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Impact of Variable Generation on the Dispatch Operation in Isolated Power Systems

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***Abstract*—**Wind power penetration increased exponentially in the recent years as a result of its competitiveness compared to conventional sources of energy and its effectiveness compared to other renewable sources of energy. Wind power contributes to the reduction of emissions and to alleviating the dependency on fossil fuels. Many studies have been conducted with respect to wind integration, both financial and technical, but only a few approaches were related to isolated power systems with a high share of variable generation. In this paper, the operation of medium/small isolated power systems with a high share of variable generation is addressed and discussed. The main considerations include the influence of the market model on the dispatch of generation (in terms of both system operator approach and independent power producer), the influence of the "close to gate" time and how often the dispatch is called, the influence of wind and load forecasting in the dispatch solution, as well as the technical/economic challenges that may arise due to the limited flexibility of isolated power systems. Numerical results for the modified IEEE 30 bus test system as well as for the actual power system of Cyprus are presented and analyzed.

***Keywords*—**economic dispatch, isolated power systems, power system operation, renewable energy sources, variable power generation, wind energy.

I. Introduction

ENVIRONMENTAL factors such as global warming and pollution, together with national or regional strategies for energy security (reduction in the dependence of import of energy resources, diversity of resources) have heightened the need to introduce into the generation mix a greater percentage of renewable generation. In the last two decades, wind energy passed from a status of an alternative source to the rank of a respectable mainstream solution. However, because of wind variability and relative unpredictability, new challenges arise with regard to the integration of large amounts of wind generation into the main grid. As the cost of generation remains the key issue defining the viability of any power generation technology, the implementation of new generation solutions has to ensure their competitiveness within the electricity market.

In the modern energy management system, the economic dispatch (ED) of generation is a crucial function, both in terms of economics and system security. Different approaches and solutions may come into place when a) the ED refers to the system operator (SO) strategy to balance in real time the electricity demand and the generation (the load is estimated by the SO), and/or b) the case when the ED refers to the bidding strategy of an independent power producer (IPP) having an energy mix portfolio of generation power units (thermal, wind, hydro, etc.). In essence, the economic dispatch is an optimization problem, whose aim is to allocate the load demand (which can be fixed or known with respect to a relatively small forecasting error, or can be elastic or unknown due to the influence of bidding strategies of other market players) to the committed generating units in the most economical or profitable way, while respecting security and reliability constraints of the dispatch portfolio.

Wind power has drawn much attention as a promising renewable energy resource, which has shown significant prospects in curtailing fuel consumption and reducing the emission of pollutants into the atmosphere [1-4]. However, wind generation brought new challenges on power system operation and planning due to the undispatchable characteristic of the wind. Therefore, security concerns arise as large amounts of wind generation are integrated in the traditional power system. Many studies in recent years concentrated on the necessary increase in reserve due to the increase in variability and uncertainty of the wind power production. The methods vary from modeling wind power turbines [5], running unit commitment (UC) models that include stochastic scenarios for wind power production [6, 7], and using probabilistic approaches considering the reliability of the system [8].

Most of the impact studies for wind integration emphasized that the wind power production variability mainly impacts the so called secondary reserve (sometimes called regulation reserve) and implicitly on the balancing price. The economic dispatch problem is closely related to what is termed the *intra-hour load following*. As wind power adds more variability to the system, the reserve will be responsible for balancing the aggregated load and wind energy fluctuations. Secondary reserve is then responsible for balancing net load fluctuations for the time between successive security constrained EDs [9]. The technical challenge of wind power variability will be considered only upon the secondary reserve, in this study.

In real time operation, a short-term ED is performed every 5 to 15 minutes (e.g., Great Britain and some parts of the US regional power systems), every 30 minutes (e.g., Germany and Spain), every hour (e.g., Nordpool/Nordel), or every 3 hours (e.g., France) to match the predicted net load mean value trajectory at each subinterval of time. In this respect, the time intervals between successive dispatches, together with which players are allowed to enter in the dispatch, play an important role in the healthy and transparent functionality of the market.

Together with the technical approach of the wind integration studies, the financial and legal frameworks which are enclosed in different electricity market models may have a high impact on the dispatch of the electricity resource. Due to global climate change issues many countries around Europe, parts of Asia and the US defined targets for electricity

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generation from renewable energy resources (RES). These targets are reflected in the electricity market regulations and power dispatch procedures which may vary from financial incentives for RES (e.g., price based market instruments such as feed in tariffs and premiums in the majority of European countries, or fiscal incentives such as tax exemptions or reductions), quantity based instruments such as quota obligations (governments impose an obligation on consumers, suppliers or producers to source a certain percent of their electricity from RES), priority in the dispatch of generation (e.g., Germany, where the TSO has to grant priority dispatch for RES), exempt RES from balancing penalties (e.g., NYTSO exempts wind and run-of-river hydro units from financial penalties for deviations from expected schedules).

II. Market Models and their Influence on the Dispatch of Generation

The process of restructuring (deregulation or reregulation) in electricity markets is still dynamic in changes in most of the developed and developing countries. None of the countries yet finalized the restructuring of the competition process in the electricity industry, and rules of completion are periodically changed, sometimes with significant changes.

In spite of many economic options to create market models, in the case of electricity markets one can distinguish in practice four models [10]:

a) *Vertically integrated* companies: all the electric utilities (generation, transmission and distribution) are part of the same company (monopoly). There still are developed countries such as France and Japan (and also many states of the USA) that still maintain vertically integrated monopolies.

b) *Single buyer*: the electric utilities are financially and legally separated. The competition is limited to the generation sector only. No access agreements and direct trading between generators and distributors/suppliers take place. This model was applied in European countries at the beginning of their electricity market establishments, and it is still applied in countries like Hungary, Bulgaria, South Korea and China.

c) *Wholesale market model*: distinguishes from the previous model by moving the “competition for the market” (single buyer model) to the competition “on the market” [10], as there are different degrees of arrangements with the transmission utility.

d) *Wholesale and retail market model*: in addition to the generation competition there is a competition in the retail market, as well. There is a separation between generation and supply and regulations for customers switching.

In order to compare and analyze the different aspects of the various models, it is necessary to take into account certain circumstances and characteristics. Certainly, competition is a driving force of the market economy. Assuming that the markets are in perfect competition, then this may result to the reduction in costs and thus, reduction in prices for the final consumer. However, it is very important to distinguish who will really benefit from the competition effect – producers or consumers (buyers).

Some of the advantages and disadvantages related to ownership unbundling in electricity market models are summarized in Table I. In terms of the influence of electricity market models on the generation dispatch, in this paper reference will be made only to models b), c), and d).

TABLE I
Advantages and Disadvantages of Full Unbundling Ownership in Electricity Market Models

Advantages	Disadvantages
• strengthens the competition between generating companies and/or retail companies; • removes incentives to discriminate competing generators/supply; • removes potential cross-subsidies between regulated network and competitive businesses; • increases transparency and efficiency of the regulation.	• Increases the complexity of the regulatory framework; • loss of synergies (shared services) and high transactions costs; • lower credit ratings for the unbundled companies and higher cost of capital; • efficiency loss in coordination of planning between generation and transmission investments.

First, there is a need to distinguish between the time frames that characterize these electricity market models.

There are three major time periods that characterize different markets:

a) *Forward market* where long term contracts are traded (*x* years to *y* days ahead of the physical delivery of energy contracted). It is characterized by hedge against price volatility.

b) *Spot market* may refer to the *day ahead market* (determines the production schedule for the next day), to the *intra-day market* (optimize or correct the position established in the day-ahead market) and/or to the *balancing/real-time market* (where real time corrections are made by the SO in order to maintain the system reliability and continuity in supply).

c) *Ex-post trading market*, where the imbalances created by different generating companies are traded.

The higher impact on the dispatch of generation can be seen in the case of the spot market. The *day-ahead market* impacts the long term dispatch of generation or the UC process. Thus, in the day before the actual energy delivery, generators submit their individual price-quality offers for the supply of electricity for different production levels and time intervals. In the case of the bi-directional market, the suppliers, traders and large industrial users submit their individual bids for different production levels and time intervals. Then, the market operator (MO) matches the offer with the demand and establishes the clearing market price (MCP). Thus, the most expensive bid offered, which is needed to satisfy the demand in each time interval, determines the market clearing price, as can be seen in Fig. 1.

Corrections to the established optimal commitments made in the day-ahead market will be made by the SO after the “close to gate time” of the *intra-day market* such that to satisfy the new requirements. (The term “close to gate time” will be referenced in Section III). Changes in wind forecasts represent an important factor influencing the intra-day trading volumes, together with unexpected power station outages and changes in demand or imports/exports. The corrections may affect both the UC (only for the units which have start up times less than the close to gate time of the intra-day market and need to change their status) and the economic dispatch (ED) if other optimal generation points are set up according to the redispatch.

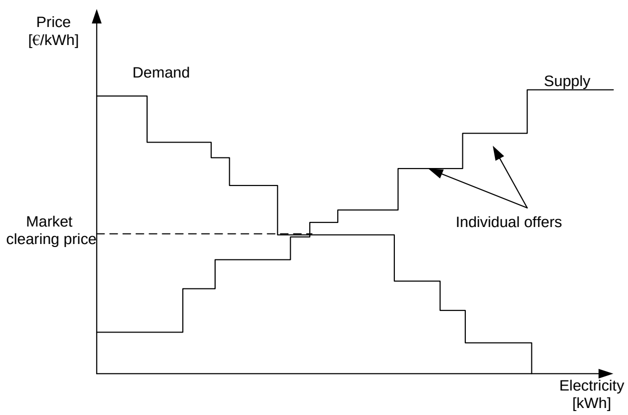

Fig. 1 Diagram of the market clearing price

Demand and variable RES generation (especially wind power) predictions are still far from being accurate. Thus, there is a need for electricity resources (ancillary services) to be used in order to correct these imbalances in real time and to maintain the continuity of supply reliably. The SO (or TSO depending on the legal framework in each market) may not have its own resources for balancing purposes (the most frequent case in the electricity market models around Europe and the US) and must purchase these support services from the market.

Ancillary service price/cost is put either in the SO (TSO) tariff (operation/transmission charges) or it may be passed to the participants that caused the imbalance. In the second case, one can distinguish two practices in charging the imbalance price: *dual imbalance price*, where a different price is paid by market participants who caused positive and/or negative imbalance volumes (e.g., Denmark, Finland, Great Britain, Germany); and *single imbalance price*, where the same price is used for both positive and negative imbalances (e.g., Greece, Norway).

Because of wind generation partial unpredictability, independent wind power producers are highly exposed to balancing risks in the electricity day-ahead market. There still is a long debate, especially in Europe, about who should pay the imbalances created by the wind power unpredictability. Since the price in the balancing market is set up by the production capacity used in the day ahead market or through bilateral-long term contracts, the price level on the balancing market will have an impact to the prices in the other markets. High balancing prices will determine scarcity and signal that there is not much production capacity left when the other markets close. Also, the functioning of the balancing market influences the liquidity in the other markets.

Many wind power impact studies have shown that the balancing price may rise with different increments (depending on the system architecture and assumptions of the study) due to the presence of wind generation fluctuations [4, 6, 7, 11-13]. These studies emphasized the role of the large interconnections in the power network, diversity of generation resources and dispersion of wind energy resources throughout the network in establishing the balancing price. Isolated systems may not benefit from the above flexibilities in order to limit the balancing price (no interconnection with other power systems which support the balancing share of resources, no large mix of generation, more concentrated fluctuation resources in sites which have high wind/solar resources), and the market may not be as efficient as in the case of large interconnected systems (less competition according to the scale of market, less transparency in purchasing the balancing resources).

III. Impact of the "Close to Gate Time" on the Dispatch of Generation

The moment designated as "gate closure" and when trading for physical delivery of electricity is ceased in the corresponding market, may differ from one market model to another. Thus, the gate closer in the balancing market for example can be every fifteen minutes (e.g., Netherlands), every half-hour (e.g., England and Wales), every hour (e.g., NordPool/Nordel), or every 3 hours (e.g., France) ahead of the physical time of electricity delivery. The impact of this time framework on the dispatch of generation is detailed in this section of the paper.

From the view point of physical system operation, the balance between supply and demand must be ensured second by second at any point of the power system network, taking into account the system limitations (e.g., the transmission capacity of the lines, generating unit thermal limits, or ramping limitations of the machines). In this respect, system operators verify whether this is the case based on current forecasts. If, for example they believe that there is insufficient supply to meet demand in one location of the network, they must procure incremental generation for that area. Or, if they believe the demand is less than the supply in that area, they must sell back generation. To be able to perform these tasks (redispatch), the SO needs to have reserve generation available in the system. Due to the system finite capacity, this reserve may need to be distributed across the system and be available in both incremental and decremental forms. Depending on the timeframe and amount of fluctuations in demand/supply mismatch, the needed reserve procurement may appear in different types: *fast responding reserve* which allows the SO to cope with short term disturbances - titled either primary control (e.g., Union of Co-ordination of Transmission of Electricity in Europe - UCTE), primary response or high frequency response (e.g., England and Wales), or momentary reserve (e.g., Nordel); and *long term reserve* used to replace the most expensive units once the immediate imbalance has been cleared (may include secondary and tertiary reserve services).

In this study, the secondary reserve corrections are considered to be needed in the balancing process. Fig. 2 presents the case when the net load and wind deviations from their predicted values may be higher/lower than the scheduled up/down secondary reserve (*UR* and *DR* respectively, which are identical to the total ramping available from the committed units), when the dispatch is called. In Fig. 2, $\Delta(W\text{-}P_D)$ is the estimated mean variation of aggregated wind power and load values over the UC interval; η_t is the deviation from the estimated mean. If the mean variation is not zero, the system frequency may temporarily deviate from its acceptable limits. If the calculation of the reserve for UC planning is performed using a deterministic approach, then such frequency violations may not be tolerated.

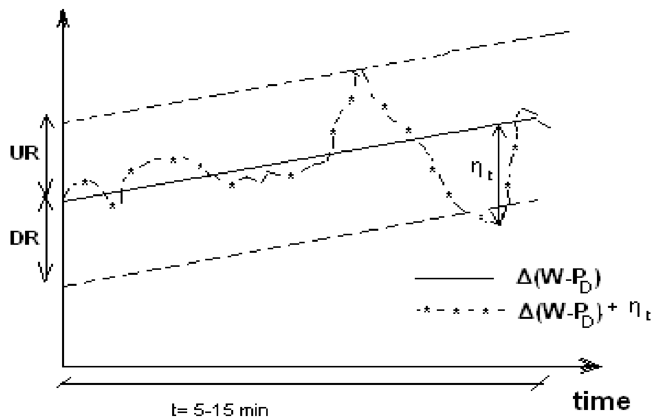

Fig. 2 Automatic secondary regulation [14]

However, if a probabilistic approach is used, some power imbalance is acceptable, if it occurs with a sufficiently low probability. In [14], it is shown that instead of using a stochastic program with recurrence, where different net load realizations are modeled by scenarios carrying a certain probability of occurrence ([6, 7] and [15]), a better and less computationally intensive solution is to incorporate the stochasticity of wind generation and load demand as a constraint in the ED model. This is the case used in this paper. The mathematical model of the ED procedure used for this analysis is described in detail in [16].

In this section, an example of an isolated system is simulated using a modified IEEE 30 bus test system, having six thermal power units and one wind farm. In order to see the impact of the close to gate time on the dispatch and reliability of the power system operation, real data from an offshore wind farm in Denmark are used. The single line diagram of the test system in presented in Fig. 3, and the characteristic data of the system are available in [16].

The ED can be run every 5 minutes, every 15 minutes, every half-hour or every hour, respectively, according to the models presented in the previous section of the paper. The analysis uses both mean forecasted values of load minus wind generation (when the forecasting is done only once, the day before the physical delivery of energy), and intra-hour forecasted values (supposing that the system is assisted online by a forecasting algorithm for wind and load predictions). In this paper it is assumed that the active power losses associated with the power generated from the wind farm are negligible compared to the active power system losses contribution of the other thermal units in the power system. Therefore, the losses of the system are considered to be the same as when the wind farm generates zero power. The assumption is not far from reality as the maximum share of wind generation for this particular example is less than 10% of the total thermal power share, while the losses are about 1.2% of the total generated power, meaning that the contribution of the wind farm to the total system losses is expected to be less than 0.12%.The study also assumes that only the thermal generating units participate in the balancing dispatch. This assumption is according to the major practice in the European market regulations, where wind farms are treated as “undispatchable units” [17]. The total load demand to be balanced by the dispatchable units of the system is calculated as the difference between the real power demand at the dispatch moment and the forecasted wind generation (mean value over the interval of the two successive dispatch runs). This assumption is based on the real case regulations (e.g., Germany) where wind generation has priority in dispatch (all the available output from the wind farms is taken by the TSO if no other technical restrictions impose wind energy shedding).

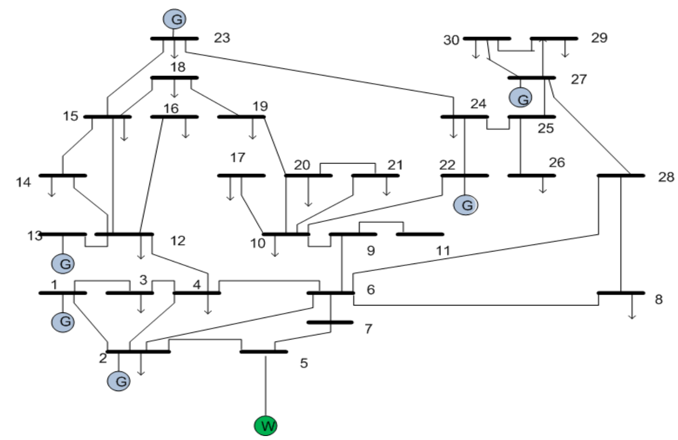

Fig. 3 Single line IEEE 30-bus system with one wind farm

Fig. 4, adapted from [5], shows the measurements with high weather turbulences of one offshore wind farm in Denmark over two hours. In the figure, the mean values of the net load and wind forecasts were calculated over the dispatch intervals: a) dispatch running every 15 minutes (from 10:00 am to 11:00 am), b) every 30 minutes (from 8:00am to 9:00 am), and every one hour (9:00 am to 10:00 am).

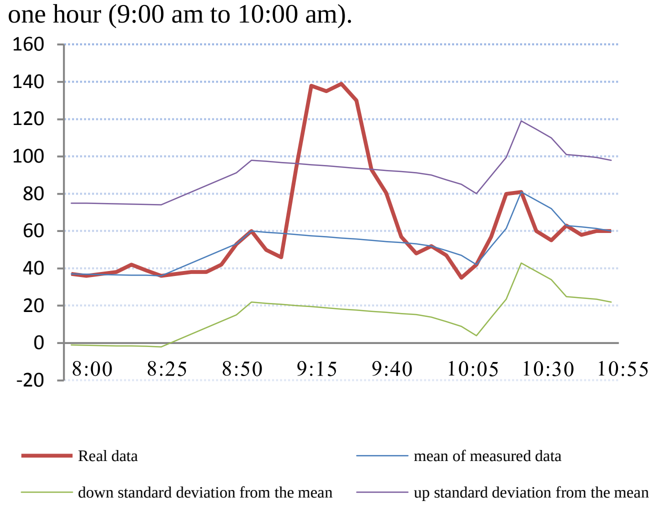

Fig. 4 Power generation of one offshore wind farm in Denmark (Jan. 18, 2005, 8:00 am - 11:00 am)

The mean aggregated load demand (true load demand minus the average forecasted wind generation) was calculated according to the 24hours approximation of the wind and load forecasting error (+/-10% from the real load demand) [8]. In this work, it was assumed that less wind generation will be available than predicted.

Real values are considered to be values received by a forecasting module, which runs before the economic dispatch (this can be seen as a real time forecasting). These values are called *real* because the standard deviation from the real data (especially for the case of the wind power forecasting) is near zero when the time horizon of prediction is less than three hours [8].

TABLE II
INTRA-HOUR LOAD DEMAND (LOAD MINUS WIND)

Time [h:min]	Real load [MW]	Mean Load close to gate ahead [MW]
8:00	1226	1221
8:30	1225.14	1198
9:00	1227	1182
10:00	1219.57	1198.25
10:15	1203	1200
10:30	1176.65	1202.75
10:45	1211	1203
11:00	1219	1218.46

Tables III-VII present the ED solutions for 15-minute, 30-minute, and one-hour intervals of running the ED program (closer to gate time). For each interval a comparison between the *real* load values and *mean* load values is examined.

TABLE III
ECONOMIC DISPATCH SOLUTIONS FOR HOUR 08:00

Power (MW)	Real	Mean
P_1	499.99	405.17
P_2	153.33	145.71
P_3	230.23	219.74
P_4	114.19	149.78
P_5	150.86	199.82
P_6	89.55	112.91
P_{wind}	37.00	42.00
Total Generation	1238.55	1233.54
Losses	12.56	12.59
Generation Cost ($/h)	15178.03	15064.79
P_{LOAD}	1226	1221

TABLE IV
ECONOMIC DISPATCH SOLUTIONS FOR HOUR 08:30

Power (MW)	Real	Mean
P_1	404.56	399.80
P_2	144.54	198.59
P_3	227.75	221.65
P_4	149.69	149.89
P_5	197.69	157.31
P_6	113.44	81.69
P_{wind}	37.86	65.00
Total Generation	1238.03	1209.57
Losses	12.63	11.31
Generation Cost ($/h)	15121.92	14789.67
P_{LOAD}	1225.14	1198

TABLE V
ECONOMIC DISPATCH SOLUTIONS FOR HOUR 09:00

Power (MW)	Real	Mean
P_1	499.99	401.19
P_2	152.35	199.99
P_3	235.33	226.49
P_4	74.44	119.68
P_5	199.99	145.96
P_6	78.43	99.56
P_{wind}	36	81.00
Total Generation	1240.91	1193.69
Losses	14.04	11.41
Generation Cost ($/h)	15194.29	14597.08
P_{LOAD}	1227	1182

TABLE VI
ECONOMIC DISPATCH SOLUTIONS FOR HOUR 10:00

Power (MW)	Real	Mean
P_1	500.00	408.24
P_2	149.29	153.02
P_3	220.70	229.33
P_4	112.52	148.27
P_5	150.37	194.53
P_6	99.15	76.28
P_{wind}	43.43	64.75
Total Generation	1232.465	1210.32
Losses	12.47	11.99
Generation Cost ($/h)	15076.58	14796.81
P_{LOAD}	1219.57	1198.95

TABLE VII
ECONOMIC DISPATCH SOLUTIONS FOR HOUR 10:15

Power (MW)	Real	Mean
P_1	413.23	407.41
P_2	198.99	148.32
P_3	221.04	225.41
P_4	150.00	111.57
P_5	149.41	199.80
P_6	81.63	119.48
P_{wind}	60	63
Total Generation	1214.92	1212.64
Losses	11.35	0.128859
Generation Cost ($/h)	14886.94	14786.69
P_{LOAD}	1203	1200

The economic dispatch solutions indicate a difference in the results depending on the case considered. It can be noticed that in all cases the mean values give a smaller dispatch price compared to the real case scenario. This is because the wind was overestimated, and therefore less power from conventional units was needed to cover the rest of the load demand. Moreover, the difference between the mean load and the real load increases as the closer to gate time increases.

IV. SPECIFIC TECHNICAL AND ECONOMIC CHALLENGES IN ISOLATED SYSTEMS (CYPRUS CASE)

This part of the paper discusses the technical and economic challenges SOs (TSOs) may face in operating isolated power systems with high concentrated amounts of wind power generation. The previous wind power impact studies [3, 6, 7, 11-13, 18, 19] emphasized that in the case of highly interconnected systems where the partial unpredictable variability in the system can be smoothed using hydro power plants having storage capability, together with high dispersion of the wind farms in the system, no significant increase can be observed in the balancing cost due to an increase in secondary reserve availability. However, significant differences were observed in the amount of increase in reserve and balancing cost respectively, from one study to another. These differences were mainly linked to system particularities (e.g., generation mix, total capacity installed compared to the peak load demand, dispersion of the wind farms and their wind profiles) and the assumptions made in the studies.

In general, the isolated power systems are small to medium size systems, where the generation mix is not very diverse, depending on the natural and economic resources of the island. It is more likely to have concentrated wind generation in sites with high wind potential, as well as due to the dimension of the geographic area the power system covers. In isolated power systems the reliability of the system is the main driven objective along with the economic and environmental benefits of wind power generation [20, 21]. Power fluctuations may affect the operations of the electric power system, as it was shown in the previous section. They may also impact the participation of wind power in the bulk-power market [20] by affecting its ancillary-services requirements in a competitive business environment.

In order to evaluate the technical and operation challenges isolated power systems may face when a high share of variable generation takes part in the power load balancing process, a study on the future architecture of the power grid of Cyprus was conducted. Cyprus is a country-island in the Mediterranean Sea. Its population is approximately 800 thousand inhabitants, reaching more than 1.5 million during the summer months due to the influx of tourists. Naturally, the maximum power demand in Cyprus appears in the summer. Hence, the power demand difference between summer and winter is large, reaching a coefficient of variance of 0.246. The characteristics of the system are described in Tables IV and V. In Cyprus there are currently three power stations (PSs) owned and operated by the Electricity Authority of Cyprus (EAC) and one independent power producer/self producer (IPP). At present, the power generation mix is formed by steam turbines (ST), gas turbines (GT), and internal combustion engines (IC) and a combined cycle (CC).

TABLE IV
CYPRUS POWER SYSTEM: SEASONALITY OF LOAD DEMAND IN 2008

Period	*P* (MW)	*Q* (MVAr)	*S* (MVA)	pf
Winter Peak	908.08	278	949.68	0.956
Spring Off-Peak	282.45	-81	293.83	0.961
Summer Peak	1024.48	466.13	1125.54	0.933
Autumn Off-Peak	290.6	-93	305.12	0.952

The wind power capacity to be installed (agreed for operation) in Cyprus by 2011 is around 455 MW. The wind capacity is clustered in three major regions as can be seen in the simplified single line diagram of the system (Fig. 6). The three clusters of wind farms (WF) are divided as follows: one in the Pafos–Limassol (PL) region with a total installed capacity of 118 MW and two in Larnaca-Lefkosia (LL) region (one of installed capacity 311 MW and one of 26.5 MW).

TABLE V
GENERATION AND LOAD CHARACTERISTICS IN CYPRUS (CURRENT AND PROJECTED)

Year	Wind approved to operate (MW)	Controllable electricity sources (MW)	Min. annual load (MW)	Max. annual load (MW)	Wind penetration level (%)
2008	0	1181	282	1010	0
2011	455	2412	320	1107	35.7

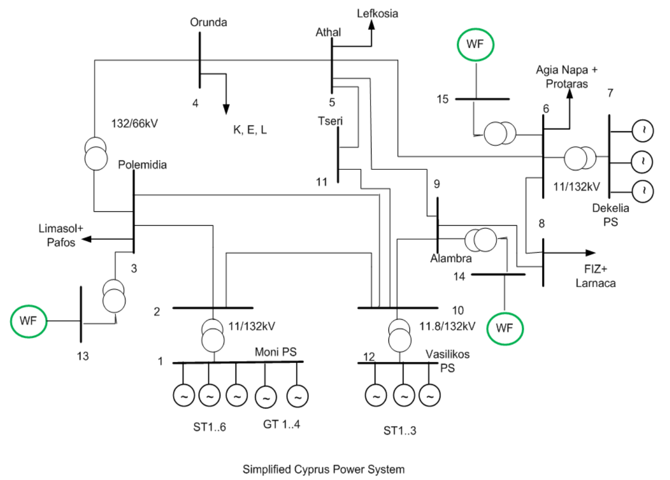

Fig. 6 Single line diagram of the power system of Cyprus

This study assumed the following: all the wind farms have only 2 MW wind turbines and their production is proportional to the sum of the power output of all wind turbines in the wind farm; and, the wind power production was calculated by fitting real measurements of the wind speed to the power curve for a commercial 2 MW turbine; four representative periods were analyzed: summer and winter peak load periods and spring and autumn valley load periods for one year.

The analysis was carried out using the open source version of the WILMAR stochastic optimal unit commitment and economic dispatch program [22]. The study distinguishes between two major cases: the case when it is supposed that the wind will not participate in the load balancing process (*NoWind* case: this is the current status in Cyprus), and the case when wind shares a large amount of load in the system (*withWind* case). A detailed description and analysis of results can be found in [23]. A summary of the most important results is given below.

There might be cases when wind shedding will be necessary (Fig. 7) due to stability reasons. This case appears mainly during the valley load periods, when there is a good wind potential, but less load demand. Cyprus does not have water resources and there are no operational hydropower plants or any other form of economic storage available. Being an isolated power system, no import/exports take place with any other power system.

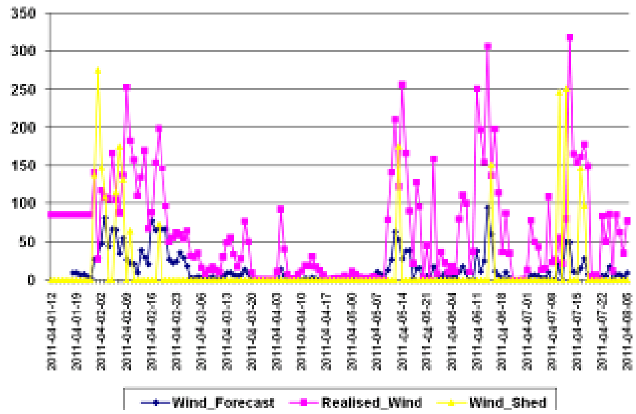

Fig. 7 Wind shedding in the period of valley-load in the one region of Cyprus (*withWind* case)

It was observed that there is an increase in the change in loading (Figs. 8 and 9), of the load following units (fast gas turbines) for the case *withWind* compared with the case when the variability of wind power generation was not present in the system. Thus, an increase in the stress of the unit may appear, and consequently a decrease in the maintenance period. Therefore, an increase in the cost of operation may occur.

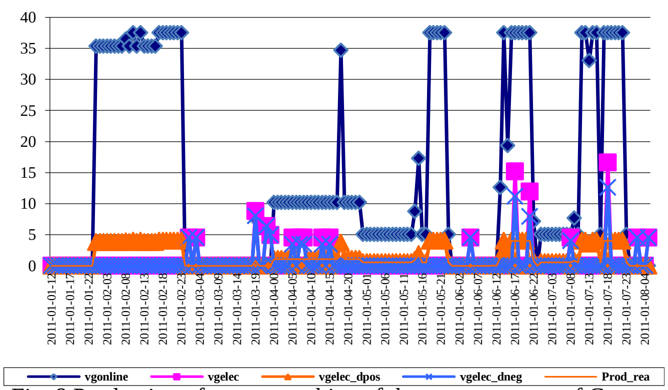

Fig. 8 Production of one gas turbine of the power system of Cyprus (No*Wind* case). The dark blue line marks the loading of the gas turbine during one day with valley-load demand

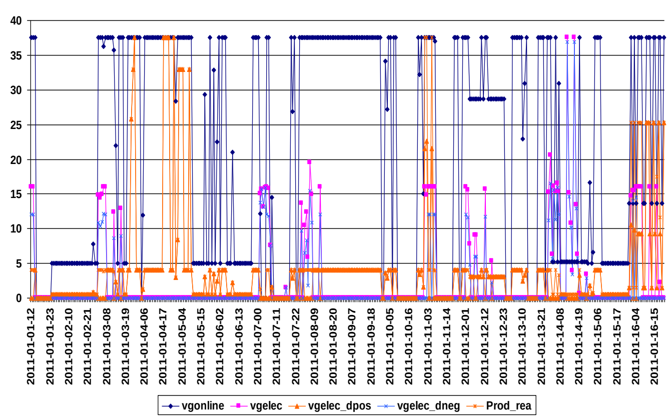

Fig. 9. Production of the GT1 unit from Moni power station (*withWind* case).The dark blue line marks the loading of the gas turbine during the same day with valley-load demand from Fig.8

There is a difference in balancing reserve between the case *withWind* and the case *NoWind*. More than this, there is a difference between the percentage of increase in the case *withWind* during the peak load and the case *withWind* during the valley load demand. Thus, during peak load periods a 10% increase in reserve margins is necessary, while a 20% increase is required for the valley-load periods in the scenario *withWind.*

Figure 10 presents the increase in spinning (secondary and tertiary) reserve with the forecasting horizon, for the case *withWind*, and for two different loading levels of the system (peak load demand and valley load demand).

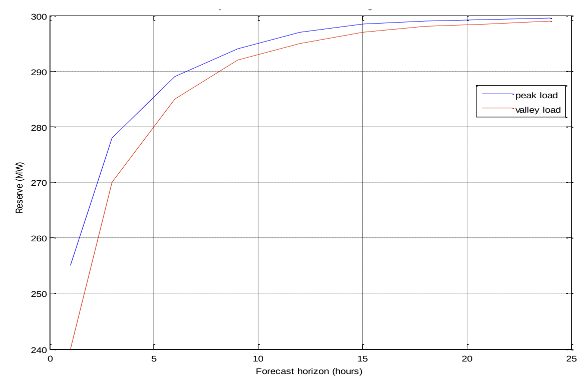

Fig. 10 Estimation of spinning reserve needs (*withWind* case)

V. Conclusions

This paper presents aspects related to the operation of isolated power systems with a high share of renewable generation, considering legal, economic, and technical issues. Electricity market models are discussed in relation to the wind generation status in the economic dispatch process: priority to the dispatch, exemption from penalties if they deviate from the schedule, role of wind farms as dispatchable or undispatchable units in the balancing market.

With respect to the closer to gate time impact on the solution of dispatch, it is observed that the solution depends heavily on the accuracy of load prediction. Therefore, as long as the forecasting procedure is called as near as possible to the economic dispatch run, a more accurate solution will be obtained. On the other hand, when less accurate data are used (e.g., the mean load data scenario), more energy from expensive generators will be used as an effect of the regulation action (for automatic control regulation units) to keep the system generation-load balance.

The study also emphasizes that the limited flexibility of the isolated power systems will be reflected in a higher increase in the need for spinning and operational reserves compared to large interconnected systems (e.g., between 10 and 20% increase in reserve for a 10% wind penetration for the isolated power system of Cyprus, compared to 2-3% increase in reserve in the case of the NordPool Scandinavian power system). This fact will have higher balancing cost consequences (economic issue) as well as higher maintenance costs for the fast units which ensure the balancing process (aspect which was not yet taken into account in the majority of the wind impact studies).

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