Coordinated Constrained Optimal Power Dispatch for Bilateral Contract, Balancing Electricity and Ancillary Services Markets

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ABSTRACT

This paper proposes a coordinated constrained optimal power dispatch (CCOPD) algorithm for bilateral contract market (BCM) with curtailment bids, balancing electricity market (BM) and ancillary services market (ASM). The CCOPD problem is decomposed into social welfare maximization subproblem which is solved by the mixed-integer linear programming (MILP) and real power loss minimization subproblem which is solved by the linear programming (LP). The social welfare maximization subproblem and the real power loss maximization subproblem are solved iteratively. The proposed CCOPD algorithm maximizes the overall social welfare of BCM, BM and ASM simultaneously subject to power balance, ancillary services requirements and line flow constraints. The CCOPD algorithm is tested on the modified IEEE 30 bus system with six generation companies (PowerGens) submitting curtailment bids in BCM, and offers to sell electricity and ancillary services in BM and ASM, respectively. The social welfare of the CCOPD is shown to be higher than constrained optimal power dispatch without coordination among BCM, BM and ASM.

1. INTRODUCTION

So far, the Energy Policy and Planning Office of Thailand (EPPO) had proposed to restructure the Thai electricity supply industry using the New Electricity Supply Arrangement (NESA) [1]. Under NESA, most of power purchase transactions are in the form of bilateral agreements whereas a small power exchange (PX) will be used as a system balancing mechanism. The proposed NESA structure is shown in Fig. 1.

The Electricity Generating Authority of Thailand (EGAT), who currently owns and operates most of power station and transmission grid in Thailand, will be unbundled into GridCo and three generation companies (PowerGens). NESA encourages PowerGens and IPPs to compete in selling electricity to the retailers and large consumers through bilateral contracts instead of power pool in the earlier recommended ESI structure [2]. The regulated GridCo owns and operates the high voltage transmission system under the instruction of independent system operator (ISO). In distribution level, the Metropolitan Electricity Authority (MEA) in Bangkok and vicinity and Provincial Electricity Authority (PEA) in the rest of Thailand, who own and operate the low voltage distribution grids, will be formed as the regulated electricity delivery company (REDCo). Each REDCo, which combines the distribution company (DisCo) and supply company (SupplyCo), delivers and sells electricity to consumers. DisCo owns and operates the low voltage distribution system whereas SupplyCo sells the electricity to the captive consumers. Additionally, commercial retail companies (RetailCos) compete in selling electricity to non-captive consumers. The imbalances between contractual and physical electricity consumptionin real time are handled by a balancing mechanism in balancing market (BM).

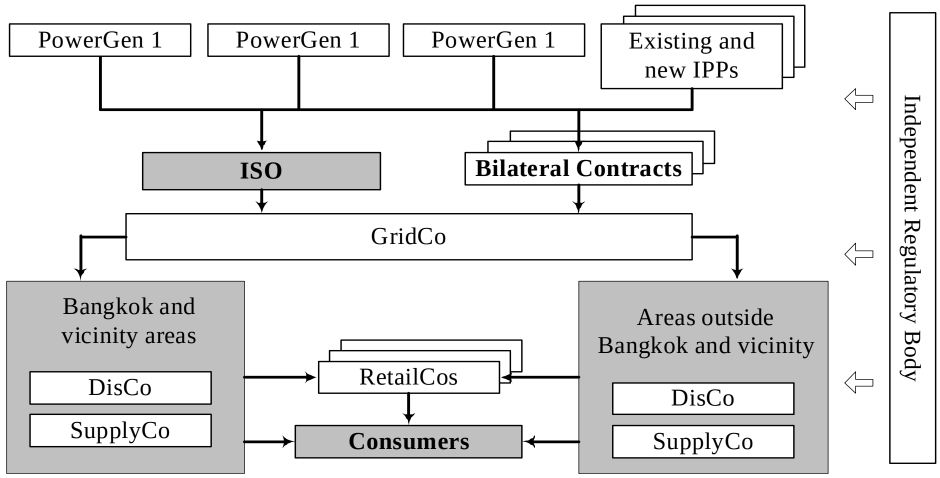

Fig. 1 The proposed NESA for Thai ESI [1]

To alleviate network congestion in the bilateral contract market (BCM) when the supply in BM are not enough, it might be necessary for the ISO to curtail some of the transactions for economical and security reasons [3-7]. The choice of curtailment of bilateral transaction is important since it would affect the financial deals of all parties involved in the contract. Therefore, the ISO should act in a fair and nondiscriminatory manner to all parties, when deciding on the curtailment of bilateral transactions.

Some curtailment strategies aim to minimize deviations from transaction requests made by market participants in bilateral and multilateral contract markets [3]. The consumer willingness to pay factors to avoid curtailment has been used in [4-5]. To coordinate the bilateral contract market with pool dispatch, the congestion was managed in the economical manner using either BM or the bilateral contract curtailment bids [6]. However, the ancillary services market (ASM) was not included. Meanwhile, the utilization of spinning reserve and replacement reserve in real-time balancing were incorporated in [7]. Nevertheless, the optimal ancillary services procurement in ASM to meet the minimum security requirement was not taken into account.

In this paper, a coordinated constrained optimal power dispatch (CCOPD) algorithm for BCM with curtailment bids, BM, and ASM is proposed. The problem is decomposed into two subproblems including the social welfare maximization and the real power loss minimization subproblems. The proposed CCOPD algorithm maximizes the overall social welfare in BCM, BM and ASM simultaneously subject to power balance, ancillary services requirements and line flow constraints. In the real power loss minimization subproblem, the linearized real power loss is formulated as a function of generator voltages and transformer tap settings by using the unified Jacobian matrix [11].

The organization of this paper is as follows. Section 2 formulates the CCOPD problem. The spot price and payment schemes are addressed in Section 3. The simulation results on the modifiedIEEE 30 bus system with six PowerGens are illustrated in Section 4. Lastly, the conclusion is given.

2. FORMULATION OF CCOPD FOR BCM, BM, AND ASM

In NESA, PowerGens/IPPs and consumers arrange physical electrical energy transactions with each other based on their own financial interests in BCM. Instead of letting the ISO know the prices of their contracts, participants must report the quantities of their bilateral contracts to the ISO before their actual dispatch time. In BM, ISO receives hourly electricity offers from PowerGens/IPPs and demand bids from dispatchable load consumers. The demands in BCM are either dispatchable or non-dispatchable loads whereas the demands in BM are dispatchable loads.

In addition to NESA, both generator and consumer agree to submit curtailment bids for their bilateral contract in order to receive the financial compensation for congestion management. In BM, ISO receives hourly electricity offers from PowerGens/IPPs and demand bids from supply companies or dispatchable load consumers. The curtailment bids for dispatchable loads in BCM are submitted for point-to-point curtailment in which the loads can respond to the ISO dispatch instruction. On the other hand, the curtailment on the contract of non-dispatchable load is imposed only on the generation side and the load is supplied by BM.

In ASM, the ancillary services offer prices and quantities are submitted by the PowerGens/IPPs. The selected ancillary services are AGC, TMSR, and TMOR. It is assumed that the AGC, TMSR, and TMOR are offered by the PowerGens/IPPs in $/MW and procured by ISO in hourly basis [8-10].

The CCOPD problem is decomposed into social welfare maximization subproblem which is solved by the mixed-integer linear programming (MILP) and real power loss minimization subproblem which is solved by the linear programming (LP).

2.1 Social Welfare Maximization Subproblem

The objective function for social welfare maximization subproblem CCOPD can be expressed as:

$$\text{Max} \quad SW = \sum_{i\in BD}\sum_{j=1}^{ND_i} D_{ij}P_{Dij} - \sum_{i\in BG}\left[\begin{array}{l}\sum_{j=1}^{NS_i} S_{ij}P_{Gij} + OAGC_i\cdot AGC_i + OTMSR_i\cdot TMSR_i + OTMOR_i\cdot TMOR_i \\ +\sum_{j=1}^{DPLi} CTB_{ij}^{DPL}\,\Delta P_{Gij}^{BCDPL} + \sum_{j=1}^{NDPLi} CTB_{ij}^{NDPL}\,\Delta P_{Gij}^{BCNDPL}\end{array}\right], \quad (1)$$

Subject to the power balance constraints,

$$P_{Gi} - P_{Di} = \sum_{j=1}^{NB} |V_i||V_j||y_{ij}|\cos(\theta_{ij} - \delta_{ij}), \quad \text{for } i = 1,\ldots,\text{NB}, \quad (2)$$

$$Q_{Gi} - Q_{Di} = -\sum_{j=1}^{NB} |V_i||V_j||y_{ij}|\sin(\theta_{ij} - \delta_{ij}), \quad \text{for } i = 1,\ldots,\text{NB}, \quad (3)$$

where,

$$P_{Gi} = \sum_{j=1}^{NS_i} P_{Gij} + P_{Gi}^{BC}, \quad \text{for } i = 1, \ldots, \text{NG}, \quad (4)$$

$$P_{Gi}^{BC} = \sum_{j=1}^{NB} P_{Gij}^{BCDPL} - \sum_{j=1}^{NB}\Delta P_{Gij}^{BCDPL} + \sum_{j=1}^{NB} P_{Gij}^{BCNDPL} - \sum_{j=1}^{NB}\Delta P_{Gij}^{BCNDPL}, \quad \text{for } i = 1, \ldots, \text{NG}, \quad (5)$$

$$0 \le P_{Gij} \le P_{Gij}^{\max}, \quad \text{for } j = 1, \ldots, \text{NSi}, \quad (6)$$

$$P_{Di} = \sum_{j=1}^{ND_i} P_{Dij} + P_{Di}^{BC}, \quad \text{for } i = 1,\ldots,\text{NB}, \quad (7)$$

$$P_{Di}^{BC} = \sum_{j=1}^{NG} P_{Gji}^{BCDPL} - \sum_{j=1}^{NG} \Delta P_{Gji}^{BCDPL} + \sum_{j=1}^{NG} P_{Gji}^{BCNDPL}, \qquad \text{for } i = 1, \ldots, \text{NB}, \tag{8}$$

$$0 \le P_{Dij} \le P_{Dij}^{\max}, \qquad \text{for } j = 1, \ldots, \text{NDi}, \tag{9}$$

and the line flow limit constraints,

$$|f_l| \le f_l^{\max}, \text{ for l=1, …, NC}, \tag{10}$$

and the ancillary services requirement constraints,

$$AGCR = \%AGC \cdot (\sum_{i \in BD} P_{Di} + P_{loss}) \le \sum_{i \in BG} AGC_i, \tag{11}$$

$$TMSRR = \%TMSR \cdot (\sum_{i \in BD} P_{Di} + P_{loss}) \le \sum_{i \in BG} TMSR_i, \tag{12}$$

$$TMORR = \%TMOR \cdot (\sum_{i \in BD} P_{Di} + P_{loss}) \le \sum_{i \in BG} TMOR_i, \tag{13}$$

and the generator maximum operating limit constraints,

$$P_{Gi} + AGC_i + TMSR_i + TMOR_i \le P_{Gi}^{\max}, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{14}$$

$$0 \le P_{Gi} \le P_{Gi}^{\max} \cdot Z_i, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{15}$$

and the generator minimum operating limit and AGC low regulating limit constraints,

$$A_i \cdot (P_{AGC,i}^{low} - P_{Gi}^{\min}) + Z_i \cdot P_{Gi}^{\min} - P_{Gi} \le 0, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{16}$$

where, $P_{AGC,i}^{low} \ge P_{Gi}^{\min}$, for $i = 1, \ldots,$ NG,

and the AGC limit and high regulating limit constraints,

$$0 \le AGC_i \le AGC_i^{\max} \cdot A_i, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{17}$$

$$P_{Gi} + AGC_i \le P_{AGC,i}^{high} \cdot A_i, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{18}$$

where, $P_{AGC,i}^{high} \le P_{Gi}^{\max}$, for $i = 1, \ldots,$ NG,

and the AGC supply constraints,

$$A_i - Z_i \le 0, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{19}$$

and the TMSR limit constraints,

$$0 \le TMSR_i \le TMSR_i^{\max} \cdot Z_i, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{20}$$

and the TMOR limit constraints,

$$-TMOR_i - P_{Gi}^{\min} \cdot Z_i + P_{Gi}^{\min} \cdot U_i \le 0, \qquad \text{for } i = 1, \ldots, \text{NG}, \tag{21}$$

$$0 \le TMOR_i \le TMOR_i^{\max} \cdot U_i, \qquad \text{for } i = 1, \ldots, \text{NG}. \tag{22}$$

where, $A_i, Z_i, \text{and } U_i \in \{0,1\}$, for $i = 1, \ldots,$ NG.

Under AGC low ($P_{AGC,\,i}^{low}$) and high ($P_{AGC,\,i}^{high}$) regulating limits, the generator can perform AGC function. should be higher than or equal to $P_{Gi}^{\min}$ and $P_{AGC,\,i}^{high}$ should be lower than or equal to $P_{Gi}^{\max}$. However, some of these limits may be coincident. For instance, in a hydro unit, $P_{AGC,\,i}^{low}$ $P_{Gi}^{\min}$ and coincide with zero whereas $P_{AGC,\,i}^{high}$ and $P_{Gi}^{\max}$ are the same [10].

A_i is the on ($A_i = 1$) and off ($A_i = 0$) AGC status of the generator *i* whereas Z_i is the committed ($Z_i = 1$) and uncommitted ($Z_i = 0$) status of the generator *i*. In Eqs. (15) and (16), when the generator *i* is committed ($Z_i = 1$), must be higher than or equal to $P_{Gi}^{\min}$ and when the generator *i* is not committed ($Z_i = 0$), P_{Gi} must be zero. In addition, when the AGC status of the generator *i* is on ($A_i = 1$), P_{Gi} must be higher than or equal to $P_{AGC,\,i}^{low}$. On the other hand, in Eq. (18), P_{Gi} plus AGC_i must be less than $P_{AGC,\,i}^{high}$.

In Eqs. (17) and (19), the AGC offer of generator *i* can be selected ($A_i = 1$) only when the generator *i* is committed to the system ($Z_i = 1$). In Eq. (20), the $TMSR_i$ can be selected only when the generator *i* is committed to the system ($Z_i = 1$). On the other hand, in Eqs. (21) and (22), the $TMOR_i$ can be selected regardless of the status of generator *i*. But if the generator *i* is not committed to the system ($Z_i = 0$), the minimum accepted quantity is $P_{Gi}^{\min}$. Otherwise, it is zero. U_i is the selected ($U_i = 1$) and unselected ($U_i = 0$) TMOR status of the generator *i*.

Note the market clearing price (MCP) is set to the Lagrange multiplier of the real power balance constraint, obtained by solving social welfare maximization subproblem. The accepted real power demand bid (P_{Dij}), accepted real power generation offer (P_{Gij}), accepted AGC quantity (AGC_i), accepted 10 min spinning reserve quantity ($TMSR_i$), accepted 30 min operating reserve quantity ($TMOR_i$), AGC on/off status (A_i), generator's on/off status (Z_i), TMOR selected status (U_i), the curtailment on dispatchable load bilateral contract (ΔP_{Gij}^{BCDPL}) and the curtailment on non-dispatchable load bilateral contract (ΔP_{Gij}^{BCNDPL}) are the output of the social welfare maximization subproblem.

2.2 Real Power Loss Minimization Subproblem

To minimize the real power loss, the real power loss minimization subproblem is solved iteratively with the social welfare maximization. The objective is formulated as:

$$\text{Min} \quad \Delta P_{loss} = [\frac{\mathbf{dP_{loss}}}{\mathbf{d|V|}} \;\; \frac{\mathbf{dP_{loss}}}{\mathbf{dT}}] \begin{bmatrix} \mathbf{\Delta|V|} \\ \mathbf{\Delta T} \end{bmatrix}, \tag{23}$$

Subject to the power balance constraints in Eqs. (2) and (3), and the bus voltage and transformer tap-change limits constraints,

$$|V_i^{\min}| - |V_i| \le \Delta|V_i| \le |V_i^{\max}| - |V_i|, \qquad \text{for } i = 1, \ldots, NB, \tag{24}$$

$$T_i^{\min} - T_i \le \Delta T_i \le T_i^{\max} - T_i, \qquad \text{for } i = 1, \ldots, NT. \tag{25}$$

The formulation of real power loss minimization subproblem is obtained by the unified Jacobian matrix [11]. The computation procedure is shown in Fig. 2.

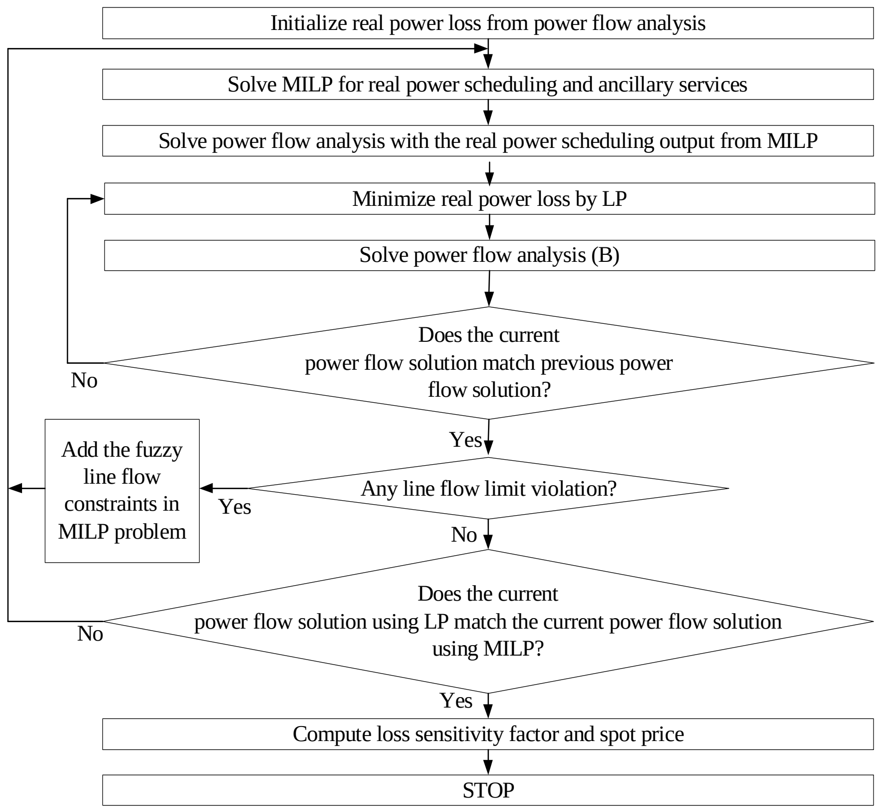

Fig. 2 CCOPD computational procedure

3. SPOT PRICE AND PAYMENT SCHEMES

In this paper, the payment schemes include competitive electricity price (CEP) and competitive electricity and ancillary services price (CEASP) schemes [8]. Note the real power loss minimization subproblem and the social welfare maximization subproblem are solved iteratively in both schemes.

3.1 Competitive Electricity Price Scheme

This scheme maximizes the social welfare in BM by using optimal power dispatch without coordination with BCM and ASM as:

$$\text{Max} \qquad SW = \sum_{i \in BD} \sum_{j=1}^{ND_i} D_{ij} P_{Dij} - \sum_{i \in BG} \sum_{j=1}^{NS_i} S_{ij} P_{Gij} \,, \tag{26}$$

Subject to power balance constraints in Eqs. (2) and (3), line flow limit constraints in Eq. (10), and the generator commit/decommit constraints,

$$Z_i \cdot P_{Gi}^{\min} - P_{Gi} \leq 0, \qquad i = 1, \ldots, NG \tag{27}$$

After the solution of BM is obtained, the scheme minimizes the total ancillary services cost in the ASM as:

$$\text{Min} \quad ASC = \sum_{i \in BG} \left[OAGC_i \cdot AGC_i + OTMSR_i \cdot TMSR_i + OTMOR_i \cdot TMOR_i \right], \tag{28}$$

Subject to ancillary services requirement constraints in Eqs. (11) - (13), generator maximum operating limits in Eqs. (14) and (15), and conditions for supply ancillary services in Eqs. (16) - (22).

The market clearing price (MCP) is the actual system short-run marginal price or system lambda. The spot price for CEP scheme including the system lambda, marginal transmission loss, and network quality of supply [12] is:

$$\rho_i^{CEP} = \lambda + \eta_{L,i} + \eta_{QS,i}, \tag{29}$$

where,

$$\eta_{L,i} = \lambda \cdot (-ITL) = \lambda \cdot \left(-\frac{dP_{loss}}{dP_i}\right), \tag{30}$$

$$\eta_{QS,i} = -\sum_{i=1}^{NC} v_l \cdot a_{li}, \tag{31}$$

$$a_{li} = \frac{df_l}{dP_i}, \tag{32}$$

$$ITL_i = \frac{dP_{loss}}{dP_i}. \tag{33}$$

The ITL_i is the change in total system loss due to the change in injection real power at bus *i*.

In ASM, PowerGens are paid at the marginal ancillary services prices and the total ancillary service payment is allocated to each consumer under pro rata basis [8]. The total ancillary services payments to PowerGens is:

$$TASP = \lambda_{AGC} \cdot AGCR + \lambda_{TMSR} \cdot TMSRR + \lambda_{TMOR} \cdot TMORR. \tag{34}$$

In addition, the payment for real power loss and congestion is allocated to the consumers in bilateral contract market by the marginal loss ($\eta_{L,i}$) network quality of supply ($\eta_{QS,i}$) components. Fig. 3 illustrates the payments for electricity and ancillary services to PowerGens and from the consumers under CEP scheme. Note the transmission charge is beyond the scope of this paper.

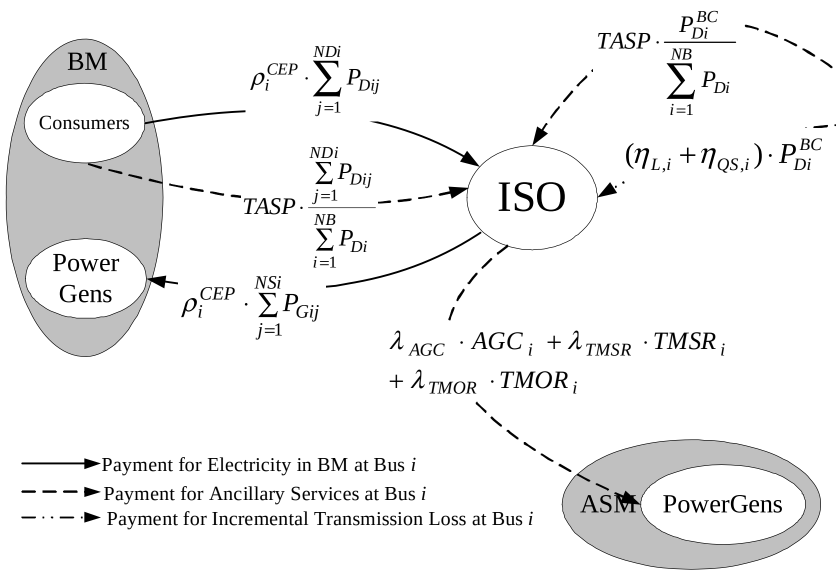

Fig. 3 Payments under CEP scheme

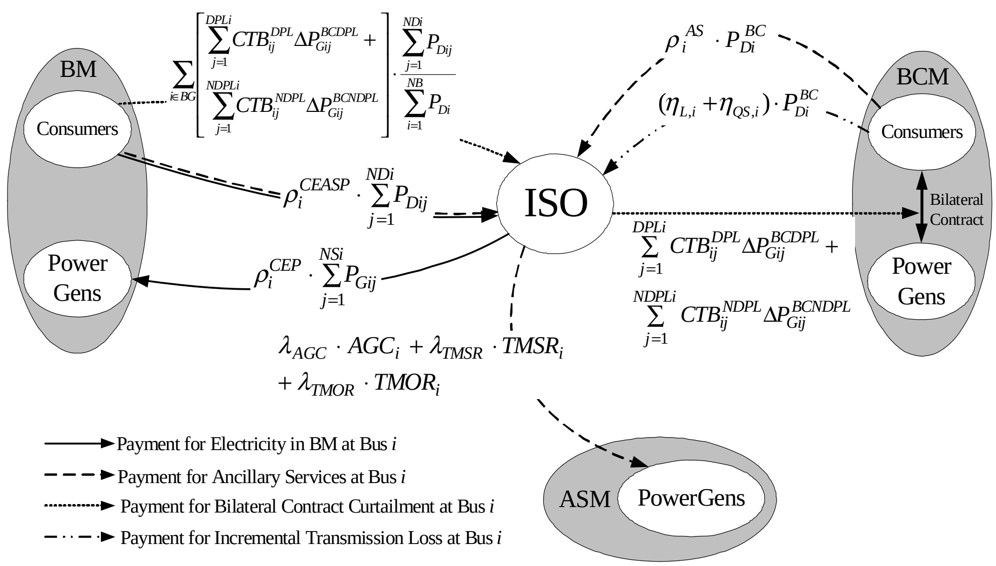

Fig. 4 Payments under CEASP scheme

3.2 Competitive Electricity and Ancillary Services Price Scheme

For this scheme, the proposed CCOPD is used. The social welfare of BM, ASM and BCM with curtailment bids will be maximized simultaneously in the social welfare maximization subproblem in Eq. (1), subject to power balance constraints in Eqs. (2) and (3), line flow limit constraints in Eq. (10), ancillary services requirement constraints in Eqs. (11) - (13), generator maximum operating limits in Eqs. (14) and (15), and conditions for supply ancillary services in Eqs. (16) - (22). The bus spot price including marginal electricity price and marginal ancillary services price is used to charge the consumers in BM. Meanwhile, the spot price excluding the ancillary services marginal prices in Eq. (29) is received by each PowerGen. The spot price for CEASP scheme including the system lambda, marginal transmission loss, network quality of supply, and the additional marginal prices of ancillary services [8] is:

$$\rho_i^{CEASP} = \lambda + \eta_{L,i} + \eta_{QS,i} + \lambda_{AGC} \cdot \frac{dAGCR}{dP_{Di}}(1 - ITL_i) + \lambda_{TMSR} \cdot \frac{dTMSRR}{dP_{Di}}(1 - ITL_i) + \lambda_{TMOR} \cdot \frac{dTMORR}{dP_{Di}}(1 - ITL_i). \quad (35)$$

The PowerGens are paid for ancillary services at the ancillary services marginal price as in CEP scheme. The consumers in BCM are charged for the AGC, TMSR, and TMOR based on the ancillary services spot price components. More specifically, the ancillary services spot price applied to the consumers in BCM is,

$$\rho_i^{AS} = \lambda_{AGC} \cdot \frac{dAGCR}{dP_{Di}} \cdot (1 - ITL_i) + \lambda_{TMSR} \cdot \frac{dTMSRR}{dP_{Di}} \cdot (1 - ITL_i) + \lambda_{TMOR} \cdot \frac{dTMORR}{dP_{Di}} \cdot (1 - ITL_i). \quad (36)$$

Similarly, the payment for real power loss is allocated to the consumers in bilateral contract market by the marginal loss ($\eta_{L,i}$) network quality of supply ($\eta_{QS,i}$) components. Fig. 4 illustrates the payments for electricity and ancillary services to PowerGens and from the consumers under CEASP scheme.

4. NUMERICAL RESULTS

The test data are obtained from the optimal power flow analysis on the modified IEEE 30 bus systems [13] with the line 11-9 limit of 40 MVA instead of 65 MVA. The network diagram is shown in Fig. 5. Table 1 shows the bilateral contracts and curtailment bids in BCM. The electricity offer prices and quantity and demand side bids in BM are shown in Tables 2 and 3, respectively. The ancillary services offer prices and quantities is shown in Table 4.

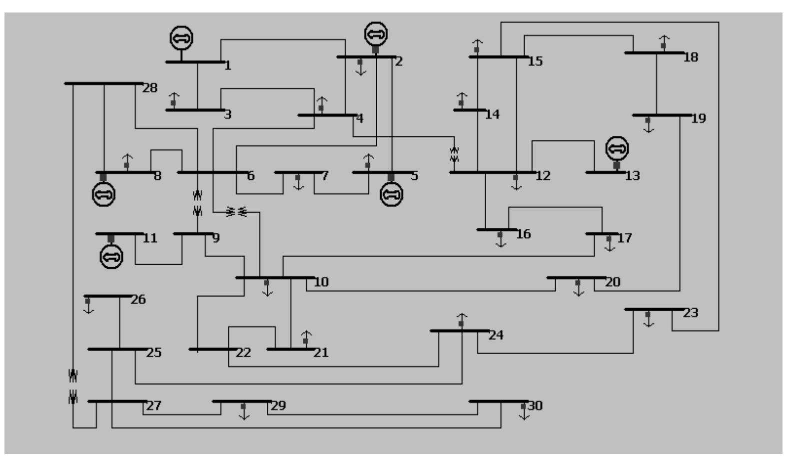

Fig. 5 The modified IEEE 30 bus system single line diagram

The generator and load bus operating ranges of voltage magnitudes are 0.95-1.05 p.u. The AGC is required to be 3% of the total real power dispatch whereas the TMSR and TMOR are required to be 5% of the total real power dispatch. The AGC low and high regulating limits are set at the minimum and maximum real power generation, respectively.

Table 1 The bilateral contracts and curtailment bids in BCM

From Bus (Gen)	To Bus (Load)	Quantity (MW)	Curtailment Bid	
			Price ($/MW)	Quantity (MW)
Contract with dispatchable load				
11	3	2	4.12	0.2
5	30	10	5.13	1.1
5	8	27	5.15	3.0
13	15	7	5.17	0.8
5	4	8	6.20	0.8
2	12	10	7.11	1.1
2	5	18	8.11	1.0
13	24	8	8.15	0.9
5	5	22	8.19	2.4
8	5	27	8.19	3.0
13	5	9	9.17	0.8
2	19	9	10.11	1.0
11	16	4	10.16	0.4
11	23	3	11.11	0.3
Contract with non-dispatchable load				
11	7	20	4.00	2.3
5	14	6	5.21	0.6
13	29	2	8.17	0.2
2	21	16	9.92	1.8
13	17	8	10.19	0.9
1	26	4	10.70	0.4
Contract with non-dispatchable load				
13	20	2	12.15	0.2
1	10	5	12.29	0.6
1	18	3	12.78	0.3
1	2	20	13.67	2.2
1	5	8	13.67	1.2

The simulation includes CEP scheme, CEASP schemes with and without bilateral contract curtailment bids. Fig. 6 shows the dispatch results of CEP scheme and CEASP schemes with and without bilateral contract curtailment bids. The PowerGens electricity and ancillary services dispatch results of CEP scheme, CEASP schemes with and without bilateral contract curtailment bids are shown in Tables 5-7.

The simulation shows that the MCQ in BM under CEASP scheme without bilateral contract curtailment bid is higher than CEP scheme, whereas the CEASP scheme with bilateral contract curtailment bids results in the highest MCQ. Due to the line flow limit violation on line 11-9, CEASP scheme with bilateral contract curtailment bids results in a curtailment on bilateral contract between buses 11 to 3 of 0.021 MW whereas neither curtailment is imposed on CEP nor CEASP without bilateral contract curtailment bid. Note all schemes include binding solutions that the flows on line 11-9 of 40 MVA.

Table 2 The PowerGens electricity offer prices and quantities in BM

Gen Bus	From MW	To MW	Offered Prices ($/MWh)
1	0	5	9.00
	5	15	15.40
2	0	10	8.05
	10	18	20.25
5	0	10	7.46
	10	15	20.20
8	0	10	7.05
	10	15	20.00
11	0	10	6.25
	10	15	15.50
13	0	10	10.23
	10	18	20.50

Table 3 The Demands bids prices and quantities in BM

Load Bus	From MW	To MW	Bid Prices ($/MWh)
2	0	5	17.60
	5	10	7.55
3	0	2	17.50
	2	4	6.50
4	0	5	17.50
	5	7	9.50
5	0	5	17.25
	5	12	8.25
7	0	3	17.10
	3	6	5.75
8	0	8	12.45
	8	12	6.00
10	0	3	17.50
	3	5	8.50
12	0	4	16.50
	4	8	9.50
14	0	3	17.75
	3	5	7.00
15	0	2	16.00
	2	4	7.45

Load Bus	From MW	To MW	Bid Prices ($/MWh)
16	0	1	17.00
	1	2	6.30
17	0	2	17.00
	2	7	8.00
18	0	1	17.15
	1	2.5	5.25
19	0	1	17.75
	1	5	5.75
20	0	5	17.36
21	0	3	17.75
	3	8	9.75
23	0	1	17.20
	1	2.5	7.80
24	0	1	17.50
	1	5	6.50
26	0	1	17.85
	1	2.5	8.50
29	0	2	10.20
30	0	2	17.10
	2	4	4.27

Table 4 The PowerGens ancillary services offer prices and quantities in ASM

Gen Bus	AGC Offer		TMSR Offer		TMOR Offer	
	Price ($/MW)	MW	Price ($/MW)	MW	Price ($/MW)	MW
1	6	7	7	8	10	15
2	7	11	5	12	5	13
5	6	12	6	8	10	14
8	8	13	5	10	7	15
11	9	14	8	12	8	16
13	7	5	9	12	9	12

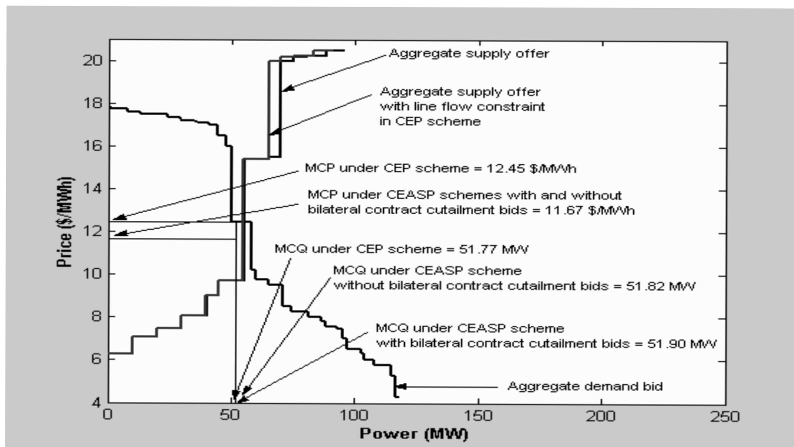

Fig. 6 BM dispatch result of CEP and CEASP schemes

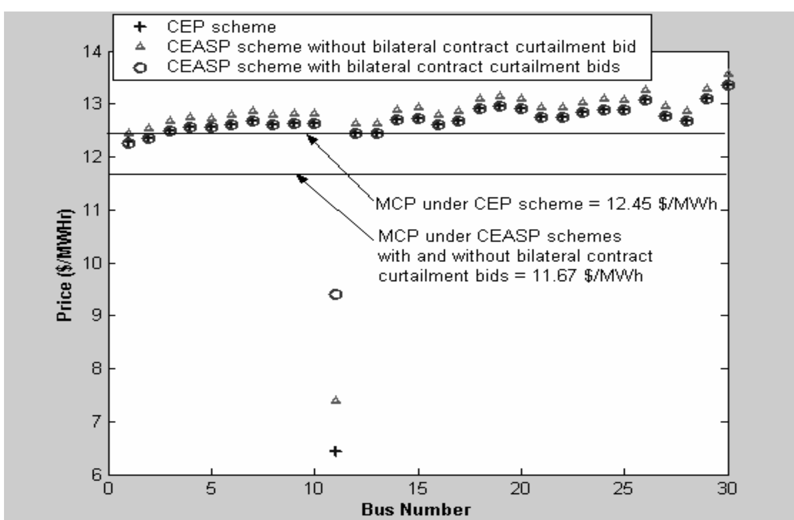

Fig. 7 Spot price of IEEE 30 bus test system

Table 8 shows the summary results and payments of CEP scheme, CEASP schemes with and without bilateral contract curtailment bids. The result shows that the MCP of CEASP schemes with and without bilateral contract curtailment bids are lower than CEP scheme. The social welfare of CEASP scheme without bilateral contract curtailment bids is higher than CEP scheme. This indicates that dispatching electricity and ancillary services markets simultaneously leads to a higher social welfare than dispatching electricity and ancillary services markets separately.

On the other hand, the social welfare of CEASP scheme with bilateral contract curtailment bids is shown to be the highest. Obviously, the supply resources in real time under CEASP scheme with bilateral contract curtailment bids can be utilized much efficient than CEP scheme and CEASP scheme without bilateral contract curtailment bids.

Table 5 Dispatch results under CEP scheme

Gen Bus	Electricity		Ancillary Services		
	BCM (MW)	BM (MW)	AGC (MW)	TMSR (MW)	TMOR (MW)
1	40	5	3.463	0	0
2	53	10	0	8.085	13
5	73	10	5.924	0	0
8	27	10	0	7.56	2.645
11	29	9.9	0	0	0
13	36	10	0	0	0
Total	*258*	*54.9*	*9.387*	*15.645*	*15.645*

Table 6 Dispatch results under CEASP scheme without bilateral contract curtailment bid

Gen Bus	Electricity		Ancillary Services		
	BCM (MW)	BM (MW)	AGC (MW)	TMSR (MW)	TMOR (MW)
1	40	5.15	3.467	0	0
2	53	10	0	8.173	13
5	73	10	5.92	0	0
8	27	10	0	7.473	2.646
11	29	9.93	0	0	0
13	36	10	0	0	0
Total	*258*	*55.08*	*9.387*	*15.646*	*15.646*

Table 7 Dispatch results under CEASP scheme with bilateral contract curtailment bids

Gen Bus	Electricity		Ancillary Services		
	BCM (MW)	BM (MW)	AGC (MW)	TMSR (MW)	TMOR (MW)
1	40	5	3.524	0	0
2	53	10	0	8.289	13
5	73	10	5.865	0	0
8	27	10	0	7.36	2.649
11	28.98	10	0	0	0
13	36	10	0	0	0
Total	*257.98*	*55*	*9.389*	*15.649*	*15.649*

Table 8 Summary of payment on the IEEE 30 bus test system

Item	CEP Scheme	CEASP Scheme without Bilateral Contract Curtailment	CEASP Scheme with Bilateral Contract Curtailment
Social Welfare in BCM, BM, and ASM ($/h)	*238.723*	*239.100*	*239.504*
Social Welfare in BM ($/h)	456.785	457.183	457.712
Social Welfare in BM and ASM ($/h)	238.723	239.100	239.589
Curtailment Cost in BCM ($/h)	0.000	0.000	0.0844
Electricity Market Clearing Price in BM ($/MWh)	*12.45*	*11.67*	*11.67*
Total Power Dispatch (MW)	*312.90*	*312.93*	*312.98*
Electricity Market Clearing Quantity in BM (MW)	*51.77*	*51.82*	*51.90*
Total Electricity Generation in BCM (MW)	*258.00*	*258.00*	*257.98*
Real Power Loss	3.13	3.11	3.10
Total Payment of ISO ($/h)	*905.563*	*844.964*	*856.069*
Payment to PowerGens for Electricity in BM ($/h)	661.501	600.881	611.861
Payment to PowerGens for AS in ASM ($/h)	244.061	244.083	244.124
Payment for Bilateral Contract Curtailment ($/h)	0.000	0.000	0.0844
Total Consumer Payment ($/h)	*1057.158*	*1010.444*	*952.113*
Payment of Consumer in BM for Electricity in BM ($/h)	665.831	624.790	616.453
Payment of Consumer in BM for AS ($/h)	41.715	41.760	41.202
Payment of Consumer in BM with Bilateral Contract Curtailment ($/h)	0.0000	0.000	0.0844
Payment of Consumer in BCM for AS ($/h)	207.528	207.561	204.479
Payment of Consumer in BCM for incremental transmission loss ($/h)	100.369	94.573	96.045
ISO Surplus ($/h)	*151.595*	*165.480*	*96.045*
Average Electricity Price in BM ($/MWh)	*13.667*	*12.863*	*12.674*

The spot prices of CEP scheme, CEASP schemes with and without bilateral contract curtailment bids are shown in Fig. 7. The spot prices including ancillary services marginal prices under CEASP scheme with bilateral contract curtailment bids are slightly higher than the spot price without ancillary services marginal price under CEP scheme due to the ancillary services marginal prices components. The low spot prices at bus 11 in all three schemes are due to the network quality of supply component. The higher spot price at bus 11 of CEASP scheme with bilateral contract curtailment bids than CEP scheme and CEASP scheme without bilateral contract curtailment bid indicates the smallest increase in social welfare when relaxing the constrained line flow limit by one MW (ν_{11-9}). As a result, the ISO's surplus in CEASP scheme with bilateral contract curtailment bids due to the higher payment to generator at bus 11.

The total consumer payment under CEASP scheme with bilateral contract curtailment bids is lower than CEP scheme and CEASP scheme without bilateral contract curtailment bid. As a result, the average electricity price in BM of CEASP scheme with bilateral contract curtailment bids is lower than CEASP scheme without bilateral contract curtailment bids and CEP scheme. Obviously, to relieve congestion, CEASP scheme with curtailment on bilateral contract could trade off between dispatching the high price generator in BM and payment for bilateral contract curtailment bids.

5. CONCLUSIONS

In this paper, a coordinated constrained optimal power dispatch (CCOPD) algorithm for BCM, BM and ASM is proposed. The CCOPD algorithm is successfully and effectively maximizing the social welfare in BCM, BM and ASM by the MILP and minimizing the real power loss by the LP. The proposed CEASP scheme is potentially applicable to the future Thailand NESA due to the higher social welfare, lower average electricity prices and its effectiveness to relieve the transmission congestion.

6. ACKNOWLEDGEMENTS

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7. NOMENCLATURE

AGC_i	=	the accepted AGC quantity supplied by generator i (MW)
$AGC_i^{\max}$	=	the offer AGC quantity of generator i (MW)
AG₵	=	the AGC price paid to generator i (\$/MW)
$AGCR$	=	the total system AGC requirement (MW)
ASC	=	the ancillary services cost (\$/h)
a_{li}	=	the line l sensitivity factor to the real injection power at bus i
BD	=	set of buses connected with demands
BG	=	set of buses connected with generators
CTB_{ij}^{DPL}	=	the bilateral contract curtailment bid of the bilateral contract between generator bus i and the dispatchable load bus j (\$//MWh)

CTB_{ij}^{NDPL}	=	the bilateral contract curtailment bid of the bilateral contract between generator bus i and the non-dispatchable load bus j ($//MWh)
D_{ij}	=	the bid price of the demand block j at bus i ($/MWh)
$f_l^{\max}$	=	the MVA flow limit at line or transformer l (MVA)
f_l	=	the MVA flow at line l (MVA)
ITL_i	=	the incremental transmission loss at bus i
NB	=	the total number of buses
NC	=	the total number of line flow constraints
ND_i	=	the number of segments of demand bid at bus i
NS_i	=	the number of segments of generator supply cost at bus i
NT	=	the total number of on load tap-changing transformers
$OAGC_i$	=	the AGC offer price of generator i ($/MWh)
$OTMOR_i$	=	the 30 min operating reserve (TMOR) offer price of generator i ($/MWh)
$OTMSR_i$	=	the 10 min spinning reserve (TMSR) offer price of generator i ($/MWh)
$P_{AGC,i}^{high}$	=	the high regulating limit of generator i (MW)
$P_{AGC,i}^{low}$	=	the low regulating limit of generator i (MW)
P_{Di}	=	the total real power demand at bus i (MW)
P_{Dij}	=	the accepted demand bid block j at bus i (MW)
$P_{Dij}^{\max}$	=	the demand bid block j at bus i (MW)
P_{Di}^{BC}	=	the total real load power obligation in the bilateral contract of load bus i (MW)
P_{Gi}	=	the real power generation at bus i (MW)
P_{Gij}	=	the accepted generator offer block j at bus i (MW)
$P_{Gij}^{\max}$	=	the generator offer block j at bus i (MW)
P_{Gi}^{BC}	=	the total real power generation obligation in the bilateral contract of generator i (MW)
P_{Gij}^{BCDPL}	=	the real power generation obligation for the non-dispatchable load bus j in the bilateral contract of generator bus i (MW)
P_{Gij}^{BCNDPL}	=	the real power generation obligation for the dispatchable load bus j in the bilateral contract of generator bus i (MW)
$P_{Gi}^{\max}$	=	the maximum real power generation at bus i (MW)
$P_{Gi}^{\min}$	=	the minimum real power generation at bus i (MW)
P_i	=	the injection real power at bus i (MW)

P_{loss}	=	the total system real power loss (MW)
Q_{Gi}	=	the reactive power generation at bus i (MVAr)
Q_{Di}	=	the reactive power demand at bus i (MVAr)
SW	=	the social welfare or surplus to the society ($/h)
S_{ij}	=	the offer price block j of generator at bus i ($/MWh)
T_i	=	the tap setting of the transformer i (MW)
$TASP$	=	the total ancillary services payment to PowerGens ($/h)
$TMOR_i$	=	the accepted quantity of TMOR supplied by generator i (MW)
$TMOR_i^{\max}$	=	the offer TMOR quantity of generator i (MW)
$TMORR$	=	the total system TMOR requirement (MW)
$TMSR_i$	=	the accepted quantity of TMSR supplied by generator i (MW)
$TMSR_i^{\max}$	=	the offer TMSR quantity of generator i (MW)
$TMSRR$	=	the total system TMSR requirement (MW)
$\lvert V_i \rvert$	=	the voltage magnitude at bus i (kV)
$\lvert V_i^{\max} \rvert$	=	the maximum voltage magnitude at bus i (kV)
$\lvert V_i^{\min} \rvert$	=	the minimum voltage magnitude at bus i (kV)
$\lvert y_{ij} \rvert$	=	the magnitude of the y_{ij} element of Y_{bus} (mho)
θ_{ij}	=	the angle of the y_{ij} element of Y_{bus} (radian)
δ_{ij}	=	the voltage angle difference between bus i and j (radian)
ρ_i^{CEP}	=	the spot price at bus i under CEP scheme ($/MWh)
ρ_i^{CEASP}	=	the spot price at bus i under CEASP scheme ($/MWh)
ρ_i^{AS}	=	the ancillary services spot price ($/MWh)
λ	=	the electricity marginal price or market clearing price (MCP) ($/MWh)
λ_{AGC}	=	the AGC clearing price ($/MWh)
λ_{TMOR}	=	the TMOR clearing price ($/MWh)
λ_{TMSR}	=	the TMSR clearing price ($/MWh)
$\eta_{L,i}$	=	the network marginal loss at bus i ($/MWh)
$\eta_{QS,i}$	=	the network quality of supply at bus i ($/MWh)
ν_l	=	the increase in social welfare by relaxing the line constraint l ($/MWh)
$\%AGC$	=	the AGC requirement in percentage of total real power dispatch
$\%TMOR$	=	the TMOR requirement in percentage of total real power dispatch
$\%TMSR$	=	the TMSR requirement in percentage of total real power dispatch
ΔP_{Gij}^{BCDPL}	=	the curtailment on (MW)

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