

INCORPORATING INERTIA CONSTRAINTS INTO THE POWER MARKET

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Incorporating Inertia Constraints into the Power Market

Addressing the problem of inadequate frequency
response by consideration of inertia in UC

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Foreword

EFORIS, Elmarknadens funktion och roll i samhället, is a research program on electricity market design. The goal is to develop a better understanding of the electricity market and its role in society.

Reported here are the results and conclusions from a project in a research program run by Energiforsk. The author / authors are responsible for the content and publication which does not mean that Energiforsk has taken a position.

Sammanfattning

I denna studie har vi utvecklat en förenklad matematisk modell av inertia, det vill säga tröghet/motstånd mot förändring. Denna modell har sedan använts för att bestämma de begränsningar avseende inertia som finns i systemet med avseende på vilka anläggningar som ska köras med avseende på kostnader och systemsäkerhet.

Genom att specifikt ta hänsyn till frekvenshållning belyser det som vi kallar för "begränsande körorder avseende inertia" (the Inertia Constrained Unit Commitment (ICUC) Problem). Skillnaden mellan ICUC och en obegränsad (avseende frekvens) optimering av merit order är att den förra tar hänsyn till största begränsande fel (n-1) avseende. ICUC garanterar därmed god frekvenshållningskaraktäristika.

Modelleringen går sedan ett steg längre och vi söker ett pris som reflekterar kostnader för både produktion men också systemets behov av inertia. Vi får då priser (i vår 32-bussmodell) i det nordiska systemet som är högre än i den icke begränsade modellen. I vår större modell (44-buss nordisk) fick vi lägre priser men observerade att modellen genererade negativa vinster för vissa anläggningar. Det vore då troligt att dessa anläggningar skulle lämna marknaden snarare än att producera till förlust. Det senare problemet löstes med tillägg till de matematiska modellerna vilka kompenserade för förlusterna.

Summary

In this report the results of work on a market approach towards the frequency response adequacy of the power network has been presented and discussed. Firstly, the importance of having enough resources to ensure desirable frequency response has been clarified. In addition, it has been pointed out that to secure a level of frequency response, we need adequate rotating mass inertia in the power system. Thus we have studied the consequences of incremental penetration level of renewable generation in terms of their effect on frequency response. The two indicators for inertia sufficiency, namely Nadir (the lowest frequency) and ROCOF (rate of change of frequency), have been analyzed and their relationship with wind generators have been explained in detail and illustrated in several diagrams. For instance, Figure 1. shows that the more wind capacity the network integrates, the more severe ROCOF will the system experience during contingency situations.

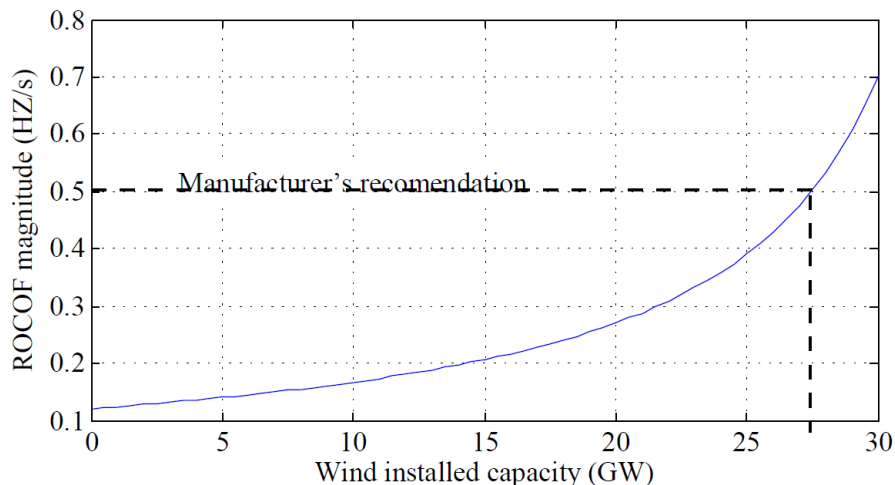


Figure 1 -The relation between installed wind capacity and ROCOF[19]

Furthermore, having more installed wind capacity leads to recording of lower frequency dips after occurrence of a contingency. This relation has also been illustrated by Figures 4 and 5 in chapter II.

And above all, the fact that ensuring enough inertia in the power system imposes an extra cost to the system which is illustrated by executing simulations on some test systems, including the Nordic 32-bus test system and Nordic 44-bus test system¹. The analysis has been performed utilizing a novel endogenous formulation of the unit commitment problem, in which the frequency response requirements, including inertia and governor ramp rate requirements, which have been integrated in the optimization problem as constraints.

In other words, we have formulated inertia requirements with algebraic equations and inequalities, instead of checking the adequacy of inertia with an external program or algorithm out of the main unit commitment optimization problem. Unit Commitment (UC) is an optimization problem to decide on the generation

¹ The data for Nordic 32 and 44 bus networks are respectively available in [25] and [26].

schedule considering the power system constraints including power balance and reserve constraints. Then we added these algebraic models as constraints in the optimization problem. This inertia-constrained OPF problem considers the adequacy of frequency response during the optimization and takes care of having enough inertia and ramp rate in the system. Two main algebraic equations are formulated and integrated in the UC optimization problem to take care of having enough inertia and avoid violating the limits for Nadir and ROCOF. The first equation is to ensure that the ROCOF does not violate the desired limit² and the second equation is to take care that the frequency drop is not more than the amount recommended by the operators and stays in a safe region³.

With these two constraints, we are now working with a novel version of UC problem, which is called ICUC⁴ in this report. Furthermore, to extract the prices from the ICUC optimization problem, a linearization method has been computationally implemented. In fact, both UC and ICUC optimization problems are of Mixed Integer Linear Programming (MILP) type since we have utilized binary variables to represent the commitment decisions. Hence, we used a linearization approach to change the programming method from MILP to Linear Programming LP. The proposed linearization approach mainly consisted of 3 steps:

1. Execution of a MILP and obtain the optimal unit commitment results.
2. Fixing the binary variables at their optimal values, reached by MILP, and treating them as real continuous variables in the optimization code.
3. The problem is now a LP, running the optimization code of the LP may give us the prices.

Through running this LP optimization problem, the prices are obtained for both UC and ICUC after running the simulations for Nordic 32-bus network. The energy prices for each generator are as shown below in Euros/MW:

Table 1-UC and ICUC prices in Nordic 32 bus test system

hour	1	2	3	4	5	6	7	8	9	10	11	12
UC prices	154	154	154	154	154	154	154	154	154	154	154	154
ICUC prices	205	205	205	205	205	205	154	154	205	154	154	154

Now that we have the prices, it is noteworthy to mention the following:

- There is price change due to considering inertia in 7 out of 12 hours simulation period.
- Since this is a "marginal price" and all generators are being paid the same, even those generation units who are not providing inertia, are being paid more after inertia is considered.

² The ROCOF limit in Nordic power system is 0.5 Hz/Sec.

³ Lowest possible frequency (Nadir) is 49 Hz.

⁴ Inertia Constrained Unit Commitment

- The market operator should avoid allowing negative profits for inertia providers. This is important as negative profits may actually induce those generators to leave the market.
- As previously mentioned, the ICUC problem is a nonconvex MILP optimization problem.⁵ Hence, we are facing a nonconvex pricing rule. There are several methods to deal with nonconvex pricing and preventing negative profits, e.g. making uplift payments, which are explained in detail in chapter 4 of this report.

As noted above, the operator should take care to avoid negative profits for generators. After executing ICUC simulation, the profits of different generation units are as follows:

Table 2- Profits by running ICUC before making uplift payments

Gen No.	Hour					
	1	2	3	4	5	6
9	34117	40587	40587	40587	40587	40587
11	-14390					
18	-10760					
19	-8090					
20	37162	38062	38062	38062	38062	38062
Gen No.	Hour					
	7	8	9	10	11	12
1	-8090		51000			
8				-8090		
9	14958	14958	41000	15365	15365	15365
20	18997	18997	38273	18479	18479	18479

The empty fields of the table above indicates zero profits. i.e. the generators sells electricity only recovering costs. As can be seen the marginal generators are experiencing negative profits. In other words, they are providing a service for us and has to pay for it. This situation may lead them to leave the market.

Hence, some measures should be taken to prevent them from leaving the market. One of these measures may be to create uplift payments. These methods are elaborated upon in the chapter 4 of this report.

In chapter 4, the possibility of negative profit for the inertia providing units have been elaborated on and a method for making uplift payments in order to prevent them from leaving the market has been proposed. One of these methods was implemented and the results - which imply that the method has compensated all

⁵ Convex optimization means that there can be only one optimal solution, which is globally optimal or you might prove that there is no feasible solution to the problem, while in nonconvex optimization there may exist multiple locally optimal points and it can take a lot of time to identify whether the problem has no solution or if the solution is global.

negative payments - have been presented. Our method is mainly based on Lagrange multipliers and taking the derivative of the lagrangian function with respect to the commitment decision variable. More details of this and the mathematical procedure have been explained in the report.

Table 3- Profits by running ICUC before making uplift payments

Gen No.	Hour					
	1	2	3	4	5	6
9	40587	40587	40587	40587	40587	40587
20	38062	38062	38062	38062	38062	38062
Gen No.	Hour					
	7	8	9	10	11	12
1			51000			
9	14958	14958	41000	15365	15365	15365
20	18997	18997	38273	18479	18479	18479

As can be seen in table 3, all of the profits are now positive or at least zero. Hence, through uplift payments we create a situation in which system critical generation is induced to remain in the market.

Furthermore, two other methods – partial equilibrium and minimum uplift method – have been discussed briefly in the final section of the report. Further investigation of these techniques is left to the future extension of this work.

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1 Theoretical Basis and Introduction

Being one of the crucial issues in power system operation, frequency response has been subject of an extensive research in recent years [1,2]. The fact that the contingency situations, such as faults or generator emergency trips, are inevitable in even most secure and reliable power systems raises the need to have enough units committed to maintain frequency response adequacy and avoid severe deviations from the safe region for frequency.

Some references such as [3-7] have proposed considering the inertia as an ancillary service. However, a solution of the problem which treats inertia as an ancillary service may have the following problems in formulation and implementation:

- It imposes high computational work of running another market optimization program. In a real system, the extra processing time may eventuate in quite a few problems or if enough powerful computers and processors are not available, it may even be impossible.
- Procurement of inertia service separately from energy might lead to inefficient use of generation and transmission resources.
- There is an inevitable fact that the power cannot be separated from inertia. These two are joint products together and they are not separate products, which can be easily sold in different markets.

In this report, the issue of having a market based approach towards inertia is investigated and some methods to address the problem have been suggested and implemented. First, the necessity and importance of having rotating mass inertia in a power system and its role in *Primary Frequency* response will be explained in detail. The reasons for its increasing importance in future power systems will be described in what follows.

The penetration of renewable energies such as wind and solar is increasing at an exceeding rate. These units are reducing system net load and consequently reduce the use of conventional types of electrical energy conversions. However, renewable generation such as wind or solar do not bring as much inertia to the power system as traditional units does. As a result, it is clear that there will be an increase in the need for inertia providers such as steam generators or gas generators.

The Following diagram is anticipating the mixture of energy production in the Swedish energy network for the next 35 years. [8]

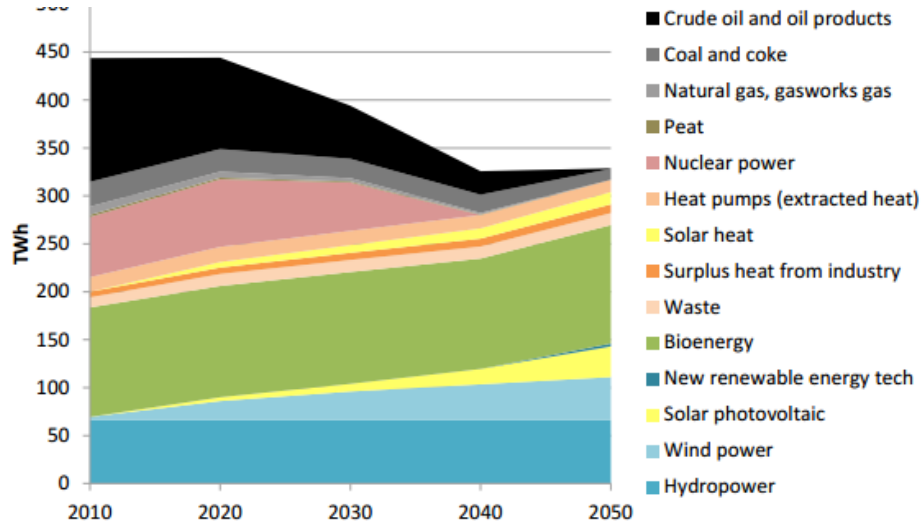


Figure 2-Prediction of Swedish Environmental Research Institute about A Swedish energy production scenario until 2050[8]

The more penetration of electronically-connected renewables we have in the system, the higher requirement for inertia providing units we will have in the system. Hence, we must add more inertia provider units which results in an extra cost for power system operation.

In what follows, the issue of primary frequency response, its necessity, its importance and a market approach to address the problem of how to price inertia will be studied. Several earlier works [9-10] and an IEEE task force [11] have emphasized the significance of having market approach towards frequency response and the necessity of incentivizing the actions that contribute to enhanced frequency response.

In our next step, we review the physical and mathematical basis behind the problem.

1.1 PHYSICAL AND MECHANICAL BASIS

In this study, the inertia analysis has been performed utilizing a one-machine model and the following equations are about to present how it has been derived.

From a mechanical perspective, a change in the kinetic energy comes from a change in the torques in the machines. Let T_{ei} be the torque in the generator shaft i from the electrical load P_{ei} , and let T_{mi} be the torque in the turbine shaft associated with the mechanical power output P_{mi} . The mechanical velocity of the machine will be given by:

$$J_i \frac{d\omega_{mi}}{dt} = T_{mi} - T_{ei}, i \in I \quad (1-1)$$

where ω_{mi} is the angular velocity of the shaft, and J_i is the moment of inertia of generator i . We can measure ω_{mi} with respect to a synchronous reference that

rotates at the synchronous frequency ω_0 , so $\omega_i = \omega_{mi} - \omega_0$, where ω_i is the deviation of machine speed from the synchronous speed. The torques can be expressed as power using the relationship $P = T\omega$, so

$$J_i \omega_{mi} \frac{d\omega_{mi}}{dt} = \omega_{mi} (T_{mi} - T_{ei}) = P_{mi} - P_{ei}, i \in I \quad (1-3)$$

If one assumes that frequency deviations ω in stable operation are small, $\omega_{mi} = \omega_0 + \omega_i \approx \omega_0$, so that (1-3) becomes

$$J_i \omega_0 \frac{d\omega_{mi}}{dt} = \omega_0 (T_{mi} - T_{ei}) = P_{mi} - P_{ei} \quad (1-4)$$

If the machine i has p_i pair of poles, (1-4) can be expressed in terms of the electric frequency f_i at bus i :

$$J_i \frac{2\pi f_0}{p_i} \frac{d\omega_{mi}}{dt} = P_{mi} - P_{ei} \Leftrightarrow \frac{1}{f_0} J_i \left(\frac{2\pi f_0}{p_i} \right)^2 \frac{df_i}{dt} = P_{mi} - P_{ei} \quad (1-5)$$

Note that the total kinetic energy K_i of machine i at nominal system electrical frequency f_0 is defined as

$$\frac{2k_i}{f_0} \frac{df_i}{dt} = P_{mi} - P_{ei} \quad (1-6)$$

so that (1-5) is given by

$$\frac{1}{f_0} J_i \left(\frac{2\pi f_0}{p_i} \right)^2 \frac{df_i}{dt} = K_i \quad (1-7)$$

Two machines can be connected through a transmission line l_{ij} . Neglecting shunt impedances, a transmission line can be represented by an inductance X_{ij} and a resistance R_{ij} , which correspond to an admittance Y_{ij} . The power transferred from bus i to j is given by

$$P_{ij} - (\sqrt{-1})Q_{ij} = V_i \angle \delta_i^* Y_{ij} \angle \theta_{ij} V_j \angle \delta_j \quad (1-8)$$

where V_i is the voltage of bus i with phase δ_i respect to a phase reference. Then, using the Euler's identity,

$$P_{ij} = V_i V_j Y_{ij} \angle \delta_{ij} - \theta_{ij} \quad (1-9)$$

where $\delta_{ij} = \delta_i - \delta_j$. Alternatively, if G_{ij} and B_{ij} are line parameters, (3.9) can be written as

$$P_{ij} = V_i V_j (G_{ij} \cos \delta_{ij} + B_{ij} \sin \delta_{ij}) \quad (1-10)$$

Considering the contribution of all system machines on machine i , the electric power in bus (machine) i can be written as:

$$P_{ei} = \sum_{j \in I, j \neq i} V_i V_j (G_{ij} \cos \delta_{ij} + B_{ij} \sin \delta_{ij}) \quad (1-11)$$

If there is a forced outage of generator at bus k , a sudden loss of power of magnitude P_k (contingency) occurs at bus k , and all systems generators will

contribute with a mechanical kinetic energy change to maintain energy conservation per its location with respect to bus k. This contingency will also cause a sudden change in the angle of the bus where the contingency has happened, and will produce a change in the angles of all other buses per its location with respect to bus k. As mentioned above, it is assumed that the system has been reduced so that all buses have only one machine.

Before the contingency, the power imbalances at all buses can be assumed to be close to zero, so system frequency is also close to nominal (f_0) at all buses according to (1-7)

$$\frac{2k_i}{f_0} \frac{df_i}{dt} = 0 \Leftrightarrow f_i = f_0 \quad (1-12)$$

After the contingency, the imbalance will be distributed according to (1-11). If one assumes adequate reactive compensation, the voltages should not change significantly after the contingency, and small variations of K_i should occur for a stable operation of the system. Then, (1-11) can be linearized with respect to an initial condition δ_{ik}^0 to find the variation in power after the contingency in each bus:

$$\Delta P_{ei} = \sum_{j \in I, j \neq i} \frac{\partial P_{ei}}{\partial \delta_{ij}} \Delta \delta_{ij}, \delta_{ij} = \delta_{ij}^0 \quad (1-13)$$

The angle at bus k will suddenly change, while the angle at other buses will not change suddenly since the inertia of machines' rotors will not allow the angle to vary instantaneously; then, $\Delta \delta_{ij} = 0$ for all i, j while $j \neq k$. At time $t = 0$ the imbalance will be distributed amongst all system buses according to:

$$\Delta P_{ei} = \frac{\partial P_{ei}}{\partial \delta_{ik}} \Delta \delta_{ik} = K_i \Delta \delta_{ik}, \delta_{ik} = \delta_{ik}^0 \quad (1-14)$$

and

$$\Delta P_k = \sum_{i \in I, i \neq k} \Delta P_{ei} \quad (1-15)$$

where K_i is normally called in the literature the "power synchronizing factor" between machine k and i. From (1-15) and (1-16)

$$\Delta P_{ei} = \frac{K_i}{\sum_{i \in I, i \neq k} K_i} \Delta P_k \quad (1-16)$$

Thus, the sudden change ΔP_k is distributed in system buses by smaller steps of magnitude as predicted by (1-16). The dynamics of the system in each bus is then governed by expression (1-7) and (1-16)

$$\frac{2k_i}{f_0} \frac{df_i}{dt} = \Delta P_{mi} - \Delta P_{ei} \quad (1-17)$$

This gives the frequency behavior in each generation bus of the system. In a system of many buses, one must examine the frequency at all buses for an assessment of frequency adequacy. In large systems, it may be of interest to develop a representation of the overall behavior of system frequency.

If one takes the sum of all terms in 1-17

$$\sum_{i \in I, i \neq k} \frac{2k_i}{f_0} \frac{d\Delta f_i}{dt} = \sum_{i \in I, i \neq k} \Delta P_{mi} - \Delta P_{ei} \quad (1-18)$$

where ΔP_m is the overall system mechanical power response. Multiplying by

$\frac{1}{\sum_{i \in I, i \neq k} K_i}$ both sides of (1-18):

$$\begin{aligned} \frac{1}{\sum_{i \in I, i \neq k} K_i} \frac{2}{f_0} \frac{d}{dt} \sum_{i \in I, i \neq k} K_i \Delta f_i &= \frac{1}{\sum_{i \in I, i \neq k} K_i} (\Delta P_m - \Delta P_k) \quad (1-19) \\ \frac{2}{f_0} \frac{d}{dt} \left(\frac{\sum_{i \in I, i \neq k} K_i \Delta f_i}{\sum_{i \in I, i \neq k} K_i} \right) &= \frac{1}{\sum_{i \in I, i \neq k} K_i} (\Delta P_m - \Delta P_k) \\ \frac{2}{f_0} \frac{d}{dt} (\overline{\Delta f}) &= \frac{1}{K} (\Delta P_m - \Delta P_k) \end{aligned}$$

where K is the total kinetic energy within the system, and Δf is known in the literature as the “frequency inertial center”. This equation represents system frequency by a one machine model that greatly simplifies the analysis of frequency adequacy.

An important point which can be inferred from equation (19) is the fact that kinetic energy plays a key role in frequency control and frequency response performance of the power system. The more kinetic energy a unit has during electrical energy production, the more it can contribute in primary frequency response. This equation also highlights the role of rotating mass inertia in frequency response. Nuclear, hydro, gas and conventional steam generators are currently the main sources of providing inertia, whereas the renewable energies like wind or solar power, which are connected to the network through power electronic convertors, do not provide this important service for the network. This is mainly because these converters which connect them to the network are isolating the rotational speed from the system frequency [12].

It is to be noted that there are other types of inertia providers, which provide synthetic inertia. This type of inertia is being provided through adding a controller that emulates inertial frequency response of synchronous generators or other inertia providers [12]. However, synthetic inertia does not have the same characteristics of natural inertia per unit of installed capacity.

The increasing penetration of renewable energies may result in lack of rotating mass inertia in the power network and consequently, reduced frequency response. The figure below shows the rise in the investment in renewable energies worldwide. Figure 3 suggests that it will continue to rise at an exceeding rate. This diagram indicates that there will be a significant share of low inertia power in the future power networks, which is mainly injected to the network by these newly installed wind generators.

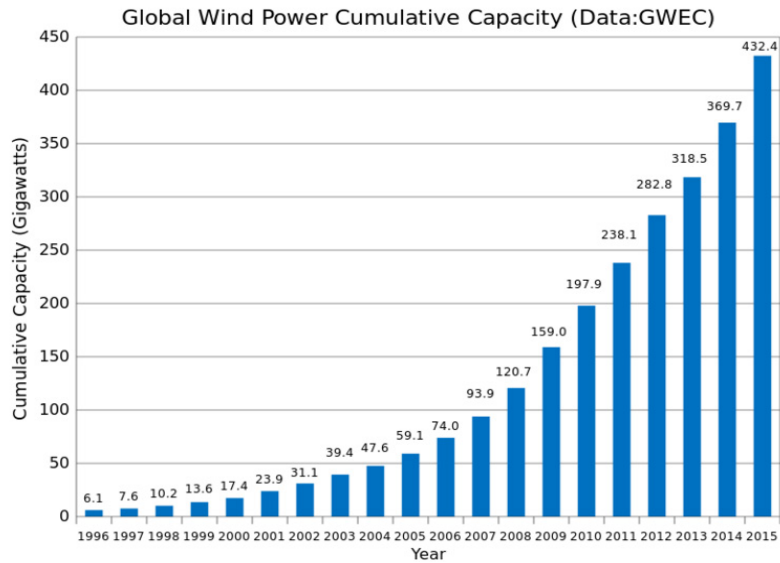


Figure 3-Total wind installed capacity by year [13]

1.2 THE PROBLEM OF FREQUENCY RESPONSE

When wind capacity or solar power is integrated to the network, the load on conventional generators is reduced, thus reducing inertia in the system. This results in reduced frequency response. Frequency response requirements accounts for two important factors. One of which is the rate at which the frequency drops right after occurrence of a contingency, which – in this report – is called 'Rate of Change of Frequency' (ROCOF). The ROCOF can be considered as an indicator of the severity of frequency changes after a contingency. There is a minimum negative amount for this indicator, the amount of which is different in different networks.

Another indicator is called Nadir. The Nadir indicator takes care of the amount of instantaneous frequency drop that a network experiences during a fault or contingency. Nadir is the minimum frequency that can be recorded right after a contingency.[32]

As mentioned above, there are different frequency response requirements in different networks. Here in this study, the power system under investigation is Nordic 32-bus test system. This system is the stylized test system based on the NORDEL network. NORDEL was founded in 1963 and consists of an association of Denmark, Finland, Iceland, Norway and Sweden for establishing a common framework for the development of a harmonized Nordic electricity market. It includes system operators from all of the countries mentioned above which are Energinet.dk (Denmark), Fingrid Oyj (Finland), Landsnet hf (Iceland), Statnett SF (Norway), and Sverka Kraftnät (Sweden).[19]

1.2.1 ROCOF suggestions in NORDEL

Preliminary studies on the interconnection on wind generation [14] established a ROCOF islanding detection of 0.1 Hz/s. This recommendation seems to be too sensitive according to [15]. The report presents an analysis of frequency drops during one year in the NORDEL system, detecting ROCOF in excess of 0.1 Hz/s. This report also emphasizes that the ROCOFs in the future may be more severe due to the integration of variable generation with limited inertia contribution, recommending a ROCOF islanding detection of -0.5 Hz/s. Although this value is not systematically determined, it is consistent with current manufacturer recommendations.

The only NORDEL country that has official rules for ROCOF islanding detection is Denmark [16]. The requirement is 2.5 Hz/s. However, no specific rationale is provided for this particular value. Recently, ENTSO-E has considered imposing a ROCOF ride through of -2 Hz/s [17].

The technical aspects of a secure operation in NORDEL can be found in [18]. This grid code defines detailed rules for frequency control, but it does not define rules for inertia levels in terms of ROCOF. The Nordic grid code does define automatic load shedding at 48.8 Hz@ 0.15 s, so a conservative adequacy criterion would be to maintain system frequency above 49.0 Hz at all times. Thus, the adequacy criteria for primary control in this work are:

- ROCOFs must be larger than -0.5 Hz/s,
- Frequency nadirs must be larger than 49 Hz.

1.2.2 Impact of Renewable Energy Integration on Frequency Response

In order to have a better idea of how the introduction of wind may deteriorate the conditions regarding frequency response, an illustrative curve has been shown in Figure 4. It shows the impact of wind integration on the amount of Nadir. As can be seen in the diagram, the more wind capacity we have installed in the grid, the deeper drop in frequency we will experience during a contingency. Hence, the power system operators and planners should consider the fact that some frequency control measures should be put into practice so as to avoid the under frequency load shedding relays to trip.

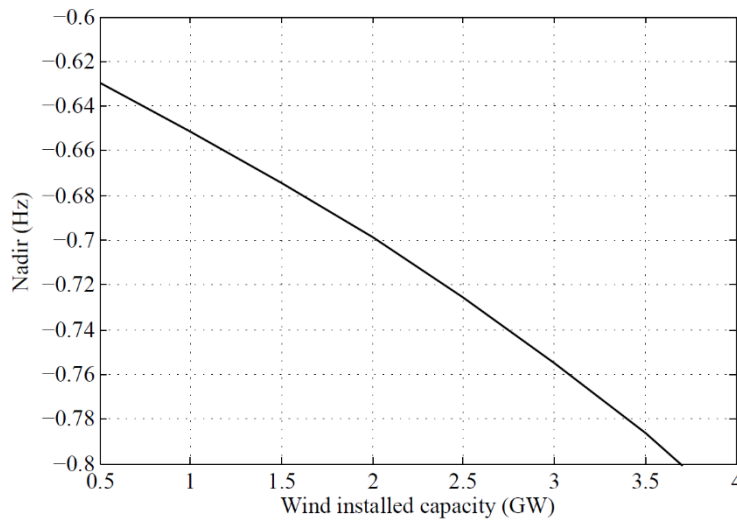


Figure 4- Effect of Integrating Wind Turbines on Nadir in Nordic power system [19]

In order to compensate the effect of adding wind capacity on the system, there should be enough ramping capability in the system to avoid high amounts of frequency drops. As can be inferred from the curves in Figure 5, having more ramp rate in the system results in enhanced frequency response, in terms of Nadir value. Hence, to keep the frequency for the operator required and favorable region, adequate ramping capacity should be considered in the economic dispatching.

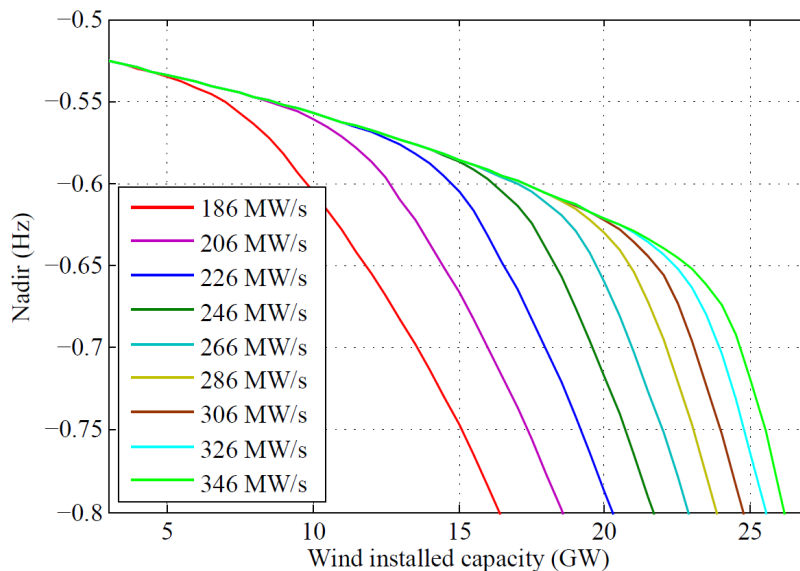


Figure 5 - Effect of Integrating Wind Turbines on Nadir Considering Different Ramp Rates [19]

Figure 6 illustrates the way that additional wind capacity influences the Rate at which frequency drops after a contingency (Rate of Change of Frequency or ROCOF). As can be seen, increasing wind capacity above a threshold results in

failing to meet the frequency control requirements. Hence, when adding extra wind turbines to the system, rather than just considering it as a negative load, one should consider the consequences of this action in frequency response behavior of the power system.

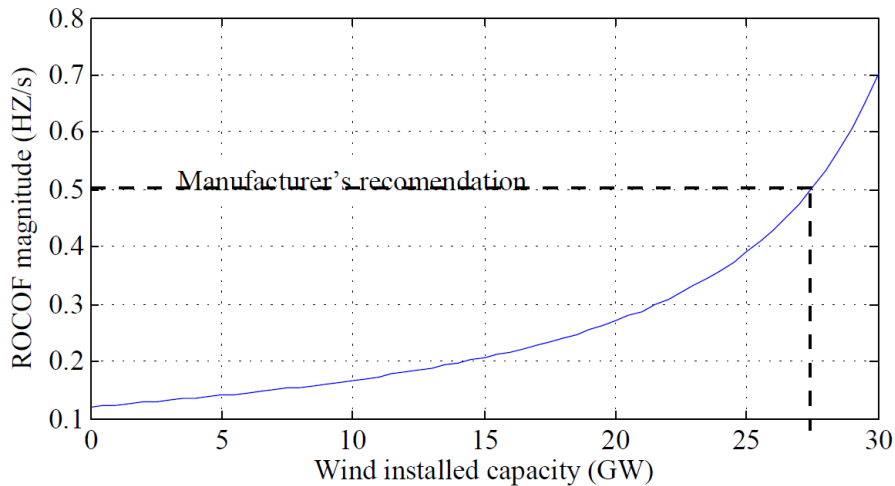


Figure 6- Effect of Integrating Wind Turbines on ROCOF in Nordic power system[19]

Now that we know the fact that the ability of operator to control the frequency will be significantly reduced as we add intermittent renewables, it seems to be of high importance to find out solutions to address the problem of inadequate frequency response. Hence, measures are to be taken to improve the two main representatives, Nadir and ROCOF, of frequency response adequacy of the system.

Two main features of the conventional generation units enable frequency response abilities. First and most important, having rotating mass inertia, has a remarkable effect on primary frequency response. Secondly, having enough ramp rate in the system is needed to give more power to the operator in order to apply secondary control actions.

2 Modeling Inertia Constraint in Unit Commitment Formulations

In the literature some authors propose an exogenous modeling of FR requirements [1,20]. according to these, the requirements for inertia and governor ramp rates are checked after each iteration of economic dispatch to see if the dispatch can provide adequacy in frequency response or not. The problem with this approach is, even though it guarantees that the frequency response requirements are satisfied, it does not necessarily reach an optimal solution and probably more than adequate inertia and ramp-rate providers will be committed. Although the technique is good for modeling and ensuring enough inertia, it does not necessarily lead to an optimal solution.

The other approach can be an endogenous one where frequency response is integrated as a constraint in the optimization problem. This constraint should take care of having enough inertia and ramp-rate in the grid to ensure that there will be enough resources to keep the frequency in the favorable interval of 50 to 49.4 Hz and also avoid rates of reduction steeper than 0.5 Hz/second. In this manner, not only is it guaranteed that there is enough inertia and ramp rate in the generation schedule for the next day, but also the amount of power and spinning reserve is optimized in a manner that they can satisfy the frequency response constraints in an economical and efficient fashion.

2.1 A UNIT COMMITMENT FORMULATION

A typical unit commitment optimization problem has been formulated and implemented.

The objective function includes four terms, each of which representing a fraction of system costs; having a look on the nomenclature shows the specific costs that each of the terms in objective function stand for.

$$\min \sum_i \sum_k (C_i^P P_{i,k} + C_i^R R_{i,k} + C_i^v v_{i,k} + C_i^w w_{i,k}) \quad (1)$$

Where C_i^P is the cost of energy per MWh, C_i^R represents cost of reserve capacity, C_i^v is the startup cost and C_i^w indicates shut down cost of unit i. Also, $P_{i,k}$ and $R_{i,k}$ is the amount of power and reserve provided by the unit i in hour k. $v_{i,k}$ is a binary variable which shows the starting up of unit i in hour k. $w_{i,k}$ is another binary variable which shows the shutting down of unit i in hour k.

2.1.1 Constraints

A cursory look on the constraints shows that the first seven of them are the same as ordinary economic dispatch.

$$\sum_i P_{i,k} = D_k \quad (1-a)$$

$$\sum_{i \neq l} R_{i,k} = P_l \quad (1-b)$$

$$R_{i,k} + P_{i,k} \leq P_l \quad \forall i, k \quad (1-c)$$

$$u_{i,k} - u_{i,k-1} = v_{i,k} - w_{i,k-1} \quad \forall i, k \quad (1-d)$$

$$\sum_{t=k-t_l^{UP}-1}^k v_{i,t} \geq u_{i,k} \quad \forall i, k \quad (1-e)$$

$$\sum_{t=k-t_l^{DN}-1}^k w_{i,t} \geq 1 - u_{i,k} \quad \forall i, k \quad (1-f)$$

Constraint (1-a) is to make sure that the power balance condition is met in this network. The constraint (1-b) is added in order to secure the continuity of supply by having enough reserve to avoid any interruption in serving the demand. Constraint (1-c) represents the fact that total reserve and power of a generation unit cannot be more than the capacity of the unit at any time. The three other constraints are to make sure that the unit start-up, online and shut- down variables are taking their right values.

Now, consider the three following constraints which are added to take care of inertia and governor ramp rate adequacy:

$$\sum_{i \neq l} u_{i,k} h_i \geq f'_{min} P_l \quad (1-g)$$

$$\sum_{i \neq l} u_{i,k} h_i \geq K_{l,k} \quad (1-h)$$

$$R_{i,k} P_l - 2c_i K_{l,k} (f_0 - f_{min} - f_{db}) \leq 0 \quad \forall i, k, i \neq l \quad (1-i)$$

Constraints (1-g), (1-h) and (1-i) are there to model the inertia and governor ramp rates. Constraint (1-g) is to consider the rate of change of frequency and constraints (1-h) and (1-i) is about to have enough inertia in the system. Constraint (1-h) shows how the total inertia is calculated by adding up all of the inertias of the units which are committed.

Constraints (1-g)-(1-i) explicitly models the inertia constraints in the standard unit commitment problem. This model allows us to quantify the impact of inertia service on social cost and market prices.

2.2 SOME ILLUSTRATIVE EXAMPLES

First we consider the following simple network; in which there are 5 generators and 5000 MW of load.

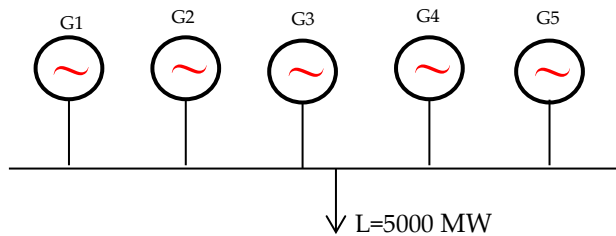


Figure 7- 5-bus illustrative network to show the effect of considering inertia on total dispatch cost

The total cost of unit commitment for the cases with and without ROCOF and nadir constraints are as follows:

Table 4- Generator Data for the 5 generator system, SRMC: Short run marginal cost

Generators	G1	G2	G3	G4	G5
SRMC for power (€/MWh)	82	90	100	130	140
SRMC for reserve (€/MW)	60	40	20	70	80
Inertia constant (MWs/Hz)	4000	1500	2000	3000	2300

Table 5 – The dispatch cost of the proposed OPF formulation with and without frequency response constraints, INC: Increased

Type of OPF formulation	The total dispatch cost (€/h)
Base case	493,800
With ROCOF Constraint	540,900 (9.5% INC)
With Nadir Constraint	493,800 (0% INC)
With Both Constraints	551,598 (12.1% INC)

As can be seen, the total dispatch cost experiences a considerable increment due to adding the frequency response requirements. The simulation in this case also shows that the nadir constraint is not binding and it has already been satisfied in the base case economic dispatch. However, adding the ROCOF constraint or both ROCOF and Nadir constraints will impose the extra cost for the system. It is to be noted that the arrangement of generators being committed is the same for both models.

Now, consider another illustrative case which consists of 7 wind farms and 2 conventional generators with high inertia. In this case-study, we have executed the simulation for a 24-hour period. In order to better illustrate the impact of considering inertia in unit commitment optimization problem and highlight the extra costs it may impose, the price of the conventional generators was set to considerably higher values than the wind farms. The basic data is presented in Table 6:

Table 6- Generator Data for the 9 Generator Test Case, SRMC: Short run marginal cost

Generators	G1	G2	G3	G4	G5	G6	G7	G8	G9
SRMC for power (€/MWh)	82	83	100	130	140	154	150	170	182
SRMC for reserve (€/MW)	60	40	20	70	80	94	80	100	102
Inertia Constant	6	6	6	6	6	6	6	6000	6000

And the Load Curve for 24 hours is illustrated in Figure 8.

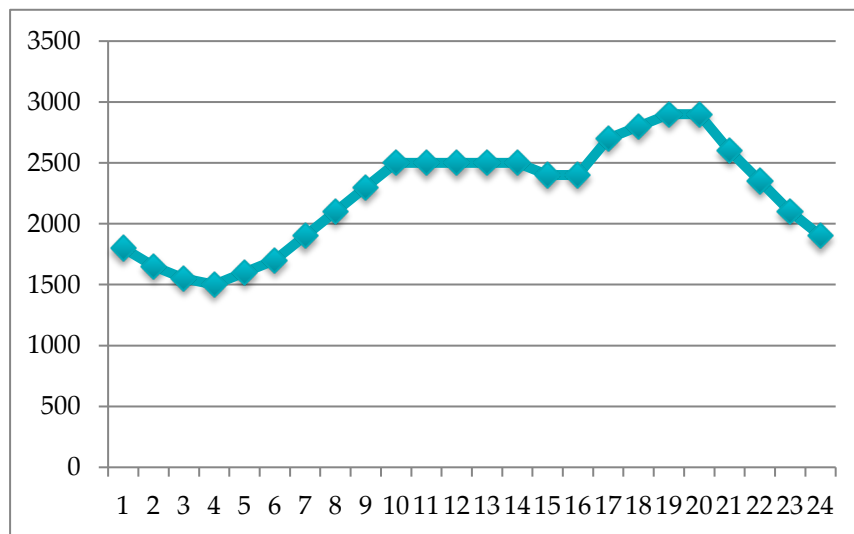


Figure 8- Daily Load Curve for the Demand (in MWs) for the 9 generator illustrative case

The results are available in the tables 7 and 8 in the following pages.

Table 7- The Amount of Unit Online Variable After Economic Dispatch (Total Cost of Energy Production for One Day Period: 6,854,513)

Gen No.	Hour					
	1	2	3	4	5	6
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4	1	1	1	1	1	1
7	1	1	1	1	1	1

Gen No.	Hour					
	7	8	9	10	11	12
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4	1	1	1	1	1	1
5			1	1	1	1
6		1	1	1		
7	1	1	1	1	1	1

Gen No.	Hour					
	1	2	3	4	5	6
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4	1	1	1	1	1	1
5	1	1	1	1	1	1
6						1
7	1	1	1	1	1	1
9	1	1	1			

Gen No.	Hour					
	1	2	3	4	5	6
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4	1	1	1	1	1	1
5	1	1	1	1	1	1
6	1	1	1			
7	1	1	1	1	1	1
8						1

Table 8-The Amount of Unit Online Variable After Economic Dispatch (Total Cost of Energy Production for One Day Period: 7,020,252)

Gen No.	Hour					
	1	2	3	4	5	6
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4		1	1	1	1	1
6	1					
7	1					
8	1	1	1	1	1	1
9	1	1	1	1	1	1

Gen No.	Hour					
	7	8	9	10	11	12
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4	1	1	1	1	1	1
5				1	1	1
8	1	1	1	1	1	1
9	1	1	1	1	1	1

Gen No.	Hour					
	1	2	3	4	5	6
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4	1	1	1	1	1	1
5	1	1	1	1	1	1
8	1	1	1	1	1	1
9	1	1	1	1	1	1

Gen No.	Hour					
	1	2	3	4	5	6
1	1	1	1	1	1	1
2	1	1	1	1	1	1
4	1	1	1	1	1	1
5	1	1				
8	1	1	1	1	1	1
9	1	1	1	1	1	1

After running the proposed OPF formulation in both conditions (i.e. with and without inertia constraint), the results can be seen in Tables 7 and 8.

As presented above, when the market operator is not taking inertia and primary frequency response into account, the conventional expensive generators, have only been dispatched for a few hours of the day. G9 has been committed for 3 hours and G8 is going to be committed for only one hour.

However, when adding the constraints for inertia, the importance of these units in providing inertia for the network is being seen more clearly. As it is easy to detect from Table 8, the two expensive conventional units have been committed to provide power or reserve during the entire day. Considering their high startup cost and marginal cost, it is obvious that they have not been committed merely as sources to serve electrical energy; rather, they can be served as inertia providers. Participation of these two units leads to a significant raise in system price. This new price has the inertia marginal cost in its calculation.

2.3 HOW TO PRICE INERTIA

As noted in previous section, inertia comes at a price. Knowing this, there is still a question left unanswered. The question is, how to price this inertia service. How much should we pay to each generator and how much to take from customers? The answer to this question needs pricing of inertia service under the nonconvexity conditions created by unit commitment decisions. In other words, since the ICUC model has binary variables the Lagrange multipliers do not reflect the marginal cost of production. We propose the following way of pricing for the proposed ICUC model.

3 Nonconvex Pricing Considering Inertia

Until now, several crucial issues regarding inertia have been put forward in this study, the most important of which are:

- So as to have a favorable level of frequency response, the system needs adequate rotating mass inertia in the power system;
- Adding intermittent renewable generation as wind and solar energy may reduce the frequency response ability of the power system;
- Inertia imposes a cost on the system operator including commitment of new units or keeping more units in spinning reserve mode.

Knowing the above facts, and because the newly added generators which provide inertia may have a considerable effect on the marginal price, it appears more important to investigate the effect of this inertia on the marginal price of the system.

3.1 THE LINEAR PROGRAMMING FORMULATION OF THE MILP MODEL OF ICUC

As previously mentioned, the proposed ICUC is a mixed-integer linear program (MILP). To derive a linear programming formulation of this MILP we propose the following process.

First the MILP optimization problem is solved in order to find the optimal solution of integer variables. Then, we fix the integer variables of the MILP model to the levels found from the MILP solution. The new LP problem is solved and the Lagrange multipliers are calculated.

To clarify what has been done in GAMS⁶ coding, see figure 9, which belongs to the MILP optimization. In this code, $u_{i,k}$, $v_{i,k}$ and $w_{i,k}$ have been defined as binary variables.

Binary Variables

```
u(i,k)  unit online variables
v(i,k)  unit turn-on variables
w(i,k)  unit turn-down variables;
```

Variables

```
H          total system inertia
objfun     cost function variable;
```

Positive variables

```
p(i,k)     generator i dispatch at interval k
R(i,k)     generator i governor reserve at interval k;
```

Figure 9- The Coding Syntax for Defining u, v and w variables in MILP Optimization

⁶ General Algebraic Modeling System language (www.gams.com)

Meanwhile, in the linearized code, these variables have been defined as ordinary real variables as can be seen below:

Variables

```
u(i,k)    unit online variables
v(i,k)    unit turn-on variables
w(i,k)    unit turn-down variables
H          total system inertia
objfun     cost function variable;
```

Positive variables

```
p(i,k)    generator i dispatch at interval k
R(i,k)    generator i governor reserve at interval k;
```

Figure 10- The Coding Syntax for Defining u,v and w variables in MILP Optimization

Then, by having the results of MILP, we can define three new constraints in order to make sure that the three previously binary variables will take their optimal amounts. This can be seen in Figure 11.

```
z..objfun=e=sum(i,sum(k,Cp(i)*p(i,k)+CR(i)*R(i,k)+Cv(i)*v(i,k)+Cw(i)*w(i,k)));
cn2(k)..sum(i,p(i,k))=e=D(k);
cn3(l,k)..sum(i$(ord(i) ne ord(l)),R(i,k))=g=(Pcapacity(l)/12)*u(l,k);
cn4(i,k)..p(i,k)+R(i,k)=l=Pcapacity(i)*u(i,k);
cn5(i,k)..u(i,k)-u(i,k-1)=e=v(i,k)-w(i,k);
cn6(i,k)..sum(t$( (ord(t) le ord(k)-1) and (ord(t) ge ord(k) - tUP(i))),u(i,t))=;
cn7(i,k)..sum(t$( (ord(t) le ord(k)-1) and (ord(t) ge ord(k) - tDW(i))),1-u(i,t));
cn8(l)..sum(i$(ord(i) ne ord(l)),sum(k,u(i,k)*hh(i))) =g= fmin*Pcapacity(l);
cn9(l,k)..sum(i$(ord(i) ne ord(l)),u(i,k)*hh(i))=e=H(l,k);
cn10(i,l,k)$(ord(i) ne ord(l))..R(i,k)* Pcapacity(l)-2*c(i)*H(l,k)*(f0-fmin-fdi
cn11(i,k)..p(i,k)+R(i,k)=g=Poutput(i)*u(i,k);
cn12(i,k)..v(i,k)=e=vi(i,k);
cn13(i,k)..u(i,k)=e=ui(i,k);
cn14(i,k)..w(i,k)=e=wi(i,k);
```

Figure 11-The Coding Syntax for Fixing u,v and w variables in LP Optimization to their optimal values

3.2 RESULTS OF RUNNING THE LP MODEL OF ICUC

The following load curve has been considered for the 12-hour dispatch period:

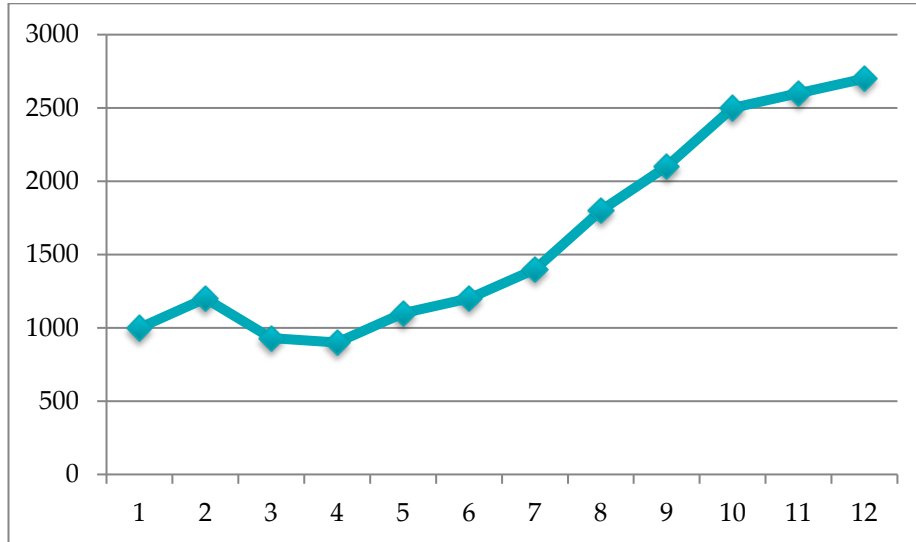


Figure 12- Load Curve for 12hour simulation on Nordic 32bus test system (the Demand is in MWs)

Table 9 reports the prices resulting from the proposed LP model.

Table 9- Marginal Prices for The Linearized Dispatch Problem in Base Form (Without Inertia Constraint)

Hour	Price[Euros/MWh]
1	154
2	154
3	154
4	154
5	154
6	154
7	154
8	154
9	154
10	154
11	154
12	154

In table 10, the prices for the simulation after considering inertia can be found.

Table 10-Marginal Prices for The Linearized Dispatch Problem Considering Inertia Constraint

Hour	Price[Euros/MWh]
1	205
2	205
3	205
4	205
5	205
6	205
7	154
8	154
9	205
10	154
11	154
12	154

As can be seen, there is price difference in 7 hours out of 12 hours of the day. Hence, the same amount of energy will be more expensive if the operator requires improved frequency response.

It has been shown that the marginal generators in 7 hours are the conventional steam generators who are acting as inertia providers here in this power system. The fact that these inertia providers are also marginal generators implies an important point, that is, if these generators are honest in their bids (i.e. they bid their true marginal costs and do not manipulate) they are getting zero profit or, even worse, negative profit, mainly due to the fact that their startup costs are not covered because of selling electricity at a price equal to their marginal cost of electricity production. Hence, these inertia providers do not have any incentive to remain in this market any longer and they are being urged to leave the market (if they experience the negative profits). Hence, these negative profits should be compensated in order to help these generators to survive in the market. One way to resolve this issue is to make uplift payments by the operator [21- 23]. In Table 11, the profit of each generator in each hour of the dispatch can be seen. It is to mention that if a field has no number in it, its amount is zero. Hence, the dispatched generators who are experiencing zero profit are not shown in Table 11. The Model Under Study was Nordic 44, with a total of 20 generation units.

Gen No.	Hour					
	1	2	3	4	5	6
9	34117	40587	40587	40587	40587	40587
11	-14390					
18	-10760					
19	-8090					
20	37162	38062	38062	38062	38062	38062
Gen No.	Hour					
	7	8	9	10	11	12
1	-8090		51000			
8				-8090		
9	14958	14958	41000	15365	15365	15365
20	18997	18997	38273	18479	18479	18479

Table 11- The Amounts of Profits Before Applying Uplift Payments

3.3 NORDIC 44-BUS CASE STUDY

During the study, it has been suggested by the reference group to include another case study on Nordic system. The 44-bus test system is simulated in this section [26].

Figure 13 shows the demand curve considered for the simulation results of this section. The results of ICUC model is reported in Tables 12 and 13.

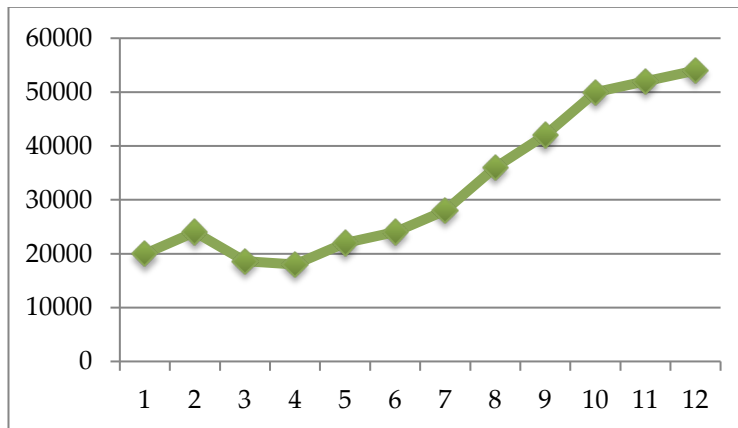


Figure 13- Load curve for 12hour simulation on Nordic 44 bus test system (Demand is in MWs)

Table 12-GAMS Code Results for The Case without Considering Inertia(Total cost: 1.31 E 07)

Hour Gen.	1	2	3	4	5	6
1	2700.000	2700.000	2700.000	2700.000	2700.000	2700.000
3	3500.000	3500.000	3500.000	3500.000	3500.000	3500.000
4	1280.000	1280.000	1280.000	1280.000	1280.000	1280.000
5	1100.000	994.000	1100.000	1100.000	1100.000	994.000
6		2900.000			794.000	2900.000
7	2016.000	3222.000	616.000	16.000	3222.000	3222.000
10	8170.000	8170.000	8170.000	8170.000	8170.000	8170.000
15	1234.000	1234.000	1234.000	1234.000	1234.000	1234.000
Hour Gen.	7	8	9	10	11	12
1	2700.000	2700.000	2700.000	2700.000	2700.000	2700.000
2				3365.333	5365.333	6791.667
3	3500.000	3243.667	3500.000	3500.000	3500.000	3500.000
4	1280.000	1280.000	1280.000	1232.000	1232.000	1232.000
5	1100.000	1100.000	1100.000	1100.000	1100.000	1100.000
6	2900.000	2900.000	2900.000	2900.000	2900.000	2900.000
7	3222.000	3222.000	3222.000	3222.000	3222.000	3222.000
8				2540.667	2540.667	2540.667
9				896.000	896.000	896.000
10	8170.000	8170.000	8170.000	8170.000	8170.000	8170.000
11	3150.000	3150.000	3150.000	3150.000	3150.000	3150.000
12	744.000	4400.000	4400.000	4400.000	4400.000	4400.000
13		4290.000	4290.000	4290.000	4290.000	4290.000
15	1234.000	1234.000	1234.000	1234.000	1234.000	1234.000
16			2754.000	4000.000	4000.000	4000.000
17		310.333	3300.000	3300.000	3300.000	3300.000
18						573.660

Table 12 shows the results of simulation for the case in which the inertia and frequency response requirements are not considered. The total cost of dispatch was 1.31 Million units. Table 13 shows the results of the same simulation considering frequency response. In the latter one, the total cost is 1.35 Million units⁷, which shows around 4% increase in the total cost of dispatch to satisfy frequency response requirements:

⁷ Since the marginal costs of the generators were not available for Nordic 44 bus test system, we used some illustrative costs to run the simulation and illustrate the fact that there is cost difference when we add inertia constraints. Hence, no monetary units have been mentioned.

Table 13-GAMS Code Results for the Case Considering Inertia (total cost: 1.45 E07)

Hour Gen.	1	2	3	4	5	6
1	2619.110	2619.110	2619.110	2619.110	2619.110	2619.110
3	3419.110	3419.110	3419.110	3419.110	3419.110	3419.110
4	1199.110	1199.110	1199.110	1199.110	1199.110	1199.110
5	1019.110	1019.110	1019.110	1019.110	1019.110	1019.110
6		2896.323			1224.186	2896.323
7	2442.509	3218.323	1042.509	442.509	3218.323	3218.323
10	8089.110	8089.110	8089.110	8089.110	8089.110	8089.110
11		327.862				327.862
15	1211.939	1211.939	1211.939	1211.939	1211.939	1211.939
Hour Gen.	7	8	9	10	11	12
1	2619.110	2619.110	2643.693	2619.110	2619.110	2619.110
2				3492.777	5492.777	6919.110
3	3419.110	3419.110	3419.110	3500.000	3500.000	3500.000
4	1199.110	1199.110	1199.110	1199.110	1199.110	1199.110
5	1019.110	1019.110	1019.110	1047.370	1047.370	1043.693
6	2896.323	2896.323	2900.000	2896.323	2896.323	2900.000
7	3218.323	3218.323	3222.000	3222.000	3222.000	3222.000
8				2995.110	2995.110	2995.110
9				815.110	815.110	815.110
10	8089.110	8089.110	8089.110	8089.110	8089.110	8089.110
11	3069.110	3069.110	3069.110	3069.110	3069.110	3069.110
12	1258.752	4319.110	4319.110	4400.000	4400.000	4400.000
13		1713.178	4267.939	4267.939	4267.939	4267.939
15	1211.939	1211.939	1234.000	1234.000	1234.000	1234.000
16			3391.241	3926.464	3926.464	3926.464
17		3226.464	3226.464	3226.464	3226.464	3226.464
18						573.667

As can be seen, there not much difference between the two dispatch results. Unit 11 which has been committed after considering inertia, does not have a higher price than other online units. There is no price difference between the two cases. However, the total cost is higher by about 4%, and this means some entities should pay more.

4 Uplift Methods

Three methods will be discussed and one of them will be implemented to see the results and how it wipes out the negative profits [23].

4.1 CALCULATING THE UPLIFT BASED ON FIRST ORDER KARUSH KUHN TUCKER (KKT) CONDITIONS

The proposed ICUC model is derived in (1a)-(1i).

$$\text{Minimize } \sum_i \sum_k (C_i^P P_{i,k} + C_i^R R_{i,k} + C_i^V v_{i,k} + C_i^W w_{i,k}) \quad (4-1a)$$

Subject to:

$$\sum_i P_{i,k} = D_k \quad (4-1b)$$

$$\sum_{i \neq l} R_{i,k} = P_l \quad (4-1c)$$

$$R_{i,k} + P_{i,k} \leq P_l \quad \forall i, k \quad (4-1d)$$

$$\sum_{t=k-t_l^{UP}-1}^k v_{i,t} \geq u_{i,k} \quad \forall i, k \quad (4-1e)$$

$$\sum_{t=k-t_l^{DN}-1}^k w_{i,t} \geq 1 - u_{i,k} \quad \forall i, k \quad (4-1f)$$

$$\sum_{i \neq l} u_{i,k} h_i \geq f'_{min} P_l \quad (4-1g)$$

$$\sum_{i \neq l} u_{i,k} h_i \geq K_{l,k} \quad (4-1h)$$

$$R_{i,k} P_l - 2c_i K_{l,k} (f_0 - f_{min} - f_{db}) \leq 0 \quad \forall i, k, i \neq l \quad (4-1i)$$

The optimization problem (1) is a MILP. If we solve this MILP model, we can find the optimal level of all binary variables in (1). By fixing these binary variables at their optimal values, we arrive at the following LP model.

$$\text{Minimize } \sum_i \sum_k (C_i^P P_{i,k} + C_i^R R_{i,k} + C_i^V v_{i,k} + C_i^W w_{i,k}) \quad (4-2a)$$

Subject to:

$$\sum_i P_{i,k} = D_k \quad (4-2b)$$

$$\sum_{i \neq l} R_{i,k} = P_l \quad (4-2c)$$

$$R_{i,k} + P_{i,k} \leq P_l \quad \forall i, k \quad (4-2d)$$

$$\sum_{i \neq l} u_{i,k} h_i \geq f'_{min} P_l \quad (4-2e)$$

$$\sum_{i \neq l} u_{i,k} h_i \geq K_{l,k} \quad (4-2f)$$

$$R_{i,k} P_l - 2c_i K_{l,k} (f_0 - f_{min} - f_{db}) \leq 0 \quad \forall i, k, i \neq l \quad (4-2g)$$

$$v_{i,k} = v_{i,k}^* \quad (4-2h)$$

$$u_{i,k} = u_{i,k}^* \quad (4-2i)$$

$$w_{i,k} = w_{i,k}^* \quad (4-2j)$$

The KKT conditions have been utilized for optimization problem (2) to obtain an amount of uplift, which is expected to counteract the negative profits of the inertia providers in the network. If we write the first order conditions for the linearized formulation of the economic dispatch problem, it leads to:

$$\lambda_{i,k} = C_i^p + \theta_{i,k} - \eta_{i,k} \quad (4-3)$$

$$\pi_{i,k} = C_i^p - \theta_{i,k}P_{i,max} + \eta_{i,k}P_{i,min} \quad (4-4)$$

$$\eta_i \geq 0 \quad (4-5)$$

$$\theta_i \geq 0 \quad (4-6)$$

Where $\theta_{i,k}$ and $\eta_{i,k}$ are respectively the Lagrange multipliers of the unit maximum and minimum output constraints. Since the negative profits are mainly related to the startup costs of the inertia providing units, it appears rational to consider the Lagrange multiplier of the constraint related to startup of generators to determine the proper amount of uplift payment (or at least a part of it). Reference [23] proposes to add the term $\pi_{i,k} \times v_{i,k}$ to the amount being paid to generator i in hour k . The term $\pi_{i,k}$ is called the commitment ticket price, which is the Lagrange multiplier of the unit start-up constraint [22].

The amounts of profits for each generator, in Nordic 32-bus test system, before and after implementing this uplift method, are presented in the Table 14.

Table 14- The Amounts of Profits After Applying Uplift Payments

Gen No.	Hour					
	1	2	3	4	5	6
9	40587	40587	40587	40587	40587	40587
20	38062	38062	38062	38062	38062	38062
Gen No.	Hour					
	7	8	9	10	11	12
1	51000					
9	14958	14958	41000	15365	15365	15365
20	18997	18997	38273	18479	18479	18479

It should be noted that since we need to have the optimal value variables in hand in order to run the linearized optimization problem, this formulation is not about to find the optimal solution. Rather, it aims at defining and interpreting associated marginal prices. In other words, the transfer from MILP to LP was made mainly in order to find out the marginal prices for each hour using the Lagrange multipliers.

Furthermore, negative profits are alerting signals for the market operators that some generators are being incentivized to leave the market. In order to illustrate this with a more intuitive indicator, it can be stated that the more zeros and the less negative amounts we have in the profits table (given among the results of GAMS simulation), the closer we are to the stable condition.

Table 11 belongs to the case before applying the uplift method. As can be seen, this table includes several negative amounts, which indicates that some of the generators are unhappy with the current market payment. And what makes the situation even worse in our case, is the fact that these unhappy generators are mostly those who are providing a considerable amount of inertia for the power system.

About the Nordic 44-bus system, the problem is a bit different. In this case the power network specifications are such that there is no price difference between the cases with and without considering inertia. But there is still cost difference between these two cases, mainly because we need more reserve to secure proper frequency response.

Actually, in this case, the inertia cost is hidden in the total cost. The wind turbines are not responsible for increasing the price mainly because with and without considering inertia the price is the same. In this case, there is another way to compensate for uplift payments, recommended by literature [24]; and that is to avoid charging the generators and simply charge customers.

All in all, as a result of our proposed method, the minimum amount of the uplift payment is determined to be paid to the inertia providing generators and keep them competitive in the market. Since the uplift payment is an extra to the marginal price of the market, it may be considered as a disturbance to free and impartial operation of the market in the short term view. However, considering the fact that in the long run, high penetration of electronically connected renewable energy resources will highlight the impact of lacking inertia in the network and if the market operators simply let the open market to decide, they may actually let the inertia providing units to leave the market due to lack of competitiveness and this will cause significant problems in system small signal security and frequency response after contingencies.

Hence, the final decision about whether or not these amounts of uplift should be made is left in hands of system planners and their conclusion of how much inertia and what level of frequency response is needed in the system in the long-term.

The authors of this report, as noted previously, have executed the simulations based on NORDIC system standards, i.e. 49.0 Hz for Nadir and 0.5 Hz/Sec for ROCOF. The power systems under study are also an illustrative representations of NORDIC power system. Hence, in case the NORDIC 32 and 44 bus systems are realistic representations of the real network, the results are indicating that the operator should pay some extra amounts to take care of inertia adequacy and the optimal amounts can be determined based on the discussed lagrangian method.

4.2 OTHER PROPOSED METHODS AND POTENTIAL FUTURE WORK

A discussion on other methods proposed by literature shows that some have also studied ways of allocating uplift payments or charging entities for uplift. Two of the proposed methods for allocation of uplifts have been investigated in [22], one of which proposes a framework which considers the objectives of demand side, operator and generation side simultaneously to attain optimal payment and

charging method. The other method is called the Minimum Uplift Method which tries to obtain an optimum amount for uplift. This method also emphasizes on going directly to the as-bid profits rather than considering shadow prices.

There are references which propose different methods and approaches to incentivize investment in thermal power plants and other inertia providers and keep them competitive in the market.[27-30] The future work may consist of utilizing some mathematical techniques to fairly allocate charges and payments.

Another possible area for future work is regarding optimum allocation of payment and charges. Since the markets under study use marginal pricing, it should be taken into account that if some expensive units are committed to provide inertia, all of the other market participants will be paid the same price. Technically, the 'non-inertia providing' units such as wind generators are being paid more due to considering inertia constraints, while they are not providing inertia for the network. So, should the uplifts (which are going to be paid to the inertia providers) be taken from this group instead of simply charging customers for it?

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INCORPORATING INERTIA CONSTRAINTS INTO THE POWER MARKET

In this report, the importance of having a market approach towards frequency response has been

studied. It has been explained that while adding such fluctuating renewables as wind and solar energy may reduce the frequency response ability of the system, in order to have a favorable level of frequency response, we need adequate rotating mass inertia in the power system.

Inertia imposes a cost on the system operator including commitment of new units or keeping more units in spinning reserve mode. Commitment of more units may result in increased price. This has been shown through simulations on Nordic 32 and 44 bus networks. It has been explained in detail that we are dealing with a non-convex optimization here and addressing the challenges related to non-convex pricing. Some mathematical techniques have been exploited to linearize the problem and find the optimal amount of uplift to be paid to the generators in order to at least reach the zero profit condition so as to make it acceptable for them to stay in the market.

The main issue is: due to the fact that the inertia providing units are mostly selling electricity at marginal cost price, it should be taken into account that they should not experience negative profits. In other words, providing inertia and then pay us! This situation may lead them to leave the market. Hence, some methods have been discussed and implemented in order to avoid these negative profits. An uplift method has been implemented and its results have been evaluated on Nordic 32 bus network.

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