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Optimal Variable Renewable Energy Generation Schedules Considering Market Prices and System Operational Constraints

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Abstract: The maximization of output from variable renewable energy (VRE) sources considering system operational constraints (SOCs) is a traditional method for maximizing VRE generators' profits. However, in wholesale electricity markets, VRE participation tends to reduce marginal prices (MP) because of its low marginal costs. This circumstance, called the "merit-order effect" (MOE), reduces the generators' profits. Thus, the traditional method is possibly no longer the best and only method to maximize the generators' profits. Moreover, the VRE support schemes also affect MP, making MOE more severe. VRE curtailment can relieve MOE, but VRE output must be decreased, thereby reducing the generators' profits. This paper proposes a method to find the optimal VRE generation schedules that maximize VRE generators' profits while considering the trade-off among the VRE output, MP, and SOCs. The method combines the merit-order model and the unit-commitment model solved by the optimization tools in MATLAB. Thailand's electrical system was the test system. The result shows that VRE generators' profits from the proposed method are significantly higher than from the traditional method when the system has high wind penetration, and the generators have no support scheme. Curtailing approximately 7–10% of wind output can increase the average MP by 23.6–30%.

Keywords: merit-order effect; profit maximization; system operational constraints; unit-commitment; variable renewable energy; renewable energy support scheme

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1. Introduction

Renewable energies (RE) continue to grow in importance for electrical systems because of a rapid decline in investment costs, their use of free energy from nature and environmental friendliness [1]. RE generation resources include both dispatchable RE sources, such as hydro, and non-dispatchable RE sources known as variable renewable energies (VRE), such as solar and wind. VRE forms a substantial proportion of RE targets in many countries, including Thailand [2,3]. In wholesale electricity markets, VRE is generally prioritized for supplying electricity because of its low marginal costs (MC). A traditional method to leverage low-cost resources, i.e., VRE, is to maximize its generated electricity (output). The maximization basically considers system operational constraints (SOCs) consisting of electrical system constraints and generation characteristic constraints. However, when there is VRE proportion in the markets, the marginal price (MP) at that time is inevitably diminished. The greater the VRE output, the greater the drop in MP. Moreover, VRE generators often supply electricity uncorrelated with electricity demand because of their non-dispatchable characteristics. The output could highly exceed the demand during windy or sunny hours, contributing to very low MP (possibly zero or even negative). Therefore, VRE output affects MP during the day in both quantity and distribution form. This circumstance is called the "merit-order effect" (MOE) [4–16].

Any generators in wholesale electricity markets gain their revenue based on MP; thus, MOE contributes to reductions in the generators' revenue. Additionally, many countries around the world provide support schemes for RE generation to reach their RE targets. The common support schemes are feed-in tariffs (FIT), contract for difference feed-in tariffs

(CFD-FIT), and feed-in premiums (FIP) [17]. The RE support schemes involve prices RE offered to the market [18], which affects MP and probably makes MOE more severe.

As a result, maximizing VRE output into wholesale electricity markets cannot allow maximum profits from the generators. Selling less energy to the markets to gain high MP possibly makes more profit than selling maximum energy at low MP. Thus, VRE curtailment can relieve MOE. VRE curtailment causes a reduction in the use of wind or solar generation, despite the available wind or sunlight [18–23]. Research [11] has stated that, in the United States, the average reductions in MP for an additional percentage of VRE penetration are 0.19–0.81 $/MWh before curtailment and 0.21–0.87 $/MWh after curtailment.

There are both technical and economic reasons to curtail VRE. The technical reasons focus on maintaining electrical systems while considering SOCs. The curtailment is done by system operators. The curtailed generators could gain compensation or remuneration for their curtailed energy based on the regulations of each system. For economic reasons, VRE curtailment contributes to significant reductions in investment, requiring both grid and storage extension. The curtailment is done by both system operators to minimize system costs and generators to maximize their profits [18,21–24]. Moreover, in wholesale electricity markets, one of the generators' strategic goals is withholding the electricity generation with low marginal costs from the market to increase the MP when the MP is low. VRE generators might curtail their output following their strategic aim to maximize profits from the markets [18,25,26].

However, VRE curtailment can be problematic. Generating electricity at a level below their actual capability contributes to reductions in the generators' revenue from selling less electricity than their availability [4,7–10]. It also decreases their ability to recover their capital costs because of the reductions in the output [21]. Therefore, the method that considers the trade-off between the amount of VRE output and the MP will provide the maximum profits to the generators. Furthermore, the method needs to satisfy the SOCs.

There have been several studies dealing with VRE curtailment optimization in generation systems; both technical and economic issues were considered. One paper [22] demonstrated an analytical model that can solve a two-period unit-commitment problem considering the SOCs and a model of energy production to study the mechanisms of VRE curtailment for economic reasons. The beneficial finding was that if decisions to curtail VRE were taken by generators independently, it would result in a sub-optimal level of curtailment. However, the models were aimed at minimizing generation costs, not maximizing the profits of the generators. Another paper [18] illustrated the optimal VRE curtailment done by both system operators and VRE generators. The optimization considered the investment in system infrastructure. The compensation for curtailed generators was discussed. The study also found that optimal curtailment would be increased along with an increased share of VRE. The study pointed out the generators' profits from the compensation; however, the authors did not focus on strategic bidding to maximize VRE generators' profits.

This paper proposes a method to find the optimal VRE generation schedules, in terms of maximizing the profits of VRE generators. The total profits of all VRE generators are maximized instead of those of individual generators to avoid sub-optimal results. The method considers the trade-off among the amount of VRE output, the MP, and the SOCs. The VRE support schemes involving prices VRE offered to the market are considered. The method is the combination of the merit-order model, which is nonlinear, and the unit-commitment model, which is mix-integer and linear. The first model simulates the wholesale electricity market's operation, and the second one satisfies the SOCs. The models were solved by the optimization tools "Fmincon" and "Intlinprog" in MATLAB, respectively.

The remainder of the paper presents background knowledge about MOE, RE support schemes, and VRE curtailment in Sections 2–4. The proposed method is in Section 5. Data used in the models are in Section 6. Results and discussion are in Section 7. The conclusions are in Section 8, and references are in the last section.

2. Merit-Order Effect

In wholesale electricity markets with the current market design, the MP at a specific time is the MC of the last power plant needed to meet the electricity demands at that time. Among all generators offering their energy to the markets, VRE generators are prioritized because of their low MC. When VRE generators supply their output into the markets, the most expensive generators on the markets are driven out, and the MP is diminished. The greater the VRE output, the greater the drop in MP. Moreover, VRE generators often supply electricity with no regard for demand because of their non-dispatchable characteristics. The output could highly exceed the demand during windy or sunny hours, contributing to very low MP (possibly zero or even negative). That means VRE output affects the MP quantity and distribution during the day. This circumstance is called the "merit-order effect" (MOE). Any generators in wholesale electricity markets gain their revenue based on MP; thus, MOE contributes to reductions in generators' revenue [4–16].

Many studies confirmed that MP is declined by VRE penetration and its output. Research [27] found that the MP was decreased around 0.63 $/MWh in Germany and 0.95 $/MWh in Spain per additional percent of wind infeed. In the case of Italy, [28] proved that 1 GWh from solar and wind reduces the average MP by 2.73 $/MWh and 4.99 $/MWh, respectively. In the United States, research [11] found that the average load-weighed MP for each additional percentage of VRE penetration declined by 0.2–0.9 $/MWh (CAISO, NYISO, SPP, and ERCOT), similarly to [12], in which case it was 0.1–0.8 $/MWh (CAISO and ISO-NE). Research [29] indicated that European wholesale electricity prices had dropped by nearly two thirds since their all-time high in 2008. The largest factor depressing the prices was the expansion of VRE. VRE is expected to become competitive in energy markets. However, the competitiveness might not be enough to ensure profitability on wholesale electricity markets if the MP falls too low [30–33].

The methods to illustrate MOE are based on two main approaches: first, the development of electricity market models which simulate the operation of a wholesale electricity market and calculate the resulted MP for various scenarios; second, the regression analysis approach, which uses historical prices and generation data to quantify the actual reductions in MP for a given period. Both the approaches were combined in some studies [15].

3. Renewable Energy Support Schemes

Many countries provide support schemes for RE generation to reach their RE targets. The schemes are not only provided to VRE generators, but also other RE generators, such as biomass and hydro plants, but this paper focuses on the support provided to VRE generators. The schemes help covering the cost disadvantages faced on liberalized electricity markets [34]. However, the schemes involve prices VRE generators have offered to the markets [18] that unintentionally affect MP and probably make MOE more severe. The common support schemes are feed-in tariff (FIT), contract for difference feed-in tariff (CFD-FIT), and feed-in premiums (FIP). These support schemes have been applied in 23 out of 27 EU countries [17], and many other countries around the world. The approaches of the schemes are as follows:

- Feed-in Tariff (FIT): Generators receive a fixed price per kWh for each unit of electricity generated, differing according to the generation sources (wind, solar, etc.) [34]. The fixed prices, which are independent from the MP, are mostly determined by the government. This means that generators do not receive any revenue directly from the markets [35].
- Contract for difference feed-in tariff (CFD-FIT): Generators receive a fixed price per kWh for each unit of electricity generated. The price called the "strike" price or "reference" price is established by the government through bidding. At a specific time, generators sell their energy at the MP that can be above, below, or the same as the strike price. If the MP is equal to the strike price, then there is no further action. If the MP is below the strike price, generators will get payment on top of the MP to reach

the strike price. If the MP is above the strike price, generators have to pay back the difference [35,36].

- Feed-in premiums (FIP): Generators receive the MP from the market and an additional fixed payment per kWh on top of the MP. The fixed payment could vary according to the associated risk sharing between the generators and the public [35].

The differences in support schemes are shown in Figure 1. FIT and CFD-FIT-supported generators receive fixed revenue regardless of the MP. FIP-supported generators' revenue depends on the MP at a specific time. In wholesale electricity markets, generators need to ensure that they will be committed to selling energy; thus, they will offer the lowest prices they can accept without loss. Supported VRE generators will offer negative prices equal the support prices they receive, and VRE generators without support will offer their MC [18].

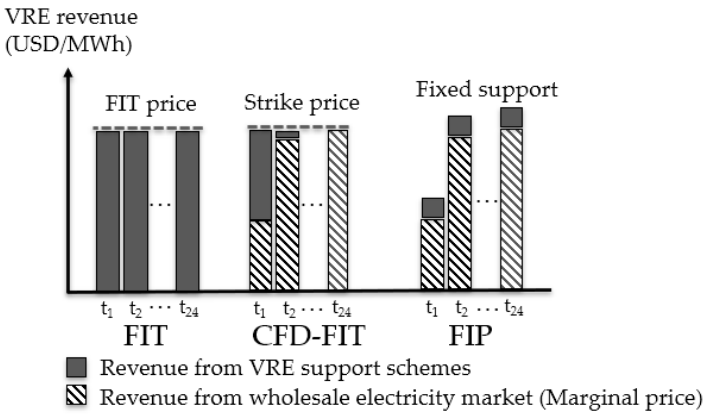


Figure 1. The differences among the support schemes.

There are other RE support schemes, such as green certificates, investment support, low interest loans, and tax exemptions [35]. The details of them depend on the policies of the countries implementing them. However, they are not directly relevant to energy selling. Such schemes are beyond the interest of this paper.

4. Variable Renewable Energy Curtailment

VRE curtailment is a reduction in the output of wind or solar generation from the output possible with the available wind or sunlight [18–23]. There is no standard method to measure curtailment. However, the common metric to measure it is as a percent of the output that the generation could have produced [21]. Many studies stated that VRE curtailment levels grow with VRE penetration [24].

There are both technical and economic reasons to curtail VRE. For technical reasons, the most common ones are to avoid insufficient transmission, local congestion, and excessive supply during low-load periods (oversupply). It is possible that these different reasons correlate in time. The curtailment called technical curtailment is done by system operators; the curtailed generators could gain compensation or remuneration for their curtailed energy based on the regulations of each system. For economic reasons, VRE curtailment contributes to significant savings in both grid and storage extension investments. Avoiding the curtailment would require investing in transmission lines and storage, which would be very costly if it were only used for a few hours per year. The curtailment called economic curtailment is done by both system operators to minimize system costs and generators to maximize their profits [18,21–24]. Moreover, MP is decreased by VRE output, as mentioned in the previous section. In markets, a small amount of capacity at the steepest part of the merit-order curve makes a significant difference in MP. One of generators' strategies in bidding is withholding electricity generation with low marginal costs from the market to increase the MP when the MP is low. VRE generators might curtail their output following their strategic bidding to maximize profits from the markets [18,25,26].

On the other hand, curtailment can be problematic, since it decreases the capacity factor of the generators. When the electricity generation is lower than intended by the design, it can be considered as a reduction in generators' revenue from selling less electricity than their capability [4,7–10]. Curtailment also decreases generators' ability to recover their capital costs because of the reductions in the revenue [21]. Compensation to generators for revenue loss from curtailment varies greatly across the U.S. and Europe [23]. For technical curtailment, the costs terms of lost generation are discussed based on MP and support levels including the rationale for compensating the curtailed energy. For economic curtailment, it is allowed without compensation [18].

5. Proposed Method

This paper proposes a method to find the VRE generation schedules that maximize the profits of VRE generators while considering the trade-off among the amount of VRE output, the MP, and the SOCs. Moreover, the VRE support schemes involving the prices of VRE offered to the market were considered. The method in this paper is the combination of the merit-order model (Section 5.1) and the unit-commitment model (Section 5.2). The first model is for optimizing VRE output, and the second one is for satisfying the SOCs. The traditional method to maximize VRE generators' profits, which is the maximization of VRE output, was also demonstrated to compare the VRE profit with the one from the proposed method (Section 5.3).

5.1. The Merit-Order Model

The merit-order model simulates the operation of wholesale electricity markets for a variety of cases. In wholesale electricity markets with the theoretically perfect competition, generators offer two parameters to the markets at a specific time: first, their capability to produce energy; second, the price they would like to sell their energy at. Generators will offer the lowest price they can accept without loss to make sure that they can be committed to selling the energy [18]. The merit-order curve over time is determined by those offers. The MP at that time is then set by the intersection of the merit-order curve and the electricity demand at the time. There is no market participant that is able to affect the MP [37]. However, in real-life situations, generators could use strategies to drive up MP to gain more profit from the markets. First, they could curtail their output (offered less energy). Second, they could offer to sell their energy at high prices. These two different approaches lead to the same results: higher MP, higher profits, and withheld output [25,26]. This paper applied the first approach into the merit-order model to illustrate the relationship between VRE output and MP. Additionally, the VRE support schemes involving the prices VRE offered to the market were included in the model. Figure 2 demonstrates the concept of the merit-order model.

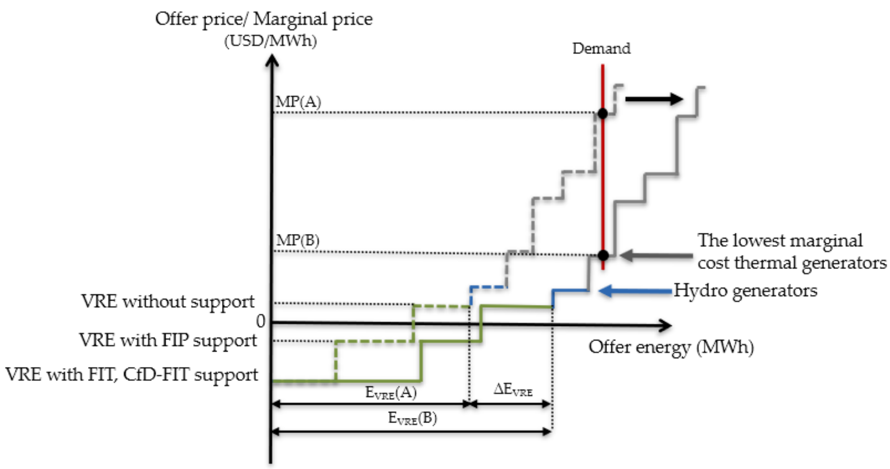


Figure 2. The concept of the merit-order model.

In Figure 2, the support schemes are classified into two types: FIP schemes where VRE generators receive the fix support price on top of the MP; and FIT and CFD-FIT schemes where VRE generators receive only the fixed price. Both types of supported VRE generators will offer the negative prices equal to the support prices they receive. VRE generators without support will offer their MC. This strategy guarantees that they can be committed to selling the energy. Moreover, even if they are the last power plant committed to supplying energy (marginal unit), the MP will be at least equal to their support prices (if they are supported) or MC (if they are not supported). Therefore, their revenue gained from both the MP and support schemes is at least zero. That means no negative revenue from selling energy is possible.

In a specific time, the MP depends on the electricity demands at that time, the energy offered by the VRE (E_{VRE}), the energy offered by other generators, and the prices offered by all other generators. Note that this paper focuses on the relationship of VRE output and MP. Thus, other parameters involved in MP, such as all thermal and hydro generators' energy offers and price, were assumed to be fixed. Their collective offered energy was assumed to be the maximum energy they could provide, and their offered prices were assumed to be their MC at their maximum capability. Lastly, consumers were assumed to not react to the MP. In Figure 2, if VRE-offered energy is increased from $E_{VRE}(A)$ to $E_{VRE}(B)$, the merit-order curve will be shifted to the right. The MP will decline from $MP(A)$ to $MP(B)$. E_{VRE} always affects the MP regardless of the support schemes the VRE generators receive because they shift the merit-order curve. Thus, a greater E_{VRE}, contributes to a greater drop in MP (MOE), whereas a low E_{VRE} means generators sell less electricity. As a result, if generators offer the optimal E_{VRE} into the markets, they will gain the maximum profits.

In the merit-order model, the objective function is the maximization of daily VRE profit. The optimal VRE generation schedules of a considered day are determined at a resolution of one hour. The total profits of all VRE generators are maximized, rather than the profits of each individual generator, to avoid sub-optimal results. All VRE generators in the system are classified into two groups based on their resources, i.e., solar and wind. Thus, any parameters relevant to VRE in this paper refer to the total values of all solar or wind generators in the system.

The VRE generators' daily profits are calculated by summing the generators' hourly revenues (*Revenue*(t)), and subtracting the generators' hourly variable costs (*VC*(t)), and their capital costs per day (*CC*), as shown in Equation (1); t is a specific time.

$$\begin{aligned} Max\,\Bigg(\bigg(\sum_{t=1}^{24} Revenue_{Solar}(t) - \sum_{t=1}^{24} VC_{Solar}(t) - CC_{Solar}\bigg) \\ +\bigg(\sum_{t=1}^{24} Revenue_{Wind}(t) - \sum_{t=1}^{24} VC_{Wind}(t) - CC_{Wind}\bigg)\Bigg) \end{aligned} \tag{1}$$

As shown in Figure 1, VRE generators that receive no support scheme will gain their revenue only from the MP. FIP-supported VRE generators will gain their revenue from the MP and the FIP support price (SP_{FIP}). FIT and CFD-FIT supported VRE generators will gain their revenue only from the FIT support price (SP_{FIT}). Both SP_{FIP} and SP_{FIT} are constants. The *Revenue*(t) is determined by summation of the MP and the support schemes (if any) multiplied by the VRE output (E(t)). The *Revenue*(t) calculations differentiated by VRE support schemes and resources are shown in Equations (2) and (3). The *MP*(t) is the function of the merit-order curve and electricity demand (D(t)) at a specific time, as shown in Equation (4).

$$Revenue_{Solar}(t) = \begin{cases} MP(t) \times E_{Solar}(t) & ;\ Solar\ generators\ without\ support \\ (MP(t) + SP_{FIP,Solar}) \times E_{Solar}(t) & ;\ Solar\ generators\ with\ FIP\ support \\ SP_{FIT,Solar} \times E_{Solar}(t) & ;\ Solar\ generators\ with\ FIT\ support \end{cases} \tag{2}$$

$$Revenue_{Wind}(t) = \begin{cases} MP(t) \times E_{Wind}(t) & ;\ Wind\ generators\ without\ support \\ (MP(t) + SP_{FIP,Wind}) \times E_{Wind}(t) & ;\ Wind\ generators\ with\ FIP\ support \\ SP_{FIT,Wind} \times E_{Wind}(t) & ;\ Wind\ generators\ with\ FIT\ support \end{cases} \tag{3}$$

$$MP(t) = Merit - order\,curve\,(D(t)) \tag{4}$$

The $VC(t)$ is the generators' hourly variable costs calculated by multiplying their marginal costs (MC) and their $E(t)$, as shown in Equations (5) and (6). CC is the generators' capital costs per day calculated, as shown in Equations (7) and (8). C is the generators' capital costs per installed capacity. $ICAP$ is the generators' total installed capacity. Note that MC, C, and $ICAP$ are constants.

$$VC_{Solar}(t) = MC_{Solar} \times E_{Solar}(t) \tag{5}$$

$$VC_{Wind}(t) = MC_{Wind} \times E_{Wind}(t) \tag{6}$$

$$CC_{Solar} = C_{Solar} \times ICAP_{Solar} \tag{7}$$

$$CC_{Wind} = C_{Wind} \times ICAP_{Wind} \tag{8}$$

The objective function is optimized, subject to the VRE resource constraints. The $E(t)$ have to be less than or equal to the VRE generation capability at the time ($Profile(t)$), which is determined by the available solar irradiance and wind speed, multiplied by the installed capacity ($ICAP$), as shown in Equations (9) and (10).

$$E_{Solar}(t) \leq ICAP_{Solar} \times Profile_{Solar}(t) \tag{9}$$

$$E_{Wind}(t) \leq ICAP_{Wind} \times Profile_{Wind}(t) \tag{10}$$

The outputs from the merit-order model are $E_{Solar}(t)$ and $E_{Wind}(t)$, which are the VRE outputs offered to the markets that provide the maximum profit to VRE generators. The time series of the VRE output during the day is herein referred to as the VRE strategic schedule. The merit-order model consisting of nonlinear multivariable functions was solved by the optimization tool "Fmincon" in MATLAB. Fmincon has an interior-point algorithm that can handle various types of nonlinear problems. Moreover, the algorithm uses little memory and can solve large problems quickly [38].

5.2. The Unit-Commitment Model

After getting the VRE strategic schedules from the merit-order model, the unit-commitment model was then used to find whether SOCs can be satisfied when VRE supplies energy follows the VRE strategic schedules. If the VRE strategic schedules contribute to the unsatisfiable SOCs in some period during the day, VRE strategic schedules will be modified by curtailing the output at the time.

The objective function of the unit-commitment model is based on the unit commitment problem (UCP) with a resolution of one hour. The UPC minimizes the daily VC of all thermal hydropower plants incurred from supply energy to support residual demand (RD), as shown in Equations (11) and (12); n is a given power plant, $nthermal$ is the total number of thermal power plants in the system, and $nhydro$ is the total number of hydropower plants in the system.

$$\text{Min}\left(\frac{\sum_{t=1}^{24}\left(\sum_{n}^{nthermal} VC_{n,thermal}(t) + \sum_{n}^{nhydro} VC_{n,hydro}(t)\right)}{\sum_{t=1}^{24} RD(t)}\right) \tag{11}$$

$$RD(t) = D(t) - E_{Solar}(t) - E_{Wind}(t) \tag{12}$$

The $VC(t)$ is calculated from the generators' MC multiplied by their $E(t)$. Equation (13) shows the calculation of the $VC(t)$ of hydropower plants, where the MC of hydropower plants are constant values. Equation (14) shows the calculation of the $VC(t)$ of thermal power plants. MC of thermal power plants depend on their incremental cost curves, which indicate the cost of producing one more MW of power from the plant. This paper treats the curve as a piecewise linear function.$MC^1_{n,thermal}$, $MC^2_{n,thermal}$, $MC^3_{n,thermal}$ are the piecewise costs from the incremental cost curve of the thermal power plant n. $P_{n,thermal}(t)$ is the output power of thermal power plant n at time t; $P^{\min}_{n,thermal}$ is minimum output power of the thermal power plant n; and $P^{R1}_{n,thermal}$, $P^{R2}_{n,thermal}$, $P^{R3}_{n,thermal}$ are ranges of piecewise power derived from the incremental cost curve of the thermal power plant n.

$$VC_{n,hydro}(t) = MC_{hydro} \times E_{n,hydro}(t) \tag{13}$$

$$VC_{n,thermal}(t) = \begin{cases} MC^1_{n,thermal} \times E_{n,thermal}(t) & ; \quad P^{\min}_{n,thermal} \le P_{n,thermal}(t) \le P^{R1}_{n,thermal} \\ MC^2_{n,thermal} \times E_{n,thermal}(t) & ; \quad P^{R1}_{n,thermal} < P_{n,thermal}(t) \le P^{R2}_{n,thermal} \\ MC^3_{n,thermal} \times E_{n,thermal}(t) & ; \quad P^{R2}_{n,thermal} < P_{n,thermal}(t) \le P^{R3}_{n,thermal} \end{cases} \tag{14}$$

The objective function is optimized, subject to the SOCs: firstly, electrical system constraints such as serving electricity demand, committing must-run units, and providing operating reserves requirement that cover demand and VRE forecast errors, along with spinning reserves requirement for contingency events fixed by the N-1 approach; second, generation characteristic constraints, i.e., minimum/maximum generation, ramp capability, minimum up/downtime, and the limitations of hydro units which depend on the amount of water reserved on the considered day. The UCP is defined to be mixed-integer programming (MIP) because it can address issues with non-convexity related to the SOCs [39]. The UCP, which is mixed-integer linear function was solved by the mixed-integer linear programming optimization tool "Intlinprog" in MATLAB.

The outputs from the combination of the merit-order model and the unit-commitment model are optimal VRE generation schedules that provides the maximum VRE profits while considering the trade-off among the amount of VRE output, the MP, and the SOCs. The MP and VRE generators' profits are then determined according to the schedules. The outputs of the proposed method are the optimal VRE generation schedules, the MP, and the VRE generators' profits that are consistent.

5.3. The Traditional Method

This paper illustrates the VRE generators' profits when using the proposed method and when using the traditional method, which is the maximization of VRE output. The UCP was also used to find VRE generators' profits and generation schedules based on the traditional method. The objective function is shown in the Equation (15). The generators' (i.e., VRE, thermal, and hydro; $D(t)$) total VC in the system was minimized; thus, the output from low MC generators, i.e., VRE, was automatically maximized.

$$\text{Min}\left(\frac{\sum\limits_{t=1}^{24} \left(VC_{Solar}(t) + VC_{Wind}(t) + \sum\limits_{n}^{nthermal} VC_{n,thermal}(t) + \sum\limits_{n}^{nhydro} VC_{n,hydro}(t) \right) }{\sum\limits_{t=1}^{24} D(t)} \right) \tag{15}$$

The constraints of the optimization are also the electrical system and the generators' characteristic constraints, such as the constraints of the unit-commitment model mentioned in Section 5.2. The UCP of traditional method was also solved by the optimization tool "Intlinprog" in MATLAB. The outputs are the VRE generation schedules, the VRE generators' profits, and the MP based on the traditional method.

Later, the outputs from the proposed method and the traditional method are compared. Moreover, we performed sensitivity analysis on VRE penetration and proportion, and the characteristics of electricity demand (workday and holiday), to find the effects of these parameters on the optimal VRE generation schedules and the maximized profits. Figure 3 shows the flow chart of the optimization and sensitivity analysis.

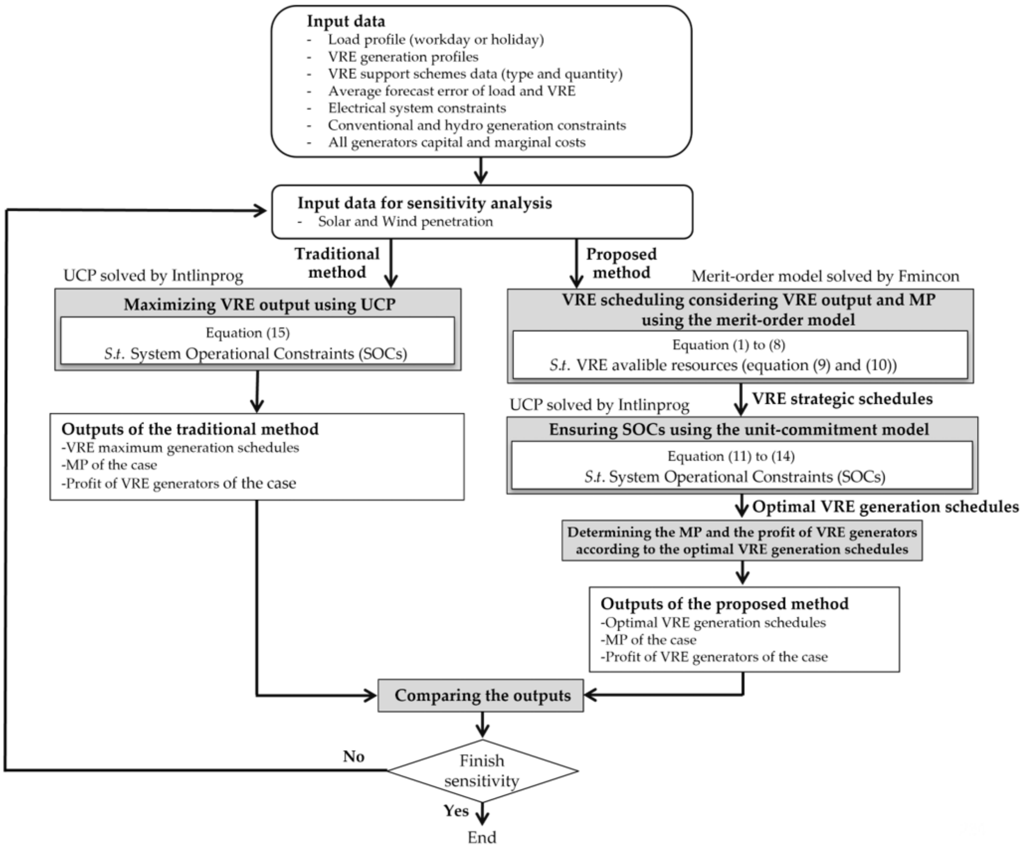
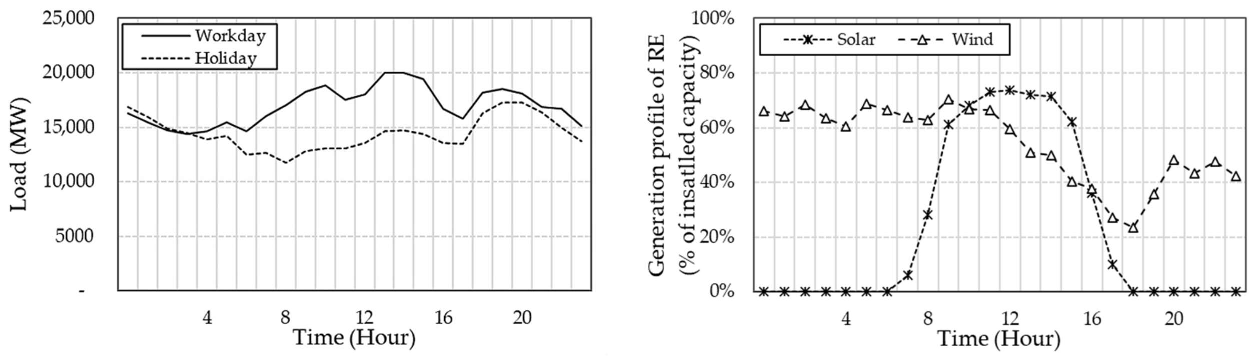


Figure 3. Flow chart of the optimization and sensitivity analysis.

6. Data

This paper used Thailand's electrical system as the sample system. Although the system has a vertically integrated structure, this paper assumed it as a liberalized structure. The load (electricity demand) profiles of both workdays and holidays, and VRE generation profiles, are shown in Figure 4. The forecast error of solar was around 12–16.6%, and that of wind was 6.7–12.4% (mean absolute percentage error, MAPE). The system has 18 hydropower plants, one thermal power plant consisting of 18 combined cycle gas turbines (CCGT) power plants, and 8 coal power plants. The generation characteristics of each power plant depend on the individual configuration. Table 1 shows a summary of the characteristics. The generation capital costs and operation costs, i.e., variable costs, startup costs, and load-following costs, are shown in Table 2. The VRE support schemes prices of many countries are collected in Figure 5.



(**a**) (**b**)

Figure 4. (**a**) Load profiles of workdays and holidays. (**b**) RE generation profiles [40].

Table 1. Summary of generation characteristics [40].

Technologies	Min. Power (%FL [1])	Ramp Up (%FL/Hr.)	Ramp Down (%FL/Hr.)	Min. Uptime (Hr.)	Min. Downtime (Hr.)
CCGT	50.00–72.02	79–100	25–100	1–5	1–5
Coal	23.91–53.28	52–100	52–100	2–23	2–23
Hydro	42.55–100.00	100	100	0	0

[1] %FL means percentage of full-load generation.

Table 2. Summary of generation costs.

Technologies	Capital Costs [1] ($/kW)	Variable Costs [2]						Startup Costs [2] ($/MW$_{installed}$)	Load Following Costs [3] ($/ΔMW)
		pw_1 ($/MWh)	pw_2 ($/MWh)	pw_3 ($/MWh)	P_{R1} (%FL)	P_{R2} (%FL)	P_{R3} (%FL)		
CCGT	-	36.97–55.45	34.85–54.55	33.94–53.64	57–91	58–92	100	6.52–95.91	0.64–1.92
Coal	-	19.70–33.64	17.88–32.12	17.27–30.61	23–87	24–88	100	6.42–57.58	2.45
Hydro	-	14.48						-	-
Solar	894	6.06						-	-
Wind	1176	12.4						-	-

[1] Capital costs of all technologies are considered as investment costs at discount rate 10%. The data were provided by [41] (Thailand is a Non-OECD country; if the analysis is used for OECD country, the discount rate would be 7% [42]). [2] Variable costs and startup costs (assumed to be all hot start) of CCGT and coal were provided by [40]. The exchange rate THB/USD was 33/1 (on 4 February 2021). The other data were from [41].[3] Load following costs were taken from [43].

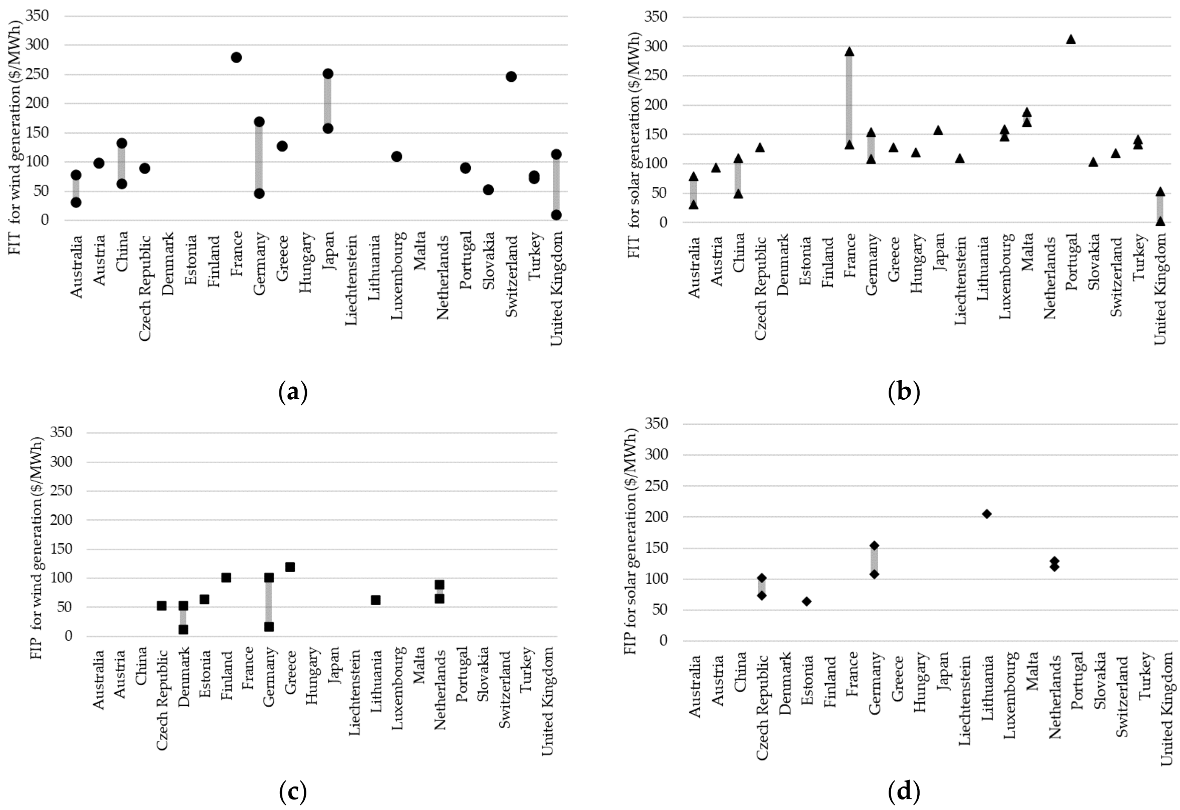


Figure 5. (**a**) FIT for wind generation data. (**b**) FIT for solar generation data. (**c**) FIP for wind generation data. (**d**) FIP for solar generation data [17,44–47].

As shown in Figure 5, some countries provide different prices depending on the installed capacity of individual generators, and some proportions are substantially higher or lower than the others; thus, we calculated the medians of the data and used them as the VRE support schemes' prices for the calculation. The medians of the data: $SP_{FIT,Wind}$, 91.24 \$/MWh.$SP_{FIT,Solar}$, 127.73 \$/MWh. $SP_{FIP,Wind}$, 64.47 \$/MWh. $SP_{FIP,PV}$, 114.41 \$/MWh.

For sensitivity analysis, seven cases of VRE penetration and proportion are shown in Table 3. VRE penetration was varied and the VRE proportion in the system was divided into three types, i.e., wind based, solar based, and mixed, to investigate effects of system configuration on the results. More VRE penetration than 15 GW is impossible because the SOCs cannot be satisfied by the existing system's configuration. All the cases were sensitivity analyzed by adjusting types of VRE support schemes and the characteristics of electricity demand, i.e., workdays and holidays.

Table 3. VRE penetration and proportions for sensitivity analysis.

		VRE Proportion	
Case	**VRE Penetration**	**Wind (GW)**	**Solar (GW)**
1	Existing	1.5	3
2	10 GW	-	10
3		10	-
4		5	5
5	15 GW	-	15
6		15	-
7		7.5	7.5

7. Result and Discussion

The method was applied to the test system to find the optimal VRE generation schedules that maximized VRE generators' profits while considering MP and system reliability. The traditional method is also illustrated to compare the results. The seven cases of the VRE penetration and proportion were sensitivity analyzed in more than 80 simulations, adjusting types of VRE support schemes and the characteristics of electricity demand, i.e., workdays and holidays. The VRE generators' daily profits and the VRE outputs from both methods during a workday and a holiday are shown in Tables 4 and 5, respectively. In the tables, the comparisons of the profit and output are presented in the "difference" columns.

Table 4. The VRE generators' daily profits and the output during a workday.

Case	VRE Support Scheme Scenarios	Wind						Solar					
		Proposed		Traditional		Difference		Proposed		Traditional		Difference	
		Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)
1	None	0.515	19.473	0.515	19.473	0	0	0.406	17.329	0.406	17.329	0	0
	FIP	1.771	19.473	1.771	19.473	0	0	2.389	17.329	2.389	17.329	0	0
	FIT	1.366	19.473	1.366	19.473	0	0	1.731	17.329	1.731	17.329	0	0
2	None	-	-	-	-	-	-	1.316	56.154	1.316	56.154	0	0
	FIP	-	-	-	-	-	-	7.741	56.154	7.741	56.154	0	0
	FIT	-	-	-	-	-	-	5.608	56.154	5.608	56.154	0	0
3	None	3.332	129.472	3.332	129.472	0	0	-	-	-	-	-	-
	FIP	11.680	129.472	11.680	129.472	0	0	-	-	-	-	-	-
	FIT	9.085	129.472	9.085	129.472	0	0	-	-	-	-	-	-
4	None	1.713	64.736	1.713	64.736	0	0	0.592	25.269	0.592	25.269	0	0
	FIP	5.887	64.736	5.887	64.736	0	0	3.483	25.269	3.483	25.269	0	0
	FIT	4.542	64.736	4.542	64.736	0	0	2.523	25.269	2.523	25.269	0	0
5	None	-	-	-	-	-	-	1.814	80.632	1.814	80.632	0	0
	FIP	-	-	-	-	-	-	11.039	80.632	11.039	80.632	0	0
	FIT	-	-	-	-	-	-	8.035	80.632	8.035	80.632	0	0
6	None	3.268	171.287	2.000	186.790	1.267	−15.503	-	-	-	-	-	-
	FIP	14.290	186.023	14.044	186.790	0.247	−0.767	-	-	-	-	-	-
	FIT	13.014	186.790	13.014	186.790	0	0	-	-	-	-	-	-

Table 4. Cont.

Case	VRE Support Scheme Scenarios	Wind						Solar					
		Proposed		Traditional		Difference		Proposed		Traditional		Difference	
		Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)
	None	2.473	97.104	2.473	97.104	0	0	0.953	42.115	0.953	42.115	0	0
7	FIP	8.736	97.019	8.734	97.104	0.002	−0.086	5.771	42.115	5.771	42.115	0	0
	FIT	6.813	97.104	6.813	97.104	0	0	4.206	42.115	4.206	42.115	0	0

Table 5. The VRE generators' daily profits and the output during a holiday.

Case	VRE Support Scheme Scenarios	Wind						Solar					
		Proposed		Traditional		Difference		Proposed		Traditional		Difference	
		Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)	Profit (MUSD)	Output (GWh)
	None	0.508	19.472	0.508	19.473	0	0	0.399	17.329	0.399	17.329	0	0
1	FIP	1.764	19.473	1.764	19.473	0	0	2.382	17.329	2.382	17.329	0	0
	FIT	1.366	19.473	1.366	19.473	0	0	1.731	17.329	1.731	17.329	0	0
	None	-	-	-	-	-	-	0.752	56.134	0.752	56.134	0	0
2	FIP	-	-	-	-	-	-	7.174	56.134	7.174	56.134	0	0
	FIT	-	-	-	-	-	-	5.605	56.134	5.605	56.134	0	0
	None	1.661	129.119	1.661	129.119	0	0	-	-	-	-	-	-
3	FIP	9.986	129.119	9.986	129.119	0	0	-	-	-	-	-	-
	FIT	9.055	129.119	9.055	129.119	0	0	-	-	-	-	-	-
	None	2.166	62.568	1.438	64.736	0.729	−2.168	1.034	27.932	0.427	28.077	0.606	−0.145
4	FIP	5.611	64.736	5.611	64.736	0	0	3.640	28.077	3.640	28.077	0	0
	FIT	4.542	64.736	4.542	64.736	0	0	2.804	28.077	2.804	28.077	0	0
	None	-	-	-	-	-	-	0.134	65.978	−0.310	66.143	0.444	−0.165
5	FIP	-	-	-	-	-	-	7.258	66.143	7.258	66.143	0	0
	FIT	-	-	-	-	-	-	6.211	66.143	6.211	66.143	0	0
	None	0.713	142.805	−0.209	165.966	0.921	−23.161	-	-	-	-	-	-
6	FIP	11.105	162.984	10.492	165.966	0.613	−2.982	-	-	-	-	-	-
	FIT	11.294	165.966	11.294	165.966	0	0	-	-	-	-	-	-
	None	1.012	92.868	1.012	92.868	0	0	0.081	32.021	−0.169	36.334	0.250	−4.313
7	FIP	7.025	91.308	7.000	92.868	0.025	−1.560	4.211	36.189	3.988	36.334	0.222	−0.145
	FIT	6.463	92.868	6.463	92.868	0	0	3.502	36.334	3.502	36.334	0	0

From Tables 4 and 5, the overview of the results is that generators' profits depend on the quantity of output and the revenue they gain from the MP and support schemes. FIP-supported generators made the most profits in most scenarios because they received revenue from both MP and support schemes. However, both FIP and FIT-supported generators made considerably greater profits than the generators without support. Wind generators' profits were generally higher than solar generators' profits with the same installed capacity and support schemes, although the capital costs and the variable costs of wind generation are higher than solar. That is because the wind generation profile is more distributable than solar, contributing to a higher capacity factor and more profits.

To illustrate the benefit of the proposed method, the "difference" columns in Tables 4 and 5 show the differences between profit and output from the proposed method and the traditional method. If there is no difference (0), it means the results from the proposed method and the traditional method were the same; maximizing the VRE output is still the method that provides the maximized profit in that situation. The results show that the VRE output of the proposed method was diverse, depending on the support schemes that involve MP and revenue. The VRE output of traditional method was the same regardless of the support schemes because the method maximized VRE output in any case.

Moreover, the results prove that VRE generators' profits from the proposed method were higher than from the traditional method in the cases of the system having high VRE penetration and low electricity demands—i.e., cases 6 and 7 for workdays, and cases 4–7 for the holidays. For example, in case 6 for workdays, the profits from the proposed method were higher than for the traditional method by $1.267 million, though the output from the proposed method was less than that from the traditional method by 15.503 GWh.

That means selling less electricity to gain high MP (the proposed method) provided more profits than continually selling maximized electricity at low MP (the traditional method). The reason is that in cases where the system has high VRE penetration, yet the electricity demand is low, the MP is greatly diminished, contributing to severe MOE. The marginal units in these situations tend to be hydro or coal power plants that have low MC; thus, it is worth curtailing some VRE output to change the marginal unit to be CCGT power plants because the MP will be significantly driven up. Therefore, the proposed method provides more VRE profits than the traditional method on holidays than workdays, because the electricity demand on holidays is lower.

Additionally, the proposed method provided more profits than the traditional method in the scenarios where VRE generators received no support and VRE generators received FIP support schemes, because their generators' profits depend on the MP. However, the proposed method provided significantly more profits than the traditional method when VRE generators received no support because MP was the only factor involved in their profits. FIT-supported generators are always maximizing their outputs (same as traditional method) because they gain a fixed price for every MWh they produce, and their profits are independent of the MP.

Furthermore, selling electricity at low MP decreases the generators' ability to recover their capital costs and leads to negative profits. The proposed method avoided negative profits in cases 5–7 of the holidays. For instance, in case 5, the profits of solar generators from traditional method were −\$0.310 million because the daily revenue did not cover the daily capital costs. The profits from the proposed method were \$0.134 million. That means curtailing 0.165 GWh avoided the negative profits and provided more than \$0.444 million in profits.

The results also showed that the differences in wind generators' profits and outputs between the proposed method and the traditional method were higher than for solar. This is because, from Figure 4, wind generation generates a high output when the demand is low, i.e., during 12 a.m. to 8 a.m.; thus, curtailing wind at the time to drive up the MP is worth it. Solar power generates electricity during daytime, i.e., 8 a.m. to 6 p.m. The electricity demand during that time is high. Thus, the MP at the time is high. As a result, selling maximal electricity provides maximized profits for solar generators, especially on working days. However, during 6 p.m. to 11 p.m., there is no curtailment of either wind or solar because the demand is high, but VRE output is low, contributing to high MP. Thus, maximized electricity production also provides maximized profits for VRE generators during that time.

The VRE optimal generation schedules and the MP of every case are presented in Tables 4 and 5. This paper presents a case where the proposed method provided greater profits than the traditional method, which is case 6, wherein VRE received no support. Figure 6 shows the optimal VRE generation schedules and the MP of that case.

Figure 6a,c shows that the wind output from the proposed method was lower than from the traditional method, contributing to a higher MP, as shown in Figure 6b,d. The outputs from the proposed method and the traditional method were higher on the holiday. The proposed method could increase the MP from the traditional method by 26.81 \$/MWh at 12 a.m. on the workday, and by 20.80 \$/MWh at 6 a.m. on the holiday. The average MP during the day was driven up to around 8.8 \$/MWh (23.6%) on the workday, and 7.9 \$/MWh (30%) on the holiday. Table 6 shows the optimal VRE output levels during a day in the unit of percent of the maximum output that generators could provide. The average VRE outputs from the proposed method and traditional method were 90% and 97% on the workday and 78% and 88% on the holiday. That means, in the case where there was high VRE penetration (15 GW) and where wind generation was the main VRE proportion, i.e., case 6—and the wind generators received no support—curtailing approximately 7% of the wind output on the workday and 10% of the wind output on the holiday could provide the maximized profits of wind generators. Note that there was no solar penetration in case 6; thus, there was no solar generation in Table 6.

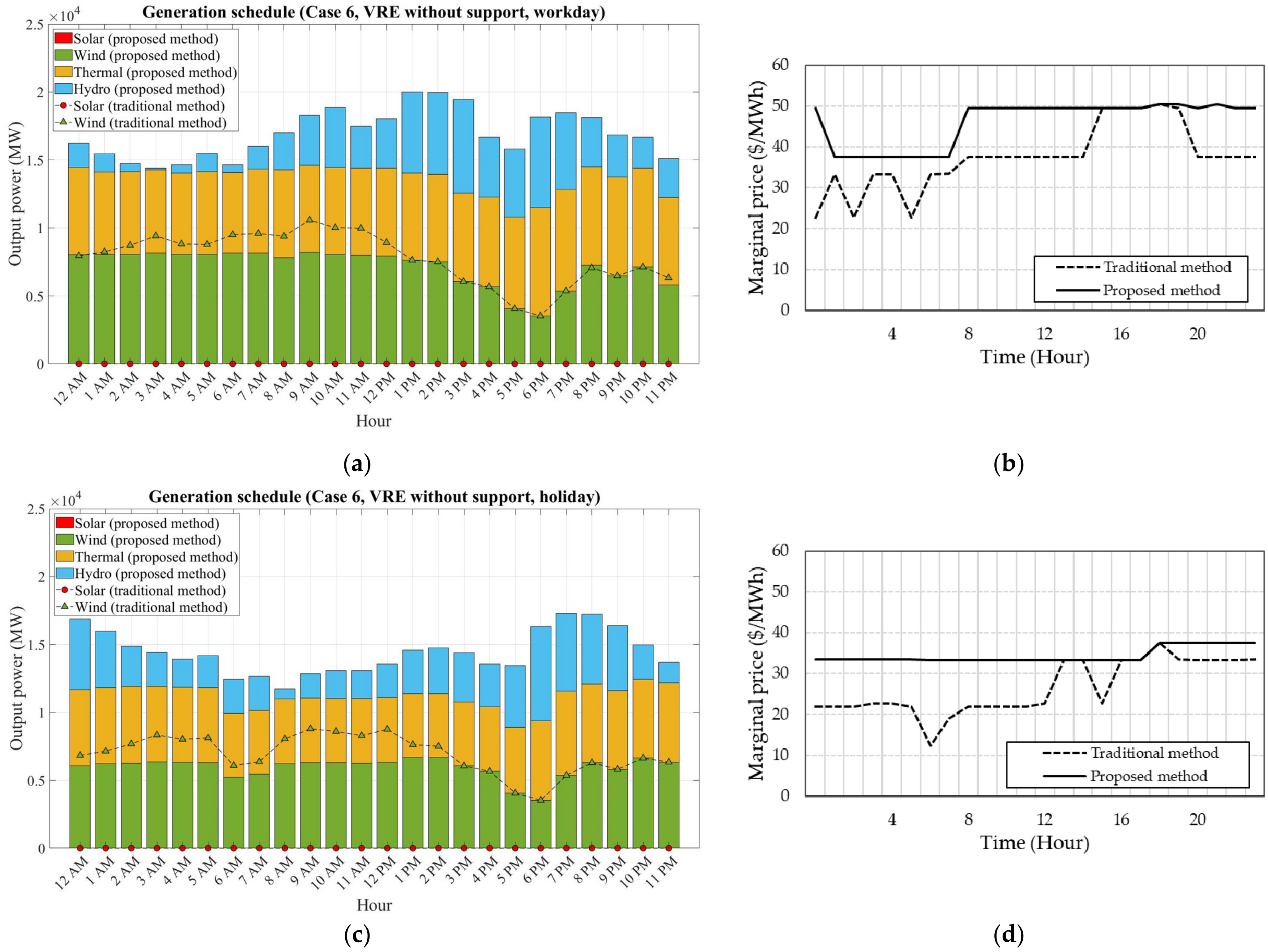


Figure 6. (**a**) The optimal VRE generation schedule on the workday of case 6, where VRE received no support. (**b**) The MP on the workday of case 6 in the in the scenario of VRE receiving no support. (**c**) The optimal VRE generation schedule on the holiday of case 6 in the in the scenario of VRE receiving no support schemes. (**d**) The MP on the holiday of case 6 in the scenario of VRE receiving no support schemes.

In all cases, VRE were not the marginal units because the VRE penetration was not enough to serve the electricity demands. More VRE penetration was impossible because of the unsatisfiable SOCs. However, if the system's flexibility is improved and more VRE can be integrated, the MP would be very low if VRE were to be the marginal unit. The MP could be equal to the VRE MC, if VRE generators are not supported, or there could be negative support prices, if VRE generators are supported. In these cases, the proposed method will show more significant benefits than the traditional method. Moreover, VRE generators can gain more revenue by using energy storage. The curtailed VRE output from the proposed method can be stored and sold back to the system during the time when electricity demand is high. However, the costs incurred from using energy storage, such as installation costs, and costs from lost energy due to the efficiency of the energy storage, must be less than the revenue to avoid negative profits.

Table 6. The optimal VRE output level during a day of case 6: the scenario of VRE without support (% of the generators' maximum output).

	Wind			
	Workday		Holiday	
Time	Proposed	Traditional	Proposed	Traditional
12 a.m.	81%	80%	61%	69%
1 a.m.	84%	86%	65%	74%
2 a.m.	79%	85%	61%	75%
3 a.m.	86%	99%	67%	87%
4 a.m.	89%	97%	70%	88%
5 a.m.	78%	85%	61%	79%
6 a.m.	82%	95%	53%	61%
7 a.m.	85%	100%	57%	66%
8 a.m.	83%	100%	66%	86%
9 a.m.	78%	100%	59%	83%
10 a.m.	80%	100%	63%	86%
11 a.m.	80%	100%	63%	83%
12 p.m.	89%	100%	71%	98%
1 p.m.	100%	100%	88%	100%
2 p.m.	100%	100%	89%	100%
3 p.m.	100%	100%	100%	100%
4 p.m.	100%	100%	100%	100%
5 p.m.	100%	100%	100%	100%
6 p.m.	100%	100%	100%	100%
7 p.m.	100%	100%	100%	100%
8 p.m.	100%	97%	87%	87%
9 p.m.	100%	100%	90%	90%
10 p.m.	100%	100%	93%	93%
11 p.m.	92%	100%	100%	100%
Avg	90%	97%	78%	88%

8. Conclusions

The main contribution of this paper is a method for finding the optimal VRE generation schedules which maximize the profits of VRE generators. The method considers the trade-off among the amount of VRE output, the MP, and the SOCs. The VRE support schemes involving prices VRE offered to the market are considered. Sensitivity analysis of VRE penetration and the characteristics of electricity demand (workdays and holidays) was performed to demonstrate the relationships among these parameters and the results. The method is a combination of the merit-order model and the unit-commitment. The results showed that VRE generators' profits were higher when using the proposed method than when using the traditional method, in the case of the system having high VRE penetration and low electricity demands. In the case where wind was the main VRE and VRE received no support, that was especially true. The proposed method also avoids negative profits of VRE generators when the MP are low. The average MP was increased around 8.8 $/MWh (23.6%) on the workday and 7.9 $/MWh (30%) on the holiday, by curtailing approximately 7% or 10% of the wind output on the workday or holiday, respectively. VRE generators could apply this method to find the optimal VRE generation schedules which maximize the profits of VRE generators.

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Abbreviations

CCGT	Combined Cycle Gas Turbines
CFD-FIT	Contract for Difference Feed-in Tariff
FIP	Feed-in Premiums
FIT	Feed-in Tariff
MC	Marginal Costs
MIP	Mixed-Integer Programming
MOE	Merit-Order Effect
MP	Marginal Prices
RE	Renewable Energies
SOCs	System Operational Constraints
UCP	Unit Commitment Problem
VRE	Variable Renewable Energies

Nomenclature

C	The generators' capital costs per MW installed ($/MW/day)
CC	The generators' capital costs per day ($/day)
$D(t)$	The electricity demand at specific time t (MWh)
$E(t)$	Generators output at specific time t (MWh)
$ICAP$	Total generators installed capacity (MW)
$MP(t)$	Marginal price at specific time t ($/MWh)
MC	Generators marginal costs ($/MWh)
n	The given power plant
$nthermal$	The total number of thermal power plants in the system
$nhydro$	The total number of hydropower plants in the system
$P_{n,thermal}(t)$	Power of thermal plant n at specific time t (MW)
$P^{\min}_{n,thermal}$	Minimum generation of thermal plant n (MW)
$MC^1_{n,thermal}, MC^2_{n,thermal}, MC^3_{n,thermal}$	Piecewise costs from the incremental cost curve of thermal plant n ($/MWh)
$P^{R1}_{n,thermal}, P^{R2}_{n,thermal}, P^{R3}_{n,thermal}$	Piecewise power from the incremental cost curve of thermal plant n (MW)
$Profile(t)$	Generation profile of VRE (%of installed capacity)
$RD(t)$	The residual demand at specific time t (MWh)
$Revenue(t)$	Generators' hourly revenue ($)
SP_{FIP}	FIP support price ($/MWh)
SP_{FIT}	FIT support price ($/MWh)
t	Time (1st hour = 1, 2nd hour = 2)
$VC(t)$	Total generators hourly variable costs ($)

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