BALANCING PRODUCT SPECIFICATIONS

Frequency restoration product specifications and the role of fast reserve generators

Wärtsilä Finland Oy

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Task and objective:

- What should be the properties and specifications for balancing products for frequency restoration (secondary control) in a system with a high degree of renewable sources (more fluctuations / less inertia) that provide adequate frequency quality for the Continental European synchronous power system?
- How does a selection of properties and specifications for balancing products (as mentioned above) influence the system costs?

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Reference to part of this report which may lead to misinterpretation is not permissible.

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1 EXECUTIVE SUMMARY

This report presents the results of a study performed to investigate the requirements for and impacts of properties and specifications for balancing products for frequency restoration reserves (FRR) in a representative future power system. The following research questions to be answered in this study were formulated:

– What should be the properties and specifications for balancing products for frequency restoration in a system with a high degree of renewable sources that provide adequate frequency quality for the Continental European synchronous power system?
– How does a selection of properties and specifications for balancing products influence the system costs?

To answer the research questions, a two-step approach was taken. First, using a technical model, the adequacy of different balancing products was assessed. Next, selected combinations of specifications on frequency restoration reserves have been evaluated in an economic model of the European power system. This step gives a quantitative analysis on how the reserve requirements impact the operational expenses of the system and the availability and reservation of capacity for power balancing purposes. The operational expenses assessed relate to keeping balancing capacity available for the system. Throughout the course of the project the relation between the different requirements for FRR were considered from a broader perspective which led to the following observations.

FRR capacity

The system response performance rapidly deteriorates if the available capacity is less than the open loop imbalance. If the capacity is increased beyond the open loop imbalance, the increase in system performance depends mainly on the nature of the imbalance and the reserve activation regime.

Full activation time of spinning capacity

Decreasing the full activation time (increasing speed) of FRR leads to significant system performance improvements in the simulated trip studies. Since activation is governed by the system's automatic generation control (AGC), this requires the AGC is adapted appropriately.

Percentage of non-spinning capacity

Spinning FRR can be replaced by fast non-spinning FRR (as specified in this study) while improving the system response, subject to two conditions. Firstly, the full activation time of the non-spinning reserves is shorter than the full activation time of the spinning reserves they replace. Secondly, the AGC is adapted appropriately to accommodate the faster reserves. As such, without changing the requirements regarding activation time on spinning FRR, the system response can be improved by replacing part of the spinning FRR by non-spinning FRR.

Full activation time versus capacity

The base case simulation contained 750MW of FRR in the Netherlands (linearly scaled to other countries in Europe as explained in chapter 3) with a full activation time of 900s. It was found that when comparing either increasing the capacity to 1000MW or decreasing the activation time to 675s (both yield comparable improvement in system response to a generator outage under the pro-rata activation regime) that decreasing the activation time yields less increase of operational expenditures than increasing the capacity.

Renewable providing downward FRR

Having renewable generation (solar and wind) providing downward FRR (up to 10% of the momentary value) decreases the operational expenditures.

Cross-border sharing of reserves

Allowing cross-border sharing of FRR without considering transmission limitations decreases operational expenditures on a European level but not necessarily on a country level. Cross-border reserve sharing reduces the market share for fast reserve generators as the spare generation capacity within Europe is more optimally used for reserve provision.

Fast reserve generators

Fast reserve generators (as specified for this study in chapter 3) compete with running inflexible thermal generation (e.g.: coal and CHP) in the provision of FRR. If fast reserve generators are present in the generation portfolio they have a significant impact on the distribution of upward FRR by also contributing to the upward FRR availability. They have a marginal impact on the distribution of downward FRR.

In general the following preference ranking can be set up for the provision of upward FRR. The order is from most preferable (1) to least preferable (4).

1. Available headroom capacity regardless of reserve requirement (generators on partial load, must run CHP, marginal units)
2. Non-spinning reserve provision from fast reserve generators
3. Spinning reserve provision from coal fired power plants dispatched because of the reserve requirement
4. Spinning reserve provision from gas fired power plants dispatched because of the reserve requirement (assuming a high gas-price; for low gas-price this option can become preferred to the above option of dispatching coal-fired power plant to provide reserve capacity.

Portfolio impact

The conclusions above hold for the different generation portfolios in the Netherlands that were studied (high wind, high PV and high coal). However, in a portfolio with a high share of inflexible thermal generation the market share of fast reserve generators is less. In such a portfolio, more reserve capacity is provided using the spare generation capacity of inflexible thermal generation operating at part-load.

The results and conclusions presented in this report hold for the variations within the simulated domain only. Also as the actual system response depends on the composition of the frequency restoration portfolio, in the technical part of this study a homogeneous composition of FRR was assumed since the objective is to find generic requirements which would apply to all reserves participating in balancing.
All economic observations and conclusions relate to the availability of FRR only. Costs and revenues related to the activation of FRR depend on whether bids for FRR are actually activated. The actual activation depends amongst others on the amount of imbalance, the position in the merit-order for balancing energy and the activation mechanism. This analysis is explicitly excluded from this study.

2 INTRODUCTION

Wärtsilä Finland Oy has asked DNV GL – Energy for a study into the required characteristics of balancing products. In December 2013 to April 2014, DNV GL – Energy carried out this study, investigating both technical and economic aspects for different balancing products. This report describes the context, methodology, results and conclusions of this study.

2.1 Framework setting

In any electricity system there must always be a balance between supply and demand. Any mismatch between the two will lead to a frequency deviation and, in a synchronously interconnected power system, also to deviations from the scheduled exchanges. In order to keep and restore the power balance of the power system, ancillary services for active power balancing are used.
In Europe, to deal with mismatches between generation and load, the European Network of Transmission System Operators for Electricity (ENTSO-E) has set up the Network Code on Load Frequency Control and Reserves. This network code aims at /1/:

- Achieving and maintaining a satisfactory level of System Frequency quality and efficient utilization of the power system and resources;
- Ensuring coherent and coordinated behaviour of the transmission systems and power systems in real-time operation; and
- Determining common requirements and principles for frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR); determining common requirements for cross-border exchange, sharing, activation and sizing of reserves.

The Network Code on Load Frequency Control and Reserves defines multiple types of balancing processes and corresponding products as can be observed in **Figure 2-1**.

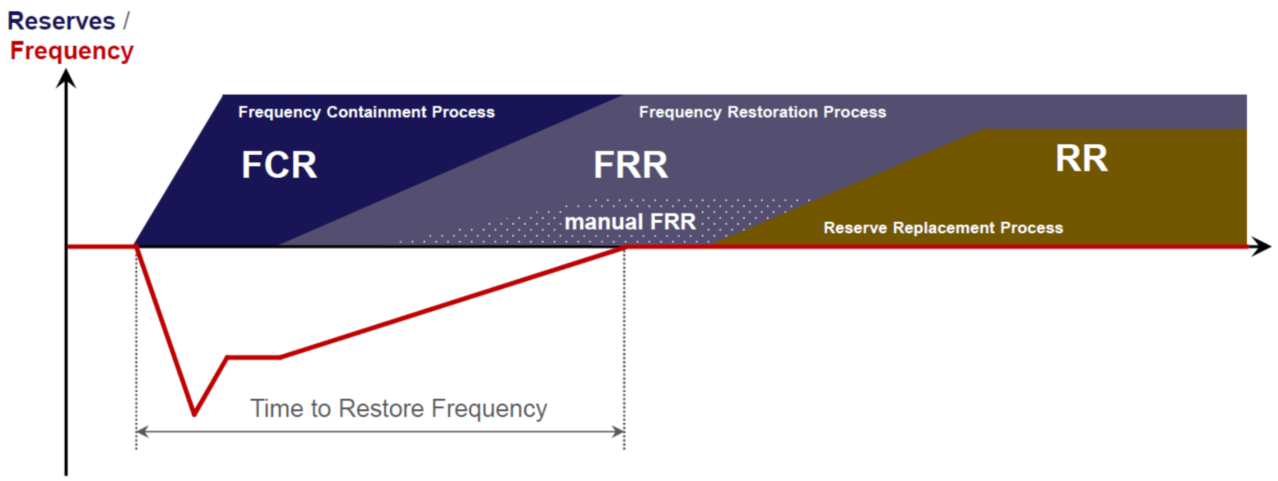

Figure 2-1 Resources for power balancing as defined by ENTSO-E /2/.

- The frequency containment process is the process that aims at stabilizing the system frequency by compensating imbalances by means of appropriate reserves /1/.
- The frequency restoration process is the process of activating active power to restore system frequency to the nominal frequency. If the synchronous area consists of more than one load frequency control (LFC) area it also has the objective to restore the power balance to the scheduled value /1/.

- The reserve replacement process concerns the process of restoring/supporting the required level of FRR in order to be prepared for additional system imbalances /1/.

To determine the requirements for the balancing resources, the Network Code on Load Frequency Control and Reserves gives frequency quality target parameters /1/. According to /1/ the frequency restoration reserves and replacement reserves have to fulfil these requirements such that the target parameters are satisfied. This study focusses on the frequency restoration process.

2.2 Study objective

According to /1/ all Transmission System Operators (TSOs) of a load frequency control block shall determine the ratio of automatic FRR capacity, manual FRR capacity, automatic FRR full activation time, manual FRR full activation time such that the quality requirements are fulfilled. Currently ENTSO-E is in the process of defining the balancing requirements /1/,/3/. One of the objectives is to promote international cooperation in balancing /4/. To obtain a so-called common merit order lists (CMOL) standardization of balancing products is required /3/. In the process of defining requirements for balancing products the question arises whether different parameters (such as for example activation time and capacity) are exchangeable.

Wärtsilä Finland Oy (hereafter Wärtsilä) has built up a portfolio of reciprocating engine based power plants. These types of plants distinguish themselves for their fast start-up and ramping capabilities compared to many other types of conventional plants. In a previous study from 2012 for Wärtsilä, DNV GL (former KEMA) showed the following aspects within the selected simulation framework.

- Regarding second-scale events the frequency response is dominated by the trade-off between response time (ramping capabilities) and the system inertia. As such for the system there is no visible negative effect of the decreasing inertia in the system as this is compensated by high enough ramp rates.
- Regarding slightly slower effects (several seconds), adding fast ramping generators to the power system increases the primary response (FCR) of the system which leads to better frequency stability.

To obtain more insight in the aspects that impact general requirements for frequency restoration reserves, to determine the possible contribution of reciprocating engine based power plants in load frequency control and to evaluate the impacts of balancing product requirements on operational expenditures by influencing economic dispatch, DNV GL carried out this additional concept study on behalf of Wärtsilä. This document provides the reader with adequate background information for further discussion on this subject.

2.3 Research questions and approach

From the problem description two research questions were distilled:

What should be the properties and specifications for balancing products for frequency restoration (secondary control) in a system with a high degree of renewable sources (more fluctuations / less inertia) that provide adequate frequency quality for the Continental European synchronous power system?

How does a selection of properties and specifications for balancing products (as mentioned above) influence the system costs?

To answer the research question above the study focusses on the following topics:

- Amount of frequency restoration reserves
  A TSO should acquire sufficient reserves to deal with imbalances in the power system. One objective of the study is to define the amount of required reserves.
- Ratio of spinning and non-spinning capacity as balancing product
  Whereas the Network Code on Load Frequency Control and Reserves elaborates on automatic and manual FRR capacity, this study expands these resources into spinning and non-spinning resources with the objective to determine whether (part of) the spinning FRR capacity can be replaced by non-spinning FRR capacity1.
- Preparation period
  Any non-spinning capacity needs a preparation period. This is defined as the time between first request for power and first delivery or withdrawal of power.
- Ramping period
  This is the time between first delivery (or in case of down-regulating, withdrawal of) power until time of full capacity.
- Renewable generation providing down regulating reserves
  If part of the reserve requirement is fulfilled by renewable generators, how does this effect system operational expenses and the utilization of fast responding reserves?

2.4 Scope of the study

The general setup of the research is to perform a technical analysis first to determine what the technical requirements of frequency restoration reserves should be. Secondly, for selected cases an economic analysis shows how these requirements impact the operational expenses of the power system. Combined, these two analyses lead to a proposed set of requirements for frequency restoration reserves.

The focus of this study is on the power system in Central Europe. The models applied in this study have the Netherlands modelled in detail whereas other European countries are modelled on a more aggregate level. However, the approach was chosen such that by applying different portfolio scenarios for the Dutch generation portfolio, the results of the Dutch power system can be generalized (e.g.: for other countries) to portfolios with substantial more photovoltaic or more coal-fired capacity.

The study focusses on the requirements for the reservation and activation of frequency restoration reserves. As such specific requirements on frequency containment reserves or on replacement reserves are not explicitly investigated. More information on frequency containment reserves can be found in /8/. The replacement reserves are implicitly taken into account by not incorporating the replacement of frequency restoration reserves. Normally, the replacement reserves are used to relief frequency restoration reserve by providing the required balancing energy after 15 minutes of the start of the imbalance (see also **Figure 2-1**). However, the replacement of frequency restoration reserves is not explicitly modelled in the technical analysis: it is assumed that the balancing energy is provided for the duration of the imbalance.

More modelling specific assumptions and boundary conditions are given in chapter 03.

[1] Here we assume non-spinning capacity to have a defined fixed set of characteristics as elaborated in chapter 3 of this report.

2.5 Scenarios

As phrased above, the focus of this study is on the Central European power system with the Netherlands in detail. Therefore the Netherlands is modelled in detail and other European countries are modelled on an aggregate level according to ENTSO-E's "EU2020" scenario /5/. The EU2020 scenario will be explained further in section 2.5.1.To be able to elaborate on the impact of a generation portfolio composition and to be able to obtain more generic observations, multiple scenario variations are introduced. The following subsections elaborate on the scenario variations that apply to the portfolio of the Netherlands. For the other countries of the European power system, the generation portfolios are identical for all scenarios.

2.5.1 Portfolio: Base case

The base case (Netherlands 2020 high wind) of this study corresponds to ENTSO-E's "EU2020" scenario /5/. The "EU2020" scenario is a high wind case and was selected as the base case as it is often assumed that the frequency stability is jeopardized by replacing conventional generation with renewables. The generation portfolio of this scenario is such that the share of wind power is occasionally more than 50% of the momentary load in the Netherlands, while also surrounding countries have considerable shares of wind power compared to their demand. In the portfolio also a large share of CCGT is present. This is illustrated in Appendix A. The following figures display the composition of the generation portfolios.

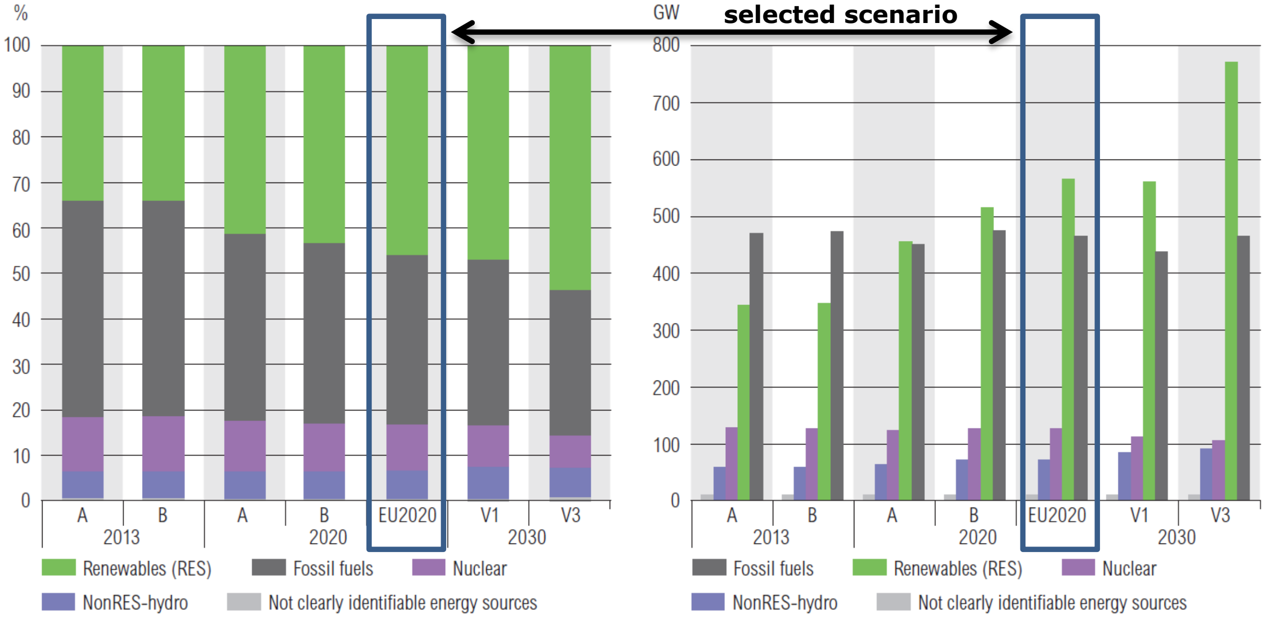

Figure 2-2 ENTSO-E generation scenarios /5/**. The scenario selected for this study is marked with the boxes.**

The generation capacity indicated by Renewable Energy Sources (RES) in **Figure 2-2** is composed of different sources as can be observed in **Figure 2-3**.

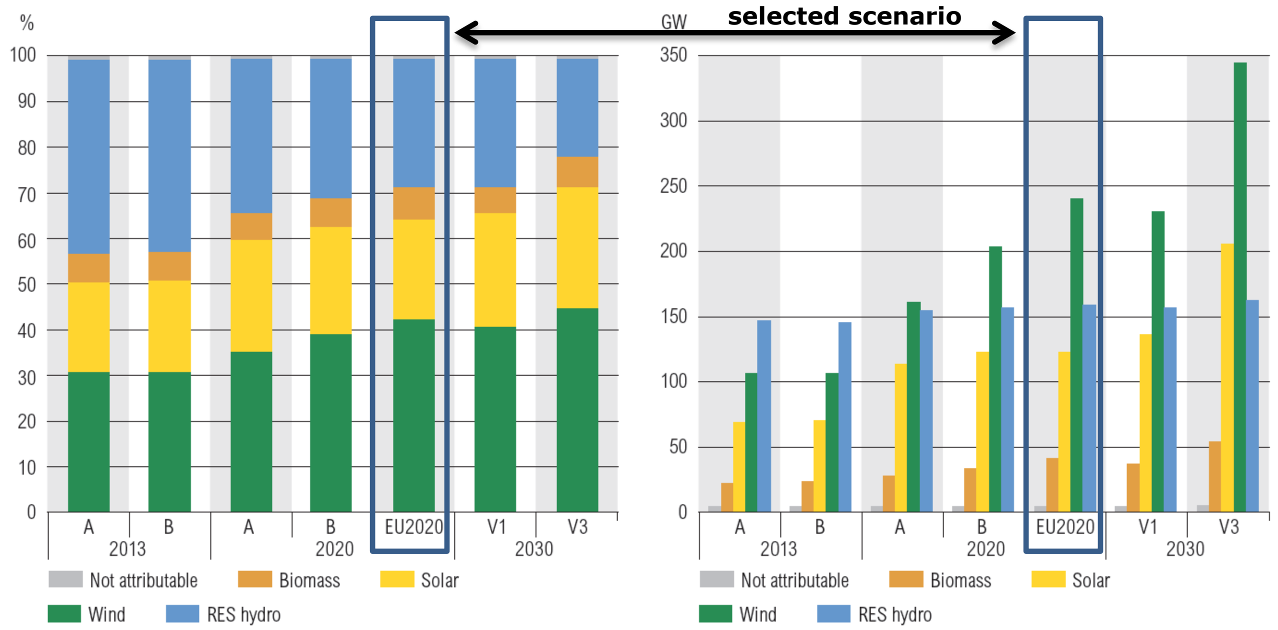

Figure 2-3 Composition of the renewable generation for the ENTSO-E generation scenarios /5/. The scenario selected for this study is marked with the boxes.

2.5.2 Portfolio: Netherlands 2020 high PV

To observe the impact of portfolios with high degrees of photovoltaic generation (such as for example Germany), a scenario variation was introduced to obtain a portfolio that more closely reflects the German portfolio: the photovoltaic generation capacity was increased by replacing part of the offshore wind and CHP generation capacities. The total generation capacity in this portfolio in the Netherlands is higher than in the base case. **Figure 2-4** shows the generation mix for the high PV portfolio. It can be observed from **Figure 2-4** that the share of PV is higher than in the high wind base case portfolio.

2.5.3 Portfolio: Netherlands 2020 high coal

To observe the impact of portfolios with high degrees of coal generation (such as for example Poland), a scenario variation was introduced to obtain a portfolio that more closely reflects the Poland portfolio. As such, the coal power plant generation capacity was increased by replacing the offshore wind and part of the CHP capacities with coal fired generation as can be seen in **Figure 2-4**. The total generation capacity in this portfolio in the Netherlands is slightly smaller than in the base case.

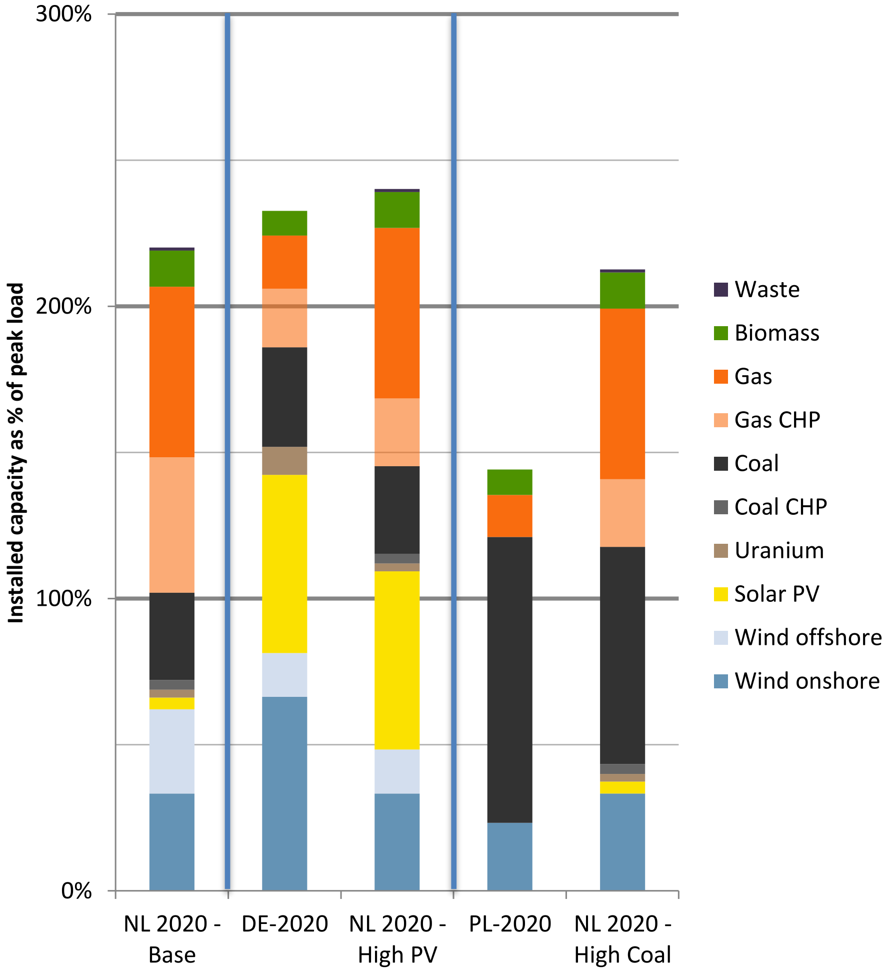

Figure 2-4 Generation portfolio mix for the base, high PV and high coal scenarios.

2.5.4 Additional scenario variations

Besides the portfolio scenarios in which the generation portfolio of the Netherlands was modified to identify the impact of a portfolio composition, other variations were introduced to see the impact on system operational expenses.

- Renewable generation providing down reserves
  In this scenario variation both wind and photovoltaic generation throughout entire Europe can decrease their generation up to 10%[2] of the momentary value to provide downward reserves. It is assumed that as the degree of penetration of renewable generation increases, the regulatory framework will be adjusted to incentivise this. Upward reserve provision by renewable generation is not considered in this study as it would require continuous curtailment of renewable generation.
- Fast reserve generators providing frequency restoration reserves
  In this scenario variation it is assumed that fast reserve generators are installed in the Netherlands up to 100% of the frequency restoration reserve required capacity. As the economic model will perform a unit commitment and economic dispatch optimization it determines whether these generators are actually applied as either spinning or non-spinning capacity. The fast reserve generators applied in this study have properties as defined in section 3.3.3.

2 10% was chosen to get a clear indication on the qualitative impacts of this variation.

- Cross-border procurement
  As phrased in /4/ the Network Code on Electricity will facilitate promoting the exchange of balancing services and sharing of balancing services. In this context it is to be expected that the exchange of balancing services will increase in the next years. To evaluate the impact of this a scenario variation was included in which the exchange of balancing services is fully enabled.

2.6 Report structure

In chapter 3 of this report the methodology is elaborated in detail. This includes both the technical as well as the economic simulation frameworks used in this project. Chapter 4 gives a further description of the case studies that were simulated of which the results are given in chapter 5. Chapter 6 of this document gives the conclusions of the project including answers to the research questions phrased in this chapter.

3 METHODOLOGY

3.1 Introduction

To answer the research questions mentioned in chapter 2 of this report this chapter will elaborate on the methodology applied.

3.2 Process

The two research questions of this project require a methodology containing a number of sequential steps. The first research question will be answered from a technical point of view using the KERMIT[3] model, whereas the second research question will be answered from an economic context using the PLEXOS[4] model.

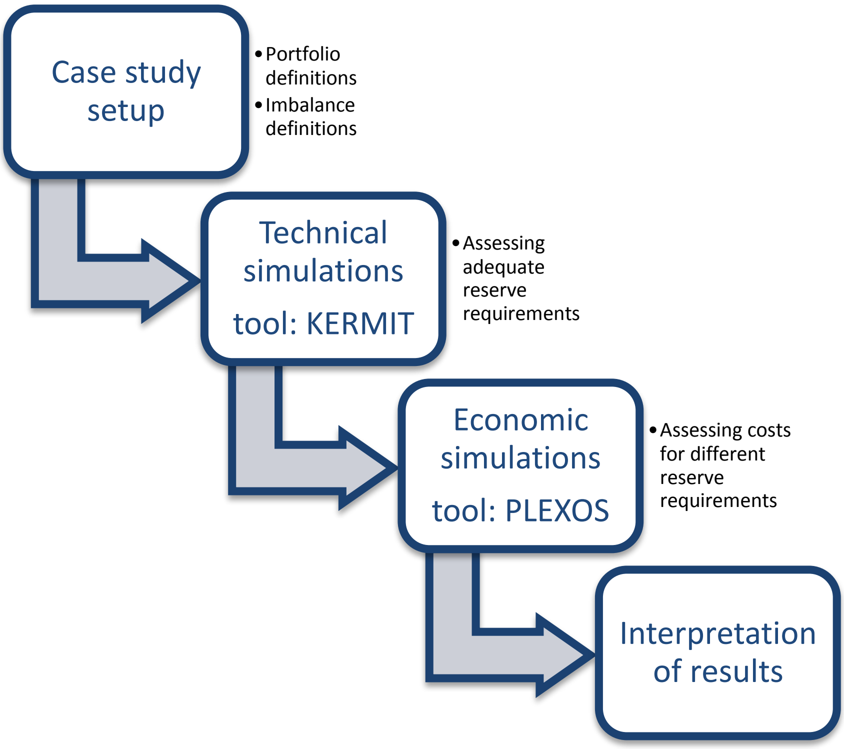

Figure 3-1 Project methodology. The tools KERMIT and PLEXOS are elaborated in Appendix C.

For the overall analysis two separate simulation frameworks have been applied. The next sections will elaborate on the objective and content of these two simulation frameworks. The setup of the case studies is elaborated separately in chapter 4 of this report.

3 KERMIT is DNV GL - Energy's proprietary tool for studying the impact of power balance on system frequency. More information on KERMIT can be found in Appendix C.

4 PLEXOS is a state-of-the-art generation optimisation and price forecasting model. PLEXOS was specifically developed for the electricity industry and is a powerful simulation tool that integrates generation dispatch, transmission flows, and pricing simulation with risk management, hydro, emissions and ancillary services dispatch. More information on PLEXOS can be found in Appendix C.

3.3 Technical simulation framework (KERMIT)

3.3.1 Objective of the technical model

The first research question addresses the technical requirements for frequency restoration reserves (FRR). To quantify the performance of characteristics of FRR a power system model simulation framework was selected. The power system simulation framework used in this study is DNV GL – Energy's proprietary KERMIT (see Appendix C). This model is geared towards simulating the electricity system's performance in one second to one day time frames. In that way, it captures the range of dynamics that concern technical stability issues and control loops. The model is based upon /6/.

3.3.2 Setup of the technical simulation framework

The KERMIT model includes among other:

- Generation and load schedules
  Generation and load schedules define the set points of generators and load without any dynamics.
- Dynamic load (sensitive to frequency)
  Load in a power system has a frequency dependent part that decreases if frequency is below the nominal frequency and vice versa. This contributes to the inherent stability of a power system.
- Generator models (incl. governor control)
  Generators in power systems have dynamics. To obtain realistic responses to power set points, these dynamics are included in the model. These dynamics also include the governor controller which has the objective to keep the frequency of the grid stable.
- Network model
  As the model consists of multiple countries, each modelled as a node, the interconnections between the countries are modelled as well.
- Automatic Generation Control (AGC) (as proportional-integral controller)
  The AGC (a.k.a. secondary controller) has as an objective to restore the frequency to its nominal value. This controller activates the frequency restoration reserves.

The relations between the components in the model are illustrated in **Figure 3-2**.

For the purpose of this study the model was updated to represent the Central European power system. As such each European country is modelled as a single node ('copper-plate', i.e. without losses), leading to 23 nodes with 43 interconnectors. To limit computational efforts the Netherlands is modelled in detail with 101 generators whereas other European countries have a limited number of generators. An overview of the European power system with each country modelled as a separate node is given in **Figure 3-3**.

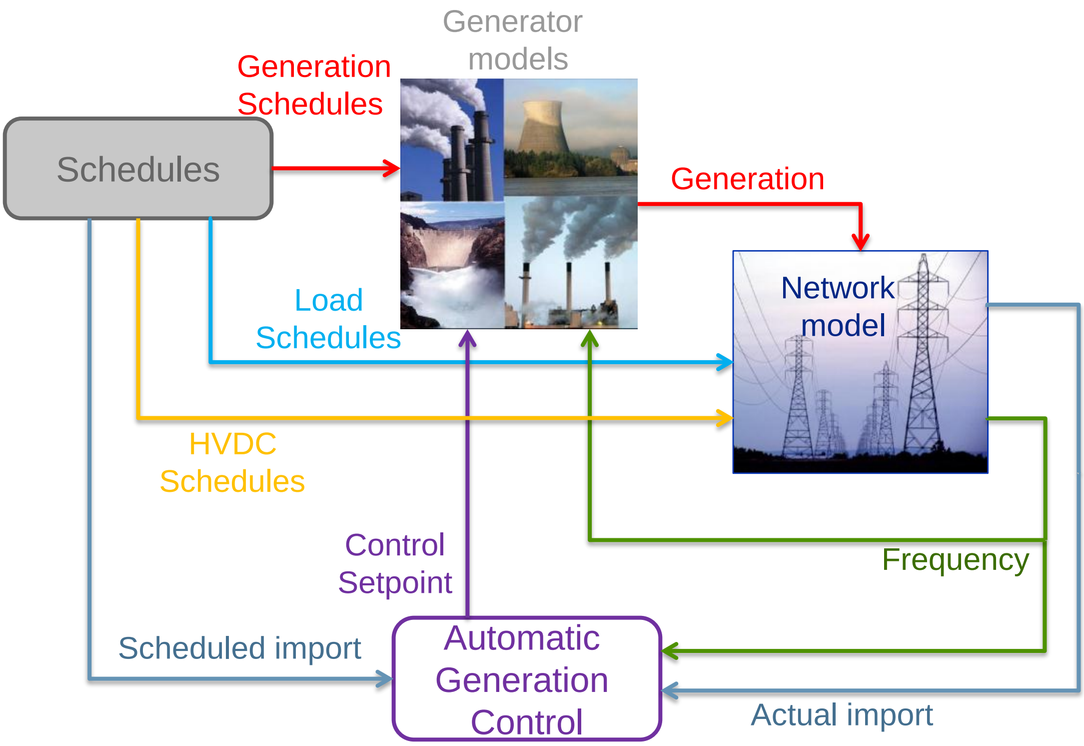

Figure 3-2 Technical simulation framework as modelled in KERMIT

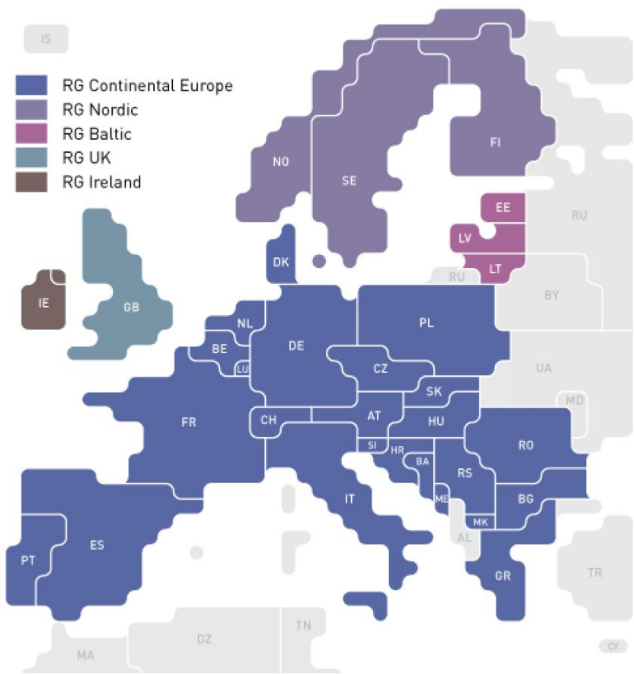

Figure 3-3 The power system model applied in this study models each country as a separate node. In accordance with the actual power system, the model consists of 5 (CE, Nordic, Baltic, UK and Ireland) synchronous areas that are connected via HVDC interconnectors /7/**.**

As the research question was to investigate the FRR requirements in case of high penetration of renewable generation, it was decided to make a simulation of the year 2020 with corresponding generation portfolios and network capacities. For this the ENTSO-E EU2020 scenario was used for the generation portfolio and network expansions based on ENTSO-E information were applied. These are largely based upon ENTSO-E prognoses, combined with objectives of the European Union.

Further information on the setup and validation of the model can be found in /8/.

3.3.3 Fast reserve generators

To investigate which requirements apply to generators providing frequency restoration reserves (FRR) it was decided to include so-called "Ideal FRR generators" in the KERMIT model. These "Ideal FRR generators" are defined as fast reserve generators that perform exactly according to predefined specifications. In other words, their dynamics are (limited) such that they consist of a tuneable capacity, a tuneable ramp rate and a tuneable mix of spinning and non-spinning generators.

Any Ideal FRR generator in the model is characterized by the following variables:

- Capacity (positive for up, negative for down regulating).
- Preparation period (once the set point deviates from 0, the delay time is the required time by the generator to start changing its output). Spinning generators have preparation period 0.
- Ramping period (time required to activate the full capacity after the preparation period).
- Full activation time. This is not explicitly defined but a combination (i.e. the sum) of the preparation period and the ramping period.
- To avoid non-spinning generators to respond to noise, they are only started if the set point is higher than an adjustable deadband.
- Non-spinning fast reserve generators were implemented with a minimum-off time of 5 minutes.

The different parameters of the reserve generators are illustrated in **Figure 3-4**.

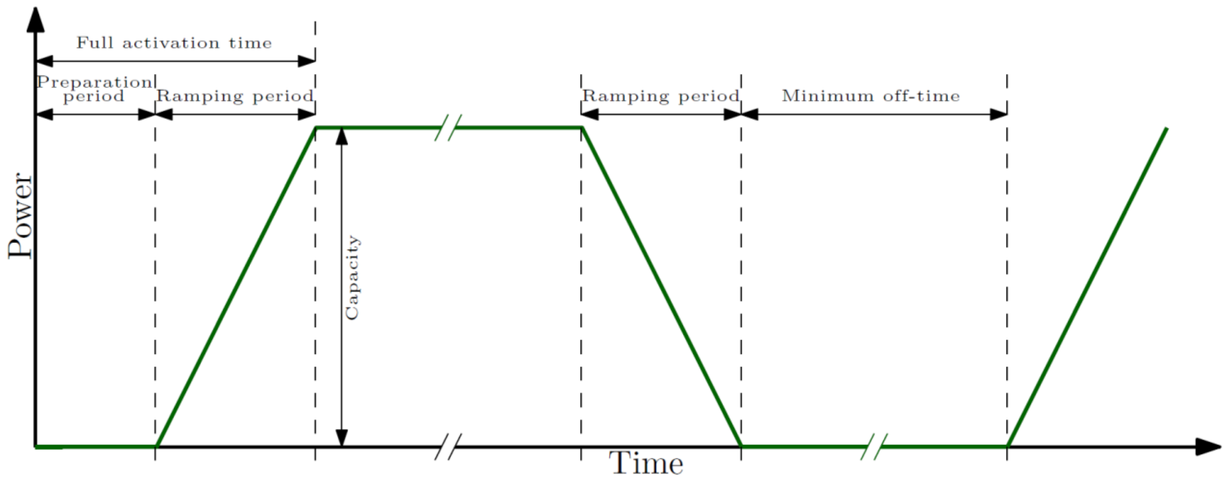

Figure 3-4 Fast reserve generator characteristics.

The modelling specifications of fast reserve generators are given in Appendix D.

3.3.4 Technical model variations

Within the European power system, there exist different manners to activate reserves. The two manners most applied are:

1. Pro-rata activation
2. Merit-order activation

According to /9/ most countries in Europe apply the pro-rata activation system.

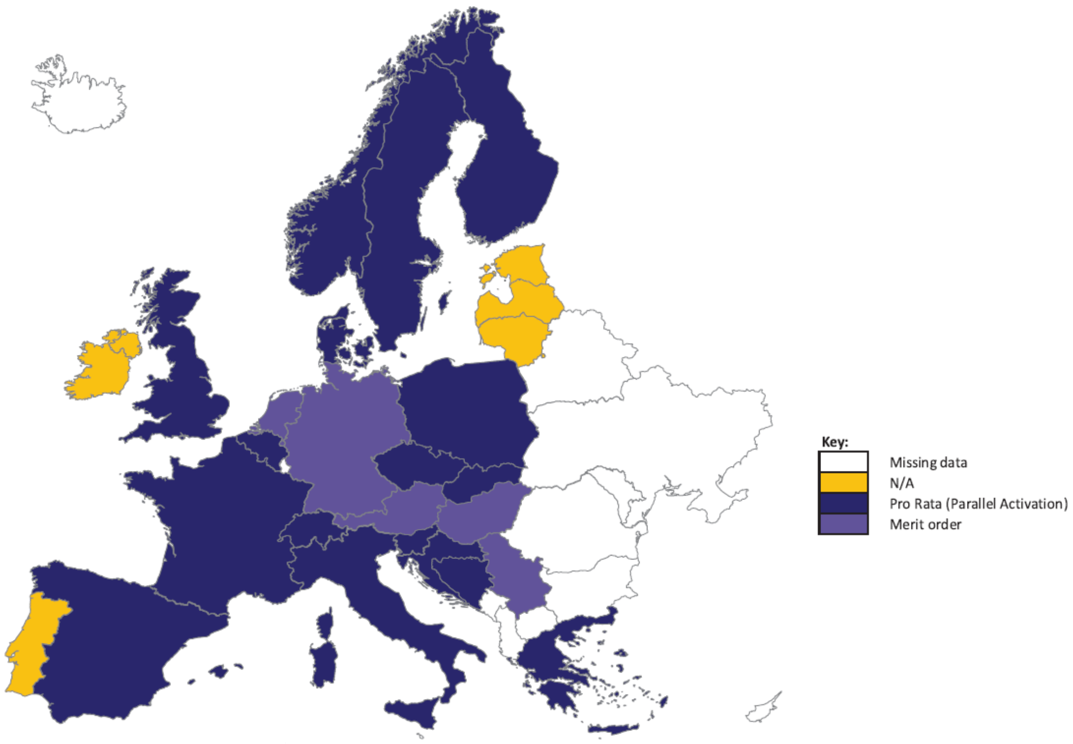

Figure 3-5 Activation rules for frequency restoration reserves in Europe /9/**.**

In pro-rata activation, all available reserves are activated proportionally (to their respective amount of capacity available for balancing) up to the amount of the imbalance. As a consequence all generators available for provision of reserves ramp simultaneously, resulting in a high aggregate ramp rate for the system.

In merit-order activation, available reserves are activated consecutively, based on their price in the merit-order list (cheapest being activated first), up to the amount of the imbalance. As a consequence the aggregate ramp rate for the system increases with the number of bids activated and thus with size of the imbalance. This effect is illustrated in the **Figure 3-6**.

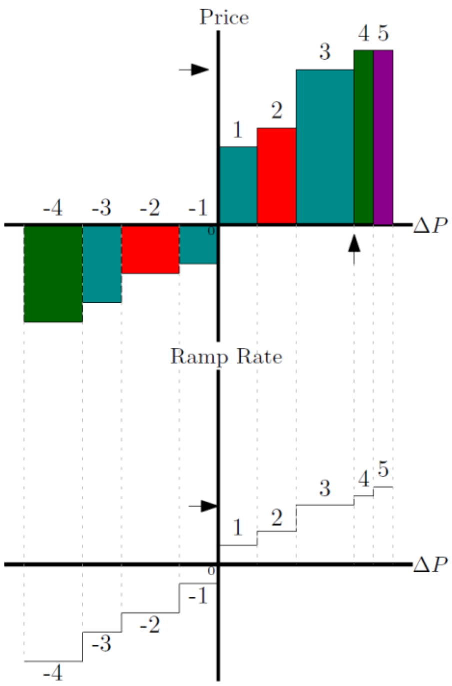

Figure 3-6 In merit-order activation, the aggregate ramp rate depends on the number of bids activated. Bids are activated consecutively up to the amount of imbalance. In the upper figure, the arrow marks (as an example) that three bids (1, 2 and 3) need to be activated to settle the imbalance, the three activated bids define the ramp rate as marked with the arrow in the lower figure.

The simulations in the technical framework have been executed both for pro-rata and for merit-order activation rules. It should be noted that the AGC needed to be fine-tuned to the activation rules to optimally exploit the reserve capabilities.

3.3.5 Technical simulation framework assumptions

The technical simulation framework is based upon a number of assumptions. The most relevant ones are elaborated below.

- Imbalance is only imposed in the Netherlands
  Although in a real power system all countries contribute to the total system imbalance, in this analysis the objective was to find which resources should be available to deal with a country's imbalance. As the Netherlands was modelled in more detail than other countries, it was decided that only the Netherlands will contribute to the system imbalance. All other countries are assumed to have perfect power balance (generation + scheduled import - load). However, if frequency deviations occur, the other countries do contribute to frequency containment reserves whereas during the simulation they will mitigate the system imbalance.
- Each country is responsible for its own balancing
  Objective of the technical analysis is to obtain insight in the reserve requirements to deal with imbalances. As imbalance is caused in the Netherlands, it was decided that the frequency restoration reserves are also located in the Netherlands as they can then be activated by the AGC of the Netherlands. Cross-border activation of frequency restoration reserves is therefore not modelled in the technical simulation framework. However, this aspect is covered in the economic simulation framework.

- Reserve generators are assumed not to have any impact on the total system inertia
  The inertia of the power system has an impact on the rate of change of frequency in case of a system imbalance. The total inertia is defined by the number of generators online and connected to the power system. It is assumed that the reserve generators do not contribute to inertia, regardless of their spinning or non-spinning mode. The average total system conventional (excluding wind and solar power) generation is around 300GW. The capacity in frequency restoration reserves in the Netherlands is less than 1% of the total conventional capacity and its contribution to inertia is thus considered negligible.
- The own consumption of non-spinning FRR capacity is assumed to be negligible.
- Renewable generators are assumed not to have any contribution to the total system inertia
- The AGC is assumed to be adapted to exploit the capabilities of the frequency restoration reserves. As in some cases (as will be elaborated in chapter 4) the reserves are very fast compared to the current reserves, the AGC is tuned to be faster. To also be able to control slow FRR, the integrator in the AGC is equipped with a so-called anti-windup module to limit overshoot of reserve activation. Also as the only country causing and solving imbalance is considered to be the Netherlands, the AGC has been set up as a controller based on frequency only, in contrast to usual AGC that also takes deviations from the cross-border schedules into account, a.k.a. frequency bias tie line control.
- All imbalances are assumed to be settled by the reserve generators specified above.
  In practice if imbalance persists over longer periods of time, part of the reserves will be made available again by activation of replacement reserves. For this study, this process was considered to be out of scope. The replacement reserves are implicitly taken into account by not incorporating the replacement of frequency restoration reserves.
- All spinning FRR generators have identical specifications per simulation. All non-spinning FRR generators have identical specifications per simulation.
- Basic merit-order implementation assumed.
  The actual implementation of merit-order activation mechanisms can be more complex than indicated before in this report. As an example TSOs can abandon merit-order activation and switch to pro-rata activation in case of emergencies. The current modelling of the merit-order activation mechanism does not include these kinds of exceptions.
- Wind imbalance characteristics
  The imbalance imposed in to the power system model caused by wind power is assumed to originate from prediction errors only. As such the wind imbalance is defined as the difference between predicted and actual power. To have a corresponding wind profile in both the technical and economic assessment (at least for the selected day of the technical assessment) the wind profile from the economic assessment (which consists of hourly values) was used. The technical assessment requires wind power time series in quarter hour resolution which were obtained by linear interpolation of the hourly values. The prediction of the wind is obtained by applying the persistence forecasting methodology. Having values per quarter hour for both the wind power and wind prediction that are both linearly interpolated in the technical model, no fast (order of minutes) wind imbalances are included in the model. To obtain insight in rapidly occurring imbalances, also generator outage simulations are therefore included in the study. In a generator outage simulation, a stepwise (i.e. very fast, below seconds) imbalance is imposed to the system.

3.3.6 Time series analysis

The technical simulation framework allows for time series analysis. This means that fixed periods of time can be simulated. Input and outputs for the time series analysis are the following:

Inputs of the technical simulation framework:

- Schedules for load, generation, HVDC
- Generation parameters
- Interconnector parameters
- Controller parameters

Outputs of the technical simulation framework:

- Generator set points
- Generator outputs
- Grid frequency.

As the grid frequency is an indicator of the power balance in a power system, post-processing of the results will be performed on the time-series of the grid frequency. Two types of time series analysis have been performed in this study which will be elaborated in the next subsections.

3.3.6.1 Natural day simulations

In natural day simulations, 24 hours are simulated. These simulations are performed to observe the system response to two different phenomena in power systems that cause imbalance. Combined, these two phenomena cause an imbalance pattern with both low and high frequency components.

- Deterministic frequency deviations

  The current market rules between generation and consumption are based on energy blocks of fixed time period and the hourly transit period for generation schedules is currently not explicitly defined between all market participants /10/. Many generators are scheduled to generate energy blocks of fixed time periods. Consequently generation schedules often look like stepwise profiles whereas the load has a more continuous profile. This is illustrated in **Figure 3-7**.

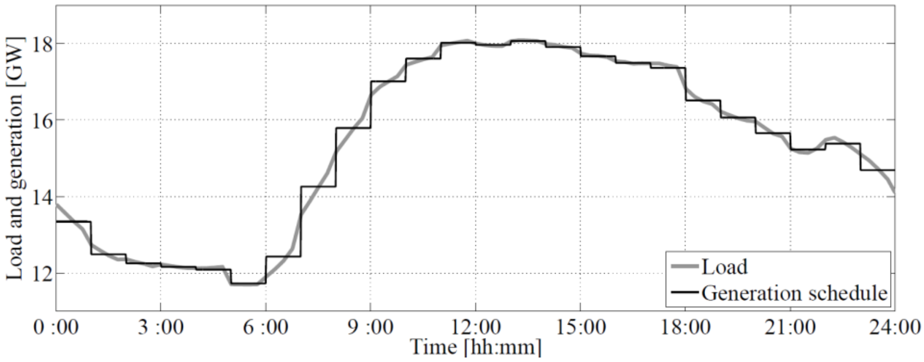

Figure 3-7 Average load profile in the Netherlands and assumed hourly generation schedules during July 27th to August 2nd 2010 /11/.

As a consequence imbalances occur at intervals of trading periods. This effect is most clear during morning and evening hours when the change in demand in the power system is largest. This effect is illustrated in **Figure 3-8**.

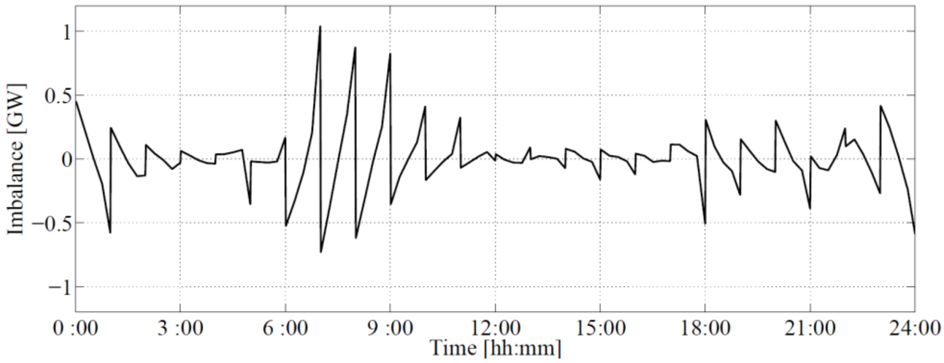

Figure 3-8 Imbalance due to mismatches between load and hourly generation schedules /11/.

The imbalance results in frequency deviations as can be observed from **Figure 3-9** that contains frequency measurements from 2010.

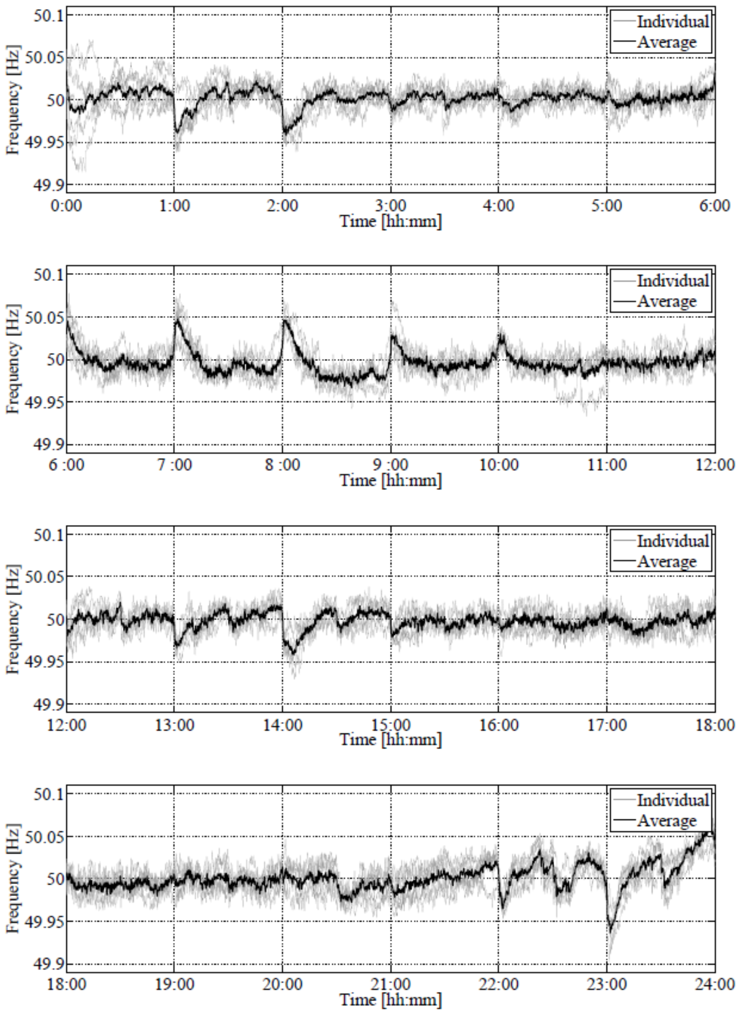

Figure 3-9 Grid frequency measurements from July 27th to August 2nd 2010. The grey lines indicate measurements for individual days while the black line indicates the average frequency over all measured days /11/.

– Wind forecast error imbalance
  Wind power is forecasted up to several trading periods in advance. It is assumed that generation schedules of conventional generation are such that they implicitly incorporate the wind forecasts. Any deviation of the wind power from its forecast will therefore lead to imbalance. In this study we used a profile for wind power. For this profile we defined a prediction using the persistence prediction method with a forecasting time of 1h. This yields a mean absolute error of 4% of the installed capacity[5].

In the natural day simulations, a simulation of 24 hours is performed. Based on the 2020 high wind scenario (see chapter 2) a single day was selected from the economic simulations to be used in the technical natural day simulations. These economic simulations have been performed assuming fuel and emission prices as defined in section 3.4 of this chapter. A day was selected with a significant share of wind generation both in the Netherlands as well as in surrounding countries. The generation profiles for the selected day are displayed in **Figure 3-10** and **Figure 3-11** as well as in Appendix B.

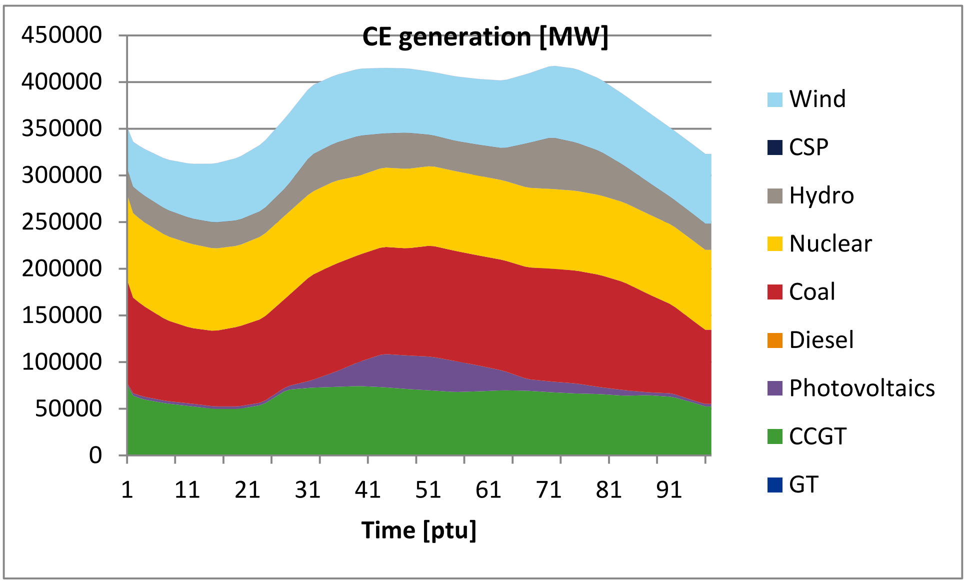

Figure 3-10 Generation profile in Central Europe (CE) for the natural day simulation.

5 Depending on aggregation level and forecasting method, 1 hour ahead predictions are known to have a mean absolute error between 2% and 7% of the installed capacity.

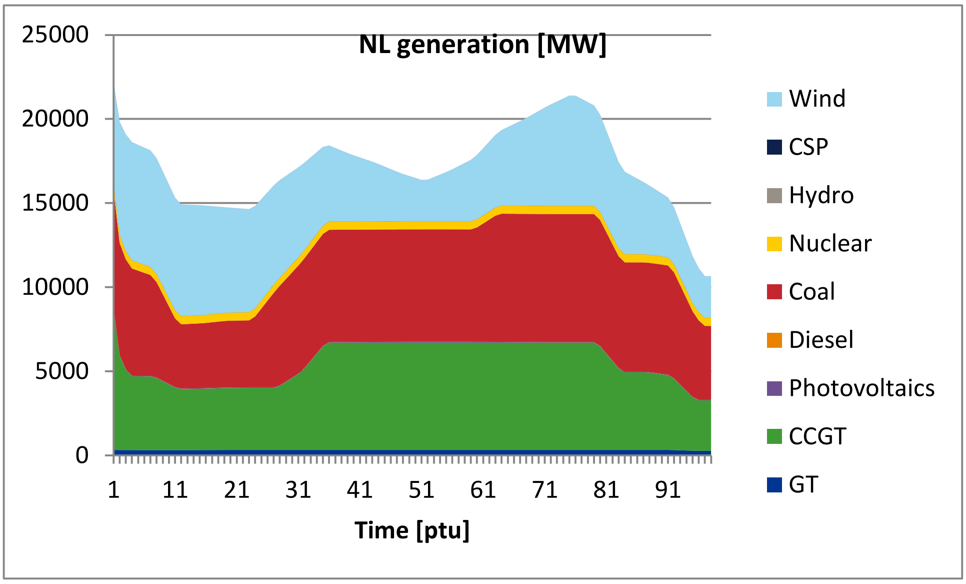

Figure 3-11 Generation profile for the Netherlands (NL) for the natural day simulation.

Combining the imbalance signals from schedule changes with wind forecast errors the following imbalance signal is constructed (**Figure 3-12**) which is imposed upon the power system in the natural day simulations.

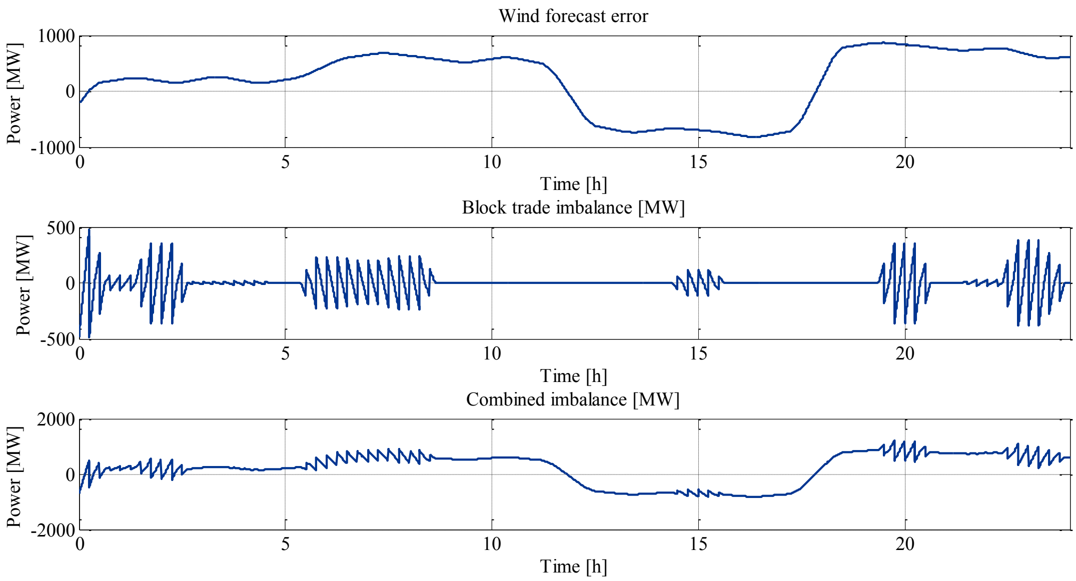

Figure 3-12 System imbalances in natural day simulations.

3.3.6.2 Generator outage simulations

When studying frequency stability, the classical event to consider is a trip of a power production unit in the system. In practice a power system should be capable of overcoming a trip of the largest power plant. Such a contingency would lead to a sudden drop in frequency. Frequency containment reserves from the other production units should halt the drop in frequency and stabilize frequency to a level that is lower than the nominal frequency but stable. After this event, frequency restoration reserves take over to restore frequency containment reserves and bring the frequency back to the nominal level. Desired system behaviour during and after a trip is well defined by ENTSO-E /12/, /13/. In this simulations we apply a generator outage of 600MW which is less than the reference outage defined by ENTSO-E of 3000MW. It should be noted that the selected performance indicator (explained further in section 3.3.7) is scaled to the maximum frequency deviation (i.e. the size of the disturbance).

3.3.7 Performance indicators

The approach of the project is such that in a first technical assessment the performance of different categories of reserves is obtained. Based on performance indicators, a selection of cases for further economic assessment is selected.

ENTSO-E describes performance indicators (minutes per year that frequency is outside threshold values, trumpet curve, etc.) for adequate performance of the balancing mechanisms. To assess the natural day simulations, the ENTSO-E criteria of number of minutes per year that the frequency is outside a threshold value was translated into a criterion related to standard deviation of the frequency, assuming normal distribution of the grid frequency. However, after first simulations it was found that, based on the simulation of the selected natural day, in all simulated cases the adequateness of these criteria is satisfied. Therefore alternative quality indicators have been chosen to quantitatively compare the performance of different characterizations of reserves. As the grid frequency can be regarded as an indicator for the power system balance, the quality indicators are based upon the grid frequency. To mitigate the impact of noise, the average[6] Central European frequency is used. The following subsections elaborate on the setup of these quality indicators.

3.3.7.1 Standard deviation of frequency

For the natural day simulations, the simulation output yields 24 hours of frequency time series. If the balancing resources are adequate, frequency deviations will be mitigated. Therefore the main performance indicator chosen is the standard deviation of the frequency. If the standard deviation is smaller the frequency is closer to the nominal frequency, hence FRR is considered more adequate.

3.3.7.2 Integral quality indicator

In case of a generator outage the required frequency response is defined by the so-called trumpet curve /13/. This trumpet curve is defined in /13/ as a function of the maximum frequency deviation (thus also indirectly as a function of the size of the disturbance). In all cases the time to restore the frequency to the nominal frequency plus/minus allowed deviation is considered to be 900 seconds. The integral quality indicator here is defined as the absolute value of the frequency deviation from 50Hz divided by the difference between the respective trumpet curve and 50Hz. If this ratio is smaller, the performance of the FRR is considered to be more adequate.

6 Each node having equal weight.

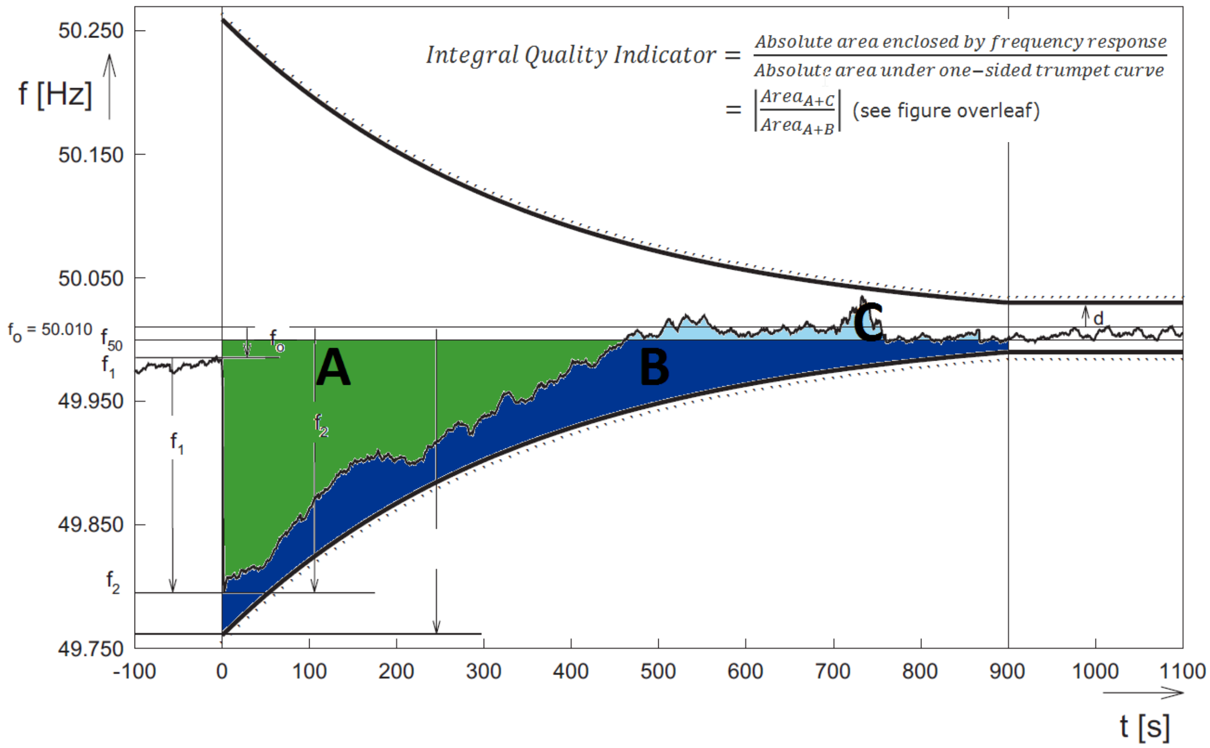

Figure 3-13 Integral quality indicator. Based on /13/**.**

It is assumed that when assessing the quality of the system performance that the grid frequency must be completely restored to its nominal value. As such the imbalance needs to be completely restored and at least the size of the disturbance is needed as FRR capacity.

3.4 Economic model (PLEXOS)

3.4.1 Objective of the economic model

The second research question concerns the economic impact of different requirements for FRR on the system costs. The system costs consist of all operational costs associated to the generation of electricity: fuel and emission costs, variable operation and maintenance costs, start costs and start fuel costs. The economic impact of different FRR requirements is assessed by performing simulations of the European electricity market. The European electricity market is simulated by calculating the dispatch of the generation capacity within Europe by minimizing total system costs. This is performed using the commercial power system simulation framework PLEXOS, developed by Energy Exemplar. By comparing the results of PLEXOS simulations with different FRR requirements each, we can assess the impact of the FRR requirements on the system costs.

PLEXOS optimizes the unit commitment and economic dispatch of the power plants based on minimizing total system costs in order to have sufficient generation to meet the specified demand. The simulations are performed for each scenario for a full year while using an hourly time resolution. The optimization takes chronological constraints into account: maximum ramp rates, minimum up and down times.

The FRR requirements are co-optimized with the generation of electricity: PLEXOS determines the least-cost solution for generating sufficient electricity and having sufficient FRR capacity available (or a penalty is incurred for not meeting the required reserve capacity). It must be stressed that PLEXOS does not model the actual activation of balancing capacity: providing balancing energy is not modelled.

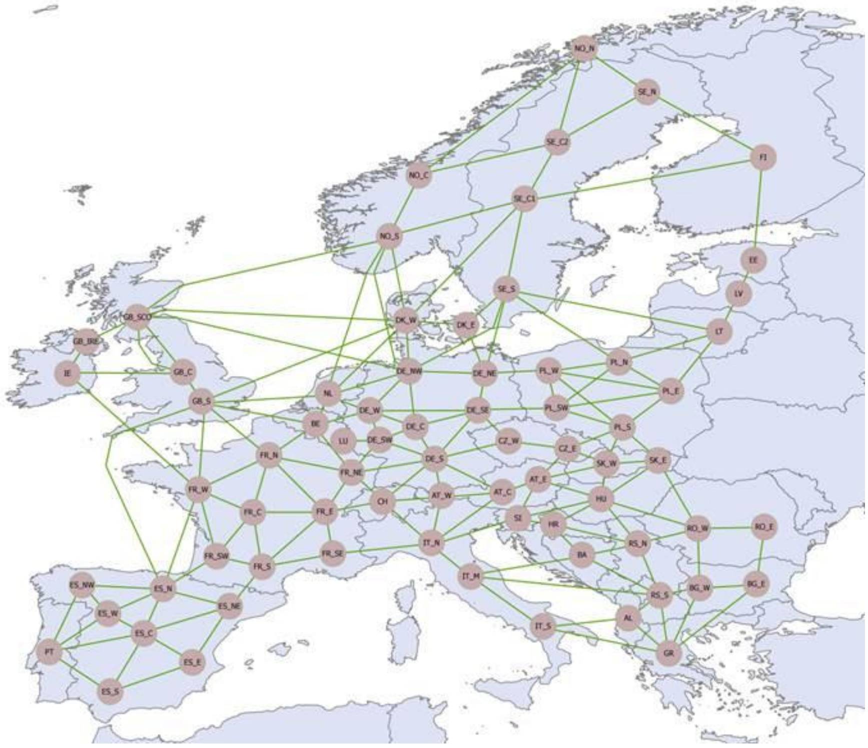

Figure 3-14   PLEXOS simulation model with interconnected nodes.

In the model, the European power system is represented by 72 interconnected nodes. Each node corresponds to a geographical region and contains a set of conventional power plants, renewable generation capacity, and electricity demand. The nodes represent regions with no internal transmission constraints (i.e. 'copper-plates'); the actual grid constraints are represented by the transmission capacity between the nodes. The Netherlands is modelled with a high level of detail, whereas the other regions are modelled with less detail. In section 3.4.3 we will discuss the model assumptions more extensively.

To obtain generic results, we model different portfolios for NL as is described in the previous section 2.5.

To reduce computational efforts, required to perform sufficient simulations within a limited timeframe, we have chosen to fix the generation schedules and reserve provision from hydro. We performed one simulation in which generation and reserve provision from hydro storages are optimized and use the hydro schedules of that run as input for the other simulations. In Chapter 5 we discuss the impact of this assumption on the results.

3.4.2 Fast reserve generators in the model

Fast reserve generators are included in several PLEXOS scenarios. They are only added to the Dutch power system and not to other countries. The number of fast reserve generators is such that their combined installed capacity is equal to the FRR up reserve requirement of the Netherlands.

In addition to the properties listed above, the fast reserve generator has the ability of providing spinning and non-spinning FRR capacity. The non-spinning reserve capacity provision requires the generator to be in standby modus: the fast reserve generator consumes a small amount of power during that period.

The decision regarding 'to provide' or 'not to provide' non-spinning balancing capacity is modelled by assigning an additional integer decision variable[7] to each fast reserve generator. Introducing this additional decision variable allows PLEXOS to explicitly optimize the reserve provision of the fast reserve generators.

3.4.3 Model assumptions and constraints

The European electricity market is modelled in PLEXOS from a cost minimization perspective. We perform full-year runs with an hourly time resolution. The model inputs are based on DNV GL databases and publicly available information. All simulations are performed for scenarios of the year 2020.

Table 3-1 Overview of sources used for modelling assumptions.

Input	Source
Conventional power plant – installed capacity	PLATTS (2013) and ENTSO-E
Conventional power plant – other properties	DNV GL
Renewable generation - installed capacity	ENTSO-E SO&AF (2012) - EU2020 scenario
Renewable generation – profiles for wind and solar	DNV GL
Interconnection capacity – NTC values	ENTSO-E and DNV GL
Load profiles	ENTSO-E historical data and ENTSO-E SO&AF (2012) – EU2020 scenario
Fuel and emission prices	IEA World Energy Outlook 2013 – New Policies scenario
FRR capacity requirements	Scenario input from KERMIT

- The conventional power plants are modelled with detailed properties. Minimum up and down times, start costs and start fuel offtake are defined for each conventional power plant (with the exception of the fast reserve generators as these parameters are 0 for the fast reserve generators).
- The Dutch power system is modelled in detail: the power plants are individually represented in the model. Furthermore, combined heat and power plants (CHP plants) are modelled in detail. Three types of CHP plants are distinguished: district heating (they have an hourly varying heat demand profile and can choose to use heat-only boilers for heat generation), industrial heat supply (these are considered as must-run and have a flat heat demand profile) and horticultural heat supply (flexible heat demand because they are part of heat networks and/or have heat storages). The generation mix of the Netherlands is adjusted to represent different mixes. The base case represents the original generation mix as based on DNV GL information and renewable capacity according to the EU2020 scenario of ENTSO-E /5/.

7 Decision variables are the parameters that are varied by the solver to find and define the optimal solution. Another decision variable is the generation outputs of the power plant for an hour.

- The power systems of the other European countries are modelled in an aggregated fashion. The power plants are aggregated per technology per fuel and per age category. Different technology and fuel types included are: steam coal, steam gas, steam nuclear, steam lignite, steam oil, gas turbine and combined cycle gas turbine. The age categories span five years, e.g. steam-coal-2000 and steam-coal-2005. The aggregation is for each node separately.
- Renewable power generation is specified per node. The different renewable energy sources are modelled in different ways. Intermittent renewables such as solar and (onshore and offshore) wind are modelled using hourly profiles specifying the amount of available generation. Biomass and geothermal is treated as dispatchable generation capacity similar to conventional generation. Three different types of hydro are distinguished: run-of-river (modelled using a relative flat profile), storage (modelled as storage with a certain inflow) and pumped storage (modelled as a pumped storage). The hydro generation is fixed using the results from an initial simulation run.
- Each country has an hourly demand profile. The annual electricity demand and peak demand are based on ENTSO-E Scenario Outlook & Adequacy Forecast – EU2020 scenario /5/. The shape of the profile is based on historical demand profile published by ENTSO-E.
- The interconnection capacities are based on the NTC values. The transmission lines are approximated as DC-lines. The transmission capacity of lines between countries is based on ENTSO-E values. The transmission capacity within a country is based on DNV GL insights.
- The reserve requirements are in principle specified per country. Two reserve requirements are specified: an up and a down reserve capacity requirement. The scenario with the cross-border sharing is the exception: in that case there is one European reserve requirement for up and one for down reserve capacity. The reserve requirement is modelled as a certain capacity that should be provided throughout the year. The size of the reserve requirements for the Netherlands is based on the KERMIT analysis. The size of the reserve requirements in the model of other countries are linearly scaled accordingly by using the square root law for FRR dimensioning /13/ as a reference point. We defined a Value or Reserve Shortage of 2000 €/MW[8] as a penalty in case of reserve shortage.
- Power plants (with the exception of the fast reserve generators) can only provide spinning reserve requirements. A maximum reserve provision is specified for each power plant, based on its ramp rate. Fast reserve generators can provide both spinning and non-spinning reserve capacity. In addition, depending on the scenario, also wind and solar are assumed to provide up to 10% of their momentary output as down reserve capacity. For the other types of generation, the table below specifies which types can provide spinning reserve.

8 The NEISO system in the US has a maximum Value of Reserve Shortage of 1000 $/MW (WPTF Comments on Reserve Shortage Pricing details, https://www.caiso.com/Documents/WPTFCommentson31-May-2007IssuePaper.pdf). Based on this information and DNV GL expert views we assumed 2000 €/MW.

Table 3-2 Reserve provision by generation of different fuel types.

Type of generation	Reserve provision
Coal	Yes
Lignite	Yes
Nuclear	No[9]
CHP	Yes (limited in downward provision)
Gas	Yes
Oil-fired	Yes
Biomass	Yes
Hydro	Yes
Wind	Only downward if selected in scenario
PV	Only downward if selected in scenario

- The fuel prices are based on International Energy Agency's (IEA) World Energy Outlook 2013 – New Policies scenario (see **Figure 3-15**).

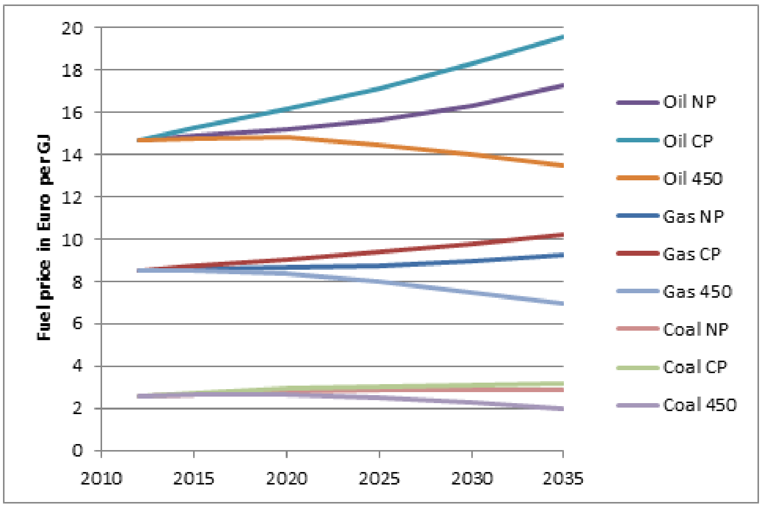

Figure 3-15 Fuel prices forecast from IEA World Energy Outlook 2013. The used New Policies scenario is indicated with 'NP'. A CO_2 credit price of 20 euro per ton CO_2 is used.

3.4.4 Output of the model

The main outputs of the simulations are time series of the electricity generation and reserve capacity provision per power plant. Based on these time series, we have the following relevant outputs:

- Generation schedules for each power plant
- Reserve capacity provision per power plant
- Line flows through transmission lines
- Fuel use and costs
- Emission costs
- Start costs
- Variable Operation & Maintenance costs.

The fuel costs, emission costs, start costs and variable operation and maintenance costs combined define the operational expenses (OPEX).

9 Nuclear power plants can contribute to reserve capacity provision, but this is not current practice (except for France) /14/. Additional simulations with reserve capacity provision from nuclear power plants show that the conclusions of this study are not affected by this assumption.

3.4.5 Performance indicators

The three main indicators for the economic analysis are: operational expenditures of the European electricity system, the utilization of the fast reserve generators for generation and reserve provision, and the reserve market size.

3.4.5.1 Operational Expenses (OPEX)

The operational expenses (OPEX) of the European system of simulations with different FRR designs are compared to assess the impact of FRR design on the system costs. Based on this comparison, it is possible to assess the trade-off between more stringent reserve requirements (i.e. improved system response) and a possible increase in OPEX, or the possible reduction in OPEX from allowing wind and solar to provide down reserves or cross-border sharing.

The European operational expenses consist of:

- Fuel costs of all power plants
- Emission costs of all power plants
- Start costs of all power plants: maintenance costs and start fuel offtake
- Variable operation and maintenance costs of all power plants.

3.4.5.2 Fast reserve generators

The fast reserve generators can be used for both generation and the provision of (spinning/ non-spinning) reserve capacity. Based on the simulations we can determine the preference for the use of these generators from a least-cost perspective.

Questions that will be addressed for different FRR requirements and Dutch generation portfolios are:

- What is the capacity factor of fast reserve generators for electricity generation and their utilization for reserve provision?
- What are the benefits of fast reserve generators for the Dutch OPEX?

3.4.5.3 Market size and minimum market share

The reserve market size and minimum market share of fast reserve generators constitute the third indicator. This indicator is used to give an idea of the competition among generators to provide reserve.

The market size is a ranked hourly curve (i.e. duration curve) of the available reserve capacity from different types of generation. The available reserve capacity for FRR up is defined as part of the headroom of part-load generators and non-spinning reserve capacity from fast reserve generators. The available reserve capacity for FRR down is defined as part of the generation room between current generation and the minimum stable level. From the duration curve of available capacity it is possible to get an indication of the size of the market per hour and see who are competing for the reserve capacity provision.

The minimum market share is determined for the fast reserve generators. This represents the minimum amount of reserve capacity that is provided by the fast reserve generators in those hours where the available reserve capacity from other generators[10] is not sufficient to provide the full required capacity.

[10] This 'available reserve capacity from other generators' includes head room capacity from power plants running at part load because of inflexibility (e.g. co-generation of heat, minimum up time and high start costs). And this includes reserve capacity from additional power

We look at the *minimum* market share, and not simply at the market share of fast reserve generators as one cannot determine the actual market share during hours of oversupply of FRR capacity. (We define 'oversupply' in a country in the situation where the available FRR capacity is larger than the required FRR capacity.) In the case of an oversupply of available capacity, there are multiple but equivalent ways of assigning the limited reserve requirement to power plants with available capacity as assigning the provision of capacity to certain available capacity has no impact on system costs. The solver within PLEXOS will choose one arbitrary realisation, but it might just as well have chosen any other combination.

plants committed in the optimization to have additional reserve capacity available (excluding the reserve capacity from non-spinning fast reserve generators).

4 CASE STUDY DESCRIPTION

Chapter 3 of this report described the objectives and setup of the technical and economic simulation frameworks for this study. As mentioned in chapter 2, the approach of the study is first to determine the technical performance of (combinations of) reserve characteristics. Based on the technical performance, adequate cases are then selected. For this subset of adequate cases, an economic assessment is performed. This economic assessment gives insight in the economic performance of combinations of reserve characteristics.

This chapter will elaborate on the complete set of case studies. As such, this chapter elaborates on the case studies for the technical analysis as well as on the selection of case studies for the economic assessment. In chapter 5 the results of the simulations are described, here it can also be found how the subset of cases for economic assessment was obtained.

4.1 Degrees of freedom

In chapter 2, the following variations on frequency restoration reserves were introduced:

- Amount of frequency restoration reserves;
- Ratio of spinning and non-spinning capacity as balancing product;
- Preparation period;
- Ramping period;
- Renewable generation providing down regulating reserves.

For the technical simulations we aim to get a set of requirements. It is assumed that if renewable generation participates in the provision of downward reserves, this does not affect the requirements on frequency restoration reserves. For spinning generators providing reserves the preparation time is considered negligible. Therefore for these generators full activation time is equal to the ramping period. For non-spinning generators a single combination of preparation period and ramping period was considered. The preparation period considered was 30 seconds in accordance with the ENTSO-E Network Code on Load Frequency Control and Reserves (section 47.1.d) /1/, combined with a ramping period of 91 seconds[11], as specified for the fast reserve product, which is possible to be achieved by fast ramping generators. With these considerations, the set of variations could be reduced further into a set of three degrees of freedom.

- Capacity in frequency restoration reserves;
- Full activation time of spinning capacity;
- Percentage of non-spinning capacity.

For the technical simulations, each degree of freedom was given 5 possible values leading to in total 5^3=125 combinations as displayed in **Figure 4-1**. The next subsections will elaborate on these three degrees of freedom.

11 As specified by Wärtsilä.

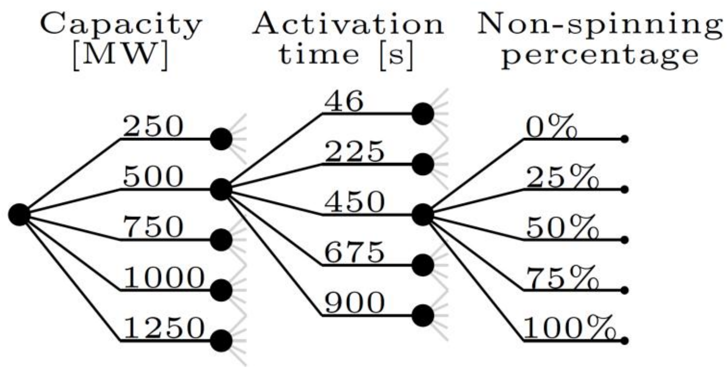

Figure 4-1 Structure of simulations with three degrees of freedom leading to 125 simulations.

The natural day simulations will be performed for all combinations. Generator outage simulations are only performed for combinations with capacity of either 750 or 1000MW whereas a 600MW generator outage is imposed to the model.

4.1.1 Capacity in frequency restoration reserves

The capacity available in frequency restoration reserves in the Netherlands is based upon the imbalance that is imposed to the model. In 5 linear steps the installed capacity is increased to 1250MW. As such the following values are used.

1 250MW;
2 500MW;
3 750MW;
4 1000MW;
5 1250MW.

It should be noted that any value that applies to the capacity is used both for upward and downward reserves.

4.1.2 Full activation time of spinning capacity

The current activation time of spinning capacity needs to be at most 900 seconds /13/. The fastest generators considered in this study are considered to have a ramp rate of 130%/min. This is equal to an activation time of 46 seconds. Between these extremities in activation times, three intermediate values were selected. Combined this leads to the following values used for activation time:

1 46 seconds;
2 225 seconds;
3 450 seconds;
4 675 seconds;
5 900 seconds.

The activation times apply for both up and down regulating reserves. It should be noted that these activation times only apply to spinning capacity. Non-spinning upward capacity is considered to always have a full activation time of 121 (30s Preparation period + 91s Ramping period) seconds[12] as specified for the fast reserve product.

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12 As specified by Wärtsilä.

4.1.3 Percentage of non-spinning capacity

The percentage of non-spinning capacity in frequency restoration reserves is varied in 5 equal steps from 0% to 100%. As such the following values are used:

1 0%
2 25%
3 50%
4 75%
5 100%.

The percentages mentioned here are percentages of the total installed reserve capacity in the upward direction. As non-spinning generators cannot provide downward capacity, they do not replace spinning capacity in this direction.

4.1.4 Additional degrees of freedom in economic simulations

As defined in chapter 2 some additional scenario variations are imposed in the economic simulations only. These are:

5 Renewable generation providing down reserves
  - Variations: 0% or 10% of the momentary value of renewable generation (wind and photovoltaic generation) for downward reserves.

6 Fast reserve generators providing frequency restoration reserves
  - Variations: 0% or 100% of the required frequency restoration reserve capacity.

7 Cross-border procurement
  - Variations: allowed or not allowed.

It should be noted that not all combinations of variations are combined with the cases from the technical analysis. The next section will elaborate on the selection of cases for economic analysis.

4.2 Selection of cases for economic simulations

Based on the findings in the technical assessment, a subset of case studies is created fur economic assessment. This section describes these case studies. The argumentation for this case study selection follows in the next chapter, section 5.1.3.

Table 4-1 Economic case study definition

Case Name	Capacity/ Time	Base Portfolio	High PV Portfolio	High coal portfolio	Fast reserve generators	Renewable Reserves	Cross-border
P0	no reserves	X					
P1-1	750MW/900s	X					
P1-2	750MW/900s		X				
P1-3	750MW/900s			X			
P1-4	750MW/900s	X			X		
P1-5	750MW/900s	X				X	
P1-6	750MW/900s	X			X	X	
P1-7	750MW/900s	X					X
P1-8	750MW/900s	X			X		X
P1-weeks	750MW/900s	X					
P2-1	1000MW/900s	X					

Case Name	Capacity/ Time	Base Portfolio	High PV Portfolio	High coal portfolio	Fast reserve generators	Renewable Reserves	Cross-border
P2-2	1000MW/900s	X			X		
P2-weeks	1000MW/900s	X					
P3-1	750MW/675s	X					
P3-2	750MW/675s	X			X		
P3-3	750MW/675s		X				
P3-4	750MW/675s		X		X		
P3-5	750MW/675s			X			
P3-6	750MW/675s			X	X		
P3-weeks	750MW/675s	X					
P4-1	500MW/900s	X					
P4-2	500MW/900s		X				
P4-3	500MW/900s			X			
P4-4	500MW/900s	X			X		
P4-weeks	500MW/900s	X					

The table shows the following characteristics. For each case the column Capacity/Activation time gives the amount of available capacity for frequency restoration reserves in the power system of the Netherlands. This capacity is available both for up and downward reserves. The time gives the time required for full activation of the spinning capacity. The three portfolio columns indicate which generation portfolio is used for the economic assessment. The column fast reserve generators marks whether fast reserve generators are available to provide frequency restoration reserves. If marked, this means that a capacity of fast reserve generators with the respective FRR capacity is included in the generation portfolio. The column Renewable Reserves marks whether renewable generation (wind and photovoltaic generation) can provide up to 10% of their momentary power output as downward reserves. The column cross-border indicates whether cross-border sharing of reserves is allowed. If marked, no transmission constraints apply to the sharing of reserves.

The table above shows 4 groups of case studies (P1-4), each consisting of multiple case studies. Each group corresponds to a combination of capacity and activation time originating from the technical studies.

- Most case studies are performed for the base portfolio which is considered as a point of departure.
- Most simulation will be performed for activation time/capacity combination P1 which is also considered as a point of departure as will be explained in chapter 5.
- Activation time/capacity groups P2 and P3 are included to compare either increasing capacity with 1 discrete step or increasing speed of reserves with 1 discrete step.
- Activation time/capacity group P4 is included as a sensitivity analysis with respect to the required frequency restoration reserves capacity.
- Each Activation time/capacity group has one “weeks” case study. All case studies are performed for full years. To reduce simulation time in these yearly simulations, hydrological schedules are based on a single simulation run and then fixed for all other cases. For sensitivity analysis on this reduction of model complexity, simulations of 4 weeks/year have been included for each activation time/capacity group. The results of this separate analysis are given in Appendix F.

5 RESULTS AND ANALYSIS

As described in chapter 3, the project uses two simulation platforms for the technical and economic assessment of reserve characteristics respectively. The case studies defined in chapter 4 are simulated and this chapter elaborates on the results of these simulations.

5.1 Technical assessment results

5.1.1 Natural day simulations

The time series of the simulated grid frequency are assessed according to the performance index elaborated in chapter 3. As there are three degrees of freedom, one of them (the share of non-spinning reserves) is used to create multiple figures. **Figure 5-1** shows the standard deviation of the frequency for different FRR capacities, ramping times and fractions of non-spinning reserves.

It should be noted that in **Figure 5-1** and any figure following regarding the technical simulation outcome that the actual simulation results are displayed with solid dots whereas planes and lines are constructed via linear interpolation of the results.

The natural day simulations are performed for both pro-rata and merit-order dispatch regimes. As the differences in simulation results between both dispatch regimes are highly comparable only results of the merit-order dispatch regime are given.

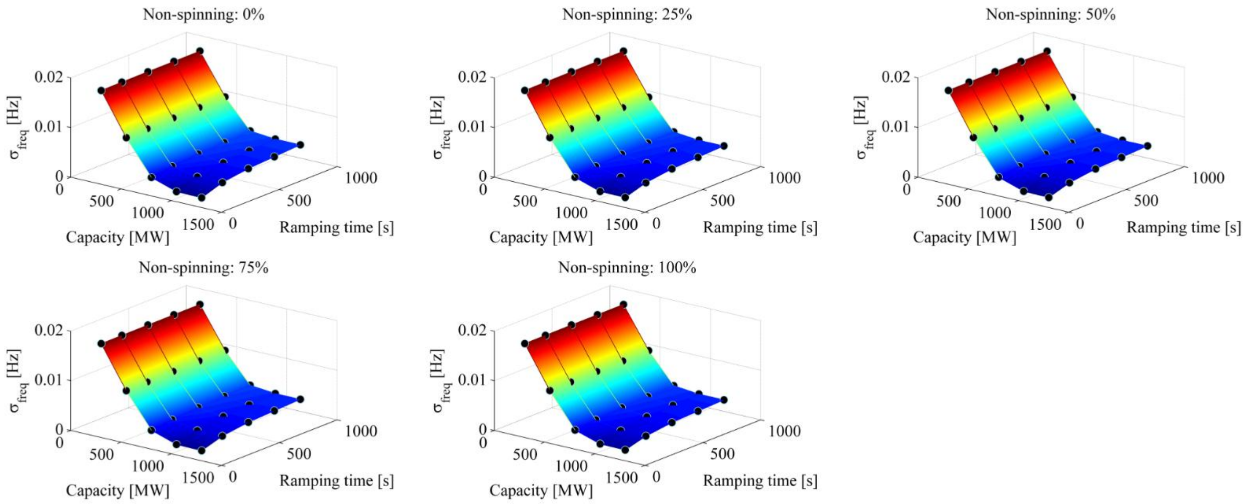

Figure 5-1 Standard deviation of the frequency for simulation variations.

The top view of the standard deviations is given in **Figure 5-2**. Here the dot size corresponds with the inverse of the standard deviation of the frequency over the 24h simulation period.
From the assessment of the standard deviation of the grid frequency the following conclusions can be drawn:

- The standard deviation of the frequency decreases significantly with increasing FRR capacity. Above 750MW (most of the time the open loop imbalance is smaller than 750MW, see **Figure 3-12**) the standard deviation does not decrease much anymore.
- The standard deviation of the frequency decreases as the ramping time of reserves decreases.
- There is little difference between the multiple ratios of non-spinning reserves indicating that both spinning and non-spinning FRR are capable of following the AGC request for balancing capacity. Also

having impact here is the fact that a large part of the day downward reserves are used. This causes upward reserves (which may be split into spinning and non-spinning reserves) to be used only for a limited part of the day.

- In a pro-rata system all reserves are activated simultaneously. In a merit-order system, (non-spinning) generators are activated sequentially during an upward slope with upward reserves. This only occurs few times in the natural day simulation as can be observed from the **Figure 5-3** that displays the time series. The delay in delivery of FRR due to the preparation delay of non-spinning generators only occurs when they are started.

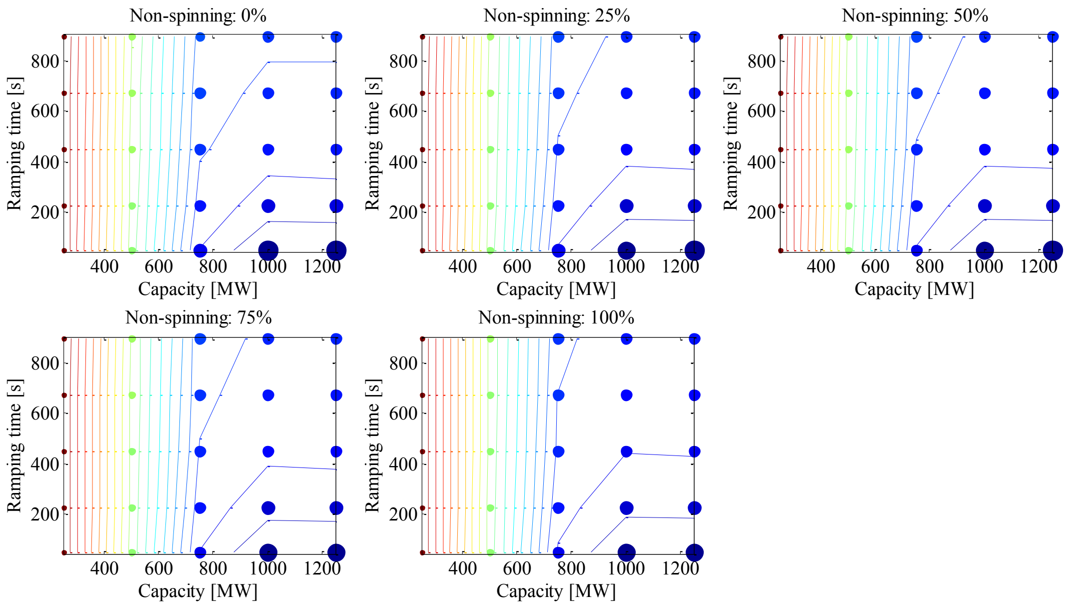

Figure 5-2 Contour plot of the standard deviation of the frequency.

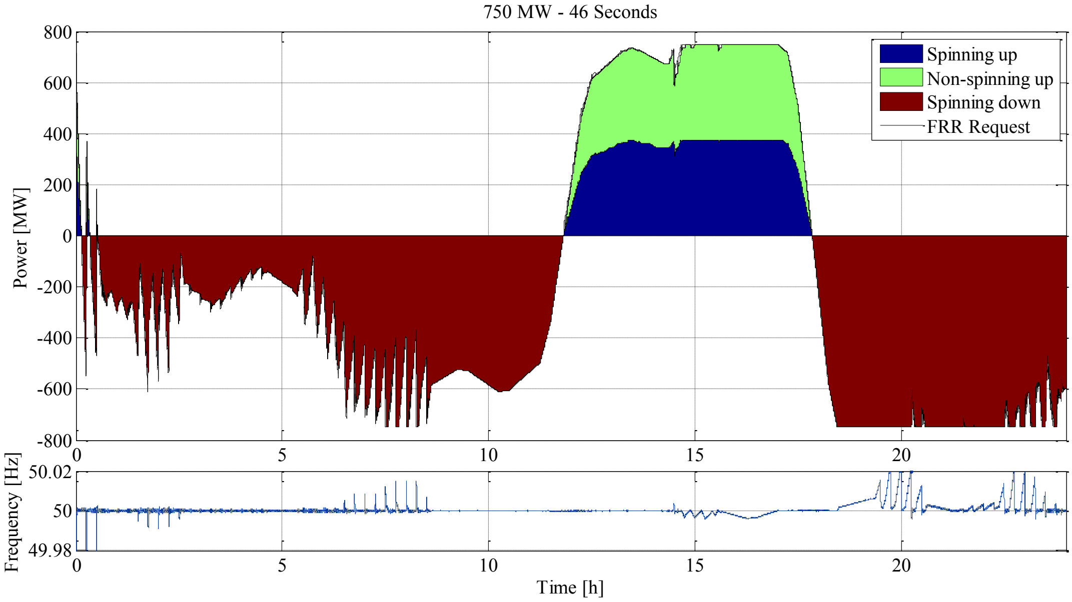

Figure 5-3 Time series of the request for FRR activation and the corresponding activation of spinning and non-spinning upward FRR and spinning downward FRR. The lower figure shows the system frequency which is used as input for system performance analysis.

5.1.2 Generator outage simulations

To simulate generator outage as well as very rapid decrease of generation, a number of generator outage simulations were performed. During generator outages the power generation is suddenly decreased with 600MW (implemented by a stepwise increase of the load). As a consequence the grid frequency will decrease until stabilized by activation of frequency containment reserves. Subsequently the frequency restoration reserves return the frequency to its nominal value.

The generator outage simulations are performed both for pro-rata and for merit-order activation regimes. Both activation regimes yield different results and are therefore discussed in the next two sections.

5.1.2.1 Pro-rata activation

Figure 5-4 to **Figure 5-7** display the response of the system frequency during a sudden generator outage.

From **Figure 5-4** can be observed that a sudden decrease of generation leads to a drop of the grid frequency due to the imbalance caused. This frequency drop is initially stopped by activation of frequency containment reserves after which the frequency is restored by activation of frequency restoration reserves. **Figure 5-4** shows that (under a pro-rata activation regime) the activation time of frequency restoration reserves defines the time required to fully restore the frequency.

For the case that the activation time is 900s, increasing the share of non-spinning FRR capacity improves the frequency restoration process. This conclusion holds also for activation times of 225s, 450s and 675s.

Figure 5-5 shows that increasing the speed of FRR capacity leads to an improvement of the frequency restoration process. Also it can be observed (when comparing to the other figures) that under a pro-rata activation regime, increasing the FRR capacity also improves the frequency restoration process.

Figure 5-6 shows that including fast non-spinning balancing capacity (for the case of 900s[13] activation time) improves (faster restoration) the recovery of the grid frequency. This is due to the fact that the non-spinning FRR capacity has an activation time (including preparation time) which is in those cases faster than the activation time of spinning FRR capacity.

Figure 5-7 shows that if the activation time of spinning FRR capacity is equal to 46s that increasing the share of non-spinning FRR capacity deteriorates the frequency restoration process. This is due to the fact that in this case the total full activation time of non-spinning FRR capacity is longer than the activation time of spinning FRR capacity.

13 Although not visible in Figure 5-6 this holds for all activation times from 225s and up.

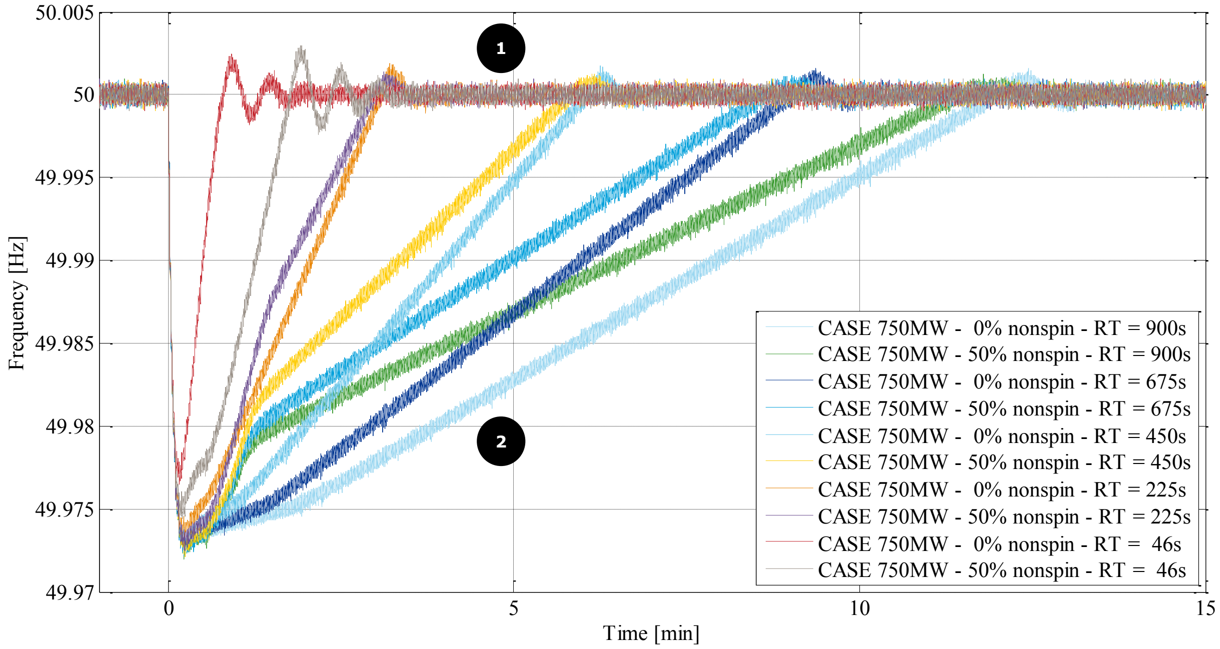

Figure 5-4 Frequency response under pro-rata activation regime with 750MW of installed capacity, varying shares of non-spinning generation and varying activation times.

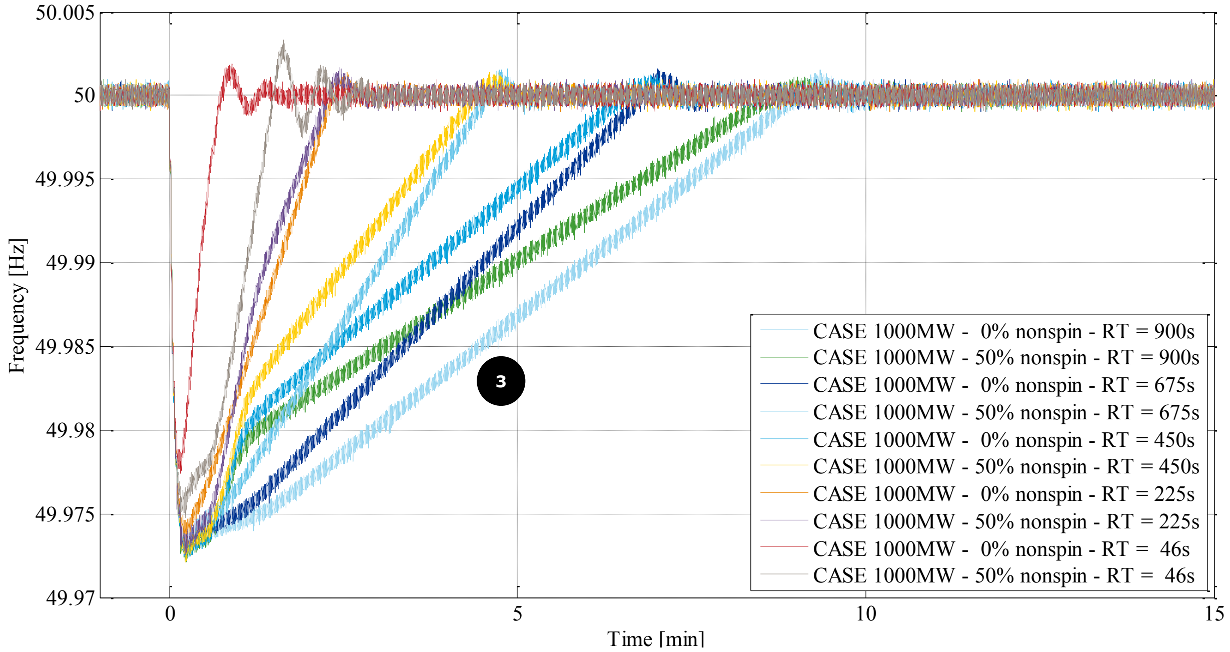

Figure 5-5 Frequency response under pro-rata activation regime with 1000MW of installed capacity, varying shares of non-spinning generation and varying activation times.

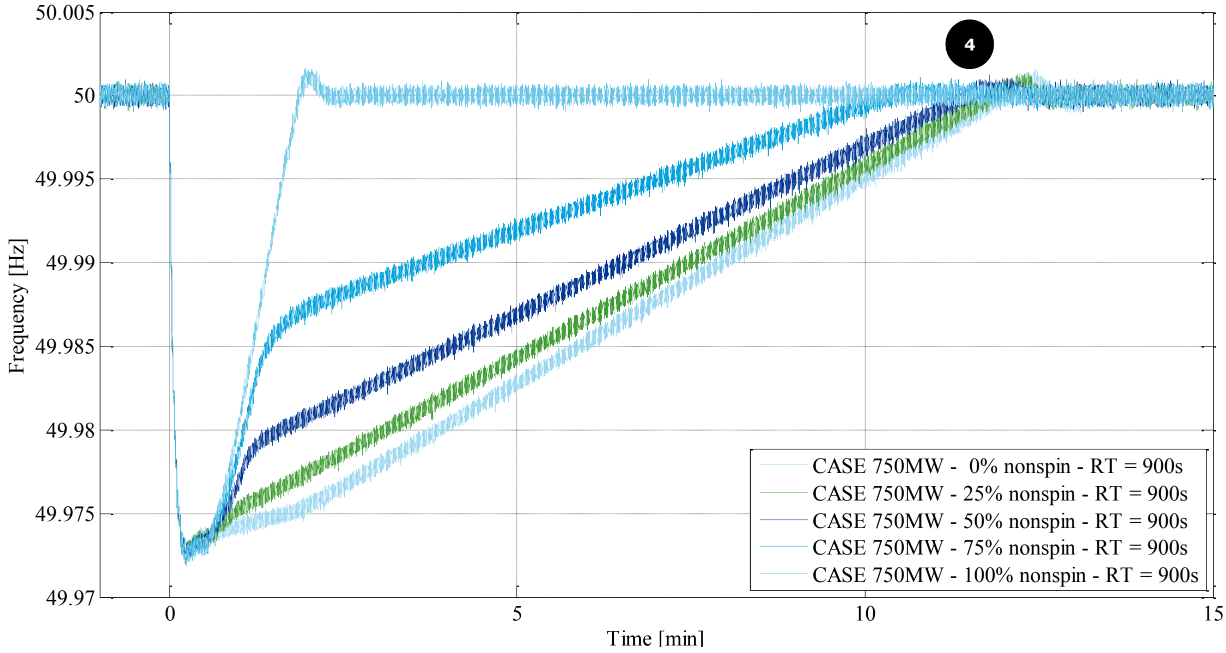

Figure 5-6 Frequency response under pro-rata activation regime with 750MW of installed capacity, varying shares of non-spinning generation and constant activation time of 900s.

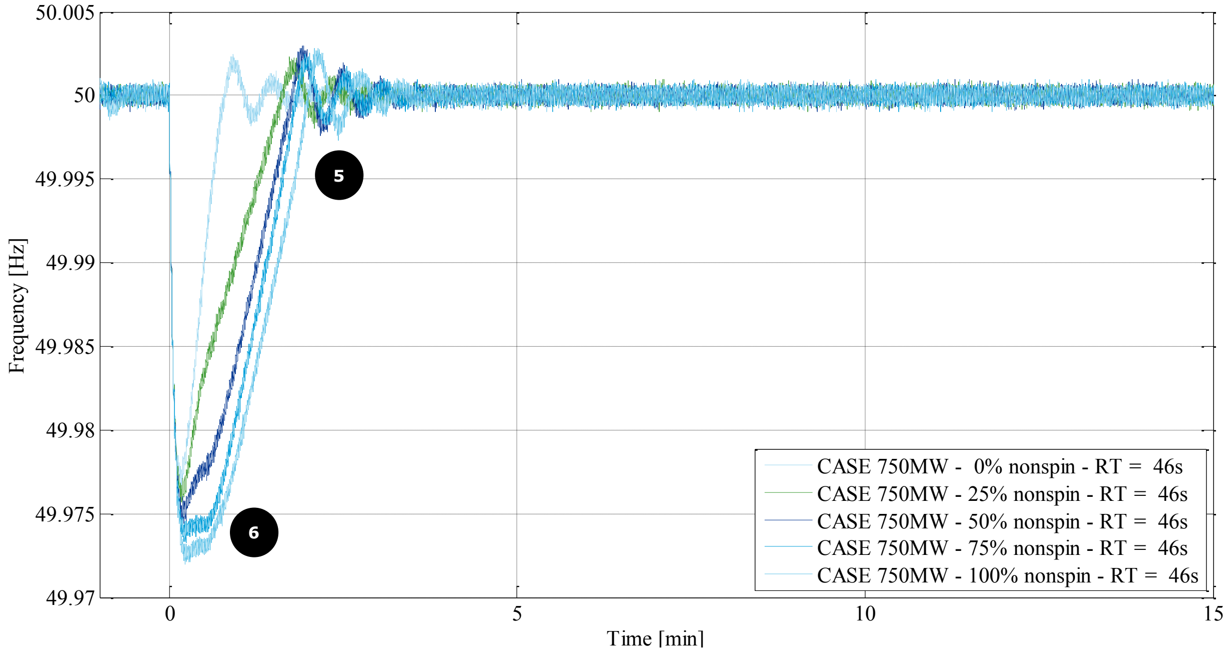

Figure 5-7 Frequency response under pro-rata activation regime with 750MW of installed capacity, varying shares of non-spinning generation and constant activation time of 46s.

5.1.2.2 Merit-order activation

The following figures display the response of the system frequency during a generator outage.

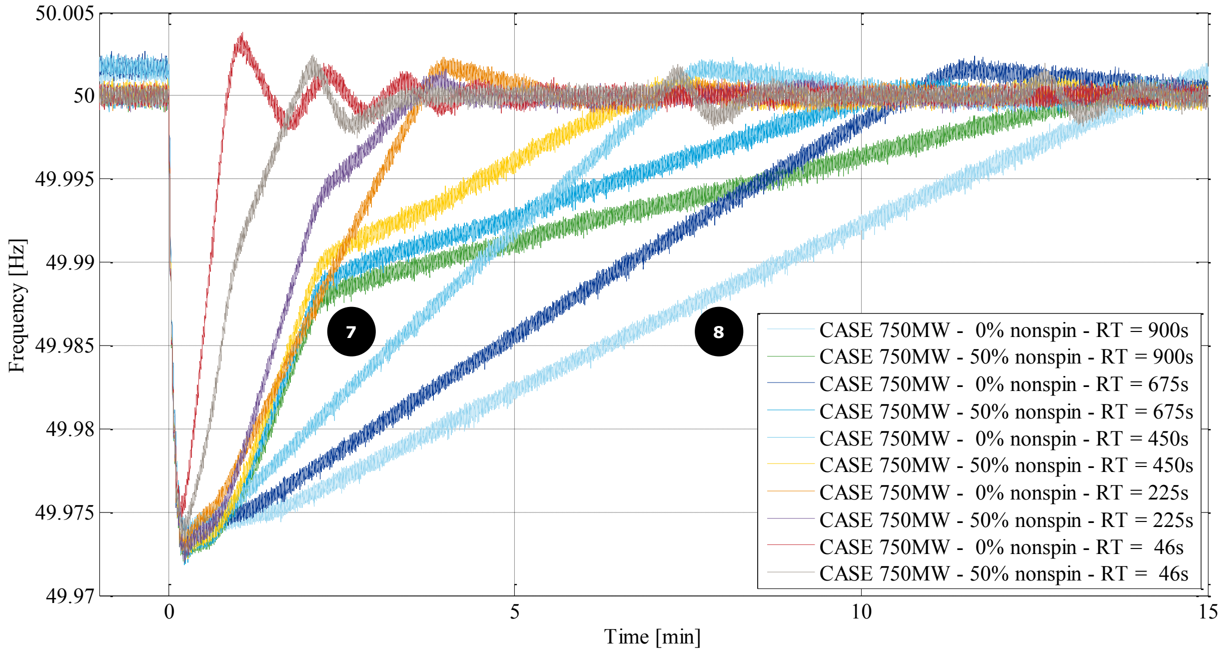

Figure 5-8 Frequency response under merit-order activation regime with 750MW of installed capacity, varying shares of non-spinning generation and varying activation times.

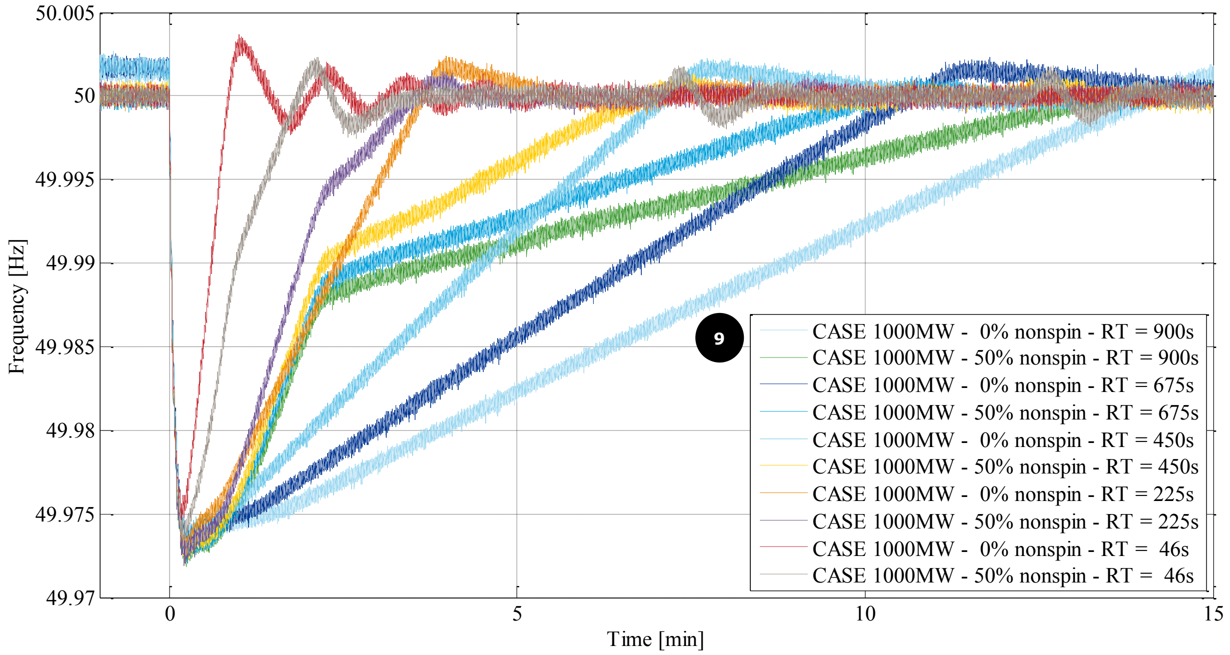

Figure 5-9 Frequency response under merit-order activation regime with 1000MW of installed capacity, varying shares of non-spinning generation and varying activation times.

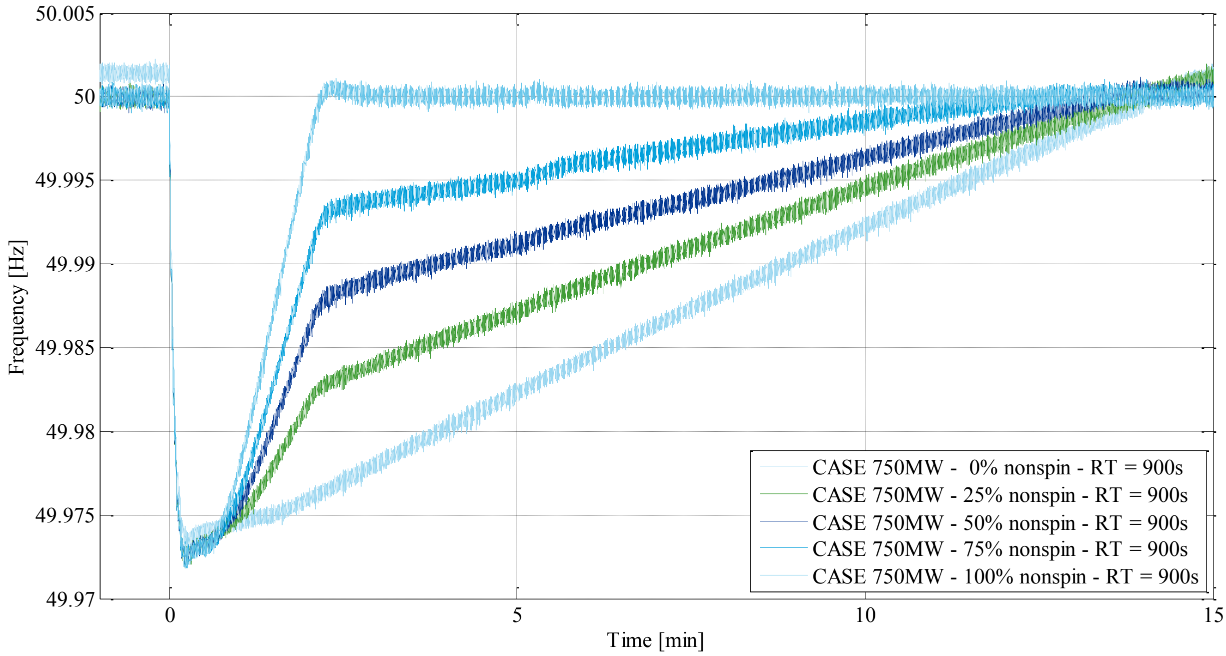

Figure 5-10 Frequency response under merit-order activation regime with 750MW of installed capacity, varying shares of non-spinning generation and constant activation time of 900s.

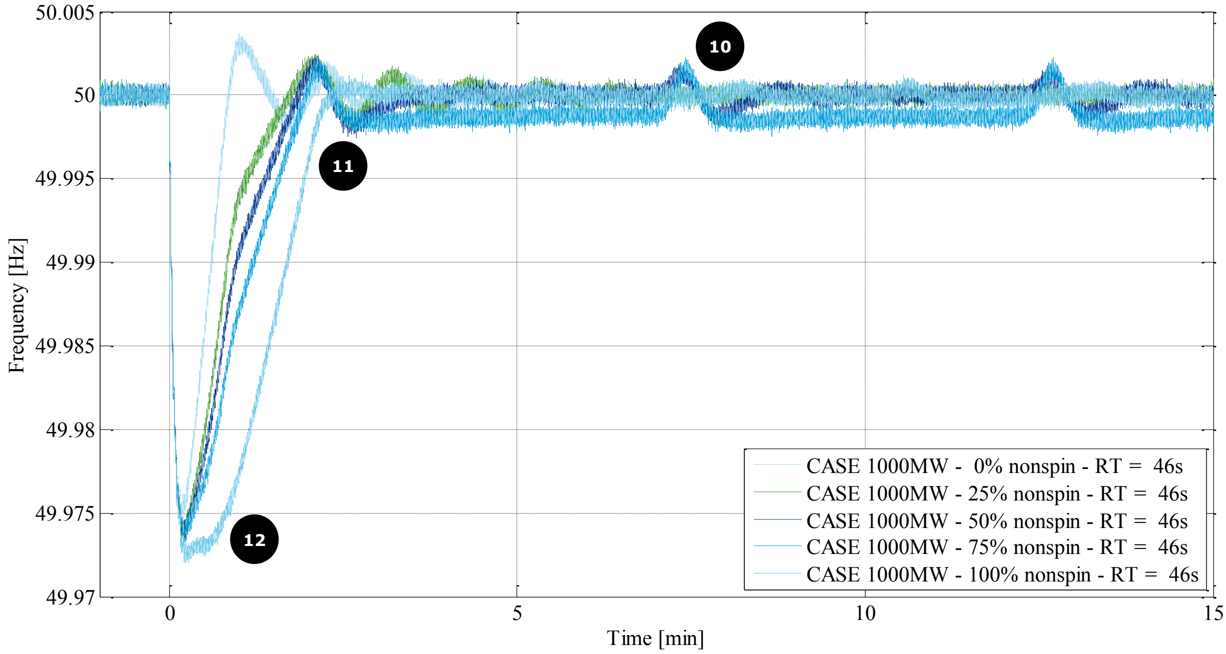

Figure 5-11 Frequency response under merit-order activation regime with 1000MW of installed capacity, varying shares of non-spinning generation and constant activation time of 46s.

Figure 5-8 shows that under a merit-order activation regime, the activation time of reserves defines the recovery of the grid frequency.

Figure 5-9 (and comparing it to **Figure 5-8**) shows that under a merit-order activation regime (in contrary to the pro-rata activation regime) increasing the FRR capacity does not lead to a further improvement of the frequency restoration process. This assumes that at least the size of the disturbance is available as FRR reserves.

Figure 5-10 show that increasing shares of non-spinning FRR capacity improves the frequency restoration process for the cases with activation times of 900 seconds[14]. **Figure 5-11**shows that for activation times of 46s, increasing the share of non-spinning FRR capacity deteriorates the frequency restoration process.

If the activation time of FRR is 46s, increasing the share of non-spinning FRR capacity deteriorates the frequency restoration process (**Figure 5-11**) as in this case the non-spinning FRR capacity is slower than the spinning FRR capacity. The peaks in the grid frequency at approximately 7 and 12 minutes are caused by interchanging of spinning and non-spinning generators due to the non-spinning generators being blocked for 5 minutes once being switched off[15]. More specific observations on the interpretation of the frequency restoration process are given in Appendix G.

5.1.2.3 Post-processing and observations from generator outage simulations

To obtain further insight in the simulation results, **Figure 5-12** and **Figure 5-13** give the value of the performance indicator (Integral quality indicator) specified for generator outage simulations as specified in chapter 3. The performance indicator gives the ratio of the integral (area) of the grid frequency (with respect to 50Hz) over the integral (area) enclosed by the corresponding trumpet curve. A lower value indicates a better frequency restoration.

The following observations can be made from the time series figures from generator outage simulations. Corresponding marks in the figures show where the observations can be made.

Capacity in frequency restoration reserves

- Under the pro-rata activation regime, increasing capacity from 750MW to 1000MW leads to increased system performance with a 600MW disturbance (comparing **Figure 5-4** with **Figure 5-5**).
- Under the merit-order activation regime, the impact of increasing FRR capacity from 750MW to 1000MW depends on the composition of the merit-order (**Figure 5-13** mark 18).
- In merit-order, the impact of increasing capacity depends on the composition of the merit-order[16] (**Figure 5-13** mark 18).

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14 Also not observed from **Figure 5-10** this conclusion holds also for activation times of 225s, 450s and 675s.

15 Due to the merit-order activation mechanism as non-spinning generators are first switched on during the overshoot, and then switched off, they have to remain off for at least 5 minutes. During this blocking time their power will be delivered by spinning generators. Once the 5 minutes minimum off-time has passed, the non-spinning generators abruptly start generating again, replacing the other generators. The different activation times of the spinning and non-spinning generators create frequency variations.

16 The fractions of non-spinning reserves are fractions of capacity in the merit order. In the merit-order activation regime, the actual fraction of non-spinning capacity contributing to the system depends on the composition of the merit-order. We assume alternating activation of spinning and non-spinning reserves. As a consequence in the 25% and 75% cases, increasing the total FRR capacity moves the response to the case of 50% non-spinning reserves.

Full activation time

- The activation time defines the time to restore the frequency (**Figure 5-4** mark 1).
- Merit-order activation allows non-spinning generators to ramp faster; they are not withheld by spinning generators. This is most probable a side-effect of the different AGC settings (comparing **Figure 5-4** with **Figure 5-8** mark 7).
- Under pro-rata activation regime increasing speed and capacity both lead to improved system response (**Figure 5-4** mark 2 and **Figure 5-5** mark 3).
- Under merit-order activation regime, available capacity is of lesser importance than speed once sufficient capacity is available (comparing **Figure 5-8** mark 8 with **Figure 5-9** mark 9).
- In pro-rata, increasing capacity and decreasing activation time both lead to improved system performance. Decreasing activation time only leads to improved system response for activation times of 225s and higher[17] (**Figure 5-12**).
- In merit-order, decreasing activation time leads to improved system performance. Decreasing activation time only leads to improved system response for activation times of 225s and higher[18] (**Figure 5-13**).

Percentage of non-spinning capacity

- Partly replacing spinning reserves by non-spinning reserves does not affect the restoration time under pro-rata regime for activation times from 225s and up (**Figure 5-6** mark 4) but it does lead to improvement of the system performance as can be seen in **Figure 5-12** mark 15 and **Figure 5-13** mark 18.
- For the activation time of 46s, including non-spinning reserves deteriorates the frequency response (**Figure 5-7** mark 5, **Figure 5-11** mark 11, **Figure 5-12** mark 13 and **Figure 5-13** mark 16).
- The frequency nadir (deepest point) is marginally affected by the FRR characteristics, except for activation time of 46s in which case the frequency nadir decreases as responses of FCR and FRR start to overlap more (**Figure 5-7** mark 6 and **Figure 5-11** mark 12).
- Under the merit-order activation regime, small oscillations occur after restoration of the frequency with 5 minute intervals as explained above. This is due to the dynamics of the non-spinning FRR generators that, if they are being switched off, should remain off for at least 5 minutes (**Figure 5-11** mark 10).
- In case of 100% non-spinning reserves, the activation time is always fixed and does not depend on the activation time of spinning reserves (x-axis). Therefore values are expected to be independent of the ramping time of spinning reserves (x-axis). In case of pro-rata, the 1000MW cases perform better than the 750MW cases. This is due to imperfections in AGC tuning (**Figure 5-12** mark 14 and **Figure 5-13** mark 17).

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17 It can be observed that the tipping point lies between 46s and 225s (assuming a linear interpolation). No simulations with activation times in between both values were performed.

18 It can be observed that the tipping point lies between 46s and 225s (assuming a linear interpolation). No simulations with activation times in between both values were performed.

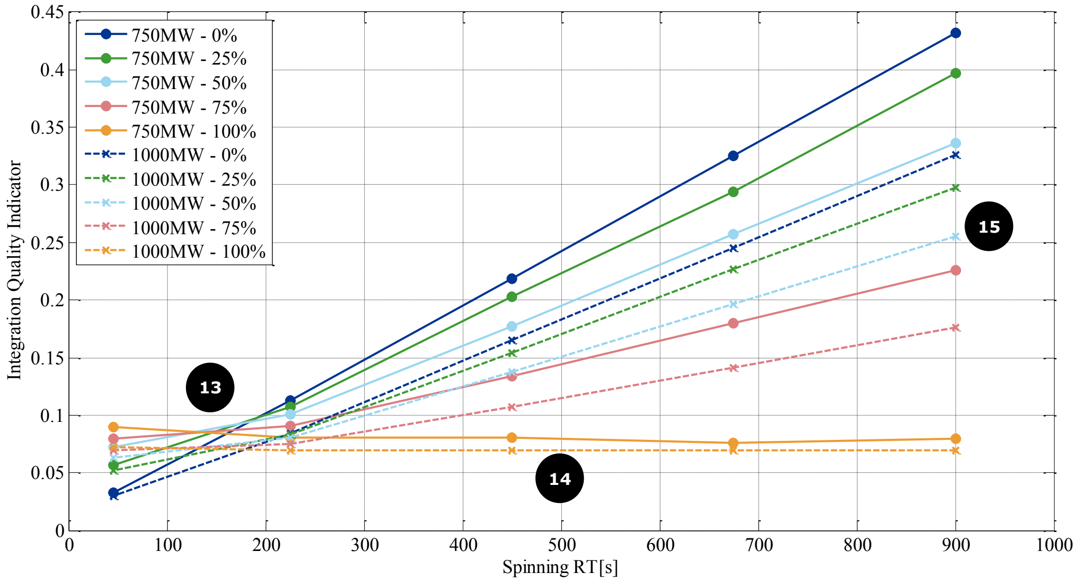

Figure 5-12 Integral Quality Indicator for all generator outage simulations under a pro-rata activation regime.

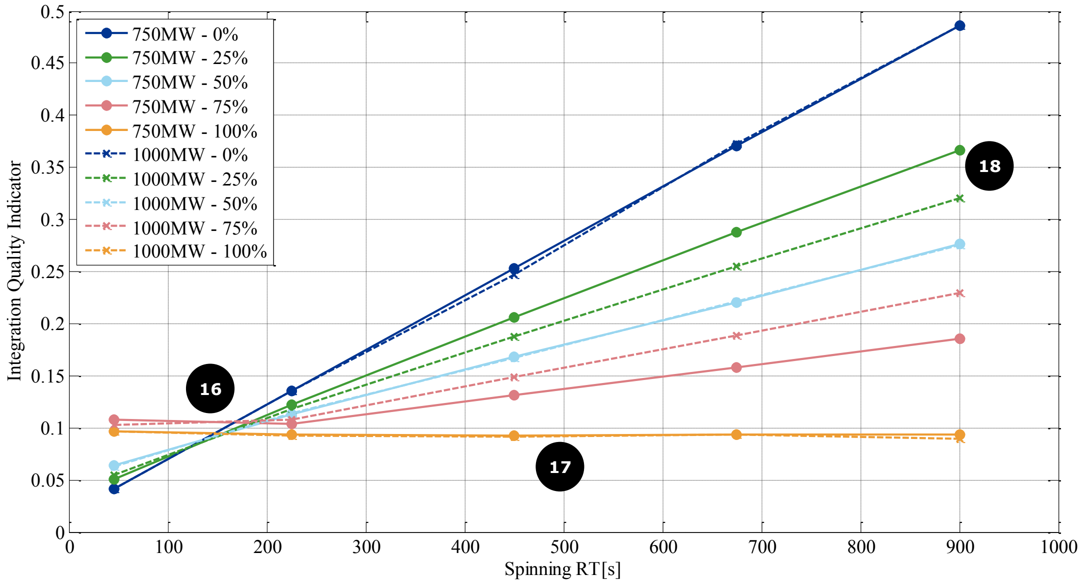

Figure 5-13 Integral Quality Indicator for all generator outage simulations under a merit-order activation regime.

5.1.3 Selection of economic case

Based on the observations from the technical assessment, a selection of cases was made for further economic assessment. This list was already presented in chapter 4 of this report. To obtain this selection the following argumentation applies.

The technical simulations (combined natural day and generator outage simulations) indicate that adequate system response can be obtained with FRR characterizations of 750MW combined with an activation time of 900s. As indicated before, the required capacity depends on the open loop imbalance, imposed to the system. The open loop imbalance is composed out of the different types of imbalances:

forecast errors, block trade effects and disturbances and as such the required FRR capacity depends on these phenomena. The impact of these phenomena on the required FRR capacity is addressed further in the economic assessment by including an additional case with reduced required FRR capacity.

- As a base case for economic assessment we apply the case with 750MW and an activation time of 900 seconds.
- From the trip study post-processing it can be observed that under a pro-rata activation regime, both increasing the capacity from 750MW to 1000MW and decreasing activation time from 900s to 675s yield approximately a similar improvement in system response. Therefore these two alternatives will be addressed as well.
- To observe the sensitivity for the open loop imbalance, and as the 1000MW case is already covered (see above), an additional case with 500MW of FRR capacity is introduced with an activation time of 900s for the reason mentioned before.

Combined this leads to the points of departure as indicated in **Table 5-1**.

Table 5-1 Cases selected as point of departure for economic analysis.

Case Name	Capacity	Activation Time
P1-1	750MW	900s
P2-1	1000MW	900s
P3-1	750MW	675s
P4-1	500MW	900s

The case names in **Table 5-1** corresponds to the case names as indicated in chapter 4. For each case selected as point of departure, variations based on the additional degrees of freedom in the economic assessment have been added as elaborated in chapter 4 of this report.

5.2 Economic assessment results

All cases described in chapter 4 have been simulated using PLEXOS. The results can be compared based on the performance indices introduced in chapter 3 of this report. This section describes the results and observations from these analyses.

It should be noted that each of the analyses below only reflects expenditures related to ensuring the availability of reserves. Any costs or revenues related to the activation of reserves are excluded from the analysis.

5.2.1 Operational expenditures

Figure 5-14 show the European operational expenditures (OPEX) in absolute values for the different simulations. **Figure 5-15** presents the differences compared to the case with no reserve requirement.

Looking at **Figure 5-14** and **Figure 5-15** we observe that the OPEX increase with stricter FRR requirements. This is observed when changing the FRR capacity from 750 to 1000MW or from 500 to 750MW. Second, the OPEX increase when shortening the ramping period from 900 seconds to 675 seconds. Third, the additional OPEX related to the reserve requirement reduces when giving more freedom to the FRR reserve such as intermittent renewable energy sources being able to contribute to down reserve and European cross-border reserve sharing.

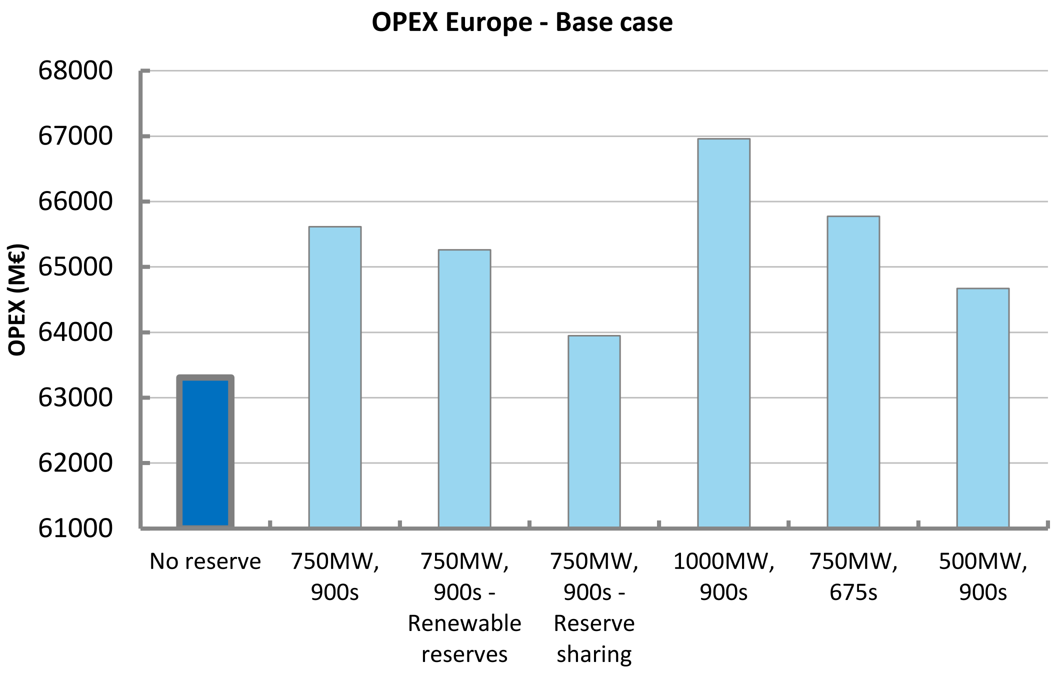

Figure 5-14 Annual operational expenditures in the European power system in which the Netherlands has the high wind base case portfolio. The bars correspond to different reserve requirements and designs for the Netherlands. The reserve requirements in the other European countries are scaled according to the change in the Dutch reserve requirements.

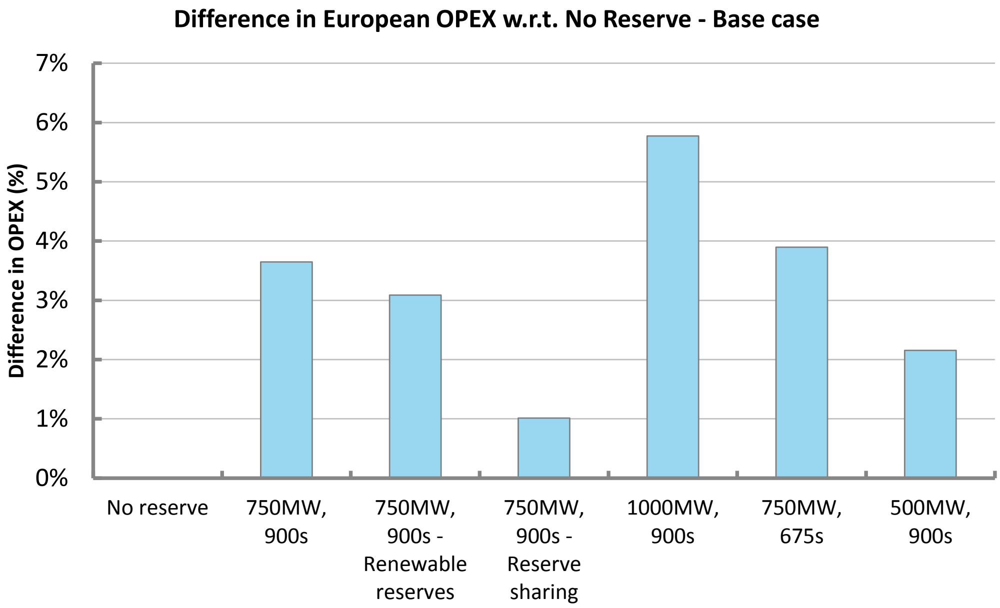

Figure 5-15 Difference in annual OPEX compared to the base case with no reserve requirements.

In addition, both figures show that reducing the ramping period has a smaller impact on OPEX than increasing the FRR capacity. This is observed when comparing the impact on OPEX from increasing the FRR capacity from 750 MW to 1000 MW to the case of reducing the ramping period to 675 seconds.

The differences in OPEX originate from different dispatch of the power plants (**Figure 5-16**):

- Increasing the FRR capacity from 750 MW to 1000 MW leads to an increase in dispatch of relatively more flexible power plants at the expense of inflexible low-cost base-load: generation from uranium is reduced and the generation from coal-fired, gas-fired and oil-peak generation is increased.
- A decrease in activation time from 900s to 675s has a smaller impact on OPEX as mainly lignite generation is decreased and coal-fired and gas-fired generation is increased.

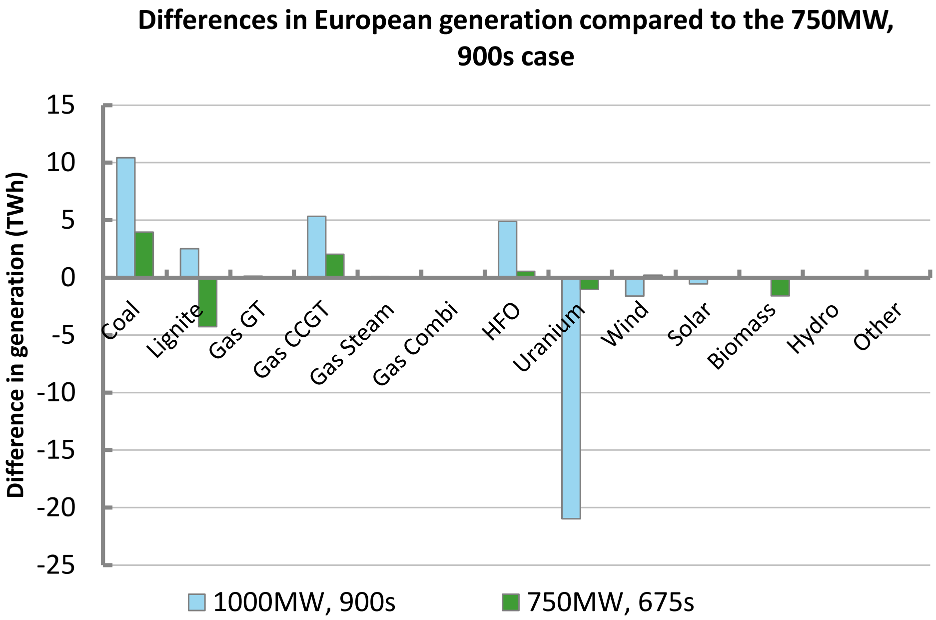

Figure 5-16 Differences in European electricity generation of two cases (1000MW, 900s and 750MW, 675s) compared to the case of 750MW, 900s. As a reference: total European annual demand is 3447 TWh.

Allowing intermittent renewable generation (wind and PV) contribute to down reserve capacity reduces OPEX as it reduces the need for conventional generation during hours of high renewable generation. This option mainly reduces the generation of coal-fired and lignite-fired power plants during hours of low load and high renewable generation, as can be seen in **Figure 5-17**. In addition, renewable reserves reduce the curtailment of renewable energy during such hours as less flexible conventional generation needs to be committed. Furthermore, this option allows more nuclear generation.

Cross-border reserve sharing significantly reduces European OPEX as it reduces the generation from expensive gas-fired and oil-fired generation that otherwise would have been dispatched for providing reserve capacity (see **Figure 5-17**). This generation is now provided by nuclear generation. Allowing cross-border sharing increases the utilization of low-cost reserve capacity available within Europe. Power plants are less often dispatched because of the reserve requirement. There is sufficient generation (for down reserve) and spare generation (for up reserve) capacity available in Europe for most of the time.

Note that the impact of different FRR requirements on national OPEX of individual countries can differ from the overall European trends. Different requirements can lead to different interchanges between countries: less generation in country A while country B increases its generation, hence, country A has lower OPEX and country B has higher OPEX. This is for example the case for the Netherlands with the cross-border sharing enabled: the Netherlands increase their generation and as a results also its OPEX.

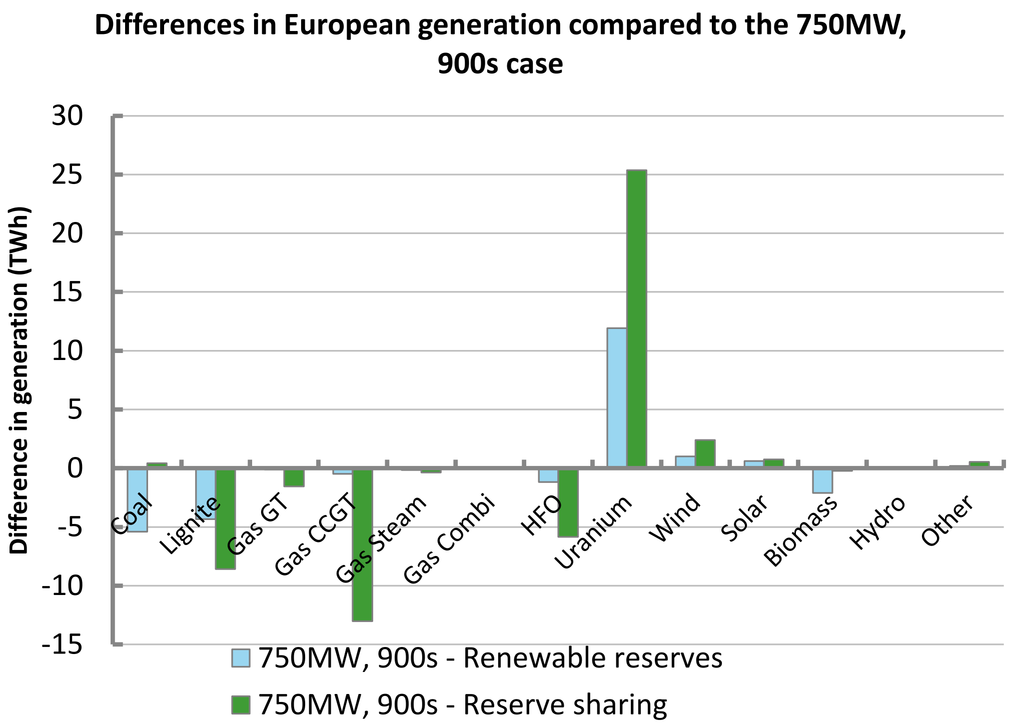

Figure 5-17 Differences in European electricity generation of two cases (renewable reserves and cross-border reserve sharing) compared to the case of 750MW, 900s. As a reference: total European annual demand is 3447 TWh.

5.2.2 Market size at European level

The market size of the FRR up and down reserve capacity is defined as the available reserve capacity in Europe. **Figure 5-18** and **Figure 5-19** show the European market sizes for up and down FRR per hour, ranked by size.

Both **Figure 5-18** and **Figure 5-19** show that more than sufficient reserve capacity is (made) available to meet the required amount. Only during approximately 10% of the hours there is scarcity in the FRR up capacity market: the available capacity is (almost) equal to the required capacity Also for the case of cross-border reserve sharing there is significantly more capacity available than required.

Some additional observations regarding the market size of FRR up capacity are:

- Increasing the required FRR capacity also increases the amount of available capacity: more power plants are dispatched to meet the required FRR capacity.
- Allowing intermittent renewables to provide down reserve capacity gives a small increase in the FRR down market size, but it has no impact on the up reserve market size
- Reducing the activation time decreases the market size as power plants provide less capacity, especially during hours with oversupply.

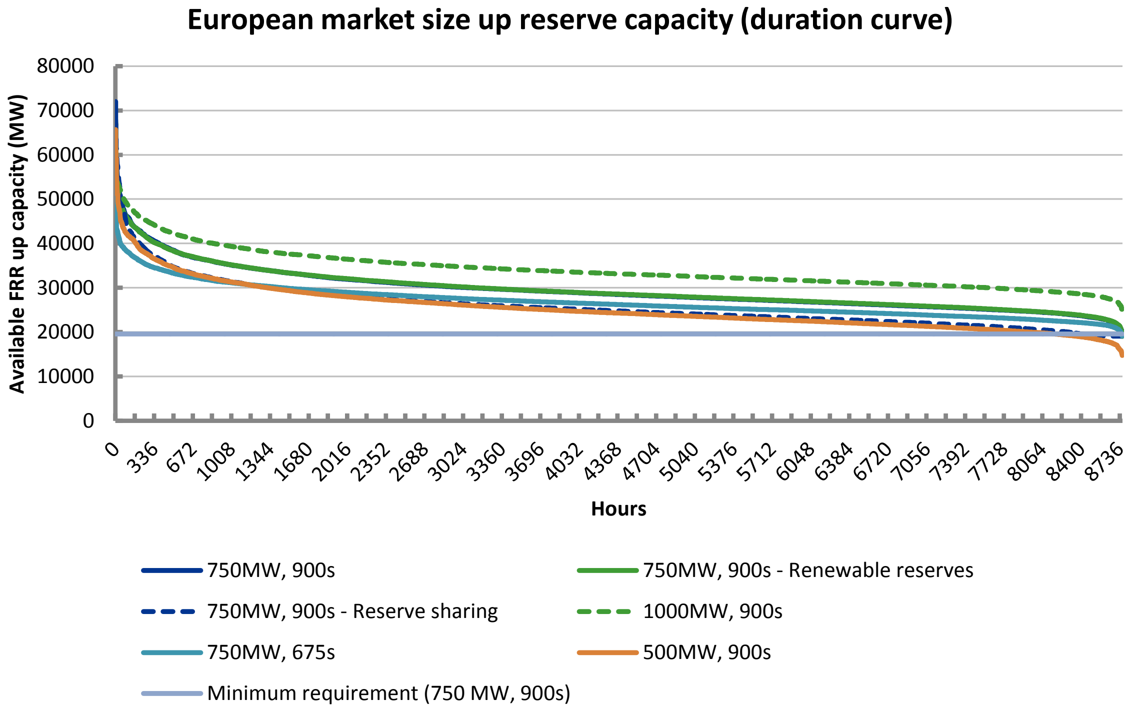

Figure 5-18 Market size of European FRR up reserve for different FRR designs. The lines for 750MW, 900s and 750MW, 900s – Renewable reserves overlap.

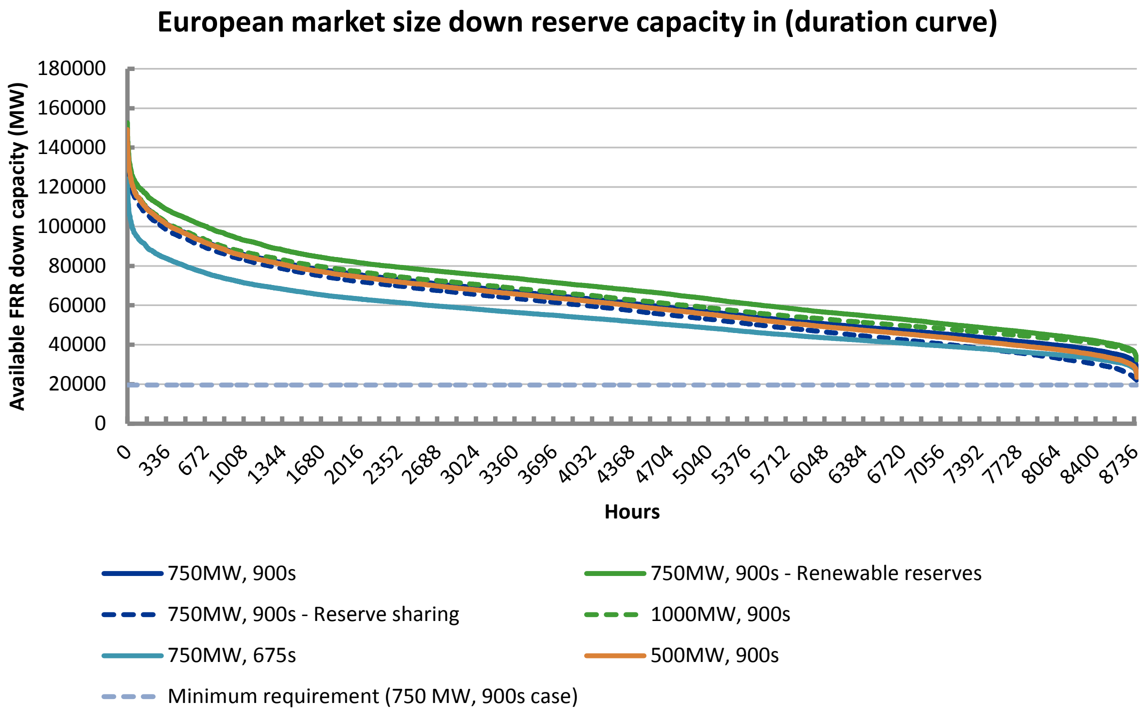

Figure 5-19 Market size of European FRR down reserve for different FRR designs.

5.2.3 Including fast reserve generators

The impact of adding fast reserve generators can be analyzed at a European level and at a national (the Netherlands) level. As the fast reserve generators are only added to the Dutch generation portfolio, the overall impact of these generators on the European OPEX is negligible compared to the impact of different FRR requirements: less than 0.2% change.

Some key observations about the use of the fast reserve generators:

- The fast reserve generators are mainly used to provide non-spinning reserve capacity.
- They are sometimes used for electricity generation for an individual hour combined with providing spinning reserve (they have higher generation costs but no start costs), but their overall capacity factor is low: 0.05 to 0.4%.
- They are not used for provision of FRR down reserve capacity.
- The utilization of the fast generators for the reserve provision is around 71% for the high wind base portfolio.

On a national level, the impact of adding fast reserve generators is more pronounced compared to the impact of different FRR requirements.

Figure 5-20 shows the impact of fast reserve on the national OPEX using generation cost intensity as the observable. Different FRR requirements influence the dispatch and the exchange with other countries and therefore the generation of the Dutch portfolio (see the blue and green dots in **Figure 5-20**). A reserve requirement forces certain power plants to run at a certain level such that sufficient FRR capacity is available. This is in fact a 'must-run' obligation and influences the national generation and the market prices. Consequently, the electricity exchange between countries and the national OPEX are affected. For example, in the case of allowing cross-border sharing of reserve capacity, cross-border sharing reduces the generation in Belgium and UK (generation that was otherwise provided by relative expensive units that were required to provide FRR capacity) and allows an increase in net export of the Netherlands to these countries. This increase in net export increases the generation and the OPEX within the Netherlands compared to other FRR requirements.

To accommodate for possible differences in generation, we also look at the generation cost intensity of the Netherlands: total OPEX divided by total generation. Comparing **Figure 5-20** and **Figure 5-21** shows that the total OPEX and the OPEX intensity are influenced by reserve requirements in a similar way.

From **Figure 5-20** it becomes clear that adding fast reserve reduces the additional OPEX costs from reserve requirements by up to 58%. The (up) reserve provision from the fast reserve generators allows coal-fired and gas-fired power plants to be switched off, lowering generation and OPEX. Some detailed observations:

- Allowing cross-border sharing of reserves reduces the benefit of having fast reserve generators in a specific country, as its reserve capacity is shared with other countries.
- Renewables providing down reserves does not significantly impact the benefit of fast reserve generators.
- The larger the reserve capacity requirement, the larger the relative reduction in the impact of the FRR requirement on national OPEX from adding fast reserve generators: 32% for 500 MW, 44% for 750 MW, and 58% for 1000 MW (note that the installed capacity of fast reserve generators was equal to the FRR capacity requirement).

From **Figure 5-20** and **Figure 5-21** we see that lowest national OPEX (total and intensity) are obtained by combining fast reserve generators with renewable reserve provision. The impact of the fast reserve generators and the renewable reserve provision are complementary: the fast reserve generators reduce the OPEX associated to the FRR up capacity provision, and the intermittent renewable down reserve provision reduces the costs associated to the FRR down capacity provision.

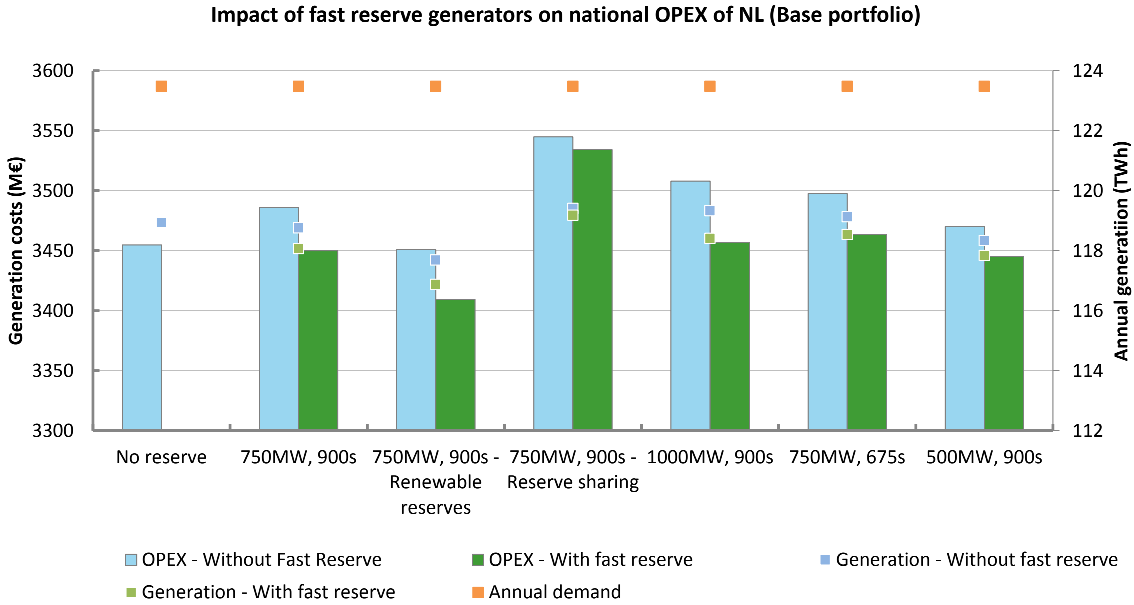

Figure 5-20 Impact of fast reserve generators on the national OPEX. The first blue column is the national OPEX for the case without reserve requirements: the difference between this column and the other columns represents the additional OPEX cost from the reserve requirement. The difference between national demand (orange dots, right-axis) and generation values (green and blue dots,right-axis) represents the net exchange with neighboring countries (import minus export).

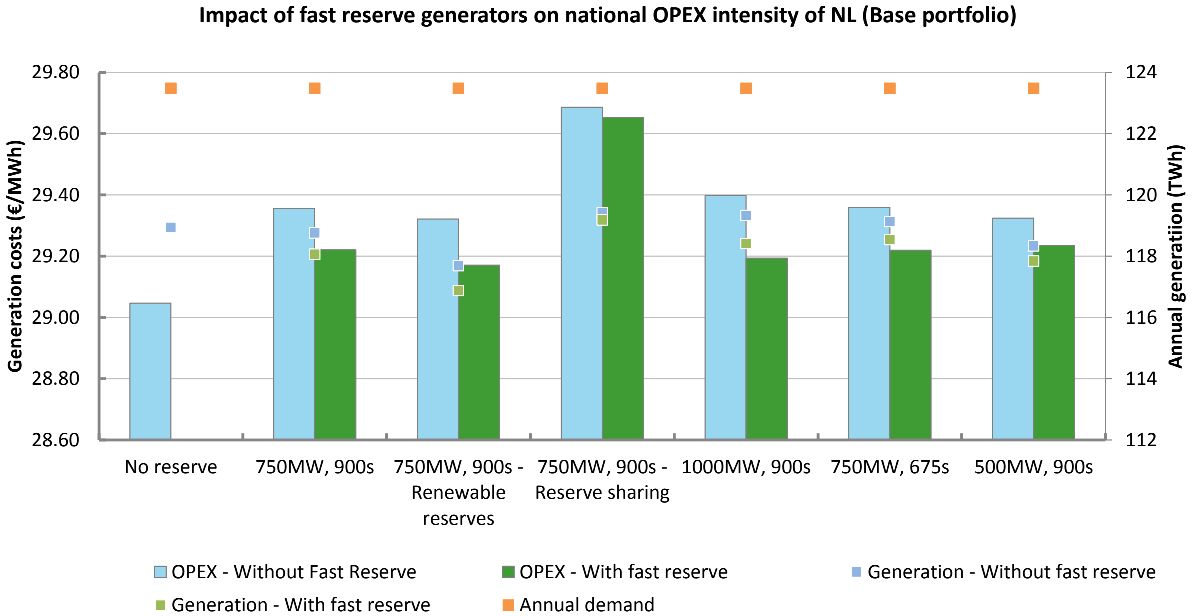

Figure 5-21 Impact of fast reserve generators on the national OPEX intensity (defined as total Dutch OPEX divided by generation in the Netherlands). The first blue column is the national OPEX for the case without reserve requirements: the difference between this column and the other columns represents the additional OPEX cost from the reserve requirement. The difference between national demand (orange dots, right-axis) and generation values (blue

and green dots, right-axis) represents the net exchange with neighboring countries (import minus export).

The impact of fast reserve generators on national OPEX depends on the portfolio of the country, as is illustrated in **Figure 5-22**. In this study three different portfolios were analyzed: high wind (base), high PV and high coal.

We observe that the impact is largest in the high PV case, this case has more PV and less CHP compared to the base case. In this portfolio, a shift in generation from flexible gas towards cheaper base load coal is observed when adding fast reserve generators: the required reserve capacity that was initially provided by gas-fired power plants is now provided by fast reserve generators.

In the high coal case, the impact of adding fast reserve is lowest with a -0.4% OPEX reduction. This is for two reasons: 1.) reserve provision from fast reserve generators is for this case less than in the other cases (see next section); 2.) fast reserve generators reduce the generation (at part load) of the less expensive coal-fired generation instead of the more expensive gas-fired generation in the other two portfolios.

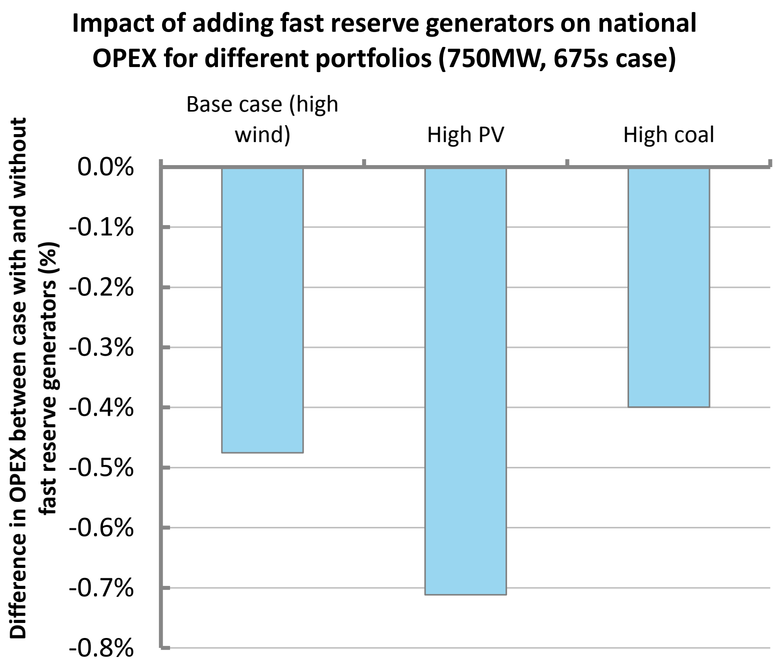

Figure 5-22 Impact of adding fast reserve generators to the Dutch generation portfolio for different type of portfolios: base case (high wind), high PV and high coal. The impact is defined as the relative change in normalized OPEX (€ / MWh generated) when adding fast reserve generators to the portfolio.

5.2.4 Minimum market share at national level

In this section we determine the minimum market share: the minimum amount of FRR capacity that is provided by the available fast reserve generators reserve capacity if the available FRR capacity from other power plants is not sufficient to meet the required FRR capacity. Note that this minimum market share represents the bare minimum, as it looks at the total available reserve capacity from the all power plants and assumes that the non-spinning reserve capacity from fast-reserve generators is the last option to meet the required FRR capacity. The actual market share will depend on the operating strategy of the power plants, including the fast reserve generators. The results are shown in **Figure 5-23** to **Figure 5-26**.

Figure 5-27 shows that the minimum market share of fast reserve generators is significant in almost all cases, the only exception being the case with cross-border reserve sharing. The fast reserve generators are a low-cost option for reserve capacity provision because of their capability of providing non-spinning reserve capacity.

Figure 5-23 to **Figure 5-25** show that fast reserve generators compete with coal-fired generation and gas CHP in the provision of FRR up capacity in all three cases, but the extent depends on the portfolio.

- Coal fired power plants are relatively inexpensive generation capacity and able to provide low cost reserve capacity when acting as marginal generator (which occurs more frequently because of increase in renewable generation). In addition, because of their relative (economic) inflexibility due to minimum up and down times and relative high start costs compared to gas-fired generation, they operate more often at part-load (instead of switching off) and this allows them to provide 'headroom' reserve capacity. ('Headroom reserve capacity' meaning that power plant would have operated at part-load independent of reserve requirement.)
- Gas CHP is dispatched partly because of the co-generation of heat, forcing them to be dispatched (industrial CHP) or have additional revenue from the heat market which makes their electricity less expensive (district heating CHP). The available spare generation capacity can be considered as 'headroom' reserve capacity.

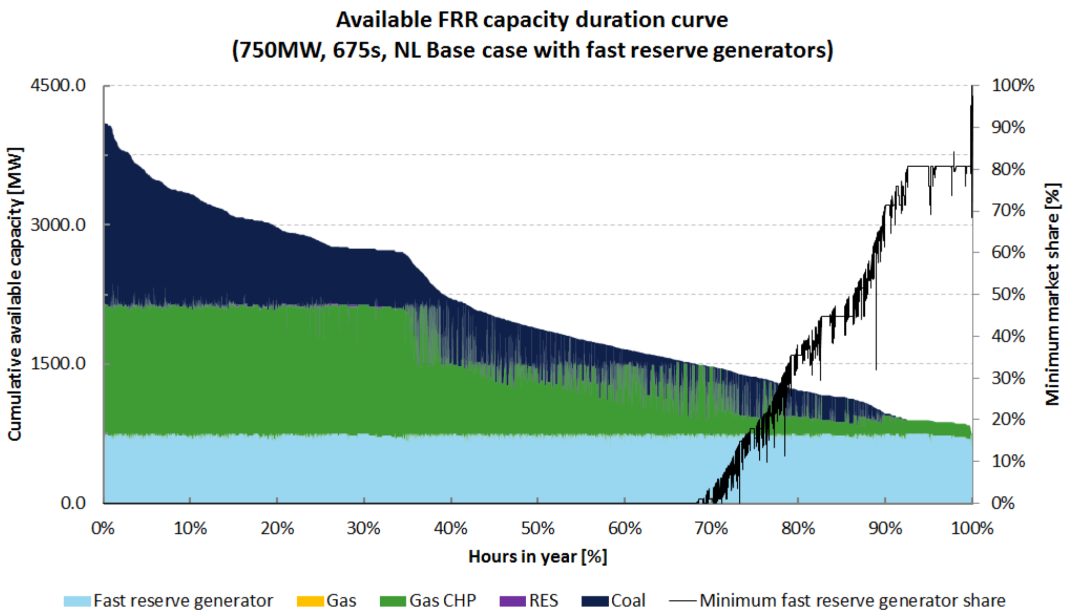

Figure 5-23 Duration curve of the available FRR up capacity in the Netherlands for the high wind base portfolio. The black line represents the minimum market share of fast reserve generators during those hours (e.g. 70% of the hours the minimum market share of fast reserve generators is zero).

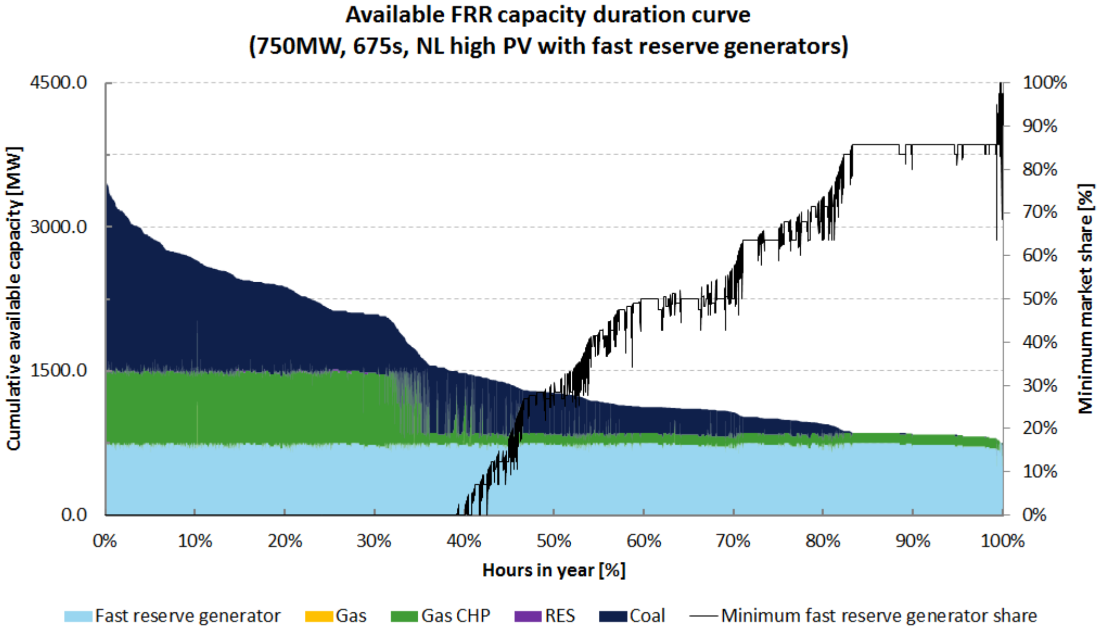

Figure 5-24 Duration curve of the available FRR up capacity in the Netherlands for the high PV portfolio. The black line represents the minimum market share of fast reserve generators during those hours.

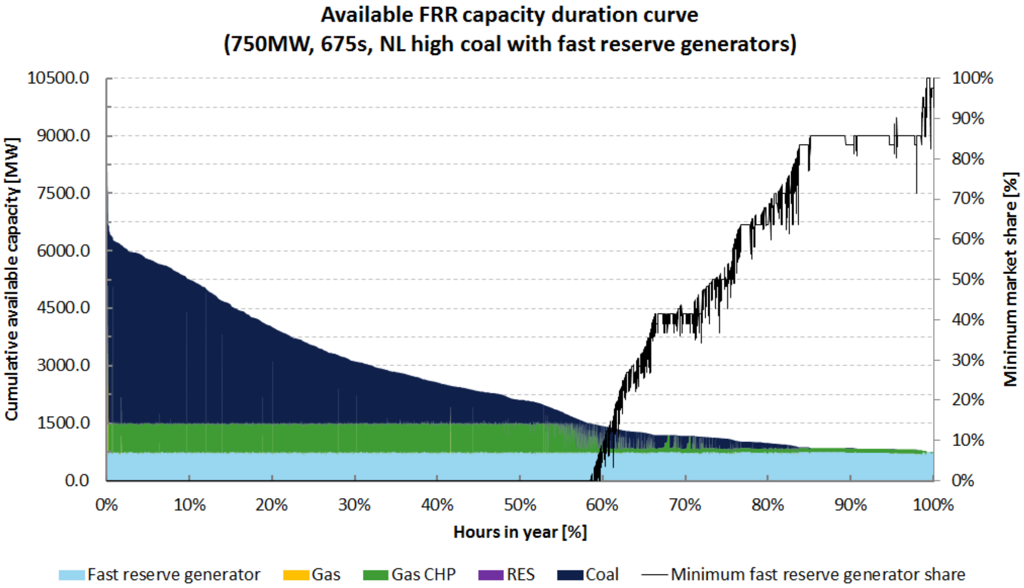

Figure 5-25 Duration curve of the available FRR up capacity in the Netherlands for the high coal portfolio. The black line represents the minimum market share of fast reserve generators during those hours.

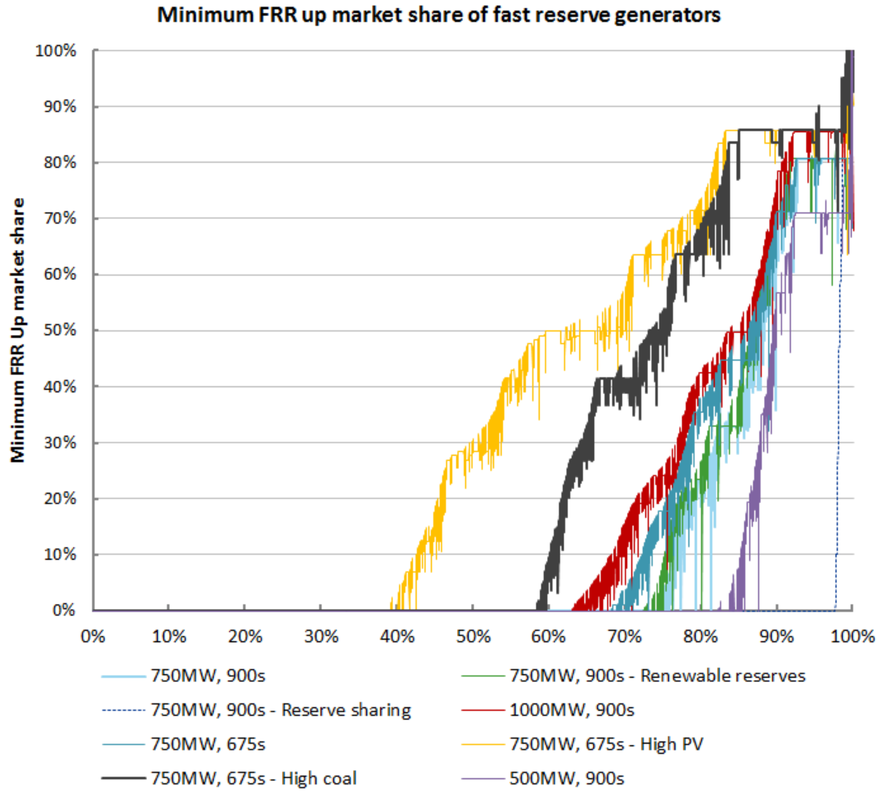

Figure 5-26 The minimum FRR up market share of fast reserve generators for different reserve requirements and portfolios per hour. The hours are ranked based on total available capacity of each case, as is shown in Figure 5-23 to Figure 5-25. All cases are for the high wind base portfolio, except 'High coal' or 'High PV' is explicitly mentioned.

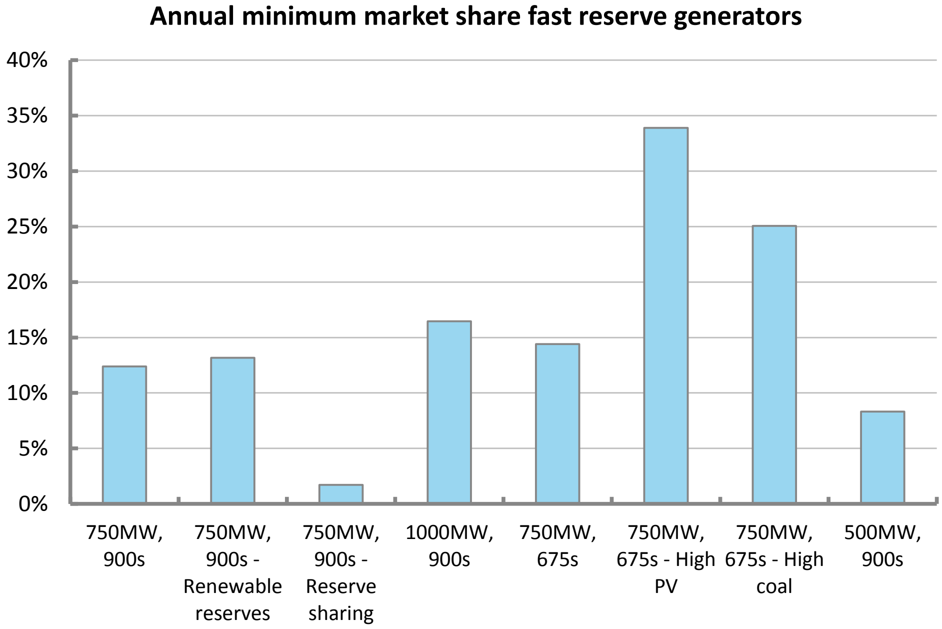

Figure 5-27 Annual minimum market share of fast reserve generators. These percentages are obtained by the area below the lines in Figure 5-26. Note that the value for the reserve sharing case is also a share of 750MW per hour instead the total European capacity.

In the high PV case the available CHP capacity is less than in the high wind base case, as there is less CHP generation and more PV generation in the high PV portfolio. This decreases the available reserve capacity from CHP and results in increases of the minimum market share of fast reserve generators from 14% (high wind base portfolio) to 34% on an annual basis (see **Figure 5-27**).

The high coal case has significantly more available FRR up capacity from coal-fired power plants running at part load than the high wind base case. However, the available FRR capacity from CHP is less, leading to an increase in minimum market share from 14% to 25% (see **Figure 5-27**).

Figure 5-26 and **Figure 5-27** show how the minimum market share of fast reserve generators depends on the FRR requirements:

- Increasing the required FRR capacity increases the minimum market share of fast reserve generators: the 'headroom' capacity from coal-fired and CHP power plants remains more or less the same while the required reserve capacity increases. The non-spinning reserve provision from fast reserve generators is less expensive than dispatching a power plant for spinning reserve provision.
- Decreasing the FRR activation time reduces the 'headroom' capacity from coal-fired and CHP power plants that can be used for reserve provision, requiring a larger minimum market share of fast reserve generators.
- Allowing cross-border sharing of reserve capacity reduces the minimum market share of fast reserve generators in the European FRR up capacity market to almost zero: there is almost sufficient headroom or other low-cost FRR up capacity available within Europe to meet the required FRR capacity. Note that this scenario corresponds to the most extreme case of reserve sharing as we did not take interconnection constraints into account with regard to the sharing of reserve capacity. Taking interconnection limits into account for the reserve sharing will most likely increase the minimum market share of fast reserve generators.

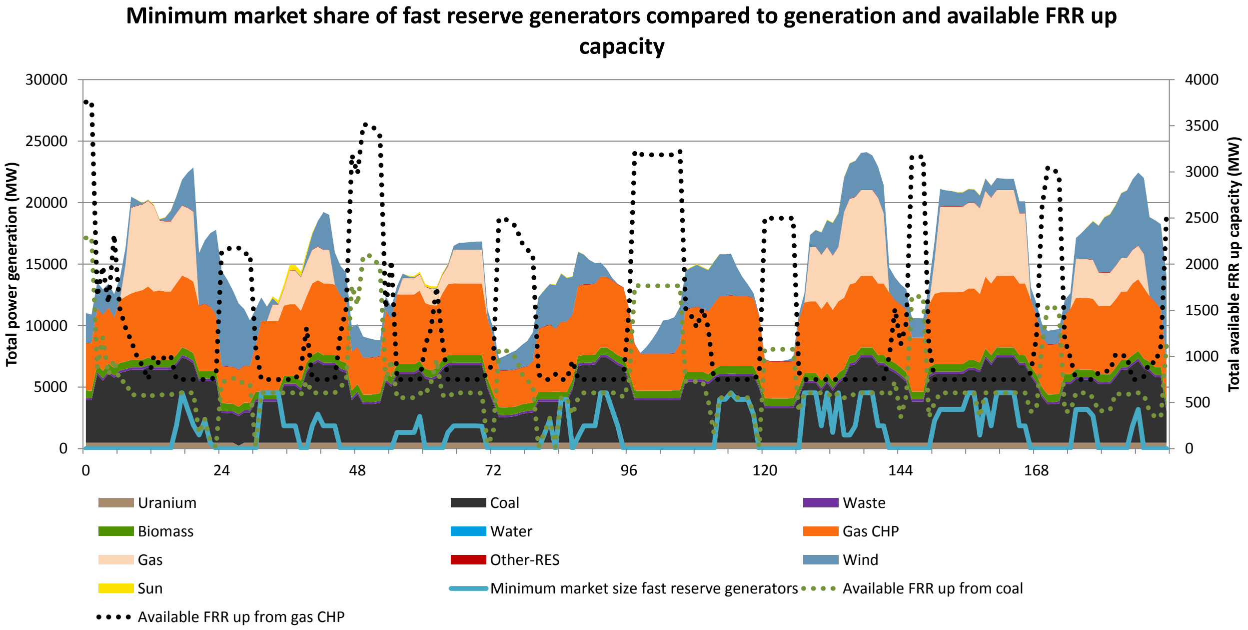

Figure 5-28 Period of 8 days showing how the minimum market shares of fast reserve generators varies in time (blue solid line). In addition, the graph shows the generation and available FRR up capacity profile in the Netherlands

Figure 5-28 shows how the minimum market share of fast reserve generators varies in time. The non-spinning FRR up capacity is mainly used during peak-hours: high load and therefore relatively low headroom (available FRR up capacity) of coal and gas CHP. There is a dip in the minimum market share of fast reserve generators during the afternoon, coinciding with a dip in the national demand: there is a small increase in headroom from coal and/ or gas CHP.

5.3 Combined analysis of technical and economic assessment

In this section we present a short summary of the conclusions from the technical (KERMIT) and economic assessment (PLEXOS) that are relevant for the fast reserve generators. Several key observations about the fast reserve generators are:

- From a technical perspective it was shown that upward FRR may be replaced by non-spinning generators (assuming high ramp rate as specified before and tuned AGC control) without jeopardizing the power system response. It should be noted that in practice the activation (and corresponding remuneration) will be based upon the position of fast reserve generators in the merit-order. The technical study assumed a merit-order for balancing energy consisting of non-spinning fast reserve capacity alternating with spinning capacity.
- It should be noted that activation revenues of reserves are not incorporated in this study. The technical merit-order case studies assumed a merit-order activation for balancing energy in which spinning and non-spinning bids were alternated. The economic assessment looked into the impact of the reserve capacity reservation and did not model the actual activation of the reserve capacity Taking the actual activation into account can have impact on activation of fast reserve generators depending on the actual merit-order for balancing energy. This has impact on both merit-order KERMIT results and OPEX.
- If available, fast reserve generators were found to provide significant upward FRR capacity in all three portfolios analyses (base/ high wind, high PV and high Coal). In addition, the reserve provision from fast reserve generators reduced the impact of the reserve requirement on national OPEX significantly (by 30-50%) and reduced the national overall OPEX. It should be noted that the actual activation (and corresponding remuneration) will be based upon their position in the merit-order.
- In case of cross-border reserve sharing fast reserve generators still lead to a reduction of (national) OPEX.
- Allowing wind and PV to provide FRR downward reserve capacity does not have a significant impact on the benefits of fast reserve generators: fast reserve generators still lead to reduction of (national) OPEX.

6 CONCLUSIONS

6.1 Framework

This report presents the results of a study performed to investigate the requirements for and impacts of properties and specifications for balancing products for frequency restoration reserves (FRR) in a representative future power system. In the introduction chapter of this report the following research questions to be answered in this study were formulated:

- What should be the properties and specifications for balancing products for frequency restoration (secondary control) in a system with a high degree of renewable sources (more fluctuations / less inertia) that provide adequate frequency quality for the Continental European synchronous power system?
- How does a selection of properties and specifications for balancing products (as mentioned above) influence the system costs?

To answer the research questions, a two-step approach was taken. In the first step, using a technical model, the adequacy of different balancing products was assessed. This analysis was performed by simulating the power system response to possible disturbances with balancing products which have different characteristics. To define in which of the simulation cases the system response is adequate, quantitative performance indicators were defined that enable comparison of the different case studies. This led to a selection of combinations of specifications that were analysed further in the second step of the project.

During the second step in the project, the selected combinations of specifications on frequency restoration reserves have been evaluated in an economic model of the European power system. This step gives a quantitative analysis on how the reserve requirements impact the operational expenses of the system and the availability and reservation of capacity for power balancing purposes.

6.2 Technical requirements

The technical specifications of FRR capacity were investigated using three degrees of freedom:

- Capacity in frequency restoration reserves;
- Full activation time of spinning capacity;
- Percentage of non-spinning capacity.

The specifications were evaluated on different types of imbalances: deterministic imbalances (block-trade effect), wind power forecast errors and generator trips. As different countries apply different activation mechanisms, the simulations were performed both under pro-rata and under merit-order activation regimes. The main conclusions from the technical simulations are presented below.

FRR capacity

The system response performance rapidly deteriorates if the available capacity is less than the open loop imbalance. This can be observed in **Figure 6-1** by the strong increase in the standard deviation of the network frequency for low capacities.

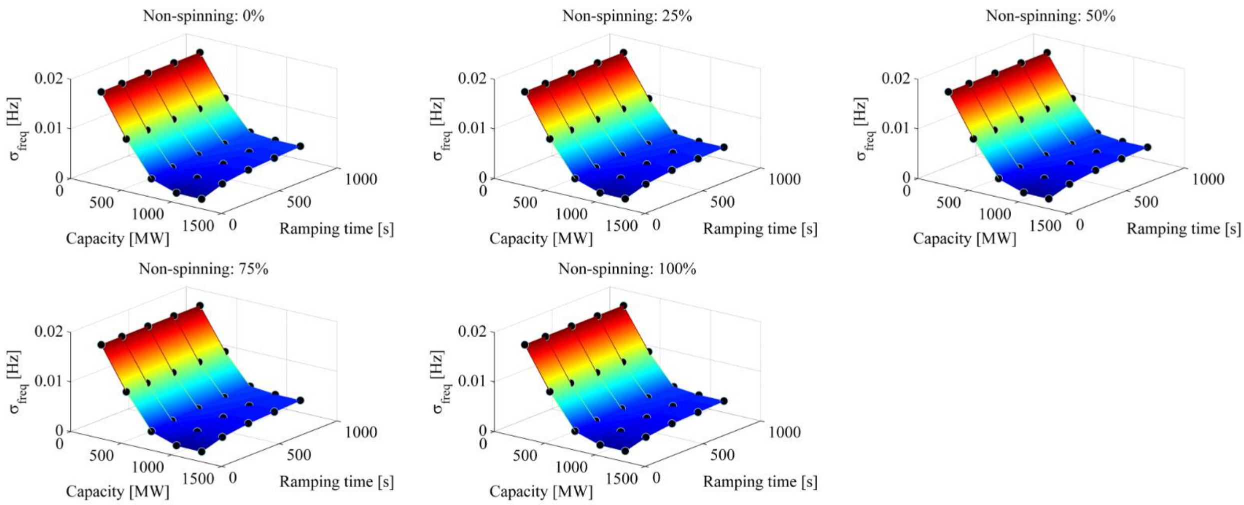

Figure 6-1 Standard deviation of the frequency for simulation variations. Lower standard deviation corresponds to better system performance.

For trip studies, once the capacity in frequency restoration reserves is equal or higher than the open loop imbalance (system disturbance) further improvements can be obtained by further increasing the capacity if a pro-rata activation regime is applied. Under a merit-order activation regime the additional improvements by increasing capacity on the frequency restoration process are not observed as under merit-order activation regime only FRR is activated up to size of the disturbance. The impact of capacity on trip studies can be observed in **Figure 6-2**.

Full activation time of spinning capacity

In the simulated trip studies (very fast/sudden imbalance), decreasing the full activation time (increasing speed) of FRR leads to significant system performance improvements. Since activation is governed by the system's automatic generation control (AGC), this requires the AGC is adapted appropriately. The impact of the activation time on trip studies can be observed in **Figure 6-2**.

For the natural day simulations it is observed that once reserves are sufficiently fast to follow the control signal from the AGC (or the open loop imbalance) increasing speed or capacity further yields no significant changes on system performance. The impact of the activation time on natural day simulations can be observed in **Figure 6-1**.

Percentage of non-spinning capacity

Spinning FRR can be replaced by fast non-spinning FRR (as specified in this study) while improving the system response, subject to two conditions. Firstly, the full activation time of the non-spinning reserves is shorter than the full activation time of the spinning reserves they replace. Secondly, the AGC is adapted appropriately to accommodate the faster reserves. As such, without changing the requirements regarding activation time on spinning FRR, the system response can be improved by replacing part of the spinning FRR by non-spinning FRR. Under merit-order activation regimes, the actual bid stack composition influences the impact on system response for cases where there is a mix of spinning and non-spinning FRR. The impact of replacing spinning reserves by non-spinning reserves on trip studies can be observed in **Figure 6-2**. Here, the horizontal axis gives the speed of spinning FRR whereas the vertical axis displays the value of the defined quality indicator. A lower value represents a better system response. The different lines represent the value of the quality indicator for different FRR capacities (dot/cross) and different ratios (colors) of non-spinning FRR and spinning FRR for varying speed of spinning FRR.

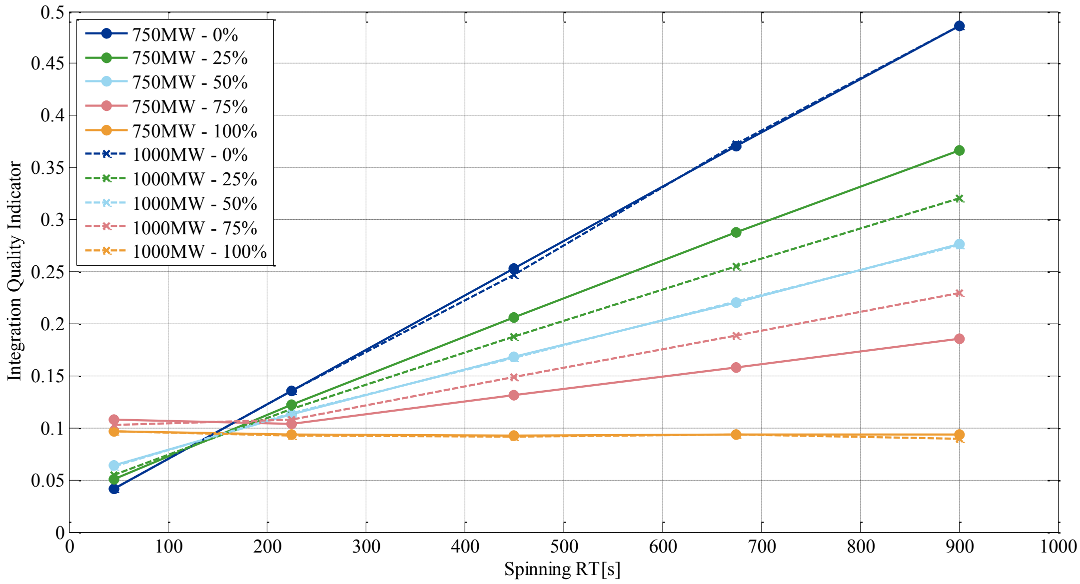

Figure 6-2 Quality indicator for all generator outage simulations under a merit-order activation regime. A lower quality indicator value corresponds to better system performance.

6.3 Economic impact of requirements

After the technical requirements had been determined, the impact of different reserve requirements on operational expenditures, use of fast reserve generators and impact on market share were investigated by economic analysis using PLEXOS simulation. In this investigation unit commitment and economic dispatch of generators within Europe were determined and investigated. The following conclusions can be drawn from this analysis.

Full activation time versus capacity

The base case simulation contained 750MW of FRR in the Netherlands (linearly scaled for other countries in Europe as explained in chapter 3) with a full activation time of 900s. It was found that when comparing either increasing the capacity to 1000MW or decreasing the activation time to 675s that decreasing the activation time yields less increase of operational expenditures than increasing the capacity (both yield comparable improvement in system response to a generator outage under the pro-rata activation regime). An increase in required capacity or decrease in activation time causes flexible units (the units that can provide relatively more FRR per MW of installed capacity) to replace inflexible units from the merit order for balancing energy. The impact of different FRR requirements on OPEX can be observed from **Figure 6-3**.

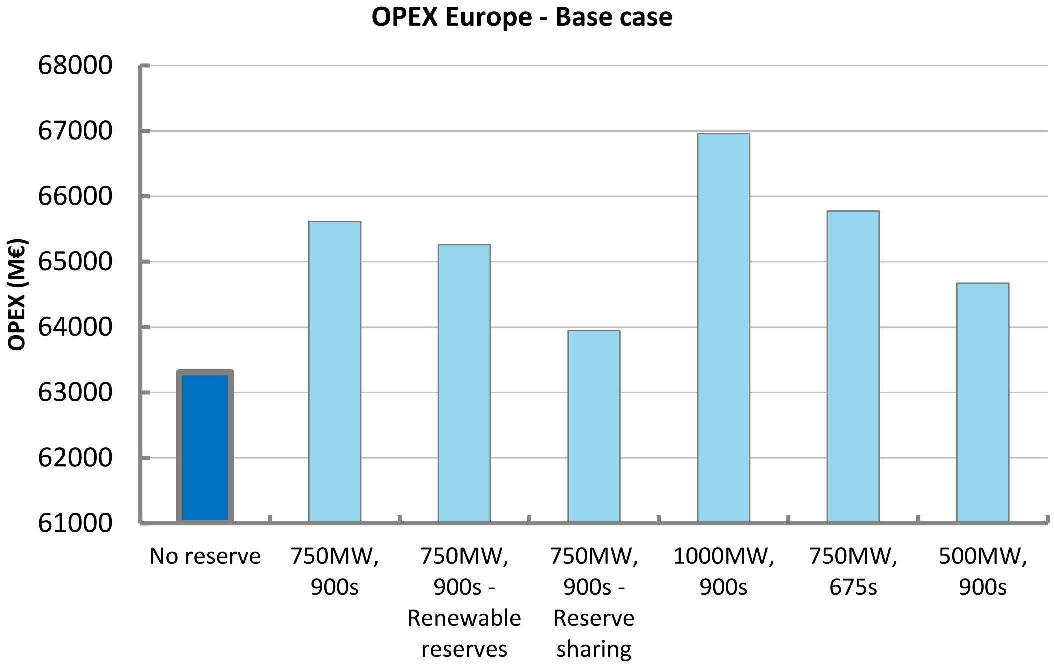

Figure 6-3 Annual operational expenditures in the European power system in which the Netherlands has the base case portfolio for the different FRR requirements (capacity and activation time).

Renewable providing downward FRR

Having renewable generation (solar and wind) providing downward FRR (up to 10% of the momentary value) decreases the operational expenditures as can be observed in **Figure 6-3**. This has a strong impact on the distribution of downward FRR to different resources. Having renewable generation providing downward FRR has a marginal impact on the distribution of upward FRR to different resources.

Cross-border sharing of reserves

Allowing cross-border sharing of FRR without considering transmission limitations decreases operational expenditures on a European level (**Figure 6-3**) but not necessarily on a country level. Cross-border reserve sharing reduces the market share for fast reserve generators as the spare generation capacity within Europe is more optimally used for reserve provision. Possible transmission constraints or need for geographical distribution[19] will reduce the impact of the cross-border sharing of reserves observed in this study.

Fast reserve generators

Fast reserve generators provide a large share of upward FRR by providing non-spinning reserve capacity (**Figure 6-4**). The required standby power consumption of these fast reserve generators does not obstruct this. Fast reserve generators compete with running inflexible thermal generation (e.g.: coal and CHP) in the provision of FRR. If fast reserve generators are present in the generation portfolio they have a significant impact on the distribution of upward FRR by also contributing to the upward FRR availability. They have a marginal impact on the distribution of downward FRR.

In general the following preference ranking can be set up for the provision of upward FRR. The order is from most preferable (1) to least preferable (4).

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19 Both transmission constraints and needs for geographical distribution are disregarded in this study.

1 Available headroom capacity regardless of reserve requirement (generators on partial load, must run CHP, marginal units)
2 Non-spinning reserve provision from fast reserve generators
3 Spinning reserve provision from coal fired power plants dispatched because of the reserve requirement
4 Spinning reserve provision from gas fired power plants dispatched because of the reserve requirement (assuming a high gas-price; for low gas-price this option can become preferred to the above option of dispatching coal-fired power plant to provide reserve capacity.

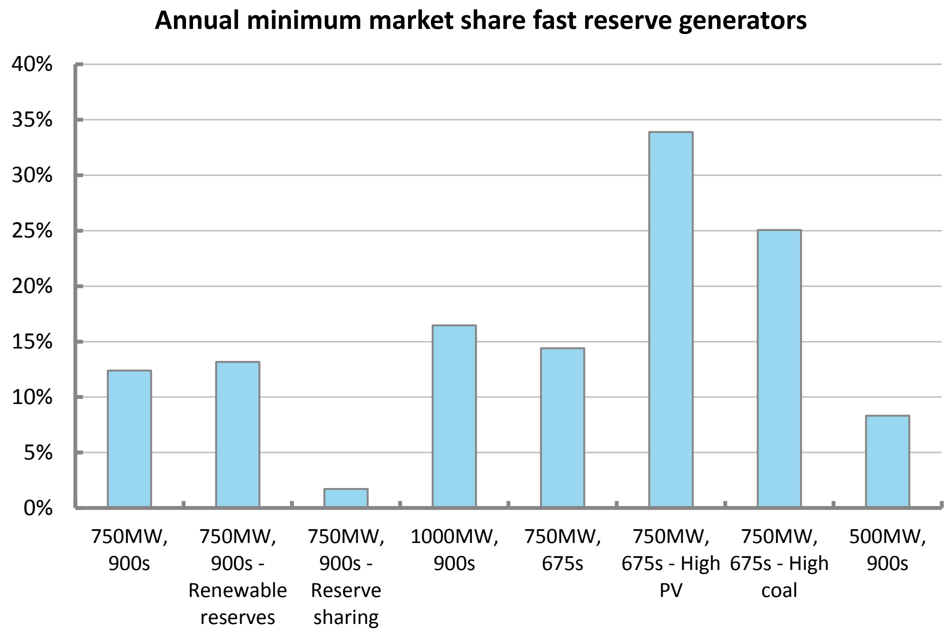

Figure 6-4 Annual minimum market share of fast reserve generators in the Dutch FRR up capacity provision. The blue bars correspond to the different FRR requirements for the high wind base portfolio, except where high PV or high coal is explicitly mentioned.

Portfolio impact

The conclusions above hold for the different generation portfolios in the Netherlands that were studied (high wind, high PV and high coal) (**Figure 6-5**), however it was found that as the share of inflexible thermal generation in a portfolio increases (for example by increasing the share of coal power plants) that the market share of fast reserve generators decreases as the reserves are then provided by the inflexible thermal generation running at part-load that can use their headroom to provide FRR up capacity.

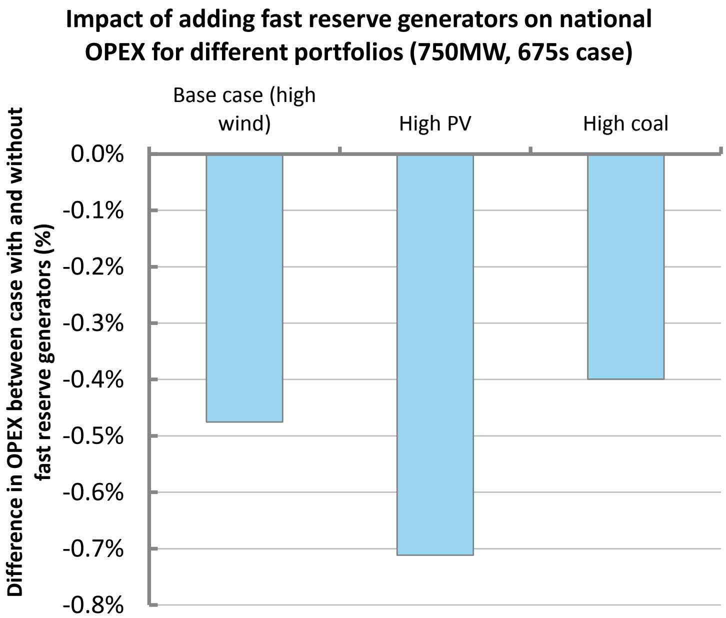

Figure 6-5 Impact of adding fast reserve generators to the Dutch generation portfolio for different type of portfolios: base case, high PV and high coal. The impact is defined as the relative change in normalized OPEX (€ / MWh generated) when adding fast reserve generators to the portfolio.

6.4 Additional notes that qualify the conclusions

The results and conclusions presented in this report hold for the variations within the simulated domain only. Also as the actual system response depends on the composition of the frequency restoration portfolio, in the technical part of this study a homogeneous composition of frequency restoration reserves was assumed since the objective is to find generic requirements which would apply to all reserves participating in balancing.

All economic observations and conclusions relate to the availability of FRR only. Costs and revenues related to the activation of FRR depend on whether bids for FRR are actually activated. The actual activation depends amongst others on the amount of imbalance, the position in the merit-order for balancing energy and the activation mechanism. This analysis is explicitly excluded from this study.

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APPENDIX A
List of abbreviations

AGC	Automatic Generation Control
CCGT	Combined Cycle Gas Turbine
CE	Central Europe
CHP	Combined Heat and Power
CMOL	Common Merit Order List
DE	Germany
ENTSO-E	European Network of Transmission System Operators for Electricity
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves
HVDC	High Voltage Direct Current
IEA	International Energy Agency
LFC	Load Frequency Control
NL	Netherlands
OPEX	Operational Expenses
PL	Poland
PV	Photovoltaics
RES	Renewable Energy Sources
RR	Replacement Reserves
RT	Ramping time
TSO	Transmission System Operator

APPENDIX B
Generation profiles

The technical natural day simulations are performed with the generation schedules as indicated in chapter 3 of this report. This appendix gives the system load and relative wind generation for the Netherlands, Belgium and Germany.

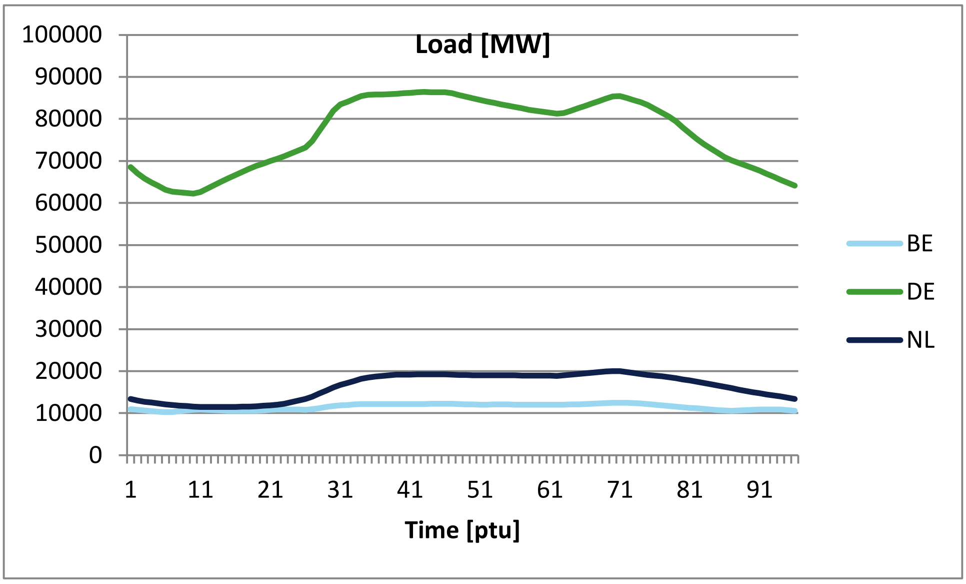

Figure B-1 Load for natural day simulations.

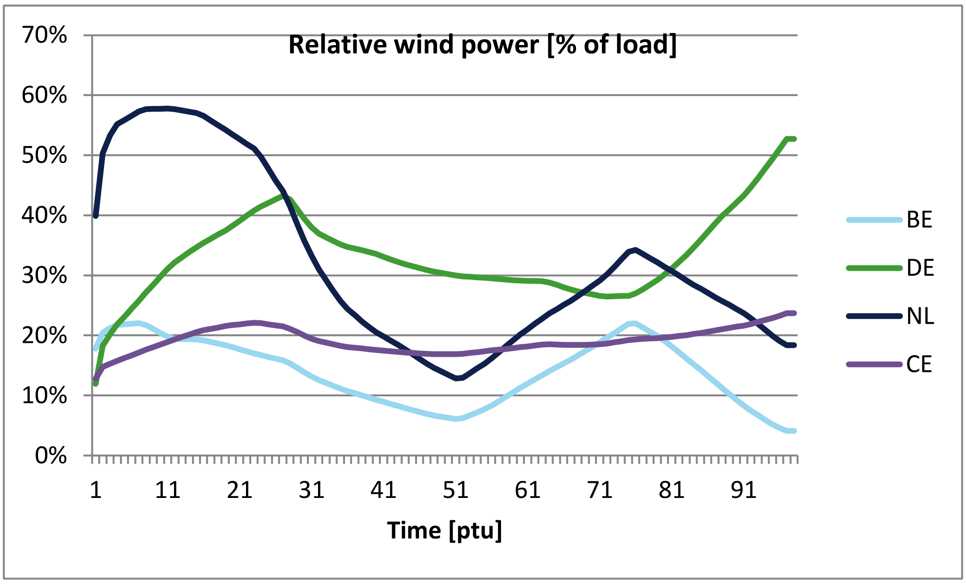

Figure B-2 Relative wind generation as a fraction of national load for natural day simulations.

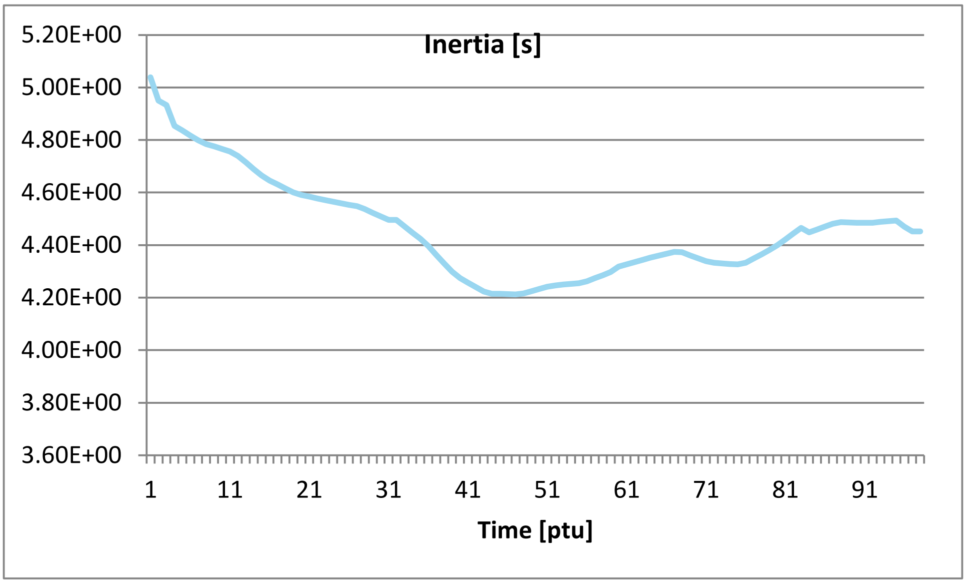

Figure B-3 Continental European system inertia for natural day simulations.

APPENDIX C
Simulation tools

KERMIT

The DNV GL's proprietary power system simulation model KERMIT (KEMA Renewable Model Integrating Technologies) model has been developed by DNV GL over the past 12 years. This simulation model, which employs a dynamic model of the power system and its generators, is geared towards simulating the electricity system's performance in one second to one day time frames. In that way, it captures the range of dynamics that concern technical stability issues and control loops on the one hand, and economic considerations on the other hand.

The KERMIT model is configured for studying power system frequency behaviour over a time horizon of 24 hours (however, this can be extended if required). As such, it is well suited for analysis of pseudo steady-state conditions associated with Automatic Generation Control (AGC) response including events such as generator trips, sudden load rejection, and volatile renewable resources (e.g. wind) as well as time domain frequency response following short-time transients due to fault clearing events. The KERMIT tool is MATLAB Simulink based and equipped with a variable time-step possibility. This means that the software determines the adequate time step automatically and can change this during the simulation depending on the dynamic behaviour of the model. Advantage of this setting is the ability to increase the resolution whenever fast dynamics are observed whereas the resolution can be decreased if no fast dynamics are observed to increase the simulation speed.

Model inputs include data on power plants, wind production, daily load, generation schedules, interchange schedules, system inertias & interconnection model, and balancing and regulation participation. Model outputs include ACE, power plant output, area interchange and frequency deviation, real time dispatch requirements and results, and numerous other dynamic variables. The figure below depicts the model inputs and outputs graphically.

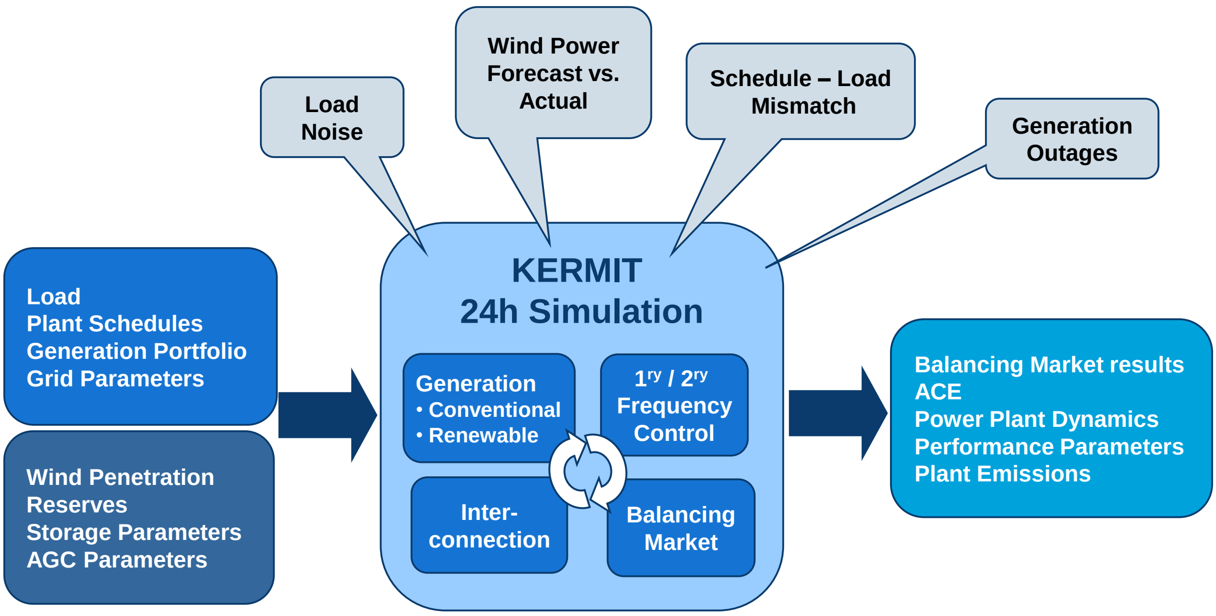

Figure C-1 KERMIT Simulation framework.

The tool is designed to be able to make direct comparisons of different cases to highlight the results of changes from one scenario to the next, such as increased wind development, increased use of regulation for the same scenario, impact of varying levels of storage, impact of different control algorithms and tuning, and comparison of completely different strategies such as storage versus increased ancillaries.

PLEXOS

DNV GL has developed an integrated approach for short and long-term modelling of power generation in Europe, using the well proven capacity expansion and UCED functionalities of PLEXOS for Power Systems™ ("PLEXOS").

In our PLEXOS model, we propose to calculate economic optimal dispatch[20] to meet the electricity and reserve capacity demand requirements, whilst minimising total system costs:

PLEXOS is a state-of-the-art generation optimisation and price forecasting model. PLEXOS was specifically developed for the electricity industry and is a powerful simulation tool that integrates generation dispatch, transmission flows, and pricing simulation with risk management, hydro, emissions and ancillary services dispatch. It has the capability to apply mixed-integer optimization for unit build as well as unit "on/off" decisions, respecting minimum up and down times and other dynamic operating constraints (e.g. ramp rates, minimum stable levels, etc.). It applies security-constrained unit commitment and optimises the commitment with respect to transmission and generation contingencies. The software also allows imposing several types of (user defined) constraints of operational, environmental, transmission, generation, contractual and fuel nature.

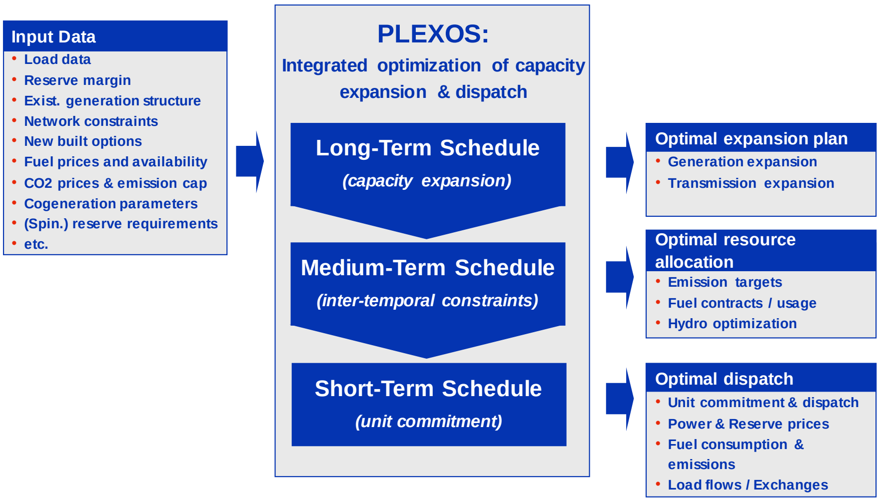

Figure C-2 PLEXOS approach - From long-term expansion planning to dispatch simulations.

PLEXOS can be used for long term studies as an automatic expansion model as well as short-term unit commitment and dispatch modelling.

20 Dispatch of power plants and reserve capacity provision is co-optimized based on operational cost of the power plants and the feasible operating ranges of such facilities

APPENDIX D
Fast reserve generator modeling specifications

The fast reserve generators are modeled in the technical model with the following specifications.

Type	Capacity	Preparation period	Ramping period	Full activation time	Minimum off-time
Spinning	case specific	n.a.	46s/225s/450s/ 675s/900s	46s/225s/450s/ 675s/900s	n.a.
Non-spinning	case specific	30s	91s	121s	300s

APPENDIX E
Generation capacity in PLEXOS

Table E-1 Installed generation capacity for the different Dutch portfolio scenarios

[GW]	High wind (base)	High PV	High coal
Wind	11.2	8.7	6.0
Sun	0.7	11.0	0.7
Coal	6.9	6.9	18.4
Gas	13.6	12.1	12.1
Gas CHP	6.0	2.9	2.9
Uranium	0.5	0.5	0.5
Hydro	<0.1	<0.1	<0.1
Biomass	1.0	1.0	1.0
Other	0.2	0.2	0.2
Total	40.1	43.4	41.9

Table E-2 Installed generation capacity Europe (excluding the Netherlands)

[GW]	Installed generation capacity (ENTSO-E, EU2020)
Wind	235
Sun	123
Coal	114
Lignite	56
Gas	238
Oil	44
Uranium	133
Hydro	226
Biomass	40
Other	2

APPENDIX F
Impact of fixing hydrological schedules in PLEXOS

A comparison is made between the yearly simulations with hydrological schedules fixed and the weekly simulations with the hydrological schedules not fixed. It is expected that the latter gives more accurate results. To reduce computational efforts the hydrological schedules were fixed in the yearly simulations. The figure below gives the operational expenses for the weeks for which also weekly simulations were performed.

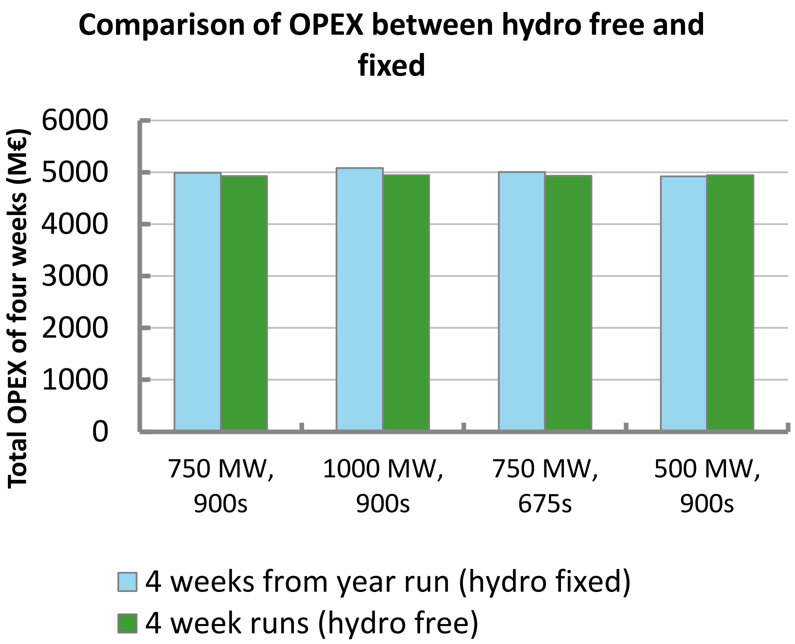

Figure F-1 Comparison between simulations with hydro fixed and hydro free (i.e. optimized) to assess impact of fixing hydro approach to the OPEX results.

The following observations can be made from the figure above:

- For cases with 900s and 675s activation time the operational expenses for the simulated weeks with hydrological schedules fixed are comparable to the simulated weeks where the hydrological schedules are not fixed.
- For shorter activation times, it was experimentally observed that this model reduction does not hold.

APPENDIX G
Interpretation of trip study variations

This appendix elaborates further on the interpretation of the frequency recovery process under both pro-rata and merit-order activation regimes.

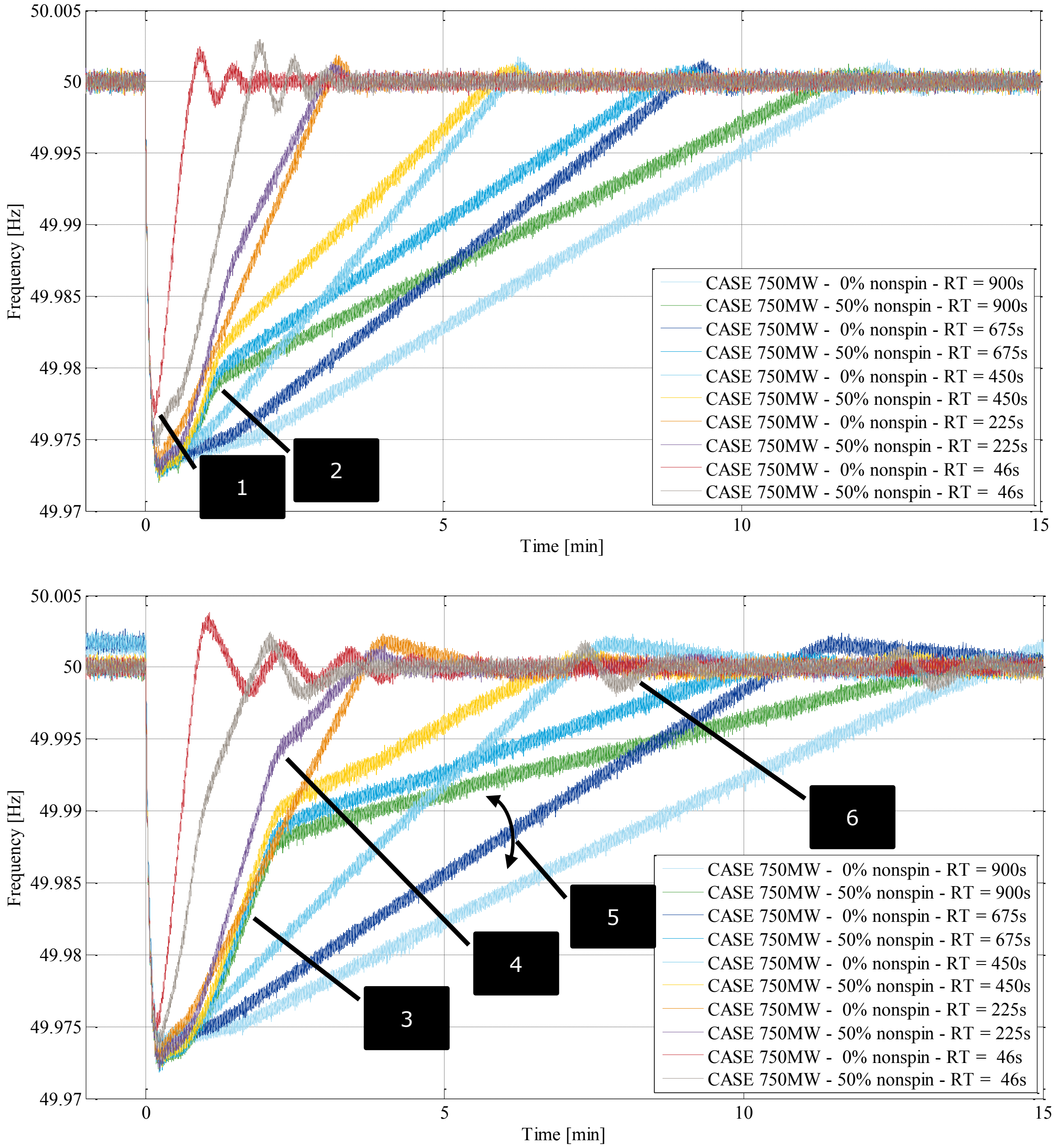

Figure G-1 Frequency restoration process by activation of different types of frequency restoration reserves under pro-rata (upper figure) and merit-order (lower figure) activation regimes.

1) The reduced frequency nadir (deepest point) for very fast frequency restoration reserves is caused by the interaction of frequency restoration reserves with frequency containment reserves.
2) A lower breakpoint is observed in pro-rata than in merit-order. This breakpoint only occurs in cases where non-spinning generators provide FRR to the system. The breakpoint is the point when the aggregate ramp rate of FRR is no longer dominated by fast non-spinning generators but by slower spinning generators. Under the pro-rata activation regime, different AGC settings apply than under the merit-order activation regime to avoid unwanted frequency behavior. These different AGC settings result in slower recognition of the total imbalance size by the AGC, thus in a reduced activation of non-spinning generators.
3) The initial fast recovery of the frequency is due to the aggregate ramp rate of both spinning and non-spinning frequency restoration reserves. Under merit-order activation regime the non-spinning reserves are fully activated at the breakpoint.
4) As the activation time of spinning reserves becomes shorter, the aggregate ramp rate of spinning and non-spinning frequency restoration reserves becomes shorter. With the same total activation time of non-spinning reserves, this means that the breakpoint lies closer to the nominal frequency.
5) The difference in the angle of the frequency restoration process after all non-spinning reserves are activated (under merit-order) is caused by the different amounts of spinning reserves also contributing to the frequency restoration process.
6) Under merit-order activation regimes, when both non-spinning generators and spinning generators are present in the system, frequency variations occur at approximately 7 and 12 minutes (5 minute intervals). These variations are caused by the initial over-activation of non-spinning reserves (around 2 minutes, gray line). The over-activation leads to overshoot of the frequency restoration process and is compensated by switching off some of the non-spinning generators. Consequently a shortage is created which again needs to be compensated by activation of reserves. However, the initial non-spinning generators that were switched on, and then later switched off after the overshoot of the frequency, are now blocked (due to their minimum off-time) of at least 5 minutes. Consequently the next bid (being a spinning generator) is activated. After 5 minutes, the non-spinning generator has surpassed the blocking time of 5 minutes and can ramp up again. This again causes an increase of frequency, causing the AGC to down regulate the spinning generator that was initially replacing the blocked non-spinning generator.

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