The Impact of Load-Following Reserve Requirement Levels on the Short-Term Generation Scheduling

Emmanouil A. Bakirtzis, Student Member, IEEE, Pandelis N. Biskas, Senior Member, IEEE, and Anastasios G. Bakirtzis, Fellow, IEEE

Abstract—This paper studies the effect of load-following reserve requirement levels on the short-term power system scheduling. To this purpose, a rolling unified unit commitment-economic dispatch model is used. The model performs economic dispatch with up to 36-hour look-ahead capability including unit commitment revision and uses variable time resolution to contain computational requirements. A load-following reserve determination method that uses the standard deviation of the forecast error, applied to the particularities of the rolling, variable time resolution unit commitment model, is presented. The proposed model is tested under various reserve requirements via annual simulations of the Greek Interconnected Power System short-term operations using real 2013 data. The effect of the load-following reserve levels on system performance indices are calculated and discussed.

Index Terms—multiple time resolution, renewable generation, reserves, rolling unit commitment

I. NOMENCLATURE

A. Indices and Sets

\[ f \in F \] steps of the marginal cost function of unit \( i \).
\[ i \in I \] generating units (fast and slow); \( I = I^{\text{fast}} \cup I^{\text{slow}} \)
\[ t \in T \] time intervals (of variable duration).

B. Parameters

\[ B_{if}(C^e_{it}) \] quantity (price) of step \( f \) of unit \( i \) marginal cost function, in time interval \( t \), in MW (€/MWh).
\[ C^\text{up}(dn)_{it} \] start-up (shut-down) cost of unit \( i \), in €.
\[ C^r(\text{r}=)_{it} \] upward (downward) reserve price of unit \( i \), during time interval \( t \), reflecting the additional cost incurred by the unit to provide reserves, in €/MWh.
\[ C^{\text{VLL}} \] value of lost load, considered 25,000 €/MWh.
\[ C^{\text{VLW}} \] value of lost wind power, considered 150 €/MWh.
\[ \Delta_t \] duration of time interval \( t \), in hours.

\[ P_{i}^{\text{max(min)}} \] maximum (minimum) power output of unit \( i \), MW.
\[ P_{i}^{\text{syn}(\text{dis})}_{\text{crit}} \] power output of unit \( i \), at synchronization (desynchronization) phase, during time interval \( t \), that starts (shuts down) at time interval \( t \), in MW.
\[ P^{\text{(w),for}}_t \] System load (wind power) forecast during time interval \( t \), in MW.
\[ P_{\text{sched}}^t \] System total aggregated power schedules (imports minus exports minus pumping) during time interval \( t \), in MW.
\[ R_{i}^{\text{up}(dn)} \] ramp-up (ramp-down) rate of unit \( i \), in MW/hour.
\[ R_t^{(\text{+}(-)}) \] system requirement in upward (downward) reserve during time interval \( t \), in MW.
\[ T_{i}^{\text{syn}(\text{des})} \] synchronization (desynchronization) time of unit \( i \), at time interval \( t \), in time intervals.

C. Variables

\[ a_t^{(w)} \] load shedding (wind power curtailment), during time interval \( t \), in MW.
\[ \phi_{it} \] portion of step \( f \) of the marginal cost function of \( i \)th unit, loaded in time interval \( t \), in p.u.
\[ p_{it} \] power output of unit \( i \) during time interval \( t \), in MW.
\[ p^\text{syn(\text{des})}_{it} \] power output of unit \( i \) during the synchronization and soak (desynchronization) phase, at time interval \( t \), in MW.
\[ r_t^{\text{+}(-)[\text{\text{\text{\text{s}}}}} \] contribution of unit \( i \) in upward (down) [non-]spinning reserve, during time interval \( t \), in MW; binary variable which is equal to 1 if unit \( i \) is on during time interval \( t \).
\[ u_{it} \] binary variable which is equal to 1 if unit \( i \) is in synchronization (desynchronization) operating phase, during time interval \( t \).
\[ u^\text{disp}_{it} \] binary variable which is equal to 1 if unit \( i \) is in dispatchable operating phase, during time interval \( t \).
\[ u_{it}^{\text{ns}} \] binary variable which is equal to 1 if unit \( i \) provides non-spinning reserve, during time interval \( t \).
\[ y_{it}(z_{it}) \] binary variable which is equal to 1 if unit \( i \) is start-up (shut-down) during time interval \( t \).

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II. INTRODUCTION

POWER generation needs to be scheduled several hours before real time delivery [1]. Since the deregulation of the electricity sector, the short-term scheduling of power systems has, therefore, been based on a two-level settlement scheme comprising a day-ahead forward market (DAM) and a real-time market (RTM) [2] supplemented by additional reliability functions, such as the Reliability Unit Commitment (RUC) which uses ISO load forecasts instead of demand entities bids. However, the large penetration of renewable energy sources (RES) in the generation mix challenges the adequacy of the traditional practices owing to the uncertain and variable nature of the primary energy sources (e.g. wind speed and solar radiation). To face the increased uncertainty and variability, System Operators (SO) in the US have already begun to restructure their short-term operations by using frequently updated forecasts [3], maintaining increased reserve levels [4], including rolling RUC with hourly granularity [3] and faster markets for fast-start unit commitment [5]. Real-time dispatch with look-ahead capabilities (e.g. next hour) [5]-[6] and fast-start unit commitment [7] are also implemented to manage the forthcoming wind energy variations.

Several scheduling concepts aiming to face increased uncertainty have been presented in literature. The effect of RES generation is examined in multiple time frames of the short-term power system operations simultaneously in [8]. In [9] and [10] rolling deterministic unit commitment models are presented with hourly and sub-hourly resolutions respectively. Motivated by these trends and considering both current operations practice and research findings, the authors in [11] have presented a novel deterministic model that unifies the unit commitment and economic dispatch functions (UUCED) in a rolling real-time tool that uses variable time resolution and a scheduling horizon of up to 36 hours to better accommodate large amounts of RES generation.

Accurate determination of the reserve requirements is crucial for the reliable and economic operation of power systems and considerable research effort has been already devoted towards this goal. In [12]-[14] the load, the conventional generation and wind generation are considered uncorrelated variables and convolution is used to determine the reserve amount for different target LOLP values. In [15] modern SO practices were presented and in [16] a probabilistic approach, using the standard deviation to calculate reserves, was proposed. In all the above research the reserve calculation methods implied the use of static (not rolling) and constant time resolution UC models. A novel UC formulation is presented in [17], where, instead of energy blocks, the output power is modeled as a continuous function (piece-wise linear). The formulation represents in detail the scheduling of operating reserves, in order to obtain a more efficient energy and reserves schedule.

In this paper we examine the effect of different reserve levels on the rolling power system short-term scheduling under high renewable penetration. To this purpose, a variable time resolution unified unit-commitment-economic dispatch (UUCED) model is presented. The model was introduced in [11], however the implications of using a rolling, variable time resolution scheduling on the reserve requirements were not addressed. To this purpose, a detailed probabilistic method using the standard deviation for quantifying the load-following reserve requirement levels, adapted to the particularities of the UUCED model (rolling execution, variable time resolution) is presented here. Finally, the UUCED model is tested under various reserve requirements via annual simulations of Greek Interconnected Power System short-term operations using real 2013 data. The effect of reserve levels on dispatch costs, system marginal price, energy balances, wind power curtailment and unit cycling are calculated and thoroughly discussed.

The remainder of the paper is organized as follows: Section III provides a description of the variable time resolution unified unit commitment-economic dispatch model. The reserve quantification method is described in Section IV. Section V presents the test cases and results and, finally, conclusions are drawn in Section VI.

III. UNIFIED UNIT COMMITMENT ECONOMIC DISPATCH

A. UUCED description

The unified unit commitment-economic dispatch model (UUCED) integrates the short-term scheduling with the real-time operation into a single real-time tool that uses a scheduling horizon of up to 36 hours to better manage the uncertain nature of renewable generation. Variable time resolution is used in order to contain the computational requirements. The commitment and dispatch decisions of the first scheduling interval are binding (dispatch instructions), while the remaining dispatch schedule is advisory. This unified approach increases the flexibility of the generation fleet by allowing unit re-commitment and re-dispatch for the entire scheduling horizon. The binding dispatch and commitment decisions of the first intervals are very robust, since they are taken in anticipation of forecasted system conditions for an extended scheduling period.

1) Length of the Scheduling Horizon

The length of the scheduling horizon varies from 12h to 36h, depending on the starting point during the day, as shown in Fig. 1, where it is assumed that the generating units submit techno-economic data (complex bids) to the SO at 11:30 every day.

![Figure 1. Length of the scheduling horizon for different starting points during the day.](image)

2) Variable Time Resolution

Load and wind forecasts are more accurate for short lead times [18]. Therefore, adopting finer time resolution near real-
time, results in lower frequency regulation requirements since wind power and demand variability can be better captured with smaller dispatch intervals. Using, however fine resolution over the entire scheduling horizon (i.e. 36 hours) would cumber the optimization with unnecessary computational burden, since wind forecasts tend to be rather inaccurate for long lead times. These opposing needs lead to a variable time resolution compromise whose basic concept is described in [11]. Fig. 2 illustrates all possible combinations of the variable time resolution horizon depending on the specific 15-min interval of hour h that the scheduling begins. In order to modify the scheduling horizon from a constant time-step to a variable time-step framework, the time constants that are usually used in a typical unit commitment model (e.g. unit minimum up/down time, etc.) need to be converted from minutes (or hours) to variable time intervals and become functions of the current time interval, as detailed in [11].

<table>
<thead>
<tr>
<th>0:00</th>
<th>0:15</th>
<th>0:30</th>
<th>0:45</th>
</tr>
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<tbody>
<tr>
<td>15</td>
<td>15</td>
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<td>30</td>
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<tr>
<td>15</td>
<td>15</td>
<td>15</td>
<td>15</td>
</tr>
</tbody>
</table>

Figure 2. Definition of the variable time intervals

B. Mathematical Formulation of the UUCED

In this section the UUCED is formulated as a MILP optimization problem, as follows. It is noted that the uncertainty drivers considered in this work are load and wind power for each time interval, as detailed in [11].

1) Cost definition equations

\[
\begin{align*}
\text{Minimize} & \quad \sum_{t \in T} \left[ \Delta_t \cdot \left( \sum_{f \in F} C_{ij}^{\text{ij}} \cdot B_{ij} \right) + C_{ij}^{\text{up}} \cdot y_{it} + C_{ij}^{\text{dn}} \cdot z_{it} \right] + \Delta_t \cdot \left( C_{ij}^{\text{vl}} \cdot a_{i}^{l} + C_{ij}^{\text{vlw}} \cdot a_{i}^{w} \right) \\
& \quad + \sum_{t \in T} \left[ \Delta_t \cdot \left( \sum_{f \in F} \left( C_{ij}^{\text{ij}} \cdot B_{ij} \right) \right) \right] \\
& \quad + \sum_{t \in T} \left[ \Delta_t \cdot \left( \sum_{f \in F} \left( C_{ij}^{\text{ij}} \cdot B_{ij} \right) \right) \right] \\
& \quad + \sum_{t \in T} \left[ \Delta_t \cdot \left( \sum_{f \in F} \left( C_{ij}^{\text{ij}} \cdot B_{ij} \right) \right) \right] \\
\end{align*}
\]

Subject to:

\[0 \leq \beta_{ij} \leq 1 \quad \forall i \in I, f \in F, t \in T\]

Objective function (1) aims to minimize the cost which is a function of the units’ step-wise marginal cost, start-up and shutdown cost, the cost of unserved energy and the wind power curtailment cost. Constraints (2) and (3) define the power output of the unit as a function of the variables \(\beta\), which express the portion of the step \(f\) of the unit’s marginal cost function loaded during interval \(t\).

2) Logical state of commitment

\[
\begin{align*}
\text{Constraints} (4) & \quad \text{ensure that if unit } i \text{ is online, only one of the commitment states is allowed. Constraints (5) relate the start-up and shut-down status of unit } i, \text{ with its commitment status. Constraints (6) ensure that start-up and shut-down do not coincide.}
\end{align*}
\]

3) Synchronization / desynchronization phase constraints

\[
\begin{align*}
\text{Constraints (7) ensure that unit } i \text{ is in synchronization and soak phase during time interval } t, \text{ if it incurred start-up during the prior } T_{i}^{\text{syn}} \text{ intervals. Constraint (8) determines the power output of unit } i, \text{ during the synchronization phase in terms of } P_{i}^{\text{syn}}. \text{ Similarly constraints (9) and (10) model the desynchronization phase of unit } i.}
\end{align*}
\]

4) Minimum up/down constraints

\[
\begin{align*}
\text{Constraints (11) ensures that unit } i \text{ remains online during interval } t, \text{ if it started-up within the previous } T_{i}^{\text{up}} \text{ intervals. Constraint (12) ensures that unit } i \text{ remains offline if it was shut down within the previous } T_{i}^{\text{dn}} \text{ intervals.}
\end{align*}
\]

5) Ramp up/down constraints

\[
\begin{align*}
\text{Constraints (13) and (14) enforce the unit ramp-rate limits. The last terms of both constraints relax the ramp-rate limits during synchronization, soak and desynchronization phase.}
\end{align*}
\]

6) Power output constraints

\[
\begin{align*}
\text{Constraints (15) - (16) constrain the unit power output and reserve commitment within the unit capabilities. The first two terms of the right hand side of the equations constrain the power output during synchronization and desynchronization phase with the help of (8) and (10).}
\end{align*}
\]

7) Power balance equation

\[
\begin{align*}
\text{Constraint (17) enforces the system power supply-demand balance in all time intervals.}
\end{align*}
\]
### Reserve Requirements Constraints

\[
\begin{align*}
    r_{it}^+ &\leq 15 \cdot R_{it}^p \quad \forall i \in I, \forall t \in T \quad (18) \\
    r_{it}^- &\leq 15 \cdot R_{it}^d \quad \forall i \in I, \forall t \in T \quad (19) \\
    r_{it}^\text{ns} &\leq 15 \cdot R_{it}^p \quad \forall i \in I, \forall t \in T \quad (20) \\
    P_{it}^{\text{min}} \cdot u_{it}^\text{ns} &\leq t_{it}^\text{ns} \leq P_{it}^{\text{max}} \cdot u_{it}^\text{ns} \quad \forall i \in I, \forall t \in T \quad (21) \\
    u_{it}^\text{ns} &\leq (1 - u_{it}) \quad \forall i \in I, \forall t \in T \quad (22) \\
    \sum_{i=1}^{I} r_{it}^+ + \sum_{i=1}^{I} r_{it}^\text{ns} &\geq R_t^+ \quad \forall t \in T \quad (23) \\
    \sum_{i=1}^{I} r_{it}^- &\geq R_t^- \quad \forall t \in T \quad (24)
\end{align*}
\]

Constraints (18)-(19) define the (ramp-limited) maximum contribution of each unit to the system upward and downward spinning reserve. Constraints (20)-(22) dictate that only offline fast units can provide the non-spinning reserve. Constraints (23)-(24) ensure that the total system upward and downward reserve requirement are met.

Additional system-specific constraints, such as mandatory hydro injection constraints are modeled but not presented here for simplicity. Here it is clarified that in the simulations presented in Section V, hydro production comprises two parts: a mandatory hydro injection part (approximately 90% of the total hydro injection), which is common for all cases, and a bid-based part, where hydro units bid their hydro production in excess of their mandatory injection at a price higher than the one of the most expensive CCGT unit.

### IV. Forecasts and Reserve Quantification

Basic input to the UUCED model is the system load and wind power forecasts (\(P_{it}^{\text{w,for}}\) and \(P_{it}^{\text{l,for}}\)), as well as the reserve requirements (\(R_t^+\) and \(R_t^-\)) which must be available at the same variable length time resolution as required by the scheduling model (Fig. 2).

This section describes how these basic UUCED model inputs are computed based on historical system load and wind power measurement and forecast data of the Greek Power System. Historical measurement data are available for year 2013 on a 15-min resolution. System load and wind power forecast data are available for year 2013 on an hourly resolution. These forecasts are 24-hour static forecasts, meaning they are performed once, at 11:00 of the day preceding the dispatch day and they forecast the load of the 24 hours of the dispatch day, i.e. the forecast lead times are between 13 and 37 hours. These forecasts are used as input for the day-ahead unit commitment of the Greek System Operator.

The standard deviation of the system load and wind power forecast errors are depicted in Fig. 3 for each of 24 hours of the day. The system load is equal to the consumer load net the distributed RES generation, comprising mainly photovoltaic generation. This explains the error increase in sunshine hours 9-18 in Fig. 3. Wind power forecast error tends to have a gradual increase for longer lead times.

#### A. Load and wind power forecasts

The calculation of load and wind power forecasts (\(P_{it}^{\text{w,for}}\) and \(P_{it}^{\text{l,for}}\)) adapted to UUCED is based on the available hourly load and wind power forecasts and measurements for year 2013. The UUCED is a rolling real time model with a scheduling horizon ranging from 12 to 36 hours. The wind power forecast error tends to increase with the forecast lead time [18] based on the curve of Fig 4. Therefore the available static 24-hour day-ahead forecast errors are modified with the help of Fig. 4 in order to be adjusted to the UUCED timeline. The same approach is applied for the calculation of the load forecasts with a similar curve of Fig. 4. Note that this procedure is performed before each rolling simulation. It is noted that we assume perfect forecast for the first 5min time interval of the optimization horizon.

#### B. Reserves Requirements Quantification for the UUCED

The reserve requirements quantification method is based on load and wind power uncertainty, which increases with forecast lead time (Fig. 4). The reserve requirements (\(R_t^+\) and \(R_t^-\)) are calculated separately for each time interval of the scheduling horizon using the load and wind power forecast error mean and standard deviation values (Fig. 3) derived from the statistical analysis of the respective forecasts and measurements.

Assuming that the load and wind power errors are uncorrelated, the standard deviation of the net load (load minus wind generation) forecast error is calculated as the geometric sum of the standard deviations of the individual errors while the
mean of the net load forecast error is equal to the algebraic difference between the individual mean values as depicted in equations (25) and (26), where $\mu_t^i$, $\mu_t^w$, $\sigma_t^i$, and $\sigma_t^w$ are the load/wind power forecast error mean and standard deviation, adapted to the correct (UUCED) forecast lead time. As before, the mean and the standard deviation of the forecast error are adapted to the correct lead time with the use of the curve of Fig. 4 before they are used in (25)-(26). This procedure is also performed before each rolling simulation. The multiplier $m$ determines the reserve level, depending on the reliability policy which can be a $1\sigma$, $2\sigma$ or $3\sigma$ rule. The absolute function is used, because the forecast error mean can receive, in practice, non-zero values. Perfect forecast is assumed for the first 15min time interval of the optimization horizon, therefore, no reserves are scheduled for that interval ($R_{t=1}^R = R_{t=1}^W = 0 MW$).

$$R_t^\mu = \mu_t^i - \bar{\mu}_t + \sigma_t^i \sqrt{\left(\frac{1}{2}\right)^2 + \left(\frac{1}{2}\right)^2} \forall t \in T$$ (25)

$$R_t^\sigma = -\mu_t^w + m_t^w + \sigma_t^w \sqrt{\left(\frac{1}{2}\right)^2 + \left(\frac{1}{2}\right)^2} \forall t \in T$$ (26)

V. TEST CASES AND RESULTS

The UUCED model is tested under various reserve requirements via annual simulations, in order to examine the effect of different reserve levels on the Greek power system operation. The annual simulations require that UUCED is executed on a rolling basis, every 15 minutes, resulting in a total of 35,040 rolling simulations, a sufficient number to draw solid conclusions. The dispatch and commitment decisions of the first 15-minute time interval of a certain run are binding and, therefore, are used as initial conditions for the next run and so on. The load and the wind power forecasts (along with reserve levels) are updated every 15 minutes, before each simulation. Refreshing forecasts in such frequency may not be the current Greek TSO practice, but it is very likely to become in the near future due to the increased RES penetration.

The total energy demand (net distributed RES generation) of the Greek Interconnected Power System during 2013 was 46,569 GWh, the total wind production was 3,347 GWh, the total energy export was 3,898 GWh, the total energy import was 5,754 GWh and the total energy used for pumping was 49.3 GWh. It is mentioned that we want to test the models on future scenario with increased wind penetration, therefore we double the wind power injection (i.e. 6,694 GWh) in our simulations (both forecasts and measurements and consequently the mean and the standard deviation of wind forecast errors are accordingly doubled). Taking into account the distributed RES plants injection, this scenario refers to a 22% RES penetration, excluding hydro production, in terms of energy injected. The Greek generation fleet data are summarized in Table I. OCGT and hydro units constitute the fast units of the system.

### Table I

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Fuel</th>
<th>Number</th>
<th>Capacity (MW)</th>
<th>Marginal Cost Range (€/MWh)</th>
<th>Response Speed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam</td>
<td>Lignite</td>
<td>16</td>
<td>4,302</td>
<td>35 – 45</td>
<td>Slow</td>
</tr>
<tr>
<td>CCGT</td>
<td>Gas</td>
<td>10</td>
<td>4,209</td>
<td>81 – 90</td>
<td>Slow</td>
</tr>
<tr>
<td>OCGT</td>
<td>Gas</td>
<td>3</td>
<td>147</td>
<td>117</td>
<td>Fast</td>
</tr>
<tr>
<td>Hydro</td>
<td>Hydro</td>
<td>17</td>
<td>3,034</td>
<td>95 – 96</td>
<td>Fast</td>
</tr>
<tr>
<td>Wind</td>
<td>Wind</td>
<td>-</td>
<td>1,502</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>46</td>
<td>13,194</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

A. Test Case Description

Initially, a base case that uses perfect forecast is created as benchmark. The perfect-forecast case uses perfect load and wind power forecasts and, consequently, schedules no load following reserves ($R_t^\mu$ and $R_t^\sigma$ are zero). Regulation and contingency reserves are omitted in this study. Seven main cases are then formed, differentiated by the scheduled reserve levels. The first case schedules no reserves while the other six cases schedule reserves based on the 0.5$\sigma$, 1$\sigma$, 1.5$\sigma$, 2$\sigma$, 2.5$\sigma$ and 3$\sigma$ rule, respectively (the multiplier $m$, in (25) and (26) is set to 0.5, 1, 1.5, 2, 2.5 and 3 respectively). All test cases, their respective total and average (per rolling simulation) execution times, are summarized in Table II. All simulations were performed on Intel Core i7 processors using MATLAB [20] calling GAMS [21] calling the CPLEX [22] solver with an optimality gap equal to 0.1%.

### Table II

<table>
<thead>
<tr>
<th>Case number</th>
<th>Case name</th>
<th>Type</th>
<th>Total Execution Time (h)</th>
<th>Average Execution Time (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Perfect forecast</td>
<td>82</td>
<td>8.4</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>No reserves</td>
<td>91</td>
<td>9.3</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Reserves 0.5$\sigma$</td>
<td>100</td>
<td>10.3</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Reserves 1.0$\sigma$</td>
<td>108</td>
<td>11.1</td>
<td></td>
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<tr>
<td>5</td>
<td>Reserves 1.5$\sigma$</td>
<td>117</td>
<td>12.0</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Reserves 2.0$\sigma$</td>
<td>128</td>
<td>13.2</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Reserves 2.5$\sigma$</td>
<td>169</td>
<td>17.4</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Reserves 3.0$\sigma$</td>
<td>250</td>
<td>25.7</td>
<td></td>
</tr>
</tbody>
</table>

B. Results

Table III presents the annual production and number of start-ups per generation technology for all test cases. Lignite unit production tends to decrease, while CCGT production tends to increase with increasing reserves, which is intuitive since CCGT units are more flexible and therefore are able to provide higher amounts of reserves. OCGT production is negligible in all cases due to OCGT units’ high marginal costs. Hydro production tends to decrease with increasing reserves among cases 2-6, however an increase in observed in cases 7-8. Therefore, no solid conclusion can be drawn concerning the relation of hydro production and reserves level. Here it is clarified that hydro production comprises two parts: a mandatory hydro injection part, which is common for all cases, and a bid-based part, where hydro units bid their hydro production in excess of their mandatory injection at a price higher than the most expensive CCGT unit. Concerning the number of start-ups, it is evident that increasing reserve levels result in higher lignite and CCGT unit cycling.

### Table III

<table>
<thead>
<tr>
<th>Case number</th>
<th>Case name</th>
<th>Type</th>
<th>Total Production (GWh)</th>
<th>Number of Start-ups</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Perfect forecast</td>
<td>82</td>
<td>35,040</td>
<td>100</td>
</tr>
<tr>
<td>2</td>
<td>No reserves</td>
<td>91</td>
<td>33,374</td>
<td>90</td>
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<tr>
<td>3</td>
<td>Reserves 0.5$\sigma$</td>
<td>100</td>
<td>32,576</td>
<td>80</td>
</tr>
<tr>
<td>4</td>
<td>Reserves 1.0$\sigma$</td>
<td>108</td>
<td>31,870</td>
<td>70</td>
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<tr>
<td>5</td>
<td>Reserves 1.5$\sigma$</td>
<td>117</td>
<td>31,170</td>
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<tr>
<td>6</td>
<td>Reserves 2.0$\sigma$</td>
<td>128</td>
<td>30,470</td>
<td>50</td>
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<tr>
<td>7</td>
<td>Reserves 2.5$\sigma$</td>
<td>169</td>
<td>29,770</td>
<td>40</td>
</tr>
<tr>
<td>8</td>
<td>Reserves 3.0$\sigma$</td>
<td>250</td>
<td>29,070</td>
<td>30</td>
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</tbody>
</table>
Table IV presents the mean system marginal price (SMP), derived as the dual variable value of constraint (17), along with the number of real time intervals with negative SMP and the total wind energy curtailment for all test cases. It is evident that the mean system marginal price increases with increasing reserve levels. Total wind energy curtailment and accordingly the number of time intervals with negative SMP (time intervals where there is wind curtailment) decrease with increasing reserve levels. The above results are intuitive since high reserve levels require the operation of flexible units with higher marginal costs and, in turn, higher accommodation of wind energy can be achieved.

Table V presents the system operating costs for all test cases. Operating costs include the unit energy costs, start-up costs, load shedding costs and wind power curtailment costs. The optimal operation is, therefore, a trade-off between economic operation and security based on the value of lost load.

VI. CONCLUSIONS

The effect of load-following reserve levels on the short-term operation of power systems is examined in this paper. A rolling variable time resolution unified unit commitment-economic dispatch model is presented for this purpose, along with a probabilistic reserve determination method. The effect of reserve levels on several performance indices is examined via an annual simulation of the short-term operation of the Greek Interconnected Power System. The results show that UUCED results in most economic operation when scheduling relatively low reserve levels. The optimal operation is achieved by scheduling load-following reserves based on the 0.5σ rule, that is, equal to half a standard deviation of the forecast errors.


