Economic Dispatch Management of Electric Power Plants for Profit Maximisation

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Abstract—**This paper presents a spreadsheet-based optimization program that was developed to help make a management decision on how much electricity and steam should be generated by each of the dual power plants and sold to each group of the customer during peak hours and off-peak hours to achieve the maximum profit without violating their sales contractual agreements. Several quantitative determination processes of unit cost, prices and profits were constructed to help understand the calculation procedure hierarchically and embedded into the program. The mathematical linear programming models for optimizing the total profit during both periods of time of use were formulated. Two feasible scenarios for each period of peak hours and off-peak hours towards profit maximization attainment were simulated. The simulation results show that the optimal scenario between the two is applicable to be executed in both periods of time of use. Although some electricity demand could not be fully satisfied and the company had to be penalized financially, this scenario provided the total maximum profit and was able to satisfy the power systems and the legal constraints and not severely violate the sales contractual agreements relative to another scenario. The results from sensitivity analysis show strong effects on the profitability allowing to examine a series of possible changes that will not affect the optimal solution of economic dispatch management.**

Index Terms—**Economic dispatch, operations management, power plant optimization, linear programming, Excel solver, profit maximization**

I. Introduction

The key business strategy of the power plant business in the deregulated electricity supply industry (ESI) is to maintain profitability. National Power Supply (NPS) is the private cogenerated-power company that sells debentures to the general public to raise funds for business expansion. The right strategic move is to maximize profit from selling electricity and steam, at the same time funding the intensive research and development program to seek for new alternative energy in order to supplant limited fuels and lower cost of production.

The corporate annual report showed that electricity and steam is the major source of revenue ranging from 75% to 90%, but both revenue and profit have declined for the past five years. Decreased profit was partly due to monopolized pricing determination and volatile macroeconomic factors. The executives identified that the decreased profit is caused by independent management without applications of economic dispatch (ED) among the power plants, resulting in excessively stocking up the fuels, scheduling unplanned maintenance from machine breakdown and not being able to deliver some outputs to the customer.

The focus of this researchb022+ 4567890-53[]\ 5p+/7 study is on an ED management with two com wparative scenarios of optimal solutions towards profit maximization. The study aims to develop an optimization program for strategically managing ED of electricity and steam for the dual power plants to ultimately achieve the maximum profit. Sensitivity analysis was also performed to investigate the effects of cost-price-related factors on profitability allowing to foresee a series of possible changes that will not affect the best ED management solution.

A. Literature Review

According to the U.S. Energy Policy Act of 2005 [1], economic dispatch is defined as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limit of generation and transmission facilities". The key underlying objective of ED problem solving is to determine the optimal point of generation units with minimum cost while satisfying load demands and system constraints [2].

Towards the end of the year 2016, a number of research papers in the field of ED have been published in many reputable sources. It seems that the entire set of recent studies intended to achieve this objective, but some of which [3-11] chose to minimize fuel cost instead of total cost of generation [12-19]. The rationale behind this might be because the fuel cost almost covers the total cost of generation. There is only one paper by [20] aiming to solve the ED problem for profit maximization; however, their constraints in the power system are generally indifferent to those found in common ED problems.

Two different power plant systems have been interested in the recent studies: the power only and the combined heat and power (CHP) systems. Apparently, most of the work devoted to solving ED problems in the plant system with power generating units, conversely only a few [14], [15], and [20] chose to solve ED problems in CHP system where both electricity and steam can be produced at the same time.

Considering solution methods applied, they are very diverse from simple methods to sophisticated ones since the authors modified or improved those particular methods to fit their ED problem characteristics or to improve the accuracy of computational results. For examples, [10] and [15] modified regular particle swarm optimization (PSO) method of [3] and [4] improved differential evolutionary (DE) of [12]. Alternatively, some authors innovatively developed solution methods; for instances, [6] developed a cuckoo search (CS) algorithm, and [13] developed an artificial immune system (AIS) algorithm. While the same solution method was used more than once but in different plant systems. For example, the AIS algorithm was first used by [13] in a conventional plant system and later used by [14] in a CHP plant system.

This study fills the research gap by extending the application of ED for profit maximization in a group of CHP/cogeneration power plants and considering local constraints in terms of system, demand-supply balances and contractual agreements. Briefly, the summary of the recent publications (2008-2016) about ED and the gap of this research study is demonstrated in Table I.

TABLE I
Summary Of The Recent Publications On Economic Dispatch.

Authors	Year	Objective	Plant System	Profit Max	Solution Methods
Balamurugan & Subramanian	2008	Minimum generation cost	Power	No	Differential evolutionary algorithm
Mahor	2009	Minimum fuel cost	Power	No	Particle swarm optimization
Behera	2011	Minimum generation cost	Power	No	Artificial immune system algorithm
Mahdad & Srairi	2011	Minimum fuel cost	Power	No	Improved parallel differential evolution
Basu	2012	Minimum generation cost	CHP	No	Artificial immune system algorithm
Dike	2013	Minimum fuel cost	Power	No	Modified lambda-iteration
Mohammadi-Ivatloo	2013	Minimum generation cost	CHP	No	Particle swarm optimization with time varying acceleration coefficients
Naama	2013	Minimum generation cost	Power	No	Tabu search algorithm
Sashirekha	2013	Minimum generation cost	CHP	No	Lagrangian relaxation
Serapião	2013	Minimum fuel cost	Power	No	Cuckoo search algorithm
Ashfaq & Khan	2014	Minimum fuel cost	Power	No	Modified linear programming
Rahli	2015	Minimum generation cost	Power	No	Variable weights linear programming
Tsai [1]	2015	Maximum profit	CHP	Yes	Improved genetic algorithm
Al-Shetwi & Alomoush	2016	Minimum fuel cost	Power	No	Genetic algorithm
Hansen & Mladenovic	2016	Minimum generation cost	Power	No	Dynamic programming
Srikanth	2016	Minimum fuel cost	Power	No	Genetic algorithm
Vignesh	2016	Minimum fuel cost	Power	No	Quantum particle swarm optimization
Zaman	2016	Minimum fuel cost	Power	No	Differential evolutionary algorithm
This research study	2017	Maximum profit	CHP	Yes	Linear programming

Remark: [1] Operational and system constraints are holistic and indifferent to typical ED problems.

II. Quantitative Determination For Costs, Prices And Profits Of Electricity And Steam

A. Unit Cost of Production

To estimate the cost per unit of electricity and steam generated, the data about coal, biomass, demineralized water, sand, chemicals, ash disposal, lime, sea freight and land freight is required. Variable cost, including fuels and consumable raw materials, is assumed to cover all of the unit cost. The components of the total unit cost and the estimation process flowchart can be shown in Eq. (1) and Fig. 1, respectively.

Total Unit Cost = Total Fuel Cost + Total Consumable Raw Material Cost (1)

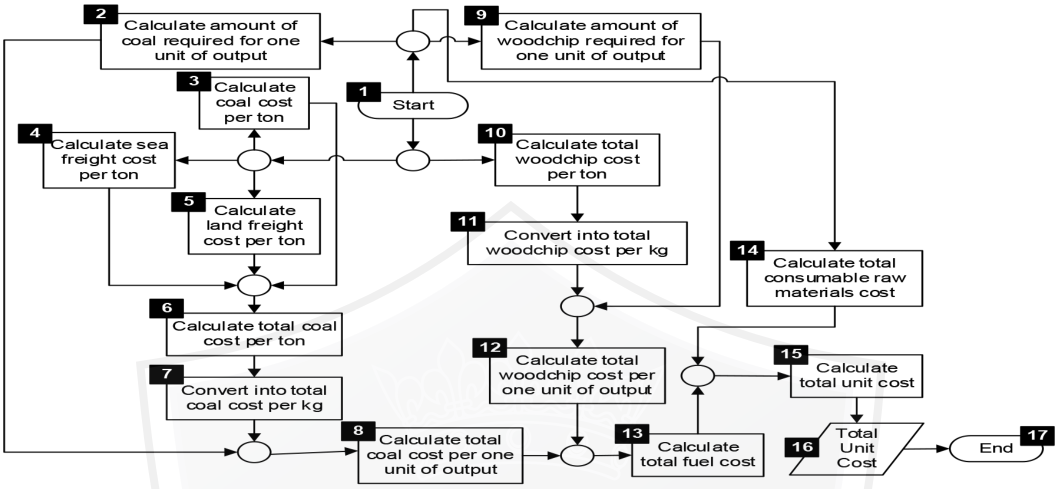


Fig. 1. Estimation process flowchart for the total unit cost of production

B. Unit Prices

The unit prices can be separately estimated for different products (electricity and steam), different groups of customers (EGAT, AA and Industry) and different times of use (peak hours and off-peak hours). For instances, estimating the electricity price sold to EGAT during peak hours should follow the estimation process flowchart illustrated in Fig. 2, on the other hand, estimating the electricity price sold to EGAT during off-peak should follow the estimation process flowchart illustrated in Fig. 3.

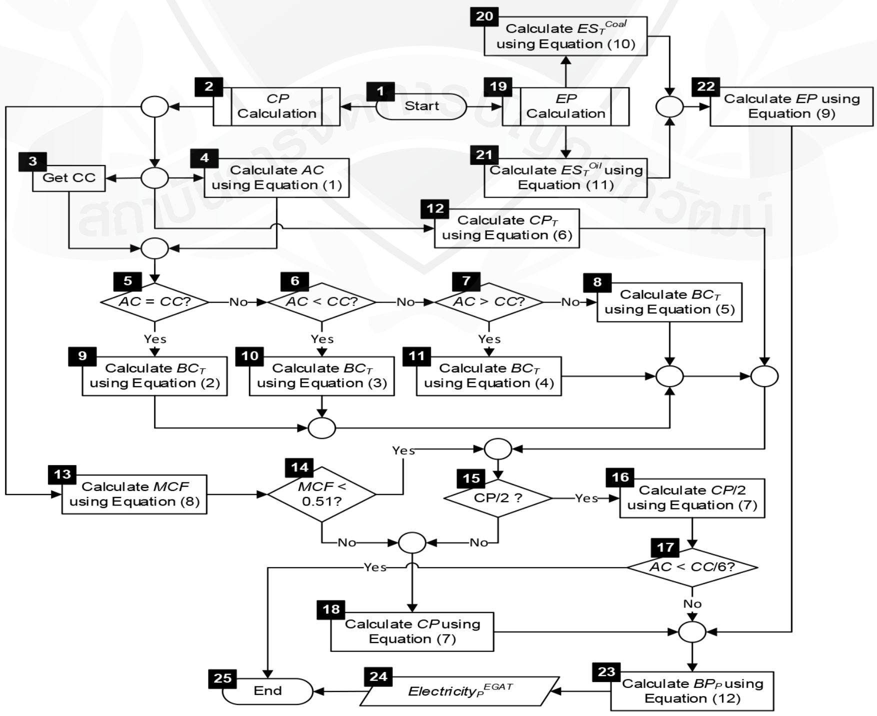


Fig. 2. Estimation process flowchart for selling price to EGAT during peak hours

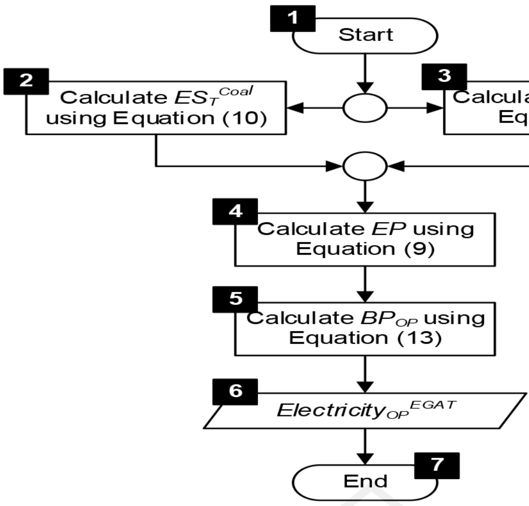


Fig. 3. Estimation process flowchart for selling price to EGAT during off-peak hours

C. Unit Profits

Profits can be calculated by directly subtracting the cost from selling price. However, they must be individually calculated due to different electrical products, different groups of customers and different times of use. For example, the electricity profit gained from EGAT during peak hours can be estimated by subtracting the unit cost of production from the selling price to EGAT during peak hours.

III. Spreadsheet-Based Economic Load Dispatch Program For Profit Maximization

A. Conceptual Design

1. Functionality

The developed program was given a name *NPS Economic Dispatcher* and must be embedded with a computation algorithm that is applicable to manage ED of the dual power plants by generating the optimal ED solutions under several restrictions with the maximum profit to the company.

2. Usability

NPS Economic Dispatcher must have a user-friendly human-software interface that requires only minimum knowledge in computer operation and application platform of users. They should not be required to understand the computation algorithm and the data entry procedure should be simple without spending excessive physical and mental efforts.

3. Validity

NPS Economic Dispatcher must provide valid solutions to the production planners that assists them in making decisions about ED management. After developing the program, the optimal solutions given by the program should be consistent with actual practices.

B. Formulation of Linear Optimization Model

1) Decision Variables

Let $X_{EGAT,A}^{Electricity}$ = Number of electricity units produced and sold to EGAT by Plant A

$X_{EGAT,B}^{Electricity}$ = Number of electricity units produced and sold to EGAT by Plant B

$X_{AA,A}^{Electricity}$ = Number of electricity units produced and sold to AA by Plant A

$X_{AA,B}^{Electricity}$ = Number of electricity units produced and sold to AA by Plant B

$X_{Industry,A}^{Electricity}$ = Number of electricity units produced and sold to Industry by Plant A

$X_{Industry,B}^{Electricity}$ = Number of electricity units produced and sold to Industry by Plant B

$X_{AA,A}^{LPSteam}$ = Number of LP steam units produced and sold to AA by Plant A

$X_{AA,B}^{LPSteam}$ = Number of LP steam units produced and sold to AA by Plant B

$X_{AA,A}^{MPSteam}$ = Number of MP steam units produced and sold to AA by Plant A

$X_{AA,B}^{MPSteam}$ = Number of MP steam units produced and sold to AA by Plant B

2) Objective Functions

a) Maximize the Profit during Peak Hours

$$\text{Maximise}\quad P_{EGAT,P}^{Electricity}X_{EGAT,A}^{Electricity} + P_{EGAT,P}^{Electricity}X_{EGAT,B}^{Electricity} + P_{AA,P}^{Electricity}X_{AA,A}^{Electricity} + P_{AA,P}^{Electricity}X_{AA,B}^{Electricity} + P_{Industry,P}^{Electricity}X_{Industry,A}^{Electricity} + P_{Industry,P}^{Electricity}X_{Industry,B}^{Electricity} + P_{AA,P}^{LPSteam}X_{AA,A}^{LPSteam} + P_{AA,P}^{LPSteam}X_{AA,B}^{LPSteam} + P_{AA,P}^{MPSteam}X_{AA,A}^{MPSteam} + P_{AA,P}^{MPSteam}X_{AA,B}^{MPSteam} \quad (2)$$

where $P_{EGAT,P}^{Electricity}$ = Profit per unit from selling electricity to EGAT during peak hours

$P_{AA,P}^{Electricity}$ = Profit per unit from selling electricity to AA during peak hours

$P_{Industry,P}^{Electricity}$ = Profit per unit from selling electricity to Industry during peak hours

$P^{LPSteam}_{AA,P}$ = Profit per unit from selling LP steam to AA during peak hours

$P^{MPSteam}_{AA,P}$ = Profit per unit from selling MP steam to AA during peak hours

b) Maximize the Profit during Off-Peak Hours

Maximize
$$P^{Electricity}_{EGAT,OP}X^{Electricity}_{EGAT,A} + P^{Electricity}_{EGAT,OP}X^{Electricity}_{EGAT,B} + P^{Electricity}_{AA,OP}X^{Electricity}_{AA,A} + P^{Electricity}_{AA,OP}X^{Electricity}_{AA,B} + P^{Electricity}_{Industry,OP}X^{Electricity}_{Industry,A} + P^{Electricity}_{Industry,OP}X^{Electricity}_{Industry,B} + P^{LPSteam}_{AA,OP}X^{LPSteam}_{AA,A} + P^{LPSteam}_{AA,OP}X^{LPSteam}_{AA,B} + P^{MPSteam}_{AA,OP}X^{MPSteam}_{AA,A} + P^{MPSteam}_{AA,OP}X^{MPSteam}_{AA,B} \quad (3)$$

where $P^{Electricity}_{EGAT,OP}$ = Profit per unit from selling electricity to EGAT during off-peak hours

$P^{Electricity}_{AA,OP}$ = Profit per unit from selling electricity to AA during off-peak hours

$P^{Electricity}_{Industry,OP}$ = Profit per unit from selling electricity to Industry during off-peak hours

$P^{LPSteam}_{AA,OP}$ = Profit per unit from selling LP steam to AA during off-peak hours

$P^{MPSteam}_{AA,OP}$ = Profit per unit from selling MP steam to AA during off-peak hours

3) Model Constraints

Subject to
$$0 \leq X^{Electricity}_{EGAT,A} \leq 91{,}800 \quad (4)$$
$$0 \leq X^{Electricity}_{EGAT,B} \leq 91{,}800 \quad (5)$$
$$X^{Electricity}_{AA,A} + X^{Electricity}_{AA,B} = 60{,}000 \quad (6)$$
$$X^{Electricity}_{Industry,A} + X^{Electricity}_{Industry,B} = 140{,}000 \quad (7)$$
$$X^{LPSteam}_{AA,A} + X^{LPSteam}_{AA,B} \geq 11{,}184 \quad (8)$$
$$X^{MPSteam}_{AA,A} + X^{MPSteam}_{AA,B} \geq 906 \quad (9)$$
$$\frac{X^{LPSteam}_{AA,A} + X^{LPSteam}_{AA,B} + X^{MPSteam}_{AA,A} + X^{MPSteam}_{AA,B}}{X^{Electricity}_{EAGT,A} + X^{Electricity}_{EGAT,B} + X^{Electricity}_{AA,A} + X^{Electricity}_{AA,B} + X^{Electricity}_{Industry,A} + X^{Electricity}_{Industry,B} + X^{LPSteam}_{AA,A} + X^{LPSteam}_{AA,B} + X^{MPSteam}_{AA,A} + X^{MPSteam}_{AA,B}} \quad (10)$$
$$X^{Electricity}_{EGAT,A} + X^{Electricity}_{AA,A} + X^{Electricity}_{Industry,A} + X^{LPSteam}_{AA,A} + X^{MPSteam}_{AA,A} \leq 149{,}000 \quad (11)$$
$$X^{Electricity}_{EGAT,B} + X^{Electricity}_{AA,B} + X^{Electricity}_{Industry,B} + X^{LPSteam}_{AA,B} + X^{MPSteam}_{AA,B} \leq 149{,}000 \quad (12)$$
$$X^{Electricity}_{EGAT,A} + X^{Electricity}_{EGAT,B} + X^{Electricity}_{AA,A} + X^{Electricity}_{AA,B} + X^{Electricity}_{Industry,A} + X^{Electricity}_{Industry,B} + X^{LPSteam}_{AA,A} + X^{LPSteam}_{AA,B} + X^{MPSteam}_{AA,A} + X^{MPSteam}_{AA,B} \leq 298{,}000 \quad (13)$$

The dual objectives represented by Eq. (2) and Eq. (3) are to maximize the profits during peak hours and off-peak hours, respectively. Basically, they are the sum of the products of profit per unit and electricity/steam units produced and cannot be combined into a single objective function since the profits per unit for two periods are distinct and the optimal answers of how much electricity and steam to be generated and sold to the clients for both periods must be separately obtained. If only one set of constraints is assigned in a combined single objective, the answers will not be optimal and realistic.

TABLE II
Description of Model Constraints

Equation	Constraint Description
Eq. (4)	The number of electricity units produced and sold to EGAT by Plant A must not exceed 91,800 kW (102% of the CC). Otherwise, the CP will be halved resulting in decreased unit price and profit obtained. Alternatively, nothing produced and sold is possible as EGAT has other SPPs ready, but NPS has to be charged.
Eq. (5)	The number of electricity units produced and sold to EGAT by Plant B must not exceed 91,800 kW (102% of the CC). Otherwise, the CP will be halved resulting in decreased unit price and profit obtained. Alternatively, nothing produced and sold is possible as EGAT has other SPPs ready, but NPS has to be charged.
Eq. (6)	The sum of electricity units produced and sold to AA by Plant A and Plant B must exactly equal to 60,000 kW. Zero unit is not allowed since AA needs electricity for its manufacturing and office buildings.
Eq. (7)	The sum of electricity units produced and sold to Industry by Plant A and Plant B must exactly equal to 140,000 kW. Zero unit is not allowed since Industry needs electricity for its manufacturing and office buildings.
Eq. (8)	The sum of LP steam units produced and sold to AA by Plant A and Plant B must be at least 11,184 kW (in an equivalent unit of electricity). The upper limit is not specified since AA requires tons of steam for its manufacturing.
Eq. (9)	The sum of MP steam units produced and sold to AA by Plant A and Plant B must be at least 906 kW (in an equivalent unit of electricity). The upper limit is not specified since AA requires tons of steam for its manufacturing.
Eq. (10)	According to the SPP cogeneration rule, this constraint is to make sure that the sum of LP steam units and MP steam units generated is minimum 10% of the EGG.
Eq. (11)	To ensure the sum of electricity and steam units produced and sold to all customers must not surpass the maximum capacity of Plant A of 149,000 kW. Please note that the installed generating capacity of Plant A is 164,000 kW but 15,000 kW is used by its station service.
Eq. (12)	To ensure the sum of electricity and steam units produced and sold to all customers must not surpass the maximum capacity of Plant B of 149,000 kW. Please note that the installed generating capacity of Plant B is 164,000 kW but 15,000 kW is used by its station service.
Eq. (13)	To ensure the sum of electricity units and steam units produced and sold to all customers must not surpass the total maximum capacity of both plants of 298,000 kW. Please note that the total installed generating a capacity of Plant A and Plant B is 328,000 kW but 30,000 kW is consumed altogether by their station services.

C. Computation Algorithm

The program utilizes the quantitative determination procedure to further develop a computation algorithm and generate the optimal solutions on how to manage ED of dual cogeneration power plants while achieving the maximum profit. Fig. 4 presents a flowchart of the computation algorithm.

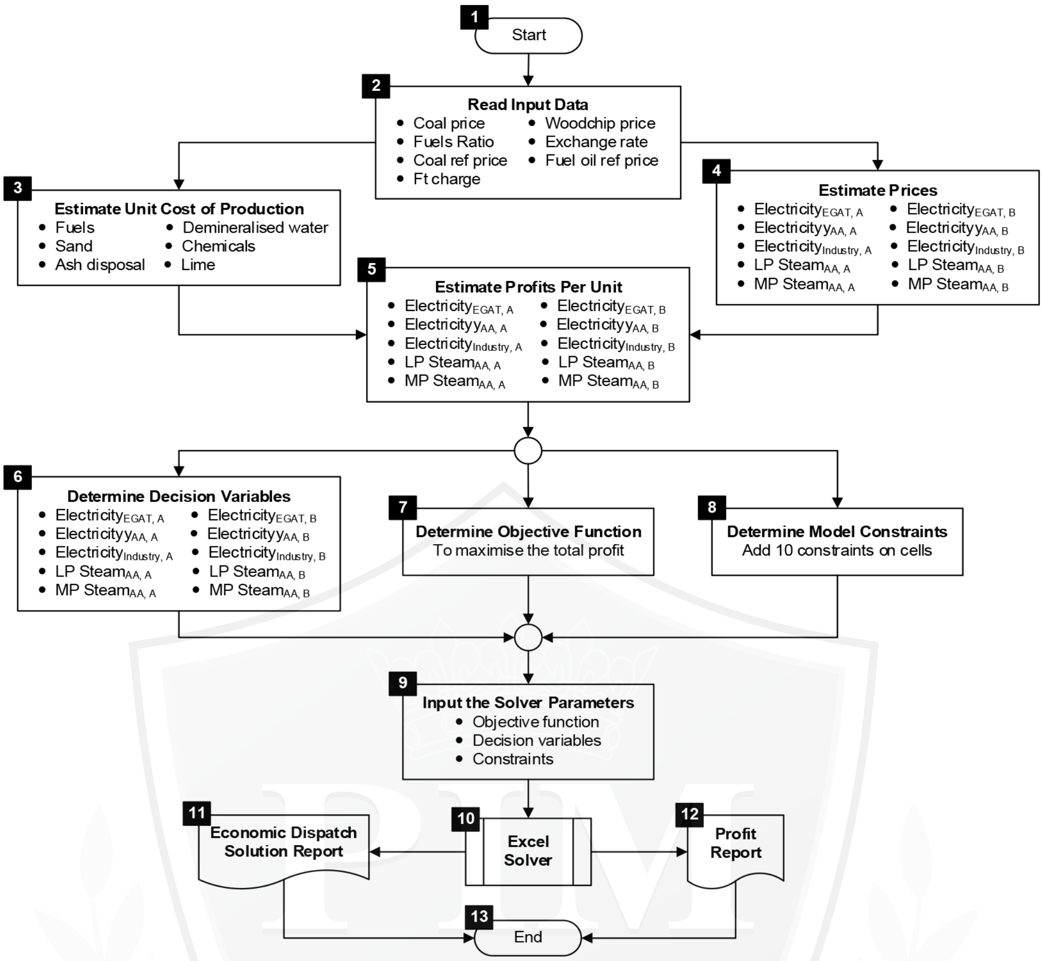


Fig. 4. Flowchart of the computation algorithm

This flowchart can be applied to solve the models for peak and off-peak periods. The computation algorithm starts by reading seven types of input data. The unit cost of production and the prices are estimated using the input data, which can be used to estimate the profits per profit later. Next, the decision variables, the objective function of maximizing the total profit and the model constraints are determined and embedded in cells of the spreadsheets. Then, the Solver Parameters tool in the Microsoft Excel program is input with these three components. Finally, the Excel Solver generates two reports that summarize the model results in terms of ED solution management and profit.

D. Assumptions of the Program

NPS Economic Dispatcher program is subject to the following set of assumptions:

- The unit cost of production is wholly represented by the variable cost, covering mixed fuels of coal and biomass, consumable raw materials and transportations.
- The fuel cost has already been minimised and found that the optimal mixed-fuel ratio is to use 95% of coal and 5% of woodchip as biomass.
- The unit cost of production is the same for electricity and steam when both products are converted into equivalent gross generation (EGG) units.
- All variables and parameters in the models are deterministic (known and constant).
- There is no discount rate on the prices of electricity and steam for all customers.
- The profit per unit is a direct subtraction of the unit cost of production from the selling price per unit. There is no other type of profit considered in this case.
- Heat loss during the generation process is neglected. Input mixed fuels are heated and entirely converted into electricity and steam.
- Power loss in the transmission and the distribution lines is neglected. Total electricity generated can be transmitted to EGAT and distributed to AA and Industry customers.
- Demands for electricity and steam are deterministic. Contract agreements are long-term, and requesting to change capacity at any specifictime is not allowed.
- The SPP cogeneration regulation of minimum 10% heat output remains unchanged.

E. Feasible Scenarios towards Maximum Profit

Considering the total maximum capacity of 298,000 kW, it is impossible to generate and fully sell electricity to EGAT by each plant according to the *CC* of 90,000 kW each. Only 85,910 kW or less (298,000 – 60,000 – 140,000 – 11,184 – 906 = 85,910 kW) is left to be partially sold to EGAT when the generating capacity is fully operated during both periods.

The following two scenarios, as shown in Table 3, were thereby created and used to replace the original constraints of Eq. (4) and Eq. (5). A simulation was performed in the next section to see which of the two allows NPS to achieve the maximum profit.

TABLE III

TWO FEASIBLE SCENARIOS TOWARDS MAXIMUM PROFIT ACHIEVEMENT

Plant	Scenario 1	Scenario 2
A	$MCF \geq 0.51$ $45{,}500 \leq AC \leq 91{,}800$	$MCF \geq 0.51$ $45{,}500 \leq AC \leq 91{,}800$
B	Loss *MCF* AC = 0	Loss *MCF* $15{,}000 \leq AC \leq 45{,}400$

In Scenario 1, Plant A is set to generate and sell electricity between 45,500 kW and 91,800 kW, where the value of *MCF* is 0.51 at a minimum so that *CP* will not be halved. Whilst, Plant B is set to generate and sell nothing to EGAT, where the value of MCF is zero, and the firm will have to be charged some penalty fee.

In Scenario 2, Plant A is set exactly the same as Scenario 1 to avoid a 50% reduction of *CP*. Whereas, Plant B is set to generate and partly sell electricity between 15,000 kW and 45,500 kW to EGAT, where the value of *MCF* is below 0.51 and *CP* is halved.

F. Program Development

NPS Economic Dispatcher was developed using Microsoft Excel 2013 (64-bit) on a notebook computer with Microsoft Windows 10 Pro Operating System and Intel Core i5 Central Process Unit. The users are not required to enable a 'Macro' option before running the program, simply just working with the spreadsheets.

There are eight spreadsheets embedded in the program. The first group of four spreadsheets is for mainly data entry, data processing and data storage: (1) Unit Cost sheet, (2) EGAT Price sheet, (3) AA and Industry Price sheet and (4) Steam Price sheet. The second group of four spreadsheets acts like a display screen showing the objective function, the series of constraints and the results in terms of optimal ED management solutions, profits and a financial penalty, if necessary.

Fig. 5, Fig. 6, Fig. 7 and Fig. 8 illustrate the four display screens and the results of (1) Peak Hours under Scenario 1, (2) Peak Hours under Scenario 2, (3) Off-Peak Hours under Scenario 1 and (4) Off-Peak Hours under Scenario 2, respectively.

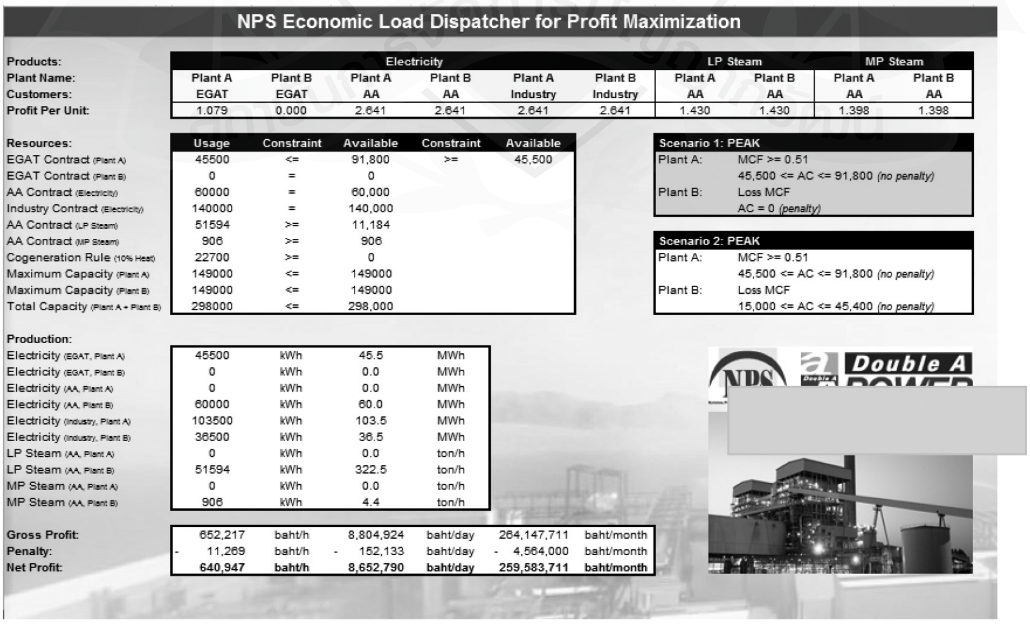
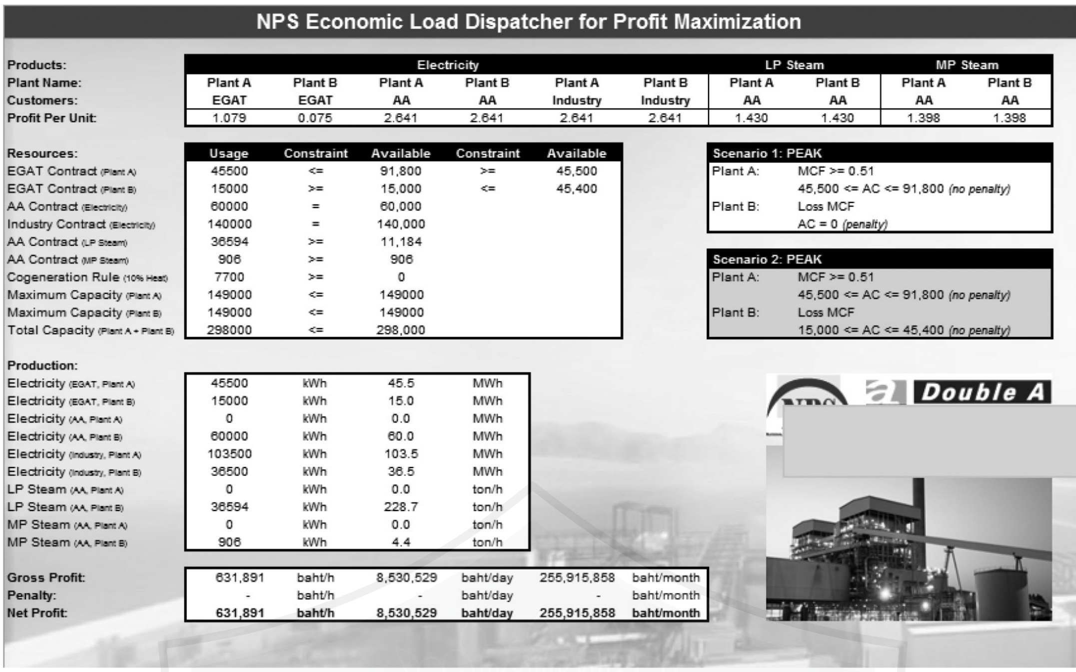


Fig. 5. NPS Economic Dispatcher for peak hours under scenario 1



NPS Economic Load Dispatcher for Profit Maximization

Products:	Electricity						LP Steam		MP Steam	
Plant Name:	Plant A	Plant B	Plant A	Plant B	Plant A	Plant B	Plant A	Plant B	Plant A	Plant B
Customers:	EGAT	EGAT	AA	AA	Industry	Industry	AA	AA	AA	AA
Profit Per Unit:	1.079	0.075	2.641	2.641	2.641	2.641	1.430	1.430	1.398	1.398

Resources:	Usage	Constraint	Available	Constraint	Available
EGAT Contract (Plant A)	45500	<=	91,800	>=	45,500
EGAT Contract (Plant B)	15000	>=	15,000	<=	45,400
AA Contract (Electricity)	60000	=	60,000		
Industry Contract (Electricity)	140000	=	140,000		
AA Contract (LP Steam)	36594	>=	11,184		
AA Contract (MP Steam)	906	>=	906		
Cogeneration Rule (10% Heat)	7700	>=	0		
Maximum Capacity (Plant A)	149000	<=	149000		
Maximum Capacity (Plant B)	149000	<=	149000		
Total Capacity (Plant A + Plant B)	298000	<=	298,000		

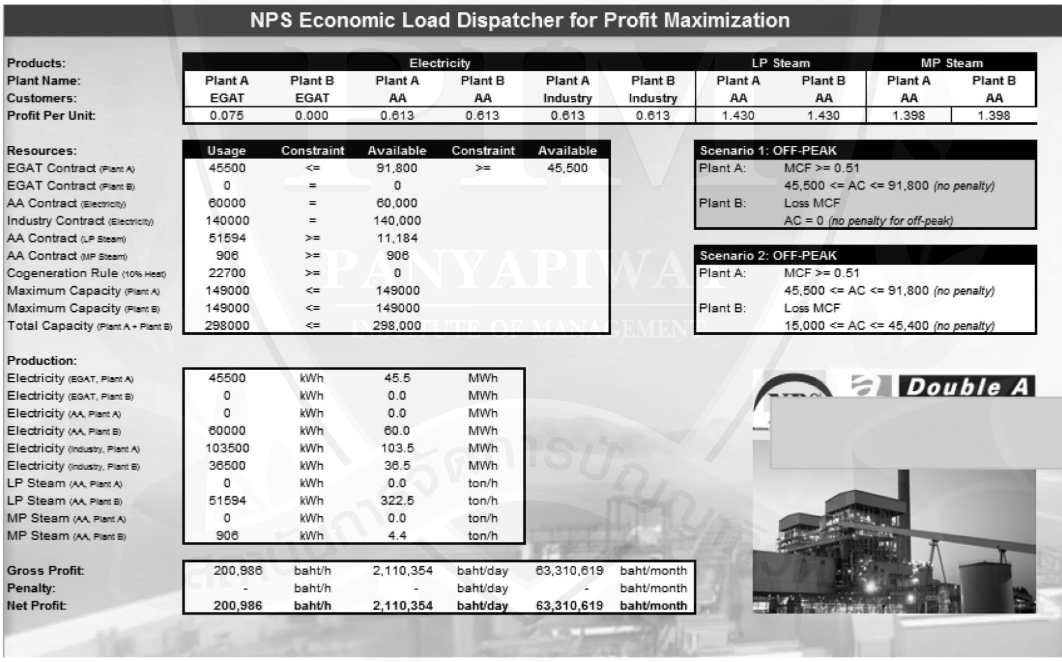
Scenario 1: PEAK
Plant A: MCF >= 0.51
45,500 <= AC <= 91,800 *(no penalty)*
Plant B: Loss MCF
AC = 0 *(penalty)*

Scenario 2: PEAK
Plant A: MCF >= 0.51
45,500 <= AC <= 91,800 *(no penalty)*
Plant B: Loss MCF
15,000 <= AC <= 45,400 *(no penalty)*

Production:				
Electricity (EGAT, Plant A)	45500	kWh	45.5	MWh
Electricity (EGAT, Plant B)	15000	kWh	15.0	MWh
Electricity (AA, Plant A)	0	kWh	0.0	MWh
Electricity (AA, Plant B)	60000	kWh	60.0	MWh
Electricity (Industry, Plant A)	103500	kWh	103.5	MWh
Electricity (Industry, Plant B)	36500	kWh	36.5	MWh
LP Steam (AA, Plant A)	0	kWh	0.0	ton/h
LP Steam (AA, Plant B)	36594	kWh	228.7	ton/h
MP Steam (AA, Plant A)	0	kWh	0.0	ton/h
MP Steam (AA, Plant B)	906	kWh	4.4	ton/h

Gross Profit:	631,891	baht/h	8,530,529	baht/day	255,915,858	baht/month
Penalty:	-	baht/h	-	baht/day	-	baht/month
Net Profit:	**631,891**	**baht/h**	**8,530,529**	**baht/day**	**255,915,858**	**baht/month**

Fig. 6. NPS Economic Dispatcher for peak hours under scenario 2



NPS Economic Load Dispatcher for Profit Maximization

Products:	Electricity						LP Steam		MP Steam	
Plant Name:	Plant A	Plant B	Plant A	Plant B	Plant A	Plant B	Plant A	Plant B	Plant A	Plant B
Customers:	EGAT	EGAT	AA	AA	Industry	Industry	AA	AA	AA	AA
Profit Per Unit:	0.075	0.000	0.613	0.613	0.613	0.613	1.430	1.430	1.398	1.398

Resources:	Usage	Constraint	Available	Constraint	Available
EGAT Contract (Plant A)	45500	<=	91,800	>=	45,500
EGAT Contract (Plant B)	0	=	0		
AA Contract (Electricity)	60000	=	60,000		
Industry Contract (Electricity)	140000	=	140,000		
AA Contract (LP Steam)	51594	>=	11,184		
AA Contract (MP Steam)	906	>=	906		
Cogeneration Rule (10% Heat)	22700	>=	0		
Maximum Capacity (Plant A)	149000	<=	149000		
Maximum Capacity (Plant B)	149000	<=	149000		
Total Capacity (Plant A + Plant B)	298000	<=	298,000		

Scenario 1: OFF-PEAK
Plant A: MCF >= 0.51
45,500 <= AC <= 91,800 *(no penalty)*
Plant B: Loss MCF
AC = 0 *(no penalty for off-peak)*

Scenario 2: OFF-PEAK
Plant A: MCF >= 0.51
45,500 <= AC <= 91,800 *(no penalty)*
Plant B: Loss MCF
15,000 <= AC <= 45,400 *(no penalty)*

Production:				
Electricity (EGAT, Plant A)	45500	kWh	45.5	MWh
Electricity (EGAT, Plant B)	0	kWh	0.0	MWh
Electricity (AA, Plant A)	0	kWh	0.0	MWh
Electricity (AA, Plant B)	60000	kWh	60.0	MWh
Electricity (Industry, Plant A)	103500	kWh	103.5	MWh
Electricity (Industry, Plant B)	36500	kWh	36.5	MWh
LP Steam (AA, Plant A)	0	kWh	0.0	ton/h
LP Steam (AA, Plant B)	51594	kWh	322.5	ton/h
MP Steam (AA, Plant A)	0	kWh	0.0	ton/h
MP Steam (AA, Plant B)	906	kWh	4.4	ton/h

Gross Profit:	200,986	baht/h	2,110,354	baht/day	63,310,619	baht/month
Penalty:	-	baht/h	-	baht/day	-	baht/month
Net Profit:	**200,986**	**baht/h**	**2,110,354**	**baht/day**	**63,310,619**	**baht/month**

Fig. 7. NPS Economic Dispatcher for off-peak hours under scenario 1

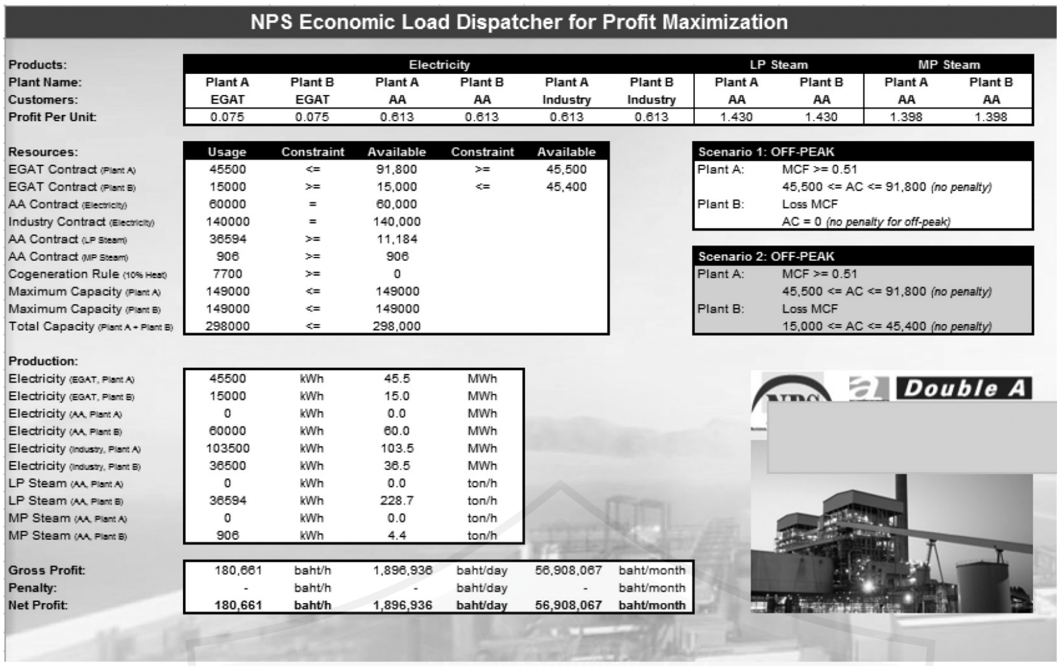


Fig. 8. NPS Economic Dispatcher for off-peak hours under scenario 2

G. Summary of the Illustrative Simulation

Considering the profit report illustrated in Table IV. Scenario 1 is optimal for both peak hours and off-peak hours due to the total maximum net profit of 322,894,330 THB per month relative to Scenario 2 although the company will have to be fined by 4,564,000 THB since no electricity is generated and sold to EGAT during peak hours.

TABLE IV
PROFIT REPORT

Time of Use Scenario	Peak Hours		Off-Peak Hours		24 Hours
	Scenario 1	Scenario 2	Scenario 1	Scenario 2	Scenario 1
Gross Profit	264,147,711	255,915,858	63,310,619	56,908,067	327,458,330
Penalty	(4,564,000)	-	-	-	(4,564,000)
Net Profit	259,583,711	255,915,858	63,310,619	56,908,067	322,894,330

Table V shows the ED management report. In terms of ED management solution when Scenario 1 is chosen due to the optimal profit. It can be observed that the simulation results of Scenario 1 between peak hours and off-peak hours are the same. EGAT partially receives electricity generated by Plant A without losing *MCF* but receives nothing from Plant B in both periods. Whereas, the demands for both electricity and steam of AA and the industry is fully met. LP steam is produced and supplied to AA more than its lower demand limit because the unit profit is greater than the unit profit of MP steam.

TABLE V
Economic dispatch management report

Time of Use Scenario	Peak Hours		Off-Peak Hours	
	Scenario 1	Scenario 2	Scenario 1	Scenario 2
$Electricity_A^{EGAT}$	45,500	45,500	45,500	45,500
$Electricity_B^{EGAT}$	0	15,000	0	15,000
$Electricity_A^{AA}$	0	0	0	0
$Electricity_B^{AA}$	60,000	60,000	60,000	60,000
$Electricity_A^{Industry}$	103,500	103,500	103,500	103,500
$Electricity_B^{Industry}$	36,500	36,500	36,500	36,500
$LPSteam_A^{AA}$	0	0	0	0
$LPSteam_B^{AA}$	51,594	36,594	51,594	36,594
$MPSteam_A^{AA}$	0	0	0	0
$MPSteam_B^{AA}$	906	906	906	906

To sum up, the best alternative towards maximum profit achievement can be the one when all demand may not be necessarily fully satisfied according to the contracted capacity. With the underlying ED principle of minimizing total cost together with the proposed program, the performances of NPS should be improved in terms of ED and financial return.

IV. Results and Discussion

NPS Economic Dispatcher program was derived from the desire of the company to consolidate the production and operations planning of its power plants as the current status is now being managed independently without the consideration of ED implementation. The consequences are too much fuel inventory and unplanned maintenance scheduling arising from machine breakdown, affecting the cost to increase while the revenue and the profit from selling electricity and steam to decline consistently over the last few years.

Fig. 9 and Fig. 10 show the revenue and the cost, respectively of electricity and steam by Plant A and Plant B under the best alternative ED solution (Scenario 1), given that their installed capacity accounts for 45.18% of the total (328 out of 726.05 MW), and therefore the revenue and the cost should represent by about the same per cent of the installed capacity.

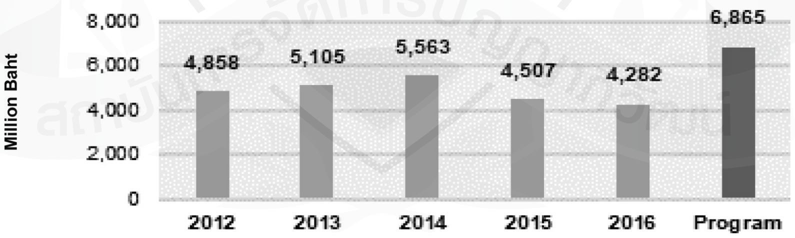


Fig. 9. Revenue from electricity and steam by Plant A and Plant B

The revenue gained from selling electricity and steam has declined from 5,563 million THB in 2014 to 4,282 million THB in 2016 or by 23.03%. This was mainly due to the lack of coordination between the power plants to produce and dispatch electric power and steam to the customers. Also, the decreases in revenue were partially from the effects of significant reductions in coal reference price, fuel oil reference price and Ft charge, which are the key variables used to compute *CP* and *EP* of the electricity prices. Conversely, with the revenue generated by the program, NPS is expected to receive a higher revenue than before, about 6,865 million THB after implementing ED management.

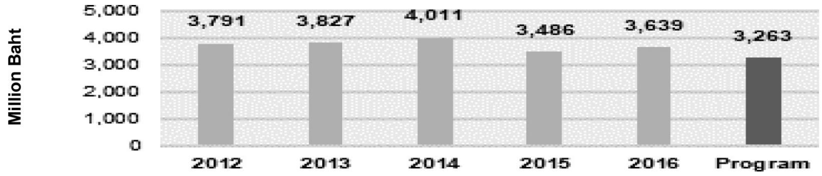


Fig. 10. Cost of electricity and steam production by Plant A and Plant B

Considering the cost of production, it has fluctuated since 2012. This was because of stocking up too much coal fuel and force maintenance cost due to machine breakdown. Over the past five years, an average cost of production represented 77.49% of the revenue; nevertheless, the cost of production generated by the program decreased dramatically to only 47.53% of the revenue after implementing ED management.

Fig. 11 illustrates the profit received from the sales of electricity and steam. Since 2014, the profit has decreased continually from 1,552 million THB to only 644 million THB in 2016, dropping by 58.51%. With the program results, the company's profit should be maximized to 3,552 million THB using Scenario 1.

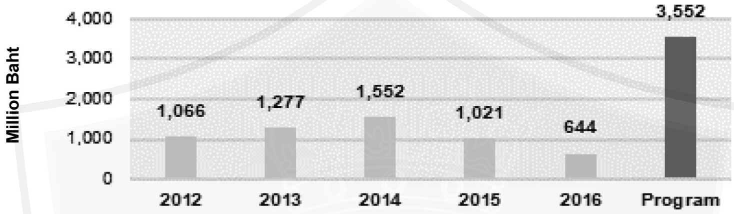


Fig. 11. Profit from electricity and steam by Plant A and Plant B

Table VI below summarises the revenue, cost, profit and EGG per year of Scenario 1. As the Scenario 1 yielded the optimal profit to NPS compared with Scenario 2, the Scenario 1 was therefore chosen for comparison of profit between Scenario 1 and Scenario 2.

TABLE VI
REVENUE, COST, PROFIT AND EGG OF SCENARIO 1

Scenario 1	Revenue [1]	Cost [1]	Profit [1]	EGG [2]
Peak Hours	4,650,693,482	1,835,619,044	2,855,420,818	1,327,590,000
Off-Peak Hours	2,124,120,508	1,427,703,701	696,416,808	1,032,570,000
Total	6,865,364,370	3,263,322,744	3,551,837,626	2,360,160,000

Remark: [1] THB
[2] kWh

Table VII shows the revenue per unit, cost per unit, profit per unit and equivalent gross generation (EGG). It can be seen the total amount of electricity and steam in the equivalent unit of kWh or EGG generated by the program significantly increases to 2,360,000 MWh when ED management is implemented. The average cost per unit is lowered to only 1.383 THB per kWh, while the average revenue per unit and the average profit per unit increase to 2.909 THB per kWh and 1.505 THB per kWh, respectively.

TABLE VII
REVENUE PER UNIT, COST PER UNIT, PROFIT PER UNIT AND EGG

KPI	2012	2013	2014	2015	2016	Program
Revenue Per Unit [1]	3.041	2.985	3.133	2.687	2.435	2.909
Cost Per Unit [1]	2.373	2.238	2.259	2.078	2.069	1.383
Profit Per Unit [1]	0.668	0.747	0.874	0.609	0.366	1.505
EGG [2]	1,597	1,710	1,775	1,677	1,759	2,360

Remark: [1] THB per kWh
[2] '000 MWh

Overall, Scenario 1 generated the same optimal ED management decision for both times of use. EGAT has not dispatched electricity according to the amount of *CC* with both plants. For Plant A, only 45.5 out of 90 MWh was sold to EGAT to maintain *MCF* of at least 51% so that *CP* would not be deducted by 50% that could result in the selling price to be very cheap. For Plant B, the report suggests that NPS should not produce and sell anything to EGAT although the company had to be charged due to unavailability. The reason for this is because NPS had to fully or at minimum supply electricity and electricity to AA and Industry customers first, see the model constraints since they could not operate manufacturing in their factories without electric power or steam. With this, 85.91 MW or less was remained for supplying to EGAT from both of the plants and that is why it was really impossible to fully meet *CC* with EGAT regardless of either Plant A or Plant B. However, it is the best scenario alternative that allows NPS to achieve the maximum profit in the end.

Fig. 12 presents the sensitivity report of Peak Scenario 1) from Excel Solver after solving the economic dispatch problem with the objective of achieving maximum profit. This sensitivity report assists a decision maker to know whether the solution is relatively insensitive to reasonable changes in one or more of the parameters of the problem.

From the sensitivity report, the solution values on how much electricity and steam to be generated and dispatched to each of the customers are shown in the Final Value column of the Variable Cells panel. It can be seen that all the customers, except EGAT, were fully satisfied according to the amounts of contracted capacity shown in the Final Value of the Constraints panel. Some customers were even supplied more than they want, such as LP steam to AA, but that was not going to result in any consequences.

Microsoft Excel 15.0 Sensitivity Report
Worksheet: [NPS Economic Dispatcher.xlsx] Peak (Scenario 1)
Report Created: 16:19:46

Variable Cells

Cell	Name	Final Value	Reduced Cost	Objective Coefficient	Allowable Increase	Allowable Decrease
C21	Electricity Sold to EGAT by Plant A	45500	0	1.0786	0.3512	1E+30
C22	Electricity Sold to EGAT by Plant B	0	0	0.0000	1E+30	1E+30
C23	Electricity Sold to AA by Plant A	0	-1.77636E-15	2.6405	1.77636E-15	1E+30
C24	Electricity Sold to AA by Plant B	60000	0	2.6405	1E+30	1.77636E-15
C25	Electricity Sold to Industry by Plant A	103500	0	2.6405	1E+30	0
C26	Electricity Sold to Industry by Plant B	36500	0	2.6405	0	1E+30
C27	LP Steam Sold to AA by Plant A	0	0	1.4298	0	1E+30
C28	LP Steam Sold to AA by Plant B	51594	0	1.4298	1E+30	0
C29	MP Steam Sold to AA by Plant A	0	0	1.3978	0	1E+30
C30	MP Steam Sold to AA by Plant B	906	0	1.3978	0.0320	0

Constraints

Cell	Name	Final Value	Shadow Price	Constraint R.H. Side	Allowable Increase	Allowable Decrease
C11	Electricity CC with AA	60000	1.2107	60000	22700	60000
C13	LP Steam CC with AA	51594	0	11184	40410	1E+30
C14	MP Steam CC with AA	906	-0.0320	906	40410	906
C15	SPP Cogeneration Rule	22700	0	0	22700	1E+30
C9	Electricity CC with EGAT (Plant A)	45500	0	91800	1E+30	46300
C9	Electricity CC with EGAT (Plant A)	45500	-0.3512	45500	22700	36500
C10	Electricity CC with EGAT (Plant B)	0	-1.4298	0	22700	0
C12	Electricity CC with Industry	140000	1.2107	140000	22700	36500
C16	Maximum Capacity of Plant A	149000	0	149000	36500	4.36557E-11
C17	Maximum Capacity of Plant B	149000	0	149000	1E+30	4.36557E-11
C18	Total Maximum Capacity	298000	1.4298	298000	4.36557E-11	25222.22222

Fig. 12. Sensitivity Report for NPS Economic Dispatcher Peak (Scenario 1)

In the Variable Cells panel, information about the effect of changes to the objective function coefficients are presented. The upper and the lower limits to which the coefficients of profit per unit of electricity or steam can be changed without impacting the optimality of the original solution is revealed by the values in the Allowable Increase and the Allowable Decrease columns. For example, the allowable increase in the objective function coefficient for Electricity Sold to EGAT by Plant A is 0.3512 THB. This means that if the unit profit of Electricity Sold to EGAT increases to 1.2000 THB (i.e. an increase of 0.1214 THB from the current value of 1.0786 THB), it is still optimal to generate and sell the numbers of electricity and steam units to the customers specified in the Final Value column.

Microsoft Excel 15.0 Sensitivity Report
Worksheet: [NPS Economic Dispatcher.xlsx] Off-Peak (Scenario 1)
Report Created: 16:43:03

Variable Cells

Cell	Name	Final Value	Reduced Cost	Objective Coefficient	Allowable Increase	Allowable Decrease
C21	Electricity Sold to EGAT by Plant A	45500	0	0.0748	1.3550	1E+30
C22	Electricity Sold to EGAT by Plant B	0	0	0	1E+30	1E+30
C23	Electricity Sold to AA by Plant A	0	-2.22045E-16	0.6127	2.22045E-16	1E+30
C24	Electricity Sold to AA by Plant B	60000	0	0.6127	1E+30	2.22045E-16
C25	Electricity Sold to Industry by Plant A	103500	0	0.6127	1E+30	0
C26	Electricity Sold to Industry by Plant B	36500	0	0.6127	0	1E+30
C27	LP Steam Sold to AA by Plant A	0	0	1.4298	0	1E+30
C28	LP Steam Sold to AA by Plant B	51594	0	1.4298	1E+30	0
C29	MP Steam Sold to AA by Plant A	0	0	1.3978	0	1E+30
C30	MP Steam Sold to AA by Plant B	906	0	1.3978	0.0320	0

Constraints

Cell	Name	Final Value	Shadow Price	Constraint R.H. Side	Allowable Increase	Allowable Decrease
C11	Electricity CC with AA	60000	-0.8171	60000	22700	60000
C13	LP Steam CC with AA	51594	0	11184	40410	1E+30
C14	MP Steam CC with AA	906	-0.0320	906	40410	906
C15	SPP Cogeneration Rule	22700	0	0	22700	1E+30
C9	Electricity CC with EGAT (Plant A)	45500	0	91800	1E+30	46300
C9	Electricity CC with EGAT (Plant A)	45500	-1.3550	45500	22700	36500
C10	Electricity CC with EGAT (Plant B)	0	-1.4298	0	22700	0
C12	Electricity CC with Industry	140000	-0.8171	140000	22700	36500
C16	Maximum Capacity of Plant A	149000	0	149000	36500	3.63798E-11
C17	Maximum Capacity of Plant B	149000	0	149000	1E+30	3.63798E-11
C18	Total Maximum Capacity	298000	1.4298	298000	3.63798E-11	25222.22222

Fig. 13. Sensitivity Report for NPS Economic Dispatcher Off-Peak (Scenario 1)

Fig. 13 shows the sensitivity report for Off-Peak under Scenario 1. The numbers of electricity and steam to be sold to the customers are exactly the same as Peak under Scenario 1. However, the objective function coefficients are changed as the profit per unit between peak hours and off-peak hours are distinct. In this case, the allowable increase in the objective function coefficient for Electricity Sold to EGAT by Plant A is 1.3550 THB. This indicates if the unit profit of Electricity Sold to EGAT rises to 1.0748 THB (i.e. a rise of 1 THB from the current value of 0.0748 THB), the ED management solution is still optimal.

V. Conclusion

This paper developed a spreadsheet-based optimization program for strategically managing economic dispatch of electricity and steam for the dual power plants to ultimately achieve the maximum profit. The development of *NPS Economic Dispatcher* was derived from the independent managed production and operations without the applications of economic dispatch among the power plants. As a consequence, the revenue has been affected and the profit has been declining consecutively for the last few years.

Apart from the decreases in revenue and profits, lack of coordination among the power plants results in the cost of goods sold to increase even more units of electricity and steam could be sold over years. This is in a contrast to what it should have actually been in both theory and real practices. Fig. 14 illustrates the comparison between the profit from selling electricity and steam over the last five years and the profit generated by the developed program.

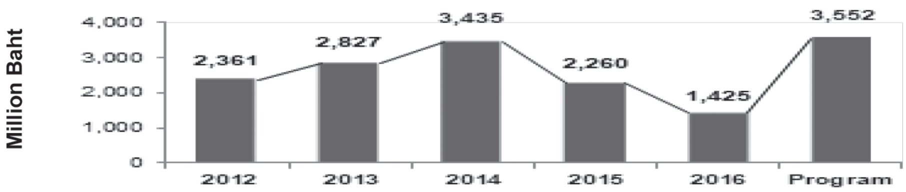


Fig. 14. Profit from Electricity and Steam in the Past 5 Years and from the Program

It can be clearly seen that the program yielded the optimal annual profit resulting from applying and well-managed economic dispatch of the dual power plants. The profit generated by NPS Economic Dispatcher of 3,552 million THB can be calculated from the sum of monthly profit from peak hours under Scenario 1 of 259,583,711 THB and monthly profit from off-peak hours under Scenario 1 of 63,310,619 THB, multiplied by eleven months, given that one month is for yearly plant maintenance outage.

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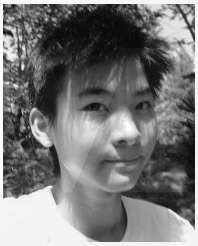

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