Power system joint energy and reserve scheduling model considering variable speed pumped hydro storage for mitigating wind curtailment

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Abstract. The large-scale integration of wind power brings great challenges to power system secure and economic operation. In order to address this challenge, the variable speed pump storage hydropower plant (VS-PSHP) technology and demand response technology have addressed a lot attention. In this paper, the coordination of the thermal power generator, the wind power plant, the VS-PSHP and multi-type flexible loads are considered, and a day-ahead and real-time coordinated scheduling model are proposed. The proposed model can formulate the generation, contingency reserve and power distribution factor schedules simultaneously. Numerical simulation results indicate that the coordination of VS-PSHP and multi-type flexible loads can increase the system operation economic and mitigating the wind power curtailment. The results also show that the VS-PSHP is good at providing contingency reserve, and the participation of VS-PSHP can lead to a relatively lower total system operation cost compared to the participation of fixed speed pump storage hydropower plant (FS-PSHP).

1. Introduction
Since the fossil energy crisis and environmental pollution issues are increasingly severe, the development and utilization of wind power have addressed a lot attention worldwide [1]. However, due to the intermittency and uncertainty of the wind power, the large-scale integration of wind power brings a great challenge on power system secure and economic operation [2]. In order to address this challenge, various solutions are studied. Among all the solutions, large-scale Electric energy storage (EES) technology and demand response technology have been recognized as two enabling ways in supporting the current and future grid operation [3,4]. Therefore, it has important theoretical and practical significance to study
the optimal scheduling strategy for the system with large-scale EES and multi-type flexible loads.

Currently, there are various EES technologies, such as Pumped storage hydropower plant (PSHP) [5], compressed air energy storage [6], batteries [7], supercapacitors [8], et al. Each of them has its distinguished characteristics, and can offer technical and economic benefits for different application purposes. Among all EES technologies, PSHP has been considered as one of the suitable technologies for large-scale storage application [6], and it is the most widely implemented large-scale EES [9]. Conventional PSHP, also named Fixed speed pumped storage hydropower plant (FS-PSHP), normally uses a direct current excitation synchronous generator, hence its rotational speed is constant at synchronous speed [10], and that results in low power regulation ability, especially when the FS-PSHP is in pumping mode. With the improvement of the power electronics technology, the Variable speed pump storage hydropower plant (VS-PSHP), which uses the alternating current excitation synchronous generator, is rapidly developed [11]. Compared with the FS-PSHP, VS-PSHP has higher hydraulic efficiency and wider operation range in generating and pumping modes, it can even regulate power while in pumping mode [12]. Therefore, the VS-PSHP is considered to have broad prospects in development and application.

The significant research work has been conducted in the optimal operation strategy of the PSHP. Zhang and Cai proposed a low-carbon dispatch model for the power system with a VS-PSHP, and the minimum cost flow algorithm was used to establish the dispatch model [11]. Chazarra, et al proposed a mixed integer linear programming model for the hourly energy and secondary regulation reserve scheduling of a price-taker and closed-loop VS-PSHP [12]. The proposed model are used to compare the income of the plant with and without using the variable speed technology, using synchronous or asynchronous machines, with and without bypassing the frequency converter in generating mode [12]. Suul, et al presented aspects of control and operation of a VS-PSHP for integration of wind power in an isolated grid [13]. Vargas-Serrano, et al estimated the economic benefits of converting an existing FS-PSHP to a VS-PSHP in Switzerland electricity market, and the simulation results showed that after converting the FS-PSHP to the VS-PSHP, the total revenue increased about 58% [14]. Muljadi, et al provided a dynamic model of the VS-PSHP including a hydrodynamic model and generator/power converter dynamic model [15]. Perez-Diaz and Jimenez assessed the contribution of a PSHP to reduce the scheduling costs of an isolated power system with high wind power penetration [16].

At present, a significant amount of attention has been given to the demand response technology. Conejo, et al proposed an optimization model to adjust the hourly load in response to hourly electricity prices considering the price uncertainty [17]. The power system optimal day-ahead scheduling model considering the coordination of wind power and price-based demand response was proposed in [18-19]. Li, et al provided a day-ahead scheduling model for the power system with the flexible loads and batteries [20]. Liu, et al proposed a power system optimal operation method for mitigating wind power curtailment considering the participation of the flexible load which has the characteristics of interruption and time-shifting [21]. Gao, et al proposed bi-level optimal scheduling method for Air-conditioning load based on Direct load control (DLC) [22]. The flexible loads were classified based on their response characteristics in [23-24], and based on the classification, the optimal dispatch model and optimal reserve model of flexible loads were proposed in [23] and [24], respectively.

The significant research was carried out from the perspective of the PSHF and flexible loads participating in power system scheduling. However, in the above literatures, the coordination of VS-PSPH and multi-type flexible loads was not considered in the scheduling; the scheduling of PSHP mainly focus on the day-ahead time scale and the contribution of PSHP in real-time dispatch time scale was not considered; in addition, the joint optimization of generation, contingency reserve and power distribution factor schedules was not considered. Note that the contingency reserve is the idle capacity provided for unexpected generator outage [25]. The main contribution of this paper are as follows:

- The coordination of the thermal power generator, the wind power plant, the VS-PSPH, the time-shifting load (TL), the interrupt load (IL), the load which has the fast response ability and can be direct controlled (named as DLC load in the rest of the paper) are considered.
A day-ahead and real-time coordinated scheduling model for the power system with a VS-PSHP and multi-type flexible loads is proposed.

The proposed scheduling model can formulated the generation schedules, contingency reserve schedules and power distribution factor schedules simultaneously.

The rest of the paper is organized as follows. In Section 2, the day-ahead and real-time coordinated scheduling framework is introduced. In Section 3, the formulation of the joint energy and reserve scheduling model is presented. In Section 4, case studies and simulation discussions are provided. Finally, Section 5 concludes the paper.

2. Day-ahead and real-time coordinated scheduling framework

In this section, a day-ahead and real-time coordinated scheduling framework is introduced. The schematic layout of the framework is shown in figure 1.

The day-ahead scheduling is performed every 24h based on the short-term forecast data of the wind power and system load. The day-ahead scheduling is used to formulate the schedules of all scheduling resources in the next day. The time resolution of the day ahead scheduling is 15 min. The execution points of the day-ahead scheduling is 96.

The real-time dispatch is used for optimal load allocation based on the ultra-short-term forecast data of the wind power and system load. The calculation period of real-time dispatch is 15min and the time horizon is 4h. Each time resolution of real-time dispatch is 5min. In each real-time schedule, the execution points is 3.

The coordination of generators, the variable speed pump storage hydropower plant (VS-PSHP) and flexible loads are considered in the scheduling model. The scheduling characteristics of the above scheduling resources are explained as follows:

1) Generators: the generator is divided into 2 categories. One is the automatic generation control (AGC) unit and another is the non-AGC unit. The AGC unit is the generator whose power output can be controlled by the AGC system.

2) VS-PSHP: the VS-PSHP has the abilities of quick start-up and shut down, however, the operation mode of the VS-PSHP cannot be frequently switched because it can have adverse effects on the operating life time of the VS-PSHP.

3) Flexible loads: the flexible loads are divided into 3 categories: the TL, the IL, the DLC load. The TL’s operation can be scheduled any time within a given time frame for providing load-shifting service in day-ahead scheduling. The IL normally can be used for providing contingency reserve service. The schedules of the DLC load can be formulated in the real-time dispatch due to its fast response ability.

In the day ahead scheduling, the security-constrained unit commitment is performed. the
ON/OFF status of the generators are formulated, and the schedules of contingency reserve and TL are made. In order to avoid the frequent start-up and shut down of the VS-PSHP, the operation mode of the VS-PSHP is also determined in the day-ahead scheduling.

In the real-time dispatch, the schedules of DLC load, the output of generators, the output of the VS-PSHP and the power distribution factors of AGC units are determined.

3. Formulation of joint energy and reserve scheduling model

3.1 Formulation of day-ahead scheduling model

3.1.1. Objective function.

The objective function of the day ahead scheduling is to minimize power system operation cost over the next 24h. The formulation of the objective function is shown as Eq.(1). The first term account for the energy costs of generators. The second term account for the operation cost of the VS-PSHP. The third term represents the load-shifting cost of TL. The fourth, fifth and sixth terms account for the contingency reserve costs of the generators, the IL and the VS-PSHP. The final term is the penalty of wind power curtailment.

\[
\min \sum_{t \in T_d} \sum_{i \in N_G} (b_{Gi} P_{Gi,t} + u_{Gi,t} c_{Gi}) + \sum_{t \in T_d} (S_{PS,t}^G + S_{PS,t}^P) + \sum_{t \in T_d} c_{TL} (P_{TL,t}^+ + P_{TL,t}^-) + \sum_{t \in T_d} c_{PS} (P_{PS,t}^G + P_{PS,t}^P) + \sum_{t \in T_d} c_{IL} (P_{IL,t}^G + P_{IL,t}^P) + \sum_{t \in T_d} c_{wind} P_{wind,t})
\]

(1)

where \(T_d\) is the set of period in day-ahead scheduling, \(N_G\) is the set of generators, including non-AGC units and AGC units. \(b_{Gi}\) and \(c_{Gi}\) are the energy cost coefficients of generator \(i\). \(P_{Gi,t}\) is the output power of generator \(i\) at time \(t\). \(u_{Gi,t}\) is the binary variable which is used stand for the ON/OFF status of the generators (1 is ON and 0 is OFF). \(S_{PS,t}^G\) and \(S_{PS,t}^P\) are the start-up costs of VS-PSHP in generating mode and pumping mode. \(P_{TL,t}^+\) and \(P_{TL,t}^-\) are the load increment and load reduction of TL at time \(t\). \(c_{TL}\) is the load-shifting cost of TL. \(\gamma_{Gi}\), \(\gamma_{IL}\) and \(\gamma_{PS}\) are the cost coefficients of providing contingency reserve by generator \(i\), IL and the VS-PSHP. \(R_{Gi,t}^E\) and \(R_{Il,t}^E\) are the contingency reserve provided by generator \(i\) and IL. \(R_{PS,t}^E\), \(R_{PS,t}^G\) and \(R_{PS,t}^P\) are the contingency reserve provided by the VS-PSHP when it is in generation mode, idling mode and pumping mode respectively. \(c_{wind}\) is the unit penalty of the wind power curtailment. \(P_{wind,t}\) is the wind curtailment at time \(t\) in the day-ahead scheduling.

3.1.2. Constraints.

1) Power balance constraints: total power production and system load demands are balanced in each period with network loss neglected. The lift side of the equation is the total generation power of time \(t\). It is equal to the right side of the equation, which is the total load of time \(t\).

\[
\sum_{i \in N_G} P_{Gi,t} + P_{PS,t}^G + P_{wind,t} - P_{wind,t}^- = P_{load,t} - P_{load,t}^- \quad \forall t \in T_d
\]

(2)

where \(P_{PS,t}^G\) and \(P_{PS,t}^P\) are the generating power and pumping power of the VS-PSHP at time \(t\); \(P_{wind,t}\) and \(P_{wind,t}^-\) are the short term forecast data of wind power output and system load.

2) Power regulation constraints: In day-ahead scheduling, a certain amount of idle capacity have to be reserved for unexpected load or wind power output variations, so that the generation schedules can be updated for restraining the power variation in the real-time dispatch.
upward power regulation constraint is expressed by (3). This constraint is expressed by fuzzy-chance constraints. In (3), the first term is the upward power regulation reserve provided by thermal generations, the second and third terms are the upward power regulation reserve provided by VS-PSHP.

\[
Cr\{ \sum_{i=1}^{N} \min(u_{Gi,i}, P_{Gi,\max} - R_{Gi,i} - P_{Gi,i} - u_{Gi,i} \Delta_{Gi,i}) + (P_{Gi,\max} - R_{Gi,i}) \}
\]

where the first term in (3) expresses the upward power regulation capacity of the generators considering its output limit, ramping limit and the capacity reserved for providing contingency reserve service. The second and third terms (3) express upward power regulation capacity of the VS-PSHP when it is in generation mode and pumping mode. \(Cr\{ \cdot \} \) is the operator which is used to account for the confidence. \(P_{Gi,\max} \) is the upper limit of generator \(i\). \(P_{Gi,\max} \) is the upward ramping rate of generator \(i\). \(\Delta_{Gi,i} \) is the response time for the power regulation in day-ahead scheduling. \(P_{Gi,\max} \) and \(P_{Gi,\min} \) are the maximum generating power and minimum pumping power of the VS-PSHP. \(\beta \) is the confidence level. \(\tilde{\varepsilon}_{Wda,i}^{+} \) and \(\tilde{\varepsilon}_{Lda,i}^{+} \) are the negative short term forecast error of the wind power output and the positive short term forecast error of system load, respectively. In this paper, the forecast errors are expressed by the triangular fuzzy number. \(\tilde{\varepsilon}_{Wda,i}^{+} \) is expressed by \((-\varepsilon_{Wda,i}^{+}, 0, 0)\); \(\tilde{\varepsilon}_{Lda,i}^{+} \) is expressed by \((0, 0, \varepsilon_{Lda,i}^{+})\). \(\varepsilon_{Wda,i}^{+} \) and \(\varepsilon_{Lda,i}^{+} \) are the maximum negative short term forecast error of wind power output and the maximum positive short term forecast error of system load.

The downward power regulation constraint is expressed by (4). The expression of (4) is similar to the (3).

\[
Cr\{ \sum_{i=1}^{N} \min(u_{Gi,i}, P_{Gi,\max} - R_{Gi,i} - P_{Gi,i} + u_{Gi,i} \Delta_{Gi,i}) + (P_{Gi,\max} - R_{Gi,i}) \}
\]

where the first term in (4) expresses the downward power regulation capacity of the generators considering its output limit and ramping limit. The second and third terms in (4) express downward power regulation capacity of the VS-PSHP when it is in generation mode and pumping mode. \(P_{Gi,\min} \) is the lower limit of generator \(i\). \(r_{Gi}^{down} \) is the downward ramping rate of generator \(i\). \(P_{Gi,\min} \) and \(P_{Gi,\max} \) are the minimum generating power and maximum pumping power. \(\tilde{\varepsilon}_{Wda}^{+} \) and \(\tilde{\varepsilon}_{Lda}^{+} \) are the positive short term forecast error of the wind power output and the negative short term forecast error of the system load, respectively. \(\tilde{\varepsilon}_{Wda}^{+} \) is expressed by \((0, \varepsilon_{Wda}, 0)\). \(\tilde{\varepsilon}_{Lda}^{+} \) is the maximum positive short term forecast error of the wind power. \(\tilde{\varepsilon}_{Lda}^{+} \) is expressed by \((-\varepsilon_{Lda}, 0, 0)\). \(\varepsilon_{Lda}^{+} \) is the maximum negative short term forecast error of the system load [18].

3) AGC reserve constraints: The AGC reserve constraints are used to ensure that there are enough committed AGC units for power regulation in the AGC stage. The first equation is used to ensure the upward AGC reserve constraint; the second equation is used to ensure the downward AGC reserve constraint.

\[
\sum_{i=1}^{N_{AGC}} \min(u_{AGCi,i}, P_{AGCi,\max} - P_{AGCi,i} - u_{AGCi,i} \Delta_{AGCi,i}) + R_{AGCi,i}^{up} \geq R_{AGCi,i}^{down}, \quad \forall t \in T_{di}
\]

\[
\sum_{i=1}^{N_{AGC}} \min(u_{AGCi,i}, P_{AGCi,\min} + P_{AGCi,i} - u_{AGCi,i} \Delta_{AGCi,i}) \geq R_{AGCi,i}^{down}, \quad \forall t \in T_{di}
\]

where \(N_{AGC} \) is the set of the AGC units. \(u_{AGCi,i} \) is the binary variable which is used stand for the ON/OFF status of the AGC units (1 is ON and 0 is OFF). \(P_{AGCi,i} \) is the power output of AGC unit \(i\). \(P_{AGCi,\max} \) and \(P_{AGCi,\min} \) are the maximum and minimum output of AGC unit \(i\). \(R_{AGCi,i}^{up} \) is the contingency reserve provided by AGC unit \(i\). \(R_{AGCi,i}^{down} \) and \(R_{AGCi,i}^{down} \) are
the upward and downward ramping rates of AGC unit \( i \), respectively. \( \Delta t_i \) is the response time for power regulation in AGC stage. \( R_{AGC,i}^{dc} \) and \( R_{AGC,i}^{ac} \) are the expected power regulation reserve in AGC stage. \( R_{AGC,i}^{dc} \) and \( R_{AGC,i}^{ac} \) can be quantified by the high frequency component of the wind power and system load forecast value \( ^{\text{ hysteretic}} \).

4) System contingency reserve constraints: The contingency reserve should compensate the loss of the outage of a single generator in 15min. The contingency reserve is used to compensate the loss of generation outage.

\[
\sum_{i \in N_G} R_{Gi}^E + R_{Gi}^G + (R_{PSG,i}^E + R_{PSG,i}^G) \geq u_{Gi} P_{Gi,max}, \quad \forall t \in T_{da}, \forall n \in N_G
\]

where generator \( n \) is the outage generator.

5) Transmission line capacity constraints: Direct current flow method is used to calculate the transmission line flow. The transmission line capacity constraint is used to ensure the power transmission flow of each transmission line is less than its upper limit.

\[
-L_{l,max} \leq L_{l,j} \leq L_{l,max}, \quad \forall l \in L, \forall t \in T_{da}
\]

where \( L \) is the set of transmission lines. \( L_{l,max} \) is maximum transmission capacity for the transmission line \( l \).

6) Generators operating constraints: Eq.(8) ensures the upper and lower limits of power output of each generator. Eq.(9) enforces the ramping rate limits of each generator. Eq.(10) represents the limit of contingency output.

\[
u_{Gi}, P_{Gi,max} \leq P_{Gi,t} \leq u_{Gi}, P_{Gi,max}, \quad \forall t \in T_{da}, \forall i \in N_G
\]

\[
P_{Gi,t-1} \leq P_{Gi,t} \leq P_{Gi,t-1} + \Delta t_i + (1 - u_{Gi,t-1}) P_{Gi,max}, \quad \forall t \in T_{da}, \forall i \in N_G
\]

\[
u_{Gi} - u_{Gi} \leq 0, \quad \forall r: 1 \leq r - (t - 1) \leq M_{Gi}^{ON}, \forall t \in T_{da}, \forall i \in N_G
\]

\[
u_{Gi} + u_{Gi} \leq 1, \quad \forall r: 1 \leq r - (t - 1) \leq M_{Gi}^{OFF}, \forall t \in T_{da}, \forall i \in N_G
\]

\[
0 \leq R_{Gi}^E \leq \min(u_{Gi} P_{Gi,max} - P_{Gi,t}, u_{Gi} \Delta t_i r_{i,j}^{\text{ up}}), \quad \forall i \in N_G, \forall t \in T_{da}
\]

where \( M_{Gi}^{ON} \) and \( M_{Gi}^{OFF} \) are the minimum ON/OFF time of generator \( i \).

7) TL operating constraints: The maximum load increment and reduction constraints are expressed by Eq.(12). Eq.(13) ensures the electricity consumption of TL remain unchanged after the scheduling. Normally, the total schedulable load has to be within a certain range. Eq.(14) is used to model the constraint.

\[
0 \leq P_{TL,j}^* \leq P_{TL,max}, \quad \forall t \in T_{TL}
\]

\[
0 \leq P_{TL,j} \leq P_{TL,max}, \quad \forall t \in T_{TL}
\]

\[
\sum_{t \in T_{TL}} P_{TL,j}^* = \sum_{t \in T_{TL}} P_{TL,j}
\]

\[
\sum_{t \in T_{TL}} P_{TL,j} \leq P_{TL}^a \leq P_{TL,max}
\]

where \( T_{TL} \) is the set of time at which the operation of TL can be scheduled. \( P_{TL,max} \) and \( P_{TL,min} \) are the maximum load increment and reduction, respectively. \( P_{TL}^a \) is the maximum total schedulable load of TL.

8) IL operating constraints: The upper limit of the contingency reserve provided by IL is modelled by Eq.(15). Eq.(16) represents the total schedulable load constraints of IL.

\[
0 \leq R_{IL,j}^E \leq R_{IL,max}, \quad \forall t \in T_{da}
\]

\[
\sum_{t \in T_{da}} R_{IL,j}^E \leq P_{IL,max}
\]
where $R_{\text{IL},\text{max}}$ is the upper limit of the contingency reserve provided by IL. $P_{\text{IL, max}}^{\text{da}}$ is maximum total schedulable load of IL.

9) VS-PSHP operating constraints:

The water balance constraint is shown in (17), and water limits are imposed to water volume variable in all periods. The water limits constraints are shown in (18). Water balance and limits in lower reservoir are not considered in this model for the purpose of simplicity [10].

\[
v_i = v_{i-1} + \sum_{t \in T_{da}} \Delta t(q_{\text{PHS,i,t}}^G - q_{\text{PHS,i,t}}^P) \quad (17)
\]

\[
v_i \leq v_i \leq v_i, \quad \forall t \in T_{da}
\]

where $v_i$ is the water volume of the upper reservoir. $v$ and $v$ are the lower and upper water limits of the upper reservoir. $q_{\text{PHS,i,t}}^G$ and $q_{\text{PHS,i,t}}^P$ are the water discharge and pumped water at time $t$, respectively.

The generating power and pumping power can be calculated by,

\[
\begin{align*}
\rho_{\text{PHS,i,t}}^G &= 9.81 q_{\text{PHS,i,t}}^G H_{\text{PHS,i,t}} \eta_{G,i,t}^G, \quad \forall t \in T_{da} \\
\rho_{\text{PHS,i,t}}^P &= 9.81 q_{\text{PHS,i,t}}^P H_{\text{PHS,i,t}} \eta_{P,i,t}^P, \quad \forall t \in T_{da}
\end{align*}
\]

where $H_{\text{PHS,i}}$ is the water head of the upper reservoir. $\eta_{G,i,t}^G$ and $\eta_{P,i,t}^P$ are generating efficiency and pumping efficiency, respectively. The variations of the water head and the efficiencies are ignored in this model for simplicity.

The generating and pumping power limits are described by (20) and (21).

\[
\begin{align*}
\rho_{\text{PHS,i,t}}^G &\leq R_{\text{PHS,i,t}}^G P_{\text{PHS,i,t}}^G, \quad \forall t \in T_{da} \\
\rho_{\text{PHS,i,t}}^P &\leq R_{\text{PHS,i,t}}^P P_{\text{PHS,i,t}}^P, \quad \forall t \in T_{da}
\end{align*}
\]

where $u_{\text{PHS,i,t}}^G$ and $u_{\text{PHS,i,t}}^P$ are the binary variables which is used to indicate the PSHP plant is in generating and pumping modes, respectively (1 is ON and 0 is OFF).

Normally, the generating mode and pumping mode can not occur simultaneously. Eq.(22) is used to model the limit.

\[
u_{\text{PHS,i,t}}^G + u_{\text{PHS,i,t}}^P \leq 1, \quad \forall t \in T_{da}
\]

Frequent start-up, shut-down and operation modes conversion can lead to the decrease of the service life of the PSHP plant. Therefore, the minimum operating time limits in pumping, idling and generating modes are considered in the model. The minimum operating time limits are described by,

\[
\begin{align*}
M_{\text{PHSg,i,t}} &\geq M_{\text{PHSg}}^{\text{min}} \\
M_{\text{PHSi,i,t}} &\geq M_{\text{PHSi}}^{\text{min}} \\
M_{\text{PHSp,i,t}} &\geq M_{\text{PHSp}}^{\text{min}}
\end{align*}
\]

where $M_{\text{PHSg,i,t}}$, $M_{\text{PHSi,i,t}}$ and $M_{\text{PHSp,i,t}}$ are the duration that the VS-PSHP is in generating, idling and pumping modes, respectively. $M_{\text{PHSg}}^{\text{min}}$, $M_{\text{PHSi}}^{\text{min}}$ and $M_{\text{PHSp}}^{\text{min}}$ are the minimum duration that the VS-PSHP is in generating, idling and pumping modes, respectively.

Eqs.(26), (27) and (28) represent the limits of the contingency reserve provided by the PSHP plant in pumping mode, idling mode and generating mode, respectively. Since the PSHP plant has the quick start-up and shut-down abilities, the operation mode conversion process of PSHP plant is normally within 15min. Therefore, the ramping rate limits can be ignored in the contingency reserve constraints of PSHP plant.

\[
\begin{align*}
0 &\leq R_{\text{PHSg,i,t}}^E \leq P_{\text{PHSg,i,t}}^P u_{\text{PHSg,i,t}}^P, \quad \forall t \in T_{da} \\
(1 - u_{\text{PHSg,i,t}}^G - u_{\text{PHSg,i,t}}^P) P_{\text{PHSg,i,t}}^G &\leq R_{\text{PHSg,i,t}}^E \leq (1 - u_{\text{PHSg,i,t}}^G - u_{\text{PHSg,i,t}}^P) P_{\text{PHSg,i,t}}^P, \quad \forall t \in T_{da} \\
0 &\leq R_{\text{PHSp,i,t}}^E \leq u_{\text{PHSp,i,t}}^G P_{\text{PHSp,i,t}}^G - P_{\text{PHSp,i,t}}^P, \quad \forall t \in T_{da}
\end{align*}
\]

Note that, compared to the VS-PSHP, the FS-PSHP has lower generating and pumping efficiencies, and narrower power regulation range (the FS-PSHP has to maintain the rate pumping power in pumping mode). Therefore, in FS-PSHP operating constraints, the
generating and pumping efficiencies ($\eta_{G,t}$ and $\eta_{P,t}$) are relatively lower; the lower limits of generating power ($P_{PHS,min}^G$) is relatively higher; and output power limits of pumping is changed to (29).

$$P_{PHS,t}^P = u_{PHS}^P P_{PHS,rate}^P, \quad \forall t \in T_{th}$$

where $P_{PHS,rate}^P$ is the rate pumping power of the FS-PSHP.

3.2. Formulation of real-time scheduling model

3.2.1. Objective function. The objective of the real-time dispatch is minimizing the power system operation cost over the next 4h. The formulation of the objective function is shown as (30). The first term account for the energy costs of generators. The second term account for the operation cost of the DLC load. The third term represents the penalty of wind power curtailment. The fourth term accounts for the AGC regulation cost.

$$\min \sum_{t \in T_{th}} \sum_{i \in Ng} (b_i \Delta t_i + u_{G,i} c_{G,i}) + \sum_{t \in T_{th}} \varepsilon_{DLC}(P_{DLC,1}^+ + P_{DLC,1}^-)\Delta t_i + \sum_{t \in T_{th}} \varepsilon_{DLC,1} P_{DLC,1}^{cur} + \sum_{i \in N_{AGC}} \alpha_{G,i} t [E(\varepsilon_{Wt,1}^+ - \varepsilon_{Lt,1}) + E(\varepsilon_{Lt,1})]$$

where $T_{th}$ is the set of time period in real-time dispatch. $\Delta t_i$ is the time resolution of the real-time dispatch. $\varepsilon_{DLC}$ is the scheduling cost of the DLC load. $P_{DLC,1}^+$ and $P_{DLC,1}^-$ are the load increment and load reduction of DLC load at time $t$. $P_{DLC,1}^{cur}$ is the wind power curtailment in the real-time dispatch. $\gamma_{AGC,i}$ is the regulation cost of AGC unit $i$. $\alpha_{i,t}$ is the power distribution factor of AGC unit $i$. $E(\cdot)$ represents the expectation. $\varepsilon_{Wt,1}^+$ and $\varepsilon_{Lt,1}^+$ are the positive and negative ultra-short term forecast error of the wind power output. $\varepsilon_{Lt,1}^-$ and $\varepsilon_{Wt,1}^-$ are the positive and negative ultra-short term forecast error of the system load. The forecast errors of the ultra-short term are also expressed by the triangular fuzzy number. $\varepsilon_{Wt,1}^+$ is expressed by $(0.0, \varepsilon_{Wt,1}^+, \varepsilon_{Wt,1}^-)$; $\varepsilon_{Lt,1}^+$ is expressed by $(-\varepsilon_{Lt,1}^+, 0, 0)$; $\varepsilon_{Lt,1}^-$ is expressed by $(0.0, \varepsilon_{Lt,1}^-, 0)$. 

3.2.2. Constraints. 1) Power balance constraints. The

$$\sum_{i \in Ng} P_{G,i}^t + P_{DLC,1}^+ + P_{DLC,1}^- + P_{AGC,i}^t = P_{Wt,1} + P_{Lt,1} + P_{Ht,1} + P_{Rs,1} + P_{Rs,1}^{cur}, \quad \forall t \in T_{th}$$

where $P_{Wt,1}^t$ and $P_{Lt,1}^t$ are the ultra-short term forecast data of wind power output and system load.

2) Power distribution factor constraints: The power distribution factor constraints of the AGC units is shown by (32); the system power distribution factor constraints is described by (33).

$$\alpha_{AGC,i} \leq u_{AGC,i}, \quad \sum_{i \in N_{AGC}} \alpha_{AGC,i} = 1$$

3) Transmission line capacity constraints: The transmission line capacity constraints in the real-time dispatch is the same as the relative constraints in the day-ahead scheduling.

4) AGC unit operating constraints: After considering the power regulation uncertainty in AGC stage, the power output of the AGC units can be described by,

$$P_{AGC,i} = P_{AGC,i}^t + \alpha_{AGC,i} (\varepsilon_{Wt,1}^+ + \varepsilon_{Lt,1}^- + \varepsilon_{Lt,1}^+ + \varepsilon_{Lt,1}^-)$$
where $\bar{P}_{AGC_{i,j}}$ is the power output of the AGC unit $i$ at time $t$ considering the power regulation uncertainty in AGC stage.

The power output constraints of the AGC units are modelled by the fuzzy chance constraint, and these constraints are show by (35). Similarly, the ramping rate constraints of the AGC units are modelled by the fuzzy chance constraint. The ramping rate constraint are shown by.

$$\begin{align}
\Pr[|\dot{P}_{AGC_{i,j}} - \dot{P}_{AGC_{i,j-1}}| \leq \Delta_{AGC} + (1-u_{AGC_{i,j-1}})P_{AGC_{i,j-1}}] &\geq \beta, \quad \forall t \in T_n, \forall n \in N_{AGC} \\
\Pr[\dot{P}_{AGC_{i,j}} - \dot{P}_{AGC_{i,j-1}} \leq \Delta_{AGC} + (1-u_{AGC_{i,j-1}})P_{AGC_{i,j-1}}] &\geq \beta, \quad \forall t \in T_n, \forall n \in N_{AGC} \\
\Pr[\dot{P}_{AGC_{i,j-1}} - \dot{P}_{AGC_{i,j}} \leq \Delta_{AGC} + (1-u_{AGC_{i,j}})P_{AGC_{i,j}}] &\geq \beta, \quad \forall t \in T_n, \forall n \in N_{AGC}
\end{align}$$

(35)

5) No-AGC unit operating constraints: The power output constraints and ramping rate constraints of No-AGC units in the real-time dispatch are similar to the relative constraints in the day-ahead scheduling.

6) DLC load operating constraints: The maximum load increment and reduction constraints are expressed by(37).

$$\begin{align}
0 \leq P^*_{DLC,j} \leq P^*_{DLC,max}, \quad \forall t \in T_n \\
0 \leq P^*_{DLC,j} \leq P^*_{DLC,max}, \quad \forall t \in T_n
\end{align}$$

(37)

where $P^*_{DLC,max}$ and $P^*_{DLC,min}$ are the maximum load increment and reduction, respectively.

7) VS-PSHP operating constraints: The water balance constraints, water volume limits have to be considered in the real-time dispatch. In the real-time dispatch, the capacity reserved for the contingency reserve should be ensured. The generating and pumping power limits in the real-time dispatch are described by(38) and(39).

$$\begin{align}
R_{PHSG,j}^G - R_{PHSG,j}^E \leq P_{PHS,j}^G &\leq R_{PHSG,j}^G - P_{PHS,j}^G - R_{PHS,j}^E, \quad \forall t \in T_n \\
\max(R_{PHSC,j}^G - P_{PHS,j}^G - P_{PHS,j}^C, 0) + &\leq P_{PHS,j}^C &\leq \min(R_{PHSC,j}^G - P_{PHS,j}^G - P_{PHS,j}^C, 0), \quad \forall t \in T_n
\end{align}$$

(38)

(39)

4. Case study

In this section, the performance of the proposed scheduling model is illustrated. The impacts of the coordination of VS-PSHP and multi-type flexible loads on system operation costs are analysed. The system scheduling results considering the participation of the VS-PSHP and FS-PSHP are also compared in the end of this section.

4.1 Data

An eight-bus system is used for the case study [27]. The diagram of the eight-bus system is shown in figure 2. There are six generators. A wind farm and a PSHP plant are located at Bus 2. The scheduling parameters of generators are shown in table 1. The AGC units are G1, G3 and G6; other generators are no AGC units.

The scheduling parameters of the VS-PSHP are shown in table 2. In order to compare the performances of the VS-PSHP and the FS-PSHP, in this paper, a FS-PSHP whose scheduling parameters are basically the same as the VS-PSHP is set. However, since the efficiencies of the FS-PSHP are relatively lower than the VS-PSHP and the regulation ranges of the FS-PSHP are relatively narrower than the VS-PSHP. The minimum generating power and pumping power are set to be 100MW and 200MW respectively. The generating and pumping efficiencies of the FS-PSHP are set to be 86% and 88% respectively. The scheduling parameters in table 1 and 2 are selected based on the parameters in [11, 12, 20].

TL and DLC load are assumed to be located at Bus 3. The IL is assumed to be located at Bus 5. The TL are schedulable at 0:00-10:00 and 20:00-24:00. The maximum load increment and reduction of the TL are both set to be 200MW. The maximum total schedulable load of the TL is 1000MW. The load-shifting load cost of the TL is set to be 11 $(/(MW.h). The maximum load increment and reduction of the DLC are both 50MW. The scheduling cost of the DLC load is set to be 35 $(/(MW.h). The upper limit of the contingency reserve provided by IL is set to be
150 MW. The maximum total schedulable load of IL is 1500MW.h. The cost coefficient of providing contingency reserve by IL is 15 $/MW.

The forecasted load and wind power are shown in figure 3. The curves of load and wind power forecast data are coming from the real operation data. The maximum short term forecast errors of wind power output and system load are set to 30% and 10%, respectively. The maximum ultra-short term forecast errors of wind power output and system load are set to 5% and 2.5%. The confidence levels of all fuzzy chance constraints in the proposed model are set to 0.95. The unit penalty of the wind power curtailment is 80 $/(MW.h).

![Diagram of the eight-bus system](image)

**Figure 2.** The diagram of the eight-bus system

![Short term and ultra-short term forecast data of system load](image)

![Short term and ultra-short term forecast data of wind power output](image)

**Figure 3.** (a) Short term and ultra-short term forecast data of system load; (b) Short term and ultra-short term forecast data of wind power output.

**Table 1.** The scheduling parameters of generators.

| Generators | G1  | G2  | G3  | G4  | G5  | G6  |
|------------|-----|-----|-----|-----|-----|-----|
| Minimum power output (MW) | 100 | 10  | 90  | 75  | 20  | 60  |
| Maximum power output (MW)  | 300 | 100 | 300 | 220 | 200 | 300 |
| Ramp up/down rates (MW/min) | 7.8 | 6.0 | 7.9 | 6.9 | 7.8 | 8.1 |
| Start-up cost ($)          | 1600| 750 | 1400| 1700| 1200| 1500|
| Minimum ON/OFF time (h)   | 4   | 2   | 4   | 4   | 4   | 4   |
| Cost coefficient b ($/MW.h) | 20.00| 25.23| 34.75| 38.15| 30.10| 16.63|
| Cost coefficient c ($/MW.h) | 650 | 550 | 580 | 620 | 590 | 700 |
| Contingency reserve cost coefficient ($/MW) | 14.50| 13.60| 18.20| 17.50| 12.80| 16.60|
| Regulation cost of AGC units | 16.90| /   | 26.60| /   | /   | 22.40|

**Table 2.** The scheduling parameters of the VS-PSHP.
The proposed optimal joint energy and reserves scheduling problem is a mixed integer programming problem. In this paper, IBM ILOG CPLEX 12.6.3 is employed to solve the problem.

### 4.2 Results and analysis

1) Analysis of the scheduling results

The generating schedules of the six generators are shown in figure 4 (a). The generating schedules of flexible loads and the VS-PSHP are shown in figure 4 (b). The wind curtailment of each time period is also shown in figure 4 (b). The power distribution factors of the three AGC units are shown in figure 4 (c). The contingency reserve schedules of each scheduling resources are shown in figure 4 (d).

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**Figure 4.** (a) Generating schedules of the six generators; (b) Generating schedules of the flexible load, the VS-PSHP and the scheduling results of wind curtailment; (c) Contingency reserve schedules of each scheduling resources.
It can be seen from the figure 4 (a) that, G1 and G6, which have relatively lower operation costs, take a large amount of system load in a day. According to the figure 4 (d), both G1 and G6 are not used for providing contingency reserve. Therefore, during the peak time, these two generators can maintain the high generation level. In addition, both G3 and G5 are committed. G3 is mainly used for generation, however, it basically maintains the minimum power output because of the relatively high generation cost. G5 has the lowest contingency reserve cost coefficient among the generators, it is scheduled to undertake almost 21.1% contingency reserve demand of the day.

It can be observed from the figure 4 (b) that both TL and VS-PSHP has the ability of shifting the net load (the difference between system load and wind power output) from peak to valley. It can also be found in figure 4 (b) that, the DLC load are not frequently scheduled due to its relatively high scheduling cost. However, it can be used to restrain the high frequency power fluctuation during the real-time dispatch. Additionally, the total wind curtailment of the day is 12.43MW.h, and the wind curtailment basically occurs during the period of low system net load.

According to figure 4 (c), G1, which has lowest regulation cost among the 3 AGC units, undertakes a large proportion of the AGC regulation task. G3 and G6 undertake the 10.8% and 1.7% AGC regulation task of the day.

It is shown in figure 4 (d) that, the VS-PSHP is an important resource that is used for providing contingency reserve. Almost 64.4% contingency reserve demand of the day is provided by the VS-PSHP. That is mainly because 1) the VS-PSHP has fast shut down and start-up abilities so that it can change from the pumping mode to generating mode when providing contingency reserve; 2) it has lower contingency reserve cost coefficient than generators. It can also be seen from figure 4 (d) that, IL undertakes about 21.1% contingency reserve demand of the day. However, among all generators, only G5 is scheduled to provide contingency reserve. That is mainly because the IL has advantage in the cost of providing contingency reserve.

2) Impacts of the coordination of VS-PSHP and multi-type flexible loads on costs
In order to analyse the impacts of the coordination of VS-PSHP and multi-type flexible loads on system operation costs. Two extra scenarios are set: 1) scenario 1: there are no VS-PSHP at Bus 2. 2) Scenario 2: there are no TL and DLC load at Bus 3, beside, there is no IL at Bus 5. 3) In scenario3, the system is shown in figure 2. The costs of three scenarios are listed in table 3.

| Costs ($) | Scenario 1 | Scenario 2 | Scenario 3 |
|-----------|------------|------------|------------|
| Operation cost of generators | 417798 | 392844 | 359448 |
| Operation cost of VS-PSHP | —— | 4371 | 2398 |
| Load shifting cost of TL | 4121 | —— | 6446 |
| Contingency reserve cost of generators | 92431 | 35815 | 19423 |
| Contingency reserve cost of IL | 22500 | —— | 15644 |
| Contingency reserve cost of VS-PSHP | —— | 55143 | 55676 |
| Operation cost of DLC load | 10397 | —— | 2662 |
| AGC regulation cost | 16441 | 16272 | 16534 |
| Penalty of wind power curtailment | 38021 | 14255 | 994 |
| Total cost | 609109 | 525450 | 484925 |

It can be seen from the table 4, compared with the total cost of scenario 3, the total costs of scenario 1 and 2 are increased by 25.6% and 8.4%, respectively. Moreover, the wind power curtailment penalties of scenario 1 and 2 increase significantly compared with the wind power curtailment penalty of scenario 3. The results indicate that the coordination of VS-PSHP and multi-type flexible loads can increase the system operation economic and mitigating the wind power curtailment.

3) Comparison of the impact of VS-PSHP and FS-PSHP on system operation costs
In order to compare the impact of VS-PSHP and FS-PSHP on system operation costs, it is assumed that a same scale FS-PSHP is located at Bus 3. Note that, the scheduling parameters of the FS-PSHP has been introduced in Subsection 4.1. The operation costs of the system with VS-PSHP and FS-PSHP are listed in Table 4.

### Table 4. Operation costs of the system with VS-PSHP and FS-PSHPs

| Costs ($)       | VS-PSHP | FS-PSHP |
|-----------------|---------|---------|
| Operation cost of generators | 359448  | 376003  |
| Operation cost of VS-PSHP       | 2398    | 3572    |
| Load shifting cost of TL        | 6446    | 8552    |
| Contingency reserve cost of generators | 19423  | 17859   |
| Contingency reserve cost of IL  | 15644   | 19088   |
| Contingency reserve cost of VS-PSHP | 55676  | 54812   |
| Operation cost of DLC load      | 2662    | 2953    |
| AGC regulation cost            | 16534   | 16335   |
| Penalty of wind power curtailment | 994    | 1022    |
| **Total cost**                 | 484925  | 500196  |

According to the results in the table 4, after using the FS-PSHP, the system total operation cost increases about 3.1%. The operation cost of generator, VS-PSHP and load shifting cost of TL are all has a significant trend of increase. However, the penalty of wind power curtailment does not change a lot. It indicates that the participation of VS-PSHP can lead to a relatively lower total system operation cost compare to the participation of FS-PSHP. That is mainly because the VS-PSHP has wider power regulation range and higher efficiency.

### 4.3. Discussion

After the VS-PHS and demand side resources participate in power system scheduling, the wind power curtailment can be significantly decreased, and that lead to the decrease of the total power output of thermal power units. In addition, due to the decrease of the wind power curtailment, the air pollution can also be reduced.

Compared with the FS-PSHP, VS-PSHP has higher hydraulic efficiency and wider operation range in generating and pumping modes, it can even regulate power while in pumping mode. Therefore, the VS-PSHP is considered to have broad prospects in development and application. The proposed scheduling model is developed based on the day-ahead and real-time coordinated scheduling framework, which has been applied in many region power system in China. In addition, the energy and reserve joint scheduling framework has been considered as the developing trend in power system scheduling.

### 5. Conclusion

In this paper, a day-ahead and real-time coordinated scheduling model for the power system containing a wind farm, thermal power generators, a VS-PSHP and multi-type flexible loads. The generation schedules, contingency reserve schedules and power distribution factors of AGC units can be formulated simultaneously. Based on the numerical simulation results, the following conclusions can be drawn: (1) Both TL and VS-PSHP has the ability of shifting the system load from peak to valley; DLC load can be used to restrain the high frequency power fluctuation during the real-time dispatch. (2) VS-PSHP is good at providing contingency reserve due to its fast start-up and shut down abilities and relatively low contingency reserve cost; in addition, IL can also be an important resource for providing contingency reserve. (3) The coordination of VS-PSHP and multi-type flexible loads can increase the system operation economic and mitigating the wind power curtailment. (4) Since the VS-PSHP has wider power
regulation range and higher efficiency, the participation of VS-PSHP can lead to a relatively lower total system operation cost compare to the participation of FS-PSHP.

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