REPORT TO THE CREG

COST-BENEFIT ANALYSIS ON REQUIREMENTS FOR GENERATORS APPLICABLE ON EXISTING AND NEW GENERATING UNITS BETWEEN 1 AND 25 MW

DECISION (B)658E/79 OF 14 JULY 2022

Final report

(after public consultation)

19/12/2023

1. Introduction

1.1 Description of the incentive

The objective of this incentive is to perform a cost-benefit analysis (CBA) of the application of one or more requirements currently applicable only to new type B power generating modules (hereinafter referred to as PGMs) to PGMs that are considered as existing, have an installed capacity between 1 and 25 MW (not included) and are connected to the Elia grid. The requirements to be assessed are those applicable to new type B PGMs (PPMs and SPGMs). They are listed in the document "Requirements of General Application of the RfG" (hereinafter referred to as GR RfG), as per Article 7(4) of the European Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators (hereinafter referred to as NC RfG).

The cost-benefit analysis will evaluate, for a given set of requirements applicable to new type B PGMs:

- the benefits for the transmission system of applying one or more of these requirements to existing PGMs with a capacity between 1 and 25 MW connected to the transmission system;
- the costs associated with the application of these requirements to be borne by the owners of these existing PGMs.

1.2 Context and justification

A number of network codes have been created (NC RfG, NC DCC, NC HVDC) following the adoption of the Third Energy Package. These codes are intended to both foster a level playing field between EU Member States and ensure the enhanced robustness of electricity networks by defining criteria for connecting to these networks taking into account the evolving energy landscape.

The NC RfG defines the requirements for connecting new PGMs.

At Belgian federal level, these requirements are set out in the Royal Decree of 22 April 2019 establishing a grid code for the management of and access to the electricity transmission system (Part 3, Book 1, Title 4, Chapters 3 & 6).

At Belgian regional level, the document "Requirements of General Application of the NC RfG" details the requirements applicable to new PGMs.

Although the requirements in the NC RfG apply to new PGMs, Article 4 of the NC RfG defines the framework for the application of these requirements to existing PGMs:

- Article 4.1 foresees the application of all or part of the requirements of the NC RfG to existing PGMs in the following cases:
    - Art. 4.1 a) in case of substantial modernisation for type C and D units.
    - Art. 4.1 b) when, following a proposal made by a TSO, the regulatory authority or a Member State decides to apply certain requirements set out in the NC RfG to an existing PGM after conducting a cost-benefit analysis.
- Article 4.3 allows a TSO to propose to the competent regulatory authority the application of all or part of the requirements of the NC RfG to a number of existing PGMs, also following a cost-benefit analysis.

Articles 4.3, 4.4, 38 and 39 of the NC RfG specify how a cost-benefit analysis should be conducted.

In the future, this cost-benefit analysis will serve as an objective basis for the regulator's decisions regarding:

- the application of Articles 4.1 b) and 4.3 of the NC RfG to existing PGMs with an installed capacity between 1 and 25 MW (not included);
- a possible extension of the current exemption from the principle of substantial modernisation to existing PGMs that have a maximum installed capacity below 25 MW and a voltage at the point of connection greater than or equal to 110 kV (which are by definition considered type D modules);
- the evaluation of the extension of the concept of substantial modernisation to units with an installed capacity between 1 and 25 MW.

1.3 Description of the work performed

This section describes the work performed in connection with this incentive and explains the structure of the report.

Elia began working on this incentive in early 2023.

The first phase involved making preparations. Elia compiled an inventory of the PGMs falling within the scope of this incentive (see Chapter 2 for more details), proposed a methodology for a qualitative cost-benefit analysis and submitted the results of this assessment to the market parties in a first report.
The results of this phase were presented to the market parties during the Users' Group Belgian Grid meeting on 17 May 2023.

Following this presentation, Elia held a meeting for stakeholders to give their feedback on the first phase of the incentive and put forward ideas on how to proceed. This meeting took place on 3 July 2023. A summary of the feedback from the market parties can be found in Appendix 2.

The third phase of the incentive encompassed the collection of data from the market parties concerning the costs associated with the application of the requirements under the RfG to existing PGMs with an installed capacity between 1 and 25 MW. The market parties were given a questionnaire, which they filled in with their input between 21 August and 22 September 2023. Elia subsequently reworked the cost-benefit analysis and proposed a "quantitative +" CBA. The methodology and results of this CBA are set out in Chapter 4.

Elia's conclusions regarding this incentive can be found in Chapter 6. This report will be subject to a public consultation between 6 November and 2 December 2023.

2. Inventory of type B PGMs

This section quantifies the amount of existing and new PGMs. This information is key to being able to quantify the potential benefits for the system of applying these requirements.

2.1 Definition of the criteria

The RfG entered into force on 26 May 2016. According to Article 4 of the RfG, a PGM shall be considered as existing if it was already connected to the network on the date of the entry into force of the RfG (or if the PGM owner had concluded a final and binding contract for the purchase of the main generating plant within two years of the entry into force of the RfG).

Article 35 of the Federal Grid Code defines the difference between existing PGMs and new PGMs.

At regional level, a range of decisions determine what is considered an existing PGM and what is a new PGM.[1]

However, for this study we applied a different definition of existing and new PGMs.

Although the RfG provides a legal framework for the requirements, according to Art. 7 it is the TSOs that define the requirements of general application.

At federal level, the requirements are included in the Federal Grid Code (Part 3, Book 1, Title 4, Chapters 3 & 6), which was published on 27 April 2019.

At regional level, the regional regulators approved the Requirements of General Application of the RfG in September and November 2019 for application two months later.[2]

The content of the requirements is the same at both levels.

Given that the new requirements were officially published on 27 April 2019 via the Federal Grid Code, Elia continued to communicate the old requirements to grid users until that date.

As such, we used 27 April 2019 as a key date for determining whether a PGM could be categorised as an existing or a new PGM. The PGMs for which the detailed study had been delivered before 27 April 2019 are considered existing PGMs, while any PGMs with a detailed study delivered was delivered after this date are considered new PGMs.

2.2 Results

The amount of type B PGMs considered as existing and connected to the Elia network is equal to 112 (numbers from early February 2023). There are also 24 new type B PGMs which are already connected (13) or which will probably be connected to the Elia network considering that they are either under construction (4) or in an engineering/permitting phase (7).

[1] VREG: Beslissing 2019-06; CWaPE: CD-18j25-CWaPE-0233; Brugel: Décision 20190424-91

[2] BESL-2019-39 (VREG), CD-19h28-CWaPE-0347 (CWaPE), DECISION-20190904-117 (Brugel)

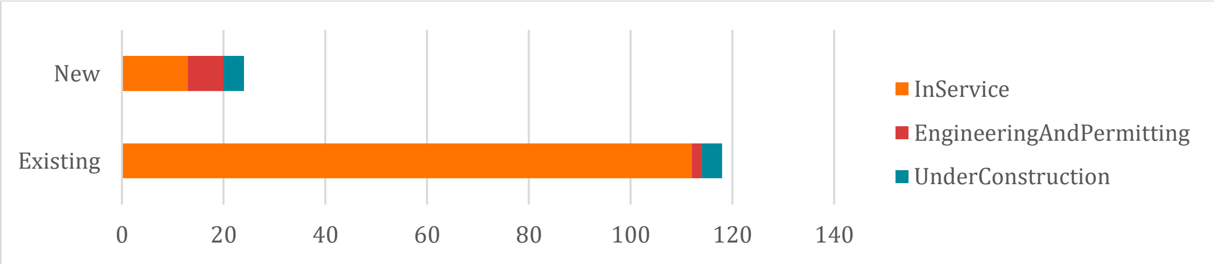


Figure 1 Amount of new and existing PGMs connected to the Elia network

If we consider the power repartition, we can see at the Figure 2 that 86,5% of the installed power for type B PGMs are existing PGMs.

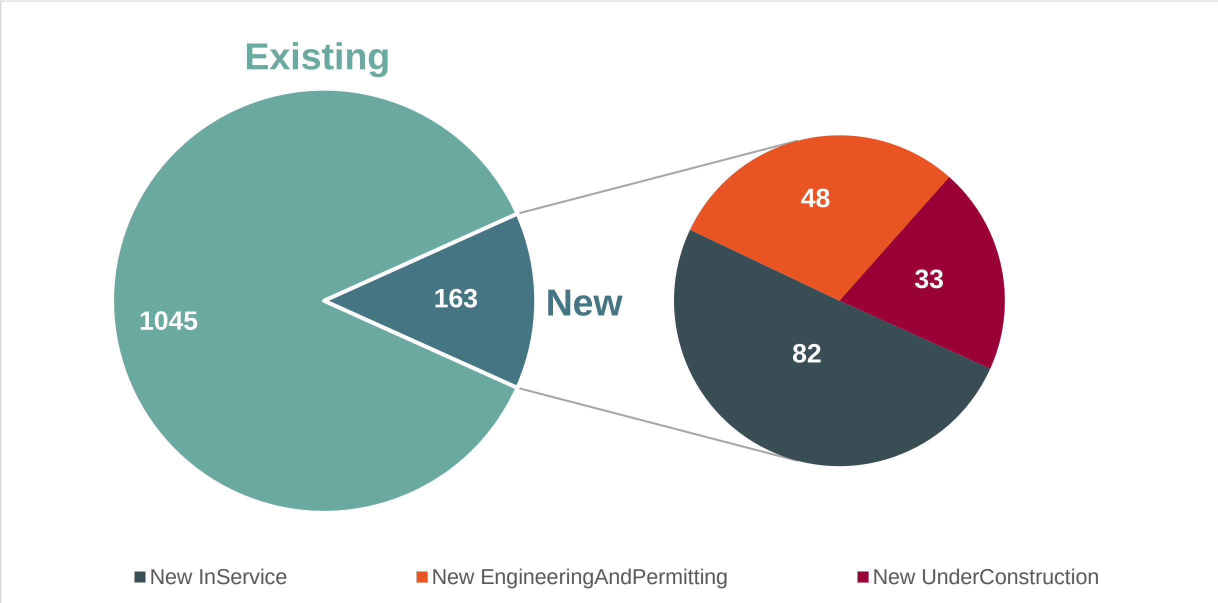


Figure 2 Repartition in power [MW] of the existing and new PGMs

The 1045 MW of existing type B PGMs are made of different technologies as described in Table 1 and Figure 3. One can see that the three most important technologies of type B existing PGMs are Cogeneration units, Wind Turbines and Incineration Stations.

Table 1 Distribution of existing type B PGMs per production type

PRODUCTION TYPE	INSTALLED POWER (MW)
Classical (Steam Turbine)	53,4
Diesel	45,6
Hydro Unit - Run Of River	21,8
Incineration Station	164,318
Solar	59,63
STEG - Steam Turbine	20
Turbojet	108
Wind Onshore	216,6
WKK	355,783
TOTAL	**1045,131**

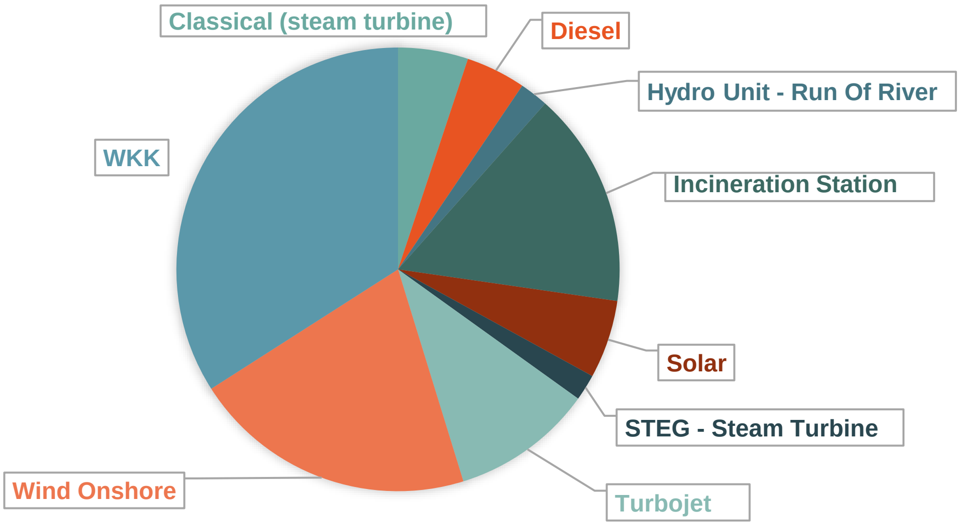


Figure 3 Distribution (in power) of per technology of the type B PGMs

More generally, existing type B PGMs are mainly Synchronous Power-Generating Modules (SPGMs) where new type B PGMs are mainly Power Park Modules (PPMs).

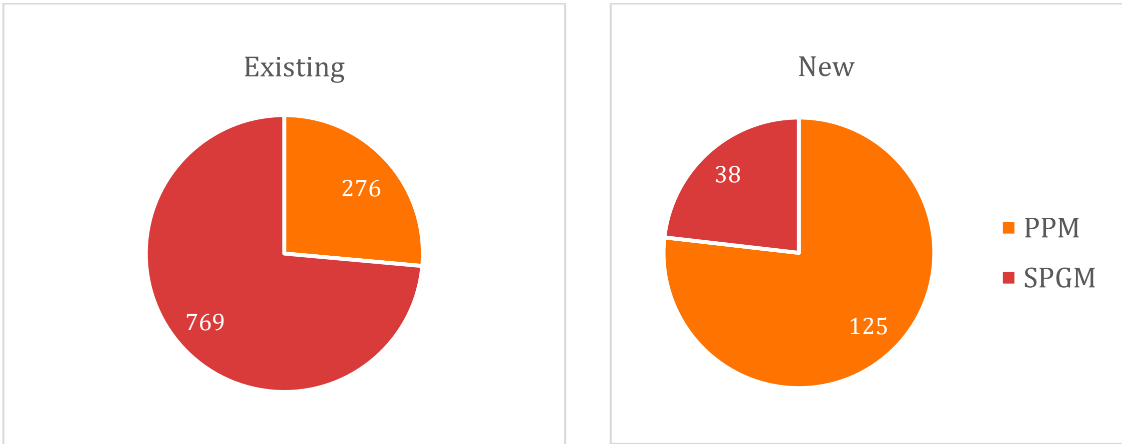


Figure 4 Distribution (in MW) of PPMs and SPGMs for existing and new PGMs

It is also interesting to know which proportion of the existing PGMs between 1 and 25 MW are connected to the transport grid (Federal competence) and to the local transport grid (Regional competence). This information is given in the table below. During the workshop on 3 July, the market parties mentioned the need to also put those numbers in comparison with the amount of PGMs between 1 and 25 MW connected to the DSO grid.

Authority	Percentage of PGMs (in Installed Power)
Federal level	21%
Regional level	79%

Proportion (in installed power [MW]) of the PGMs between 1 and 25 MW connected to the Federal and Regional level

During the workshop, the market parties also raised the need to identify the age of the PGMs falling within the scope of this incentive. The Figure 5 shows that most of those PGMs were put in service between 2005 and 2020.

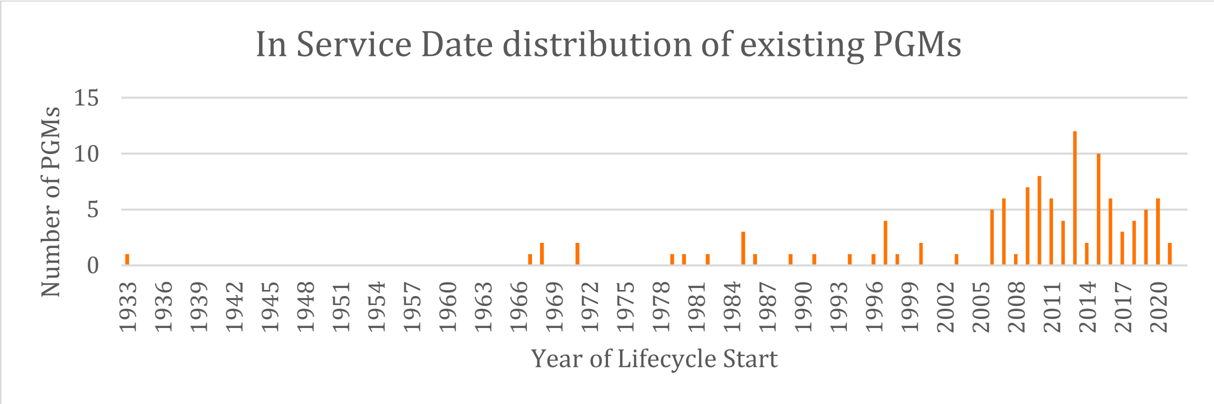


Figure 5 In Service Date distribution of the existing PGMs between 1 and 25 MW connected to the Elia network

3. Comparison of the requirements applicable to new and existing type B PGMs

3.1 Introduction

The requirements for PGMs type B are sorted in different categories:

Category 1: Data questionnaire and models

Category 2: Internal compliance proof (RGIE) , equipment capabilities & protection scheme agreement

Category 3: Voltage & Frequency requirements

Category 4: Information exchange / telecom requirements

Category 5: Balancing/Congestion management requirements

Category 6: Power Quality requirements

Category 7: Emergency & Restoration requirements

Category 8: Protections requirements

3.2 Category 1 : Data questionnaire and models

3.2.1 Data questionnaire

I) Requirement applicable to existing PGMs

According to Article 354 of the FGC the grid user should provide Elia with the required filled data questionnaire. The installation document (or data collection questionnaire) is provided by Elia and must be filled by the grid user. The information provided through this data questionnaire must be in accordance with the other relevant requirements listed further in this document.

II) Requirement applicable to new PGMs

According to article 30 of the NC RfG :

the power-generating facility owner shall ensure that the required information is filled in on an installation document obtained from the relevant system operator […].

This installation document (or data collection questionnaire) is provided by Elia and must be filled by the grid user. The information provided through this data questionnaire must be in accordance with the other relevant requirements listed further in this document.

III) Comparison

The data questionnaire requirement is similar for new and existing PGMs (or slightly more stringent for new PGMs).

3.2.2 Simulation models

I) Requirement applicable to existing PGMs

The PGM Owner had to submit a model including the functional block diagrams.

II) Requirement applicable to new PGMs

The PGM Owner shall submit the static and dynamic models of each PGM units-including transformers, cables or other relevant assets and control system and protection with an appropriate guidance note to ELIA. The documentation shall be submitted in DIgSILENT PowerFactory format and the documentation and data collection in the format defined in coordination with ELIA during connection process.

III) Comparison

The requirement is more severe for new PGMs than for existing ones. For existing PGMs, the grid users had to provide the functional block diagram. For the new PGMs, the model files must be submitted to Elia.

3.3 Category 2 : Internal compliance proof (RGIE), equipment's capabilities & protection scheme agreement

3.3.1 Internal compliance proof – RGIE

The existing and new PGM must be compliant with the RGIE. The requirement is as consequence considered as similar for new and existing PGMs.

3.3.2 Equipment Capabilities - Annex 1 - Icc max

The values set out in the tables in Annex 1 of the relevant grid code apply to facilities, regardless of their voltage level. All PGMs, load facilities or CDS connected to the transmission system must, at the voltage level of the interface point, comply with the values set out in the tables in Annex 1.
Installations at the first voltage level below the voltage level of the interface point shall be sized so that they do not limit the maximum permissible short-circuit power at the connection point, this maximum permissible short-circuit power at the connection point being the value given in Annex 1 respectively for this voltage level.

I) Requirement applicable to existing PGMs

This requirement is detailed in the appendix 1 A of the Federal or Regional Grid Code. This appendix summarizes the requirements regarding the short-circuit currents.

1A. Caractéristiques techniques d'une installation considérée comme existante existante conformément à l'article 35, §§ 7, alinéa 1er, 8 et 9

Niveau de tension (kV)	Um Equipement (kV)	LIWV Uw (kV)		Disjoncteurs	Autres équipements		
				Isc (kA)	I thermique		I dynamique (kA)
					Durée	(kA)	
380	420		1550 ou 1425 (*)	50 ou 63 (*)	>= 1 s	50	125
220	245		1050	40	>= 1 s	40	100
150	170		750	40 ou 50 (*)	>= 1 s	40	100
70	82.5	Hors Zone Liège	380	20	>= 1 s	20	50
		Zone Liège	380	31.5	>= 1 s	31.5	80
36	40.5		200 ou ≥ 170 (*)	31.5	>= 1.2 s	31.5	80
30	36		170	31.5	>= 1.2 s	31.5	80
26	30		145	25	>= 2 s (1)	25	63
15	17.5		95	20	>= 2 s (1)	20	50
11-12	17.5		95	25	>= 2 s (1)	25	63
10	12		75	25	>= 2 s (1)	25	63
6	7.2		60	25	>= 2 s (1)	25	63
					Duur	(kA)	

(*): suivant décision gestionnaire du réseau.

(1): correspondant au temps de déclenchement de la protection en réserve

II) Requirement applicable to new PGMs

This requirement is detailed in the appendix 1 B of the Federal or Regional Grid Code. This appendix summarizes the requirements regarding the short-circuit currents.

1B. Caractéristiques techniques d'une installation considérée comme nouvelle conformément à l'article 35, §§ 7, alinéa 1er, 8 et 9

Niveau de tension (kV)	Um Equipement (kV)	LIWV Uw (kV)	I dynamique (kA)	Disjoncteurs	Autres équipements travées haute tension		Liaison en câble souterrain / ligne aérienne	
				Isc (kA)	I thermique		I thermique (3φ et 1φ)	
					Durée	(kA)	Durée	(kA)
380	420	1425	160 ou 125 (*)	63 ou 50 (*)	>= 1 s	63 ou 50 (*)	0,6 s	50
220	245	1050	125 ou 100(*)	50 ou 40 (*)	>= 1 s	50 ou 40 (*)	0.6 s	40
150	170	750	125 ou 100 (*)	50 ou 40 (*)	>= 1 s	50 ou 40 (*)	0.6 s	40
110	123	550	100	40	>= 1 s	40	0.6 s	Cable: 40 Ligne: 40 ou 31,5 (*)
70	82.5	380	100 ou 80 ou 50 (*)	40 ou 31.5 ou 20 (*)	>= 1 s	40 ou 31.5 ou 20 (*)	0.6 s	Cable: 25 Ligne: 25 ou 20(*)
36	40.5 (42)	200 ou ≥ 170 (*)	100 ou 80(*)	40 ou 31.5 (*)	>= 1.2 s	40 ou 31.5 (*)	3φ: 1.2 s 1φ: 1,2 s	3φ: 31,5 1φ: 4
30	36	170	100 ou 80 (*)	40 ou 31.5 (*)	>= 1.2 s	40 ou 31.5 (*)		
26	30	145	80 ou 63 (*)	31.5 ou 25 (*)	>= 2 s (1)	31.5 ou 25 (*)		
15	17.5	95	63	25	>= 2 s (1)	25	3φ:2 s 1φ: 3,3 s	3φ: 25 1φ: 4
11-12	17.5	95	63	25	>= 2 s (1)	25		
10	12	75	63	25	>= 2 s (1)	25		
6	7.2	60	63	25	>= 2 s (1)	25		

(*): suivant la décision du gestionnaire du réseau

(1): correspondant au temps de déclenchement de la protection en réserve

III) Comparison

The requirements is more stringent for new installations. However, this requirement is part of Demand Connection Code. As consequence, we propose not to include this requirement in the eligible requirements for this incentive.

3.3.3 Equipment Capabilities - Annex 2 – Protections

The bays of the connection facilities are equipped with protections, in order to selectively eliminate a fault within an interval of time determined as the maximum allowable, including the time of operation of the protection, operation of the circuit breaker and extinction of the arc. The values to be respected are mentioned in Annexes 2 of the relevant grid codes.

I) Requirement applicable to existing PGMs

This requirement is detailed in the appendix 2 A of the Federal or Regional Grid Code:

2A. Temps maximal d'élimination d'un défaut par protections pour une installation considérée comme existante existante conformément à l'article 35, §§ 7, alinéa 1er, 8 et 9.

Niveau de tension (kV)	LIGNES, CABLES, TRANSFO * Base (ms)	Refus Protect (ms)	Refus Disj. (ms) déf. mono	Refus Disj. (ms) déf. poly	Réserve ligne/ câble suivant (ms)	Réserve jeux de barres suivants (ms) **** Déf. mono	déf. poly	Réenclenchement ligne (ms) mono.	Poly_ phasé	Défaut JEUX DE BARRES Base (ms)	Réserve du couplage (ms) déf. mono.	déf. poly
380	100	100	300	170	1000	500	250	1	10	100	250	170
220	120	120	-	-	1000	600	600	1	***	100	300	300
150	120	120	-	-	1000	600	600	1	***	100	300	300
70	120**	2250	-	-	1000	600	600	-	***	600	-	-
36	120	2250	-	-	1200	1200	1200	-	***	600	-	-
30	120	2250	-	-	1200	1200	1200	-	***	600	-	-
15	1100	3100	-	-	-	1800	1800	-	***	1800	-	-
12	1100	3100	-	-	-	1800	1800	-	***	1800	-	-
10	1100	3100	-	-	-	1800	1800	-	***	1800	-	-

* Transformateur: niveau de tension = tension nominale max. du transformateur

** Pour les lignes, cette valeur est d'application pour l'extrémité située le plus proche du défaut; pour l'autre extrémité, un temps d'élimination de 500 ms est autorisé.

*** A déterminer par le gestionnaire du réseau en fonction des paramètres de réglage des protections des installations avoisinantes

**** Aussi applicable pour défaut entre transformateur de courant et disjoncteur

Remarque: Tous les temps sont les valeurs maximales permises.

II) Requirement applicable to new PGMs

This requirement is detailed in the appendix 2 B of the Federal or Regional Grid Code:

2B. Temps maximal d'élimination d'un défaut par protections pour une installation nouvelle au sens de la législation applicable et de l'article 71, § 2.

Niveau de tension (kV)	LIGNES, CABLES, TRANSFO *									DEFAUT JEUX DE BARRE S		
	Base (ms)	Refus Protect (ms)	Refus Disj.(ms) *****	Refus Disj.(ms) *****	Réserve ligne/câble suivant (ms)	Réserve jeux de barres suivants (ms) ****		Réenclenchement ligne (s)		Base (ms)	Réserve du couplage (ms)	
			déf. mono	déf. poly		Déf. mono	déf. poly	mono.	Pol ypha sé		déf. mono.	déf. poly
380	100	100	300	250	1000	500	270	1	10; 16	100	170	170
220	120	120	300	300	1000	600	600	1	***	100	330	330
150	120	120	300	300	1000	600	600	1	***	100	330	330
110	120**	2250	300	300	1000	600	600	-	***	100	330	330
70	120**	2250	-	-	1000	600	600	-	***	600	-	-
30-36	120**	2250	-	-	1200	1200	1200	-	***	600	-	-
10-29,9kV	1100	3100	-	-	-	1800	1800	-	***	1800	-	-

* Transformateur: niveau de tension = tension nominale max. du transformateur

** Pour les lignes, cette valeur est d'application pour l'extrémité située le plus proche du défaut; pour l'autre extrémité, un temps d'élimination de 500 ms est autorisé.

*** A déterminer par le gestionnaire du réseau en fonction des paramètres de réglage des protections des installations avoisinantes

**** Aussi applicable pour défaut entre transformateur de courant et disjoncteur; ces valeurs sont valables pour les deux extrémités des lignes connectées au jeu de barre concerné

***** Seulement pour les disjoncteurs des barres haute tension raccordées aux jeux de barre

Remarque: Tous les temps sont les valeurs maximales permises.

III) Comparison

The requirements is rather equivalent for existing and new installations. However, this requirement is part of Demand Connection Code. As consequence, we propose not to include this requirement in the eligible requirements for this incentive.

3.3.4 Specific protections scheme agreement

In certain cases, the detailed study (EDS) or the minor change letter indicates that the Grid user must implement some changes in the settings of his protections.

This requirement is defined in point 4.2.1 in the GR RfG for the new PGMs or in article 46 in the Federal Grid code for new and existing PGMs. Consequently, this requirement is identical for new and existing PGMs.

3.4 Category 3 : Voltage and frequency requirements

3.4.1 Frequency withstand capability

I) Requirement applicable to existing PGMs

A power generation unit or nLon-synchronous storage considered as existing in accordance with Article 56, must be able to operate in synchronous mode with the transmission system

The proposed frequency range for existing units are as following:

Frequency Range	Duration
< 48,0 Hz	Islanding
48,0 Hz – 48,5 Hz	Mutual Agreement
48,5 Hz – 51,0 Hz	Unlimited
51,0 Hz – 52,5 Hz	Mutual Agreement
> 52,5 Hz	Islanding

Figure 6: Minimal Frequency withstand capability for existing generating units

II) Requirement applicable to new PGMs

A production unit of type B must be able to stay connected to the grid for a certain time even if the frequency of the grid deviates from 50 Hz. The applicable regulation for this requirement is the article 13.1 (a) of the NC RfG. Elia has defined requirements in line with this regulation in the section 3.1.1 of the GR RfG (see Requirements section) and the article 83§1 of the Federal Grid Code.

Proposed frequency range and minimum time period are as following:

Frequency Range	Duration
[47,5 Hz – 48,5 Hz[	30 minutes
[48,5 Hz – 49,0 Hz[	30 minutes
[49,0 Hz – 51,0 Hz]	Unlimited
]51,0 Hz – 51,5 Hz]	30 minutes

Figure 7 Minimal frequency withstand capability

III) Comparison

This requirement is similar for new and existing PGMs.

3.4.2 Rate of Change of Frequency (ROCOF)

I) Requirement applicable to existing PGMs

This requirement is not applicable for existing unit.

II) Requirement applicable to new PGMs

Regarding the rate of change of frequency withstand capability of a production unit, article 13.1(b) of the RfG states the following:

With regard to the rate of change of frequency withstand capability, a power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection.

The RoCoF limit was defined by Elia at the section 3.1.2 of the RG for RfG and at the article 83§2 of the Federal Grid Code :

The proposed RoCoF withstand capability is defined considering frequency against time profile as depicted in the Figure 7 with explicit measurement technique taking into consideration 2 Hz/s for a duration of 500 ms. For PGM connected to Transmission Network and relying on Loss Of Main (LOM) detection based on RoCoF measurement, the protection settings should not be conflicting with RoCoF withstanding capabilities requirements unless in case of local event detection (and not an overall power system event).

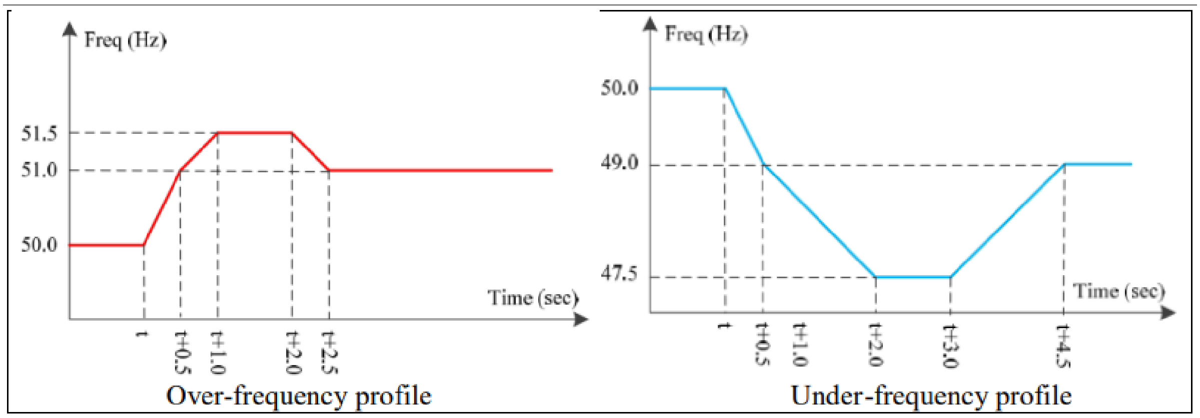


Figure 8 Frequency against time withstanding capabilities

III) Comparison

This requirement is not applicable to existing PGMs. It is then more severe for new PGMs than for existing PGMs.

3.4.3 Maximum allowable power reduction

I) Requirement applicable to existing PGMs

In Accordance with the Article 59 of the FGC, in the event of a sudden change or significant deviation in frequency, no device of a power generation unit or a non-synchronous storage or a non-synchronous storage facility considered as existing, may interfere with the primary control of the system.

II) Requirement applicable to new PGMs

Regarding the maximum allowable power reduction of a production unit, article 13.1(b) of the RfG states the following:

§4 : The relevant TSO shall specify admissible active power reduction from maximum output with falling frequency in its control area as a rate of reduction falling within the boundaries, illustrated by the full lines in Figure 9:

I) below 49 Hz falling by a reduction rate of 2 % of the maximum capacity at 50 Hz per 1 Hz frequency drop;

II) below 49,5 Hz falling by a reduction rate of 10 % of the maximum capacity at 50 Hz per 1 Hz frequency drop.

§5 : The admissible active power reduction from maximum output shall:

a) clearly specify the ambient conditions applicable;

b) take account of the technical capabilities of power-generating modules.

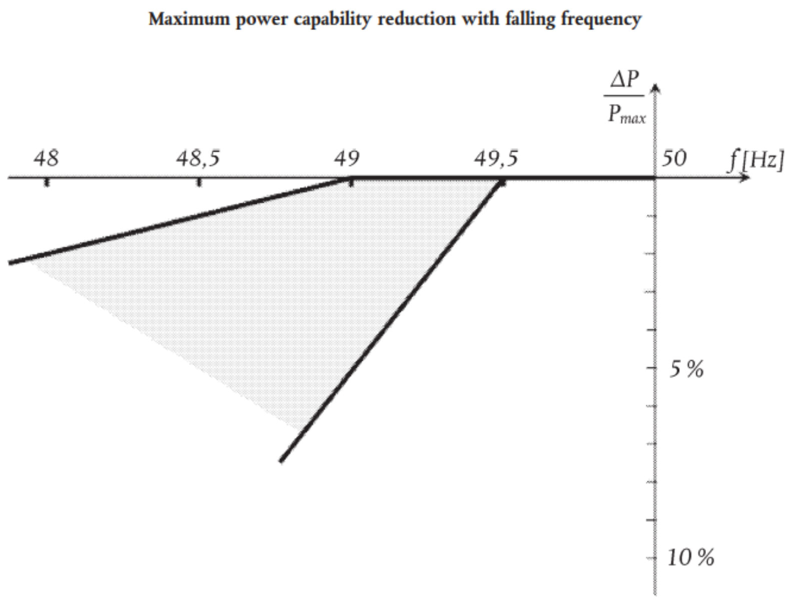


Figure 9 Maximum power capability reduction with falling frequency

The diagram represents the boundaries in which the capability can be specified by the relevant TSO.

The capability was defined by Elia at the section 3.1.5 of the GR RfG and at the article 83§4 of the Federal Grid Code.

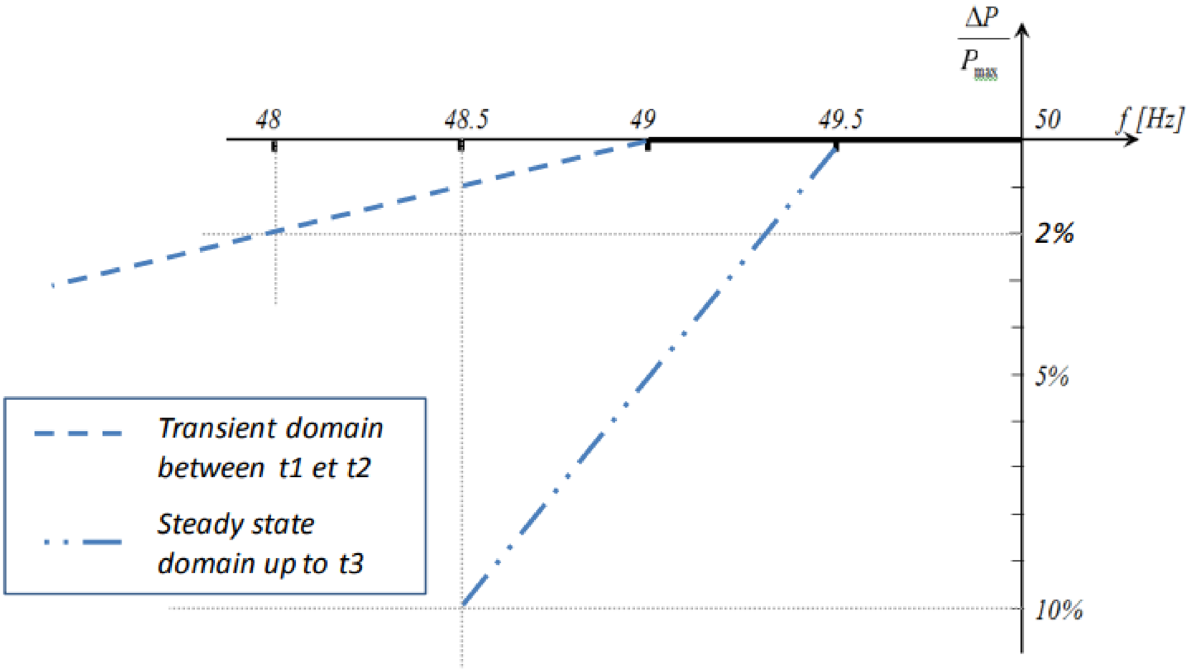


Figure 10 Maximum admissible active power reduction from maximum output for transient and steady state domains

In the case of PPM, no active power reduction is admissible above 49 Hz, below 49 Hz a maximum active power reduction of 2%/Hz is admissible (although it is not expected as PPMs have no specific technology limitation within this range).

In the case of SPGM, in order to take into consideration system needs and technology limitations, two profiles are covering separately transient domain and steady state domain. In case no technical limitation to maintain active power are existing, active power reduction should be avoided. Figure 11 covers the requirement during the transient period where the PGM are expected to respect the limit of 2 % active power reduction per Hz from maximum output for a duration up to 30 seconds this would allow other frequency control means to act. During the steady state period, the PGM are allowed if needed to reduce the active power from maximum power output respecting the limit of 10% / Hz.

	Parameter	**Requirement**
Transient domain	Frequency threshold	49 Hz
	Slope	2 % / Hz
	t 1	≤ 2 seconds
	t 2	30 seconds
Steady state domain	Frequency threshold	49.5 Hz
	Slope	10 % / Hz
	t 3	30 minutes

Figure 11 Maximum admissible active power reduction from maximum output

The standard applicable ambient conditions are defined as following:

- Temperature: 25 °C
- Altitude between 400 m and 500 m
- Humidity: between 15 and 20 g H_2O/Kg

Compliance will be based on homologation certification or on a case-by-case base with the power generator facility owner.

III) Comparison

This requirement is less severe for new PGMs than for existing PGMs.

3.4.4 Voltage withstand capability

I) Requirement applicable to existing PGMs

In alignment with Article 65 §2, for any connection point voltage between 0.9 and 1.05 of the normal operating voltage, the generating unit considered as existing must ensure an unlimited time period for operation, except in the case of a limitation due to restrictions on the generator voltage or the generator stator current. A limitation on the stator current may not intervene in the fast voltage setting.

The limitation on the voltage at the generator terminals must be in alignment with rules described in other articles mainly during Faults or Voltage dips.

II) Requirement applicable to new PGMs

The voltage withstand capability requirement is described at the section 2.1.1 of the GR RfG.

This requirement should be met at the connection point. Voltage withstand capabilities are only mentioned in NC RfG for type D PGMs (art 16.2), similar capabilities (cfr. Table 1) are necessary for other PGMs, in order to guarantee safe operation of the grid.

	Voltage Range	**Time period for operation**
Voltage ranges below 300kV	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	To be agreed between the TSO and the facility owner in the connection agreement
Voltage ranges above 300kV	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	To be agreed between the TSO and the facility owner in the connection agreement

Table 1: Voltage withstand capabilities

The following base values are to be considered as reference for the pu values reported in the Table 1 for PGM connected to TSO network:

400kV

220kV

150kV

110kV

70kV

36kV

In case broader or longer voltage withstand capabilities are technically and economically feasible, the power-generating facility owner shall not unreasonably refuse to put them at disposal of the relevant system operator.

III) Comparison

This requirement is more severe for new PGMs than for existing PGMs. It is now asked to the PGMs to stay connected longer to the network during voltage deviations.

3.4.5 LFSM-O

I) Requirement applicable to existing PGMs

This requirement is not defined nor applicable for existing generating units.

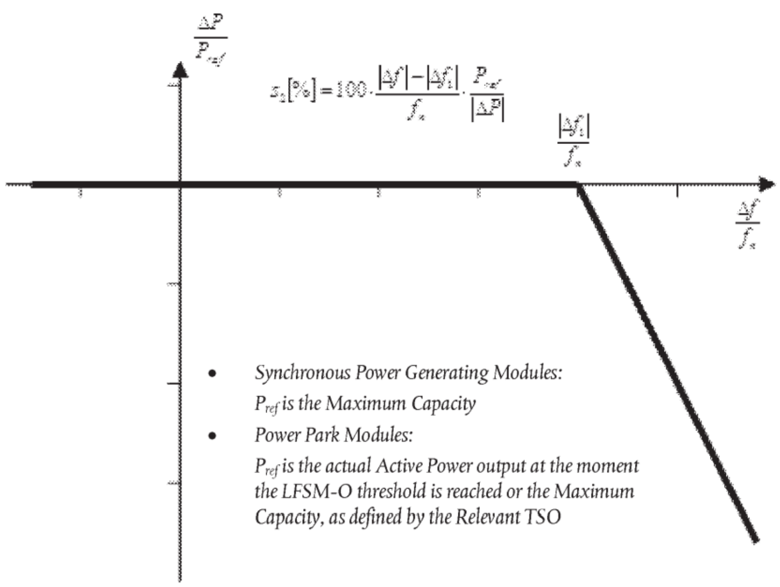
II) Requirement applicable to new PGMs

The section 3.1.4 of the GR RfG and Article 88§1 of the Federal Grid Code describe the LFSM-O requirement.

Presentation of the active power response to frequency variations

[…] the power-generating module shall be capable of activating the provision of active power frequency response according to figure 1 at a frequency threshold and droop settings specified by Elia[…]

Active power frequency response capability of power-generating modules in LFSM-O



P_{ref} is the reference active power to which ΔP is related and may be specified differently for synchronous power-generating modules and power park modules. ΔP is the change in active power output from the power-generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network. At overfrequencies where Δf is above Δf_1, the power-generating module has to provide a negative active power output change according to the droop S_2.

The NC RfG also mentions that :

[…]

- the power-generating module shall be capable of activating a power frequency response with an initial delay that is as short as possible. If that delay is greater than two seconds, the power-generating facility owner shall justify the delay, providing technical evidence to the relevant TSO

[...]

- the power-generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints. [...]

Definition of the parameters of the response of the PGM

The response of the PGM takes the following aspects in consideration. They are represented at the figure 11.

- The dead time (Td) covers the time from the frequency change event until the beginning of the response;
- The step response time (Tsr) covers the time from the frequency change event until the instant until the response reaches the tolerance range for the first time;
- The settling time (Ts) covers the time from the frequency change event until the instant, from where on the corresponding response remains within the tolerance band of the set value.

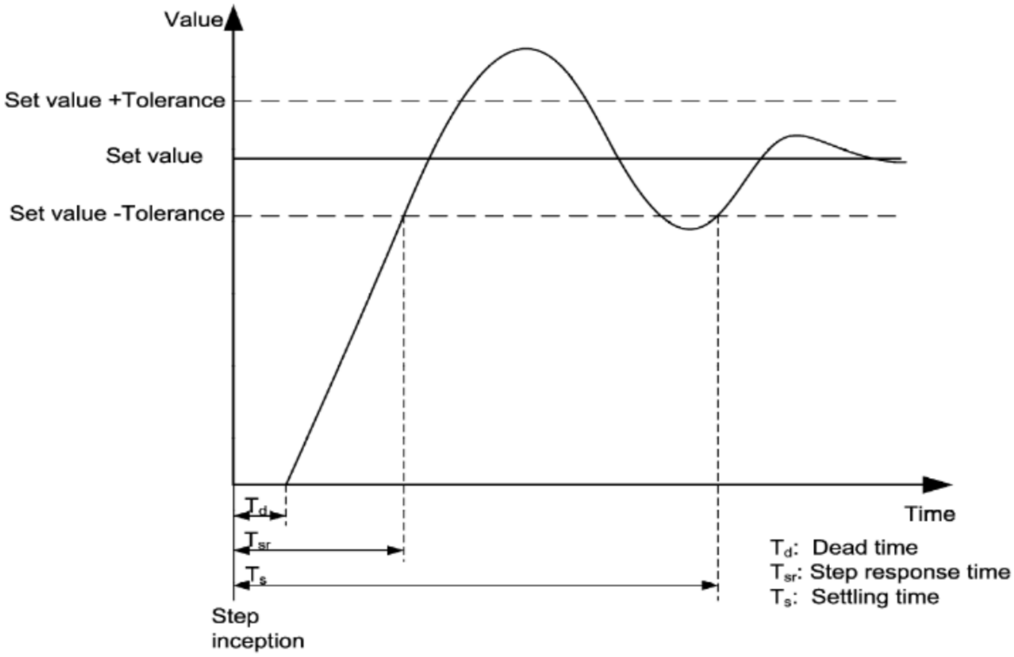


Figure 11: Definition of PGM response parameters

Definition of the droop

The droop is defined as per the following formula:

$$s[\%] = 100.\frac{|\Delta f| - |\Delta f1|}{fn}.\frac{Pref}{|\Delta P|}$$

Where ΔP is the change in active power output from the power-generating module. f_n is the nominal frequency (50 Hz) in the network and Δf is the frequency deviation in the network. At over frequencies where Δf is above Δf_1, the power-generating module has to provide a negative active power output change according to the droop s.

NC RfG allows two options for defining Pref for power park modules: either Pmax or the actual active power output at the moment the LFSM threshold is reached. In order to achieve an equitable active power response to a high or low frequency event (regardless of the number of power generating modules in operation) the reference active power Pref is therefore assigned based on the expected capacity operation:

- Pref is by default the actual active (at the moment of activation) for PPM;
- Pref can be alternatively defined as Pmax for PPM expected to operate mostly at or near maximum capacity (example for offshore wind farms connected to Elia Network).

The automatic disconnection and reconnection as referred in 13-2(b) of the NC RfG are not allowed by default. The below requirements are common for all PGM:

- The droop setting is 5% and selectable within the range 2% and 12%.
- Frequency activation threshold: 50.2 Hz;
- Dead time : by default as fast as technically possible (no intentional delay), specific provisions could be applicable in agreement with the TSO;
- Once the minimum regulating level is reached, the operation mode shall be continued at the same level (no further decrease for further frequency increase).

The requirements for SPGM units are the following:

Parameters (SPGM)	**For power increase**	**For power decrease**
Step response time	≤ 5 minutes for an increase of active power of 20 % Pmax (note that the response shall be as fast as technically possible, for example a slow reaction is not applicable in the case of an increase shortly – a few seconds – following a decrease phase)	≤ 8 seconds for a decrease of active power of 45% Pmax
Settling time	≤ 6 minutes for an increase of active power (note that the response shall be as fast as technically possible, for example a slow reaction is not applicable in the case of an increase shortly – a few seconds – following a decrease phase)	≤ 30 seconds for a decrease of active power

The requirements for PPM units are the following:

Parameters (PPM)	**For power increase**	**For power decrease**
Step response time	*For wind generation:* ≤ 5 seconds for an increase of active power of 20 % Pmax (note that the response shall be as fast as technically possible, for example for operational points lower than 50% of Pmax, a reaction can be slower but shall remain faster than 5 seconds) *For the rest:* ≤ 10 seconds for an increase of active power of 50 % Pmax	≤ 2 seconds for a decrease of active power of 50 % Pmax
Settling time	≤ 30 seconds for an increase of active power	≤ 20 seconds for a decrease of active power

For gas turbines and internal combustion engines whose technical specifications do not allow to follow the default requirements described above, the following alternative requirements are applicable:

- If Pmax ≤2 MW, at least 1.11% Pmax per second (increasing or decreasing frequency)
- If Pmax> 2 MW, at least 0.33% of Pmax per second (increasing or decreasing frequency)

III) Comparison

This requirement is only applicable to new PGMs.

3.4.6 Reactive Power Capability

I) Requirement applicable to existing PGMs

In alignment with Article 65 §1, every power generation unit considered as existing, for any value of active power likely to be injected into the transmission system between the technical minimum and the maximum connection power, at the normal operating voltage must be able to produce or to absorb at the connection point a reactive power of at least -0.1 Pmax and 0.45 Pmax.

II) Requirement applicable to existing PPMs

For PPMs in accordance with Article 58§2 that refers to the Elia requirements, any generating units considered as existing, for any value of the active power between Min and Maximum at nominal Voltage, they must be able to respectively absorb or supply at the point connection, reactive power includes at least,

- -0.2 Pmax and 0.35 Pmax.
- -20%<Q<+35% on-shore WF
- -25%<Q<+25% offshore WF

III) Requirement applicable to new PPMs

The requirement was described by Elia in section 4.4.2 of the GR RfG and in Article 89 of the FGC.
The required reactive capabilities should be met at the HV side of the step up transformer if existing; otherwise they should be met at the inverter terminals.
For PPMs of type B, the requirement for the reactive power provision capability is determined by the Q-P profile represented in Figure 11 where the limitations are based on nominal current at high active power output and by a power factor (cos(phi)) defined by the 2 points at Q= -33% and +33% of PD, where PD is the maximum active power that can be produced in case of the maximum requested reactive power output (hence equal to 0.95*Snom).
With respect to voltages different from 1pu, the required U/Uc-Q/PD profile is represented in Figure 12.
Note that the effective resulting available capability of the PPM at the connection point (that can be different than the one at the PPM terminal) should be communicated, demonstrated and put at disposal of the relevant system operator during the connection procedure.
In case the PPM unit has the capability of voltage regulation for wider values than the minimum requirement area shown in Figure 11, the PPM owner shall not unreasonably withhold consent to put them at disposal of the RSO, taking account of their economic and technical feasibility. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement.
In this case, the settings of the controllers should be agreed with the relevant system operator

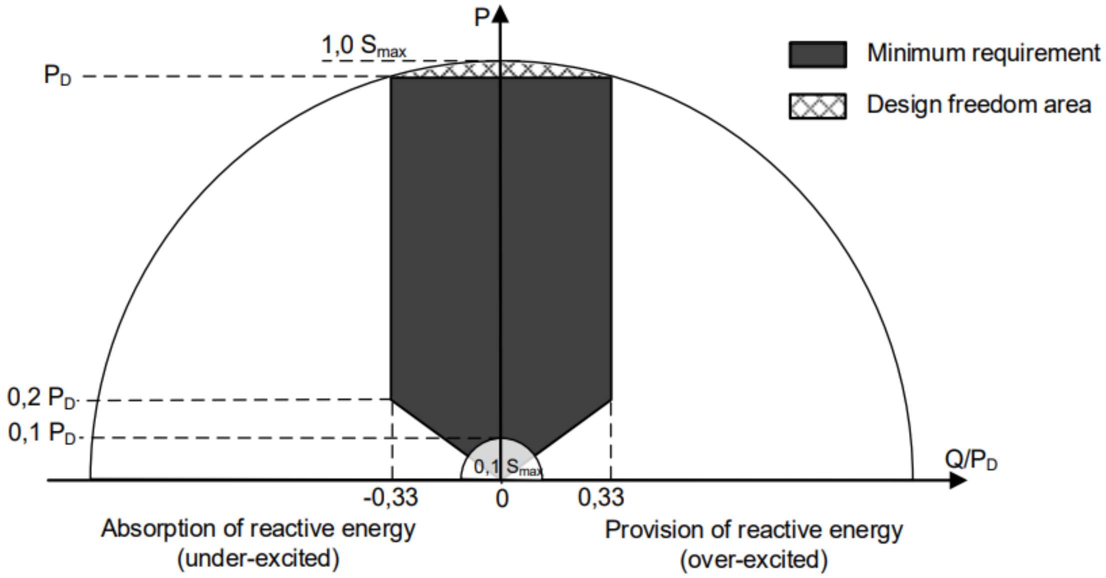


Figure 12 : Capability curve for PPM type B

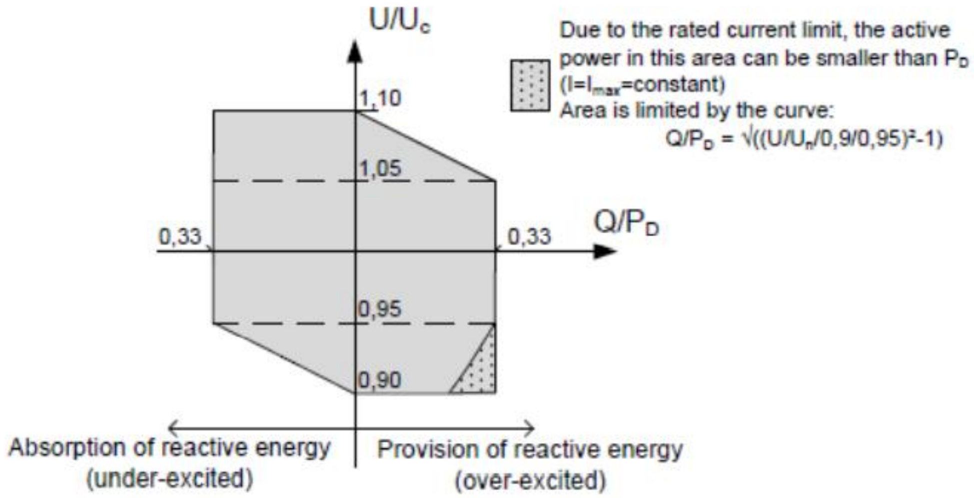


Figure 13 U/U_c – Q/P_D profile for type B PPM in order to visualize reactive power requirements for voltages different from 1 pu.

IV) Requirements applicable to new SPGMs

The required reactive capabilities should be met at the HV side of the SPGM step up transformer if existing; otherwise it should be met at the alternator terminals. The requirements apply to SPGM connected to the Elia network.

For SPGMs of type B, the requirement for the reactive power provision capability is determined by the Q/P profile represented in Figure 13 where the limitations are based on nominal current at high active power output and by a reactive power (Q) limited to -33% and +33% of PD, where PD is the maximum active power that can be produced in case of the maximum requested reactive power output (hence equal to 0.95*Snom).

With respect to voltages different from 1pu , the required U/Uc-Q/PD profile is represented in Figure 14.

Note that the effective resulting available capability of the SPGM at the connection point (that might be different than the one at the SPGM terminals) should be communicated, demonstrated and put at disposal of the relevant system operator during the connection procedure. The SPGM owner shall not unreasonably withhold consent to use wider reactive capabilities, taking account of their economic and technical feasibility. The unit is therefore expected to not limit its capabilities to comply with the minimum requirement but to use the full capability to support the system stability as stated in its agreement.

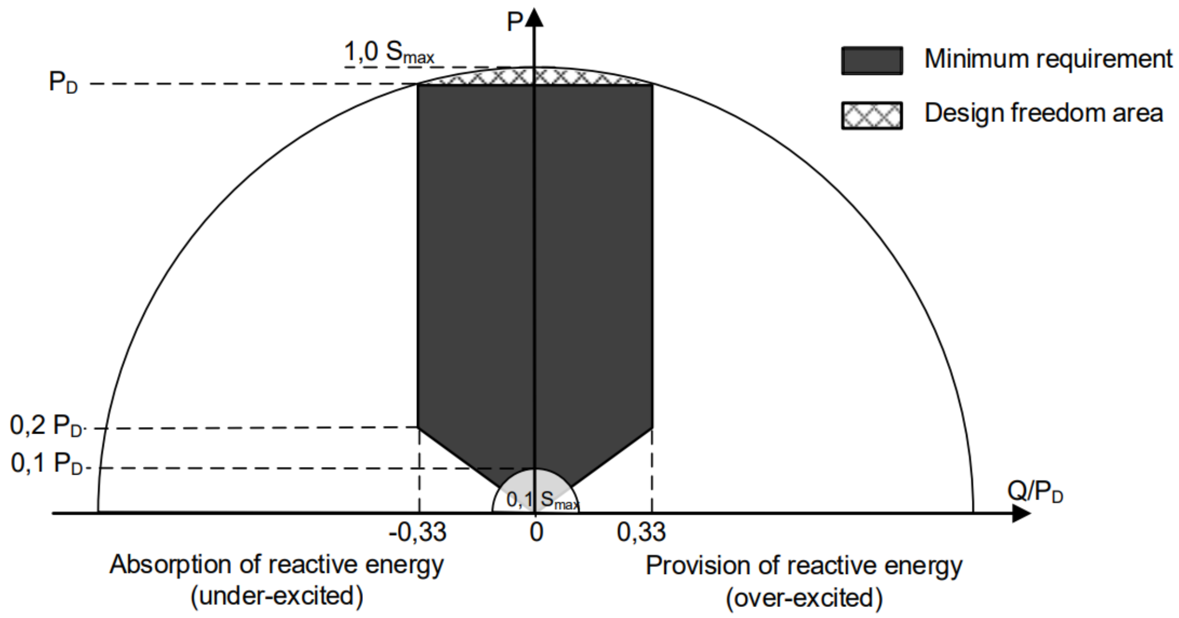


Figure 14 Capability curve for SPGM type B

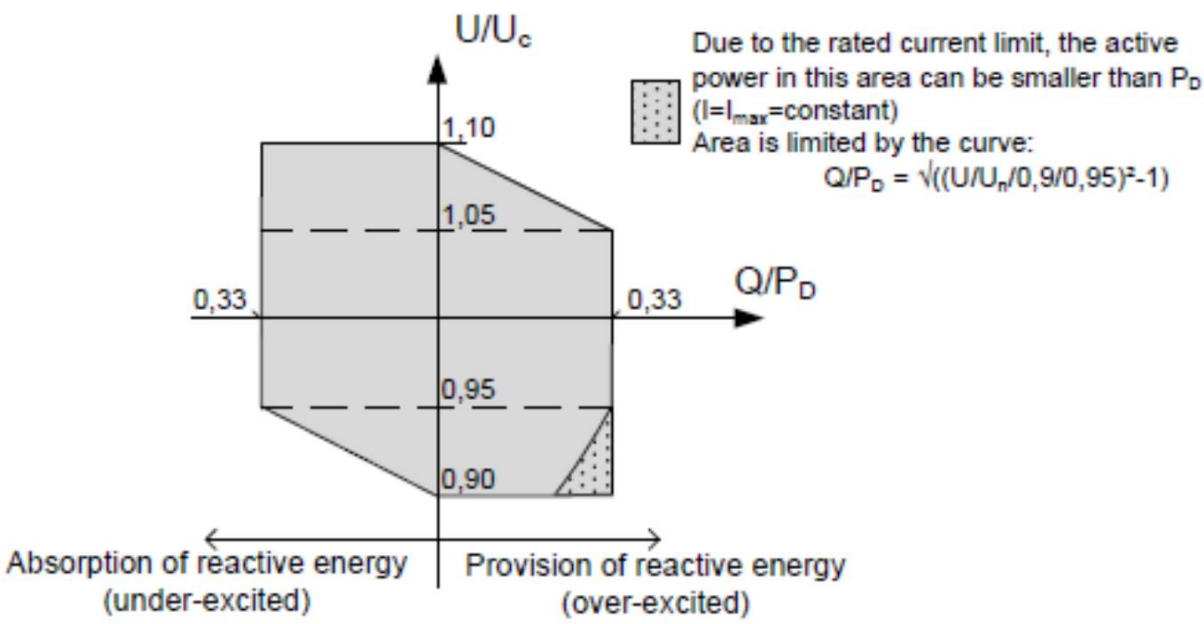


Figure 15 U/Uc – Q/PD profile for type B SPGM in order to visualize reactive power requirements for voltages different from 1 pu.

V) Comparison

This requirement is considered as more stringent for both new PPMs and SPGMs.

3.4.7 Voltage control

I) Requirement applicable to existing PGMs

In accordance with Art. 69 of the FGC, a PGM with a Pmax lower than 25 MW and which does not have a MVAr contract should operate at a reactive power setpoint of 0 MVAr.

II) Requirements applicable to new PGMs

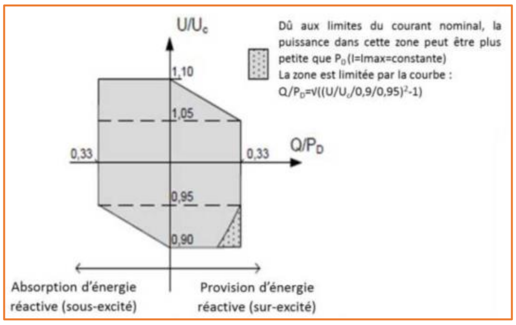
This requirement is optional for PPMs.
In line with the article 17-2(b) of the RfG :

> *with regard to the voltage control system, a synchronous power-generating module shall be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the synchronous power-generating module.*

Elia completed the requirement at the article 89§2 of the FGC and at the section 4.3.2 of the Requirements of General Application.

According to the article 89§2 of the FGC, an SPGM must be able to operate in one of the two following modes :

- Qfix : maintain a constant reactive power within the P/Q capabilities
- Q(U) : maintain a constant voltage at the terminals of the alternator



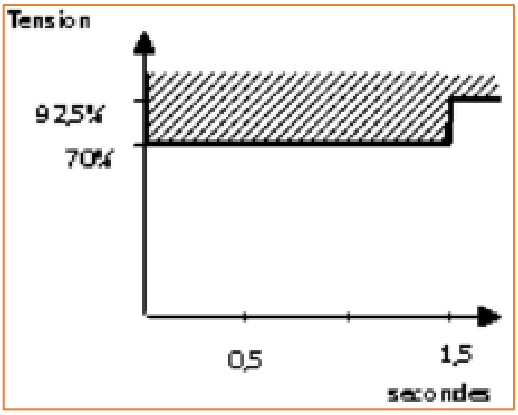
III) Comparison

This requirement is more stringent for new SPGMs. For PPMs, this requirement is not applicable.

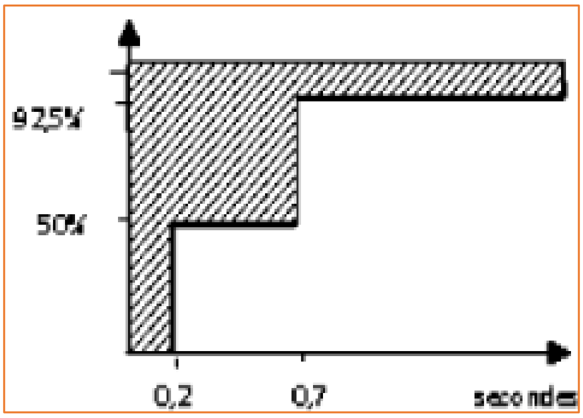
3.4.8 Fault Ride Through

I) Requirement applicable to existing PGMs

In Accordance with Article 58§1 of the federal grid code, a generating unit considered to be existing must be able to operate in its entire operating range in synchronous mode with the transmission system, when the voltage at the connection point, expressed as a percentage of the nominal voltage at this point, during a voltage dip of limited of limited magnitude, remains within the hatched area of the diagram below.



In Accordance with Article 58§1, a generating unit considered to be existing must be capable of operating throughout its operating range in synchronous mode with the transmission system when the voltage at the connection point, expressed as a percentage of the nominal voltage at this point, remains, during a voltage dip of significant magnitude, within the hatched area of the diagram below.:



II) Requirement applicable to new PPMs

In line with the NC RfG, Elia defined the fault-ride-through profile for PPMs at the section 4.4.1 of the GR RfG and at the Article 94 of the FGC:

This requirement defined by Elia as TSO should be met at the connection point.

The PPM unit should be able to support the network during fast transient voltages and network short-circuits for which the profile of the voltage versus time is referred as Fault-Ride-Through (FRT). PPM shall fulfil the requirements in Figure 15 (the evolution of the minimum voltage at the Connection Point), where the PPM shall remain connected to the grid as long as the voltage of the phase having the lower voltage is above the profile of Figure 10. It is recommended however to remain connected as long as the technical capability of the PPM would allow it. The same profile applies for asymmetrical faults. The proposed fault-ride-through parameters are presented in Table 4. A voltage U=1 pu represents the rated voltage (phase-to-phase) at the connection point.

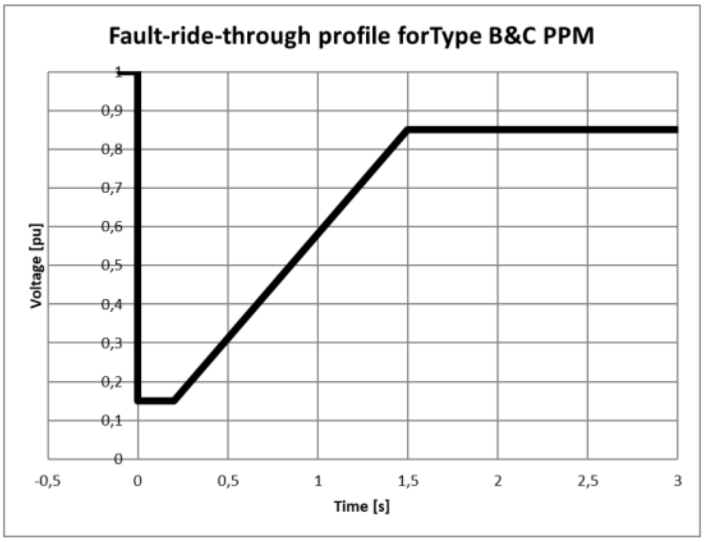


Figure 16 FRT requirement for PPM type B and C

Table 4: Parameters of the FRT requirements for PPM of type B and C.

Voltage parameters [pu]	**Time parameters [seconds]**
Uret=Uclear=Uret1= 0.15	tclear=trec1=trec2= 0.2
Urec2 = 0.85	t_{rec3}=1.5

III) Requirement applicable to new SPGMs

In line with the NC RfG, Elia defined the fault-ride-through profile for PPMs at the section 4.3.3 and at the Article 90 of the FGC:

This requirement defined by Elia as TSO should be met at the connection point.

The SPGM should be able to support the network during fast transient voltages and network short-circuits for which the profile of the voltage versus time is referred as Fault-Ride-Through (FRT). SPGM shall fulfil the requirements in the figure below, where the SPGM shall remain connected to the grid as long as the voltage of the phase having the lower voltage is above the profile.

It is recommended however to remain connected as long as the technical capability of the PGM would allow. The same profile applies for asymmetrical faults. The proposed Fault-Ride-Through parameters are presented in the figure below. A voltage U=1 pu represents the rated voltage (phase-to-phase) at the connection point.

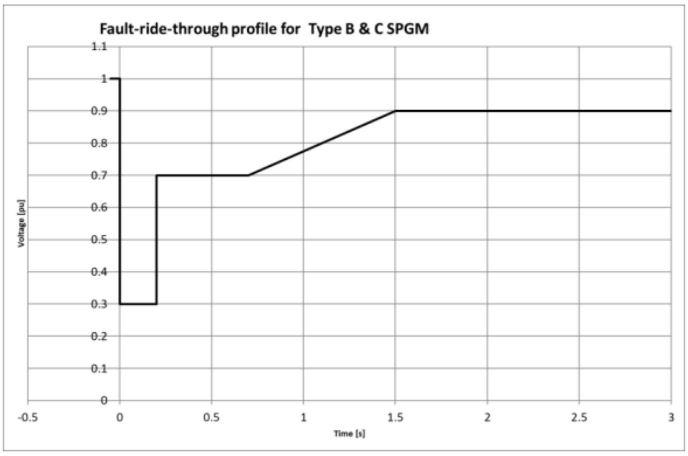


Figure 9: FRT requirement for SPGM type B and C.

Table 3: Parameters of the FRT requirements for SPGM of type B and C.

Voltage parameters [pu]	Time parameters [seconds]
Uret = 0.3	tclear = 0.2
Uclear = 0.7	Trec1=tclear
Urec1 = 0.7	trec2=0.7
Urec2 = 0.9	trec3 = 1.5

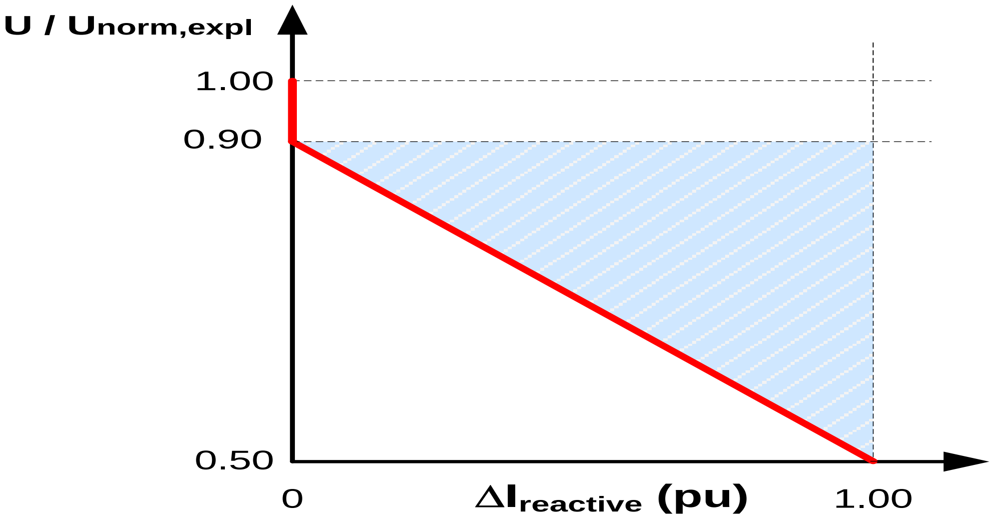
IV) Comparison

This requirement is **less** severe for new PGMs than for existing ones.

3.4.9 Fault current & dynamic voltage support

I) Requirement applicable to existing PGMs

In accordance with Article 58§2 that refers to the Elia requirements, any generating units considered as existing is ensure an injection of additional reactive current determined by the figure below, where for voltages between 1 and 0.9 in pu of $U_{nom,expl}$, the wind park should follow the normal voltage droop control mode



The magnitude of the additional reactive current injection ($\Delta I_{reactive}$) shall be determined as a linear function of the positive or negative voltage change (ΔU) with respect to the pre-disturbance value with total reactive current injection limited to 100% of rated current

II) Requirement applicable to new PGMs

This requirement is described in section 4.4.3 of the GR RfG and in Article 93§3 of the FGC and only applies to the Power Park Modules (PPMs).

The PPM unit shall be able to inject/absorb additional reactive current compared to the pre-fault state during low and high voltage conditions up to the maximum of its capability. The additional injected/absorbed reactive current shall be function of the positive sequence voltage at the connection point depending on the available capability of the PPM. The resulting fast current injection at the point of connection should be calculated and shared with the TSO by simulation in terms of active and reactive current components. The requested additional reactive current characteristic injection is illustrated in Figure 13. For voltages within the deadband [$\Delta V- act$, $\Delta V+ act$], the PPM unit should follow the normal voltage control mode. The injection or absorption of additional reactive current shall be delivered by the PPM with a minimal delay from the detection of the over/undervoltage, $tIq\ act$ .The functionality should remain active for a minimum time of $tIq\ on$ and can be deactivated if the voltage returns and remains within [$\Delta V- act$, $\Delta V+ act$] for a time longer than $tIq\ off$. The parameters of this functionality lying within the normal operational range of the installation as well as the delays of activation, dead band and duration of the activation are to be agreed during the connection process on a case by case level and fixed in the individual connection contract with the relevant system operator (it might be the DSO or Elia) in coordination with the relevant TSO. The parameter setting of this functionality is therefore site specific.

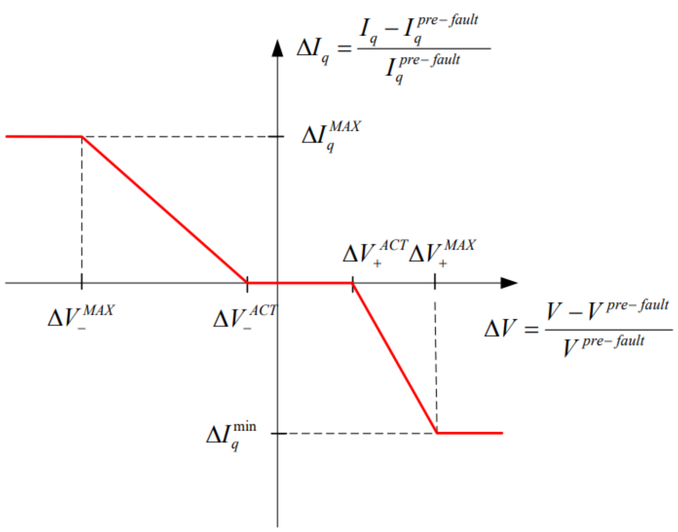


Figure 13: Injection of additional reactive current.

For the reliable detection of asymmetric faults, the PPM unit shall contribute to the fault with positive, negative and zero-sequence current. The short-circuit contribution is to be agreed during the connection process on a case by case level and fixed in the individual connection contract with the relevant system operator in coordination with the relevant TSO. The parameter setting of this functionality is therefore site specific

III) Comparison

This requirement is more severe for new PGMs than for existing PGMs.

3.4.10 Oscillation and damping Control

I) Requirement applicable to existing PGMs

In alignment with Art. 69 § 1. the transmission system user and the transmission system operator shall agree on the minimum general technical requirements, control parameters and specifications for aspects that are directly related to the safety, reliability and efficiency of the transmission system the minimum general technical requirements, control parameters and functional specifications to be adopted with respect to the transmission system user's facilities, including in particular for power system stabilizer as well as dynamic and static stability

II) Requirement applicable to new PGMs

Same requirements is applicable as for existing PGMs.

III) Comparison

The requirement is identical for new and existing PGMs.

3.4.11 Post-fault active power recovery

I) Requirement applicable to existing PGMs

In accordance to the Article 58§2 that refers to the Elia requirement, any generating unit considered as existing must follow an active power recovery, after fault clearance, with a gradient of at least 0.2 p.u/s

II) Requirement applicable to new PPMs

This requirement is defined at the article 20-3 of the NC RfG :

Type B power park modules shall fulfil the following additional requirements in relation to robustness:

a) the relevant TSO shall specify the post-fault active power recovery that the power park module is capable of providing and shall specify:
   i. when the post-fault active power recovery begins, based on a voltage criterion;
   ii. a maximum allowed time for active power recovery; and
   iii. a magnitude and accuracy for active power recovery;
b) the specifications shall be in accordance with the following principles:
   i. interdependency between fast fault current requirements according to points (b) and (c) of paragraph 2 and active power recovery;
   ii. dependence between active power recovery times and duration of voltage deviations;
   iii. a specified limit of the maximum allowed time for active power recovery;
   iv. adequacy between the level of voltage recovery and the minimum magnitude for active power recovery; and
   v. adequate damping of active power oscillations.

This requirement was completed by Elia at the section 4.4.4 of the GR RfG and at the Article 95 of the FGC:

For PPMs, the parameters of this functionality should be agreed during the connection process with the relevant TSO on a case-by-case approach and fixed in the individual connection contract. These parameters are thus site specific requirement.

III) Requirement applicable to new SPGMs

This requirement is defined at the article 17-3 of the NC RfG :
With regard to robustness, type B synchronous power-generating modules shall be capable of providing post-fault active power recovery. The relevant TSO shall specify the magnitude and time for active power recovery.

This requirement was completed by Elia at the section 4.3.4 of the GR RfG and at the Article 91 of the FGC:
It is required that SPGM of Type B are able to provide post-fault active power recovery as the unit remains connected to the network.
For SPGMs, the values of the magnitude and time for the active power recovery will be a site specific specification: it is to be agreed during the connection process with the TSO on a case by case level and fixed in the individual connection contract.

IV) Comparison

It is considered that the requirements applicable to new PGMs are similar to the requirements applicable to existing PGMs.

3.5 Category 4: Information exchange

I) Requirement applicable to existing PGMs

This requirement is not defined nor applicable for existing generating units

II) Requirement applicable to new PGMs

This requirement was defined by Elia at the section 4.2.2 of the GR RfG. According to this document, at least the following signals must be communicated to Elia by the GU :

- position of the circuit breakers at the connection point (or another point of interaction agreed with the Elia);
- active and reactive power at the connection point (or another point of interaction agreed with the Elia); and
- net active and reactive power of power generating facility in the case of power generating facility with consumption other than auxiliary consumption.

III) Comparison

This requirement is more stringent for new PGMs.

3.6 Category 5: Balancing/Congestion management requirements

Remote Control reduction of Active Power

I) Requirement applicable to existing PGMs

This requirement is not defined nor applicable for existing generating units

II) Requirement applicable to new PGMs

Article 14.2 of the NC RfG gives the description of this requirement.

Type B power-generating modules shall fulfil the following requirements in relation to frequency stability:

a) to control active power output, the power-generating module shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port; and

b) the relevant system operator shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

The GR RfG also includes a reference to this requirement at the section 4.1.1 :

Respecting the applicable regional regulatory provisions, the right to request additional equipment to allow active power to be remotely operated will be asserted by Elia as relevant system operator in due time.

III) Comparison

This requirement is more stringent for new PGMs.

3.7 Category 6 : Power quality requirements

The power quality requirements are currently described in the connection contract for both existing and new PGMs. There is, as consequence, no difference between the requirements applicable to new or existing PGMs.

3.8 Category 7 : Emergency & restoration requirements

3.8.1 Automatic Connection

I) Requirement applicable to existing PGMs

This requirement is not applicable to existing PGMs.

II) Requirement applicable to new PGMs

The conditions to allow a PGM of type B to connect to the network are the following:

1) Frequency to be within 49.9 Hz and 50.1 Hz; and
2) Voltage to be within 0.85 Un and 1.10 Un; and
3) Minimum observation time where the above conditions are satisfied of 60 seconds.

III) Comparison

This requirement is more stringent for new PGMs.

3.8.2 Automatic Reconnection

I) Requirement applicable to existing PGMs

This requirement is not applicable to existing PGMs.

II) Requirement applicable to new PGMs

The conditions to allow a PGM of type B to connect to the network are the following:

1) Frequency to be within 49.9 Hz and 50.1 Hz; and
2) Voltage to be within 0.85 Un and 1.10 Un; and
3) Minimum observation time where the above conditions are satisfied of 60 seconds.
4) Presence of a signal from Elia allowing the PGM to inject power on the grid.

III) Comparison

This requirement is more stringent for new PGMs.

3.9 Category 8 : Protection requirements

3.9.1 Loss of Main by ROCOF

I) Requirement applicable to existing PGMs

This requirement is not applicable to existing units.

II) Requirement applicable to new PGMs

Elia described this requirement in article 3.1.3 of the GR RfG and in article 83 of the Federal Grid Code.
For all PGM, a LOM based on RoCoF may be allowed and defined by the RSO in coordination with the TSO as per the provisions in Article 13. (1) b. In this case, the RoCoF measurement used for LOM protection is used to detect islanding and is not to be confused with the RoCoF immunity requirement defined in the section 3.1.2.

For PGM connected to Elia Network and relying on LOM detection based on RoCoF measurement, the threshold should be higher than 2 Hz/s for a duration of 500 ms. Note that other alternative LOM detection settings should not conflict with frequency withstand capabilities requirements unless in case of local event detection (and not an overall power system event). For technical and safety reasons, lower thresholds can be discussed on a case-by-case basis.

For the type B, C and D production units, a LoM by RoCoF protection can be implemented to avoid islanding of a part of the network. However, this is not required by Elia.

III) Comparison

This requirement is not mandatory for type B PGMs and, as consequent, it is not stricter for new PGMs than for existing ones.

3.9.2 Verification of the presence of a decoupling protection (Elia standards)

I) Requirement applicable to existing PGMs

For existing type B PGMs, the requirements are described in the following table :

	Threshold	Temporization

Frequency relay		
f<	47.5 Hz	0 ms
f>	51.5 Hz	0 ms
Voltage relay		
U>	110% Un or 100% Umax	0-100 ms
U<t	70% Un	1.5 - 3 s
U<<t	30% Un	300 ms
Uo>[3]	5 - 25%	2 - 5 s

II) Requirement applicable to new PGMs

For new type B PGMs, the requirements are described in the following table :

	Threshold	Temporization
Frequency relay		
f<	47.5 Hz	0 ms
f>	51.5 Hz	0 ms
Voltage relay		
U>	110% Un	100 ms
U<t	70% Un	1.5 - 3 s
U<<t	15% Un	300 ms
Uo>[4]	5 - 25%	2 - 5 s

III) Comparison

This requirement is very similar for new and existing PGMs.

[3] optional
[4] optional

3.10 Summary of the gap analysis

The gap analysis between type B requirements applicable to existing and PGMs can be summarized in the table below:

Category of requirements		Sub category	GAP analysis	Remark	Eligible for incentive
Category 1	Data questionnaire & Models	Data questionnaire	Small changes		
		Models	More stringent		X
Category 2	Internal compliance proof (RGIE) & protection scheme	RGIE	Identical		
		Annex 1 : Icc max	More stringent	Not in the scope : DCC	
		Annex 2 : Protections	Small changes	Not in the scope : DCC	
		Protection schemes	Identical		
Category 3	Voltage & frequency requirements	Frequency withstand capability	Small changes		
		Rate of change of frequency (ROCOF)	More stringent		X
		Maximal allowable power reduction	Less stringent		
		LFSM-O	More stringent		X
		Voltage withstand capability	More stringent		X
		Voltage control (SPGM)	More stringent		X
		Reactive power capability	More stringent		X
		Fault Ride Trough	Less stringent		
		Fault current & dyn. Voltage support (PPM)	More stringent		X
		Oscillation and damping control	Small changes		
		Post-fault power recovery (PPM)	Identical		
Category 4	Information exchange / Telecom requirements	Information exchange	More stringent		X
Category 5	Balancing/congestion man. requirements	Remote control reductions	More stringent		X
Category 6	Power quality requirements		Identical		
Category 7	Emergency & restoration requirements	Automatic connection	More stringent		X
		Automatic reconnection	More stringent		X
Category 8	Protections requirements	Loss of main protection by RoCoF	Identical		
		Decoupling protection	Small changes		

Figure 17 : gap analysis between type B requirements applicable to new PGMs compared to requirements applicable to existing PGMs

We considered as eligible for this incentive the requirements applicable to new PGMs type B being new or more stringent compared to the requirements applicable to existing PGMs type B

We also excluded the two requirements coming from the Demand Connection code.

The requirements eligible for this incentive are outlined in the table below:

Category of requirements		Sub category	GAP analysis	Remark	Eligible for incentive
Category 1	Data questionnaire & Models	Models	More stringent		X
Category 3	Voltage & frequency requirements	Rate of change of frequency (ROCOF)	More stringent		X
		LFSM-O	More stringent		X
		Voltage withstand capability	More stringent		X
		Voltage control (SPGM)	More stringent		X
		Reactive power capability	More stringent		X
		Fault current & dyn. Voltage support (PPM)	More stringent		X
Category 4	Information exchange / Telecom requirements	Information exchange	More stringent		X
Category 5	Balancing/congestion man. requirements	Remote control reductions	More stringent		X
Category 7	Emergency & restoration requirements	Automatic connection	More stringent		X
		Automatic reconnection	More stringent		X

Figure 18 Summary of the requirements eligible for this incentive

4. Qualitative assessment of Type B requirements application to new and existing PGMs

4.1 System needs

The secure and stable operation of an AC power system is highly related to its voltage and frequency stiffness capability[5], usually referred as system strength and its ability to be operated within its voltage, frequency and current limits.

Historically, this system strength was ensured nearly exclusively by the large synchronous power generating modules (SPGM) connected and distributed over the transmission system.

Indeed, these large SPGMs, by the nature of the physic used the produced electricity energy, act as voltage sources with natural inertia contributing to the system voltage and frequency stiffness. And thanks to their governor and automatic voltage controls, they provide capability to adjust the active and reactive power in order to control voltage and frequency in the system. Moreover, the nature of primary energy sources used the generate electricity allow of most of the case a controllability in the level of active power produced.

End of last century, the evolution in the power electronic technology led to the introduction of new solution to produce and inject in the AC transmission power system. The Power Park Modules (PPM) are in fact using specific control-command of the power converters to transform primary energy source into an AC power in the power system. By nature, these sources of energy do not provide natural voltage or frequency stiffness to the system without specific application in their control-command strategy and might present a high level of volatility in function of its primary energy source (wind, solar).

Since about a decade, due to technology, environmental and political evolution and decision, (ex: phase out nuclear power generation, decarbonization of the power sector), we are observing a tendency of replacement of these large centralized SPGMs towards either:

- Small SPGMs or PPMs decentralized towards in the HV or MV transmission systems or industrial sites;
- Large PPMs decentralized toward the extremity of the EHV transmission system (offshore) or far away from load centers.

This evolution is affecting seriously the voltage and frequency stiffness of the transmission system and then the ability of system operators to fulfill their objective and obligation in term of operation in normal, emergency and restoration conditions.

Moreover, the introduction and evolution of the European electricity market together with the volatile nature of some of the primary energy sources is leading to more and more variation in the current flowing through the transmission system. This increases the risk of overloading the capacity of the grid

[5] Stiffness capability refers to the "characteristic of an electrical power system that relates to the size of the change in voltage or frequency following a fault or power imbalance on the power system"

elements and triggering their uncontrolled (cascading) disconnection.
Finally, the increase in the volatility and incompressibility of energy sources is also more and more affecting the balancing capability of control areas, requiring more flexibility.
In this respect, for the perspective of ensuring secure, stable and good quality of power energy transmission, it is of upmost importance that the requirements established in the European and Belgian grid codes for small SPGM and PPM sources are contributing to the voltage and frequency stiffness of the transmission system and provide sufficient capability to support congestion management and balancing via control of their active power injection.

4.2 Classification of Type B requirements

The TYPE B requirements where a gap between existing and new PGMs (see part 3) has been identified can be classified into the categories related to the way they will contribute to the voltage and frequency stiffness of the transmission system and to support congestion management and balancing via control of their active power injection:

1. Voltage vs Frequency vs Current
    a. In the "Voltage" category, we will find requirements contributing to the voltage stiffness of the transmission system
        i. Voltage withstand capability = capability to remain connected to the grid in a certain voltage range and for a certain time
        ii. Reactive Power capability = capability to generate or absorb a certain quantity of reactive power within a voltage and active power range
        iii. Voltage control = capability to automatically adjust reactive power in function of voltage variation at the connection point
        iv. Fault current and dynamic voltage support = capability to quickly inject reactive power to the grid during voltage drop at the connection point as a result of a large grid event (usually short-circuit)
    b. In the "Frequency" category, we will find requirements contributing to the frequency stiffness of the transmission system
        i. Frequency control = capability to automatically adjust active power in function of small or large variation of the frequency at the connection point
        ii. RoCoF = capability to remain connected to the grid in case of rate of change of the frequency at the connection point up to a minimum value
        iii. LFSM-O = activating the provision of active power frequency response according to figure 1 at a frequency threshold and droop settings
        iv. Automatic connection and reconnection = condition to connect to the grid or to reconnect to the grid
    c. In the "Current" category, we will find requirements contributing to the capability to adjust active power in order to limit risk of overloading grid elements or to help balancing the control area:
        i. Active Power controllability/remote control reduction = capability to request a fast reduction of the produced active power

Requirements not entering in these 3 categories were classified as "Other".

2. Normal state vs Emergency/Restoration state application
    a. Normal state contribution = contribution which shall be required to ensure capability of the system operation to meet his obligation to operate the grid in normal frequency and voltage ranges
    b. Emergency/Restoration state contribution = contribution that will be needed to allow the system operator to stabilize and restore the system when going out of the normal operation state.

3. Be robust vs Give Robustness
    a. Be robust = capability necessary for the power plant module to stay connected to the grid following voltage or frequency variation at his connection point as a result of small or large grid event
    b. Give robustness = contribution of the power generating module to limit voltage or frequency variation at his connection point as a result of small or large grid event

4. Static vs Dynamic
    a. Static = capability contributing to the steady state performance of the power system in term of frequency, voltage or current management
    b. Dynamic = capability impacting the transient behavior of the power system and ensuring a stable performance in term of Frequency, voltage, angular or Power Electronic driven stability phenomena.

The eligible requirements have been classified according to the above categories:

Category of requirements		Sub category	GAP analysis	Steady State vs Dynamic	Frequency vs voltage vs Current vs Other	Normal state vs Emergency	Be robust vs give robustness
Category 1	Data questionnaire & Models	Models	More stringent	Other	Other	Normal	Give robustness
Category 3	Voltage & frequency requirements	Rate of change of frequency (ROCOF)	More stringent	Dynamic	Frequency	Emergency	Be robust
		LFSM-O	More stringent	Dynamic	Frequency	Emergency	Give robustness
		Voltage withstand capability	More stringent	Steady State	Voltage	Normal	Be robust
		Voltage control (SPGM)	More stringent	Dynamic	Voltage	Normal	Give robustness
		Reactive power capability	More stringent	Steady State	Voltage	Normal	Give robustness
		Fault current & dyn. Voltage support (PPM)	More stringent	Dynamic	Voltage	Normal	Give robustness
Category 4	Information exchange / Telecom requirements	Information exchange	More stringent	Other	Other	Normal	Give robustness
Category 5	Balancing/congestion man. requirements	Remote control reductions	More stringent	Steady State	Frequency/curren	ormal/Emerger	Give robustness
Category 7	Emergency & restoration requirements	Automatic connection	More stringent	Dynamic	Frequency	Emergency	Be robust
		Automatic reconnection	More stringent	Dynamic	Frequency	Emergency	Be robust

Figure 19 classification of the eligible requirements

4.3 Impact and benefit for the Belgian/European transmission system

In function of their category, fulfilling the gap of type B requirements might have different impact and benefits for the security and stability of operation of the system. Below is a qualitative assessment of the impact/benefit in function of the category :

- Frequency vs Voltage vs Current:
    - By nature, frequency is a characteristic of the transmission system influencing a whole synchronous area. Lack of performance or robustness in term of frequency related requirements might then endanger the security and even expose to black-out the whole synchronous area. In this respect, they are considered a MUST for the gap assessment.

- By nature, voltage and current are considered as local characteristic of the transmission system influencing/being influenced by a limited perimeter. Lack of performance or robustness in term of voltage or current related requirements might endanger limited part of the system in first instance and might only evolve toward more global consequences if it evolves in cascading events. In this respect, it might be seen as a NICE to HAVE for the gap assessment.

- Normal vs emergency/restoration state:
  - Normal state is considered as the state where the system is operated within the operational limits and being able to face any normal or exceptional contingency. By definition, moving outside normal state will not directly means that energy will not be supplied or delivered or lead to black-out but means that the system might be exposed to reduced power quality and impacting costly measures. In this respect, it might be seen as a NICE to HAVE for the gap assessment.
  - Emergency/restoration state are states where (part of) the system is operated out of its normal operational limits and is highly exposed to a risk of black-out or is already in black-out. Lack of performance of requirements related to Emergency/restoration state exposes directly the system to a risk of black-out or increases the time to restore it to normal state. In this respect, they are considered a MUST for the gap assessment.

- Be Robust vs Give Robustness:
  - Lack of robustness of an installation means that the risk is increase that the installation will disconnect unexpectedly and might directly or as a cascading result degrade the system state with as potential consequence a risk of partial or global black out. In this respect, they are considered a MUST for the gap assessment.
  - Giving robustness shall contribute to mitigate impact for the system and might be seen as a way to support the system operator in his objective and obligation to develop and operate the system in a secure and stable way. Most of the time alternative solutions might exist and should be considered in term of technical and cost efficiency. In this respect, it might be seen as a NICE to HAVE for the gap assessment.

- The models and information exchange related requirements, these requirements have been classified as giving robustness to the grid in normal state.

Qualitative analysis of the impact and benefits :

Based on the above, the benefit of each requirement shall be considered as HIGH if at least 2 MUST are linked to the requirement. Otherwise, the score shall be considered as MEDIUM.

The qualitative analysis of the benefit for the grid can be summarized in the following table.

Category of requirements		Sub category	GAP analysis	Impact/benefit
Category 1	Data questionnaire & Models	Models	More stringent	MEDIUM
Category 3	Voltage & frequency requirements	Rate of change of frequency (ROCOF)	More stringent	HIGH
		LFSM-O	More stringent	HIGH
		Voltage withstand capability	More stringent	MEDIUM
		Voltage control (SPGM)	More stringent	MEDIUM
		Reactive power capability	More stringent	MEDIUM
		Fault current & dyn. Voltage support (PPM)	More stringent	MEDIUM
Category 4	Information exchange / Telecom requirements	Information exchange	More stringent	MEDIUM
Category 5	Balancing/congestion man. requirements	Remote control reductions	More stringent	HIGH
Category 7	Emergency & restoration requirements	Automatic connection	More stringent	HIGH
		Automatic reconnection	More stringent	HIGH

Figure 20 qualitative analysis of the benefit for the grid per eligible requirement

Moreover, the following correlation can be established between the characteristics of each requirement and the main transmission system costs/services related domain they will impact :

- Requirement that influences the **Steady State** value of the **Frequency** in the **Normal** operating range can be associated to the **mFRR (Balancing) service**
- Requirement that influences the **Dynamic** of the **Frequency** in the **Normal** operating range can be associated to the **FCR or aFRR services**
- Requirement that influences the **Steady State** value of the Voltage in the **Normal** operating range can be associated to the **Mvar service** or **installation of Self/Capa**
- Requirement that influences the **Dynamic** of the **Voltage** in the **Normal** operating range can be associated to the **Mvar with voltage droop service** or **installation of Statcom/Synchronous condenser**
- Requirement that influences the **Steady State** value of the **Current** in the **Normal** operating range- can be associated to the **Preventive Congestion management** or **Grid thermal capacity reinforcement (Ampacimon/HTLS/new connections/…)**
- Requirement that influences the **Dynamic** of the **Current** in the **Normal** operating range can be associated to the **Curative Congestion management** or **Grid thermal capacity reinforcement (Ampacimon/HTLS/new connections/System Protection System (SPS)/…)**
- Requirement that influence the **Dynamic** of the **Frequency, Voltage or Current** during **Emergency** operating conditions can be associated to the **Defense & Restoration plan** or **risk of ENI/ENS[6] up to black out**

[6] Energy Not Injected / Energy Not Supplied

The results of this exercise are summarized in the following table:

Category of requirements		Sub category	GAP analysis	Steady State vs Dynamic	Frequency vs voltage vs Current vs Other	Normal state vs Emergency	Be robust vs give robustness	Cost/Service Domain
Category 1	Data questionnaire & Models	Models	More stringent	Other	Other	Normal	Give robustness	
Category 3	Voltage & frequency requirements	Rate of change of frequency (ROCOF)	More stringent	Dynamic	Frequency	Emergency	Be robust	Defense&Restoration plan or Risk of ENI/ENS/Black-out
		LFSM-O	More stringent	Dynamic	Frequency	Emergency	Give robustness	Defense&Restoration plan or Risk of ENI/ENS/Black-out
		Voltage withstand capability	More stringent	Steady State	Voltage	Normal	Be robust	Mvar Service or Installation of Capa/Self
		Voltage control (SPGM)	More stringent	Dynamic	Voltage	Normal	Give robustness	Mvar/Voltage droop service or installation of Statcom/Synchronous Condenser
		Reactive power capability	More stringent	Steady State	Voltage	Normal	Give robustness	Mvar Service or Installation of Capa/Self
		Fault current & dyn. Voltage support (PPM)	More stringent	Dynamic	Voltage	Normal	Give robustness	Mvar/Voltage droop service or installation of Statcom/Synchronous Condenser
Category 4	Information exchange / Telecom requirements	Information exchange	More stringent	Other	Other	Normal	Give robustness	
Category 5	Balancing/congestion man. requirements	Remote control reductions	More stringent	Steady State	Frequency/curren	rmal/Emerger	Give robustness	mFRR/aFRR & Preventive/Curative congestion Management
Category 7	Emergency & restoration requirements	Automatic connection	More stringent	Dynamic	Frequency	Emergency	Be robust	Defense&Restoration plan or Risk of ENI/ENS/Black-out
		Automatic reconnection	More stringent	Dynamic	Frequency	Emergency	Be robust	Defense&Restoration plan or Risk of ENI/ENS/Black-out

Figure 21 Link between the requirements and the main transmission system costs/services they impact

4.4 Cost and effort for Customer to fill the gap (Elia estimate)

A qualitative exercise has been done in order to estimate the cost and effort it would represent for the existing PGM type B to fill their gap compared to new PGM type B requirements.

Three categories of costs have been considered:

- low = some minor adjustments (such as settings adjustments) have to be implemented
- medium = replacement of some elements of the PGM or addition of new elements have to be implemented
- high = replacement of major elements of the PGM have to be implemented

The RfG (Art. 39) specifies the categories of costs that have to be taken into account:

- direct costs
- costs associated to loss of opportunity
- costs associated to change in maintenance and operation

For this costs analysis, further inputs from market parties is crucial in order to assess more precisely the costs estimation and costs categories.

4.4.1 Type B SPGM :

- RoCoF : By definition, TYPE B SPGMs are small size generators and are able to withstand higher RoCoF than large SPGMs. For existing TYPE B SPGM, the limitation is most of the time coming from the application and setting of decoupling protection relay. The gap between existing and new requirements related to minimum RoCoF is then mainly linked to adjusting the setting of this decoupling protection. In this respect, the cost is considered as LOW.
- LFSM-O : LFSM-O is a function of the governor control. Most of the time, every SPGMs use a governor control to work, those governor control provides the possibility to adjust active power in function of the frequency/speed. In this respect, the cost is considered as LOW.
- Voltage withstand capability: the voltage withstand capability is related to the sizing of every element part of the power plant and the settings of protection. In the case the limit of operation is defined by element capacity, the effort and cost to increase it might by high but in the case the limitation is the result of a conservative protection setting, the effort and cost to change the settings can be considered as low. In this respect, the cost is considered a HIGH/LOW.
- Voltage control : SPGM needs an excitation system to work. In case the excitation system does not have an AVR, the cost is considered MEDIUM otherwise, excitation systems are controlled

by an Automatic Voltage Controller (AVR) that will provide different possibilities to adjust excitation current and impact produced reactive power. Voltage control is usually common control on top of constant reactive power and power factor. In this respect, the cost is considered as LOW

- Reactive power capability : by its design, an SPGM has a reactive power capability which usually is in line with the expected requirement. Seen from the applicable point, this capability can be shifted by the impedance of the step-up transformer. In that case, additional device (capa/self) might be needed to meet the requirement. In this respect, the cost is considered as MEDIUM/LOW
- Remote control reduction: every SPGM is equipped with a Governor control which usually has the capability to receive an active power setpoint. However, existing SPGMs were considered as non-coordinable units and then were not equipped with the ability to receive directly this setpoint from a remote location, especially from the SCADA of the system operator. In this respect, the cost is considered as MEDIUM.
- Automatic connection: In order to connect safely to the grid, any SPGM need to ensure that voltage amplitude , frequency and voltage angle are as close as possible towards the ones of the grid at the connection point. The installation is then equipped with necessary device and operated with adequate procedures to do it. The setting used by the devices and in the procedures might differ from the ones defined by the system operator and would benefit to be aligned. In this respect, the cost is considered as LOW.
- Automatic reconnection: Being non coordinable, most the Type B unit are not equipped with the ability to receive directly this setpoint from a remote location, especially from the SCADA of the system operator. In this respect, the cost is considered as MEDIUM.

4.4.2 Type B PPM :

- RoCoF : PPMs able to withstand high RoCoF. For existing TYPE B PPM, the limitation is most of the time coming from the application and setting of decoupling protection relay. The gap between existing and new requirements related to minimum RoCoF is then mainly linked to adjusting the setting of this decoupling protection. In this respect, the cost is considered as LOW.
- LFSM-O : LFSM-O is a function of the control-command of the inverter used by the Power generating unit. Most of the inverter propose the functionality by default and its activation is just a question of settings. In this respect, the cost is considered as LOW.
- Voltage withstand capability: the voltage withstand capability is related to the sizing of every element part of the power plant and the settings of protection. In the case the limit of operation is defined by element capacity, the effort and cost to increase it might by high but in the case the limitation is the result of a conservative protection setting, the effort and cost to change the settings can be considered as low. In this respect, the cost is considered a HIGH/LOW.
- Reactive power capability: by design, a PPM has the possibility to use part of its current capability to generate or absorb reactive power as required by the requirement. Nevertheless, seen from the connection point, this capability can be shifted by the impedance of the step-up transformer. In that case, additional device (capa/self) might be needed to meet the requirement. Moreover, providing specific reactive power value from the global power plant might require the presence of a Power Park Controller. In this respect, the cost is considered a HIGH/MEDIUM.
- Fault current & dynamic voltage support: by design, a PPM inverter control-command which usually allows specific controlling option in case of large voltage dip seen from the voltage at its terminal. If the option is available, it is then question of setting adjustment. If not, it will require to change the inverter. In this respect, the cost is considered a HIGH/LOW.
- Remote control reduction: For PPM, remote control reduction will require to have the option configurable in the inverter control-command. If not, it will require to change the inverter Moreover, existing PPMs were considered as non-coordinable units and then were not equipped with the ability to receive directly this setpoint from a remote location, especially from the SCADA of the system operator. In this respect, the cost is considered as HIGH/MEDIUM.

- Automatic connection: In order to connect safely to the grid, a PPM need to ensure that voltage amplitude , frequency and voltage angle are as close as possible towards the ones of the grid at the connection point. The installation is then equipped with necessary device and operated with adequate procedures to do it. The setting used by the devices and in the procedures might differ from the ones defined by the system operator and would benefit to be aligned. In this respect, the cost is considered as LOW.
- Automatic reconnection: Being not coordinable, most the Type B unit are not equipped with the ability to receive directly this setpoint from a remote location, especially from the SCADA of the system operator. In this respect, the cost is considered as MEDIUM.

The costs associated with the requirements regarding models and information exchange have been classified as low for the former and medium for the latter as a component to allow the exchange of information between the existing PGMs and Elia must be implemented.
The following table summarises the qualitative cost analysis conducted by Elia and related to each eligible requirement. By means of a questionnaire, Elia also asked the market parties to confirm the high-level cost assessment performed. This questionnaire can be found in Appendix 1 and an analysis of the responses is provided in Chapter 5.

The results of those assessments are given in the table below. The numbers in brackets indicate the number of answers received.

Category of requirements	Sub category	GAP analysis	Impact/benefit	High-level cost assessment by Elia	High-level cost assessment by market parties
Data questionnaire & Models	Models	More stringent	MEDIUM	LOW	LOW (2) / MEDIUM (3)
Voltage & frequency requirements	Rate of change of frequency (ROCOF)	More stringent	HIGH	LOW	LOW(2) / MEDIUM (1)
	LFSM-O	More stringent	HIGH	LOW	MEDIUM (4) / HIGH (2)
	Voltage withstand capability	More stringent	MEDIUM	HIGH/LOW	LOW (2) / MEDIUM (3) / HIGH (1)
	Voltage control (SPGM)	More stringent	MEDIUM	LOW	LOW (2) / MEDIUM (3)
	Reactive power capability	More stringent	MEDIUM	MEDIUM (SPGM) HIGH/MEDIUM (PPM)	LOW (4) / MEDIUM (1)
	Fault current & dyn. Voltage support (PPM)	More stringent	MEDIUM	HIGH/LOW	MEDIUM (1)
Information exchange / Telecom requirements	Information exchange	More stringent	MEDIUM	MEDIUM	LOW (5) / MEDIUM (1)
Balancing/congestion man. requirements	Remote control reductions	More stringent	HIGH	MEDIUM (SPGM) HIGH/MEDIUM (PPM)	LOW (1) / MEDIUM (3)
Emergency & restoration requirements	Automatic connection	More stringent	HIGH	LOW	LOW (2) / MEDIUM (2)
	Automatic reconnection	More stringent	HIGH	MEDIUM	LOW (2) / MEDIUM (1)

Figure 20: qualitative analysis of costs per eligible requirement

In the above table, the following colour code is used in the last column:

- Green: The market parties believe that Elia's cost assessment is correct or that the costs are slightly overestimated.
- Orange: The market parties believe that Elia's cost assessment is slightly underestimated.
- Red: The market parties believe that Elia's cost assessment is underestimated.

We can see that the market parties mostly confirmed Elia's cost assessment, except in the case of the LFSM-O. However, the two answers describing high costs come from the same grid user and both mention the need to further investigate the costs that may be incurred.

4.5 Summary table

Based on the above qualitative assessment of costs and benefits for each eligible requirement, we can then identify which of the type B SPGM and PPM requirements might benefit from further investigation into their potential application to existing PGMs.

Category of requirements	Sub category	GAP analysis	Frequency vs voltage vs Current vs Other		Normal state vs Emergency		Be robust vs give robustness		Impact/benefit	High-level cost assessment by Elia	High-level cost assessment by market parties
Data questionnaire & Models	Models	More stringent	Other	Nice to have	Normal	Nice to have	Give robustness	Nice to have	MEDIUM	LOW	LOW (2) / MEDIUM (3)
Voltage & frequency requirements	Rate of change of frequency (ROCOF)	More stringent	Frequency	MUST	Emergency	MUST	Be robust	MUST	HIGH	LOW	LOW(2) / MEDIUM (1)
	LFSM-O	More stringent	Frequency	MUST	Emergency	MUST	Give robustness	Nice to have	HIGH	LOW	MEDIUM (4) / HIGH (2)
	Voltage withstand capability	More stringent	Voltage	Nice to have	Normal	Nice to have	Be robust	MUST	MEDIUM	HIGH/LOW	LOW (2) / MEDIUM (3) / HIGH (1)
	Voltage control (SPGM)	More stringent	Voltage	Nice to have	Normal	Nice to have	Give robustness	Nice to have	MEDIUM	LOW	LOW (2) / MEDIUM (3)
	Reactive power capability	More stringent	Voltage	Nice to have	Normal	Nice to have	Give robustness	Nice to have	MEDIUM	MEDIUM (SPGM) HIGH/MEDIUM (PPM)	LOW (4) / MEDIUM (1)
	Fault current & dyn. Voltage support (PPM)	More stringent	Voltage	Nice to have	Normal	Nice to have	Give robustness	Nice to have	MEDIUM	HIGH/LOW	MEDIUM (1)
Information exchange / Telecom requirements	Information exchange	More stringent	Other	Nice to have	Normal	Nice to have	Give robustness	Nice to have	MEDIUM	MEDIUM	LOW (5) / MEDIUM (1)
Balancing/congestion man. requirements	Remote control reductions	More stringent	Frequency/current	MUST	ormal/Emerger	MUST	Give robustness	Nice to have	HIGH	MEDIUM (SPGM) HIGH/MEDIUM (PPM)	LOW (1) / MEDIUM (3)
Emergency & restoration requirements	Automatic connection	More stringent	Frequency	MUST	Emergency	MUST	Be robust	MUST	HIGH	LOW	LOW (2) / MEDIUM (2)
	Automatic reconnection	More stringent	Frequency	MUST	Emergency	MUST	Be robust	MUST	HIGH	MEDIUM	LOW (2) / MEDIUM (1)

Figure 21 : qualitative cost-benefit analysis per eligible requirement

As a result of the qualitative cost-benefit analysis, we can summarise the key findings as follows:

- Requirements with a **HIGH impact/benefit** and **NON-HIGH costs** most likely lead to a positive CBA.
- Requirements with a **MEDIUM impact/benefit** and **LOW costs** also probably have a positive CBA.
- **Other requirements should be further investigated through a quantitative CBA.**

Category of requirements	Sub category	GAP analysis	Impact/benefit	High-level cost assessment by Elia	High-level cost assessment by market parties	New result of CBA after assessment of market partie
Data questionnaire & Models	Models	More stringent	MEDIUM	LOW	LOW (2) / MEDIUM (3)	No garanty that CBA will be positive
Voltage & frequency requirements	Rate of change of frequency (ROCOF)	More stringent	HIGH	LOW	LOW(2) / MEDIUM (1)	positive CBA
	LFSM-O	More stringent	HIGH	LOW	MEDIUM (4) / HIGH (2)	positive CBA **
	Voltage withstand capability	More stringent	MEDIUM	HIGH/LOW	LOW (2) / MEDIUM (3) / HIGH (1)	No garanty that CBA will be positive
	Voltage control (SPGM)	More stringent	MEDIUM	LOW	LOW (2) / MEDIUM (3)	No garanty that CBA will be positive
	Reactive power capability	More stringent	MEDIUM	MEDIUM (SPGM) HIGH/MEDIUM (PPM)	LOW (4) / MEDIUM (1)	positive CBA
	Fault current & dyn. Voltage support (PPM)	More stringent	MEDIUM	HIGH/LOW	MEDIUM (1)	No garanty that CBA will be positive
Information exchange / Telecom requirements	Information exchange	More stringent	MEDIUM	MEDIUM	LOW (5) / MEDIUM (1)	positive CBA*
Balancing/congestion man. requirements	Remote control reductions	More stringent	HIGH	MEDIUM (SPGM) HIGH/MEDIUM (PPM)	LOW (1) / MEDIUM (3)	positive CBA
Emergency & restoration requirements	Automatic connection	More stringent	HIGH	LOW	LOW (2) / MEDIUM (2)	positive CBA
	Automatic reconnection	More stringent	HIGH	MEDIUM	LOW (2) / MEDIUM (1)	positive CBA
						* With hypothesis that the costs for bringing the signal to the PGM are limited
						** to check (answers with high costs mention that further investigation on technical capability should be performed)

Figure 22 : selection of eligible requirements for a quantitative CBA analysis

5. Answers of the market parties

As mentioned in the introduction of this report, Elia submitted a questionnaire to the market parties to collect their input on the costs induced by the application of requirements from the RfG to existing PGMs between 1 and 25MW.

One questionnaire could be completed by the same responder for multiple PGMs. The questionnaire contained the following sections (for more details, please refer to the appendix 1).

- Requirements that are impossible to implement. The idea behind this question was to identify which requirements are technically impossible to implement on old PGMs. Those requirements, if they were to be applied to existing PGMs would lead to an anticipated end of life of those PGMs.
- Qualitative cost assessment. In this part, the market parties were asked to challenge the qualitative cost assessment that was done by Elia.
- Quantitative cost assessment. Elia also asked the market parties to provide quantitative cost assessments. This cost assessment could be different for different age and power of the PGMs.
- Elia also asked some questions regarding the reinvestment and maintenances in the existing PGMs. This was also linked to a feedback of the market parties received during the workshop.

5.1 Key numbers on the answers

Elia received 8 answers of 6 different stakeholders. Among those 6 stakeholders, 5 are Elia grid users and 1 is a group of federations. The questionnaire was supposed to be completed for a given production type (Wind, Cogen unit, Solar, Turbojet, Steam Turbine, …) . As consequence, some customers provided multiple answers (one answer per PGM type).
Two of the answers are general feedback. The questionnaire provided was not completed but an answer was provided. The first answer is feedback on the incentive. The second answer is a feedback on the length of the questionnaire and a cost assessment for the repowering/modernization of PV inverters.

This results in 6 answers that provided a completed questionnaire. Two answers concern (onshore) wind turbine, two answers concern cogeneration units (WKK); one answer concerns a turbojet unit and one answer concerns a steam turbine. As consequence, we did not receive any response for the following types of PGMs : Solar, Diesel, Hydro-Run of river and incineration station.

In the end, we received 6 answers that challenge / confirm the qualitative cost assessment. More information on this can be found at the section 5.

Only 2 answers provided quantitative cost assessment with numbers.

5.2 Requirements that are impossible to implement

The answers on the market parties concerning this point are the following:

Requirement	Amount of answer marking it as an impossible to implement requirement
Models	0
Rate of Change of Frequency (RoCoF)	3
LFSM-O	1
Voltage withstand capability	1
Voltage Control (only SPGM)	1
Reactive Power Capability	1
Fault Current & dynamic voltage support (only PPM)	1
Information exchange	1
Remote control reduction	2
Automatic connection	2

Automatic reconnection	3

It is difficult to see a global trend in the answers provided. This stresses the fact that only a case-by-case application where the limiting elements can be provided by the grid users makes sense (cfr. Substantial modernization process).

5.3 Qualitative cost assessment

Among the 6 answers to the questionnaire, not all answers contained a high-level (qualitative) cost assessment for each requirement. More details about the answers of the market parties can be found at the chapter 4.

5.4 Quantitative cost assessment

As already described above, only 2 answers provided quantitative cost assessment with numbers. Most of the answers contain more details about the high-level cost assessment and about the limitations or mention that a case-by-case analysis is needed.

The first answer provides a numerical cost assessment for the requirements RoCoF, LFSM-O and Voltage withstand capability. The second answer only provides a cost assessment for the repowering/modernization of old non drivable inverters to new and drivable inverters.

5.5 Reinvestment and maintenance cycles

The answers provided by the market parties confirm that reinvestments are done on some PGMs but it is difficult to draw general conclusions considering the limited amount of answers.
The main drivers of a reinvestment decision described by the market parties are: economic viability, strategic decision, evolutions in the legislations, availability of support schemes and environmental regulations.

Concerning the maintenance, 4 answers provided more information concerning the maintenance cycles of PGMs. They all mention that a small setting change in a controller could induce costs even if it is done during a planned maintenance. Indeed, the impact of the changes need to be investigated through studies and sometimes need to be done by skilled personal. It may also impact the service contract if the PGM owner signed such a contract with the manufacturer of the PGM.

6. Conclusion

In the context of this incentive, we compiled an inventory of the PGMs that have an installed capacity between 1 and 25 MW and are considered as existing. We compared the requirements of existing type B PGMs to those applying to new type B PGMs. Based on this comparison, we made a list of eligible requirements falling within the scope of this incentive.
With regard to said requirements, we defined criteria in order to qualitatively assess their benefit for the grid. These criteria are based on the following classifications:

- Frequency VS Voltage VS Current VS Other
- Normal State VS Emergency
- Be Robust VS Give Robustness
- Static VS Dynamic

We associated each of those classifications with a *Must* or a *Nice to have* benefit for the grid.

We performed a qualitative analysis of the benefits for the grid provided by the eligible requirements. We also estimated the potential cost of applying the eligible requirements to existing type B PGMs. Based on those two exercises, we conducted a first qualitative cost-benefit analysis that allowed us to highlight some requirements for which the benefits gained appeared greater than the costs incurred.

We shared this analysis with the market parties and sent them a questionnaire in order to collect their feedback and obtain a better estimation of the costs of a potential retroactive application of those eligible requirements, with each answer received corresponding to one or more units of the same type (e.g. wind turbine, turbojet, conventional (steam) turbine).

Our analysis of the questionnaire (for which we received very few quantitative answers (in €)) highlighted the following:

- The qualitative cost assessment provided by the market parties allowed us to refine our first estimate of the costs.
- The requirements considered as technically impossible to implement by the market parties may differ greatly from one answer to the next. As such, the application of the requirements to existing units could only be beneficial if it were rolled out on a case-by-case basis taking into account any limiting elements (as is currently done in the substantial modernisation process for type C and D PGMs).
- We did not receive answers for all the PGM types that we identified.
- Based on the responses received, we concluded that the costs of applying some requirements can vary considerably based on the type of PGM, the power and the age of the unit.

Based on the cost analysis provided by the market parties, we adapted our first qualitative analysis to a "qualitative +" cost-benefit analysis (analysis taking into account input from the market parties). This allowed us to highlight requirements with a positive "quantitative +" CBA based on the following criteria:

- High benefit for the network and non-high costs
- Medium benefit for the network and low costs

The categorisation of costs as low, medium or high corresponds to changing some settings in a controller, replacing minor parts in a PGM and replacing major parts in a PGM respectively.

We concluded this exercise as detailed below:

- Based on a "qualitative +" CBA, we were able to list a set of eligible requirements that might have a positive CBA. However, this should not lead to a retroactive application of the requirements with a "qualitative +" positive CBA if no specific need to do so has been identified on the grid.
- It was not possible to perform a quantitative CBA due to a lack of detailed cost estimates from the market parties. Even with better quantitative cost estimates, it would make little sense to expand a quantitative CBA given the wide range of existing PGMs. However, it could be useful to conduct a quantitative CBA of certain requirements and PGMs if a specific need is identified on the grid. In that case, the results of the "qualitative +" CBA could serve as a valuable starting point for the application of Articles 4.1b and 4.3 of the NC RfG to existing PGMs with an installed capacity between 1 and 25 MW.
- Extending the scope of the concept of substantial modernisation to existing type B PGMs does not currently make sense if no need to do so has been identified on the grid. However, if such a need were identified, the list of requirements with a "quantitative +" CBA might be good candidates for the scope of the substantial modernisation as long as the concept of "limiting element" is taken into account. This concept would protect eligible PGM owners from excessive upgrading costs as long as they can demonstrate that the cost of the required upgrades would exceed the costs of the initial project by X%.
- Performing a detailed "qualitative +" CBA allowed us to broaden our knowledge of how to perform qualitative and quantitative CBAs. This work could serve as a strong basis for other potential applications of cost-benefit analyses as set out in the European network codes.

Elia has organised a public consultation on the incentive.
Elia has invited all stakeholders to submit any comments and suggestions that they may have on the document submitted for consultation. The consultation period ran from 06/11/2023 to 02/12/2023.

Elia has received some feed-backs to the consultation from the following market parties :

- ODE Vlaanderen (not confidential)
- FEBEG/Febeliec (not confidential)
- FEBEG (not confidential)
- Grid User (confidential)

Elia gathered the reactions and reacted to them in a consultation report (see Appendix 3). The conclusions were also discussed during the User's group Belgian Grid that occurred on 07/12/2023.

After the public consultation, Elia adapted the conclusions of the section 6 of this report in the following way:

We concluded this exercise as detailed below:

- Based on a "qualitative +" CBA, we were able to list a set of eligible requirements that might have a positive CBA. However, this should not lead to a retroactive application of the requirements with a "qualitative +" positive CBA if no specific need to do so has been identified on the grid.
- It was not possible to perform a quantitative CBA due to a lack of detailed cost estimates from the market parties. Even with better quantitative cost estimates, it would make little sense to expand a quantitative CBA given the wide range of existing PGMs. However, it could be useful to conduct a quantitative CBA of certain requirements and PGMs if a specific need is identified on the grid. In that case, the results of the "qualitative +" CBA could serve as a valuable starting point for the application of Articles 4.1b and 4.3 of the NC RfG to existing PGMs with an installed capacity between 1 and 25 MW.
- [Adapted after public consultation] Extending the scope of the concept of substantial modernisation to existing type B PGMs is not currently considered and could only make sense as soon as a need that justifies the costs induced is identified in the grid. Determining if such a need was established in the grid or not was not in the scope of this incentive. However, if such a need was identified, the list of requirements with a "quantitative +" CBA might be good candidates for the scope of the substantial modernisation as long as the concept of "limiting element" is taken into account. This concept would protect eligible PGM owners from excessive upgrading costs as long as they can demonstrate that the cost of the required upgrades would exceed the costs of the initial project by X%".
- Performing a detailed "qualitative +" CBA allowed us to broaden our knowledge of how to perform qualitative and quantitative CBAs. This work could serve as a strong basis for other potential applications of cost-benefit analyses as set out in the European network codes.

Annexes

Appendix 1

Questionnaire

INCENTIVE : COST-BENEFIT ANALYSIS ON REQUIREMENTS FOR GENERATORS APPLICABLE ON EXISTING AND NEW GENERATING UNITS BETWEEN 1 AND 25 MW

For background information, please refer to the report for the phase 1 of this incentive (preparation of work).

This questionnaire is linked to a CBA (Cost-Benefit Analysis) concerning the application of requirements derived from the RfG (EU Network Code : Requirements for Generators) (applicable to new Power Generating Modules or PGMs) to PGMs considered as existing (detailed study delivered by Elia before 27/04/2019). Elia would like to obtain more information about the cost that could be induced by the application of these new requirements on existing PGMs. On 3 July 2023, Elia and the stakeholders agreed to collect further information and submit a questionnaire to the market parties (see PV sent on 14/07/2023)

This questionnaire is divided in five parts:

1. Identification of the responder
2. Requirements which are impossible to implement
3. Cost assessment per requirement
4. Easiest requirements to implement
5. Maintenance and reinvestment cycles

1. Part 1

Identification of the responder

We ask the information below to ensure that the respondent has the adequate knowledge to be able to fill in this questionnaire. This information will be treated according to our privacy policy, which is available on our website.

Name:	**Click or tap here to enter text.**	**Surname:**	**Click or tap here to enter text.**
Company:	Click or tap here to enter text.	**Email address:**	Click or tap here to enter text.
Function:	Click or tap here to enter text.		

Identification of the PGM

We know that the cost assessment per requirement may differ greatly between different kinds of PGM. To be able to get a clear view on the costs per type of PGM, we would like you to complete this questionnaire based on **one type of PGM**. If you own multiple PGMs of different types, you are allowed to complete this questionnaire multiple times.

We identified the following categories of PGMs, between 1 and 25MW and considered as existing according to the framework of this incentive[7]. Please check the box of the type of unit you will consider while completing this questionnaire.

Classical (Steam Turbine)	☐
Diesel	☐
Hydro Unit – Run of River	☐
Incineration Station	☐
Solar	☐
Turbojet	☐
Wind Onshore	☐
WKK (Warmtekrachtkoppeling = Cogeneration unit)	☐

2. Part 2

Could you provide a list of requirements which are – according to you - impossible to implement on the type of PGM listed above? Please only mark the requirements which you consider TECHNICALLY impossible to implement.

Requirement	Is it **impossible** to implement this requirement?	What are the limiting elements?
Models	☐	Click or tap here to enter text.
Rate of Change of Frequency (RoCoF)	☐	Click or tap here to enter text.
LFSM-O (Limited Frequency Sensitive Mode – Over frequency)	☐	Click or tap here to enter text.
Voltage withstand capability	☐	Click or tap here to enter text.
Voltage control (applicable to Synchronous Power Generating Modules (SPGM) only)	☐	Click or tap here to enter text.
Reactive power capability	☐	Click or tap here to enter text.
Fault current & dynamic voltage support (applicable to Power Park Modules only)	☐	Click or tap here to enter text.
Information exchange	☐	Click or tap here to enter text.
Remote control reduction	☐	Click or tap here to enter text.

[7] For background information, please refer to the report for the phase 1 of this incentive (preparation of work)

Requirement	Is it **impossible** to implement this requirement?	What are the limiting elements?
Automatic connection	☐	Click or tap here to enter text.
Automatic reconnection	☐	Click or tap here to enter text.

3. Part 3

With the following questions, Elia would like to get an estimation of the costs that may be caused by the retrofitting of some requirements to existing PGMs.

Elia understands that associating figures to technical requirements is a rather difficult task. To facilitate this estimation, you can use orders of magnitudes, error ranges or any other potential hypothesis that helps you.

Elia understands that you may not be able to provide estimates figures for each requirement. In this case, you can skip the requirement and go to the next question. We would kindly ask you to give a short explanation why you were not able to provide the estimate for that particular requirement.

For each requirement, please provide the following:

- **The category of cost**
- **A quantitative cost assessment (best effort)**
- **(if no quantitative cost assessment can be done) A reason for not providing a quantitative cost assessment**

1. Models

1.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

1.2. Cost assessment (figures and potential comments on these figures)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justifications:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

	Commissioning date of the PGM		
	Before 2002	Between 2002 and 2012	After 2012

Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

2. Rate of Change of Frequency (RoCoF)

2.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

2.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justifications:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

3. LFSM-O (Limited Frequency Sensitive Mode – Over frequency)

3.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

3.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

4. Voltage withstand capability

4.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

4.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justifications:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

5. Voltage control (only applicable to SPGMs)

5.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

5.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

6. Reactive power capability

6.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

6.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

	Commissioning date of the PGM		
	Before 2002	Between 2002 and 2012	After 2012

Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

7. Fault current & dynamic voltage support (applicable to PPM only)

7.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

7.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

8. Information exchange

8.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

8.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

9. Remote control reduction

9.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

9.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

10. Automatic connection

10.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

10.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).

- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

		Commissioning date of the PGM		
		Before 2002	Between 2002 and 2012	After 2012
Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

11. Automatic reconnection

11.1. Category of cost

Please select one cost category		
☐ Low cost (setting change in a controller)	☐ Medium cost (upgrade of minor components of the PGM)	☐ High cost (replacement of major parts of the PGM)

11.2. Cost assessment (numbers and potential comments on these numbers)

Complete the table below with numbers, potential comments on these numbers or, if you cannot provide a cost evaluation, one of the following justification:

- Not applicable: when this case does not exist (or not in the PGMs you own).
- Not existing: when the cost assessment is impossible. (technically impossible).
- No competent resources available: when nobody in your company is able to provide a cost assessment for this requirement.
- Not enough time: when the timing does not allow to provide a quantitative cost assessment. If you had more time, you would be able to provide numbers.

You are allowed to split you answer based on the age of the PGM and on the rated power of the PGM. Remember that you give your answer for the type of PGM selected in the part 1 of this questionnaire.

	Commissioning date of the PGM		
	Before 2002	Between 2002 and 2012	After 2012

Rated Power of the PGM	1-10 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.
	10-25 MW	Click or tap here to enter text.	Click or tap here to enter text.	Click or tap here to enter text.

4. Part 4

If you had to implement 3 requirements mentioned above, which 3 would be the easiest (cheapest) for you to implement?

Click or tap here to enter text.

5. Part 5

According to the understanding of Elia, the PGM-owners often reinvest in their assets at the end -of- life of those assets. Does your company also consider reinvestments? If yes, could you describe these reinvestment cycles? Hereunder you can find a list of questions for inspiration. Feel free to add other relevant aspects in your answer.

Did you already reinvest in an existing PGM?
How often do you reinvest in a production asset? Does it depend on the technology of the PGM?
Do you increase the power of the asset during this reinvestment? If yes, to which extend?
What are the factors that may influence the reinvestment decision?

Click or tap here to enter text.

Elia would also like to better understand the maintenance operations performed on the existing PGMs. At which frequency do you execute maintenance operations on your generation assets? What are the costs of these maintenance operations? If you had to update some parameters on the controller of your PGM during a planned maintenance, how would the price of the maintenance evolve? Would it rise by 10%? 50%? 100%? Feel free to add any other relevant element in your answer.

Click or tap here to enter text.

6. Conclusion

Elia would like to thank you for completing this questionnaire! It will enable us to provide a clear vision on the impact of changing the technical requirements for "existing" PGMs between 1 and 25MW, and provide the CREG with an final report with feedback on this incentive.

If you want to provide us with some additional feedback, you can use the box below.

Click or tap here to enter text.

Appendix 2 : PV of the workshop 03/07/2023

Report meeting 03/07/23

In the framework of the incentive *Cost-Benefit Analysis On Requirements For Generators Applicable On Existing And New Generating Units Between 1 And 25 MW*, Elia organized on 03/07/23 a meeting with its stakeholders to discuss (and challenge) the results of the phase 1of the incentive (preparation of work) . This preparation of work includes among others:

- an inventory of the existing and new PGMs (power generating modules) connected to Elia grid with a nominal power between 1 & 25 MW (not included)
- a comparison and a gap analysis between the requirements applicable to existing and new PGMs connected to Elia grid with a nominal power between 1 & 25 MW (not included)
- a selection of relevant requirements to be further evaluated through a qualitative CBA
- for the selected requirements, an evaluation of the benefits for the grid and a high level estimation of costs to be taken into account for the upgrade to the new requirements
- a methodology for qualitative CBA of applying the applying the requirements of new type B PGMs to existing type B PGMs.

The second objective of this meeting was also to request inputs from the market parties for the cost evaluation for existing PGMs for the upgrade needed in order to be compliant with the new requirements.

The main industrial federations were represented and some of their members also joined the meeting.
List of registered participants : Michaël Van Bossuyt (Febeliec), Jean-François Waignier (Febeg), Ruben Laleman (Engie), Matteo Menschaert (Engie), Etienne Burniat (Engie), Frank Buyse (Engie), Quentin Renoy (Engie), Karim Karoui (Engie), Wout Vanheusden (Eon), Michaël Gay (Eon), Tom de Waele (Eneco), Dave Vercruysse (Aspiravi), Erik Devis (Eneria), Keith Chambers (Caterpillar), Jean Marc Saliez (Eneria), Freddy Eduardo Alcazar Barrientos (Innio), Stefan Reyniers (CogenVlaanderen), Thomas Holderbeke (Luminus), Chris Celis (Ode).
List of participants: Buyse Franck (Engie), Chris Celis (ODE), Dave Vercruysse (Aspiravi), de Waele Tom (Eneco), Decoster Luc, Erik Devis (Eneria), Gay Michaël (Eon), Hans Vandersyppe, Holderbeke Thomas (Luminus), Jean-François Waignier (Febeg), Jean-Marc Saliez (Eneria), Keith Chambers (Caterpillar), Laleman Ruben (Engie), Stefan Reyniers (CogenVlaanderen), Van Bossuyt Michaël (Febeliec), Nicolas Bragard (Elia), Olivier Bronckart (Elia), Clément Hoedenaeken (Elia).

Consequences and scope of this incentive
A first concern was raised about the consequences of this incentive. Elia reminded the stakeholders that a positive Cost Benefit Analysis will not automatically lead to a retrofit of the requirement concerned to the existing PGMs. According to the stakeholders, the way to introduce possible settings changes will also have impact on the cost of these changes. Executing the changes outside the natural maintenance cycles of the PGMs could lead to an increase of the costs.
The stakeholders wanted to clarify that the gap analysis is done between the requirements applicable to existing PGMs and the requirements applicable to new PGMs in the sense of the RfG of 14 April 2016. The gap with the second version of the RfG (not yet published) is not in the scope of this incentive.
The stakeholders were also curious about the amount of PGMs connected to the DSO networks. Considering that many small PGMs are also connected to the DSO network, the stakeholders wondered if there was an added value to impose some changes only to a subset of all the PGMs between 1 and 25MW connected to the network.

Feedback on the qualitative cost assessment done by Elia
The feedback from the stakeholders was rather positive. The costs estimated by Elia for the implementation of each requirement were not rejected upfront but the stakeholders often mentioned the need to split the PGMs into different families and to evaluate the costs per family. The following divisions were proposed:

- Split based on the type of technology (SPGM/PPM). Ex: costs may be different for inverter-based technologies than for synchronous machines
- Split based on the technology. Ex: cost may be different for a wind turbine or for a PV park
- Split based on the size of the PGM. Ex: costs may be different for a 1MW or 24.9 MW PGM
- Split based on the age of the technology. Ex: costs may be different for a 20 years old PGM or for a 5 years old PGM

This last remark stressed the need to also have the information on the age of the PGMs in the final report of this incentive. The stakeholders explained that the age of the PGM is an important information because those assets follow reinvestment cycles. At the end of a cycle they are either decommissioned or a new investment is done. The repowered PGMs may then be in the scope of the substantial modernization process and as consequence, they could already become compliant with some or all the requirements applicable to new PGMs.

The stakeholders understood the high-level categorization of the costs. The stakeholders and Elia agreed that there is a difference between putting an available capability in an existing PGM at disposal of the grid (ex. changing some settings in a controller) and actually building a capability that was not designed and foreseen in the existing PGM. The latter being most likely to induce high costs or to lead to the decommissioning of the PGM. However, the stakeholders also mentioned that even a low cost change may not always be easy to execute. Some industrial companies have a limited knowledge on the installations running in their facilities (e.g.: when the PGM is linked to a maintenance contract) and sometimes, the manufacturer of the equipment's does not exist anymore. In that case the cost assessment would only make sense on a case-by-case basis.

Feedback on the next steps (quantitative CBA)

Based on all the elements described above, the stakeholders expressed their doubts concerning the ability of Elia to realize a reliable quantitative CBA for applying new requirements to existing PGMs. The costs may differ greatly between different categories of PGMs (see split on different criteria hereinabove) and collecting numerical data about the costs for all these categories will be difficult (or even impossible). The stakeholders doubt that Elia could get a numerical result on the CBA with a reasonable error range.

For this reason, the stakeholders do not see the added value for Elia to perform a quantitative CBA while a qualitative CBA complemented by a cost collection from market parties can lead already to interesting and more robust findings.

Questionnaire

However, Elia and the stakeholders agreed that Elia will send a questionnaire to the stakeholders to collect as much numerical information as possible on the costs side of the CBA. The questionnaire seems to be the best solution because a cost evaluation takes a lot of time.

This questionnaire will contain the following requests :

- As detailed as possible cost evaluation for each requirement
- A list of the requirements which are technically impossible to implement
- A selection of the easiest requirements to implement // a ranking of the requirements by feasibility
- A comment section for each requirement and for the whole process
- Questions on the maintenance and reinvestment cycles

The results collected through this questionnaire will be part of the final report of this incentive to the CREG.

Appendix 3 : Summary of the reactions to the public consultation

Elia has organised a public consultation on the incentive *Cost-Benefit Analysis on Requirements for Generators applicable to existing and new Generating Units between 1 and 25 MW*.
Elia has invited all stakeholders to submit any comments and suggestions that they may have on the document submitted for consultation.
The consultation period ran from 06/11/2023 to 02/12/2023.

Elia has received some feed-backs to the consultation from the following market parties:

- ODE Vlaanderen (not confidential)
- FEBEG/Febeliec (not confidential)
- FEBEG (not confidential)
- Grid User (confidential)

Topic	Stakeholder	Remark	Actions undertaken by Elia
General remark	Ode Vlaanderen, FEBEC, FEBELIEC	Appreciation of efforts made by Elia and the opportunity to react to the public consultation on this incentive.	Elia thanks the market parties for this supporting message and their reactions to the consultation.
Great variety of existing PGMs	ODE Vlaanderen	ODE points out that although the outome of the CBA seems positive on some technical parts, there is a great variety of renewable PGMs that would be affected by it. The outcome of the quantitative and qualitative analysis can not be generalized for all assets that are in scope of the CBA.	Elia agrees with the fact that the great variety of existing PGMs and the great variety of costs associated to a potential upgrade do not allow to draw general conclusion that could be applicable directly on existing PGMs based on quantitative CBAs. However, it could be useful to conduct a quantitative CBA, based on case-by-case analysis of certain requirements and PGMs if a specific need was identified on the grid. The concept of limiting element should be always taken into account in order to avoid any excessive costs for the existing PGMs.
	FEBEG	FEBEG fully agrees with following statement made by ELIA “It is difficult to see a global trend in the answers provided. This stresses the fact that only a case- by-case application where the limiting elements can be provided by the grid users makes sense”.	
Complexity to perform CBAs	ODE Vlaanderen	ODE mentioned that not all modifications are technically possible and definitely not financially viable for many existing PGMs. Although the sector has provided input for the CBA this complexity is not fully visible in the report.	Elia totally agrees with the complexity of performing relevant quantitative CBAs for a whole group of PGMs due to the vastness of scope and the big variation of technologies and lifetime of existing PGMs. Furthermore, performing CBAs on a wide range of PGMs is time consuming with important uncertainties regarding the results of the CBAs due to the wide range of situations to be taken into account.
	FEBEG/Febeliec	- The high technicality of the topic, the huge efforts that were needed to perform the study and the high complexity of the practicalities behind the study are for FEBEG and Febeliec already a clear indication that performing such CBA is extremely complex and therefore unlikely to results in simple and straightforward conclusions. It is also time consuming for the market parties. - The study highlighted the vastness of the scope (more than 100 PGMs) and the big variation in the technologies and lifetimes of the assets which adds to the complexity.	

	FEBEG	- On the lack of quantitative information given by market parties, FEBEG refers to the above comments. Indeed, the analysis is only possible "case by case" and no high level conclusion is possible. Therefore, an evidence based and reliable cost assessment is practically impossible. To have reliable and accurate estimates of the costs, in depth studies, performed by external consultants and experts in Grid Code requirements, would be needed for dozens of assets. This would take several months, and the costs would be too high compared to any potential benefits.	
Quantification of the benefits /"Qualitative +" CBA results	FEBEG/Febeliec	Potential benefits are still not sufficiently quantified and for FEBEG and Febeliex it is very unlikely that these would be higher than the costs.	As explained, performing CBAs on a wide range of PGMs is particularly complex. For the benefits quantification, Elia developed in the report a qualitative methodology based on Elia's expert views. This qualitative quantification of the benefits compared to the costs given by the market parties allowed to draw high level conclusions on some requirements that could have a positive CBA based on this "qualitative +" CBA methodology. However, this should not lead to a retroactive application of the requirements flagged with a positive "qualitative +" CBA if no specific need to do so has been identified on the grid and without taking into account the concept of "limiting element".
	FEBEG	FEBEG cannot agree with many of the "high level" conclusions that have been made by ELIA in the qualitative assessment. Indeed many of the qualitative assessments as performed by ELIA (based on internal and therefore limited knowledge) were clearly not in line with the feedback that was given by the market parties, who know best the assets they own and for which they are responsible. Overall, one could wonder what is the value of such qualitative analysis if not based on the real life experience with and in-depth knowledge of the technical reality behind the PGMs	
Retroactive application of requirements to existing PGMs	ODE Vlaanderen	ODE Vlaanderen wants to emphasize the objection to any changes in RfG for existing PGMs since this would severely endanger the economic viability and could lead to renewable production capacity exiting the market. Ode warns that depending on the age and type of generators, the investment costs to comply with any changes could be too high causing a loss in capacities.	- Based on a "qualitative +" CBA, Elia proposed a set of eligible requirements that might have a positive CBA. However, this should not lead to a retroactive application of the requirements with a "qualitative +" positive CBA if no specific need to do so has been identified on the grid. - Even with better quantitative cost estimates, it would make little sense to expand a quantitative

	FEBEG/Febeliec	- FEBEG and Febeliec are strongly against any ex-post implementation of grid code requirements as this would create extreme legal uncertainty and create a precedent for other retro-active changes to grid codes in the future. - Societal costs could be very high when taking into account the possible (early) termination of existing PGMs, the shock of ex-post interventions and therefore lost of confidence and trust for future projects and overall negative signale to the market parties.	CBA given the wide range of existing PGMs. However, it could be useful to conduct a quantitative CBA of certain requirements and PGMs if a specific need is identified on the grid. In that case, the results of the "qualitative +" CBA could serve as a valuable starting point for the application of Articles 4.1b and 4.3 of the NC RfG to existing PGMs with an installed capacity between 1 and 25 MW. - **In any case, the retro-active application of one or several requirements is not foreseen in the scope of this incentive.**
	FEBEG	The big issues with a potential ex-post implementation of requirements on a high-level basis is already very clear from the table on page 45 which shows that only 1 requirement could be considered (models) since all the other requirements are simply technically impossible. For FEBEG the conclusion is very simple: the CBA demonstrated that any ex-post implementation is impossible except for "models". We can in therefore remove all the other requirements in the list. In addition, we wish to underline that modelling could nevertheless be very difficult and/or impossible for older assets (as you just cannot get the information). Putting "zero" for the modelling, is already far-fetched and very optimistic in our opinion.	
Extension of the scope of the substantial modernisation	FEBEG/Febeliec	- FEBEG and Febeliec we can align with the following specific conclusion, taking into account that extending the scope to existing type B PGMs is therefore currently not considered : "Extending the scope of the concept of substantial modernisation to existing type B PGMs does not currently make sense if no need to do so has been identified on the grid. However, if such a need were identified, the list of requirements with a "quantitative +" CBA might be good candidates for the scope of the substantial modernisation as long as the concept of " limiting element" is taken into account. This concept would protect eligible PGM owners from excessive upgrading costs as long as they can demonstrate that the cost of the required upgrades would exceed the costs of the initial project by X%".	- Elia confirms that the extension of the scope of the substantial modernisation is not currently considered as long as there is no need on the grid identified to do so. - Detecting potential needs on the grid was not in the scope of this incentive. - Elia will adapt the conclusion in order to clarify this point: "Extending the scope of the concept of substantial modernisation to existing type B PGMs is not currently considered and could only make sense as soon as a need that justifies the costs induced is identified in the grid. Determining if such a need was established in the grid or not was not in the scope of this incentive. However, if such a need was identified, the list of requirements with a "quantitative +" CBA might be good candidates for the scope

			of the substantial modernisation as long as the concept of " limiting element" is taken into account. This concept would protect eligible PGM owners from excessive upgrading costs as long as they can demonstrate that the cost of the required upgrades would exceed the costs of the initial project by X%".
Application of the requirements	Grid User (confidential)	- Grid User can follow the reasoning to apply the more stringent requirements of new generators to existing generators, for fuel-based generators that can be steered. - The application of these requirements do not make sense for generators linked to chemical processes. As the energy of these generators is delivered by a chemical process, which is interrupted anyhow during a serious voltage dip, they are anyhow unavailable to help to counter this. These process generators can only comply to the following two requirements: -Voltage withstand capacity -Reactive power	- Elia points out that European network codes, requirements of general application and Federal and regional grid codes describe connection requirements which are applicable to either existing or new PGMs as soon as they are connected to the grid. No distinction is made for generators that can be steered versus generators linked to chemical processes.