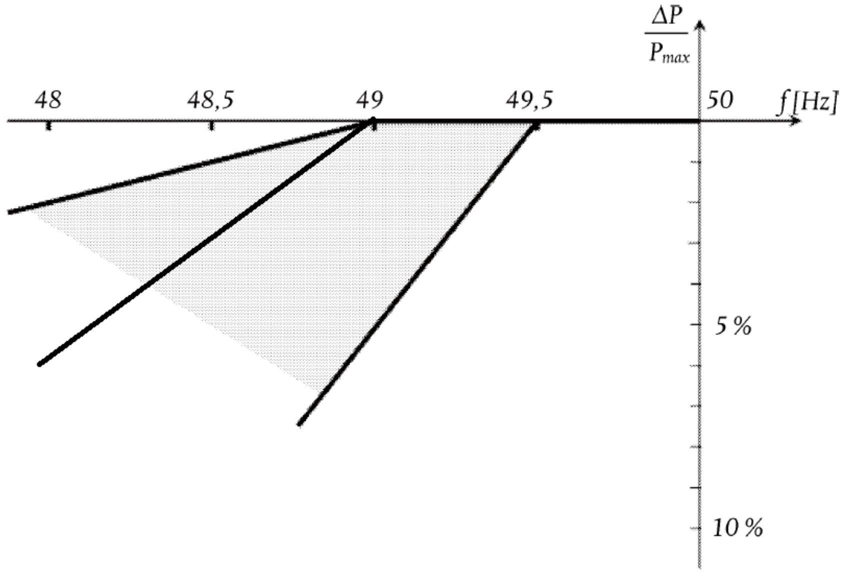

Figure 3 Maximum power reduction with decreasing frequency (Figure 2 of the Regulation with requirements added).

4.1.1 FSM

4.1.1.1 Frequency stability requirements[6]

With regard to active power controllability and control range, the power-generating facility control system must be able to adjust the active power setpoint according to Energinet instructions as follows:

SPG: minimum 1% of P_n/minute, also 10-minute response time for technology neutrality, if necessary.
PPM: minimum 20% of P_n/minute.

4.1.1.2 No accuracy requirements

It must be possible to specify setpoints for active power with a resolution of 1% of P_n or higher.

It must be possible to set the frequency parameters in the active power control functions with a resolution of 10 mHz or higher.

It must be possible to set control droops with a resolution of 1% or higher of P_n.

For all active power control functions, the accuracy of a completed or continuous control must not deviate by more than an average fault scale of 2% of P_n measured over a period of 1 minute (not applicable, however, to LFSM-O and LFSM-U).

[5] Article 13(4) and 5)
[6] Point (a) of Article 15(2)

Frequency measurements must be carried out with a ± 10 mHz accuracy or higher.

4.1.1.3 FSM response[7]

The power-generating facility must be able to activate the active power frequency response using the following parameters:

	CE:	N:
Active power range (minimum requirement)	1.5-10%	1.5-10%
Insensitivity	10 mHz	10 mHz
Frequency control range	0-200 mHz	0-500 mHz
Droop	2-12%	2-12%

Table 2 Requirements for frequency response activation parameters.

P_n is used as P_{ref} for both SPG and PPM.

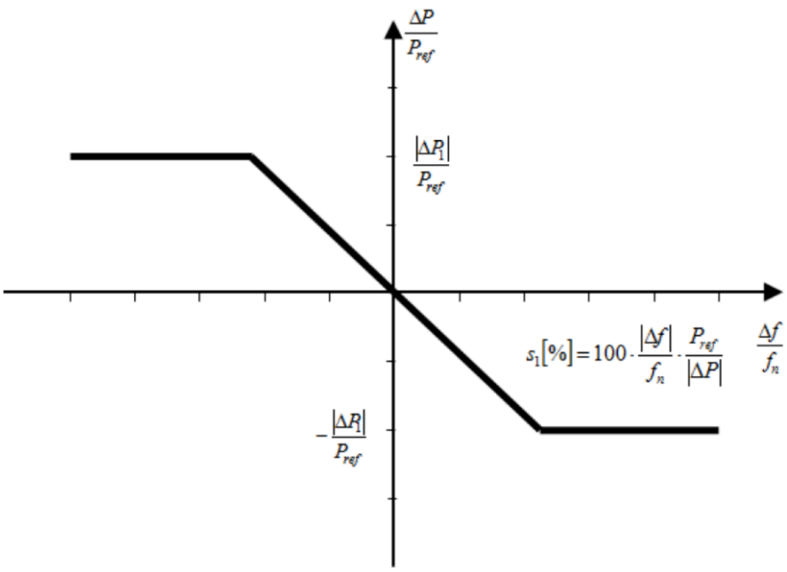

Figure 4 Requirements for activation of frequency response.

P_{ref} is the reference value for the active power to which ΔP relates. ΔP is the change in active power supplied by the power-generating facility. f_n is the nominal frequency (50 Hz) in the grid and Δf is the frequency deviation in the grid. (Figure 5 of the Regulation).

It must be possible to repeatedly reselect the frequency response deadband of frequency deviation and droop time after time.

In case of changes in frequency steps, the power-generating facility must be able to activate full active power frequency response at or above the full line in Figure 4.

The required initial activation of frequency response t_1 must not be unduly delayed and must not exceed two seconds, unless there is justification for the delay.

[7] Point (d) of Article 15(2)

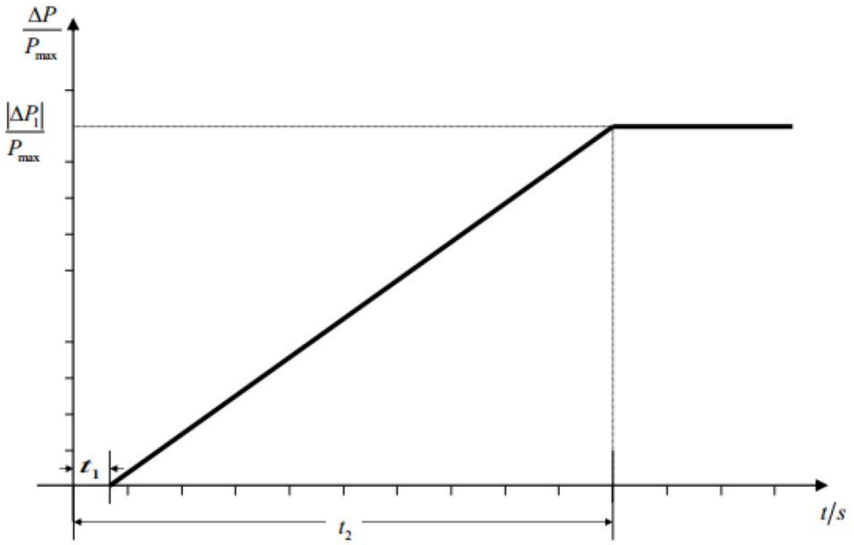

Figure 5 Initial delay of frequency response.

P_{max} is the maximum capacity to which ΔP relates.
ΔP is the change in active power supplied by the power-generating facility. The power-generating facility must supply active power ΔP up to point ΔP_1 in accordance with times t_1 and t_2. t_1 is the initial delay. t_2 is the time until full activation. (Figure 6 of the Regulation).

t_2: PGM: 30 seconds

The power-generating facility must be capable of providing full active power frequency response for a period of 15 minutes.

Within these 15 minutes, active power control must not adversely impact the active power frequency response of the power-generating facility.

[8]Real-time monitoring of frequency sensitive mode is described in section 4.3.3 on information exchange.

The communication interface for monitoring the operation of active power frequency response must be equipped to allow real-time and secure transmission of signals from the power-generating facility to Energinet's control centre upon request from the control centre.

4.1.2 LFSM-U[9]

The active power of the facility must follow the required droop when the grid frequency is less than the cutoff frequency for LFSM-U, regardless of whether the grid frequency is increasing or decreasing.

	CE:	N:
Cutoff frequency	49,8	49,5
Droop settings:		
Droop range	2-12%	2-12%
Droop SPG / PPM	5%	4%

[8] Points (i) and (ii) of Article 15(2)(g)
[9] Point (c) of Article 15(2)

Table 3 Requirements for LFSM-U.

Accuracy:

- Frequency measurements must be carried out with ±10 mHz accuracy or higher.
- The control function's sensitivity must be ± 10 mHz or higher.
- The power-generating facility must be able to activate a frequency response with an initial delay of less than 2 seconds.

In LFSM-U mode, the power-generating facility must be able to increase power up to maximum capacity.

Nominal power is used as the reference power ($P_{ref} = P_n$).

The stable operation of the power-generating facility in LFSM-U mode must be ensured.

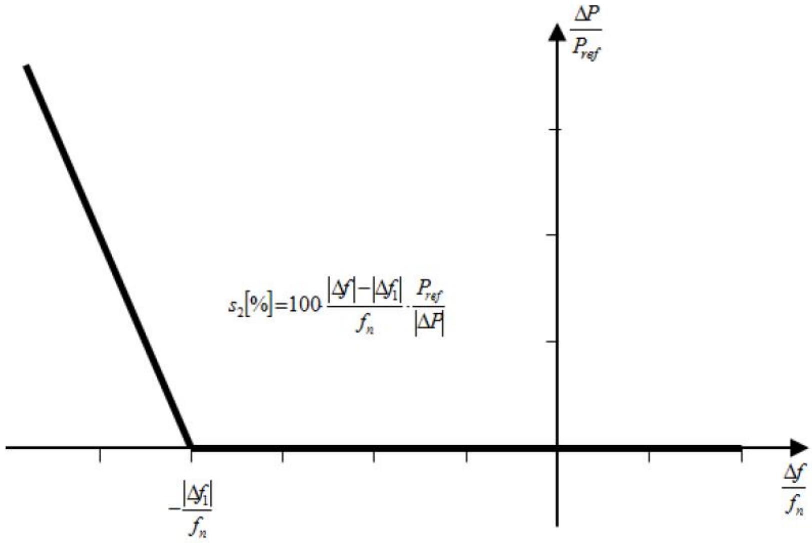

Figure 6 Figure 4 of the Regulation.

P_{ref} is the nominal power of the facility to which ΔP relates. ΔP is the change in active power supplied by the power-generating facility. f_n is the nominal frequency (50 Hz) in the grid, and Δf is the frequency deviation from the nominal power in the grid. In case of underfrequencies less than 49.8 Hz for CE (DK1) and 49.5 Hz for N (DK2), respectively, the power-generating facility must deliver a positive change in active power in accordance with the droop S_2.
(Figure 4 of the Regulation).

4.1.2.1 Frequency restoration control[10]

The power-generating facility must provide functionalities aimed at restoring frequency to nominal value or maintaining power exchange flows between system areas at their scheduled values.

For frequency restoration requirements, see Energinet's website about ancillary services: https://en.energinet.dk/electricity/ancillary-services/.

[10] Point (e) of Article 15(2)

4.1.2.2 Disconnection due to underfrequency[11]

Power-generating facilities capable of acting as load, including hydro pump-storage power-generating facilities, must be capable of disconnecting their load if the following underfrequency occurs:

CE:	49.0 Hz
N:	48.5 Hz

This requirement does not apply to auxiliary supplies.

Synthetic inertia is not used.[12]

4.1.3 LFSM-O (frequency response for overfrequency)[13]

The active power of the facility must follow the required droop when the grid frequency is more than the cutoff frequency, regardless of whether the grid frequency is increasing or decreasing. The cutoff frequency and droop are shown in table 2.

Nominal power is used as the reference power ($P_{ref} = P_n$).

Accuracy:

- It must be possible to set the frequency parameters in the active power control functions with a resolution of 10 mHz or higher.
- It must be possible to set the control droops with a resolution of 1% or higher.
- Completed or continuous control must not deviate by more than < 5% of Pn, where the fault is measured as an average over a period of 1 minute.
- Frequency measurements must be carried out with ±10 mHz accuracy or higher.

[14]The power-generating facility must be able to activate a frequency response with an initial delay of less than two seconds.

- [15]When the power-generating facility reaches the minimum regulating level, it must be able to continue operations at this power level.
- The minimum regulating level is the power level at which the facility is able to maintain stable operation. This limit is set in connection with the connection agreement.

[11] Point (f) of Article 15(2)
[12] Points (a) and (b) of Article 21(2)
[13] Points (a) and (g) of Article 13(2)
[14] Point (e) of Article 13(2)
[15] Point (f) of Article 13(2)

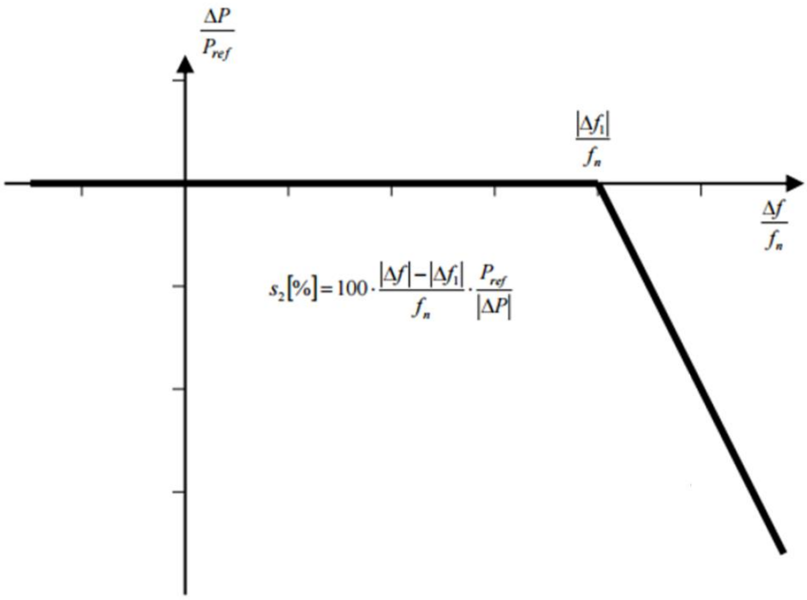

Figure 7 Requirements for LFSM-O.

16	CE:	N:
Cutoff frequency	50.2 Hz	50.5 Hz
Droop settings:		
SPG	5%	4%
PPM	5%	4%

Table 4 Requirements for LFSM-O.

4.1.4 ROCOF – Rate of change of frequency[17]

ROCOF denotes frequency change as a function of time.

A power-generating facility must be able to remain connected to the grid and maintain operation in the event of frequency changes as described below.

The frequency change, ROCOF, is calculated according to the principle below or an equivalent principle:

- The frequency measurement used to calculate the frequency change is based on a 200 ms measuring period for which the mean value is calculated.
- Frequency measurements must be made continuously, so that a new value is calculated every 20 ms.
- ROCOF [Hz/s] must be calculated as the difference between the mean value frequency calculation just done and the mean value frequency calculation done 20 ms ago.

  df/dt = (mean value 2 – mean value 1)/0.020 [Hz/s]

ROCOF must be tolerated up to 2.0 Hz/s.

16 Points (c) and (d) of Article 13(2)

17 Point (b) of Article 13(1)

4.2 Voltage stability

Energinet has defined the voltage value for 1 pu as follows:

	Base value for 1 pu.	
System voltage	CE (DK1)	N (DK2)
132 kV	-	138 kV
150 kV	152 kV	-
220 kV	220 kV	234 kV
400 kV	400 kV	400 kV

Table 5 Base values for pu voltage.

Unless otherwise stated, requirements relating to voltage refer to these values.

Clarification May 2021:
The quantity Uc refers to the normal operating voltage and differs depending on the point of connection. Uc is only used in connection with robustness requirements in relation to reactive power. The figures below regarding voltage stability have been updated so that Uc does not appear on the axis title. The values themselves are unchanged. Likewise, the quantities U_{min} and U_{max} have been removed as they served no purpose.
The symbol for nominal power - and thus the maximum exchange of active power at the point of connection (POC) - is not applied rigorously. In EU Regulation contexts, the symbol P_{max} is used, whereas in Danish literature P_n is typically used. The use of P_{max} and P_n therefore varies in this explanatory document, but the same quantity is referred to nevertheless.

[18]Without affecting the robustness rules, the power-generating facility must be able to remain in operation in the following voltage ranges and as shown in the following figures:

	110-300 kV	300-400 kV
CE:	0.85-0.90 pu/ 60 min. 1.118-1.15 pu/ 60 min.	0.85-0.90 pu/ 60 min. 1.05-1.1 pu/60 min.
N:	1.05-1.1 pu/60 min.	

Table 6 Voltage stability requirements.

[18] Point (i) of Article 16(2)(a)

CE (DK1):

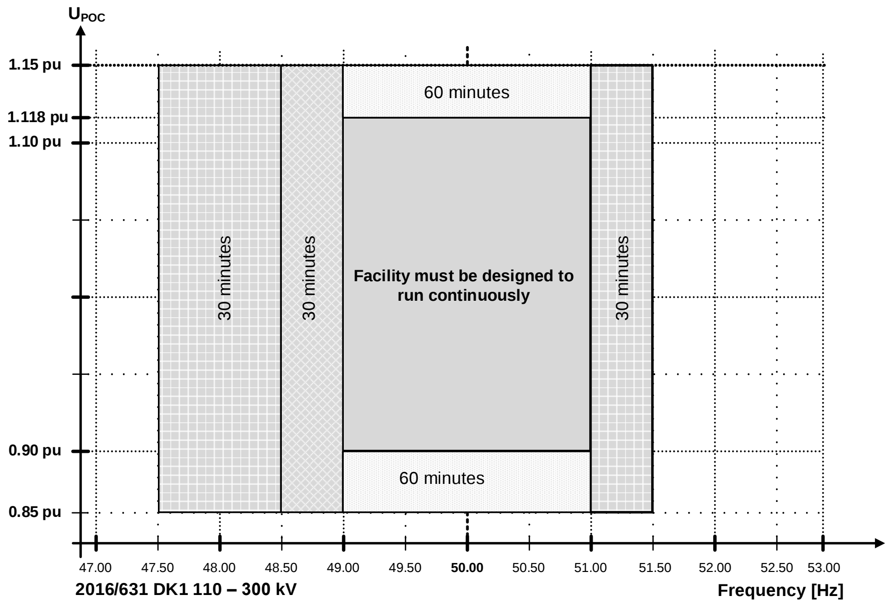

Figure 8 Voltage stability 110-300 kV – CE.

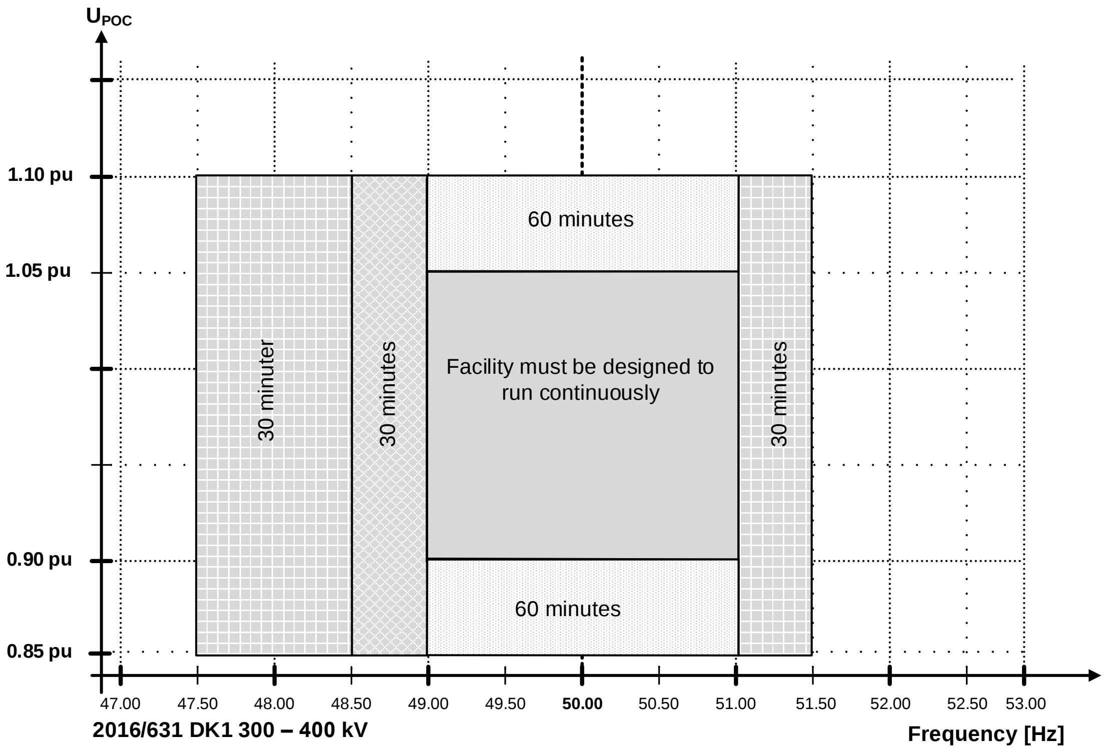

Figure 9 Voltage stability 300-400 kV – CE.

N (DK2):

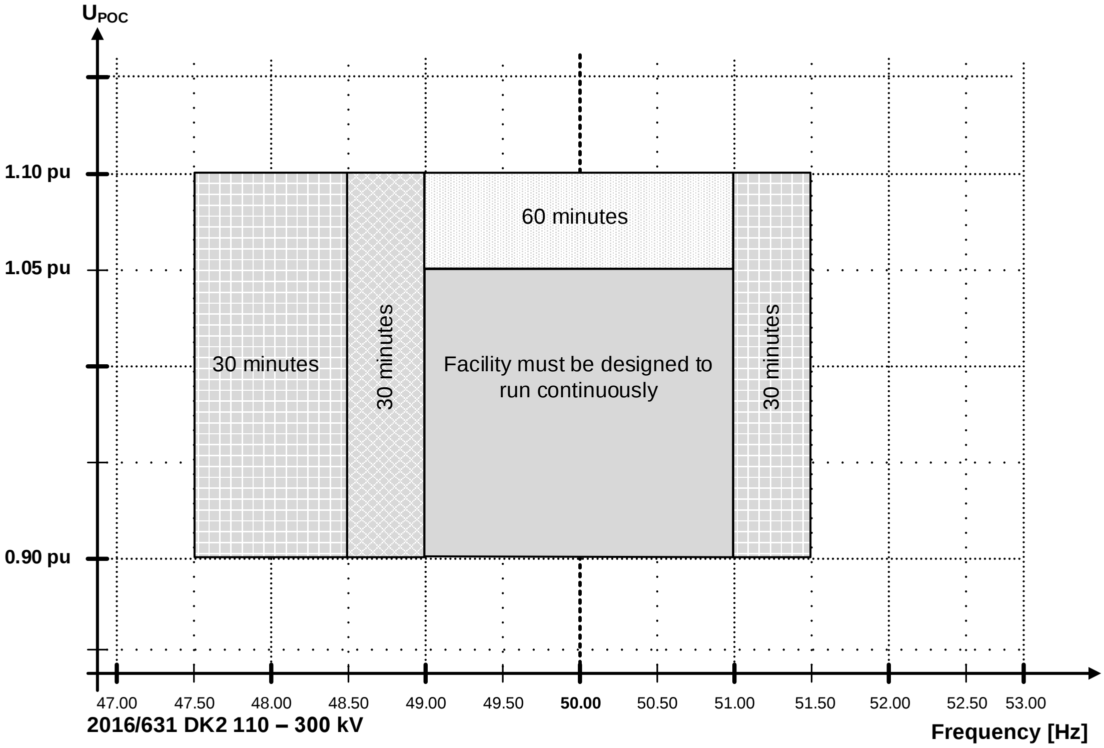

Figure 10 Voltage stability 110-300 kV – N.

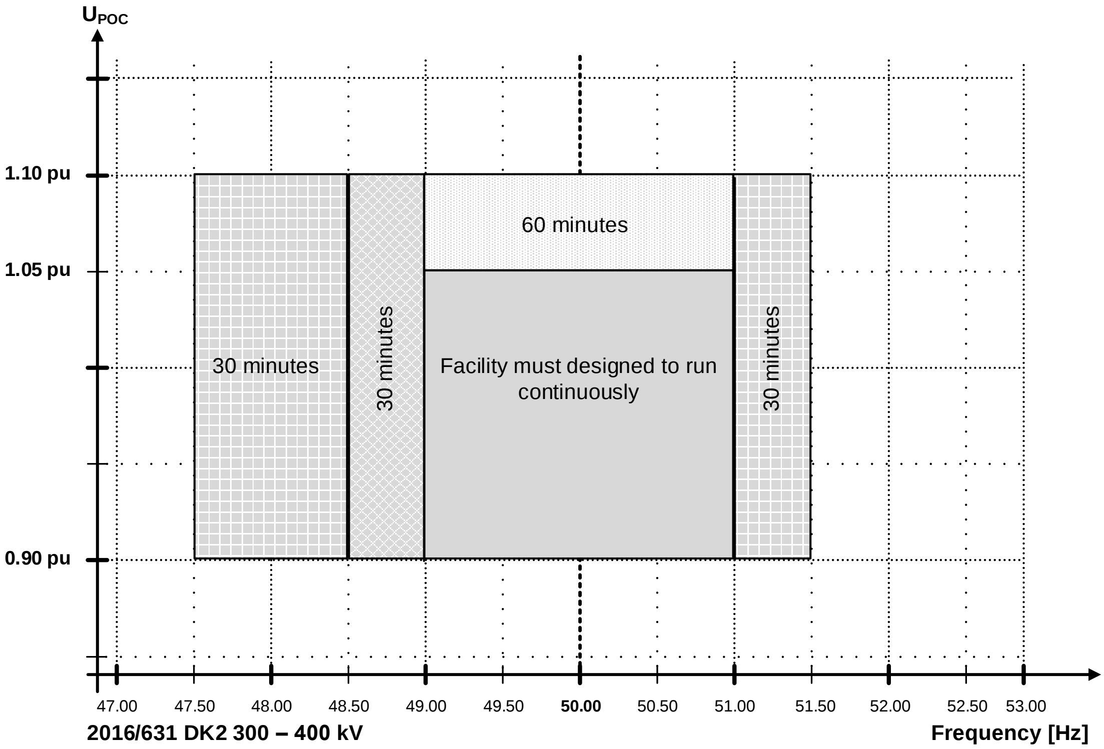

Figure 11 Voltage stability 300-400 kV – N.

4.2.1 SPG - synchronous generators[19]

4.2.1.1 Compensation

The facility owner must compensate for the facility infrastructure's reactive power in situations where a facility is disconnected or is not generating active power.

4.2.1.2 Reactive power at maximum capacity[20]

The U-Q/P_{max} profile describes the boundaries within which the synchronous power-generating facility must be able to provide reactive power at its maximum capacity.

Clarification May 2021:
Voltage Uc refers to normal operating voltage.
The requirement for Q/Pn must be considered with an accuracy of two decimal places and is thus -0.20 and 0.40, respectively.

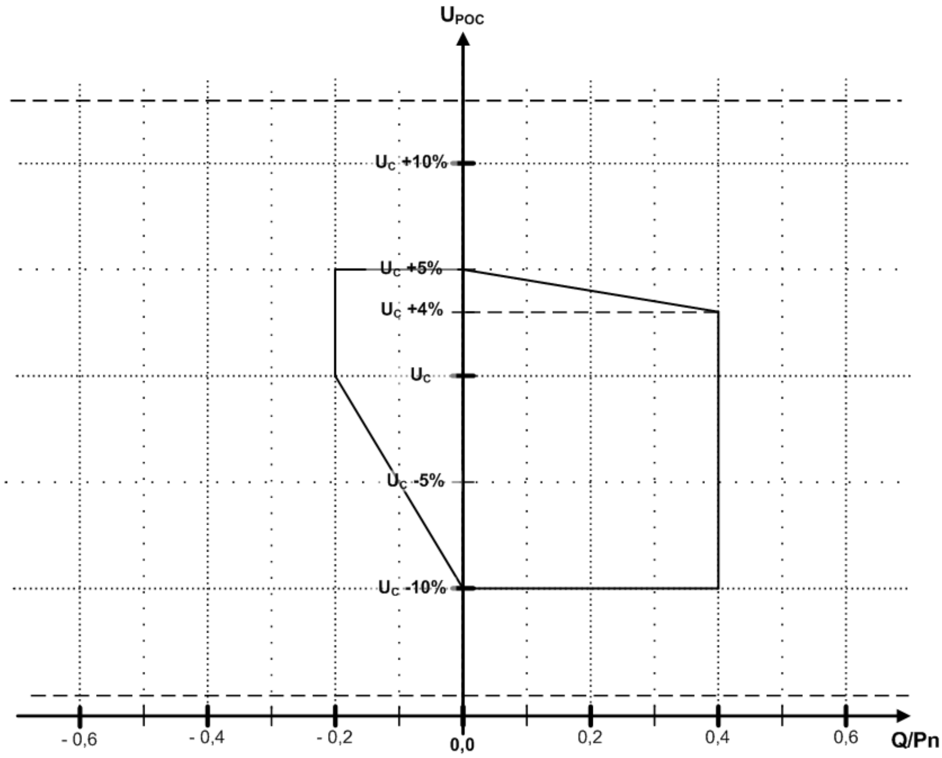

Figure 12 Requirement for delivery of reactive power U-Q/Pn for synchronous power-generating facilities.

The requirement for delivery of reactive power applies at the point of connection (POC).

The synchronous power-generating facility must be able to move to any operating point in the U-Q/P_{max} profile in appropriate timescales to target values requested by the relevant system operator.

19 Point (a) of Article 18(2)
20 Point (b) of Article 18(2)

[21]Reactive power
A synchronous power-generating facility must be able to provide reactive power when operating at an active power output below maximum capacity ($P < P_{max}$). It must be able to operate at every possible operating point in the P-Q-capability diagram of the generator of the facility, at least down to minimum stable operating level. Even at reduced active power output, reactive power supply at the point of connection must correspond fully to the P-Q-capability diagram of the generator of the facility, taking the auxiliary supply power and the active and reactive power losses of the step-up transformer, if applicable, into account.

4.2.1.3 Voltage control[22]

Parameters and settings for components for voltage control must be agreed and defined on the basis of a specific analysis.

4.2.1.4 Facility components

The following section specifies general stability requirements for generators and generator transformers in a facility.

Generator transformers/grid transformers
The maximum permissible value for the generator transformer/grid transformer's short circuit reactance is set in cooperation with Energinet, based on the facility owner's facility design studies and stability analyses. The permissible value must be stated in the grid connection agreement for the facility.

Where tap changers are used on generator transformers/grid transformers, an agreement can be made with Energinet that tap changers can be used to comply with requirements for reactive control capabilities. If such an agreement is made, this must be stated in the grid connection agreement for the facility.

Where tap changers are used on generator transformers/grid transformers, the facility owner must ensure proper coordination between the facility's reactive control functions and tap changer control.

Generators
For type D facilities, short circuit ratio and transient reactance requirements are set in cooperation with the transmission system operator, based on the facility owner's facility design studies and stability analyses. Permissible values must be stated in the grid connection agreement for the facility.

Excitation system
An SPG must be equipped with a continuously functioning automatic excitation system. The purpose is to ensure stable operation of the facility and allow it to contribute to regulating voltage and/or the reactive power balance in the public electricity supply grid.

The excitation system must be designed in conformity with European standard DS/EN 60034-16-1:2011 "Rotating electrical machines – Part 16: Excitation systems for synchronous machines – Chapter 1: Definitions" and DS/CLC/TR 60034-16-3:2004 "Rotating electrical machines – Part 16: Excitation systems for synchronous machines – Section 3: Dynamic performance".

In the event of grid disturbances resulting in voltage reduction, it must be possible to overexcite the generator for at least 10 seconds to 1.6 times the excitation current and voltage at nominal output and $\tan(\phi) = 0.4$ in the POC and

[21] Point (c) of Article 18(2)
[22] Point (a) of Article 19(2)

nominal operating voltage. If the overexcitation property depends on voltage in the POC, this property must be available at reduced grid voltages in the POC down to 0.6 pu.

The generator's overexcitation protection and other types of protection must be designed and set so that the generator's capacity for temporary overload can be utilised without exceeding the generator's thermal limits.

The excitation system's limit functions must be selective with the facility's protective functions, thereby allowing for a brief utilisation of overload characteristics without the facility being disconnected.

The excitation system's time response (measured at the generator terminals) during idling (generator disconnected from the grid and operated at nominal RPM) to a momentary 10% change to the reference voltage must be non-oscillatory and have a maximum rise time, as defined in DS/EN 60034-16-3, of 0.3 seconds for a static excitation system. For a rotating excitation system ("rotating exciter"), a time response of up to 0.5 seconds for a positive 10% change to the reference voltage is permitted, and correspondingly, up to 0.8 seconds for a negative 10% change to the reference voltage.

The excitation system's overshoot, measured at the generator terminals, as defined in DS/EN 60034-16-3, must not exceed 15% of the change during a momentary 10% change in the reference voltage.

<u>Verification requirements of excitation system</u>
Verification of the above functional requirements for the excitation equipment must be attached as documentation. Simulations carried out, relevant measurements from the commissioning tests, function descriptions and "as built" setting values must be enclosed with the full facility documentation.

Coordination between limit functions and protective functions must be documented in a P-Q-capability diagram for static and dynamic characteristics, containing trip times and activation levels.

Simulations, analyses, and commissioning tests must be used to document that the excitation system has adequate dynamic characteristics.

Simulations done must include the following test scenarios:

1. RMS simulations of voltage dips in reference to the following function, where the machine's pre-fault operating point is defined for UPOC = 1 pu, P = 1 pu, QPOC = 0.4 pu:
    a. Upoc(t) = $\begin{cases} 1\,pu\ where\ t < 0\ s \\ 0{,}6\,pu\ where\ t > 0\ s \end{cases}$
2. RMS simulation of step response test in the event of a momentary +/-10% change of the reference voltage, where the machine is operated at no load and at the nominal RPM.

Completed commissioning must comprise the following tests:

1. Step response test in the event of a momentary +/-10% change of the reference voltage, where the machine is operated at no load and at the nominal RPM.
2. Test of selectivity between underexcitation protection and underexcitation constraint. This is done by:
    a. Step response test, where it is attempted to force the machine to use an underexcitation setpoint outside the permissible underexcitation constraint range.

   b. Ramping-up of active power, from Pmin to Pn, where the machine, before the start of the test, is set to a fully underexcited setpoint.
3. Test of selectivity between overexcitation protection and overexcitation constraint. This is done by:
   a. Step response test, where it is attempted to force the machine to use an overexcitation setpoint outside the permissible overexcitation constraint range.
   b. Ramping-up of active power, from Pmin to Pn, where the machine, before the start of the test, is set to a fully overexcited setpoint.
4. Test of stator current constraint performance. This is done by:
   a. Step response test, where it is attempted to force the machine to use a setpoint outside the permissible current value for stator current constraint. The test is performed at reduced settings.
5. Test of the V/Hz constraint performance. This is done by:
   a. Step response test, where it is attempted to force the machine to use a setpoint outside the permissible ratio between voltage and frequency for the V/Hz constraint. The test is performed at reduced settings and with the machine operated at no load and at the nominal RPM.
   b. RPM change, where it is attempted to force the machine to use a setpoint outside the permissible ratio between voltage and frequency for the V/Hz constraint. The test is performed at reduced settings and with the machine operated at no load and at the nominal RPM before change to RPM.

PSS function

The PSS function must use input from rotor speed/grid frequency and active power (dual input) to derive the stability signal, where damping equipment of type IEEE PSS2B, cf. IEEE 421.5, is normative.

The PSS function must be adjusted to achieve a positive damping in the 0.2-0.7 Hz frequency range.

The phase of the supplied damping signal produced by the PSS function must be in phase with the change in speed for the generator rotor in the 0.2-2 Hz frequency range. Deviations of up to -30 degrees (undercompensated) are acceptable.

With the PSS function activated, damping of the facility’s power oscillations (exponentially declining function) must be faster than 1 second at all setpoints and for any distortion.

The facility’s natural damping of “local mode” power oscillations must not be adversely affected by the PSS function.

The PSS function must be set so that changes to the facility’s setpoint (active power) during normal operation, or in the event of a fault in for example a turbine regulator, boiler facility, feedwater facility or other auxiliary power facility must not cause the voltage on the high-voltage side of the facility’s generator transformer to change by more than 1%.

The PSS output signal must be limited so that activation of the PSS function does not lead to a change in generator voltage greater than +/- 5% of the generator’s nominal voltage. Limits may be automatically and dynamically reduced by the voltage regulator, for example when the excitation system’s limit functions are activated.

The PSS function must be deactivated automatically when generated active power is less than 20% of nominal output. It must be possible to connect and disconnect the PSS function. When the PSS function is disconnected, an alarm must be set off.

Verification requirements of PSS function

Compliance with the above functional requirements for the PSS function must be enclosed as documentation. Simulations carried out, relevant measurements from the commissioning tests, function descriptions and “as built” setting values must be enclosed with the full facility documentation.

Simulations, analyses, and commissioning tests must be used to document that the setting values used give the PSS function and the entire excitation system satisfactory dynamic characteristics.

The simulations performed must include the test scenarios below. With the exception of Test 5, these must be simulated both with the PSS function activated and deactivated:

1. Verification of the frequency characteristic, including correct phase compensation for the entire excitation system, in the form of Bode plots for amplification and phase.
2. Step response to a momentary +/- 5% change to the reference voltage. Simulations must be performed for various setpoints, e.g. 25%, 50%, 75% and 100% of the facility’s nominal power.
3. Short circuit close to the generator.
4. Disconnection of a line with the change in the public electricity supply grid moving from the strongest to the weakest grid configuration (short circuit power) Simulations must be performed for various setpoints, e.g. 25%, 50%, 75% and 100% of the facility’s nominal power.
5. A change to the generator’s supplied mechanical power from the drive system in relation to the functions below (PSS device must be active):
    a. Sine function, p(t) = $A \cdot Sin(\omega \cdot t), A = 0{,}1\ pu, \omega = 2 \cdot \pi \cdot \frac{1}{60}\ rad$
    b. Ramp function, p(t) = $\begin{cases} 0\ pu\ where\ t < 0\ s \\ 0{,}25 \cdot t\ pu\ where\ 0\ sec < t \leq 4\ s \\ 1\ pu\ where\ t > 4\ s \end{cases}$
    c. Step function, p(t) = $\begin{cases} 1\ pu\ where\ t < 0\ s \\ 0{,}6\ pu\ where\ t > 0\ s \end{cases}$

Completed commissioning must comprise the following tests:

1. Measurements of phase and gain (Bode plot) for the transfer function Vt(s)/Vref(s) with PSS function deactivated and SGM operated “off-grid”, at nominal RPM and terminal voltage.
2. Measurements of phase and gain (Bode plot) for the transfer function Vt(s)/Vref(s) with PSS function deactivated and SGM operated “on-grid”, using an operating point as close to P = 0 and Q = 0 as possible.
3. Measurement of transfer function for the PSS function.
4. Step response test of a momentary +/- 5% change to the reference voltage. The test is done for different setpoints, e.g. 25%, 50%, 75% and 100% of the facility’s nominal power with the PSS function both activated and deactivated.
5. Increase of PSS gain by a factor 3 of the proposed value.

4.2.1.5 Reactive power control functions

The following requirements are set for reactive power and voltage control functions.

The control functions for Q control, power factor and voltage control are mutually exclusive, which means that only one of the three functions can be activated at a time.

Q control

The accuracy of a completed or continuous regulation relating to the Q control function must not deviate by an average fault scale < 3% of Qn measured over a period of 1 minute. The facility must be able to receive a setpoint with a minimum Q accuracy of 100 kVAr.

Power factor control

The accuracy of a completed or continuous regulation relating to the power factor control function must not deviate by an average fault scale < 3% of Qn measured over a period of 1 minute.

The current Q value must be recalculated using the facility's current power factor setpoint.

The facility must be able to receive a setpoint with a minimum power factor accuracy of 0.01.

Automatic voltage control (AVR)

The accuracy of a completed change or continuous regulation, including setpoint accuracy, must not deviate by more than 0.5% of the voltage control setpoint.

The facility must be able to receive a voltage setpoint with a minimum resolution of 0.1 kV.

It must be possible to set the droop for automatic voltage control to a value in the range of 2-8% inclusive.

4.2.2 PPM – Power park module[23]

4.2.2.1 Fast fault current

~~A power park module must be able to supply fast fault current at the point of connection in the event of a symmetrical (three-phase) fault.~~

Clarification May 2021:

A power park module must be able to supply fast fault current at the point of connection in the event of both symmetrical and asymmetrical faults. The reactive fast fault current provided by the power park module is symmetrical in both cases.

In some graphs and requirements, voltage was incorrectly expressed as Uc instead of pu voltage. This has been corrected where relevant.

The system must be able to activate the supply of fast fault current by:

- ensuring the supply of fast fault current at the point of connection (POC), or
- measuring voltage deviations at the terminals of the individual units of the power park module (PGC – point of generator connection) and providing a fast fault current at the terminals of these units

Regulation must follow the requirements below so that the added reactive current (synchronous component) follows the characteristic with a tolerance of ±20% after 100 ms. This can be seen in the figures below, where the Y-axis indicates the applied control voltage for the 50 Hz component.

CE: IQ/In linear from 0% - 100% at U_{pgc}: 0.85 pu to 0.5 pu

N: IQ/In linear from 0% - 100% at U_{pgc}: 0.9 pu to 0.5 pu

[23] Point (b) of Article 20(2)

With regard to the control concept for the delivery of added reactive current during a voltage dip, it is up to the PPM supplier to specify the control voltage used. This may be the minimum or maximum line-to-line voltage or phase voltage. Alternatively, the synchronous voltage component may be used as long as the characteristic can be observed in the event of three-phase faults and after disconnection of all types of asymmetrical faults.
In area B shown in the figures, the delivery of reactive current takes first priority, while the delivery of active power takes second priority.

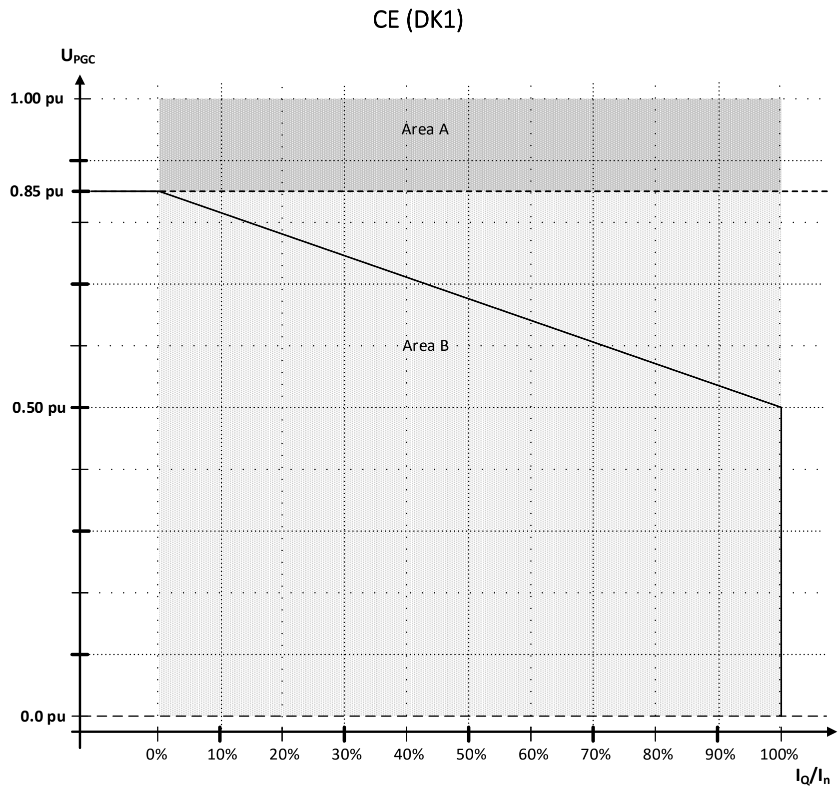

Figure 13 Requirements for added reactive current in CE (DK1).

Uc < 0.85 pu: start
Uc > 0.85 pu: stop

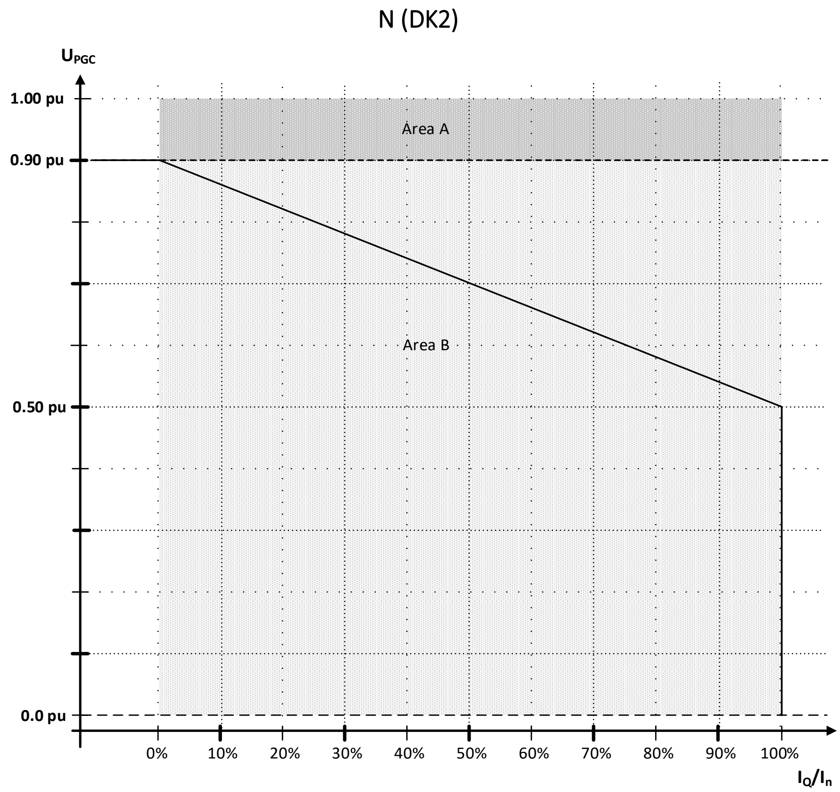

Figure 14 Requirements for added reactive current in N (DK2).

Uc < 0.9 pu: start
Uc > 0.9 pu: stop

4.2.2.2 Compensation

The facility owner must compensate for the facility infrastructure's reactive power in situations where a facility is disconnected or is not generating active power.

4.2.2.3 Reactive power at maximum capacity[24]

The U-Q/P_{max} profile describes the boundaries within which the power park module must be able to provide reactive power at its maximum capacity.

Clarification May 2021:
The voltage Uc in the figures below refers to normal operating voltage.
In the figures, the requirement for reactive power control is expressed as Q/Pn = 0.33 and PF = 0.95. The present requirement is Q/Pn = 0.33 (with two decimal places), which for clarity has been converted and rounded up to PF = 0.95. The actual number is PF = 0.9496.

[24] Point (b) of Article 21(3)

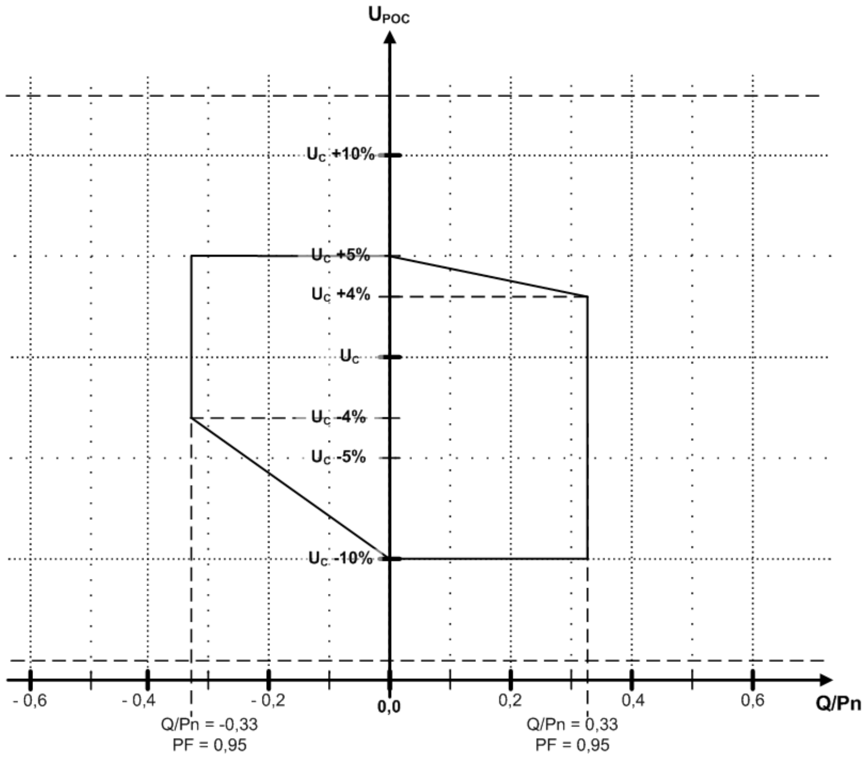

Figure 15 Requirements for delivery of reactive power U-Q/P_n at maximum capacity for PPM.

The requirement for delivery of reactive power applies at the point of connection (POC).

4.2.2.4 Reactive power below maximum capacity[25]

The P-Q/P_{max} profile describes the boundaries within which the power park module must be able to provide reactive power below maximum capacity.

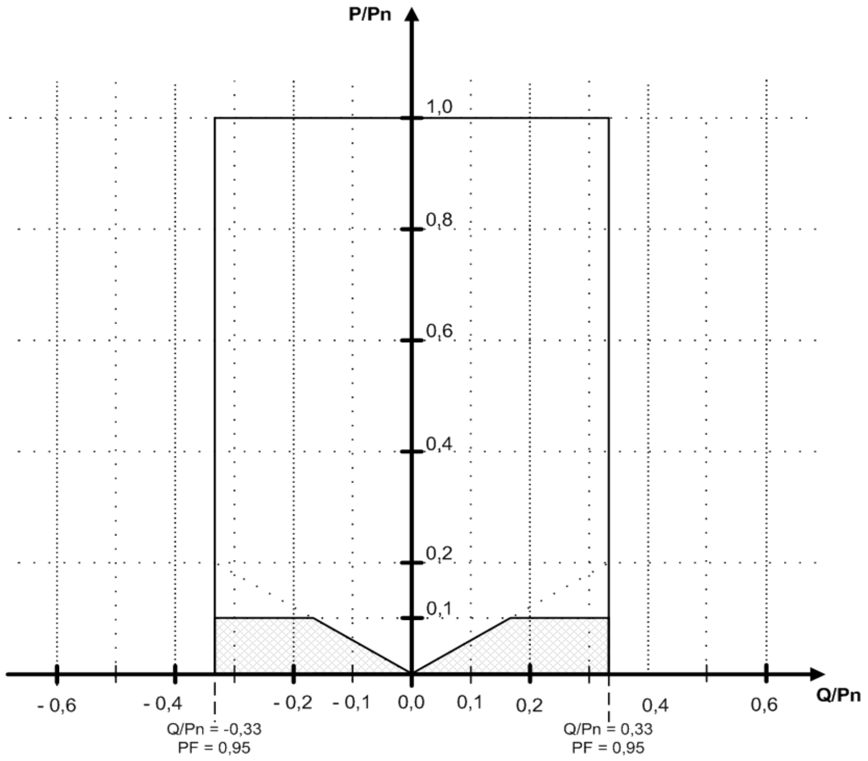

Figure 16 Requirements for the delivery of reactive power P-Q/P_n below maximum capacity.

In this area, the reactive properties for the generating facility may be limited due to maintenance or faults affecting individual units.

In this area, the reactive properties for the generating facility may be limited due to starts and shutdowns caused by primary energy, maintenance, or faults affecting individual units.

When running at active power below maximum capacity (P < P_{max}), the power park module must be able to supply reactive power at any operating point within the boundaries of the P-Q/P_{max} profile. However, the requirement is reduced if units in the power-generating facility are out of operation due to maintenance or faults.

Clarification May 2021:
All individual units must be running unless they are out of operation due to service or breakdown.
The requirement is reduced proportionately in relation to the number of units in the power-generating facility that are out of operation due to maintenance or faults.

The power park module must be able to move to any operating point in the P-Q/P_{max} profile in appropriate timescales to target values requested by Energinet.

[25] Point (c) of Article 21(3)

4.2.2.5 Reactive power control modes[26]

The power park module must be able to provide reactive power automatically by one of the following modes:

- Voltage control
- Reactive power control
- Power factor control

Voltage control mode:
Contribute to voltage control at the point of connection by provision of reactive power exchange with the grid with a setpoint voltage covering 0.95 to 1.05 pu in steps no greater than 0,01 pu, with a gradient having a range of at least 2 to 7% in steps no greater than 0.5%. The reactive power output must be zero when the grid voltage value at the point of connection equals the voltage setpoint.

The setpoint may be operated with or without a deadband selectable in a range from zero to ± 5% of reference 1 pu grid voltage in steps no greater than 0.5%.

Following a step change in voltage, the power park module must be capable of achieving 90% of the change in reactive power output within 1 second and must settle at the value specified by the gradient within 5 seconds, with a steady-state reactive tolerance no greater than 5% of the maximum reactive power.

Reactive power control mode
The reactive power setpoint is set anywhere in the reactive power range, specified above, with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full reactive power, controlling the reactive power at the point of connection to an accuracy within plus or minus 5 MVAr or plus or minus 5% (whichever is smaller).

Power factor control mode
The power factor is controlled at the point of connection within the required reactive power range, as described above, with a target power factor in steps no greater than 0.01.

Target power factor:

- Resolution of 0.01

Tolerance and time for new setpoint:

- For the control function, the accuracy of a completed control operation over a period of 1 minute may not deviate by more than 2% of Q_n.

- If the power factor setpoint is to be changed, the change must be commenced within two seconds and completed not later than 30 seconds after receipt of an order to change the setpoint.

For remote adjustment of the relevant setpoint, the control mode is conditional upon service delivery.
The Produktionstelegrafen (grid telegraph) system is used for operational and operating point changes.

[26] Point (d) of Article 21(3)

The maximum permissible value for the generator transformer/grid transformer's short circuit reactance is set in cooperation with Energinet, based on the facility owner's facility design studies and stability analyses. The permissible value must be stated in the grid connection agreement for the facility.

Where tap changers are used on generator transformers/grid transformers, an agreement can be made with Energinet that tap changers can be used to comply with requirements for reactive control capabilities. If such an agreement is made, this must be stated in the grid connection agreement for the facility.

Where tap changers are used on generator transformers/grid transformers, the facility owner must ensure proper coordination between the facility's reactive control functions and tap changer control.

Prioritisation

[27] Reactive current is prioritised during faults where fault-ride-through capability is required.

4.3 Robustness

[28] In the event of power oscillations, the power-generating facility must retain steady-state stability when operating at any operating point of the P-Q-capability diagram.

The power-generating facility must be capable of remaining connected to the grid and operating without power reduction, as long as voltage and frequency remain within the limits in these rules, taking account of the reduction with underfrequency and LFSM-U.

The power-generating facility must be capable of remaining connected to the grid during single-phase or three-phase automatic reclosure on meshed grid lines. It must be designed to withstand transitory phase jumps of up to 20° at the point of connection without disconnecting.

4.3.1 Fault-ride-through[29]

The power-generating facility is capable of staying connected to the grid and continuing to operate stably after the power system has been disturbed by cleared faults. This capability must be consistent with a voltage-against-time profile for fault conditions at the point of connection.

The voltage-against-time-profile expresses a lower limit of phase-to-phase voltages at the point of connection during a symmetrical fault, as a function of time before, during and after the fault.

The FRT requirements stated apply to both symmetrical and asymmetrical fault types. The voltage synchronous component must be considered in any voltage evaluation.

Clarification May 2021:
The FRT requirements for transmission connections set out in appendix 1D apply even if the voltage level at the point of connection is lower than 110 kV.

FRT requirements in CE

[27] Point (e) of Article 21(3)

[28] Points (a), (b) and (c) of Article 15(4)

[29] Article 16(3)

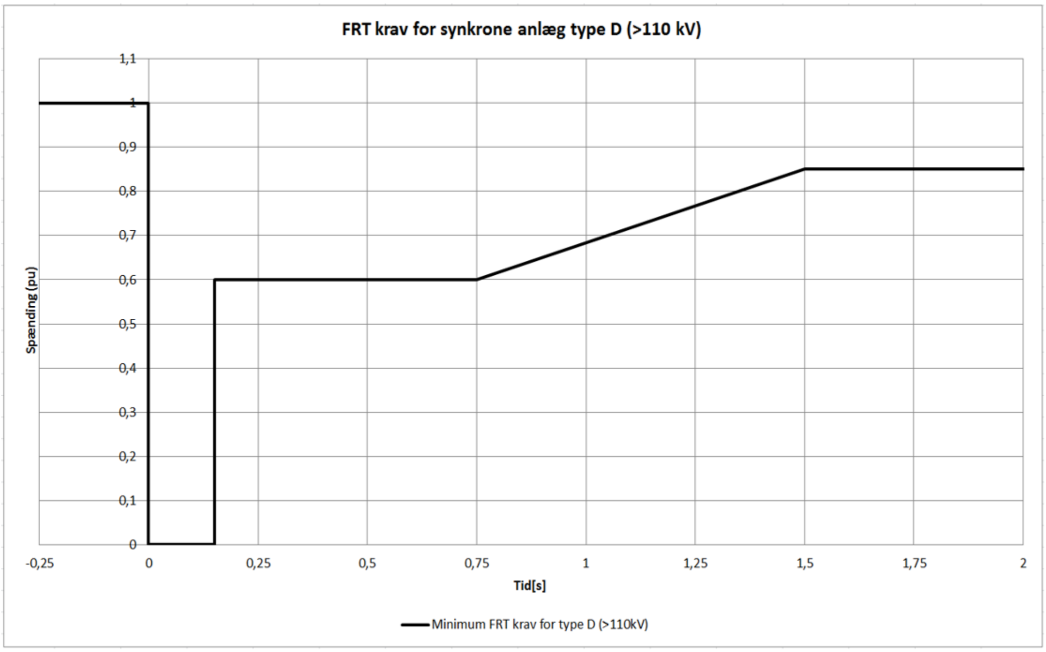

Figure 17 FRT requirements for type D synchronous facilities in CE.

Translations:

FRT-krav for synkrone anlæg type D (>110 kV): FRT requirements for synchronous facilities type D (>110 kV)

Spænding (pu): Voltage (pu)

Tid[s]: Time [s]

Minimum FRT krav for type D (>110 kV): Minimum FRT requirements for type D (>110 kV)

Spændingsparametre (pu)		Tidsparametre [sekunder]	
U_{ret}:	0	t_{clear}:	0,15
U_{clear}:	0,6	t_{rec1}:	0,15
U_{rec1}:	0,6	t_{rec2}:	0,75
U_{rec2}:	0,85	t_{rec3}:	1,5

Table 7 FRT requirements for type D synchronous power-generating facilities in CE.

Translations:

Spændingsparametre (pu): Voltage parameters (pu)

Tidsparametre [sekunder]: Time parameters [seconds]

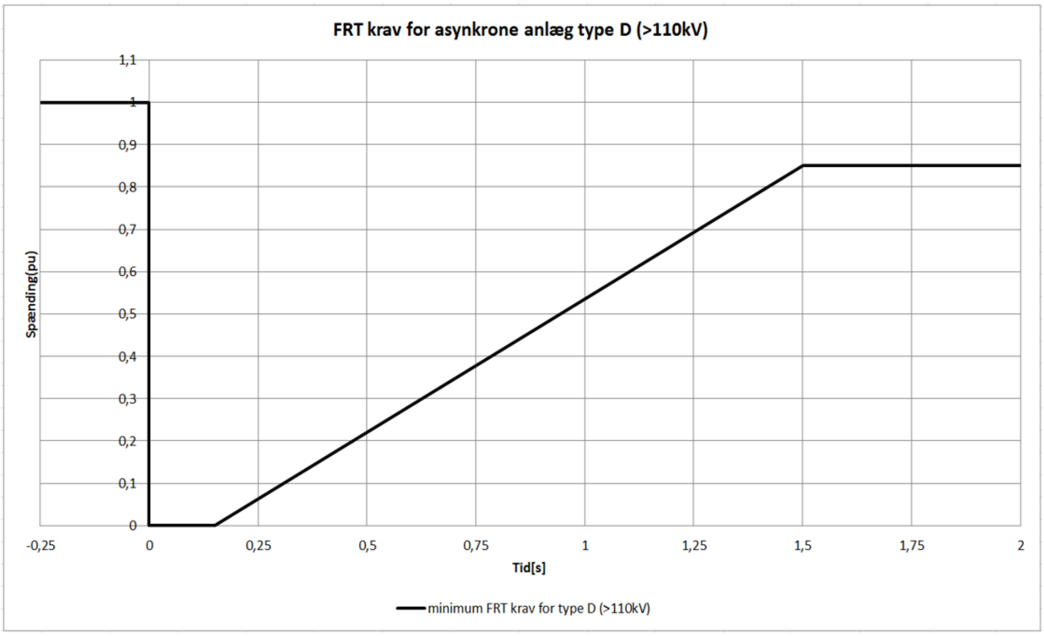

Figure 18 FRT requirements for type D asynchronous facilities in CE.

Translations:

FRT-krav for asynkrone anlæg type D (>110 kV): FRT requirements for asynchronous facilities type D (>110 kV)

Spænding (pu): Voltage (pu)

Tid[s]: Time [s]

Minimum FRT krav for type D (>110 kV): Minimum FRT requirements for type D (>110 kV)

Spændingsparametre (pu)		Tidsparametre [sekunder]	
U_{ret}:	0	t_{clear}:	0,15
U_{clear}:	0	t_{rec1}:	0,15
U_{rec1}:	0	t_{rec2}:	0,15
U_{rec2}:	0,85	t_{rec3}:	1,5

Table 8 FRT requirements for type D asynchronous power-generating facilities in CE.

Translations:

Spændingsparametre (pu): Voltage parameters (pu)

Tidsparametre [sekunder]: Time parameters [seconds]

FRT requirements in N:

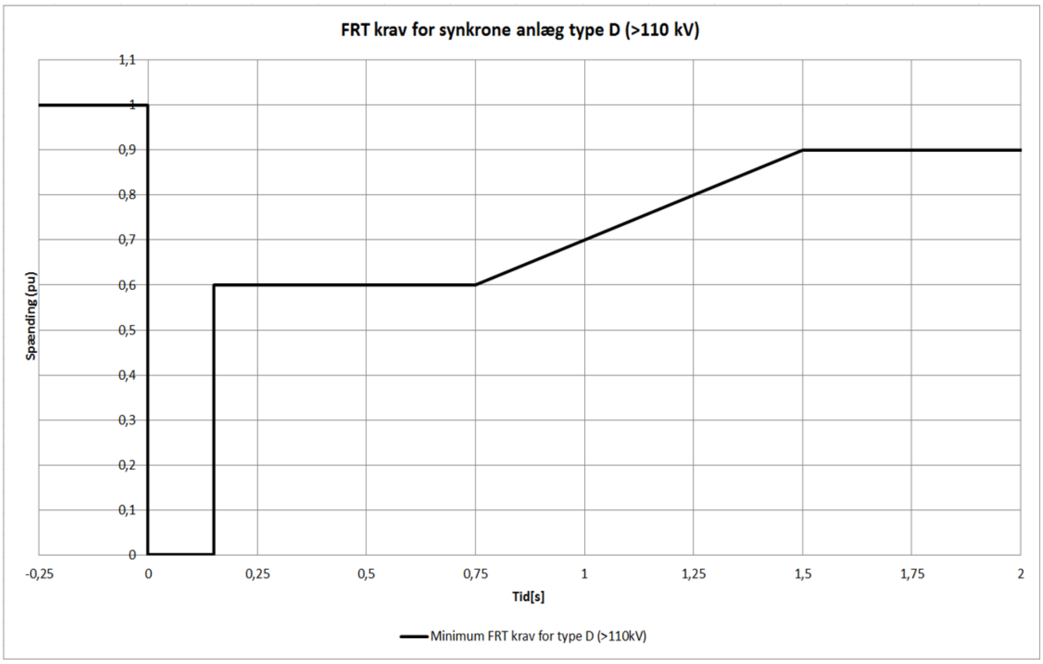

Figure 19 FRT requirements for type D synchronous facilities in N.

Translations:

FRT-krav for synkrone anlæg type D (>110 kV): FRT requirements for synchronous facilities type D (>110 kV)

Spænding (pu): Voltage (pu)

Tid[s]: Time [s]

Minimum FRT krav for type D (>110 kV): Minimum FRT requirements for type D (>110 kV)

Spændingsparametre (pu)		Tidsparametre [sekunder]	
U_{ret}:	0	t_{clear}:	0,15
U_{clear}:	0,6	t_{rec1}:	0,15
U_{rec1}:	0,6	t_{rec2}:	0,75
U_{rec2}:	0,9	t_{rec3}:	1,5

Table 9 FRT requirements for type D synchronous power-generating facilities in N.

Translations:

Spændingsparametre (pu): Voltage parameters (pu)

Tidsparametre [sekunder]: Time parameters [seconds]

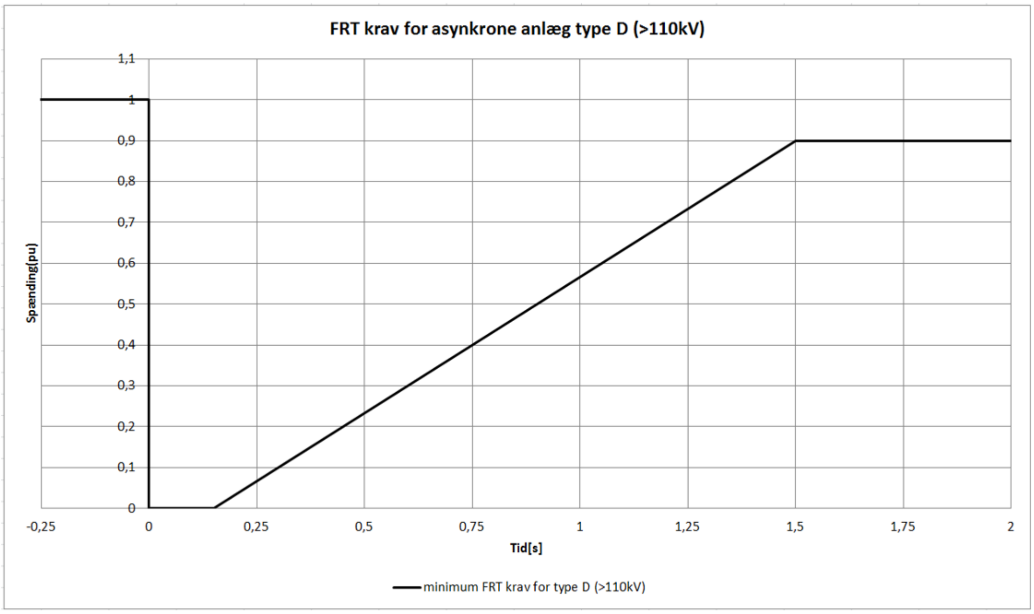

Figure 20 FRT requirements for type D asynchronous facilities in N.

Translations:

FRT-krav for asynkrone anlæg type D (>110 kV): FRT requirements for asynchronous facilities type D (>110 kV)

Spænding (pu): Voltage (pu)

Tid[s]: Time [s]

Minimum FRT krav for type D (>110 kV): Minimum FRT requirements for type D (>110 kV)

Spændingsparametre (pu)		Tidsparametre [sekunder]	
U_{ret}:	0	t_{clear}:	0,15
U_{clear}:	0	t_{rec1}:	0,15
U_{rec1}:	0	t_{rec2}:	0,15
U_{rec2}:	0,9	t_{rec3}:	1,5

Table 10 FRT requirements for type D asynchronous power-generating facilities in N.

Translations:

Spændingsparametre (pu): Voltage parameters (pu)

Tidsparametre [sekunder]: Time parameters [seconds]

The publication “Kortslutningsberegninger – Metode, jordingspraksis og forudsætninger” (Short circuit calculations – Method, earthing practice, and assumptions) determines the method for calculating short circuit power and calculates conditions in known points of connection.

The facility owner will receive the following pre-fault and post-fault conditions upon request; they must be used in calculations to demonstrate fault-ride-through capability at the point of connection:

- The pre-fault minimum short circuit capacity at each connection point expressed in MVA.
- The pre-fault operating point of the power-generating facility expressed in active power output and reactive power output at the point of connection and voltage at the point of connection.
  Facility properties = facility FRT is specified by P_n and Q_{min}.
- The post-fault minimum short circuit capacity at each connection point expressed in MVA.

Automatic reclosing
The facility owner must protect the power-generating facility against resulting mechanical and electrical effects from possible reclosures after symmetrical and asymmetrical faults in the transmission system.

Measures taken in this connection must not compromise other properties specified for the power-generating facility.

SPG
[30] Facility robustness properties must not be delayed or limited by a specific design.

[31] Energinet and the facility owner may enter into an agreement regarding the technical capabilities of the power-generating facility to aid angular stability under fault conditions.

PPM
[32] Regarding the post-fault active power recovery that the power park module is capable of providing, the facility must supply normal generation not later than 5 seconds after the operating conditions at the point of connection have reverted to the continuous generation range. Power control must be implemented with a ramp rate of at least 20% of the facility's nominal capacity.

4.4 System management

4.4.1 Control

[33] General requirements for control schemes and settings
The schemes and settings of the different control devices of the power-generating facility that are necessary for transmission system stability and for taking emergency action must be coordinated and agreed with Energinet.

System protection
When the POC is decided, Energinet will state whether there is a requirement to establish system protection.

Absolute power constraint
An absolute power constraint is used to protect the public electricity supply grid against overload in critical situations.

4.4.2 Protection

[34] Electrical protection schemes and settings:

[30] Article 17(3)
[31] Article 19(3)
[32] Points (a) and (b) of Article 20(3)
[33] Point (i) of Article 14(5)(a)
[34] Point (i) of Article 14(5)(b)

Energinet uses:

- Line protection
- Transformer protection
- Reactor protection
- Auxiliary power transformer protection
- Busbar protection.

The facility owner must ensure that:

- The facility is protected against damage resulting from faults and incidents in the grid.
- The facility is protected against internal short circuits.
- The facility is protected against disconnection in non-critical situations.

All applicable settings are specified based on the relevant grid and facility analyses. Settings are noted in the operating agreement.

Wherever possible, the public electricity supply system is protected against any unwanted impact from the facility.

The facility must be able to handle the FRT requirements set, with Energinet ensuring that faults etc. are disconnected accordingly.

4.4.3 Information exchange

[35] Power-generating facilities must be able to exchange information with Energinet in real time, or periodically with time stamp, with the following accuracy:

- The maximum functional status update time (activated/deactivated) is 10 ms.
- The maximum parameter value update time is 1 second.
- The maximum update time for measured values is 1 second.

The contents of information exchange and other requirements for the exchange are listed in appendix 1.A (signal list) to the requirements.

If a facility wishes to provide ancillary services (e.g. FCR, RR, FRR), there will be additional requirements for signals in addition to the requirements in the signal list (see the rules for ancillary services). At the same time, the balance-responsible party may be subject to additional requirements regarding signals from the power-generating facility.

4.4.4 General information

[36] System management requirements
With regard to loss of angular stability or loss of control, a power-generating facility must be capable of disconnecting automatically from the grid in order to help preserve system security or to prevent damage to the power-generating facility.

[35] Point (d) of Article 14(5)

[36] Points (a) and (b) of Article 15(6)

The power-generating facility must be equipped with protection for detection of pole slip or loss of synchronism. If pole slip or loss of synchronism is detected, the power-generating facility must disconnect immediately to safeguard system and facility safety. The protective functions used cannot affect the FRT properties of the power-generating facility as the protective settings used are determined on the basis of simulations of relevant fault scenarios.

4.4.5 Instrumentation

Power-generating facilities must be equipped with a function that records faults and supports dynamic monitoring of system behaviour. This function must record the following parameters:

- voltage
- active power
- reactive power
- frequency.

Facilities that provide ancillary services must be equipped with a PMU for verification of the specified service, including the dynamic response of the power-generating facility.

The settings for fault recording equipment (including triggering criteria and sampling rates) are described below.

Logging must be performed using electronic equipment that as a minimum can be configured to log relevant incidents for the signals below at the point of connection in case of faults in the public electricity supply grid.

The facility owner must install logging equipment (fault recorder) at the point of connection which records, as a minimum:

- Voltage for each phase for the facility
- Current for each phase for the facility
- Active power for the facility (can be computed values)
- Reactive power for the facility (can be computed values)
- Frequency for the facility
- Frequency deviations
- Speed deviations (synchronous generator)
- Activation of internal protective functions.

Specific measurement requirements are described in the grid connection agreement.

Logging must be performed as correlated time series of measured values from 10 seconds before an incident until 60 seconds after the time of an incident.

Minimum sample frequency for all fault logs must be 1 kHz.

The specific configurations for incident-based logging must be agreed with the transmission system operator upon commissioning of the facility.

All measurements and data to be collected in accordance with requirement 5.8.10 “Information exchange – Generation and demand” must be logged with a time stamp and an accuracy ensuring that such measurements and data can be correlated with each other and with similar recordings in the public electricity supply grid.

Logs must be kept for at least three months from the time of the fault situation. However, the maximum number of incidents to be recorded is 100.

Upon request, the electricity supply company and the transmission system operator must be granted access to logged and relevant recorded information.

Triggering signals from the above are used for dynamic monitoring of system behaviour, which includes an oscillation trigger that detects poorly damped power oscillations.

Energinet must be given access to the information in file format:

COMTRADE IEEE C37.111:1999, *IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems.*

4.4.6 Simulation models

[37]The simulation model requirements are specified in appendix 1.B of the requirements.

4.4.7 System protection[38]

SPG

The electricity system’s need for system protection and the implementation of system protection on the individual synchronous generator is identified once POC has been assigned. The specific conditions are described in the connection agreement.

PPM

A facility must be equipped with system protection, i.e. an emergency control function which must be capable of very quickly regulating the active power supplied by a power-generating facility to one or more predefined setpoints based on a downward regulation order. These setpoints are determined by the electricity supply company upon commissioning.

The facility must have at least five different configurable control options. The following control ranges are recommended as default values:

1. Up to 70% of rated power
2. Up to 50% of rated power
3. Up to 40% of rated power
4. Up to 25% of rated power
5. Up to 0% of rated power, i.e. the facility has shut down.

Regulation must be commenced within 1 second and completed no later than 10 seconds after receiving a downward regulation order.

[37] Point (i) of Article 15(6)(c)

[38] Point (d) of Article 15(6)

In the event that upward regulation is ordered for system protection, e.g. from step 4 (25%) to 3 (40%), it is acceptable for the design limits of the facility's generators or other facility units to increase the order completion time.

4.4.8 Downward regulation function of active power at cut-out wind speed

A power-generating facility with wind as its primary energy form must be able to reduce active power generation if high wind speeds occur before the protective functions built into the wind turbines are activated (cut-out wind speed).

If a power-generating facility uses wind as its primary energy, the facility must be capable of regulating active power to any value in the interval from 100% to 10% of Pn.

It must be possible to activate/deactivate the control function using orders.

Downward regulation can be performed as continuous or discrete regulation.

Discrete regulation must have a step size of maximum 25% of rated power within the hatched area shown in the figure below.

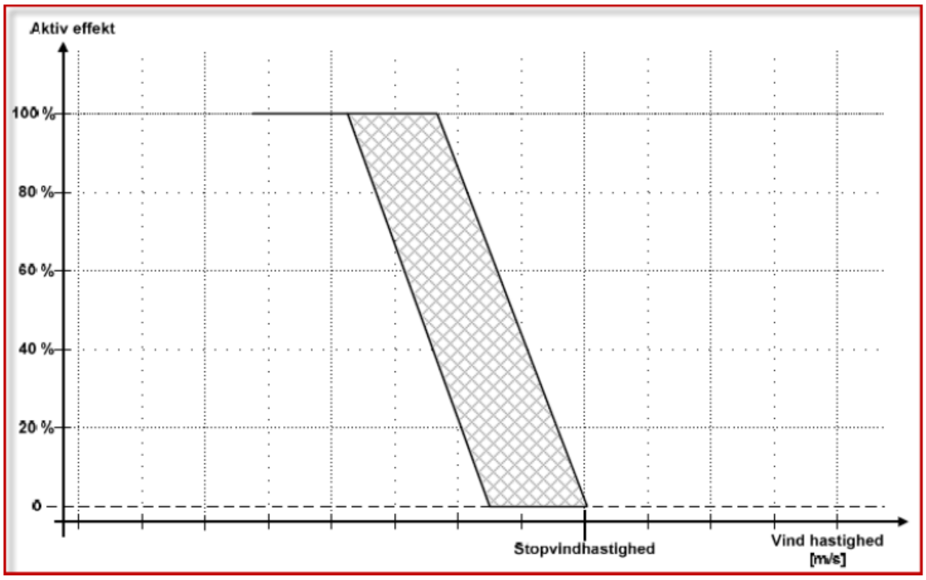

Figure 21 Requirements for downward regulation of active power.

Translations:
Aktiv effekt: Active power
Stopvindhastighed: Cut-out wind speed
Vind hastighed [m/s]: Wind speed [m/s]

The downward regulation headroom must be agreed with Energinet upon commissioning of the power-generating facility. The width of the downward regulation headroom may depend on local wind conditions.

The automatic downward regulation function is specified, as a minimum, by:

- Wind speed - activation of downward regulation [m/s]
- Wind speed - 10% of Pn [m/s]
- Wind speed - cut-out [m/s]

Clarification May 2021:
The downward regulation function must always be activated.
For downward regulation due to high winds, depending on wind turbine size and overall wind farm size, wind turbines are expected to ramp down over a change of wind speed of approx. 3 m/s - e.g. from 26 m/s to 29 m/s (10-minute values).

4.4.9 Ramp rate limitation

[39] Minimum and maximum limits for changes in active power:

Up: Min: 1% Pn/min.
Up: Max: 20% of Pn, however not exceeding 60 MW/min.

Down: Min: 1% Pn/min.
Down: Max: 20% of Pn, however not exceeding 60 MW/min.

Clarification May 2021:
The requirements for minimum and maximum ramp rates for active power apply when the facility generally regulates from one setpoint to another. This also applies

- during ramping <u>up</u> of solar/wind farms when irradiance/wind increases rapidly.
- after completion of downward regulation, e.g. caused by system protection.

The maximum ramp rate may be exceeded when required by the electricity system, e.g. in connection with ancillary services, an autonomous required response or when irradiance/wind decreases rapidly.

The ramp rate requirements referred to in point (a) of Article 15(2):

- SPG: minimum 1% of Pn/minute, also 10-minute response time for technology neutrality, if necessary
- PPM: minimum 20% of Pn/minute
- It must be possible to specify setpoints for active power with a resolution of 1% of Pn or higher

describe what the facility *must be capable* of doing – not what it *is allowed* to do.

4.4.10 Earthing

[40] For earthing arrangement of the neutral-point at the grid side of step-up transformers, the neutral-point must be insulated and installed so that it can be earthed directly or earthed through a reactance.

As a rule, the secondary side of the generator transformer is not earthed.

Other requirements are defined in the grid dimensioning criteria for grids above 100 kV.

[39] Point (e) of Article 15(6)
[40] Point (f) of Article 15(6)

4.4.11 Synchronisation

[41] The power-generating facility must be equipped with the necessary synchronisation functions, and synchronisation of the power-generating facility must be possible at frequencies within the 47.5 Hz to 51.5 Hz frequency range.

Energinet and the facility owner must agree on the settings for the synchronisation devices before the power-generating facility is put into service. This agreement must cover:

- Voltage
- Frequency
- Phase angle range
- Phase sequence
- Deviation of voltage and frequency.

4.5 Restoration of the system

4.5.1 Automatic reclosing

[42] A power-generating facility can restore the connection to the grid following a random disconnection caused by a grid disturbance under the following conditions:

- The frequency must be in the range:
  - CE: 47.5-50.2 Hz
  - N: 47.5-50.5 Hz
- The voltage must be in the range

	110-300 kV	300-400 kV
CE:	0.90 pu-1.118 pu	0.90 pu-1.05 pu
N:	0,9-1,05 pu	

- Reclosing after 3 min.
- Ramp rate: 20% P_n/min.
- Switching with own equipment permitted as long as the grid is energised.
- Switching with third party equipment is subject to agreement with the facility owner.

Installation of automatic recovery systems is subject to prior approval by Energinet.

4.5.2 Black start capability

[43] Facilities are not required to have black start capability.

Energinet regularly perform needs analyses in relation to “black start capability” and obtain quotations and concludes agreements on this basis.

Power-generating facilities with black start capability must be capable of starting from shutdown without any external electrical energy supply and within a time frame set by Energinet.

[41] Article 16(4)

[42] Points (a) and (b) of Article 14(4)

[43] Point (a) of Article 15(5)

A power-generating facility with black start capability must be able to synchronise within the frequency limits set out in point (a) of Article 13(1) and the voltage limits set out in Article 16(2).

A power-generating facility with black start capability must be capable of automatically regulating dips in voltage caused by connection of demand.

A power-generating facility with black start capability must be capable of:

- regulating load connections in block load
- operating in LFSM-O and LFSM-U, as specified in point (c) of paragraph 2 and Article 13(2)
- controlling frequency in case of overfrequency and underfrequency within the whole active power output range between minimum regulating level and maximum capacity as well as at house-load level
- parallel operation of a few power-generating facilities within one island, and
- controlling voltage automatically during the system restoration phase.

4.5.3 Participation in island operation

[44] Power-generating facilities must be capable of taking part in island operation if the frequency limits are the general frequency limits and the voltage limits are the general voltage limits.

The power-generating facility must be able to operate in FSM during island operation.
In the event of a power surplus, the power-generating facility must be capable of reducing the active power output from a previous operating point to any new operating point within the P-Q capability diagram. In that regard, the power-generating facility must be capable of reducing active power output as much as inherently technically feasible, but to at least 55% of its maximum capacity.

The method for detecting a change from interconnected system operation to island operation is agreed between the facility owner and Energinet.

Energinet's control centre changes the operational state to "alert state" for island operation.

Detection is based on PMU data with island operation detection module.

The power-generating facility must be able to operate in LFSM-O and LFSM-U during island operation.

4.5.4 Quick re-synchronisation

[45] In case of disconnection of the power-generating facility from the grid, the power-generating facility must be capable of quick re-synchronisation in line with the protection strategy agreed with Energinet.

A power-generating facility with a minimum re-synchronisation time greater than 15 minutes after its disconnection from any external power supply must be designed to switch to island operation from any operating point in its P-Q-capability diagram. In this case, the identification of house-load operation must not be based solely on the system operator's switchgear position signals.

[44] Point (b) of Article 15(5)
[45] Point (c) of Article 15(5)

A power-generating facility must be capable of continuing operation following a switch to island operation, irrespective of any auxiliary connection to the external grid. The minimum operating time is:

- SPG: 0 min.
- PPM: 0 min. because the re-synchronisation time is < 15 minutes.

4.6 Voltage quality

Voltage quality requirements are specified in Technical regulation 3.2.7, which can be found here.

5. Connection process[46]

To connect a facility, it is necessary to undergo a grid connection process. The overall steps are illustrated in the figure below and described further down.

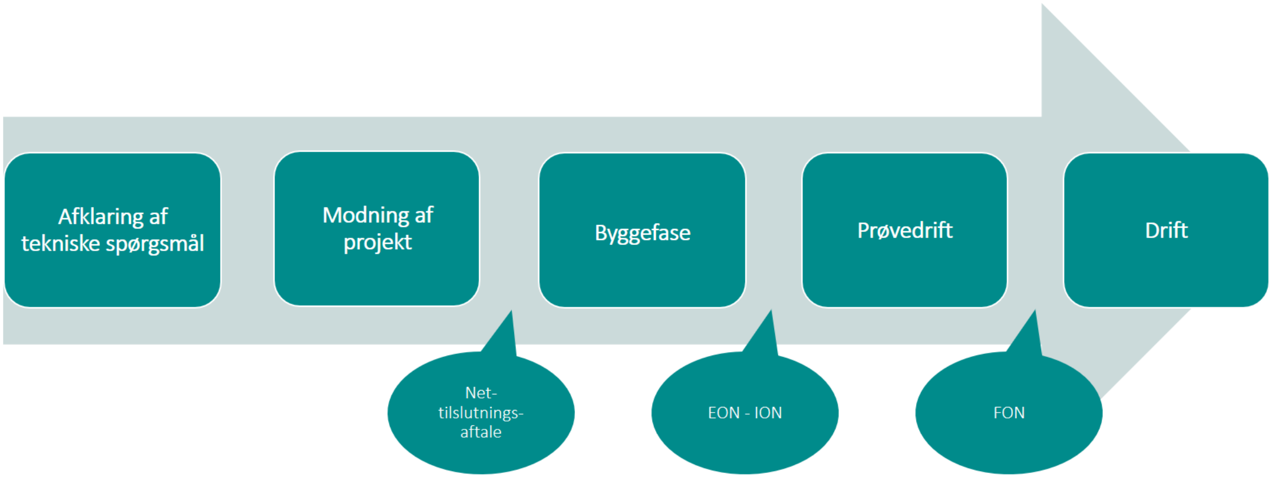

Figure 22 Grid connection process.

Translations:
Afklaring af tekniske spørgsmål: Clarification of technical issues
Modning af projekt: Project maturation
Byggefase: Construction phase
Prøvedrift: Trial/test operation
Drift: Operation
Nettilslutningsaftale: Grid connection agreement

If the intention is to connect a larger facility, the local grid company is first contacted for clarification as to whether the point of connection will be located in the distribution grid or the transmission grid. If the facility is expected to be connected to the transmission grid, the grid connection process will begin as described below and on Energinet's website. The following section briefly describes the information and documents Energinet expect to receive from facility owner as part of the connection process.

5.1 Clarification of technical issues

The facility owner contacts Energinet for answers to any general technical questions. Among other things, the following data must be used:

a) Documentation clarifying the point of connection
b) Facility owner and contact persons' name, address, telephone number and e-mail address
c) Description of the facility
d) Type of facility
e) The expected maximum output of the facility (rated power)
f) Geographical location, possibly GIS coordinates (if known)
g) Proposed concept for the technical solution
h) Expected start and end time for construction and connection of the facility
i) Clarification, if necessary, regarding nominal voltage

46 Article 41

Initial clarifications completed within 20 working hours, with Energinet providing advice on understanding requirements and preparing the agreement, are organised by Energinet.

If Energinet needs to prepare calculations/analyses in order to answer, Energinet will set up a project.

The facility owner pays for the hours spent by Energinet on calculations/analyses.

In this connection, the facility owner may be asked for a number of technical inputs to allow models to be created.

Typical elements clarified by Energinet include:

a) Expected technical requirements (reference to rules)
b) Initial concept for the technical solution
c) Expected overall time schedule for connection
d) Early identification of fundamental issues (if relevant).

The facility owner provides the necessary guarantee.

If the connection requires changes to the grid, Energinet will set up a project and obtain approval for the basis of this project.

5.2 Project maturation

The facility owner and Energinet enter into an agreement on project maturation (preparation for the construction phase), which contains a time schedule for the project and builds on the knowledge gained during the technical clarifications.

Energinet performs the necessary calculations and analyses, defining several possible solution. These will undergo technical review, so that an economic analysis of these options forms the basis for the final choice of solution.

The facility owner and Energinet enter into a grid connection agreement (covering the period from the construction phase until the actual grid connection), which contains, among other things, terms and conditions for the construction of a connection substation, installation of the point of connection, and an interconnection agreement.

The grid connection agreement is prepared on the basis of a standard template. There is a standard appendix describing the grid connection terms and conditions of power-generating facilities.

Energinet adds the facility to the master data register. The facility is given a GSRN number.

The facility owner submits documentation of an agreement with a balance-responsible party.

5.3 Construction phase

When the final choice regarding the technical solution has been made and a grid connection agreement has been concluded, the construction phase begins.

The facility owner builds its facility, and Energinet makes any necessary changes to the grid at the same time.

5.4 Energisation operational notification[47] (EON)

The energisation operational notification allows the facility owner to energise the facility's internal grid and auxiliary supplies

The energisation operational notification is issued by Energinet after the conclusion of a grid connection agreement.

In order to obtain an energisation operational notification, the facility owner must obtain documentation on the following topics:

- Master data
- Interconnection agreement
- Voltage quality/emission of harmonic distortions
- Reactive power draw
- Settlement.

5.5 Interim operational notification[48] (ION)

The interim operational notification allows the facility owner to operate the power-generating facility and generate power by using the grid connection for a limited period of up to 24 months.

The interim operational notification is issued by Energinet on the basis of the data provided and investigations carried out.

The facility owner is expected to provide documentation as described in the ION explanatory document. The framework for compliance simulations to be carried out in order to obtain an interim operational notification are described in detail in section 6.3.

5.6 Final operational notification[49] (FON)

The final operational notification allows the facility owner to operate the power-generating facility and generate power by using the grid connection.

The final operational notification will be issued by Energinet when all problem areas have been eliminated, and models and assumptions from the interim operational notification have been tested.

The framework for compliance tests to be carried out in order to obtain a final operational notification are described in detail in section 6.4.

If compliance tests or simulations cannot be carried out as agreed between Energinet and the facility owner for reasons attributable to Energinet, Energinet must not withhold the operational notification.

[47] The Danish term used in the Regulation is "idriftsættelsestilladelse" and not "spændingssætningstilladelse", which is the term used in the Danish original of this document

[48] The Danish term used in the Regulation is "midlertidig nettilslutningstilladelse" and not "midlertidig driftstilladelse", which is the term used in the Danish original of this document

[49] The Danish term used in the Regulation is "endelig nettilslutningstilladelse" and not "endelig driftstilladelse", which is the term used in the Danish original of this document

5.7 Limited operational notification[50] (LON)

Limited operational notification may be necessary in connection with changes to the facility and in fault conditions.

5.7.1 Changes to the facility

Facility owners who have been granted a final operational notification must notify Energinet of any planned change to the technical capabilities of the power-generating facility that may affect compliance with the requirements of the Regulation before the change is made[51]. The facility owner must notify Energinet of the planned test schedules and procedures to be followed for verifying the compliance of a power-generating facility with the requirements, in due time and prior to their launch. Compliance simulations to be carried out in order to obtain a limited operational notification are described in detail in section 6.3. At the same time, the facility owner applies to Energinet for a limited operational notification. Energinet approves in advance the planned test schedules and procedures.

A limited operational notification is issued by Energinet and includes the following information which must be clearly identifiable:

a) the reason for a limited operational notification,
b) responsibilities and the time limits for testing and verification, and
c) the maximum period of validity which must not exceed 12 months. The initial period granted may be shorter with the possibility of an extension if satisfactory evidence is submitted to Energinet demonstrating that substantial progress has been made towards achieving full compliance.

If the significant changes give rise to new functionalities or capacities, a new final operational notification (FON) must be applied for.

5.7.2 Faults in facilities

Facility owners who have been granted a final operational notification must immediately notify Energinet if the following applies:

a) the facility is temporarily subject to loss of capability affecting its performance, or
b) equipment failure leading to non-compliance with some relevant requirements.

The facility owner applies to Energinet for a limited operational notification if the facility owner reasonably expects the duration to exceed three months.

A limited operational notification is issued by Energinet and includes the following information which must be clearly identifiable:

a) the unresolved issues justifying the granting of the limited operational notification,
b) responsibilities and timescales for the expected solution, and
c) the maximum period of validity which must not exceed 12 months. The initial period granted may be shorter with the possibility of an extension if satisfactory evidence is submitted to Energinet demonstrating that substantial progress has been made towards achieving full compliance.

5.7.3 General information about the limited operational notification

The final operational notification will be suspended for the period of validity of the limited operational notification. This applies only to the items for which the limited operational notification has been issued.

[50] The Danish term used in the Regulation is "begrænset nettilslutningstilladelse" and not "begrænset driftstilladelse", which is the term used in the Danish original of this document

[51] Article 40(2)

A further extension of the period of validity of the limited operational notification beyond the 12 month period above may be granted upon a request for a derogation made to Energinet before the expiry of that period. Energinet will process this request in accordance with the rules on derogation applications (see section 7 Derogations).

Energinet has the right to refuse to allow the operation of the power-generating facility, once the limited operational notification is no longer valid.

If Energinet does not grant an extension of the period of validity of the limited operational notification in accordance with the derogation procedure or if it refuses to allow the operation of the power-generating facility once the limited operational notification is no longer valid, the facility owner may refer the issue for decision to the Danish Utility Regulator within six months after the notification of the decision of Energinet. .

6. Simulation and testing

6.1 Responsibility of the facility owner

The facility owner must ensure that each power-generating facility complies with the requirements under the Regulation throughout the lifetime of the facility.

The facility owner notifies Energinet of any planned modification of the technical capabilities of a power-generating facility before initiating that modification.

The facility owner must notify Energinet of any operational incidents or failures of a power-generating facility that affect its compliance with the requirements of this Regulation, without undue delay, after the occurrence of those incidents.

The facility owner must notify Energinet of the planned test schedules and procedures to be followed for verifying the compliance of a power-generating facility with the requirements of this Regulation, in due time and prior to their launch. Energinet must approve in advance the planned test schedules and procedures. Such approval by Energinet must be provided in a timely manner and must not be unreasonably withheld.

Energinet may participate in such tests and record the performance of the power-generating facilities.

6.2 Tasks of Energinet

Energinet assesses the compliance of a power-generating facility with the requirements applicable under this Regulation, throughout the lifetime of the power-generating facility. The facility owner must be informed of the outcome of Energinet's assessment.

Energinet has the right to request that the facility owner carry out tests and simulations according to a repeat plan or general scheme or after any failure, modification, or replacement of any equipment that may have an impact on the power-generating facility's compliance with the requirements of this Regulation.

Energinet will inform the facility owner of the outcome of those tests and simulations.

6.3 Common provisions for simulation[52]

Simulation of the performance of the power-generating facility aims at demonstrating that the requirements of the Regulation have been fulfilled and is necessary in order to obtain an interim operational notification (ION).

To demonstrate compliance with the requirements of this Regulation, the facility owner must provide a report with the simulation results for each individual power-generating facility within the power-generating facility. The facility owner must produce and provide a validated simulation model for a given power-generating facility. The structure of the simulation models is described in appendix 1.B[53] to the requirements.

In order to obtain an interim operational notification, the facility owner must obtain documentation on the following topics:

- Master data
- Active power control properties
- Reactive power control properties

[52] Article 43

[53] Article 51-56

- Robustness against voltage and frequency distortions
- Voltage quality
- Simulation models
- Test plan

A more detailed description of this documentation can be found in the ION explanatory document.

If the facility owner so wishes, Energinet may allow the facility owner to carry out an alternative set of simulations, provided that those simulations are efficient and suffice to demonstrate that a power-generating facility complies with the requirements of this Regulation.

If the facility owner's simulations do not suffice to demonstrate compliance with the requirements of the Regulation, Energinet may require the facility owner to perform additional or alternative simulations.

Energinet has the right to check that a power-generating facility complies with the requirements of this Regulation by carrying out its own simulations based on the provided simulation reports, simulation models, and test measurements.

Energinet provides the facility owner with technical information and a grid simulation model where these are necessary to perform the simulations.

6.4 Common provisions on testing[54]

Testing of the performance the power-generating facility aims at demonstrating that the requirements of the Regulation have been complied with and is necessary in order to obtain a final operational notification (FON).

Energinet in entitled to:

a) allow the facility owner to carry out an alternative set of tests, provided that those tests are efficient and suffice to demonstrate that a power-generating facility complies with the requirements of this Regulation,
b) require the facility owner to carry out additional or alternative sets of tests in those cases where the information supplied to Energinet in relation to testing is not sufficient to demonstrate compliance with the requirements of this Regulation, and
c) require the facility owner to carry out appropriate tests in order to demonstrate a power-generating facility's performance when operating on alternative fuels or fuel mixes. Energinet and the facility owner must agree on which types of fuel are to be tested.

The above a-c do not affect the minimum requirements for testing.

Energinet is working on a detailed list of the information and documents that facility owners must provide in order to obtain a final operational notification (FON), which will be similar to the ION explanatory document.

The facility owner is responsible for carrying out the tests in accordance with the conditions below. Energinet must cooperate with the facility owner and not unduly delay the performance of the tests.

Energinet may participate in the compliance testing either on site or remotely from the system operator's control centre. For that purpose, the facility owner must provide the monitoring equipment necessary to record all relevant test signals and measurements as well as ensure that the necessary representatives of the facility owner are available on site for the

[54] Article 42

entire testing period. If Energinet wishes to use its own equipment to record performance, relevant signals will be made available by the facility owner. Energinet have discretion to decide about their participation.

6.5 Testing for synchronous power-generating facilities[55]

Facility owners carry out tests in order to document compliance.

Instead of carrying out the relevant test, facility owners may rely upon equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In such a case, the equipment certificates must be provided to the relevant system operator.

LFSM-O:

a) the power-generating facility's technical capability to continuously modulate active power to contribute to frequency control in case of any large increase of frequency in the system must be demonstrated. The steady-state parameters of regulations, such as droop and deadband, and dynamic parameters, including frequency step change response, must be verified
b) the test must be carried out by simulating frequency steps and ramps big enough to trigger at least 10% of maximum capacity change in active power, taking into account the droop settings and the deadband. If required, simulated frequency deviation signals must be injected simultaneously at both the speed governor and load controller of the control systems, taking into account the scheme of those control systems
c) the test is deemed successful if the following conditions are fulfilled:
    i. the test results, for both dynamic and static parameters, meet the requirements set out in Article 13(2)
    ii. undamped oscillations do not occur after the step change response.

LFSM-U:

a. the power-generating facility's technical capability to continuously modulate active power at operating points below maximum capacity to contribute to frequency control in case of a large frequency drop in the system must be demonstrated
b. the test is carried out by simulating appropriate active power load points, with low frequency steps and ramps big enough to trigger active power change of at least 10% of maximum capacity, taking into account the droop settings and the deadband. If required, simulated frequency deviation signals are injected simultaneously into both the speed governor and the load controller references
c. the test is deemed successful if the following conditions are fulfilled:
    i. the test results, for both dynamic and static parameters, comply with point (c) of Article 15(2), and
    ii. undamped oscillations do not occur after the step change response.

Frequency sensitive mode:

a) the power-generating facility's technical capability to continuously modulate active power over the full operating range between maximum capacity and minimum regulating level to contribute to frequency control must be demonstrated. The steady-state parameters of regulations, such as droop and deadband and dynamic parameters, including robustness through frequency step change response and large, fast frequency deviations, must be verified
b) the test must be carried out by simulating frequency steps and ramps big enough to trigger the whole active power frequency response range, taking into account the settings of droop and deadband, as well as the capa-

[55] Article 44-46

bility to actually increase or decrease active power output from the respective operating point. If required, simulated frequency deviation signals must be injected simultaneously into the references of both the speed governor and the load controller of the unit or facility control system

c) the test is deemed successful if the following conditions are fulfilled:
    i. the activation time of full active power frequency response range as a result of a frequency step change is no longer than required by point (d) of Article 15(2)
    ii. undamped oscillations do not occur after the step change response
    iii. the initial delay time complies with point (d) of Article 15(2)
    iv. the droop settings are available within the range specified in point (d) of Article 15(2) and the deadband (threshold) is not higher than the value specified in that Article, and
    v. the insensitivity of active power frequency response at any relevant operating point does not exceed the requirements set out in point (d) of Article 15(2).

Frequency restoration control:

a) the power-generating facility's technical capability to participate in frequency restoration control must be demonstrated and the cooperation of FSM and frequency restoration control must be checked
b) the test is deemed successful if the results, for both dynamic and static parameters, comply with the requirements of point (e) of Article 15(2).

Black start capability:

a) for power-generating facilities with black start capability, this technical capability to start from shut down without any external electrical energy supply must be demonstrated
b) the test is deemed successful if the start-up time is kept within the time frame set out in point (iii) of Article 15(5)(a).

Island operation:

a) the power-generating facility's technical capability to switch to and stably operate in island operation mode must be demonstrated
b) the test must be carried out at the maximum capacity and nominal reactive power of the power-generating facility before load shedding
c) the relevant system operator has the right to set additional conditions, taking into account point (c) of Article 15(5)
d) the test is deemed successful if switching to island operation mode is successful, stable island operation has been demonstrated in the time period set out in point (c) of Article 15(5) and re-synchronisation to the grid has been performed successfully.

Reactive power capability:

a) the power-generating facility's technical capability to provide leading and lagging reactive power capability in accordance with points (b) and (c) of Article 18(2) must be demonstrated
b) the test is deemed successful if the following conditions are fulfilled:
    i. the power-generating facility operates at maximum reactive power for at least one hour, both leading and lagging, at:
        - minimum stable operating level
        - maximum capacity, and
        - an active power operating point between those maximum and minimum levels

ii. the power-generating facility's capability to change to any reactive power target value within the agreed or decided reactive power range must be demonstrated.

6.6 Testing for power park modules[56]

Facility owners carry out tests in order to document compliance.

Instead of the relevant test, the facility owner may use equipment certificates issued by an authorised certifier to demonstrate compliance with the relevant requirement. In that case, the equipment certificates must be provided to Energinet.

The Regulation sets out the following requirements for tests. Energinet is working on a detailed list of the information and documents that facility owners must provide in order to obtain a final operational notification (FON).

LFSM-O:
The LFSM-O mode testing must reflect the relevant system operator's choice of control scheme.

Limited LFSM-O mode:

a) the power park module's technical capability to continuously modulate active power to contribute to frequency control in case of increase of frequency in the system must be demonstrated. The steady-state parameters of regulations, such as droop and deadband, and dynamic parameters must be verified
b) the test must be carried out by simulating frequency steps and ramps big enough to trigger at least 10% of maximum capacity change in active power, taking into account the droop settings and the deadband. To perform this test simulated frequency deviation signals are injected simultaneously into the control system references
c) the test is deemed successful in the event that the test results, for both dynamic and static parameters, comply with the requirements set out in Article 13(2).

Active power controllability and control range:

a) the power park module's technical capability to operate at a load level below the setpoint set by the relevant system operator or the relevant TSO must be demonstrated
b) the test is deemed successful if the following conditions are fulfilled:
    i. the load level of the power park module is kept below the setpoint
    ii. the setpoint is implemented according to the requirements laid down in point (a) of Article 15(2), and
    iii. the accuracy of the regulation complies with the value specified in point (a) of Article 15(2).

LFSM-U:

a) the power park module's technical capability to continuously modulate active power to contribute to frequency control in case of a large frequency drop in the system must be demonstrated.
b) the test is carried out by simulating the frequency steps and ramps big enough to trigger at least 10% of maximum capacity active power change with a starting point of no more than 80% of maximum capacity, taking into account the droop settings and the deadband.
c) the test is deemed successful if the following conditions are fulfilled:
    i. the test results, for both dynamic and static parameters, comply with point (c) of Article 15(2), and
    ii. undamped oscillations do not occur after the step change response.

Frequency sensitive mode:

[56] Article 47-49

a) the power park module's technical capability to continuously modulate active power over the full operating range between maximum capacity and minimum regulating level to contribute to frequency control must be demonstrated. The steady-state parameters of regulations, such as insensitivity, droop, deadband, and range of regulation, as well as dynamic parameters, including frequency step change response, must be verified.
b) the test is carried out by simulating frequency steps and ramps big enough to trigger the whole active power frequency response range, taking into account the droop settings and the deadband. Simulated frequency deviation signals are injected to perform the test.
c) the test is deemed successful if the following conditions are fulfilled:
    i. the activation time of full active power frequency response range as a result of a frequency step change is no longer than required by point (d) of Article 15(2)
    ii. undamped oscillations do not occur after the step change response
    iii. the initial delay is in line with point (d) of Article 15(2)
    iv. the droop settings are available within the ranges specified in point (d) of Article 15(2) and the deadband (threshold) is not higher than the value chosen by the relevant TSO, and
    v. the insensitivity of active power frequency response does not exceed the requirement set out in point (d) of Article 15(2).

Frequency restoration control:
a) the power park module's technical capability to participate in frequency restoration control must be demonstrated. The cooperation of both FSM and frequency restoration control must be checked.
b) the test is deemed successful if the results, for both dynamic and static parameters, comply with the requirements of point (e) of Article 15(2).

Reactive power capability - A:
a) the power park module's technical capability to provide leading and lagging reactive power capability in accordance with points (b) and (c) of Article 21(3) must be demonstrated.
b) the test is carried out at maximum reactive power, both leading and lagging, and verifies the following parameters:
    i. operation in excess of 60% of maximum capacity for 30 minutes
    ii. operation within the range of 30-50% of maximum capacity for 30 minutes, and
    iii. operation within the range of 10-20% of maximum capacity for 60 minutes.
c) the test is deemed successful if the following conditions are fulfilled:
    i. the power park module operates for a duration no shorter than the requested duration at maximum reactive power, both leading and lagging, in each parameter specified in paragraph 6(b)
    ii. the power park module's capability to change to any reactive power target value within the agreed or decided reactive power range is demonstrated, and
    iii. no protection action takes place within the operation limits specified by the reactive power capacity diagram.

Voltage control mode:
a) the power park module's capability to operate in voltage control mode referred to in the conditions set out in points (ii) to (iv) of Article 21(3)(d) must be demonstrated
b) the voltage control mode test must verify the following parameters:
    i. the implemented slope and deadband according to point (iii) of Article 21(3)(d)
    ii. the accuracy of the regulation
    iii. the insensitivity of the regulation, and

    iv. the time of reactive power activation.

c) the test is deemed successful if the following conditions are fulfilled:
    i. the range of regulation and adjustable droop and deadband complies with the agreed or decided characteristic parameters set out in point (d) of Article 21(3)
    ii. the insensitivity of voltage control is not higher than 0.01 pu, in accordance with point (d) of Article 21(3), and
    iii. following a step change in voltage, 90% of the change in reactive power output has been achieved within the times and tolerances specified in point (d) of Article 21(3).

Reactive power control mode – B:

a) the power park module's capability to operate in reactive power control mode, in accordance with point (v) of Article 21(3)(d), must be demonstrated
b) the reactive power control mode test must be complementary to the reactive power capability test
c) the reactive power control mode test verifies the following parameters:
    i. the reactive power setpoint range and increment
    ii. the accuracy of the regulation, and
    iii. the time of reactive power activation
d) the test is deemed successful if the following conditions are fulfilled:
    i. the reactive power setpoint range and increment are ensured in accordance with point (d) of Article 21(3), and
    ii. the accuracy of the regulation complies with the conditions set out in point (d) of Article 21(3).

Power factor control mode – C:

a) the power park module's capability to operate in power factor control mode in accordance with point (vi) of Article 21(3)(d) must be demonstrated
b) the power factor control mode test verifies the following parameters:
    i. the power factor setpoint range
    ii. the accuracy of the regulation, and
    iii. the response of reactive power due to step change of active power
c) the test is deemed successful if the following conditions are cumulatively fulfilled:
    i. the power factor setpoint range and increment are ensured in accordance with point (d) of Article 21(3)
    ii. the time of reactive power activation as a result of step active power change does not exceed the requirement laid down in point (d) of Article 21(3), and
    iii. the accuracy of the regulation complies with the value specified in point (d) of Article 21(3).

With regard to tests for reactive power exchange, it is possible to choose between: A, B, and C.

7. Derogations

Article 60 of the Regulation provides for derogations from the requirements of the Regulation. The Danish Utility Regulator may grant derogations from one or more of the provisions of the Regulation for both new and existing power-generating facilities following an application. When the facility is connected to the transmission system, the application must follow the process in the diagram below.

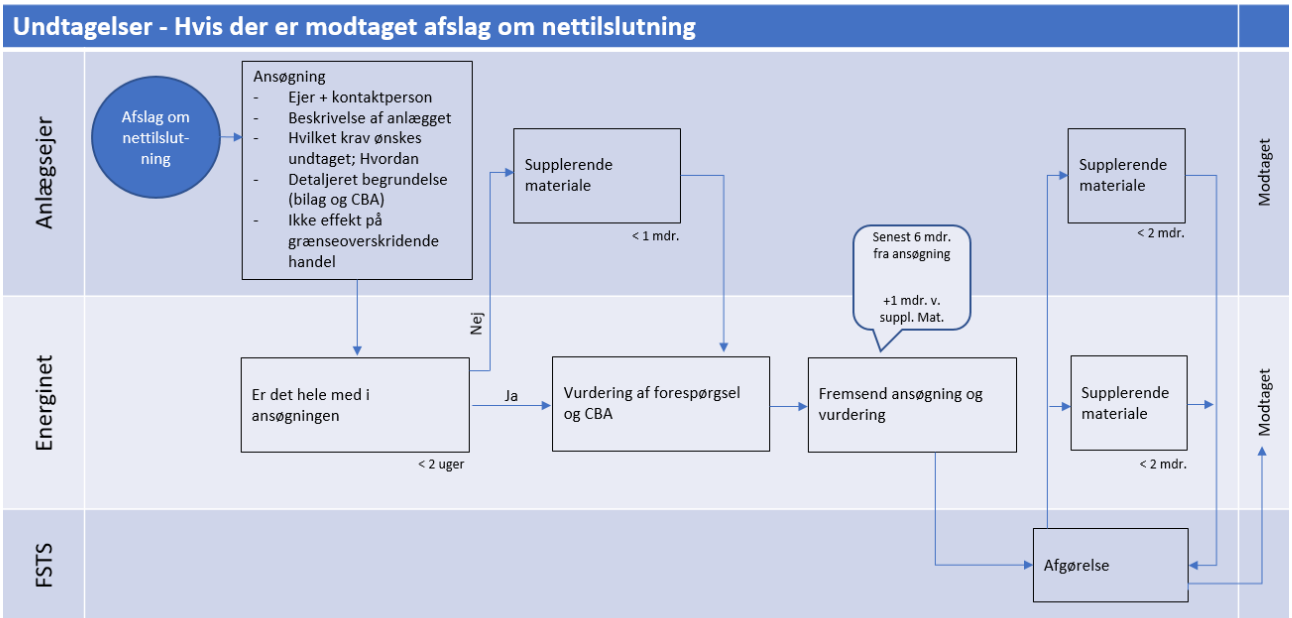

Figure 23 Derogation application process.

Translations:

Undtagelser – Hvis der er modtaget afslag om nettilslutning: Derogations – If grid connection has been refused

FSTS: Danish Utility Regulator (DUR)

Anlægsejer: Facility owner

Afslag om nettilslutning: Refusal of grid connection

Ansøgning: Application

- Ejer + kontaktperson: Owner + contact person
- Beskrivelse af anlægget: Description of facility
- Hvilket krav ønskes undtaget og hvordan: Derogation requested from which requirement(s) and how
- Detaljeret begrundelse (bilag og CBA). Detailed description (appendices and CBA)
- Ikke effekt på grænseoverskridende handel: Does not impact cross-border trade

Er det hele med i ansøgningen: Is everything included in the application

< 2 uger: < 2 weeks

Ja: Yes

Nej: No

< 1 mdr.: < 1 month

Supplerende materiale: Additional information

Vurdering af forespørgsel og CBA: Evaluation of application and CBA

Senest 6 mdr. fra ansøgning +1 mdr. V. suppl. Mat.: No later than 6 months after application +1 month in case of additional information

Fremsend ansøgning og vurdering: Submit application and evaluation

< 2 mdr.: < 2 months

Afgørelse: Decision
Modtaget: received

A facility owner may request a derogation from one or more of the requirements for its power-generating facility.

The derogation request must be submitted to Energinet and must contain:

a) an identification of the facility owner, or prospective owner, and a contact person for any communications
b) A description of the power-generating facility or modules for which a derogation is requested
c) A reference to the provisions of this Regulation from which a derogation is requested and a detailed description of the requested derogation
d) Detailed reasoning, with relevant supporting documents and cost-benefit analysis pursuant to the requirements of Article 39
e) Demonstration that the requested derogation would have no adverse effect on cross-border trade.

After Energinet has carried out an assessment, the application and assessment are sent to the Danish Utility Regulator for their decision.

In one of the following situations in which the requirements can no longer be met, a facility owner may be granted a limited operational notification from Energinet:

- The facility is temporarily subject to significant modification.
- The facility is temporarily subject to loss of capability.
- Parts of the equipment fail.

See section 5.7.

Register of derogations
The Danish Utility Regulator must maintain a register of all derogations it has granted or refused and must provide an updated and consolidated register to the Agency for the Cooperation of Energy Regulators (ACER) at least once every six months, with a copy to ENTSO-E.

The register must contain, in particular:

a) the requirement or requirements for which derogation is granted or refused
b) the content of the derogation
c) the reasons for granting or refusing the derogation
d) the consequences resulting from granting the derogation.

Monitoring of derogations
The Agency monitors the derogation procedure, and the Danish Utility Regulator ensures that the Agency receives all the necessary information.

The Agency and the Commission may issue a reasoned recommendation to a regulatory authority to revoke derogation due to a lack of justification.

8. List of appendices

1. EXPLANATORY DOCUMENT ON INTERIM OPERATIONAL NOTIFICATION (ION)

Energinet
Tonne Kjærsvej 65
DK-7000 Fredericia

+45 70 10 22 44
info@energinet.dk
CVR no. 39 31 49 59

Author: AIE
Date: 10 August 2020