ECONOMIC DISPATCH MANAGEMENT OF ELECTRIC POWER PLANTS FOR PROFIT MAXIMIZATION

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เศรษฐศาสตร์การจ่ายกำลังไฟฟ้าของกลุ่มโรงไฟฟ้าเพื่อการทำกำไรสูงสุด

นายสรจักร จันทร์จิระวิทยา

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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สรจักร จันทร์จิระวิทยา : เศรษฐศาสตร์การจ่ายกำลังไฟฟ้าของกลุ่มโรงไฟฟ้าเพื่อการทำกำไรสูงสุด (ECONOMIC DISPATCH MANAGEMENT OF ELECTRIC POWER PLANTS FOR PROFIT MAXIMIZATION) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ศ. ดร. ปารเมศ ชุติมา, 230 หน้า.

กลยุทธ์ที่สำคัญสำหรับธุรกิจโรงไฟฟ้าในอุตสาหกรรมจ่ายไฟฟ้าแบบผ่อนคลายกฎระเบียบคือการรักษาความสามารถในการทำกำไร โดยเฉพาะอย่างยิ่งบริษัทพลังงานเอกชนที่อนุญาตให้ประชาชนทั่วไปมีส่วนร่วมในการลงทุนเพื่อขยายธุรกิจ หมากกลยุทธ์ที่เหมาะสมคือการทำกำไรให้ได้มากที่สุดจากการจำหน่ายไฟฟ้าและไอน้ำ ในขณะเดียวกันต้องจัดหาทุนสำหรับแผนการวิจัยและการพัฒนาเพื่อแสวงหาแหล่งพลังงานทางเลือกใหม่มาทดแทนเชื้อเพลิงที่มีอยู่อย่างจำกัดและเพื่อลดต้นทุนการผลิต

รายงานประจำปีของบริษัทเปิดเผยว่ารายได้หลักมาจากการจำหน่ายไฟฟ้าและไอน้ำ แต่ตลอดระยะเวลาสามปีที่ผ่านมากำไรได้ลดลงอย่างต่อเนื่อง การลดลงของกำไรส่วนหนึ่งมาจากผลกระทบภายนอก ได้แก่ การกำหนดราคาแบบผูกขาดและปัจจัยเชิงเศรษฐกิจที่ผันผวน ในขณะที่บริษัทไม่สามารถปรับราคาจำหน่ายไฟฟ้าและไอน้ำให้สอดคล้องกับการเปลี่ยนแปลงของผลกระทบดังกล่าวเองได้ ผู้บริหารระบุว่าสาเหตุหลักของการที่กำไรลดลงเป็นผลจากการผลิตและการดำเนินงานอย่างอิสระ ปราศจากการประยุกต์การจ่ายโหลดอย่างประหยัดในกลุ่มโรงไฟฟ้า ด้วยเหตุนี้ทำให้บริษัทต้องเก็บสำรองเชื้อเพลิงไว้มากเกินไป และยังต้องกำหนดเวลาบำรุงรักษาโรงไฟฟ้าแบบไม่ได้วางแผนอีกด้วย ส่งผลให้ความสามารถในการผลิตลดลงและไม่สามารถจ่ายไฟฟ้าให้แก่ลูกค้าได้

โปรแกรมแผ่นตารางทำการหรือสเปรดชีตถูกพัฒนาขึ้นเพื่อช่วยตัดสินใจการบริหารจัดการการผลิตและจำหน่ายไฟฟ้าและไอน้ำให้แก่ลูกค้าในชั่วโมงที่มีความต้องการไฟฟ้าสูงและชั่วโมงที่มีความต้องการไฟฟ้าต่ำ เป้าหมายที่สำคัญคือเพื่อให้ได้รับกำไรสูงสุดโดยที่ไม่ละเมิดข้อตกลงทางสัญญากับลูกค้า กระบวนการกำหนดเชิงปริมาณสำหรับต้นทุนต่อหน่วย ราคา และกำไรถูกสร้างขึ้นและฝังในโปรแกรมสเปรดชีต ตามด้วยการพัฒนาตัวแบบโปรแกรมเชิงเส้นทางคณิตศาสตร์เพื่อให้ได้ผลกำไรรวมที่ดีที่สุด และสุดท้ายสองสถานการณ์ที่เป็นไปได้ถูกจำลองขึ้นเพื่อเปรียบเทียบและให้ทราบถึงทางเลือกที่ดีที่สุดที่นำไปสู่การได้รับกำไรสูงสุด

ผลการจำลองแสดงให้เห็นว่าสถานการณ์ที่เหมาะสมที่สุดสามารถประยุกต์ใช้ได้ทั้งในชั่วโมงที่มีความต้องการไฟฟ้าสูงและชั่วโมงที่มีความต้องการไฟฟ้าต่ำ แม้ว่าบริษัทจะไม่สามารถตอบสนองความต้องการไฟฟ้าทั้งหมดให้แก่ลูกค้าบางกลุ่มได้ แต่สถานการณ์นี้ให้ผลกำไรรวมสูงสุดและสามารถผ่านข้อจำกัดของระบบไฟฟ้ากำลังและกฎหมายที่เกี่ยวข้อง โดยที่ไม่ละเมิดข้อตกลงทางสัญญากับลูกค้าอย่างร้ายแรงเมื่อเปรียบเทียบกับอีกสถานการณ์หนึ่ง ผลการวิเคราะห์ความไวของปัจจัยต่างๆ ได้แก่ อัตราแลกเปลี่ยน ราคาถ่านหิน ราคาน้ำมันเตา สัดส่วนการใช้เชื้อเพลิงถ่านหินต่อเชื้อเพลิงชีวมวล และค่าไฟฟ้าผันแปร พบว่าปัจจัยเหล่านี้ทั้งหมดมีผลกระทบอย่างมากต่อความสามารถในการทำกำไร ซึ่งจะช่วยให้บริษัทพินิจพิจารณาถึงการเปลี่ยนแปลงที่อาจเกิดขึ้นโดยไม่ส่งผลกระทบต่อแนวทางที่ดีที่สุดของการบริหารจัดการการจ่ายโหลดอย่างประหยัดได้

ภาควิชา	ศูนย์ระดับภูมิภาคทางวิศวกรรมระบบการผลิต	ลายมือชื่อนิสิต ....
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The key strategy of power plant business in the deregulated electricity supply industry is to maintain profitability, especially for a private energy company that allows general public to take part in investment for business expansion. The right strategy move is to maximize profit from selling electricity and steam, at the same time fund intensive research and development programs to seek for new alternative energy in order to supplant limited fuels and lower cost of production.

The corporate annual report revealed that the major source of revenue comes from the sales of electricity and steam; however, profit has continually declined over the past few years. Decreasing profit was partially due to external effects, such as monopolized pricing determination and volatile economic factors. The company is not allowed to proportionally adjust the prices of electricity and steam to changes in such effects. The executives identified that the main cause of decreases in profit is from independent production and operations management without economic dispatch applications among the power plants. Consequently, the company had to excessively stock up fuels and schedule unplanned maintenance, which resulted in lower productivity and incapability to deliver some outputs to the customer.

A spreadsheet-based program was developed to help make a small-scaled managerial decision, how much electricity and steam should be generated and sold to each customer group during periods of peak hours and off-peak hours to achieve maximum profit without violating the sales contract agreements. Several quantitative determination processes for unit cost, prices and profits were constructed and later embedded in the spreadsheet program. The mathematical linear programming model for optimizing total profit during each of the periods was formulated. Two feasible scenarios for each of the periods were comparatively simulated to see the best alternative towards profit maximization.

The simulation results show that the optimal scenario is applicable to both periods. Although some electricity demand could not be fully satisfied resulting in penalty, this scenario provided the total maximum profit and was able to satisfy the power systems and the legal constraints while not severely violating the sales contract agreements relative to another scenario. The results from sensitivity analysis of exchange rate, coal price, fuel oil price, coal-to-biomass fuel ratio and fuel transfer charge also show that all of these factors have strong effects on profitability, allowing to examine a series of possible changes that will not affect the optimal solution of economic dispatch management.

Department:	Regional Centre for Manufacturing Systems Engineering	Student's Signature	....
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ABBREVIATIONS

AA	Double A (1991) Public Company Limited
AC	Actual Capacity
AEDP	Alternative Energy Development Plan
AHP	Analytic Hierarchy Process
AIS	Artificial Immune System
AP	Availability Payment
ASTM	American Society for the Testing of Materials
BC	Billing Capacity
BCG	Boston Consulting Group
BFB	Bubbling Fluidised Bed
BJI	Barlow Jonker Index
BJ JPU	Barlow Jonker: Japanese Power Utilities
BP	Billing Payment
BTU	British Thermal Unit
CC	Contracted Capacity
CFB	Circulating Fluidised Bed
CHP	Combined Heat and Power
COD	Commercial Operation Date
CP	Capacity Payment
CPI	Consumer Price Index
CS	Cuckoo Search
CSR-DIW	Corporate Social Responsibility, Department of Industrial Works
DAED	Department of Alternative Energy Development
DE	Differential Evolutionary
DMF	Department of Mineral Fuels

DOEB	Department of Energy Business
DP	Dynamic Programming
ED	Economic Dispatch
EEP	Energy Efficiency Plan
EGAT	Electricity Generating Authority of Thailand
EGG	Equivalent Gross Generation
EHIA	Environmental Health Impact Assessment
EIA	Environmental Impact Assessment
EIS	Electric Supply Industry
ELD	Economic Load Dispatch
EP	Energy Payment
EPPO	Energy Policy and Planning Office
ERC	Energy Regulatory Commission
ES	Escalation
ESB	Enhanced Single Buyer
ESI	Electric Supply Industry
ESP	Electrostatic Precipitator
EV	Electric Vehicle
FMO	Force Maintenance Outage
FS	Fuel Saving
Ft	Fuel Transfer
FX	Foreign Exchange
GA	Genetic Algorithm
GDP	Gross Domestic Product
GWh	Gigawatt-Hour
ICT	Information Communication Technology
ID	Identification

IGA	Improved Genetic Algorithm
IPDE	Improved Parallel Differential Evolutionary
IPO	Initial Public Offering
IPP	Independent Power Producer
ISO	International Standards Organisation
JPU	Japanese Power Utility Index
Kg	Kilogram
KJ	Kilojoule
KPI	Key Performance Indicator
KW	Kilowatt
KWh	Kilowatt-Hour
KV	Kilovolt
LNG	Liquefied Natural Gas
LP	Linear Programming
LP Steam	Low Pressure Steam
MCF	Monthly Capacity Factor
MEA	Metropolitan Electricity Authority
MILP	Mixed-Integer Linear Programming
MoE	Ministry of Energy
MP Steam	Medium Pressure Steam
MS	Management Science
MW	Megawatt
MWh	Megawatt-Hour
NEPC	National Energy Policy Council
NEPO	National Energy Policy Office
NESDB	National Economic and Social Development Board
NPS	National Power Supply Public Company Limited

OHSAS	Occupational Health and Safety Assessment Series
OR	Operations Research
PDP	Power Development Plan
PEA	Provincial Electricity Authority
PMO	Plant Maintenance Outage
PPA	Power Purchase Agreement
PSO	Particle Swarm Optimisation
PWA	Provincial Waterworks Authority
QN	Quasi Newton
QPSO	Quantum Particle Swarm Optimisation
REP	Renewable Energy Promotion
RC	Request Capacity
SET	Stock Exchange of Thailand
SOE	State-Owned Enterprise
SPP	Small Power Producer
SWOT	Strength, Weakness, Opportunity and Threat
TIS	Thai Industrial Standards
TS	Tabu Search
TOU	Time of Use
UK	United Kingdom
US	United States
VSPP	Very Small Power Producer

CHAPTER 1 INTRODUCTION

This chapter presents the needs for establishing this research project including its significance of the general research area, analytical background of the case study company and research overview highlighting statement of the problem together with the research question, hypothesis development, specific objective, assumptions of the study, scope of the project, expected outcomes and the structure of the dissertation.

1.1 Significance of the Project to Its General Research Area

Operations research (OR) is the application of scientific method for solving real-world business problems. The term operations research can be used interchangeably with management science (MS) since the ultimate goal is to both help businesses solve their managerial difficulties. Regardless of the words used, the heart is to determine an extreme objective of complex problems, mostly to maximize profit or to minimize cost, and to provide optimal solutions in the pursuit of better strategic decision-making.

Since its early time in the 1950s, the area of OR has been extensively applied in several industries, such as energy industry where a number of electricity companies heavily rely on OR in planning generating operations and trading power. Nevertheless, these applications of OR tend to evolve with technological breakthrough in the power system and changes underway in the electric sector, such as intricate market structure, environmental problems, socio-economic concerns and resource constraints.

This research project contributes to the general area of OR through applying its model of linear programming in an electricity company to strategically address its encountering problems arising from the operational planning and management while numerous distinct limitations are present. It is also expected that the findings of this research project will provide useful and value added insights for both researchers and practitioners to assist them deal with the challenging issues in an effective manner.

1.2 About National Power Supply Company

National Power Supply (NPS) is a subsidiary of Double A Power Group whose main operating energy business is to generate and sell electricity to the state-owned power enterprise Electricity Generating Authority of Thailand (EGAT), nearby factories and industrial estates with a portion for its internal requirements. The company was established in 1995 with an initial registered capital of 1 billion baht. Throughout more than 20 years of experience, NPS becomes one of the leaders in energy business and has achieved sustainable growth along with placing significance on both community and environment surrounded by the company.

In 2010, NPS became a public company due to selling debentures to the public shareholders with the aim to raise funds for expanding its energy business, and the company is now in the stage of preparing initial public offering (IPO) in order to enter into the Stock Exchange of Thailand (SET). This means that NPS needs to pursue the right strategic moves thereafter. The strategy is to maximize profits from generating and selling electricity and steam while funding its intensive research and development for new alternative energy resources to supplant limited fuels of oil and natural gas.

1.2.1 Competitive Business Position

At present, NPS is in a strong financial position and making an annual cash of approximately 600 million baht, even after funding the intensive R&D program and paying back to the shareholders (NPS, 2016). Although the cash generated seems to be relatively low, the company is still able to sustain level of competitiveness in the industry over the years. This robust position can be explained using the Five Forces Model by Michael Porter (Porter, 2008) as illustrated in Figure 1.

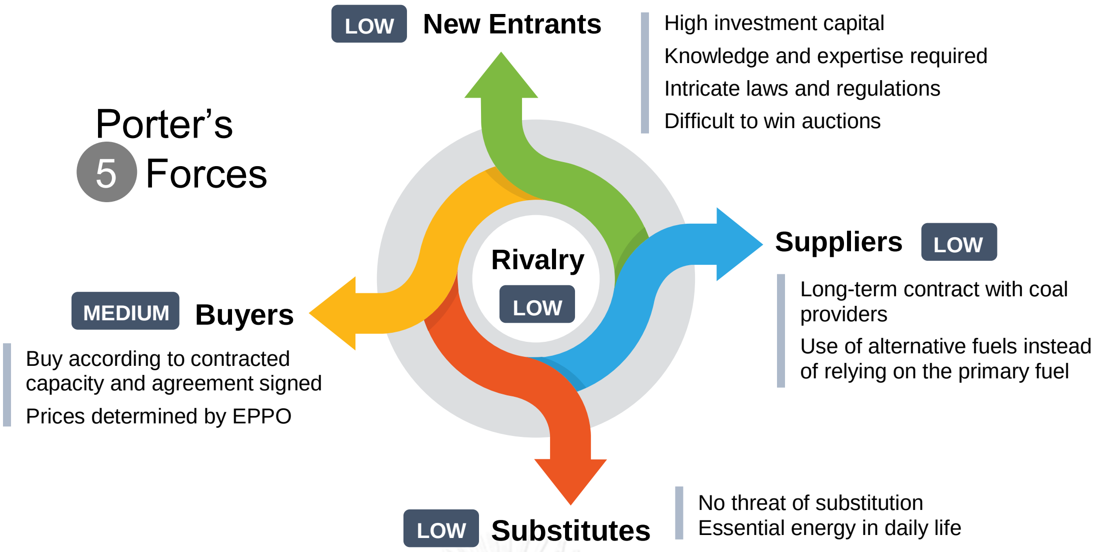


Figure 1: Porter's Five Forces Model for NPS

The competition is not so aggressive since there are not many competitors while the demand keeps increasing and the prices are monopolised by the regulator. Given the current situation, new entry into the industry is almost unlikely due to high investment capital needed, considerable expertise required and complex structure of laws and regulations. For years, NPS has made long-term contracts with the suppliers to be provided primary fuels, such as coal, whereas the company has also searched for new alternative fuels itself, so the suppliers have low bargaining power in the supply chain. There is no threat of substitutes as electricity is considered a basic and essential energy in daily life.

NPS's customers tend to have bargaining power. Medium and small-sized customers must be sufficiently supplied with the amount of electricity and/or steam specified on their contracts; otherwise, they have the legal right to sue the company. Whereas, the only large enterprise customer EGAT does not generally have this much leverage because there are still many other power producers who are able to supply electricity to EGAT adequately.

As a cogeneration power plant, two energy products in the forms of power (electricity) and heat (steam) are generated and placed in the high growth rate and low market share quadrant of the BCG matrix (Henderson, 1970), as depicted in Figure 2.

Figure 2: The Growth-Share Matrix for NPS

Source: Adapted from Henderson (1970)

Both products are demanding due to rising population, economic expansion, and industry growth. Despite not so many players, the market share is relatively low as NPS is monitored and enforced by regulators, thus gaining more share is not easy. Regarding product adoption and life cycle, the products are considered the early majority and in the growth phase, see Figure 3, where a position towards star is likely.

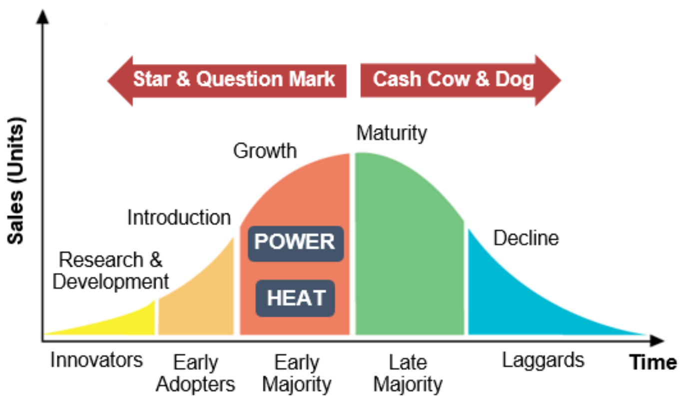


Figure 3: Product Adoption and Product Life Cycle for NPS

1.2.2 Recent Industry Trends and Future Competitive Environment

Thailand has a number of private power plant entrepreneurs and slightly relies on imported power. As of the end of 2016, the total installed generating capacity was 41,556 MW, excluding VSSP. Out of this was imported 9%, and the remaining belongs to EGAT, IPP and SPP of 40%, 36% and 15%, respectively as shown in Figure 4.

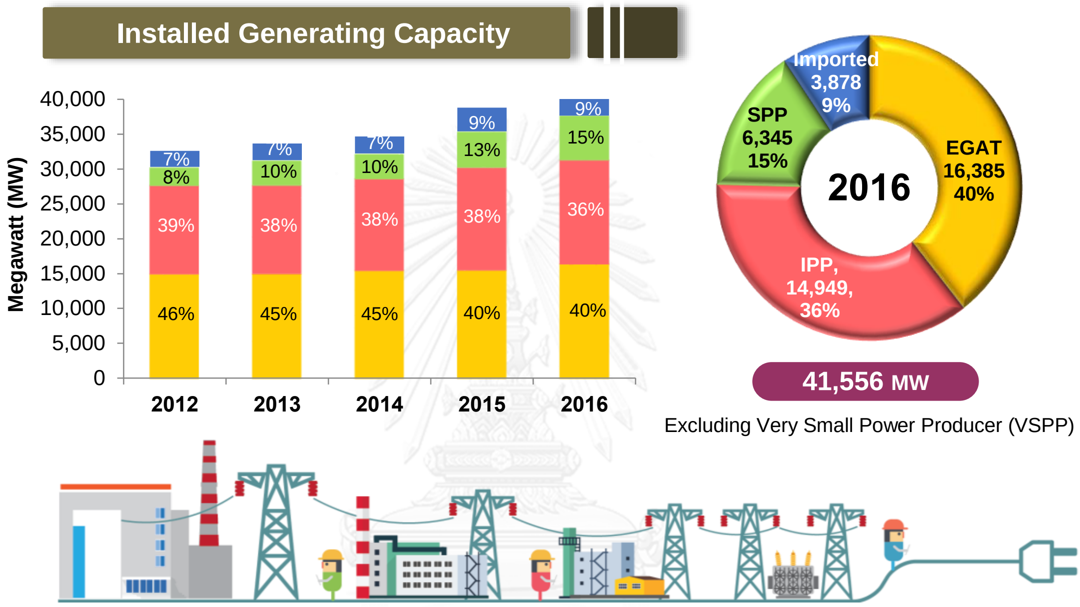


Figure 4: Installed Generating Capacity from 2012 to 2016

Source: Adapted from EPPO (2017a)

In 2016, the total power generation was 199,567 GWh increasing by 3.8% from 2015. This number can be classified by type of fuel used: 63% natural gas, 19% coal and lignite, 10% imported, 6% renewable energy, 2% hydro and 0.2% oil. Figure 5 illustrates the power generation classified by type of fuel over years. It can be observed that the amount of power generated kept rising over years. There were the increasing uses of renewable energy and imported, but the uses of hydro, natural gas and coal and oil were decreasing.

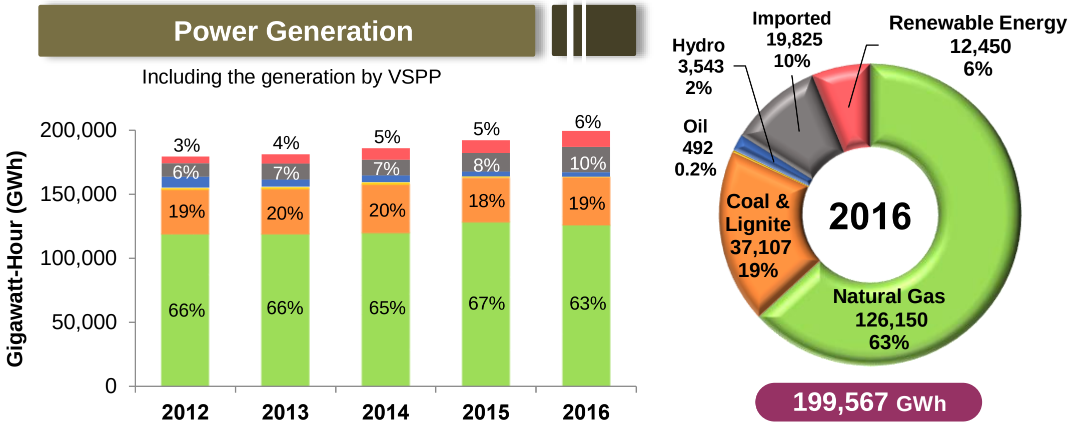


Figure 5: Power Generation Classified by Fuel Type from 2012 to 2016

Source: Adapted from EPPO (2017b)

For electricity consumption in 2016, there were 182,847 GWh for the whole country accelerating by 4.6% from the previous year. This amount represents industrial, business, residential and the remaining consumptions of 47.5%, 24.4%, 24.0% and 4.1%, respectively. Figure 6 below presents the growth rate and the share of electricity consumption in each sector.

Electricity Consumption

Sector	Growth (%)	Share (%)
Residential	▲ 6.4	24.0
Business	▲ 5.1	24.4
Industrial	▲ 3.4	47.5
Gov. and Non-Profit	▲ 12.2	0.1
Agriculture	▼ 31.0	0.2
Other	▲ 4.7	2.2
Free of Charge	▲ 8.0	1.6

Figure 6: National Electricity Consumption in 2016

Source: Adapted from EPPO (2017c)

The 2017 electricity consumption is expected to increase by 1.3% according to the projected economic growth of between 3.3% to 3.8% (Macroeconomic Strategy and Planning Office, 2017), supported by the recovery and the improvement of global economy and the expansion of key trading partners. These favourable conditions will result in more electricity consumption, especially in industrial estates, tourism services and residential sectors, where the demands for electric power are very high.

Regarding the competitive environment, Thailand presently not only has the main public power producer EGAT, but also has several private power producers IPP and SPP promoted by the government in order to supply to the consistently increased demand. There is some imported portion from nearby foreign producers under power purchase agreement (PPA). However, the competition is not highly intense because the power plant business requires huge investment and considerable expertise, even after supporting from the public sector by investing in several power plant schemes with the goal to expand the installed generating capacity in accordance with Power Development Plan (PDP) 2015.

Moreover, the electricity generated by some producers is directly sold to industrial customers, where those producers' power plants are located, and mostly operated by owners of industrial estates themselves or the owners are joint ventures of those power plants. This is the case for NPS since the company is the only private power producer in the industrial area; hence, the competition is deemed to be relatively low.

NPS aims to utilise biomass as alternative fuel for generating electricity, which helps help lower the cost, diversify the risk of fuel sourcing and align with the Energy Efficiency Plan (EEP) 2015 and the Alternative Energy Development Plan (AEDP) 2012-2021. More importantly, NPS has been improving the competitive position through its operational policies in terms of quality and services, such as maintaining stability of generation and transmission, improving and developing transmission system, managing production costs, sourcing raw materials, updating production technology and developing people. This is to handle with the increased demand and the economic growth, which in turn will lead to enhancing competitive advantage and improving profitability of the company in the near future.

1.2.3 Key External Factors and Strategic Reactions

The significant threat to the power plant business is from fuel sourcing. Coal, black liquor and biomass are three types of primary fuel used for generating electricity and steam. However, NPS found out that coal is the most risky because it is provided by the external suppliers whereas the other two are internally supplied by the subsidiaries of the company.

Fluctuation of coal prices shown in Figure 7 is greatly influential since the cost of fuel typically covers 80-90% of unit cost of production. The coal must be tested and qualified by certain standards, such as ISO and American Society for the Testing Materials (ASTM), so inability to provide coal at specified quantity and quality by the suppliers can be another threat.

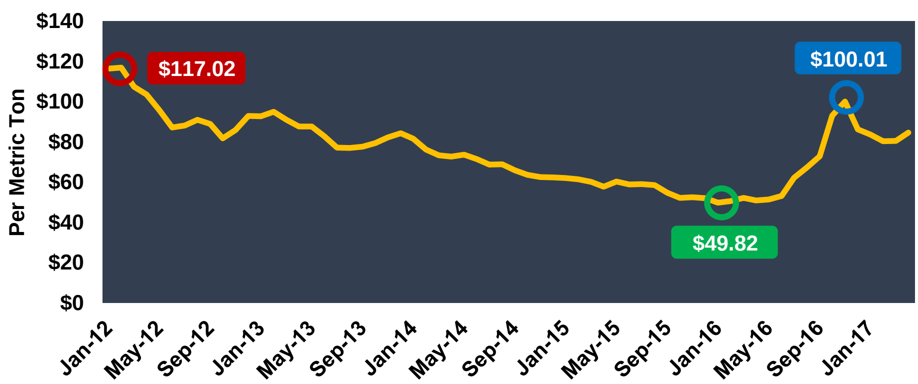


Figure 7: Coal Prices by Barlow Jonker Index (BJI)

Source: Adapted from Trading Economics (2017)

Changes in costs of primary fuel significantly impact profitability of the power plant business; nevertheless, NPS might not be able to increase the prices of electricity and steam proportionally to the increases of fuel cost. NPS can partially push the burden resulting from the changes in fuel prices, but this depends upon the contract agreements for individual type of customer. For example, the NPS-EGAT agreement allows the electricity prices to be partially quoted with changes in coal prices; conversely, the electricity prices on the NPS-Industrial Customer agreement must follow the ones determined by the Provincial Electricity Authority (PEA) in which Fuel Transfer Charge (Ft) is concerned.

From analysis of the industry trend and the competitive business environment discussed previously plus further analysis in this section, here are the key external factors and the strategic reactions by NPS which can be summarised in Table 1.

Table 1: Summary of External Factors and Strategic Reactions

External Factors	Strategic Reactions
• Increasing electricity consumption in the residential, business and industrial sectors whose demands are very high. • Slowing uses of hydro, natural gas, coal and fuel oil, but more use of alternative energy for electric power production. • Fluctuating coal prices affecting profit per unit of electricity and steam sold.	• Aiming to grow sustaining alternative energy to meet the increased demand. • Searching fuel from various sources to minimise the risk of fuel scarcity. • Researching and improving fuel quality for more effective power generation. • Mixing types of fuel to add value, manage unit cost and increase profit.

1.2.4 Corporate Strategies

NPS intends to be the power producer offering a complete range of both generation and distribution of electricity and steam, including others related supportive power generation businesses. These businesses regard fuel shipping, alternative energy and growing energy trees to enhance long-term value added for the shareholders. In addition, NPS aims to be the leading power producer in effectively using mixed fuels and residues with the goal of minimising cost of production and maximising profit. With this reason and the application of Porter's generating strategies (Porter, 1980), depicted in Figure 8, therefore explains that the competitive strategy for NPS seems to fall into cost leadership quadrant.

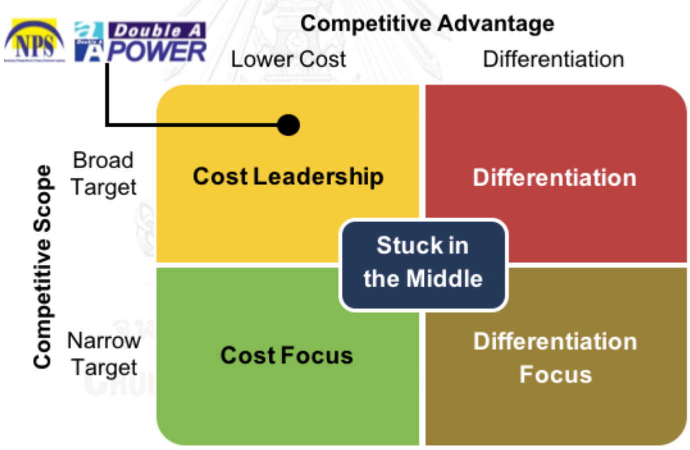


Figure 8: Porter's Competitive Strategy for NPS

Source: Adapted from Porter (1980)

Considering Miles and Snow's strategy typology (Miles *et al.*, 1978), NPS follows an analyser strategy because the company not only defences the business operations through maintaining the market share, but the company also prospects to be partly innovative through researching and developing new sources of alternative energy fuels for electric power and steam generation.

In building such corporate strategies, NPS has identified internal and external factors using the SWOT matrix as presented in Figure 9 below. The robust interactions between strengths and opportunities suggest favourable conditions allowing the company to execute a prospector strategy; conversely, the robust relations between weaknesses and threats provide lesson learnt and potential warnings allowing a defender strategy to be executed.

Strengths	**Weaknesses**
• Steady revenue from secure long-term contracts with EGAT and AA • Innovative blending use of conventional fuel and biomass • Effective power plant technology and tracking record system	• Declining profitability • Great operational risk of biomass co-fired power plants relative to traditional power plants. • High forced outages
Opportunities	**Threats**
• Increased electricity demand • Potential growth via expanding the installed capacity from IPP and SPP biddings • More role of private producers encouraged by the government	• Raising fuel prices • Fuel sourcing risk • Appreciation of Thai baht currency • Reduction of Ft charge • Change of energy policy, laws and regulations

Figure 9: SWOT Analysis for NPS

As a profit organisation, it is a must for NPS to develop the corporate strategies over the years to obtain an impressive sustaining level of profit. From the SWOT analysis above, declining profitability resulting from unsynchronised production planning and potential threats is not a good signal although growing sustainable biomass fuel has been performed for years to help reduce fuel cost and improve profit margin. This strategic approach obviously reflects through the company's vision and mission statement shown in Figure 10.

Figure 10: NPS Vision and Mission Statement

Source: Adapted from NPS (2016)

1.2.5 Production Process and Operations Management

The power plants of NPS are cogeneration or combined heat and power (CHP) which means both electricity and steam can be produced simultaneously. The total installed generating capacity of electric power and steam is 726.05 MW and 1,501.20 tons per hour, respectively. There are two key machines involved in the generation process in each of the power plants: a boiler and a steam turbine generator.

The boilers used by NPS can be separated into three different types of technology: Circulating Fluidised Bed (CBF), Bubbling Fluidised Bed (BFB) and Chemical Recovery. Each boiler technology is modern, flexible to the type of fuel used and equipped with an eliminating-preventive acid rain system and a highly efficient electrostatic precipitator (ESP) for limiting environmental impacts arising from the generation process. Figure 11 presents examples of NPS power plants using CBF, BFB and Chemical Recovery boilers.

(a) CBF for Plant A & Plant B (b) BFB for Plant G & Plant H (c) Chemical Recovery for Plant I

Figure 11: Boiler Technology Used by NPS Power Plants

Source: Adapted from NPS (2016)

For the steam turbine generators used by NPS, they are indifferent in aspect of the technology. Each steam turbine generator is equipped with an extraction condensing turbine system. This allows the steam can be extracted at different levels from low pressure to high pressure for being used in different industrial businesses for different purposes. Figure 12 illustrates the components of CFB boiler technology.

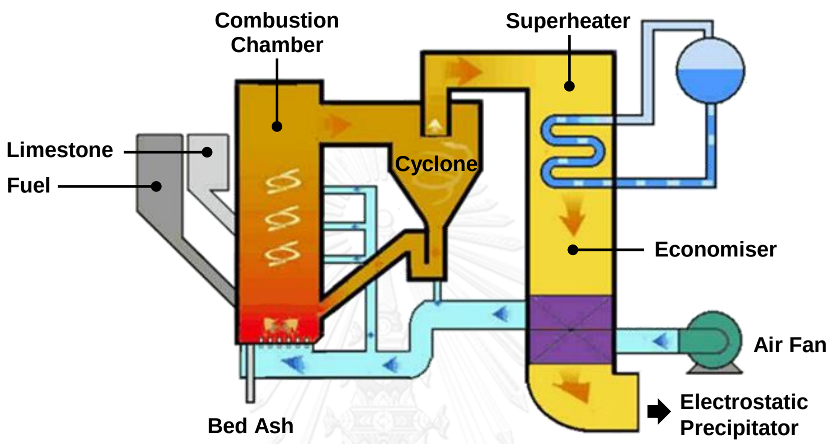


Figure 12: Circulating Fluidised Bed (CBF) Boiler Technology

Source: Adapted from ZG Boiler (2017)

CBF boiler has been used in the first two power plants: Plant A and Plant B for years due to high combustion efficiency at low temperatures to help reduce nitrogen oxide gas. The generation process starts from making hot sand circulating in a combustion chamber. The hot sand is the medium resulting complete combustion. Fuel gas is formed; meanwhile, water fed is heated by the fuel gas before passing to the economiser and the superheater, respectively. The water evaporates and becomes steam by the superheater. The steam is partially used to drive the generator, while the remaining is distributed to the customer.

In some power plants, BFB boiler is used. Similarly, the process begins with making hot sand floating in the furnace but not circulating like CFB technology. The hot sand acts as medium for combustion process; at the same time, water released through the pipe of furnace exchanges heat and becomes steam. The steam is partially used to drive the generator to produce electric power and steam and the remaining is sold to the customer.

Whereas, Chemical Recovery boiler is used in some power plants. This type of boiler differs from the other two boilers as black liquor is the fuel used in the generation process. The process starts from injecting the black liquor into the furnace of the boiler to make water temperature rise and become steam. The steam generated is partially utilised to drive the generator same as the other plants and partly distributed to the customer.

Regardless of the boiler technology used, the electricity and steam generation process for cogeneration power plants of NPS can be illustrated in Figure 13 below.

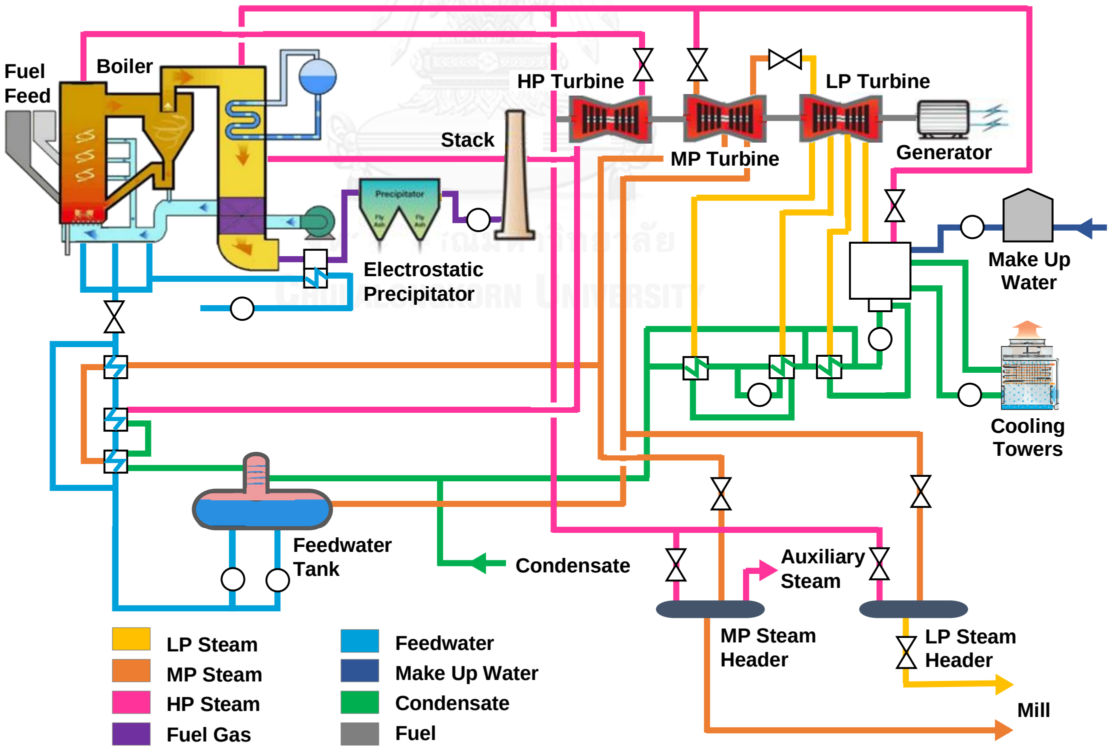


Figure 13: Electricity and Steam Generation Process of NPS

Source: Adapted from NPS (2016)

NPS determines production management policies that align with universal standards in terms of quality and operations management, such as ISO 9001, ISO 14001, TIS 18001, OHSAS 18001 and CSR-DIW, including monitoring the production system to be in line with laws and regulations. Figure 14 shows some awards and honour NPS has received.

Figure 14: Awards and Honour Received by NPS

Source: Adapted from NPS (2016)

NPS also determines an operations plan for effectiveness and keeps tracking operational performance regularly to ensure that every task managed goes in the same direction. This will lead the power plants of NPS to continuously generate electricity and steam at a full capacity with achievement of the optimal efficiency.

Here are policies and guidelines for production and operations management:

- Develop operational standards regularly for customer benefits and satisfaction
- Follow laws, standards and regulations strictly
- Lower level of risk from conflagration, chemicals and environmental issues
- Improve the generation process to minimise environmental impacts
- Allocate human resources, machines, equipment, time and budget efficiently and appropriately, and arrange training programs for staff regularly

- Communicate to stakeholders, such as customers, community and agencies, about objectives, goals and operations plans in terms of quality, environment, occupational health, safety and working environment
- Revise and improve the operational policies regularly for managerial benefits

Apart from determining those policies and guidelines, measuring operational efficiency also helps NPS to consider and evaluate whether the outputs from the production process achieve the targets as intended. For instance, electricity prices between NPS and EGAT partly rely on the operational efficiency of the power plants where are contracted with EGAT. NPS will also have to take responsibility for not complying any contract agreements by being charged some penalty fee or even being cancelled the contracts.

Hence, NPS always pays attention to the operational efficiency assessment for both generation process and power plant management by determining a set of key performance indicators (KPIs) that obviously reflect the operational performance and are consistent with the universal standards of power plant efficiency measurement and the contract agreements. The followings are such KPIs and their definitions:

- **Availability Factor**: ratio of the number of actual hours of operating a generator excluding plant maintenance hours and force maintenance hours to the total hours in a calendar year
- **Force Maintenance Outage (FMO)**: ratio of the number of force outage hours excluding planned maintenance hours to the total hours in a calendar year
- **Plant Maintenance Outage (PMO):** ratio of the number of planned maintenance hours to the total hours in a calendar year
- **Equivalent Gross Generation (EGG)**: the total amount of electricity and steam (in an equivalent unit of KWh) over actual hours of operating a generator. The amount of steam used for calculation is approximately 10% of EGG.

- **Monthly Capacity Factor (MCF)**: ratio of the units of electricity sold to EGAT to the electric energy specified on the contracts between NPS and EGAT
- **Capacity Power Purchase Agreement (Capacity PPA)**: the electric capacity must be distributed to EGAT according to the PPA between NPS and EGAT

Productivity is another factor used in the power plant business to evaluate potentiality of production process since productivity reflects capability of power plants in continuously operating their generators. This affects revenue generation for NPS meaning if productivity of the power plants is at maximum, the amount of electric power generated will be stable and can be distributed from the power plants to the customers according to the contracts.

More importantly, being able to do so means NPS can maintain the profit level at a relatively constant. The following is two capacity factors and their definitions used by the company for following up and evaluating productivity:

- **Gross Power Output**: the total amount of electric power generated over actual hours of operating a generator
- **Output Factor**: ratio of the total amount of electricity generated over actual hours of operating a generator to the total amount of electricity of the installed generating capacity over actual hours of operating a generator

1.3 Statement of the Problem

As mentioned previously, NPS was founded to operate the cogeneration power plant business using the steam turbine generators, and has invested and expanded its power plant business and many supportive businesses over the years. The company currently has ten power plants in total where are located separately. In addition, they consume different types of fuels, have different installed capacities and dispatch the outputs to different customers. Table 2 shows different details of all ten power plants.

Table 2: Type of Fuel Used, Installed Capacity and Customers of NPS

Plant	Fuel	Installed Capacity		Station Service (MW)	Customer		
		Power (MW)	Heat (ton/h)		EGAT (MW)	AA (MW)	Industry (MW)
A	Coal & Biomass[1]	164.00	100.80	15.00	90.00	60.00	140
B	Coal & Biomass[1]	164.00	100.80	15.00	90.00		
C	Coal & Biomass[2]	107.90	313.80	10.00	-	81.86	14
D	Biomass[3]	10.40	50.00	1.30	8.00	-	-
E	Biomass[3]	10.40	50.00	5.40	41.00	-	-
F	Biomass[4]	37.15	100.80				
G	Biomass[4]	37.15	100.80	13.00	50.00	24.00	-
H	Black Liquor	37.15	100.80				-
I	Black Liquor	32.90	199.40	7.80	25.00	-	-
J	Biomass[1]	125.00	384.00	15.00	-	-	-
Total		726.05	1,501.20	82.50	304.00	165.86	154

Remark: [1] Wood chip [2] Wood chip and palm branch
[3] Rice husk, wood chip and palm branch [4] Wood chip, palm branch and bark

Based on the current situation, all power plants generate electricity and steam for the customers in the way that their production and operations are managed independently. This means that each plant operates and manages its own generation process to achieve the highest efficiency at minimum cost without coordination and consideration of economic dispatch among the power plants as a whole.

Doing the production and operations like this has caused the company to encounter with stocking up too much fuels, unintentionally scheduling maintenance due to shutting down of some power plants and not being able to distribute the contract capacity to the customers, which eventually affect revenues to decrease.

The major source of revenue, see Table 3, is from selling electricity and steam, representing about 75% to 90%. However, this revenue tends to decline over five years and is being replaced by other revenues from selling water, rice bran oil and ethanol.

Table 3: Revenue Structure Classified by Type of Products and Services

Source of Revenue	2012	2013	2014	2015	2016
Electricity & Steam	10,752.85	11,299.49	12,313.63	9,975.78	9,479.36
Water	269.33	350.34	1,334.99	1,381.67	1,737.92
Rice Bran Oil	473.04	386.36	611.06	633.21	613.25
Services[1]	365.22	462.02	348.99	61.75	73.00
Ethanol	-	321.64	768.40	517.96	426.30
Other[2]	139.5	101.71	104.71	236.87	141.89
Total	11,999.94	12,921.56	15,481.78	12,807.23	12,471.72

Remark: [1] R&D, transferred goods buoys, and rental freight ships
[2] Exchange rate profit, interests, asset sales, and reversing entries of impairment assets

In 2016, the revenue from the sale of electricity and steam was 9,479.36 million baht, decreasing by 496.42 million baht or 4.98% from 2015. This was due to effects of changes in the external variables used to calculate Capacity Payment (CP) and Energy Payment (EP). For examples, the fuel oil price dropped from an average of 16.05 baht to 14.95 baht per litre, the natural gas price fell from an average of 300.47 baht to 240.12 baht per MBTU and the coal price reduced from an average of 71.23 US dollars to 63.15 US dollars per ton. Furthermore, the electricity prices for the industry customers set by PEA also declined by an average of 29 satang per unit from 2015 as the Ft charge had decreased throughout the year although there was an increase in the units of electricity and steam sold during that year.

Table 4: Revenue Structure Classified by Type of Customers

Customer	2012	2013	2014	2015	2016
EGAT	3,612.71	5,078.99	5,335.96	3,353.71	3,555.28
AA	2,683.08	2,307.32	4,228.19	3,820.47	3,922.47
Industry[1]	5,018.87	4,485.54	3,476.17	3,747.54	3,608.23
Other[2]	685.27	1,049.71	2,441.46	1,885.51	1,385.74
Total	11,999.93	12,921.56	15,481.78	12,807.23	12,471.72

Remark: [1] Companies and factories located in nearby industrial parks
[2] External customers located outside the industrial parks

From Table 4, it can be observed that the revenue gained from the customers varied from year to year although their contracts signed with NPS are long-term. This was caused by not only the external factors as discussed above but also internal factors. For instance, NPS could not supply the electricity to the customers according to the contract capacity during peak hours when the electricity prices (include CP and EP) were more expensive (due to higher demand) than off-peak hours' (include only EP). The company was then affected by dropping in the revenue or even being financially penalized in some time.

Lack of coordination and economic dispatch principles among the power plants also results cost of goods sold to rise. Particularly, the cost of making electricity, steam and water (fuel cost, maintenance cost and transportation cost), that accounts for approximately 75% of the total cost. Table 5 shows the cost structure grouped by type of products and services.

Table 5: Cost Structure Classified by Type of Products and Services

Cost	2012	2013	2014	2015	2016
Electricity, Steam, Water	8,392.32	8,472.14	8,878.21	7,716.24	8,054.40
Rice Bran Oil	473.04	388.57	869.11	600.13	565.20
Services	236.39	268.94	455.64	621.76	593.64
Ethanol	-	351.79	1,258.00	1,243.36	1,685.12
Total	11,113.75	11,494.44	11,460.96	10,181.49	10,898.36

The total cost for 2016 was 10,898.36 million baht, increasing by 716.87 million baht or 7.04% from 2015 due to many reasons. The main reason was an increase in electricity, steam and water cost of 338.16 million baht or a 4.38% increase as the number of electricity and steam units sold raised by 5.57% from the previous year.

Since 2014, the gross profit of NPS has decreased significantly from 3,916.11 million baht to 2,388.85 million baht in 2015 and to 1,431 million baht in 2016, see Table 6 and Figure 15. These decreases arisen from parametric variations of Ft charge, natural gas, fuel oil and coal prices in formula used for pricing electricity and steam.

Table 6: Profitability: Gross Profit and Net Profit in Tabular Form

Profitability	2012	2013	2014	2015	2016
Gross Profit	2,898.19	3,440.12	3,916.11	2,388.85	1,431.48
Net Profit	1,305.91	1,521.45	1,764.97	506.19	(455.19)
% Net Profit	10.88	11.77	11.40	3.95	(3.65)

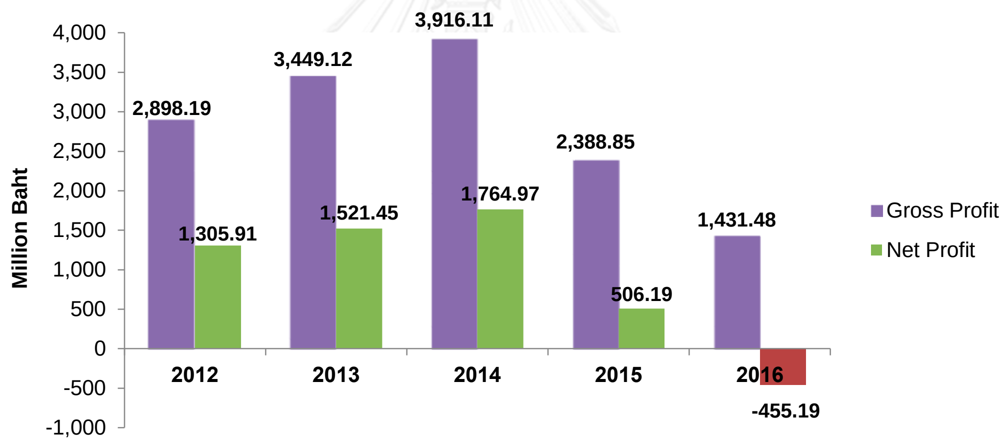


Figure 15: Profitability: Gross Profit and Net Profit in Graphical Form

Source: Adapted from NPS (2016)

The net profit sharply decreased from 1,764.97 million baht in 2014 to 506.19 million baht in 2015. In 2016, NPS had a loss of 455.19 million baht, dropping by 961.38 million baht or a 189.93% drop from last year. These negative outcomes were mainly due to the declines in gross profit of electricity and steam, see Table 7 and Figure 16.

Table 7: Gross Profit from Selling Electricity and Steam in Tabular Form

Gross Profit	2012	2013	2014	2015	2016
Electricity and Steam	2,360.53	2,827.35	3,435.42	2,259.54	1,424.96
Change	+708.69	+466.82	+608.07	-1,175.88	-834.58
% Change	+42.90	+19.78	+21.51	-34.23	-36.94

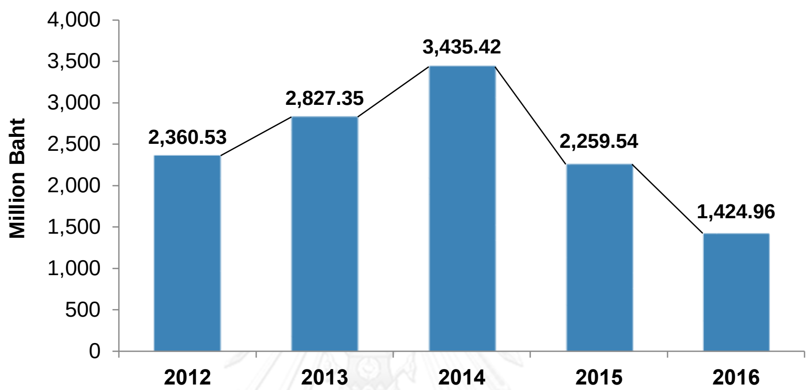


Figure 16: Gross Profit from Selling Electricity and Steam in Graphical Form

Source: Adapted from NPS (2016)

Regarding payment made by EGAT, NPS obtains money in terms of not only CP and EP but also some indicators of power plant efficiency. The company also needs to follow certain agreements, such as sustaining an MCF of 51% or more; otherwise, the firm will have to pay a penalty or even be revoked contracts for not following the agreements. These two potential consequences can be considered risks from the power plant efficiency, so the KPIs are then used for monitoring, examining, tracing and analysing the operational efficiency of all power plants. Table 8 shows the results of operational efficiency over five years.

Table 8: Key Performance Indicators for Measuring Operational Efficiency

KPI	Unit	2012	2013	2014	2015	2016
Availability Factor[1]	%	83.29	86.02	88.52	84.79	85.70
FMO[1]	%	5.26	4.03	3.63	6.43	5.38
PMO[1]	%	11.46	9.95	6.80	7.30	8.92
EGG	'000 MWh	3,526	3,786	3,930	3,713	3,893
MCF[2]	%	> 51				
Capacity PPA[2]	MW	304				

Remark: [1] Weighted average of the total installed capacity of the company

[2] Indicator determined by the power purchase agreement (PPA)

The results indicate that the overall operational efficiency of the power plants was quite good, and it was not volatile so much over the years. High values of availability factor mean high stability of the generation process. Lower FMO compared to PMO was great that indicates less production time stopped due to machine breakdown or force majeure. The amount of EGG was satisfying since it was large enough for the demand.

In terms of MCF, it was above 51% on average. This means that EGAT was sold the electricity of at least 155.04 MW out of 304 MW for Capacity PPA. Nevertheless, NPS found that the MCF values for Plant A and Plant B were sometimes below 51% as a result of less revenue gained from EGAT relative to full revenue gained when the contract capacity is fully met. Whereas, the company will have to pay a huge amount of penalty fee if an extremely low MCF was present in some period of time.

Table 9 shows two capacity factors used to monitor and evaluate productivity of the power plants. It can be clearly seen that both gross power output and output factor varied from year to year. Even though the high output factor for five years indicates that the total installed capacity has been almost fully utilised, the volatility of both capacity factors implies that the number of electricity and steam units generated tends to be instable. Such instability means sustaining the profit margin at a relatively constant is difficult to achieve.

Table 9: Capacity Factors: Gross Power Output and Output Factor

Capacity Factor	Unit	2012	2013	2014	2015	2016
Gross Power Output	'000 MWh	2,985	3,257	3,285	2,910	3,072
Output Factor[1]	%	83.07	85.33	83.94	79.96	81.50

Remark: [1] Weighted average of the total installed capacity of the company

In summary, decreased profit margin can have possible root causes in many parts of the electricity and steam generation process resulting from the internal factors and the external factors that can be divided into the following five main categories:

(1) Electricity and Steam Prices

(2) Costs of Production

(3) Operational Efficiency

(4) Manpower

(5) Power Plant Operations

These five main categories are considered the causes which have significant impacts on the profitability of NPS as discussed previously. Figure 17 on the next page is the Ishikawa, as known as the cause-and-effect diagram or the fishbone diagram showing these main causes and their root causes of decreased profit margin problem with which the company have confronted for the last few years.

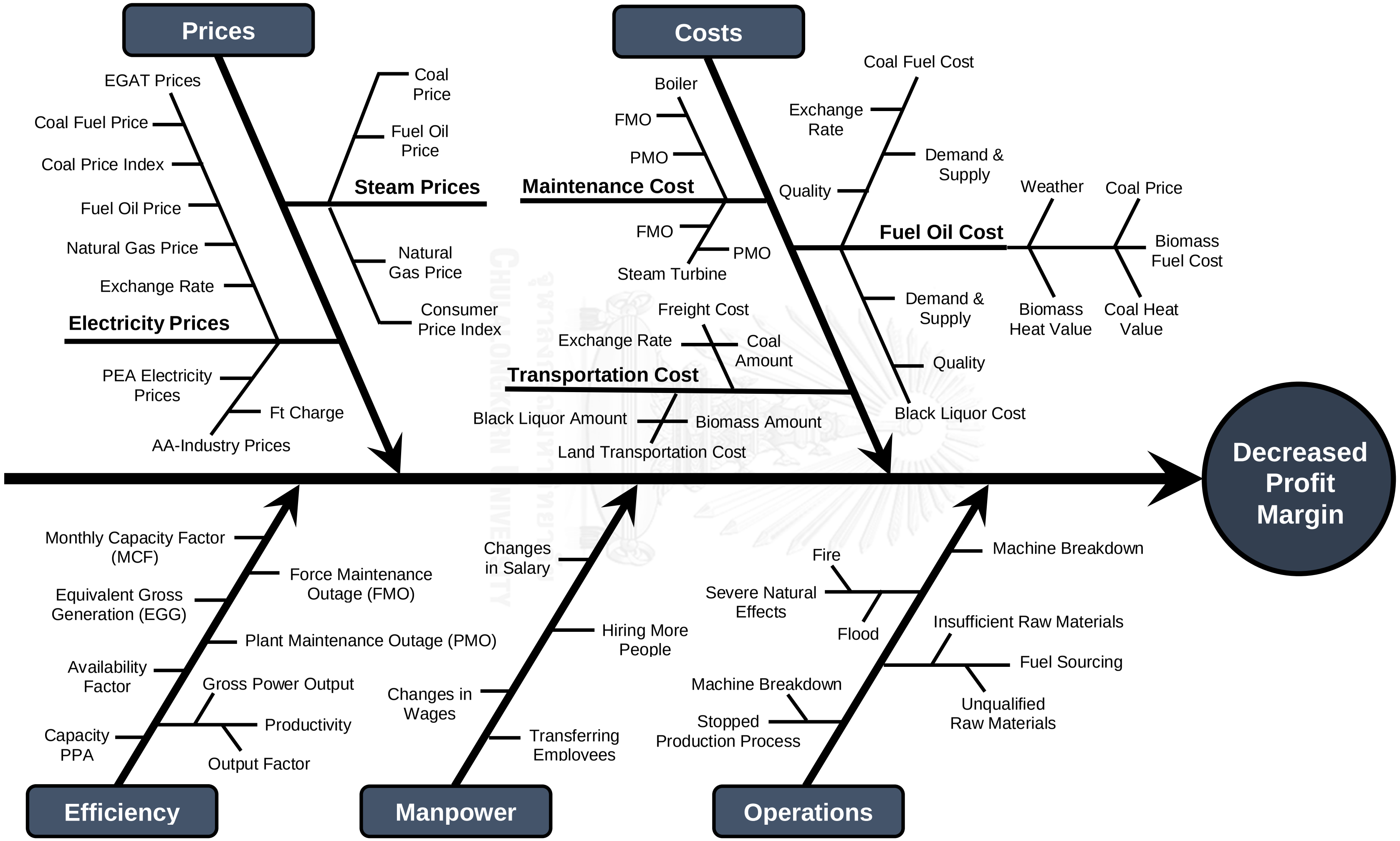


Figure 17: Summary of Possible Causes for the Decreased Profit Margin

1.4 Research Question

This research sets out to answer the following research question: "*How can National Power Supply Company strategically manage economic dispatch of electric power and steam for the dual power plants that helps achieve maximum profit?*"

1.5 Hypothesis Development

To underpin the research question set above, it was hypothesised that "*NPS strategically manages economic dispatch of electricity and steam for the dual power plants to achieve the maximum profit by virtue of developing a spreadsheet-based optimisation program*".

1.6 Research Objective

The objective of this research is *"to develop a spreadsheet-based optimisation program for strategically managing economic dispatch of electricity and steam for the dual power plants to ultimately achieve the maximum profit*".

To successfully reach this objective, the following research steps were then planned as the guidelines throughout conducting the research project:

(1) Investigating the current status of electric power and steam generation and operations management
(2) Formulating the quantitative determination for unit cost, prices and profits of electricity and steam
(3) Developing a spreadsheet-based optimisation program for economic dispatch
(4) Simulating economic dispatch management for profit maximisation
(5) Identifying and analysing major influential factors affecting profitability

1.7 Assumptions of the Study

The case study company operates power plant business to generate and distribute both electricity and steam. There are three different groups of customers which are EGAT, AA and Industry. All customers have been contracted to be distributed at different specific amounts of electricity according to each contracted capacity. The contract capacity for both AA and Industry must be met, but not necessary for EGAT. Whilst, only AA has also been contracted to be supplied at certain minimum amounts of LP steam and MP steam.

Unit costs of producing electricity and steam are the same by considering EGG. The major cost of about 90% is variable cost (fuels, consumable raw materials and transportation) and the rest of 10% is fixed cost (maintenance and operators). Both fuels and consumable raw materials are purchased yearly or quarterly under long-term contracts and given budget as a result of relatively steady costs over months of a year. Consequently, the fixed cost can be neglected assuming there is only variable cost that is deterministic (known and constant) and can be estimated using a transfer function of the generating facility.

Electricity prices are set by EGAT or PEA depending upon type of customers and are subject to change as coal prices, fuel oil prices, natural gas prices, exchange rate and Ft change. Steam prices are internally set by a specific formula and are also subject to change when those parameters plus consumer price index (CPI) change.

Unit profit of electricity and steam is assumed to be calculated by simple subtracting the unit cost from the unit price at the rate for each customer and period of a day. This can be considered manufacturing profit. No other factors are taken into account when computing profit per unit, such as tax privilege, accounting profit, etc.

A mathematical model embedded in the simulation program is also assumed to be deterministic. This means that (1) a set of optimal electricity and steam units generated and sold to individual type of customers and (2) maximum profit (output) resulting from simulating the model is conclusively determined by the parameter values and the initial conditions (input). In addition to the assumptions made based on practicality, the following further assumptions need to be made to minimize complexity of various relevant conditions:

(1) There is no heat loss during the generation process. Practically, heat loss occurs all the time but very little. Therefore, it can be neglected and assumed that heat from fuel combustion is constant and entirely used to drive the generator before totally converting into electricity and steam.

(2) There is no power loss in the transmission and the distribution lines although there is actually very little power lost. Hence, it can also be ignored and assumed that electricity generated is fully carried to the customers.

(3) Both electricity and steam demands and agreements for all customers remain constant due to long-term contracts. Requesting more or less capacity than the contracted capacity at a specific period of time is not allowed.

1.8 Scope of the Research

This research project focuses on economic dispatch management of electricity and steam for profit maximisation. Even though there are entirely ten power plants, the work was scoped to only Plant A and Plant B (excluding eight subsidiary power plants of NPS) as shown in Figure 18.

The reason for choosing these two power plants as the subject of study is due to their maximum installed capacity and the highest contracted capacity with EGAT compared to the other plants. This means that if the performance of two power plants is better, the revenue will be improved and therefore the profit will be maximised more than the other power plants.

Given the time expected to be available, all of the power plants could not be selected and carried out. Nevertheless, they could be covered and executed as the future research using ideas and concepts of what this research project has built.

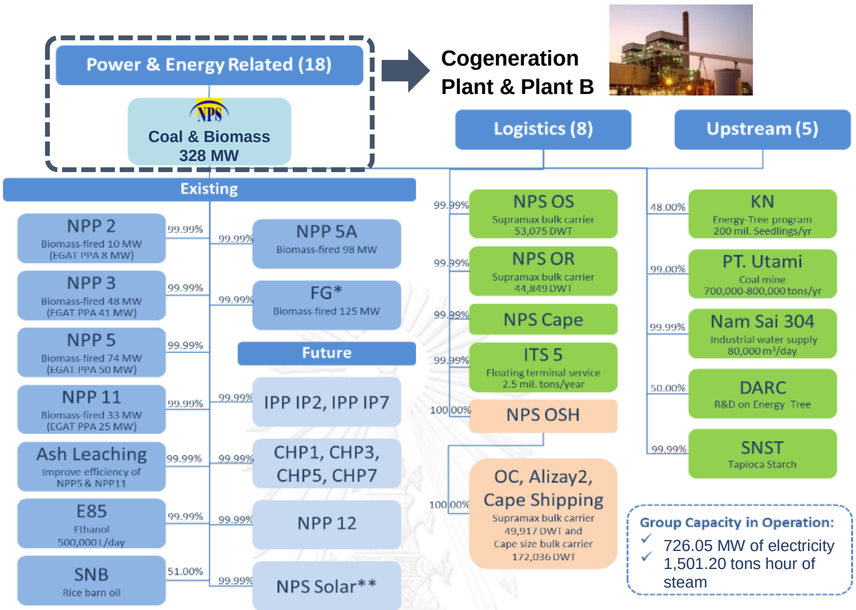


Figure 18: Scope of the Research

Source: Adapted from NPS (2016)

1.9 Expected Outcomes

The following is the summary of expected outcomes beneficial to NPS:

(1) A comprehensive strategic tool for economic dispatch management will assist NPS to optimally distribute electricity and steam to the customers.

(2) The revenue of NPS from the sales of electricity and steam will be optimal and the profit is thereby maximised with the aid of the proposed tool.

(3) Relevant academic models and techniques have been applied to the product and profit maximisation strategy used by NPS.

(4) Production and operations management systems will be improved when the new proposed tool is utilised in an optimal way.

(5) A wider understanding of profit analysis and strategy will be developed.

Beyond those outcomes to the company, some contribution has been added towards the advancement of body of knowledge in the power plant industry. Since profit maximisation strategy is greatly proprietary and partly confidential for every firm in the industry, so know-how and technical expertise is not generally propagated.

Although several scholarly published articles on individual power plant projects are available and a number of electrical engineering and business management textbooks on generic economic dispatch principles and profit strategy are published, only few deliberately emphasise on a certain, comprehensive and practical way for people working in the industry where numerous specific and local constraints exist.

1.10 Overview of Thesis Structure

The structure of this thesis book is organized into six chapters. Contents and reasons for including these individual chapters are briefly explained as follows:

Chapter 1 provides an overview and introduction of the research. Significance of the project to its research area, analytical company background, current production and operations management, statement of problem, research question, hypothesis, objective, assumptions of the study, scope of the project and expected outcomes.

Chapter 2 reviews existing literatures in various relevant topics. The topics include (1) electricity market in Thailand, (2) power generation system and operations management, (3) economic dispatch of electric-power generation schemes, (4) mathematical modelling, (5) modelling with linear programming, (6) simulation and (7) sensitivity analysis.

Chapter 3 describes and justifies research methodology of how the research project was conducted including research subjects, formulation of the research question, research methods, research design, data collection, data analysis, phases of the research study, and project risk assessment and mitigation plans.

Chapter 4 presents results and analysis of three research phases. First of all, quantitative determination of costs, prices and profits of electricity and steam was estimated. Secondly, a spreadsheet-based economic load dispatch program for profit maximisation, namely *NPS Economic Dispatcher*, was designed and developed. Lastly, sensitivity analysis of influential factors affecting profitability was performed.

Chapter 5 discusses whether the project objective has been achieved and the research question has been answered. Key research findings, comparison of the findings with the existing literatures, investigation of the findings to support the developed hypothesis, impacts of limitations on validity of the results and recommendations for practicality are critically discussed.

Chapter 6 concludes what the research project has carried out, discovered and finally accomplished, including general research findings, practical challenges and limitations, implications of the research, research contributions and future work.

CHAPTER 2 LITERATURE REVIEW

This chapter reviews existing literatures in various topics, including (1) electricity market in Thailand, (2) power generation system and operations management, (3) economic dispatch of electric-power generation schemes, (4) mathematical modelling, (5) modelling with linear programming, (6) simulation and (7) sensitivity analysis.

2.1 Electricity Market in Thailand

Since 1968, Thailand's electric supply industry (ESI) has been taken over and solely regulated by the government under state-owned enterprises (SOEs) regime. Nevertheless, the ESI has long been considered to be secure and predictable when compared to other developing countries in Southeast Asia due to its well-structured regulations and capability to serve power to meet demand of the whole nation.

2.1.1 Liberalisation and Privatisation of Thailand's Electricity Market

During the early 1990s, high growth rate in electricity demand had been gradually increasing leading the Thai government to initiate liberalising the electricity market through a privatisation program. A number of state agencies and the private sector were allowed to participate in bidding power generation contracts. The objective of the program was to supply more power into the national grid system. Nonetheless, such privatisation program caused excessive generating capacity and some restrictions on the economic load dispatch system.

Chirarattananon & Nirukkanaporn (2006) indicated that the most important driver for privatisation was to reduce investment as well as liability burden on state enterprises. Also, the privatisation has significant impacts on the ESI as Wisuttisak (2012) explored the issues influencing competition in Thailand's electricity market and found that competition intensified after the process of liberalisation and privatisation.

2.1.2 Electricity Supply Industry Structure of Thailand

In 1999, the ESI structure of Thailand was initially designed by international consultants and industry participants based on the structure used in the United Kingdom (UK). There has also been a reformation of the structure thereafter with the goals to enhance the private sector's participating role, to boost competitiveness in the industry, to enhance efficacy and to provide various choices for customers (Watana *et al*., 2008). Nevertheless, the current ESI structure of Thailand is still substantially dominated by a state-owned power utility enterprise called EGAT.

Under the Enhanced Single Buyer (ESB) model of Thailand, see Figure 19, EGAT is a single buyer responsible for generating and transmitting electric power for most of the country. Bulk electricity is purchased from the private sector including independent power producers (IPPs) and small power producers (SPPs), and some is imported from neighbouring countries. After that electricity is primarily transmitted and sold to two distributors: the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA) before eventually supplying to end-users (NEPO, 1999).

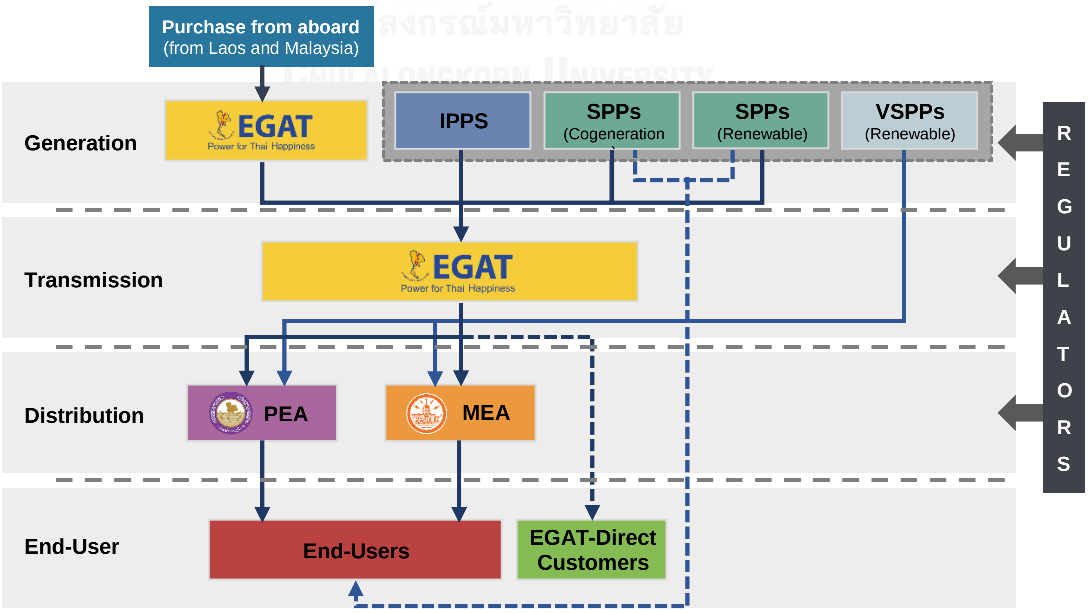


Figure 19: Thailand's Electricity Supply Industry (ESI) Structure

Source: Adapted from NEPO (1999)

2.1.2.1 Electricity Generating Authority of Thailand

EGAT is Thailand's leading state-owned enterprise under the Ministry of Energy which was founded in 1969 by the World Bank's suggestion to consolidate all existing power utilities. The main responsibility is to generate, transmit and sell electric power for the whole nation. As of 2016, EGAT owns and operates power plants at 45 different locations with the total installed generating capacity of 16,385 MW (EGAT, 2017).

Figure 20: Electricity Generating Authority of Thailand (EGAT)

Source: EGAT (2017)

The electricity generating facilities of EGAT are operated with diverse fuels, such as thermal, combined cycle, hydropower, diesel and renewable energy. They supply approximately 40% of the country's electricity, while the rest is supplied by the private producers and slightly by the neighboring countries. About 99% of EGAT's electricity is sold to MEA and PEA, and only 1% is sold directly to customers (EGAT, 2017).

2.1.2.2 Metropolitan Electricity Authority

MEA is a state-owned power enterprise responsible for exclusively distributing electricity bought from EGAT to end-users in Bangkok Metropolitan area and two satellite provinces: Nonthaburi and Samut Prakarn. This core business provides the total revenues of 99.94%. Apart from its core business, MEA also engages in related business, such as care services through design, installation and maintenance of electrical systems (MEA, 2017).

Figure 21: Metropolitan Electricity Authority (MEA)

Source: MEA (2017)

According EPPO (2017d), MEA purchased a total electric energy of 51,413 GWh from EGAT in 2016, increasing by 1,594 GWh or 3.20% from 2015. Figure 22 graphically shows electricity consumption for different sectors in MEA area over five years. Business, industrial and residential were the top three sectors to whom MEA mostly distributed its electricity. This implies that MEA's distribution system must be very secure and stable in order to serve and be able to meet increasing power demand for people in the urban area.

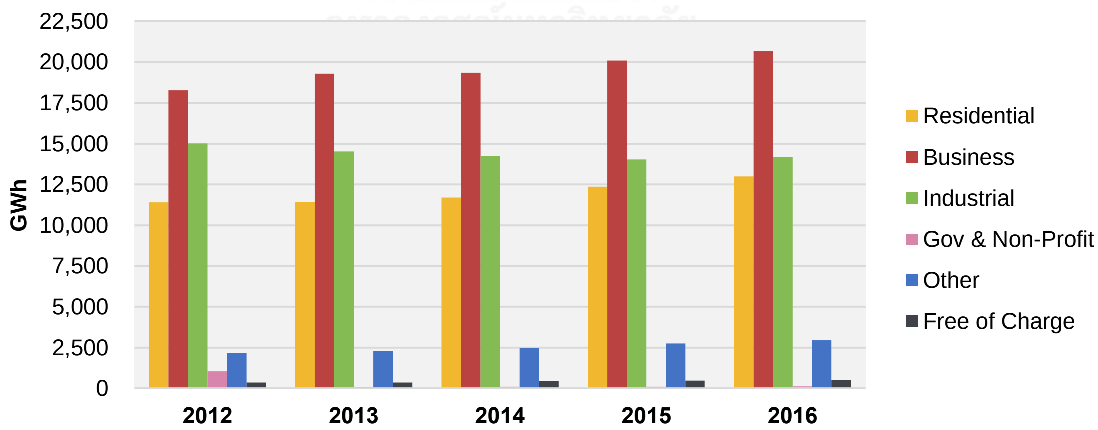


Figure 22: Electricity Consumption in MEA Area Classified by Sector

Source: Adapted from EPPO (2017d)

2.1.2.3 Provincial Electricity Authority

PEA is a state-owned power enterprise responsible for electricity distribution of purchased from EGAT to the users in provincial regions, excluding Bangkok, Nonthaburi and Samut Prakarn provinces. PEA occupies a responsibility area of 510,000 square metres or 99% of the country's entire area in where 18.89 million users live. In addition to this core business, PEA runs several related-businesses. They are constructing, renting, maintaining, inspecting, testing and evaluating electrical systems as well as training and development programs, consulting and electric system design (PEA, 2017).

Figure 23: Provincial Electricity Authority (PEA)

Source: PEA (2017)

According to EPPO (2017e), PEA purchased a total electricity of 129,671 GWh from EGAT in 2016, increasing by 6,473 GWh or 5.25% from 2015. Figure 24 graphically shows electricity consumption for different sectors in PEA area over five years. Industrial, residential and business were the top three sectors to whom PEA mostly distributed its electricity. This also implies that PEA's distribution system must be very stable and secure in order to serve and able to response to growing power demand for people in the rural area.

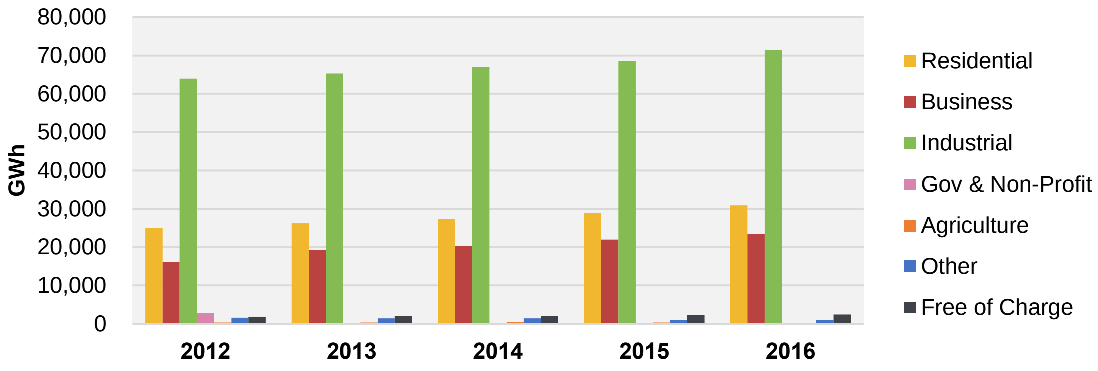


Figure 24: Electricity Consumption in PEA Area Classified by Sector

Source: Adapted from EPPO (2017e)

Comparing electricity consumption between MEA area and PEA area, the sector consuming highest electricity in MEA area was business customers, but it was industrial customers in PEA area. This means different power demands in different areas.

Considering electricity consumption in PEA area based on the tariffs for small, medium and large general service over five years as depicted in Figure 25, it can be observed that the large general service, where most of factories in industrial estates fall into this category, consumed most amount of electricity in PEA area whereas small general service consumed least. This reflects high power demand for industries to which SPPs have to readily supply electric power; otherwise, it would affect the business operations and overall economy.

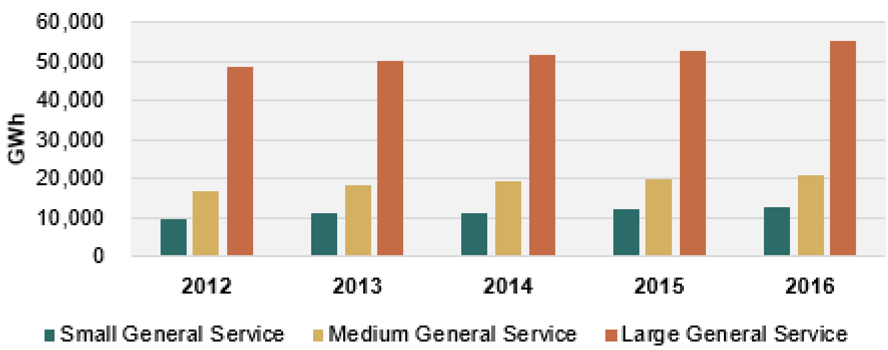


Figure 25: Electricity Consumption in PEA Area Classified by Tariff

Source: Adapted from EPPO (2017f)

2.1.2.4 Private Power Producers

As a result of deregulation in the ESI, the private sector has participated in investing in several power generation projects in the forms of IPP, SPP and VSPP to meet growth in power demand and to enhance the competition and the efficacy of the market. These three forms of private power producers are classified by installed generating capacity.

2.1.2.4.1 Independent Power Producers

IPPs are large-scale private power producers with installed capacity of over 90 MW. They primarily generate electricity from natural gas and coal and entirely sell the output to EGAT according to their PPAs. The first round of IPP solicitation occurred in 1994, and there have been three rounds of IPP biddings accumulatively representing generation capacity of 15.5 GW as of 2016. However, Nagayama (2007) found that IPPs typically face low income realisation arising from long-term contracts with EGAT of their base load power plants.

2.1.2.4.2 Small Power Producers

SPPs are private power producers who use either cogeneration or renewable energy technology to produce and sell electricity to EGAT of up to 90 MW for each contract. SPPs own sales contracts with EGAT for 20-25 years. Since their installed generating capacity is very large, additional capacity can be directly sold to nearly industrial customers. The risk of income uncertainty is faced by SPPs since their business operations depend on situations of industrial customers and external factors for pricing determination (Nagayama, 2007).

2.1.2.4.3 Very Small Power Producers

VSPPs are the smallest-scale private power producers with installed capacity of less than 10 MW connecting to the grid. They normally generate electric power from agricultural waste materials (biomass) and renewable energy (solar, wind and hydropower) for their own consumption. The excess capacity can be directly sold to MEA and PEA. Phuangpornpitak & Tia (2011) revealed that there has been higher contribution from VSPPs to generate electric power using renewable energy during the past several years due to government support.

2.1.3 Regulatory Framework for Thailand's Electricity Sector

Electric power sector of Thailand is managed and regulated by the Ministry of Energy (MoE). The MoE is mainly responsible for overseeing the following four agencies whose their duties are to plan and implement energy policies (Ministry of Energy, 2017).

(1) Energy Policy and Planning Office (EPPO)

(2) Department of Mineral Fuels (DMF)

(3) Department of Energy Business (DOEB)

(4) Department of Alternative Energy Development (DAED)

Figure 26 shows Thailand's regulatory framework for energy sector. It can be seen that the energy sector, including electric power, is governed by the MoE. The MoE is under-managed by the National Energy Policy Council (NEPC). EPPO is the only agency who acts as a national policymaker through giving advice about energy policies, including electric power policies, whereas the remaining three agencies are policy implementers. Three state-owned power enterprises are EGAT, MEA and PEA that are discussed previously.

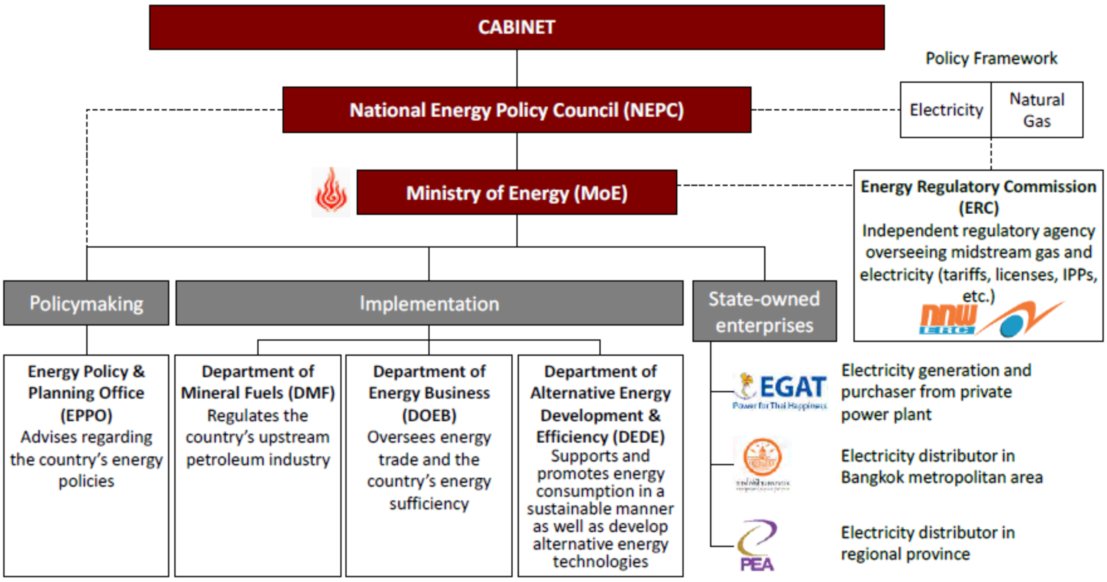


Figure 26: Regulatory Framework of Thailand's Energy Sector

Source: Ministry of Energy (2017)

2.1.4 Power Purchase Agreement for Small Power Producers

A power purchase agreement (PPA) is defined as a legal principal contract between two parties, a seller generates electricity and a buyer desires to buy electricity (Ferrey, 2004). All commercial terms regarding electricity sales between the two parties are specified on the PPA. These include COD, power delivery scheduling, penalties for under-delivery, terms of payment and contractual termination.

Different tariff structures are applicable to different private generators (IPP, SPP and VSPP), contract type (firm or non-firm) and power plant system (cogeneration or renewable). Basically, there are two main tariff structures: wholesale tariff and retail tariff. Both structures depend upon marginal generation and transmission costs of EGAT and monitored by the Energy Regulatory Commission (ERC).

SPPs always charge the wholesale tariff structure to EGAT and charge the retail tariff structure to end-users for the amount of electricity sold. Nevertheless, income earned from EGAT is based on not only capability to produce and sell electric power according to contracted capacity, but also power plant efficiency.

2.1.4.1 Estimation of Income from Selling Electricity to EGAT

Table 10 shows types of income earned by SPPs from selling electricity to EGAT. Considering a firm cogeneration contract with EGAT (NPS contract with EGAT), it lasts from 20 to 25 years. Capacity Payment (*CP*) is earned as minimum income under the contract with EGAT, and Energy Payment (*EP*) can be also obtained if electricity is actually generated and sold to EGAT according to the specific contracted capacity. Moreover, additional income set based on fuel types used and conditions can be also received (EGAT, 2016).

Table 10: Types of Income Earned by SPPs from Selling Electricity to EGAT

Type of Power Plant		Minimum Income under EGAT contract	Income based on Actual Capacity Sold	Adder Income under Gov't Support
SPP	Firm			
	- Cogeneration	CP	EP	FS
	- Renewable	CP	EP	FS, REP, Adder
	Non-Firm			
	- Cogeneration	None	EP	None
	- Renewable	None	Wholesale Tariff	Adder

Remark: Capacity Payment (CP) includes EGAT's investment costs depending on contractual period with SPP.
Energy Payment (EP) includes tariff for fuel costs covering generation and maintenance variable cost.
Fuel Saving (FS) Payment is earned when a certain level of cogeneration efficiency is achieved.
Renewable Energy Promotion (REP) is proposed to encourage SPPs to employ renewable energy.
Adder is additional buying price paid to generators set based on fuel types and conditions

According to SPP Power Purchase Agreement EGAT (2016), electric capacity refers to the capability of a power plant in electricity generation. There are three types of capacity involved in billing calculation for SPPs: Contracted Capacity (*CC*), Actual Capacity (*AC*) and Billing Capacity (*BC*), which can be elaborated as follows:

Contracted Capacity

EGAT and SPP always trade 100% capacity of *CC* with the exception:

If Capacity > *CC*: EGAT requests capacity more than *CC* and SPP agrees.

If Capacity < *CC*: Grid cannot accept more capacity or during off-peak hours.

If Capacity < *CC*: SPP cannot generate and sell to EGAT as requested, SPP stops for maintenance or asks for decrease or EGAT's force majeure.

Actual Capacity

EGAT often buys 100% capacity during Partial Peak (*PP*) hours and Peak (*P*) hours; therefore, power generation during Off-Peak (*OF*) hours with 65% of generating operation is excluded. The amount of *AC* can be computed using Equation (1).

$$\boxed{AC = \frac{3.0E_P}{13.5T_P} + \frac{10.5E_{PP}}{13.5T_{PP}}} \qquad (1)$$

where Partial Peak (*PP*) hours is from 08.00 – 18.30.

Peak (*P*) hours is from 18.30 – 21.30.

Off Peak hours (*PO*) is from 21.30 – 24.00.

E_{PP} = Sum Actual Energy$_{(PP)}$ every 15 minutes (If over 102%, use 100%) – Utility Outage Energy$_{(PP)}$ – Maintenance Energy$_{(PP)}$

T_{PP} = Monthly Hours$_{(PP)}$ – Utility Outage Hours$_{(PP)}$ – Maintenance Hours$_{(PP)}$

E_P = Sum Actual Energy$_{(P)}$ every 15 minutes (If over 102%, use 100%) – Utility Outage Energy$_{(P)}$ – Maintenance Energy$_{(P)}$

T_P = Monthly Hours$_{(P)}$ – Utility Outage Hours$_{(P)}$ – Maintenance Hours$_{(P)}$

Billing Capacity

After being able to calculate *AC*, the *AC* calculated is compared with *CC* for computing *BC* using one of these equations: Equation (2), Equation (3) or Equation (4).

If $AC = CC$; $BC_T = CC$ (2)

If $AC < CC$*; $BC_T = AC - 0.2 \times (CC - AC)$ (3)

If $AC > CC$; $BC_T = CC + 3.0 \times (RC - CC) \times \frac{H_{RC}}{H_{MO}} + \ldots$ (4)

where RC = Request Capacity, and $RC > CC$

H_{RC} = Request Hours

H_{MO} = Monthly Hours

However, it is sometimes impossible to calculate *AC* because of zero electric energy during *PP* hours or *P* hours. Equation (5) below should be used to compute *BC*.

If *AC* is incalculable ($E_{PP} = 0$, $T_{PP} = 0$ or $E_P = 0$, $T_P = 0$);

$$BC_T = \frac{\sum_{i=1}^{n} BC_{T-i}}{n} \tag{5}$$

where $n = 6$ (previous 6-month average, excluding months of force majeure)

Average backward until Commercial Operation Date if $n < 6$ months

*From Equation (3), please note that if $AC < CC/6$ yields $BC_T < 0$ or negative *BC*, EGAT will charge a penalty fee resulting from unavailability of SPP. Therefore, EGAT suggests that SPP should notify plant maintenance outage (PMO) plan to EGAT so that hours for PMO will be actually accounted for maintenance hours, and SPP should operate generators at 100% during *PP* and *P* hours for 6 days per month at minimum.

<u>Capacity Payment</u>

To calculate Capacity Payment (*CP*), two required inputs are CP_T and BC_T. For the BC_T, it can be obtained using one of the Equation (2) to Equation (5). For the CP_T, it can be computed using Equation (6) as shown below.

$$\boxed{CP_T = CP_0 \times (FP \times \frac{FX_T}{FX_0} + DP)} \qquad (6)$$

where CP_0 = Capacity Payment Base Rate (THB/kW/month)

FX_T = Foreign Exchange Rate of Last Working Day of Month (THB/USD)

FX_0 = Foreign Exchange Base Rate (THB/USD)

FP = Foreign Investment Proportion

DP = Domestic Investment Proportion

After obtaining the CP_T and the BC_T, *CP* can be calculated from multiplying CP_T with BC_T using Equation (7) shown below.

$$\boxed{\text{Capacity Payment} = BC_T \times CP_T} \qquad (7)$$

where BC_T = Billing Capacity (kW)

CP_T = Capacity Payment (THB/kWh/month)

<u>Monthly Capacity Factor</u>

MCF is the ratio of electricity units sold to EGAT to the capacity specified on the contract between SPP and EGAT, which can be computed using Equation (8).

$$\boxed{MCF = \frac{\text{Total Monthly Energy} - \text{Planned Outage Energy}}{CC \times (\text{Monthly Hours} - \text{Planned Outage Hours})}} \qquad (8)$$

If SPP cannot generate and sell electric energy to EGAT by having an MCF value of less than 0.51, or SPP can generate and sell electricity by having an MCF value of more than 1, *CP* for that particular month will be halved.

Energy Payment

For SPP with a coal-fired power plant, Energy Payment (*EP*) can be computed using Equation (9) as illustrated below. Note that this formulae of *EP* is weighted by 75% escalation of coal and 25% escalation of oil.

$$\text{Energy Payment} = EP_0^{Coal} + \left[\left(0.75 \times ES_T^{Coal}\right) + \left(0.25 \times ES_T^{Oil}\right)\right] \quad (9)$$

where EP_0^{Coal} = Energy Payment Base Rate for Coal-Fired Plant (THB/kWh)

ES_T^{Coal} = Escalation for Coal (THB/kWh)

ES_T^{Oil} = Escalation for Fuel Oil (THB/kWh)

To calculate ES_T^{Coal} and ES_T^{Oil}, Equation (10) and Equation (11) are used.

$$ES_T^{Coal} = \frac{1}{26.5877 \times 10^6} \times \left[(P_T \times FX_T) - P_0\right] \times \text{Heat Rate} \quad (10)$$

$$ES_T^{Oil} = \frac{1}{39{,}400} \times (P_T - P_0) \times \text{Heat Rate} \quad (11)$$

where P_0 = Fuel Base Price (THB/ton)

P_T = Fuel Price (USD/ton)

FX_T = Foreign Exchange Rate of Last Working Day of Month (THB/USD)

Heat Rate = 8,600 (BTU/kWh)

Billing Payment

Billing payment (*BP*) or income earned by SPP from selling one unit of electricity can be calculated using Equation (12) and Equation (13). Please note that SPP earns both *CP* and *EP* during *P* hours, but SPP earns only *EP* during *OP* hours.

$$BP_P = \frac{CP}{EGG_P} + EP \qquad (12)$$

$$BP_{OP} = EP \qquad (13)$$

2.1.4.2 Estimation of Income from Selling Electricity to Retail Customers

The electricity retail tariffs are diverse based on each type of end-users, consumption and electric capacity levels; however, fuel adjustment mechanism (*Ft*) is applied to all end-users without variation. Table 11 shows energy consumption and demand consumption for different types of end-users: (1) residential, (2) small general service, (3) medium general service, (4) large general service, (5) specific business service, (6) non-profit organisation and (7) agricultural pumping (PEA, 2015).

Table 11: Energy and Demand Consumption for Retail Customers

Type of End-User	Energy Consumption	Demand Consumption
Residential	≤ 150 kWh, > 150 kWh	n/a
Small General Service	n/a	< 30 kW
Medium General Service	< 250,000 kWh/month	30-999 kW
Large General Service	< 250,000 kWh/month	> 1,000 kW
Specific Business Service	n/a	> 30 kW
Non-Profit Organisation	< 250,000 kWh/month	< 1,000 kW
Agricultural Pumping	n/a	n/a

For example, the electricity tariff for large industrial customers consists of three parts: (1) Demand Charge, (2) Energy Charge and (3) Service Charge before being adjusted by *Ft* to reflect the actual fuel cost for power generation at a specific period of time. Table 12 below illustrates the time of use (TOU) rate for large general service determined by PEA (PEA, 2015).

Table 12: Time of Use Rate for Large General Service

Time of Use (TOU) Rate	Demand Charge (Baht/kW)	Energy Charge (Baht/kWh)		Service Charge (Baht/Month)
	Peak	*Peak*	*Off-Peak*	
At voltage level 69 kV and over	74.14	4.1283	2.6107	312.24
At voltage level 22-23 kV	132.93	4.2097	2.6295	312.24
At voltage level less than 22 kV	210.00	4.3555	2.6627	312.24

Remark: Peak Hours 09.00 – 22.00 Monday to Friday
Off-Peak Hours 22.00 – 09.00 Monday to Friday and 00.00 – 24.00 Saturday & Sunday

<u>Demand Charge</u>

According to PEA (2015), Demand Charge is based on the amount of electricity use meaning that Demand Charge will comprise a greater part of electricity bill if a lot of power is consumed over a short period, and vice versa. To calculate Demand Charge, two inputs: Capacity Payment and Total Monthly Electricity Consumption are required. Equation (14), Equation (15) and Equation (16) illustrate the formula used for computing Capacity Payment, Total Monthly Electricity Consumption and Demand Charge, respectively.

$$\boxed{\text{Capacity Payment} = \text{CC} \times \text{Demand Charge per Unit}} \tag{14}$$

$$\boxed{\text{Total Monthly Electricity Consumption} = \text{CC} \times \text{Hours}_{P/OP} \times \text{Days}_{P/OP}} \tag{15}$$

$$\text{Demand Charge} = \frac{\text{Capacity Payment}}{\text{Total Monthly Electricity Consumption}} \quad (16)$$

Energy Charge

According to PEA (2015), Energy Charge is a fixed rate and can be found directly from Table 12 shown previously. Please note that Energy Charge for peak period is always greater than the Energy Charge for off-period.

Service Charge

According to PEA (2015), Service Charge is a service fee that every electricity user has to pay to PEA once a month regardless of peak period or off-peak period. The Service Charge can be found directly from Table 12 shown previously.

Fuel Transfer Charge

In addition to Demand Charge and Energy Charge, Fuel Transfer (Ft) is also included in the electricity bill, determined and announced by Energy Regulatory Commission (ERC) every four months. Table 13 shows the Ft charge between January 2017 and April 2017.

Table 13: Fuel Transfer Charge between January 2017 to April 2017

Period of Announcement	Ft Charge (Baht/kWh)
Jan 2017 – April 2017	–0.3729

Thus, PEA electricity prices for peak hours and off-peak hours are as follows:

$$\text{PEA Electricity Price}_{P} = \text{Demand Charge} + \text{Energy Charge} + \text{Service Charge} + \text{Ft} \quad (17)$$

$$\text{PEA Electricity Price}_{OP} = \text{Energy Charge} + \text{Service Charge} + \text{Ft} \quad (18)$$

2.1.5 Electricity Demand and Supply

2.1.5.1 Electricity Demand Trends

Over the last decade, electricity demand has risen at an average of 3.69% per year, reaching 182,847 GWh in 2016. The largest power consumer is the industrial sector, representing an average of 50.05% of total demand since 2007; however, it decreased slightly from 53.41% in 2007 to 47.51% in 2016. The business and the residential sectors consumed 21.86% and 22.50%, respectively over the past ten years (EPPO, 2017c). Figure 27 shows Thailand's sectorial electricity demand from 2007 to 2016.

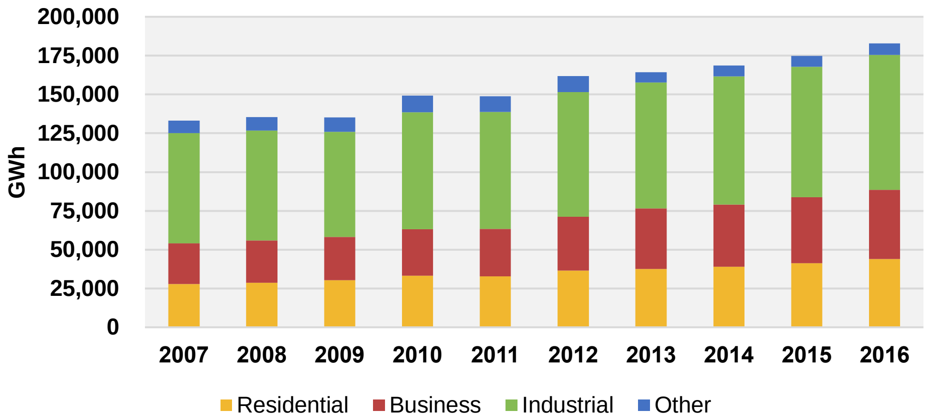


Figure 27: Thailand's Sectorial Electricity Demand from 2007 to 2016
Source: Adapted from EPPO (2017c)

Considering electricity demand versus gross domestic product (GDP) of Thailand as shown in Figure 28, it can be observed that the electricity demand has traced the country's GDP adjacently, matching a high growth of economy until 2007, a sluggish in 2009 and 2011, and a retrieval thereafter. This is consistent with Chen *et al*. (2007) as their findings indicate that there is relatively strong relationship between electricity demand and GDP, and a higher economic growth can be ensured by having an adequately large supply of electricity.

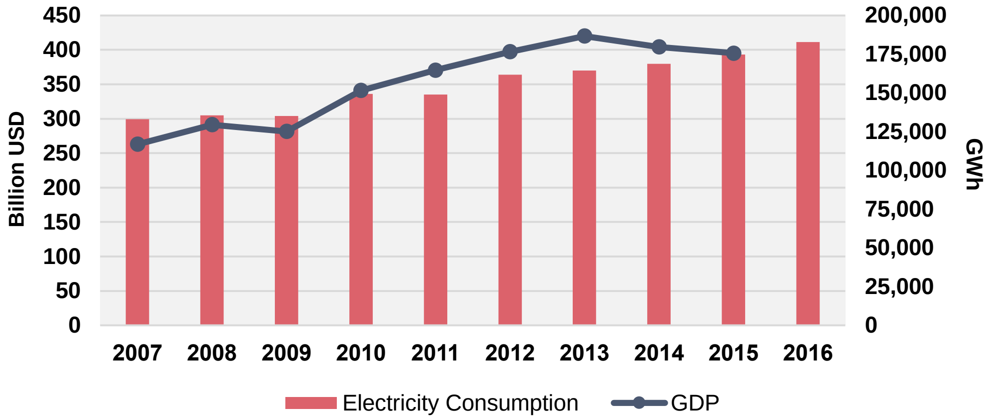


Figure 28: GDP versus Electricity Demand from 2007 to 2016

Source: Adapted from EPPO (2017c) and The World Bank (2016)

For peak demand, it usually occurs in April or May which is considered the hottest month of the year. Figure 29 shows peak demand on EGAT system (EPPO, 2017g). In 2016, peak demand reached 29,619 MW, increasing from 27,346 MW or by 8.31% in 2015. In the past decade, peak demand has risen at an average of 3.55% per annum, tracing the same pattern as annual electricity consumption.

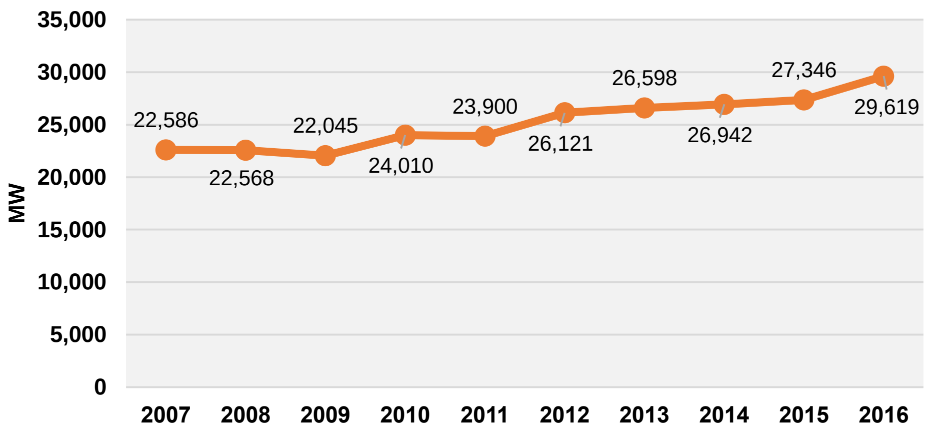


Figure 29: Peak Electricity Demand on EGAT System from 2007 to 2016

Source: Adapted from EPPO (2017g)

2.1.5.2 Electricity Demand Outlook

The electricity demand forecast is presented in Power Development Plan (PDP) 2015 formulated in align with economic growth, infrastructure development, potential energy efficiency target, rising population, urbanisation expansion and increasing growth of electricity consumers in different economic sectors. This demand is forecast based on information estimated by the National Economic and Social Development Board (NESDB), such as an average GDP growth rate of 3.94% per year and an average population growth rate of 0.03% per year during 2014-2036 (EPPO, 2015).

Table 14 shows forecast peak power demand and electric energy consumption in different years ahead (EPPO, 2015). It is expected that peak demand will hit 31,385 MW, and electric energy consumption will reach 205,649 GWh in 2017. Assuming an average growth rate of 2.52% per year from 2017 to 2036, it is expected that peak power demand and electricity consumption will be 49,655 MW and 326,119 GWh in 2036, respectively.

Table 14: Forecast Peak Power Demand and Energy Consumption

Year	Peak (MW)	Energy (GWh)
2017	31,385	205,649
2022	36,776	241,273
2027	41,693	273,440
2032	46,296	303,856
2036	49,655	326,119

Figure 30 below illustrates projected electricity consumption versus energy intensity, expressed as kWh per thousand baht. According to the PDP 2015 (EPPO, 2015), the energy intensity is projected to drop to 24.88 in 2036 from 32.75 in 2017, decreasing at an average rate of 1.40% per year over the same period.

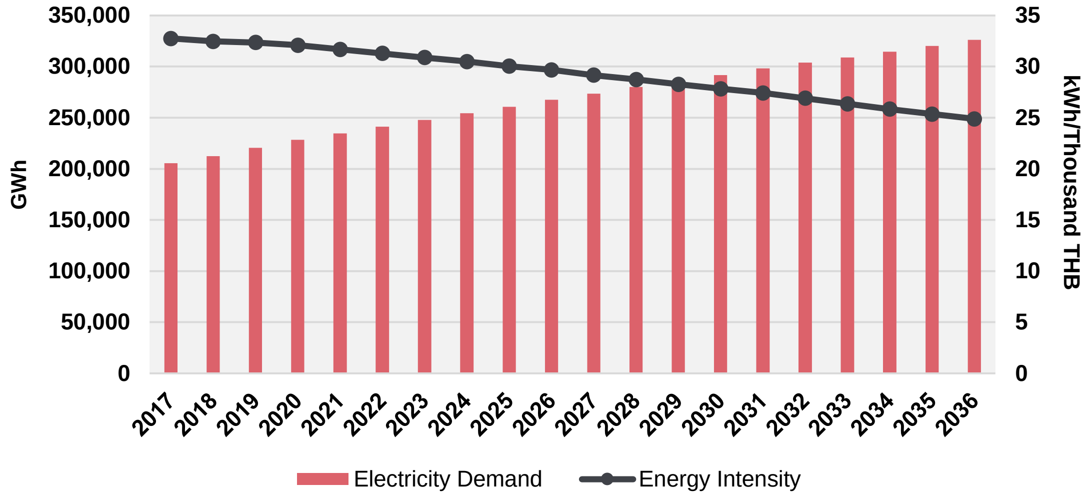


Figure 30: Forecast Electricity Demand and Energy Intensity from 2017 to 2036

Source: Adapted from EPPO (2015)

2.1.5.3 Electricity Supply Trends

As of December 2016, the total installed generating capacity of Thailand, excluding VSPP, was 41,556 MW. Although this amount of total installed capacity seems to be large enough for domestic consumption, power needs to be partly imported to meet the country's demand. According to Wattana & Sharma (2011), more than 60% of the country's electricity generation is made from natural gas that can be sourced from the Gulf of Thailand, nearby countries and Liquefied Natural Gas (LNG) imports. This can imply that Thailand's electricity generation heavily depends on natural gas. However, the industry trend shows the share of renewable energy used in power generation has increased substantially over past ten years, reaching about 6% of the total power generation in 2016 (EPPO, 2017b). Figure 31 shows electricity generation by type of fuel from 2007 to 2016.

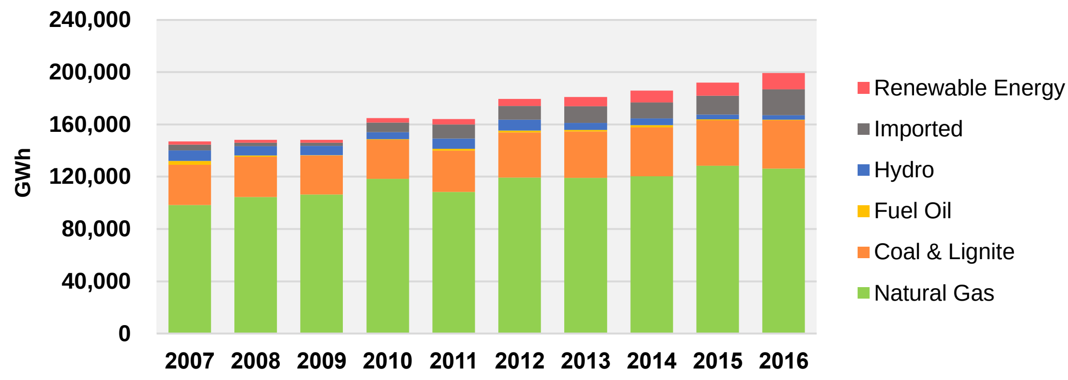


Figure 31: Electricity Generation by Type of Fuel from 2007 to 2016

Source: Adapted from EPPO (2017b)

2.1.5.4 Electricity Supply Outlook

According to PDP 2015 (EPPO, 2015), the total generating capacity is expected to reach 70,335 MW in 2036 after new additional capacity of 57,459 during 2015 and 2036. Table 15 presents new installed capacity to be added between 2015 and 2036.

Table 15: New Installed Generating Capacity during 2015 and 2036

Type of Power Plant	Capacity Additions (MW)
Renewable Power Plant	21,648
Domestic	12,105
Power Purchase from Neighbouring Countries	9,543
Pump-Storage Hydro Power Plant	2,101
Cogeneration Power Plant	4,119
Combined Cycle Power Plant	17,478
Thermal Power Plant	12,113
Coal/Lignite Power Plant	7,390
Nuclear Power Plant	2,000
Gas Turbine Power Plant	1,250
Power Purchase from Neighbouring Countries	1,473
Total New Capacity	**57,459**

Figure 32 illustrates projected electricity generation by type of fuel from 2017 to 2036. The dominant fuel used in electric power generation will still be natural in the future years. Nevertheless, the use of natural gas is expected to decrease about half from 63% in 2016 to 30-40% and will be replaced by the use of renewable energy, coal and even nuclear power by the end of PDP planning period in 2036 (EPPO, 2015).

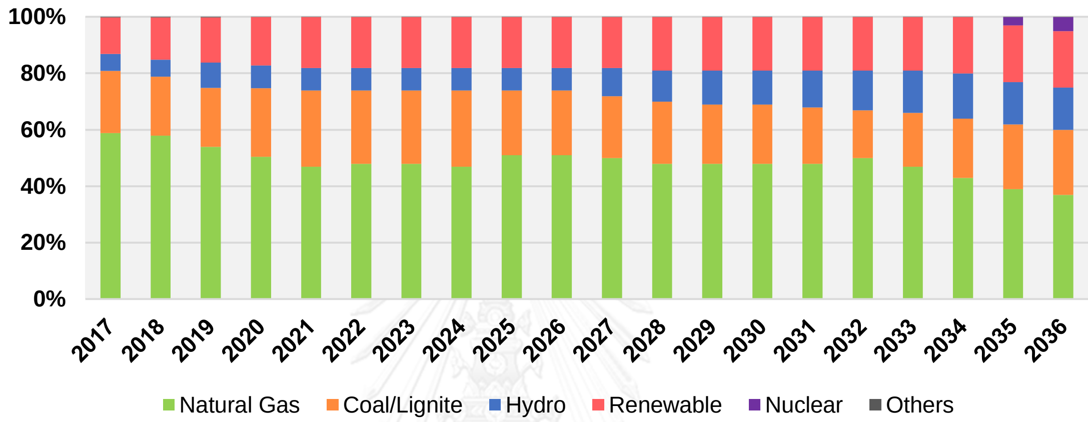


Figure 32: Forecast Share of Power Generation from 2017 to 2036

Source: Adapted from EPPO (2015)

2.1.6 Power Development Plan of Thailand

According to EPPO (2015), a Power Development Plan (PDP) of Thailand is "a master investment plan for the country's power system development prepared by the collaboration between EPPO and EGAT". The current version is PDP2015 that covers a long-term period with an outlook towards 2036. The PDP is designed to serve three pillars which are energy security, economy and ecology. Particularly, ecology as its goal is to minimise environmental and social impacts. This is supported by Nidhiritdhikrai *et al*. (2012) as renewable energy is one of the key success factors employed in strategic planning for PDP of Thailand.

This can be achieved through lessening dependence on natural gas and fuel oil, but increasing uses of green coal technology and seeking for alternative renewable energy for electricity generation instead (Tanatvanit *et al*., 2003). This is exactly what the PDP2015 is trying to achieve as Table 16 shows target share of electricity generation classified by type of fuel (EPPO, 2015). The PDP2015 aims to reduce the uses of natural gas and oil and increase the uses of other sources of fuel for power generation.

Table 16: Target Share of Electricity Generation Classified by Type of Fuel

Fuel Type	Share in 2016	Share in 2026	Share in 2036
Natural Gas	63%	45-50%	30-40%
Diesel/Fuel Oil	0.2%	-	-
Clean Coal and Lignite	19%	20-25%	20-25%
Renewable Energy	8%	10-20%	15-20%
Imported Hydropower	10%	10-15%	15-20%
Nuclear	-	-	0-5%

2.1.7 Smart Grid Master Plan of Thailand

Smart Grid is a revolutionary integrated electrical network system developed for efficiency, reliability, security, sustainability and environmental-friendliness of electric power generation, transmission, distribution through the applications of information communication technology (ICT), electronic and embedded systems, system control and automation (Farhangi, 2010).

Several developed countries around the globe have already implemented their smart power grid, but most of developing nations are still lagging behind. For instance, Thailand is now in the stage of creating a master plan of smart grid. Fadaeenejad *et al*. (2014) indicated that not all developing nations have had appropriate planning and development for smart grid. In the context of smart grid, current power generation will change, such as increasing use of renewable energy from distributed energy resources, supporting centralised power system and allowing customers to manage electricity consumption to suit to their lifestyles and behaviours. Figure 33 shows past, present and future electric systems comparison.

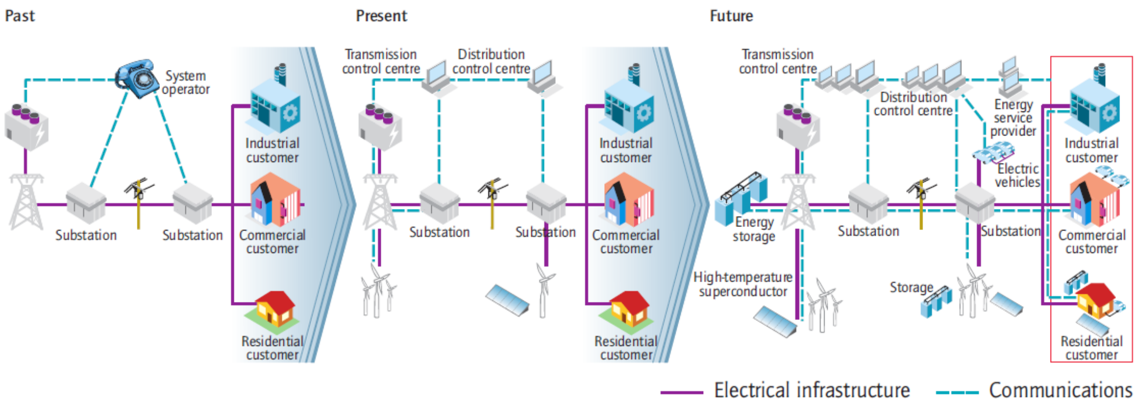


Figure 33: Past, Present and Future Electric Systems Comparison

Source: Fadaeenejad *et al.* (2014)

According to Ministry of Energy (2015), the Smart Grid Master Plan was launched in February of 2015 to be a framework for smart grid development. Its developer EPPO has set five strategic areas: (1) power reliability and quality, (2) energy sustainability and efficiency, (3) utility operation and service, (4) integration and interoperability and (5) economic and industrial competitiveness, with the aims of smart system, smart life and smart society.

Figure 34 shows an example of smart grid. For smart system, the country is able to generate and distribute to both supply and supply sides more efficiently. Apart from having conventional power plants, there will be more fuel sources from renewable energy (wind, solar, biomass and hydro), distributed generation (solar cells and small wind turbine), energy storage (ultra capacitor and electric vehicle, EV). For smart life, people living in smart and green offices, buildings and homes will be able to actively participate in managing their electricity consumption. For smart society, communities will be able to communicate through digital social network and provided electrical charging stations for EV users.

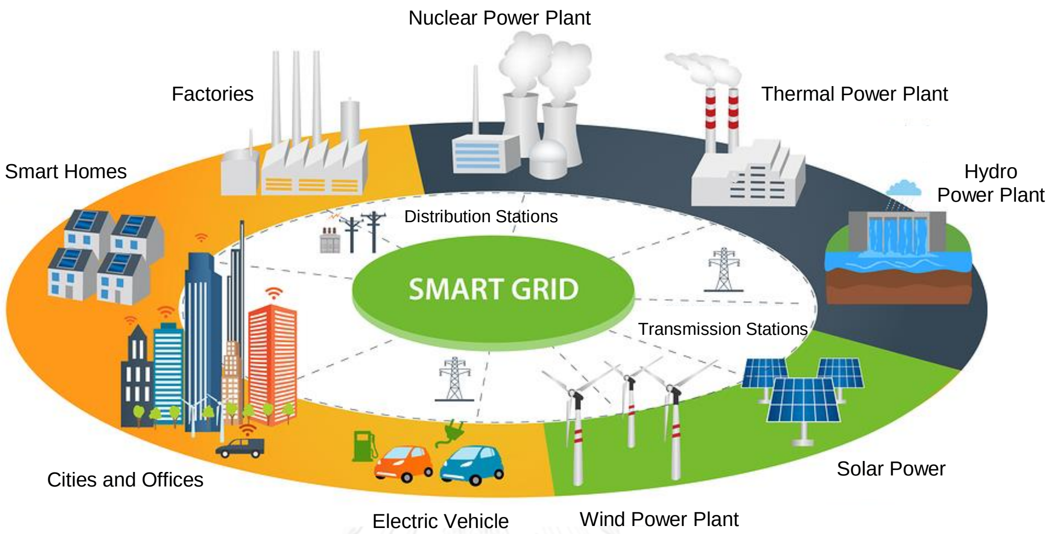


Figure 34: Smart Grid for Smart System, Smart Life and Smart Society

Source: www.robohub.org

2.2 Power Generation System and Operations Management

Since the electricity market of Thailand has been developing and liberalising by more participation of private power generators instead of being monopolised by the EGAT during the last two decades, as discussed previously in Section 2.1.1, in order to enhance efficiency, create reliability, well utilise of resources, offer some customer segments to choose their own electrical suppliers and provide them a better service. Nevertheless, these changes cause competition in the electricity market to be more intensive, so the private power producers are required to carefully manage their electricity generation (Mulugetta *et al*., 2007).

2.2.1 Basic Electricity Generation Process

Electricity generation is basically a process of transforming one primary energy into electric energy. The fundamental electricity production was discovered in the 1820s by a British scientist Michael Faraday. He found that electricity can be made from spinning coils or moving copper plate between two magnetic poles. For power plants, electricity is generated using a mechanical electric generator driven by a thermal engine or a nuclear reactor. Renewable energy including hydropower, solar wind, and geothermal energy can also be utilised for power generation.

Considering power systems, power generation is the first process in the delivery of electricity to end-consumers as illustrated in Figure 35. The remaining two processes are transmission and distribution which are executed by the electric power industry.

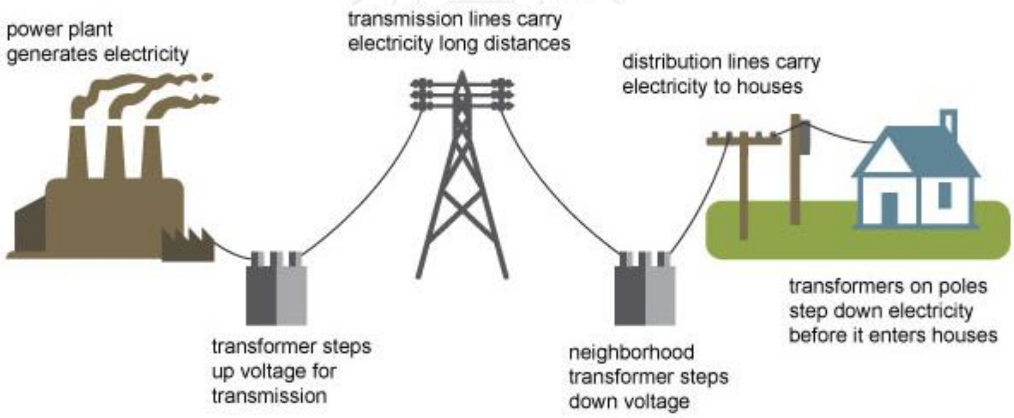


Figure 35: Electricity Generation, Transmission and Distribution

Source: Adapted from National Energy Education Development Project (public domain)

There have been several scholarly published articles interested in power generation system. For instance, Wangjiraniran & Eua-arporn (2010) studied on three fuel alternatives for long-term power generation, including natural gas, coal and nuclear energy, under limited production cost, emission and available resource, and they found that nuclear energy is the most potential relative to other fuel options.

Whereas, many researches focused on effects of electricity generation on environment impacts. For example, Al-Ali et al. (2008) proposed various scenarios of power generation planning to reduce pollutant emissions. BariŠiĆ *et al*. (2009) revealed that Circulating Fluidised Bed (CFB) boiler technology is not only able to reduce pollutant emissions, but also have good capability to support various types of fuels in co-fired power plants as shown in Figure 36 below.

Figure 36: Type of Fuels Co-Fired Used in CBF Technology Boilers

Source: BariŠiĆ *et al*. (2009)

Regardless of any type of fuels and boiler technology used, a typical electricity generation process in cogeneration power plants is still relatively similar in terms of input, process and output, as discussed previously in Section 1.2.5 of the Introduction Chapter. Figure 37 shows a simplified electricity generation principle in a cogeneration power plant.

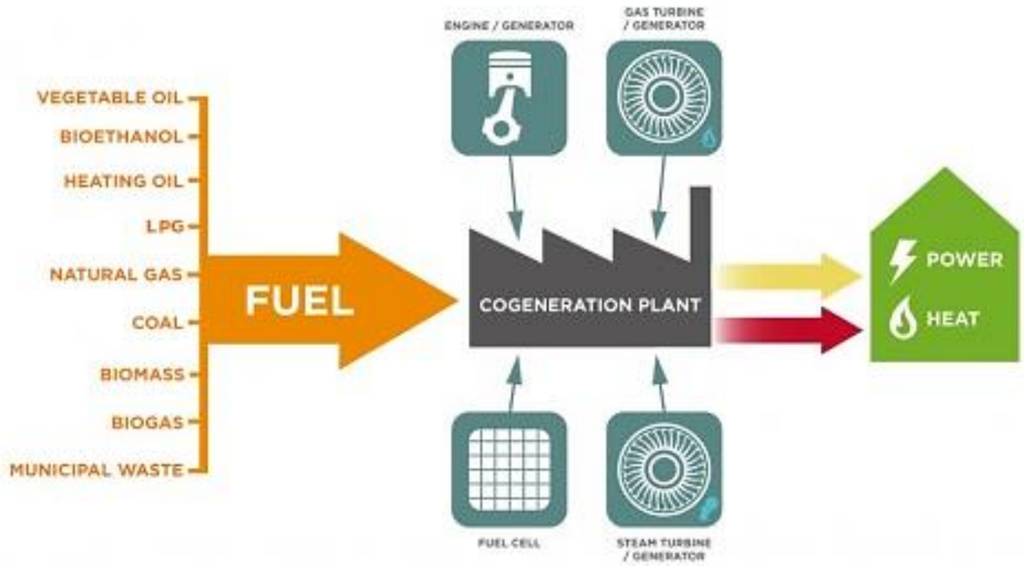


Figure 37: Simplied Principle of Cogeneration Power Plant

Source: www.cogeneurope.eu

Basically, the power production process starts from feeding fuels into a combustion chamber. If two or more types of fuels are used, they are proportionally mixed at this step. The fuels are burnt by a superheater to make water injected evaporates and becomes steam. The steam is then used to drive a turbine generator to yield electricity, while the remaining steam can be extracted at different levels of pressure before selling to customers.

2.2.2 Strategic and Operational Management in Power Plants

As mentioned earlier that the deregulation of electricity market has affected business operations of power generators meaning that they need to pursue right strategic moves for their own competitiveness. There have been a number of efforts by researchers studying on this key area. Lazzaretto & Carraretto (2006) developed managerial strategies for optimum production planning in thermal power plants in the deregulated electricity market with the goal of profit maximisation; however, their approaches are based on an assumption that the market can accept total power generated which is unrealistic. Whereas, Huang *et al*. (2004) proposed an production strategy for a cogeneration power plant using genetic algorithms in order to enhance competitiveness in the deregulated electricity market.

In addition to power plant strategies required due to changes in the market structure, some previous work emphasised on operational issues and challenges in power plants. Cerri *et al*. (2009) examined planning problems found in a network of electric power plants with regards to maintenance and system load allocation for gaining maximum profitability. A production planning embedded with its algorithm was developed, a simulation using neural network techniques was performed to validate the plan. The results show optimal electricity generation can be achieved using the new proposed plan.

Nevertheless, most of past studies looked at management in a single power plant. For example, Latifoğlu *et al*. (2013) created a production model of electric power generation under given certain assumptions and interruption scenarios to reduce the cost of producing electricity and to ensure customer satisfaction. A robust framework using heuristic procedure was also developed, and a computational experiment was conducted to validate the model.

This is similar to Kragelund *et al*. (2012) since they addressed a problem found in a power plant where three different fuel systems, but their research objective was to maximise profit instead of focusing on production cost. Heuristic approaches were used along with an optimization technique before proposing an optimal control strategy for using those different three fuel systems in the power plant. While, some of the past researches concerns about managerial planning strategies. For instance, Lazzaretto & Carraretto (2006) proposed a strategic approach to manage a power plant or a group of power plants when there is a high degree of competitiveness occurred in the market of electricity utilities.

2.2.3 Risk Management in Power Plants

The increasingly complex business processes of power generation have significantly influenced risk management. Some of the possible risks are from electricity procurement, reformation of electricity market and volatility of spot-price (Woo *et al*., 2004). It is commonly believed that systematic planning and management of electricity generation will allow the electricity producers to maximize returns and especially minimise risks (Cunha & Ferreira, 2014). These advantages were also proven by Janghorbani *et al*. (2014) since risks involved in a power plant can be systematically mitigated by good production management strategies that allow the power producers to obtain maximum profit.

2.3 Economic Dispatch of Electric-Power Generation Schemes

An increasing demand growth of electricity results in expanding the size of power stations and the generating units to increase productivity level; however, power generation system needs to be at minimum cost along with maintaining reliability and satisfying system constraints. With the assistance of economic dispatch, these issues and challenges in power management system can be alleviated. This section is intended to discuss about economic dispatch, including its definition, principles and previous research studies.

2.3.1 Definition of Economic Dispatch

According to the U.S. Energy Policy Act of 2005 (The United States Congress, 2005), economic dispatch (ED) is “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognising any operational limit of generation and transmission facilities”. Similarly, Chowdhury & Rahman (1990) defined that it is “the process of allocating generation levels to the generating units in the mix, so that the system load may be supplied entirely and most economically". Based on the given definition, it is obvious that the key of ED is to keep cost minimum while meeting power load demand.

2.3.2 Principle and Objective of Economic Dispatch Problem Solving

The key underlying principle of ED problem is to deliver electric power to consumers at the lowest total cost of generation and at the same time satisfy all relevant constraints of system and network. The sum of total electricity generated should be equivalent to the electric power demanded by consumers, and for simplicity, power losses in the transmission lines are neglected (Happ, 1977).

The objective of ED problem solving is to minimise the total cost of power generation (including fuel, operations, maintenance and more) while satisfying the following constraints: system load demand, specific requirements of the system, limits of individual generating facilities, pollutant emission allowance, network security constraints and more.

Happ (1977) revealed that one of the key challenges for solving ED problem is not only to satisfy consumer demand for electricity, but also to keep power system at the lowest cost. Moreover, the power system with several generating facilities need to be reliable, but each of them has different capabilities and parameters in terms of type of fuel, capacity, efficiency and cost of operations. In particular, the cost of operations for different electric generators since it is not constant with their outputs produced.

2.3.3 Formulation of Economic Dispatch Problem

According to Wood & Wollenberg (1984) and Saadat (1999), an economic dispatch (ED) problem can be modelled and written in mathematical form. As mentioned before that the objective of the problem is to minimise the total cost of power generation; therefore, the objective function for optimisation can be expressed mathematically as Equation (19):

$$\boxed{\text{Minimize} \quad \sum_{i=1}^{N} C_i(P_i)} \tag{19}$$

The objective function is subject to the following set of constraints:

$$\text{Power Balance:} \quad \sum_{i=1}^{N} P_i = D \tag{20}$$

$$\text{Generation Limits:} \quad P_{i,\min} \le P_{i,gen} \le P_{i,\max} \tag{21}$$

where N = Total number of generating units in a power system

C_i = Cost of power generation of generator i

P_i = Power produced by generator i

D = Total demand in a power system

$P_{i,min}$ = Minimum power of generator i

$P_{i,max}$ = Maximum power limit of generator i

The quadratic cost function of generator can be represented in Equation (22):

$$\boxed{C_i(P_i) = \alpha_i + \beta_i P_i + \gamma_i P_i^2} \tag{22}$$

For the power balance constraint expressed in Equation (20), total power generation in the system must be exactly equal to the power demand required by consumers. In this case, it is assumed there are no power losses in transmission lines. For the generation limit constraints expressed in Equation (21), the power generation of each generating unit must remain between the upper limit and the lower limit.

2.3.4 Recent Publications about Economic Dispatch

Economic dispatch (ED) has been extensively studied and applied by a number of researchers and practitioners since its inception. Mostly, it has been involved in operations management of power systems. However, recent papers have extended beyond traditional approaches by applying a wide range of solution methods to optimally schedule operations of generating facilities to serve consumer power demand at the minimum cost.

In this section, recent published articles, journals and conference papers about economic dispatch classified by solution methods are discussed. In the next section, these recent publications plus additional related papers will be critically analysed, compared and contrasted to see what have been done and what research gap is.

2.3.4.1 Linear Programming

Rahli *et al*. (2015) solved an ED problem of load flow type network with two additional constraints of line power flow limits and active line power generation limits using a variable weights linear programming (LP) method. They explained the advantage of this new method that it is less complicated when a non-linear cost function is transformed into a linear-function one. The results show more accurate but less speedy power serving to consumers when the line power flow limits were included as the constraint.

Ashfaq & Khan (2014) modified linear programming method to transform non-linear characteristics of an ED problem into linear characteristics. The purpose of this modification is to compare an optimal result obtained from the simple LP method with other complex methods: lambda iteration and firefly algorithm. It was proved that modified LP method can compete with those two methods by reaching optimal point of power to be produced for each generator.

2.3.4.2 Dynamic Programming

Hansen & Mladenovic (2016) proposed an iterative method of dynamic programming (DP), to solve an ED problem with network transmission losses included in coefficients of the quadratic cost function. The objective was to minimise total cost of electricity production in the power network. With the proposed iterative method, it was found that optimal solutions could be obtained while the total cost could be lowered substantially.

2.3.4.3 Lambda-Iteration Method

Dike *et al*. (2013) attempted to improve an ED problem of electric power generation from remote areas to power load centres situated in urban areas using modified lambda-iteration method. The MATLAB program was coded to help solve the ED problem and to provide optimal power to be generated at the cheapest fuel cost. The results from the program were moderately improved comparing to the results from using GA as both optimal solutions were not much significantly different.

2.3.4.4 Lagrangian Relaxation

Sashirekha *et al*. (2013) applied Lagrangian relaxation with multiple updates to solve sub EP problems of combined heat and power (CHP) or cogeneration plant where two levels of constraints were included. The higher level was used to optimise global constraints and the lower level was used to optimise local constraints. The method was justified by numerical computation results. The results from the numerical test proved that Lagrangian relaxation is valid and efficient for solving ED problems due to obtained the reliable results.

2.3.4.5 Particle Swarm Optimisation

Mahor *et al*. (2009) used Particle Swarm Optimisation (PSO) method to solve an ED problem. Valve-point effects, various fuels and emission were added on the cost function, which can be considered multiple objective ED problem. The results from solving the problem allowed the generating units to be scheduled optimally leading to the minimum cost.

Mohammadi-Ivatloo *et al*. (2013) used a novel approach of PSO with time varying acceleration coefficients to solve an ED problem of a CHP power plant consisting of thermal, cogeneration and heat-only units. Valve-point effects, transmission losses, generation limits and power-heat dependency were included as restrictions of the power system. The quality of results were improved relative to traditional PSO since the solution was tested in a large-scale system proving the applicability of PSO with time varying acceleration coefficients for solving ED problems of large-scale CHP power plants.

Vignesh *et al*. (2016) proposed an approach for solving ED problem of three different thermal generating units with the fuel costs are different from each other. The objective is to serve power demand at the lowest cost. A quantum particle swarm optimisation (QPSO) technique was applied to solve the ED problem, and the results were also used to compare to a regular PSO technique. It was found that power demand could be entirely satisfied while the fuel cost could be decreased up to $3 per hour relative to using the regular PSO.

2.3.4.6 Genetic Algorithm

Al-Shetwi & Alomoush (2016) applied a new solution of Genetic Algorithm (GA) to an ED problem with three generating facilities in order to find out how much optimal power output to be generated while keeping total cost of generation at minimum. The results obtained from the GA were nearly equivalent to what conventional optimisation methods have given. The MATLAP program was then used to validate the efficiency of the GA, and it was confirmed that the new proposed method is applicable and considered one of the most efficient techniques for solving ED problems.

Likewise, the research conducted by Srikanth *et al*. (2016) as MATLAB toolbox is a tool used for ED problem solving with multiple fuel options. The GA method was applied to determine the optimal economic fuel of four generating units with three different types of fuel since the costs of these three fuel options were different among those four generating units. The MATLAP program was used to simulate results, and the results show that total fuel cost could be minimised and lowered comparing to the results obtained from PSO method.

Tsai *et al*. (2015) introduced a solution for solving an ED problem of cogeneration systems by using an Improved Genetic Algorithm (IGA). The IGA introduced is based on the traditional GA and Tabu Search (TS) algorithm, but assists enhance the efficiency of problem solving proven by the results obtained from using IGA. It was also suggested that the IGA can also be further applied to planning and operations management in a power system.

2.3.4.7 Cuckoo Search Algorithm

Serapião (2013) adopt Cuckoo Search (CS) algorithm to solve ED problems with two power systems: the first system with three generators and the second with six generators. The results using the CS were simulated and compared with the results from each of six other swarm intelligence algorithms. It was found that the results from CS were superior to those six algorithms because of its cheapest fuel cost of operation.

2.3.4.8 Tabu Search Algorithm

Naama *et al*. (2013) presented the Tabu Search (TS) algorithm for solving an ED problem of security constraints where limits on line flow were concerned. The results from using TS algorithm were compared against those using GA, Mat-Power and quasi-Newton method (QN). It was revealed that, with using the TS algorithm, the quality of the optimal solution could be improved and the computation time could be reduced.

2.3.4.9 Evolutionary Algorithm

Balamurugan & Subramanian (2008) introduced a new method for solving a dynamic ED problem, namely Differential Evolutionary (DE) algorithm. The objective was to find the optimal outputs for a set of generating facilities over a specific period of time by meeting dynamic operational constraints and load demand at each time interval. They described that it is more appropriate to apply DE algorithm rather than other methods to solve dynamic ED problems since the DE algorithm is able to efficiently handle with the time constraints.

Mahdad & Srairi (2011) presented Improved Parallel Differential Evolutionary (IPDE) algorithm to solve a large-scale ED problem with constraints of generations. The proposed algorithm was implemented in a big electrical network system comprising of 40 generating units. Results from simulation program were compared against DE algorithm. It was revealed that the performances of IPDE algorithm was better than those of DE algorithm because of qualitative-based solution and reduced computational time.

Zaman *et al*. (2016) developed differential evolutionary algorithms to dynamic ED problems since traditional evolutionary algorithms rely on many factors as a result of complex problem solving. The developed evolutionary algorithms were used to simulate results. The effectiveness was also tested in a number of dynamic ED problems and it was proved that the differential evolutionary algorithms could provide optimal, qualified and reliable solutions.

2.3.4.10 Artificial Immune System Algorithm

Behera *et al*. (2011) developed Artificial Immune System (AIS) algorithm, which was based on GA algorithm, for determining optimal economic dispatch of power systems while satisfying all constraints of power systems. They also described the benefits of AIS algorithm that it helps reduce complexity of the ED problem and provides flexible solution

Basu (2012) applied AIS algorithm for solving an ED problem of CHP power plant for obtaining more accurate computation results. The AIS algorithm was tested for validity using MATLAP program. The simulation results were compared against the results from PSO and EP and found that AIS were more efficient in terms of lower cost as well as decreased computational time.

2.3.5 Critical Analysis on Recent Economic Dispatch-Related Work

Towards the end of year 2016, a number of research papers in the field of ED have been published in many reputable sources. The recent publications discussed in the previous section are just some of them that are towards the objectives and firmly support hypothesis statement of this research declared in Section 1.5 and Section 1.6 of Introduction Chapter, respectively. This is because the findings of those research studies have strongly proven that minimum cost of production can be achieved by solving ED problems and hypothetically leads to obtain maximum profit.

Referring to the key objective of ED problem that is to determine the optimal point of generation units with minimum cost while satisfying load demands and system constraints. It seems that the entire set of recent studies intended to achieve this, but some of which (Mahor *et al*., 2009; Mahdad & Srairi, 2011; Dike *et al*., 2013; Serapião, 2013; Ashfaq & Khan, 2014; Al-Shetwi & Alomoush, 2016; Srikanth *et al*., 2016; Vignesh *et al*., 2016; Zaman *et al*., 2016) chose to minimize fuel cost instead of total cost of generation (Balamurugan & Subramanian, 2008; Behera *et al*., 2011; Basu, 2012; Mohammadi-Ivatloo *et al*., 2013; Naama *et al*., 2013; Sashirekha *et al*., 2013; Rahli *et al*., 2015; Hansen & Mladenovic, 2016). The rationale behind this might be because the fuel cost almost covers the total cost of generation. There is only one paper by Tsai *et al*. (2015) aiming to solve the ED problem for profit maximization, but the constraints in the system are generally indifferent from those found in common ED problems.

Two power plant systems have been interested by the recent studies: power only and CHP plant systems. Apparently, most of the work devoted to solve ED problems in the plant system with power generating units, conversely only few (Basu, 2012; Mohammadi-Ivatloo *et al*., 2013; Tsai *et al*., 2015) chose to solve ED problems in CHP plant where both electricity and steam can be produced at the same time.

Considering solution methods applied in the recent papers, they are very diverse ranging from simple methods to sophisticated methods. This is because the authors modified or improve that particular conventional method to fit to their own ED problem characteristics or to improve accuracy of computational results. For examples, Mohammadi-Ivatloo *et al*. (2013) and Vignesh *et al*. (2016) modified regular PSO method of Mahor *et al*. (2009), and Mahdad & Srairi (2011) improved DE of Balamurugan & Subramanian (2008). Alternatively, some authors newly developed solution methods for solving ED Problems; for instance, Behera *et al*. (2011) developed AIS algorithm and Serapião (2013) developed CS algorithm. While, the same solution method was used more than once but in different plant systems. For example, AIS algorithm was first used by Behera *et al*. (2011) in a conventional plant system and later used by Basu (2012) in a CHP plant system.

Briefly, the summary of the recent publications (2008-2016) about economic dispatch and the gap of this research study are demonstrated in Table 17.

Table 17: 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 *et al.*	2009	Minimum fuel cost	Power	No	Particle swarm optimisation
Behera *et al.*	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 *et al.*	2013	Minimum fuel cost	Power	No	Modified lambda-iteration
Mohammadi-Ivatloo *et al.*	2013	Minimum generation cost	CHP	No	Particle swarm optimisation with time varying acceleration coefficients
Naama *et al.*	2013	Minimum generation cost	Power	No	Tabu search algorithm
Sashirekha *et al.*	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 *et al.*	2015	Minimum generation cost	Power	No	Variable weights linear programming
Tsai *et al.* [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 *et al.*	2016	Minimum fuel cost	Power	No	Genetic algorithm

Table 17: Summary of the Recent Publications on Economic Dispatch (continued)

Authors	Year	Objective	Plant System	Profit Max	Solution Methods
Vignesh *et al.*	2016	Minimum fuel cost	Power	No	Quantum particle swarm optimisation
Zaman *et al.*	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 from those found in typical ED problems.

2.4 Mathematical Modelling

2.4.1 What is Mathematical Modelling?

According to Dym & Ivey (1980), mathematical modelling is the activity of translating problems of an application area into mathematical representations to provide useful insights, solution and guidance for the originating application.

2.4.2 Mathematical Modelling in Scientific Method

In depiction of scientific method as illustrated in Figure 38, several phenomena and behaviours can be seen in the real world. In the conceptual world, there are observation, modelling and prediction. For observation, it is to measure what is taking place now before gathering empirical evidence and facts around. For modelling, it is to analyse the observation by creating a model that describes the phenomena and behaviours observed. For prediction, the model is exercised to tell what will occur in an anticipated set of events in the real world, and observations are repeated after predicting to validate the model (Dym & Ivey, 1980).

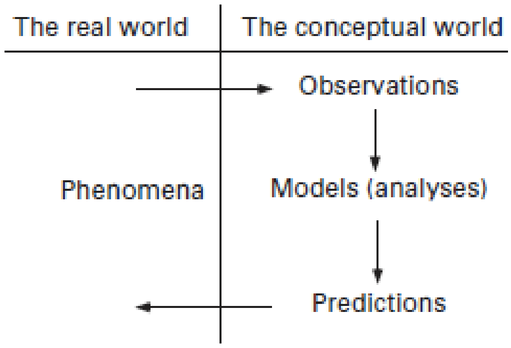


Figure 38: Mathematical Modelling and Scientific Method

Source: Dym & Ivey (1980)

2.4.3 Mathematical Modelling in Engineering Practice

Practically, engineers are interested in designing processes and systems to develop artifacts as Professor Herbert A. Simon wrote in his book *The Sciences of the Artificial* that "design is the distinguishing activity of engineering" (Simon, 1999). Thereby, such processes and systems needs to be modelled by engineers if they want to design those processes and systems. However, modelling in the engineering is normally done under assumptions.

In comparison, mathematical modellings in the scientific method and the engineering practice are interconnected as their models are applied and assist to predict what will happen in the near future. However, prediction in engineering is typically done under assumptions.

2.4.4 Steps in Mathematical Modelling

According to Dym (2004), the activity of mathematical modelling has principles to support and methods behind which can be used for numerous applications. Figure 39 shows methodological principles of modelling proposed by Carson & Cobelli (2001). The principles start by asking why a model is needed and what is willing to be known before gathering data for variables and parameters. The model is constructed under assumptions. Then, the model is test to see whether the predictions are valid and verified, and it is improved, if necessary, to ensure that it can be used in reality.

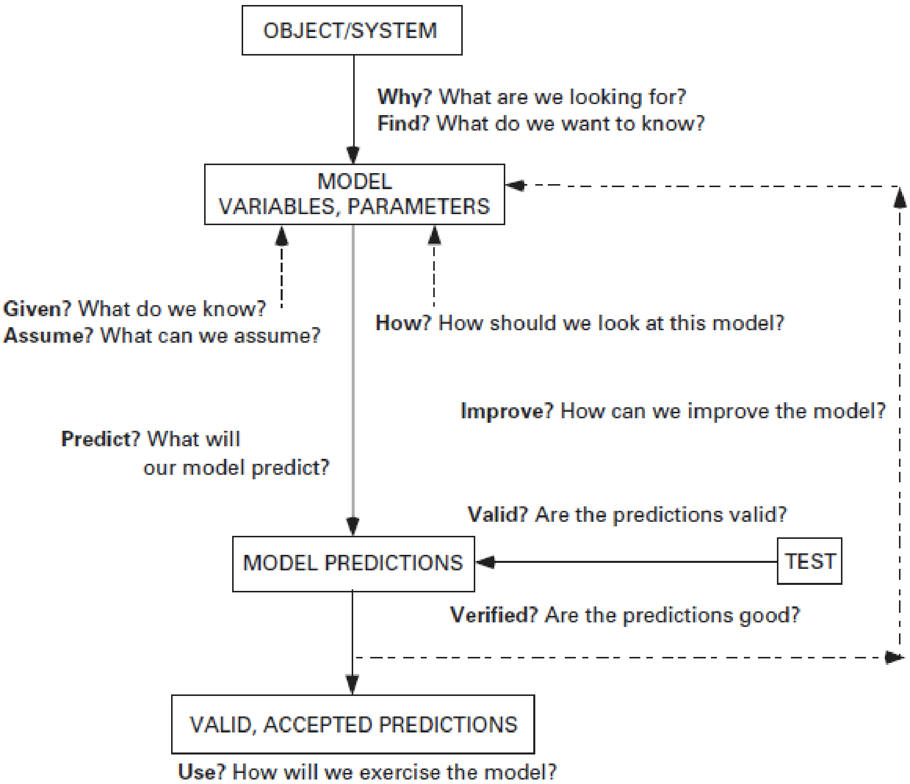


Figure 39: Methodologically Modelling Principles

Source: Carson & Cobelli (2001)

These methodically modelling principles is like the process of management science using scientific methods. According to Taylor III (2010), the general series of management science process, see Figure 40 consists of:

(1) Observation

(2) Problem definition

(3) Model construction

(4) Model solution

(5) Implementation

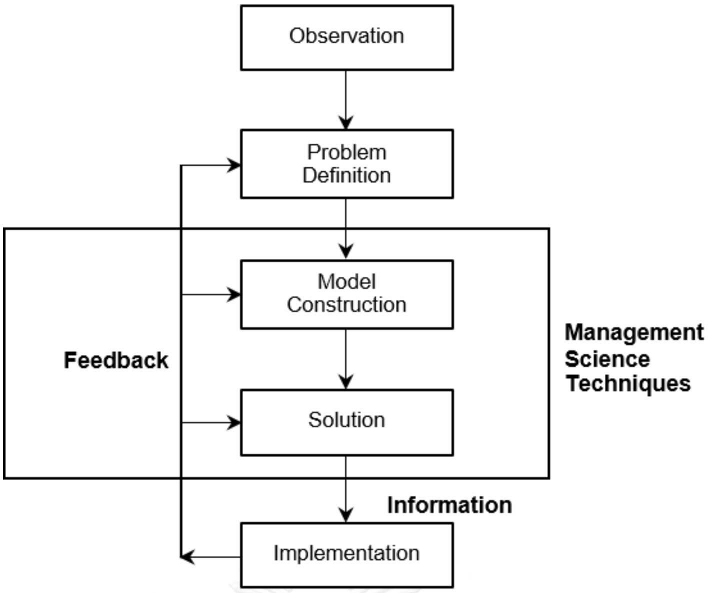


Figure 40: The Management Science Process

Source: Adapted from Taylor III (2010)

- **Observation**: This first step is to identify a problem that is happening in the system or business organisation. It is suggested that the problem identification should be continuously and closely observed as soon as the problem exists or is anticipated.

- **Problem Definition**: After identifying the problem, the problem should be distinctly and concisely defined; otherwise, no solution or improper solution is acquired if the problem is defined limitlessly and inappropriately.

- **Model Construction**: It is now time to build a model since it is a representation of a problem situation. In MS/OR, a model represents a set of mathematical relationships comprising of an objective function, decision variables, parameters and constraints.

- **Model Solution**: After constructing the model, the model is then solved using one of MS/OR techniques, such as LP, depending on appropriateness and type of that particular problem, in order to obtain a feasible solution.

- **Implementation**: This is the final step when the model developed is used; however, it is not automatically used after developing the model or finding the solution. This is because the person responsible for model implementation is frequently not the same one responsible for model development.

2.5 Modelling with Linear Programming

Most decisions faced by a business manager is to decide the best alternative to reach a company's objectives, subject to restrictions in the operating environment, such as limited resources of labour, raw materials, time and money. Hillier & Lieberman (2014) mentioned that the most common ultimate goal of business organisations is to either maximise profit or minimise cost. With a powerful technique of LP, such business issues and challenges seeking an optimisation objective with subject to restrictions can be solve systematically.

2.5.1 Meaning of Linear Programming

Linear programming (LP) is a mathematical model that describes a problem situation of concern. According to Hillier & Lieberman (2014), the adjective *linear* means the functions in the model are graphically drawn as a straight line. The term *programming* does not means computer-related programming but rather a synonym for the word *planning*. Consequently, the noun phrase *linear programming* means "the planning of activities to obtain an optimal solution among all feasible alternatives".

2.5.2 Formulation of Linear Programming Problem

Mathematically speaking, three steps of LP problem formulation are (1) defining the decision variables, (2) defining the objective function and (3) defining model constraints. The decision variables are mathematical symbols representing choices available to a decision maker. The objective function is a mathematical expression in the form of linear relationship that maximises or minimises some quantity of an operation. The constraints are restrictions on decision making. Figure 41 shows the standard form of LP maximisation model.

Maximize $Z = c_1x_1 + c_1x_1 + \cdots + c_nx_n$ **Objective Function**

subject to the restrictions

$$\left.\begin{array}{l} c_{11}x_1 + c_{12}x_1 + \cdots + c_{1n}x_n \le b_1 \\ c_{21}x_1 + c_{22}x_1 + \cdots + c_{2n}x_n \le b_2 \end{array}\right\} \textbf{Functional Constraints}$$

$$\vdots$$

$$c_{m1}x_1 + c_{m2}x_1 + \cdots + c_{mn}x_n \le b_m$$

and $x_n \ge 0$ **Nonnegativity constraints**

where c_n = Parameter

Figure 41: Standard Form of Linear Programming Maximisation Model

2.5.3 Solutions of Linear Programming Problem

For small-scaled LP problems (no more than two decision variables) can be successfully solved by using graphical method, iso-profit line method or corner-point method. However, for multi-decision variable LP problems require computer programs for determining optimal solutions, such as Excel Solver, LINGO, CPLEX, MATLAB and more (Hillier & Lieberman, 2014).

2.5.4 General Properties of Linear Programming Models

Apart from encompassing linear functional relations given by its meaning, a mathematical LP model also has the following implicit properties in common (Hillier & Lieberman, 2014):

- **Proportionality**: The slope of objective function as known as the coefficient is always constant. This means the value of objective function will change exactly the same relative changes in the value of decision variable.
- **Additivity**: The terms in the objective function and constraints are additive.
- **Divisibility**: The values of decision variables are not restricted to just integer values, but they are allowed to be any fractional values.
- **Certainty**: The values assigned to all parameters are known for sure.

2.5.5 Applications of Linear Programming in Power Plants

In an electrical power system, it is generally consisted of multiple power generation subsystems. The job of a power plant manager or a planner is to optimise and make several decisions across the systems including supplying fuel, generating and transmitting electricity. Mathematical programming like LP provides attractive benefits to assist optimise the power systems and to make a decision more precisely and accurately in an effective and timely manner.

Several research studies have used LP models to optimise planning electric power generation. Hoekstra (2000) suggested that LP method can be used for power generation decisions, such as power plant expansion planning, daily operation planning, de-bottleneck problem solving and unexpected event decision makings. Later, these applications have been interested by many researchers. For instances, Lahdelma & Hakonen (2003) used LP to model hourly CHP operation optimization planning for cost efficiency, while Tibi & Arman (2007) used LP to optimise the cost of installation and the cost of energy for a cogeneration plant system under a restriction of demand and supply balances.

These are similar to researches carried out by Khodr *et al*. (2002) and Dragićević & Bojić (2009) since their purposes are to lower the cost of selection of independent electric power generation and the total costs of energy used, respectively, but there implementation of LP models were performed in different plant systems.

Some studied used LP for optmising combination of something in power plants. For examples, Erarslan *et al*. (2001) determine the optimal mix of coal in aspects of both quality and quality using LP to meet the calorific values of the power plant. Dolara *et al*. (2017) used LP as an optimisation method to minimise the utilisation of fossil fuels in hybrid power plants with three different types of energy: renewable, diesel and battery.

Furthermore, a few research studies focuses on competition in the electricity market. Marinović *et al*. (2012) used LP to determine the optimal amount of electricity trading on how much should be purchased from individual supplier and sold to individual buyers to maximize daily profit. Whereas, Chen & Liao (2011) used LP model to find the optimal contract capacity with the aim of total cost minimisation of electricity bill, and it was found that the LP method needs less computation time comparing to using metaheuristic approaches.

Nonetheless, one of the previous work considered a linear programming model with a multiple objective for power generation expansion planning. These objectives include net present cost, system reliability and environmental impacts, subject to three constraints of operations, load requirements and budget (Climaco *et al*., 1995).

In addition to having a focus on a single power plant. There are not many researches using mathematical models for optimising a group of power plants as a whole. Some of these include Al-Ali *et al*. (2008) and Luo *et al*. (2002) as mixed-integer linear programming (MILP) model was used to reduce the total economic cost and environmental impact, respectively, which is beneficial to electricity production planning. Whereas, Luo *et al*. (2013) looked at a methodology used for optimising the operational planning of interconnected steam power plants in order to minimise the total cost under typical situation whilst allowing flexibility for unanticipated equipment failure to happen with a few incremental cost penalties.

In brief, the summary of previous research studies on the applications of LP method in power plants can be illustrated in Table 18 below.

Table 18: Summary of Past Researches on Linear Programming in Power Plants

Authors	Year	Objective	Solution Method
Climaco *et al*.	1995	Plan power generation expansion considering net present cost, system reliability and environmental impacts	Linear programming
Hoekstra	2000	Recommend the applications of LP in power generation decisions	Linear programming
Erarslan *et al*.	2001	Determine the optimal combination of coal in terms of quality and quantity to meet the required calorific values	Linear programming
Khodr *et al*.	2002	Minimise the cost of selection of independent electricity generation in a conventional power plant	Linear programming
Luo *et al*.	2002	Reduce the environmental impacts from generating electricity	Mixed-integer linear programming
Lahdelma & Hakonen	2003	Optimise hourly CHP operations planning for cost efficiency	Linear programming
Tibi & Arman	2007	Optimise the cost of installation and the cost of energy for a cogeneration plant system under a restriction of demand and supply balances	Linear programming
Al-Ali *et al*.	2008	Reduce the total economic cost of electricity production planning.	Mixed-integer linear programming
Dragićević & Bojić	2009	Minimise the total cost of energy used in a CHP power plant	Linear programming

Table 18: Summary of Past Researches on Linear Programming in Power Plants

Authors	Year	Objective	Solution Method
Chen & Liao	2011	Determine the optimal contract capacity with the aim of total cost minimisation of electricity bill	Linear programming (compared with metaheuristics)
Marinović *et al.*	2012	Determine the optimal amount of electricity trading (how much to be purchased from suppliers and sold) to buyers to maximize daily profit	Linear programming
Luo *et al.*	2013	Minimise the total cost under normal situation while allowing flexibility for unanticipated equipment failure	Linear programming
Dolara *et al.*	2017	Minimise the utilisation of fossil fuels in hybrid power plants	Linear programming

2.6 Simulation

2.6.1 Background of Simulation

Simulation began in 1950 when the prices of computer, hardware and software were relatively expensive, and computer training was very essential, resulting simulation modelling did not become well-known. However, computers had been quickly popular, and the prices has been cheaper during 1970-1980, causing simulation modelling to be more worthwhile and often used in the automotive and the aerospace industries (Ross, 2013).

In 1978, Rasmussen and George studied about uses of tools in operations research (OR) and management science (MS) and revealed that simulation was ranked the fifth in its popular use. A year later, they examined and found that 84% of total large enterprises were using simulation. Since then, simulation has been widely used in several industries, banks, transportation, logistics, distribution, hospital, computer network and business process, and it has become a standard designing tool used by small firms (Robinson, 2014).

2.6.2 Definition of Simulation

According to Taylor III (2010), simulation is "the replication of a real system with a mathematical model that can be analysed with a computer". This is similar to Banks *et al*. (2013) as they defined "simulation as the imitation of the operation of a real-world process or system over time". Based on these two definitions, it can be understood that simulation is "the process of designing a model of a real system to realise behaviours of the system".

2.6.3 Computer Simulation

Computer simulation is to study a model of a real-world system through numerical evaluation using a simulated-based program. It is the process of designing and developing a model using a computer that replicates a real system in order to understand behaviours more easily under various given conditions and constraints. Dym (2004) mentioned that two processes involved with computer simulation are model creation and model implementation.

2.6.4 Steps in Simulation Study

There is no universal procedure for studying a simulation, most book authors agree and rely on typical steps designed by Banks *et al*. (2013) as illustrated in Figure 42. Banks *et al*. (2013) explained in his book that the steps are not proceeded consequtively one time, but there are decisions, verifications, validatations to be made among these steps.

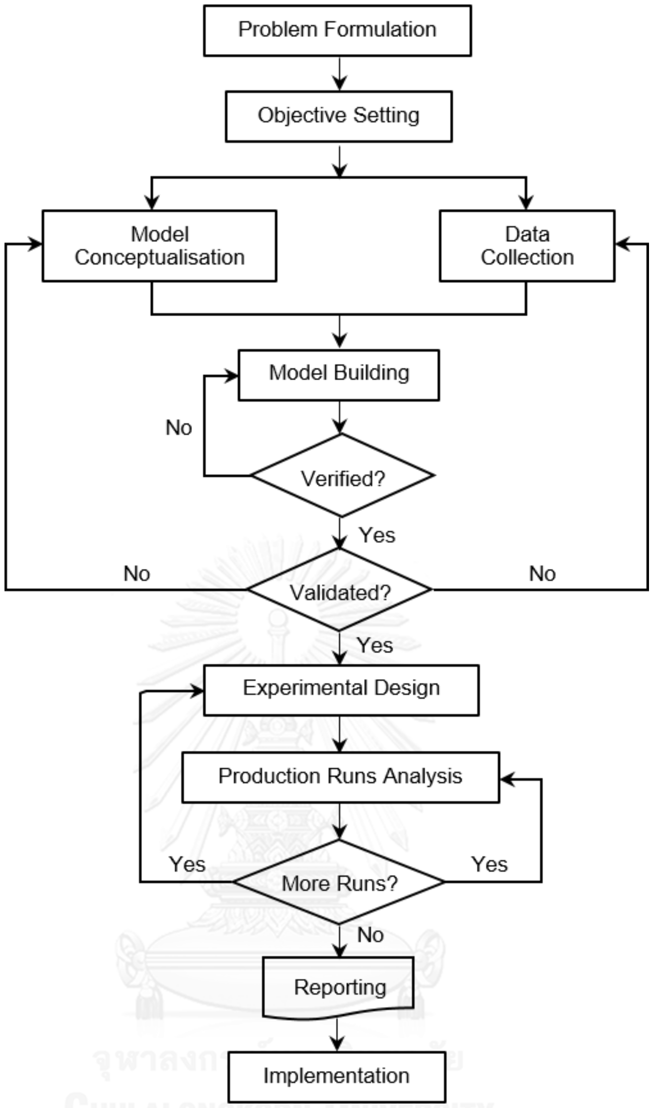


Figure 42: Steps in Simulation Study

Source: Adapted from Banks *et al*, (2013)

2.6.5 Applications of Simulation in Power Plants

Simulation has been popularly used by a number of researchers for a long time as it provides preliminary results and some insights before actual implementation. According to Ventosa *et al*. (2005), they reviewed literatures about electricity market and concluded that simulation models has been used successfully to predict what the research studies were intending to achieve. This can be proved by the following papers. For examples, Shirakawa *et al*. (2005) developed a simulation model to help determine the optimal initial operations process for a combined cycle power plant since the system design and the control design are complex and difficult to execute. Castronuovo & Lopes (2004) developed a simulation model for a wind-hydro power plant in order to manage the combination of the two energy fuels for routine operations of electricity generation. This is similar to Anagnostopoulos & Papantonis (2008) since they used a simulation to optimise a pumped-storage power plant. Whereas, Villa *et al*. (2012) used a simulation model developed for maximising the power output of the solar power plants as partial shades affect the power generation.

To conclude, the summary of previous research studies regarding the simulation in electric power plants can be demonstrated in Table 19 below.

Table 19: Summary of Previous Researches on Simulation in Power Plants

Authors	Year	Objective	Solution Method
Castronuovo & Lopes	2004	Manage the combination of the two energy fuels for routine operations in a wind-hydro power plant	Simulation model
Shirakawa *et al*.	2005	Determine the optimal initial operations process for a combined cycle power plant	Simulation model
Ventosa *et al*.	2005	Concluded that simulation models has been used successfully to predict events	Literature survey
Anagnostopoulos & Papantonis	2008	Optimise a pumped-storage power plant	Simulation model
Villa *et al*.	2012	Maximise the power output of the solar power plants with the effect of partial shades on power generation	Simulation model

2.7 Sensitivity Analysis

Referring to the linear maximisation model shown earlier in Figure 41, the functional relationship enables to see how the level of maximum value is directly affected by changes in decision variables. It is normally assumed that the parameters are fixed when developing this model. In reality, the parameters are often volatile and rarely be assumed to be constant. Changes in any of the parameters can impact the model solution, Hillier & Lieberman (2014) called an analysis projecting how sensitive a model is to changes in parameters or variables that *sensitivity analysis*. This is consistent with Taylor III (2010) as sensitivity analysis refers to the study of how much solutions change to changes in parameters.

2.7.1 Regression Approach for Conducting Sensitivity Analysis

In the context of sensitivity analysis, regression is a statistical technique used to fit a smooth surface to the model response (Kleijnen, 1992), estimating the relationship between parameters and a dependent variable. Originally, method of least squares was the earliest regression. However, Hillier & Lieberman (2014) suggested that linear regression is the most suitable if the model response is actually linear, and because it is simple and requires low computational time. Equation 23 illustrates the standard form of simple linear regression.

$$\boxed{y_i = \beta_0 + \beta_1 x_i + \varepsilon_i} \tag{23}$$

where y_i = Dependent variable

β_0 = Constant

β_1 = Slope

x_i = Independent variable

ε_i = Random error

2.7.2 Applications of Sensitivity Analysis in Power Plants

Sensitivity analysis is useful for evaluating how factors impact results. Historically, Butler *et al*. (1997) proposed techniques for the sensitivity analysis when decisions involves multiple criteria. After that, it has been widely applied in a numerous fields, including electric energy. El-Sharkh *et al*. (2006) evaluated how changes in relevant factors influenced the cost of operational strategy in a power plant. Chatzimouratidis & Pilavachi (2008) conducted sensitivity analysis on how the operational factors of power plants affected the living standard using analytic hierarchy process (AHP). One year later, they evaluated how technological, sustainable and economic factors impacted different types of power plants using the same approach Chatzimouratidis & Pilavachi (2009). Whilst, Mostafavi *et al*. (2013) created a new approach to investigate what factors contributed to changes in electricity demand.

In short, the summary of past research studies about sensitivity analysis in electric power plants can be illustrated in Table 20 below.

Table 20: Summary of Past Researches on Sensitivity Analysis in Power Plants

Authors	Year	Objective	Solution Method
Butler *et al.*	1997	Proposed techniques for the sensitivity analysis when decisions involves multiple criteria	Sensitivity analysis
El-Sharkh *et al.*	2006	Evaluated how changes in relevant factors influenced the cost of operational strategy in a power plant	Sensitivity analysis
Chatzimouratidis & Pilavachi	2008	Conducted sensitivity analysis on how the operational factors of power plants affected the living standard	Sensitivity analysis (AHP)
Chatzimouratidis & Pilavachi	2009	Evaluated how technological, sustainable and economic factors impacted different types of power plants	Sensitivity analysis (AHP)
Mostafavi *et al.*	2013	Investigate what factors contributed to changes in electricity demand	Sensitivity analysis

2.8 Summary of the Literature Review Chapter

In summary, the case study company as an SPP has become part of private power producers since the liberalisation and privatisation of the electricity market in the 1990s. As a result, the competition has been more intensified, while the establishment of ESI structure has caused all power producers to be monitored and enforced by laws and regulations under the regulatory framework of the country's electricity sector. The case study company has to also comply PPAs since they are key legal sale contracts in which power delivery scheduling, penalties for under-delivery, terms of payment and termination are specified; otherwise, their revenue could be affected. Moreover, several external factors could also affect the revenue, including natural coal price, gas price, fuel oil and foreign exchange rate, as they are wholly associated with costing and pricing determination of both electricity and steam. Apart from these external factors, the revenue could also be affected by some internal factors in terms of productions and operations management, such as lack of coordination and economic dispatch principles among the power plants of the case study company to generate and sell electricity and steam to different customers at the minimum cost of production. These factors mentioned altogether have resulted the case study company to encounter the problem of continually decreased profit margin during the past few years.

This literature review synthesises the state-of-art in power plant business for profit maximisation in relation to the objectives of this research project. It was revealed that a number of research studies have already proved that having excellent and systematic managerial strategies for production planning leads to achieve maximum profit. However, most of them seem to be developed to fit into their own local characteristics of power plants and could not be further used as a guideline for practicality in general power plants. Based on the survey of literature, economic dispatch (ED) seems to be the answer towards profit maximisation for power plant business as its underlying principle and objective are to minimise the total cost of power generation while satisfying power system and network constraints. Nonetheless, this is just a half way since the emphasis of ED is about to minimise total cost without consideration of prices in order to maximise profit. A number of recent publications on ED have already used various solution methods to solve ED problems ranging from simple to very complicated. Nearly all of them again applied the ED principle for cost minimisation and did not further extend such principle for profit maximisation. There is only one research study by Tsai *et al*. (2015) that further applied the ED principle to achieve maximum profit instead of minimum cost in a single CHP plant. Nevertheless, operational and system constraints in their ED problem are holistic to fit to market-structured level, and they are indifferent from those observed from common ED problems. Therefore, the research gap filled by this study is to extend the application of ED for profit maximisation in a group of CHP/cogeneration power plants with consideration of local constraints in terms of system, demand-supply balances and contractual agreements.

Referring to the main research goal that is to develop a spreadsheet-based program for strategically managing the economic load dispatch for the dual power plants in order to ultimately achieve the maximum profit, information from those previous literatures can altogether lead to achieve this research objective as follows: To begin with, mathematical modelling helps translate the encountering problem into a mathematical representation using a powerful technique of linear programming (LP). There are three reasons for choosing LP method: Firstly, it is capable to optimise the management decisions by maximising profit. Secondly, it is able to transform a non-linear cost function of ED problem into a linear one. Thirdly, it is less complicated but still able to yield optimal solutions relative to other complex methods as proven by a number of its applications in several power plant-related research studies. After developing the mathematical LP model, a few possible scenarios under a set of restrictions will be simulated using Microsoft Excel program to see which scenario provides the maximum profit. Once the best scenario from simulation is obtained, sensitivity analysis using statistical regression technique will be conducted to analyse the impacts of changes in parameters on the profit level. Details for each of these steps towards the accomplishment of the research objectives will be elaborated in the next chapter of the dissertation.

CHAPTER 3 RESEARCH METHODOLOGY

This chapter describes and justifies the research methodology of how the research project was conducted including research subjects, formulation of the research question, research methods, research design, data collection, data analysis, phases of the research study, and project risk assessment and mitigation plans.

3.1 Research Subjects

The case study company for this research project is National Power Supply (NPS), a subsidiary of Double A Power group, whose main operating energy business is to generate and sell electric power and steam (cogeneration) to its three groups of customers: EGAT, AA and factories in nearby industrial estates. Figure 43 below shows the case study company NPS.

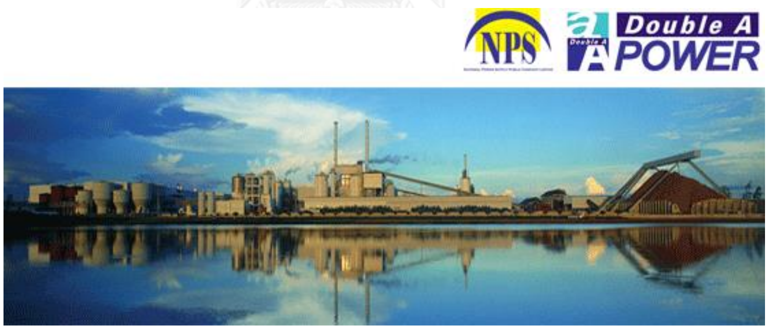


Figure 43: Case Study Company: National Power Supply

Source: NPS (2016)

The subjects of this research study belong to NPS. They are two cogeneration power plants: Plant A and Plant B as shown in Figure 44. The reason behind for selecting the two is that they both have the maximum installed capacity and the largest contracted capacity with EGAT comparing to the rest meaning that the company's revenue and profit could be improved and increased more if the performances of these two plants are better.

Figure 44: Research Subjects: Plant A and Plant B of NPS

Source: NPS (2016

3.2 Formulation of the Research Question

According to the research question stated in Section 1.4 of the Introduction Chapter "*How can NPS strategically manage economic dispatch of electric power and steam for the dual power plant that helps achieve maximum profit?*" This research question was formulated based on the 'what, why, and how' framework for crafting research questions suggested by Bryman & Bell (2015) as illustrated in Figure 45.

Figure 45: Framework for Crafting Research Questions

Source: Bryman & Bell (2015)

- **What?**: It is intriguing that what are the root-causes of decreased profit problem to be known and understood in order to solve this problem for NPS.

- **Why?**: This research advances the body of knowledge in the power plant business since know-how and technical expertise of profit strategy is not generally propagated.
- **How-conceptually?**: Economic dispatch concepts, mathematical LP models and statistical regression method can be used to help answering the research question.
- **How-practically?**: The conceptual framework will be applied using the quantitative investigative styles throughout this research study.

3.3 Research Methods

This research project relies on quantitative research methods due to the following three reasons. Firstly, the research deals with an empirical investigation of real-world power plant business problem through mathematical techniques. Secondly, many parameters and variables expressed in numerical and specific measurement forms are employed to develop a mathematical model and a computer program pertaining to the problem of decreased profit. Thirdly, research findings can be analysed and presented in the forms of tables and graphs. Table 21 shows justification of methods and expected outcomes for each research step.

Table 21: Justification of Methodology and Outcomes for Each Research Step

Research Step	Justification of Methods	Output
0. Preliminary Research		
0.1 Explore the current business operations and strategies of NPS both internal and external environments	• Porter's 5 forces model • Growth-Share (BCG) matrix • Product life cycle • Porter's competitive strategy • Miles and Snow's strategy typology • SWOT matrix	• Robust competitive position • High growth, low market share • Growth stage • Cost leadership • Analyser strategy • SWOT analysis

Research Step	Justification of Methods	Output
0.2 Identify the problems encountered by NPS	• Power plant visit • Expert interview • Company database • Corporate annual reports	• Fishbone diagram showing possible root-causes of decreased profit margin • Statistical data
0.3 Clarify the research question	• What?, Why?, and How? framework for crafting research questions	• Main research question
0.4 Develop the hypothesis statement	• Literature review	• Hypothesis to underpin the research question
0.5 Set the research objectives	• Breaking down the research question	• Primary objective and secondary objectives
0.6 Determine the scope of the research	• Breaking down the objectives into a series of actions to perform	• Scope of the research
0.7 Specify the expected outcomes	• Refining the objectives and the scope of the research	• A summary list of the expected outcomes
0.8 Write the research proposal	• Knowledge gained from thesis workshop organized by CUSE	• Research proposal
1. Investigating the Current Status of Electricity & Steam Generation and Operations		
1.1 Draw the electricity and stream generation process diagram	• Microsoft Visio 2016 • Edraw Max Pro 8.7	• Diagram of the electricity and steam generation process
1.2 Make the assumptions of the study	• Deterministic approach (parameters values are known and constant)	• Deterministic-based assumptions of the study
1.3 Finalise the preliminary research before starting the first phase of research	• Advice given by the supervisor • Comments from the thesis committee • Literature review • Proofreading	• Clarified statement of problem • Finalised research question, hypothesis, objectives, scope, expected outcomes
2. Formulating Quantitative Determination for Costs, Prices and Profits of Electricity and Steam		
2.1 Collect required data for determining costs, prices and profits of electricity and steam	• Secondary sources of data - Corporate annual reports - Company database - SPP contractual handbook - Websites	• Revenue data set • Cost data set • Formula data set • Sales contract data set • Parameter data set
2.2 Draw an estimation process flowchart for unit cost of production	• Microsoft Visio 2016	• Estimation process flowchart for unit cost of production

Research Step	Justification of Methods	Output
2.3 Estimate a unit cost of production	• Equation (24) • Transfer function	• Unit cost of production
2.4 Draw an estimation process flowchart for EGAT electricity price during peak hours	• Microsoft Visio 2016	• Estimation process flowchart for EGAT electricity price during peak hours
2.5 Estimate EGAT electricity price during peak hours	• Equation (1) to Equation (11) • Equation (12) • Microsoft Excel spreadsheets	• Unit price of electricity sold to EGAT during peak hours
2.6 Draw an estimation process flowchart for EGAT electricity price during off-peak hours	• Microsoft Visio 2016	• Estimation process flowchart for EGAT electricity price during off-peak hours
2.7 Estimate EGAT electricity price during off-peak hours	• Equation (9) to Equation (11) • Equation (13) • Microsoft Excel spreadsheets	• Unit price of electricity sold to EGAT during off-peak hours
2.8 Draw an estimation process flowchart for AA & Ind. electricity price during peak hours	• Microsoft Visio 2016	• Estimation process flowchart for AA & Ind. electricity price during peak hours
2.9 Estimate AA & Ind. electricity price during peak hours	• Equation (14), (15) and (17) • Information in Table 12 & Table 13 • Microsoft Excel spreadsheets	• Unit price of electricity sold to AA & Ind. during peak hours
2.10 Draw an estimation process flowchart for AA & Ind. electricity price during off-peak hours	• Microsoft Visio 2016	• Estimation process flowchart for AA & Ind. electricity price during off-peak hours
2.11 Estimate AA & Ind. electricity price during off-peak hours	• Equation (18) • Information in Table 12 & Table 13 • Microsoft Excel spreadsheets	• Unit price of electricity sold to AA & Ind. during off-peak hours
2.12 Estimate LP steam price sold to AA during peak hours	• Company database • Microsoft Excel spreadsheets	• Unit price of LP steam sold to AA during peak hours
2.13 Estimate LP steam price sold to AA during off-peak hours	• Company database • Microsoft Excel spreadsheets	• Unit price of LP steam sold to AA during off-peak hours

Research Step	Justification of Methods	Output
2.14 Estimate MP steam price sold to AA during peak hours	• Company database • Microsoft Excel spreadsheets	• Unit price of MP steam sold to AA during peak hours
2.15 Estimate MP steam price sold to AA during off-peak hours	• Company database • Microsoft Excel spreadsheets	• Unit price of MP steam sold to AA during off-peak hours
2.16 Estimate EGAT electricity profit during peak hours	• Electricity $_{EGAT,\ P}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of electricity gained from EGAT during peak hours
2.17 Estimate EGAT electricity profit during peak off-hours	• Electricity $_{EGAT,\ OP}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of electricity gained from EGAT during off-peak hours
2.18 Estimate AA & Industry electricity profit during peak hours	• Electricity $_{AA,\ P}$ – Unit cost • Electricity $_{Industry,\ P}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of electricity gained from AA & Ind. during peak hours
2.19 Estimate AA & Industry electricity profit during peak off-hours	• Electricity $_{AA,\ OP}$ – Unit cost • Electricity $_{Industry,\ OP}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of electricity gained from AA & Ind. during off-peak hours
2.20 Estimate LP steam profit gained from AA during peak hours	• LP Steam $_{AA,\ P}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of LP steam gained from AA during peak hours
2.21 Estimate LP steam profit gained from AA during off-peak hour	• LP Steam $_{AA,\ OP}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of LP steam gained from AA during off-peak hours
2.22 Estimate MP steam profit gained from AA during peak hours	• MP Steam $_{AA,\ P}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of MP steam gained from AA during peak hours
2.23 Estimate MP steam profit gained from AA during off-peak hours	• MP Steam $_{AA,\ OP}$ – Unit cost • Microsoft Excel spreadsheets	• Unit profit of MP steam gained from AA during off-peak hours
3. Developing the Spreadsheet-Based Optimisation Program for Economic Dispatch		
3.1 Specify conceptual design of the program	• Brainstorming • Expert interview	• Functionality • Usability • Validity
3.2 Formulate a mathematical linear programming model	• Linear programming • Modified mathematical modelling from Carson & Cobelli (2001) & Taylor III (2010)	• Mathematical linear programming model for maximising profit

Research Step	Justification of Methods	Output
3.3 Create an algorithm flowchart for computing maximum profit	• Microsoft Visio 2016	• Systematic algorithm flowchart for computing maximum profit
3.4 Code and debug the spreadsheets	• Microsoft Excel spreadsheets • Excel programming handbook written by Etheridge (2011)	• Parameters, variables and formula are embedded in the spreadsheets
3.5 Test the program using Excel Solver	• Microsoft Excel spreadsheets • Excel Solver	• Complete spreadsheet-based program for economic load dispatch without scenarios
4. Simulating Economic Dispatch Management for Profit Maximisation		
4.1 Create feasible comparative scenarios for maximum profit	• Microsoft Excel spreadsheets	• A set of feasible comparative scenarios for maximum profit
4.2 Simulate the program under all feasible scenarios	• Microsoft Excel spreadsheets • Excel Solver	• Simulation results of maximum profits for all feasible scenarios
4.3 Summarise results obtained from the simulation program	• Microsoft Excel spreadsheets • Excel Solver	• Optimal scenario solution(s) that provides maximum profit
5. Identifying and Analysing Major Influential Factors Affecting Profitability		
5.1 Identify major factors affecting profitability	• Expert interview • Corporate annual reports	• A set of influential factors affecting profitability
5.2 Gather required data for conducting the sensitivity analysis	• Secondary sources of data - Bank of Thailand - SPP Power Purchase Division - EPPO - Company database	• Foreign exchange rates • Coal reference prices • Fuel oil reference prices • Coal-to-biomass fuel ratios • Fuel transfer (Ft) charges
5.3 Examine how sensitive the profitability is to changes in foreign exchange rate	• Equation (18) • Microsoft Excel spreadsheets • Excel Analysis ToolPak	• Linear regression model of foreign exchange rates and profitability • Analysis and discussion
5.4 Examine how sensitive the profitability is to changes in coal reference price	• Equation (18) • Microsoft Excel spreadsheets • Excel Analysis ToolPak	• Linear regression model of coal reference prices and profitability • Analysis and discussion

Research Step	Justification of Methods	Output
5.5 Examine how sensitive the profitability is to changes in fuel oil reference price	• Equation (18) • Microsoft Excel spreadsheets • Excel Analysis ToolPak	• Linear regression model of fuel oil reference prices and profitability • Analysis and discussion
5.6 Examine how sensitive the profitability is to changes in coal-to-biomass fuel ratio	• Equation (18) • Microsoft Excel spreadsheets • Excel Analysis ToolPak	• Linear regression model of coal-to-biomass fuel ratios and profitability • Analysis and discussion
5.7 Examine how sensitive the profitability is to changes in fuel transfer charge	• Equation (18) • Microsoft Excel spreadsheets • Excel Analysis ToolPak	• Linear regression model of fuel transfer (Ft) charges and profitability • Analysis and discussion
5.8 Summarise results obtained from conducting the sensitivity analysis	• Microsoft Excel spreadsheets • Excel Analysis ToolPak	• Summary of the sensitivity analysis • Recommendations

3.4 Research Design

According to Cooper & Schindler (2013), research design is "the blueprint for fulfilling research objectives and answering questions". Figure 46 on next page depicts the research design and its essential components as a framework specifies what to be done in order to achieve the research objectives and answer the question.

Phase 1 is to estimate quantitative determination for unit cost, prices and profits of electricity and steam. To estimate the total unit cost of production, the costs of coal, biomass, demineralised water, sand, chemicals, ash disposal, sea freight and land freight are involved. To estimate the prices, specific formula justified in the research methods are used depending on type of products, type of customers and time of use (peak hours or off-peak hours). To estimate the profits, the unit cost is subtracted from the prices.

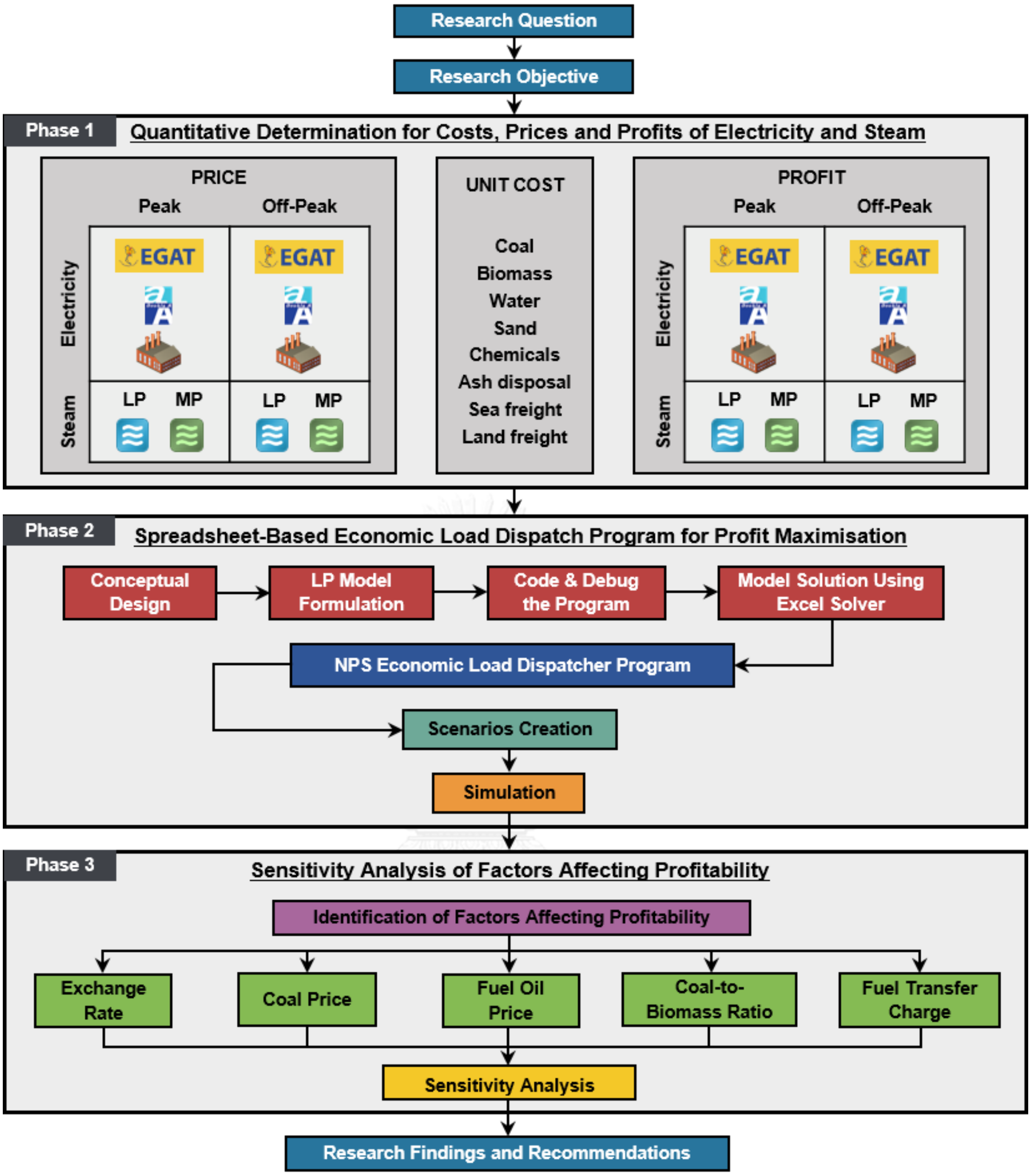


Figure 46: Research Design Framework

Phase 2 is to develop spreadsheet-based economic load dispatch program for profit maximization, namely *NPS Economic Dispatcher*. The program development process starts from specifying conceptual design in terms of functionality, usability and validity. Next, an LP model with the objective function of maximising profit will be formulated by modifying the steps in mathematical modelling proposed by Carson &

Cobelli (2001) and Taylor III (2010). After formulating the LP model, Microsoft Excel spreadsheet program will be coded and debugged using the data obtained from the first phase plus some additional relevant data. Finally, the LP model will be initially solve using Excel Solver. However, to make the program suit to the practicality, a few comparative scenarios of actual working environment will be created and simulated to see which scenario provides the maximum profit to the company.

Phase 3 is to conduct sensitivity analysis to investigate how sensitive the profitability of the optimal scenario is to changes in influential external and internal factors, including foreign exchange rate, coal reference price, fuel oil reference price, coal-to-biomass fuel ratio and Ft charge.

3.5 Data Collection

There are five data sets required to be collected: revenue, cost, formula, sales contract and parameter. Details for these data sets can be explained as follows:

3.5.1 Revenue Data Set

- **Electricity** $_{EGAT,\ P}$: Revenue from selling one unit of electricity to EGAT during peak hours (between 08.00 and 21.30) can be estimated from the summation of *CP* and *EP* using Equation (12).

- **Electricity** $_{EGAT,\ OP}$: Revenue from selling one unit of electricity to EGAT during off-peak hours (between 21.30 and 8.00) can be estimated from *EP* using Equation (13).

- **Electricity** $_{AA,\ P}$: Revenue from selling one unit of electricity to AA during peak hours (between 09.00 and 22.00) from Monday to Friday can be estimated using Equation (14), Equation (15), Equation (17), Table 12 of TOU rate for large general service at voltage level 22-23 kV and Table 13 of Ft charge.

- **Electricity** $_{AA, OP}$: Revenue from selling one unit of electricity to AA during off-peak hours (between 22.00 and 09.00) from Monday to Friday and (between 00.00 and 24.00) from Saturday to Sunday can be estimated using Equation (18), Table 12 of TOU rate for large general service at voltage level 22-23 kV and Table 13.
- **Electricity** $_{Industry, P}$: Revenue from selling one unit of electricity to Industry during peak hours (between 09.00 and 22.00) from Monday to Friday can be estimated using Equation (14), Equation (15), Equation (17), Table 12 of TOU rate for large general service at voltage level 22-23 kV and Table 13 of Ft charge
- **Electricity** $_{Industry, OP}$: Revenue from selling one unit of electricity to Industry during off-peak hours (between 22.00 and 09.00) from Monday to Friday and (between 00.00 and 24.00) from Saturday to Sunday can be estimated using Equation (18), Table 12 and Table 13.
- **LP Steam** $_{AA, P}$: Revenue from selling one unit of LP steam to AA during peak hours (between 09.00 and 22.00) from Monday to Friday can be estimated from a formula (undisclosed). Note that the selling price of LP steam is based on either of fuel oil price, natural gas price or coal price, and CPI.
- **LP Steam** $_{AA, OP}$: Revenue from selling one unit of LP steam to AA during off-peak hours (between 22.00 and 09.00) from Monday to Friday and (between 00.00 and 24.00) from Saturday to Sunday can be estimated from a formula (undisclosed). Note that the selling price of LP steam is based on either of fuel oil price, natural gas price or coal price, and CPI.

- **MP Steam $_{AA,\ P}$**: Revenue from selling one unit of MP steam to AA during peak hours (between 09.00 and 22.00) from Monday to Friday can be estimated from a formula (undisclosed). Note that the selling price of MP steam is based on either of fuel oil price, natural gas price or coal price, and CPI.
- **MP Steam $_{AA,\ OP}$**: Revenue from selling one unit of MP steam to AA during off-peak hours (between 22.00 and 09.00) from Monday to Friday and (between 00.00 and 24.00) from Saturday to Sunday can be estimated from a formula (undisclosed). Note that the selling price of MP steam is based on either of fuel oil price, natural gas price or coal price, and CPI.

Table 22 shows brief description and unit for revenue data set.

Table 22: Description and Unit for Revenue Data Set

Revenue	Description	Unit
Electricity $_{EGAT,\ P}$ [1]	Unit price of electricity sold to EGAT during peak hours	THB/kWh
Electricity $_{EGAT,\ OP}$ [2]	Unit price of electricity sold to EGAT during off-peak hours	THB/kWh
Electricity $_{AA,\ P}$ [3]	Unit price of electricity sold to AA during peak hours	THB/kWh
Electricity $_{AA,\ OP}$ [4]	Unit price of electricity sold to AA during off-peak hours	THB/kWh
Electricity $_{Industry,\ P}$ [3]	Unit price of electricity sold to Industry during peak hours	THB/kWh
Electricity $_{Industry,\ OP}$ [4]	Unit price of electricity sold to Industry during off-peak hours	THB/kWh
LP Steam $_{AA,\ P}$	Unit price of LP steam sold to AA during peak hours	THB/ton/h
LP Steam $_{AA,\ OP}$	Unit price of LP steam sold to AA during off-peak hours	THB/ton/h
MP Steam $_{AA,\ P}$	Unit price of MP steam sold to AA during peak hours	THB/ton/h
MP Steam $_{AA,\ OP}$	Unit price of MP steam sold to AA during off-peak hours	THB/ton/h

Remark: [1] *CP + EP* [2] Only *EP*
[3] Demand charge + energy charge [4] Only energy charge

3.5.2 Cost Data Set

- **Coal**: Cost of bituminous coal mainly internationally purchased from suppliers in Indonesia approximately 50,000-150,000 tons at a time.

- **Biomass**: Coal of woodchip purchased from subsidiaries of NPS. The cost of woodchip is based on coal price adjusted by heat values of coal and biomass.
- **Demineralised Water**: Cost of water used for demineralisation and cooling process purchased from a subsidiary of NPS. The cost of water is based on water supply price determined by the Provincial Waterworks Authority (PWA).
- **Sand**: Cost of sand purchased from external domestic sellers.
- **Chemicals**: Cost of chemicals from external domestic distributors.
- **Ash Disposal**: Cost of ash disposal after the generation process.
- **Lime**: Cost of lime purchased from external domestic distributors.
- **Sea Freight**: Cost of coal transportation by sea from abroad to Thailand's port
- **Land Freight**: Cost of coal transportation by trucks from the port to the plants

Table 23 shows brief description and unit for cost data set.

Table 23: Description and Unit for Cost Data Set

Cost	Description	Unit
Coal	Cost of bituminous purchased from foreign suppliers	USD/ton
Biomass	Cost of woodchip purchased from domestic suppliers	THB/ton
Demineralised water	Unit cost of demineralised water	THB/kWh
Sand	Unit cost of sand	THB/kWh
Chemicals[1]	Unit cost of chemicals	THB/kWh
Ash disposal	Unit cost of ash disposal	THB/kWh
Lime	Unit cost of lime	THB/kWh
Sea freight	Cost of sea freight for bituminous	USD/ton
Land freight	Cost of land freight for bituminous	THB/ton

Remark: [1] Sulfuric (H_2SO_4), sodium hydroxide (NaOH), sodium hydrochloride (NaHCl), hydrochloric acid (HCl), trisodium phosphate (Na_3PO_4), ammonia (NH_3), hydrazide ($C_2H_6N_2O$), anti-scaling and non-oxidising biocides

3.5.3 Formula Data Set

- **Actual Capacity (*AC*)**: Total amount of actual electric capacity sold to EGAT during either peak or off-peak hours can be calculated using Equation (1).
- **Billing Capacity of a Month (BC_T)**: Amount of billing capacity at the end of a month can be calculated by comparing *AC* to *CC* using one of Equation (2) to Equation (5).
- **Capacity Payment of a Month (CP_T)**: Amount of capacity payment at the end of a month can be calculated using Equation (6).
- **Capacity Payment (*CP*)**: Total amount of capacity payment can be calculated by multiplying BC_T with CP_T using Equation (7).
- **Energy Payment (*EP*)**: Total amount of energy payment can be calculated using Equation (9), Equation (10) and Equation (11).
- **Billing Payment during Peak Hours (BP_P)**: Amount of billing payment from selling one unit of electricity during peak hours can be calculated using Equation (12).
- **Billing Payment during Off-Peak Hours (BP_{OP})**: Amount of billing payment from selling one unit of electricity during off-peak can be calculated using Equation (13).
- **Monthly Capacity Factor (*MCF*)**: The ratio of the units of electricity sold to EGAT to the electric energy specified on the sales contracts between NPS and EGAT can be calculated using Equation (8).
- **Escalation for Coal (ES_T^{Coal})**: Coal escalation is computed using Equation (10).
- **Escalation for fuel oil (ES_T^{Oil})**: Oil escalation is computed using Equation (11).

Table 24 shows brief description and unit for formula data set.

Table 24: Description and Unit for Formula Data Set

Formula	Description	Unit
AC	Actual capacity	kW
BC_T	Billing capacity of a month	kW
CP_T	Capacity payment of a month	THB/kW/month
CP	Capacity payment	THB
EP	Energy payment	THB
BP_P	Billing payment during peak hours	THB
BP_{OP}	Billing payment during off-peak hours	THB
MCF	Monthly capacity factor	N/A
ES_T^{Coal}	Escalation for coal	THB/kWh
ES_T^{Oil}	Escalation for fuel oil	THB/kWh

3.5.4 Sales Contract Data Set

- $CC_{\text{Electricity, EGAT, Plant A}}$: Contracted capacity between NPS and EGAT to generate and sell electricity of 90,000 kW using Plant A.
- $CC_{\text{Electricity, EGAT, Plant B}}$: Contracted capacity between NPS and EGAT to generate and sell electricity of 90,000 kW using Plant B.
- $CC_{\text{Electricity, AA}}$: Contracted capacity between NPS and AA to generate and sell electricity of 60,000 kW.
- $CC_{\text{Electricity, Industry}}$: Contracted capacity between NPS and Industry to generate and sell electricity of 140,000 kW.
- $CC_{\text{LP Steam, AA}}$: Contracted capacity between NPS and AA to generate and sell LP steam of 69.9 tons per hour.
- $CC_{\text{MP Steam, AA}}$: Contracted capacity between NPS and AA to generate and sell MP steam of 4.4 tons per hour.

Table 25 shows brief description and unit for sales contract data set.

Table 25: Description and Unit for Sales Contract Data Set

Sales Contract	Description	Unit
$CC_{\text{Electricity, EGAT, Plant A}}$	Contracted capacity of electricity from Plant A with EGAT	kW
$CC_{\text{Electricity, EGAT, Plant B}}$	Contracted capacity of electricity from Plant B with EGAT	kW
$CC_{\text{Electricity, AA}}$	Contracted capacity of electricity with AA	kW
$CC_{\text{Electricity, Industry}}$	Contracted capacity of electricity with Industry	kW
$CC_{\text{LP Steam, AA}}$	Contracted capacity of LP steam with AA	ton
$CC_{\text{MP Steam, AA}}$	Contracted capacity of MP steam with AA	ton

3.5.5 Parameter Data Set

- **Capacity Payment Base Rate (CP_0)**: The capacity payment base rate for coal-fired power plants with 20-25 years of sales contract is 422 THB/kW/month.
- **Foreign Exchange Base Rate (FX_0)**: The foreign exchange base rate for all fuels excluding new gas fuel is 38 THB/USD.
- **Foreign Exchange Rate of the Last Working Day of a Month (FX_T)**: This type of data can be directly gathered from the Bank of Thailand website.
- **Foreign Investment Proportion (FP)**: The foreign investment proportion used for reference by coal-fired power plants is 70%.
- **Domestic Investment Proportion (DP)**: The domestic investment proportion used for reference by coal-fired power plants is 30%.
- **Energy Payment Base Rate for a Coal-Fired Power Plant (EP_0^{Coal})**:
- **Coal Base Price (P_0^{Coal})**: The coal base price is 0.62 THB/kWh.
- **Coal Price of a Month (P_T^{Coal})**: The monthly coal price used for reference can be gathered from the SPP Power Purchase Division website.
- **Fuel Oil Base Price (P_0^{Oil})**: The fuel oil base price is 2.9242 THB/litre.

- **Fuel Oil Price of a Month (P_T^{Oil})**: The monthly fuel oil price used for reference can be gathered from the SPP Power Purchase Division website.
- **Heat Rate**: Amount of energy for generating one unit of electricity is 8,600 BTU/kWh.
- **NPS Heat Rate**: The current amount of fuel energy used for generating one unit of electricity at NPS power plants is 9,839 kJ/kWh.
- **Coal-Biomass Ratio**: The current ratio of coal to woodchip fuels used for generating electricity and steam is coal 95% to 5% woodchip.
- **Ft Charge**: The fuel transfer charge adjusted by a mechanism to reflect actual price of electricity over a specific period can be collected from the official announcements posed on the PEA website.

Table 26 shows brief description and unit for parameter data set.

Table 26: Description and Unit for Parameter Data Set

Parameter	Description	Unit
CP_0	Capacity payment base rate	THB/kW/month
FX_0	Foreign exchange base rate	THB/USD
FX_T[1]	Foreign exchange rate of the last working day of a month	THB/USD
FP	Foreign investment proportion	N/A
DP	Domestic investment proportion	N/A
EP_0^{Coal}	Energy payment base rate for a coal-fired power plant	THB/kWh
P_0^{Coal}	Coal base price	USD/ton
P_T^{Coal}	Coal price of a month	USD/ton
P_0^{Oil}	Fuel oil base price	THB/litre
P_T^{Oil}	Fuel oil price of a month	THB/litre
Heat rate	Amount of energy used to generate one unit of electricity	BTU/kWh
NPS heat rate	Amount of energy used to generate one unit of electricity	kJ/kWh
Coal-biomass ratio	Ratio of coal to woodchip used as mixed fuels	N/A
Ft charge	Fuel transfer charge	THB/kWh

Remark: [1] Mean of the average transfer buying rates and the average selling rates

3.6 Data Analysis

There are three main data analyses performed according to three research phases. In Phase 1, all data sets of revenue, cost, formula, sales contract and parameter will be used to estimate unit cost, prices and profits of electricity and steam. The data will be entered into cells and sheets of Microsoft Excel as illustrated in Figure 47.

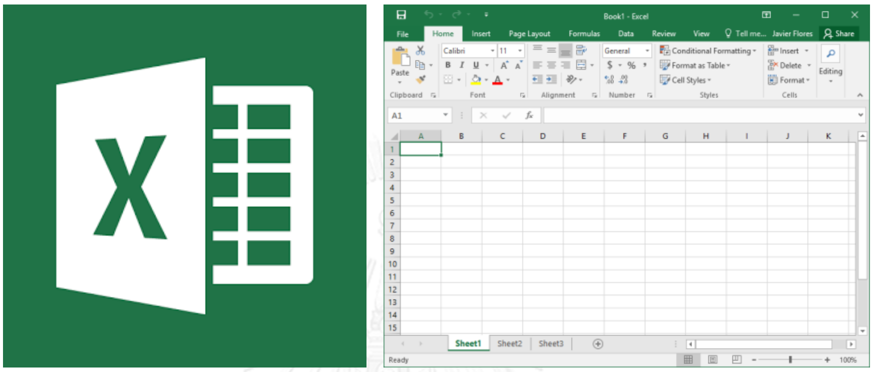


Figure 47: Microsoft Excel Spreadsheets

Source: www.microsoft.com

After completing the first phase of estimation, the raw data will be transformed into useful information of unit cost, prices and profits. In Phase 2, it is about modelling the data to build an LP model with objective function of maximizing profit under a set of constraints. An optimization tool Excel Solver will be used to solve the LP model and provide optimal solutions. A few scenarios towards profit maximum will be created using the data sets of sales contract and parameter. The program is then simulate under possible scenarios using Excel Solver to help make decisions which scenario of economic dispatch management should be chosen as maximum profit is obtained.

In Phase 3, it is about sensitivity analysis of factors affecting profitability. The data of foreign exchange rates, coal prices, fuel prices, coal-to-biomass fuel ratios and Ft charges will be used in analysing the sensitivity using Regression approach embedded in Excel Data Analysis ToolPak as illustrated in Figure 48 below.

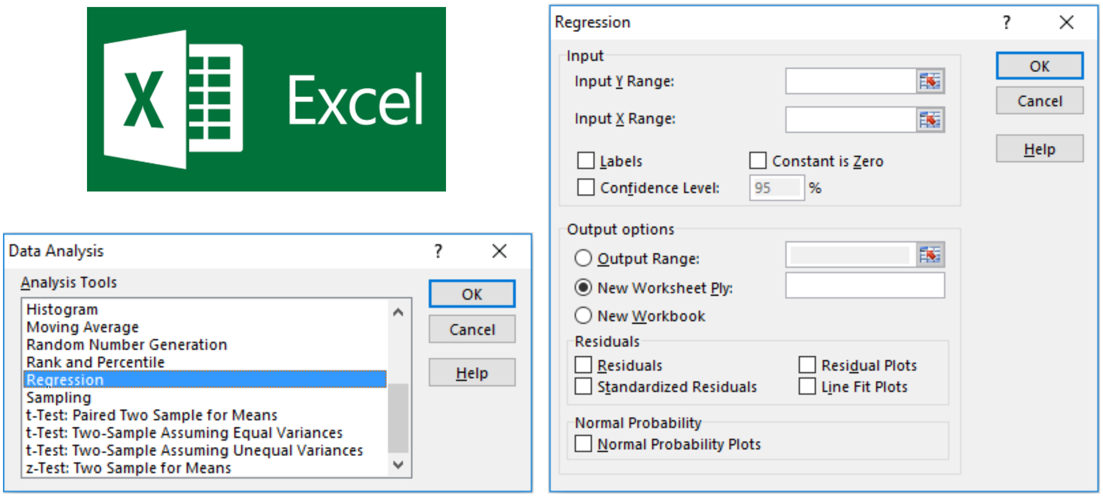


Figure 48: Excel Data Analysis ToolPak for Statiscal Linear Regression

Source: www.microsoft.com

3.7 Phases of the Research Study

Referring to the research design in Section 3.4 of this chapter, the research can be structured into three consecutive phases. They are (1) estimating quantitative determination for unit cost, prices and profits of electricity and steam, (2) developing a spreadsheet-based economic dispatch program for profit maximisation and (3) conducting sensitivity analysis of factors affecting profitability. Table 27 shows research phases and expected outcomes.

Table 27: Research Phases and Expected Outcomes

Phases		Expected Outcomes
1	Estimating quantitative determination for unit cost, prices and profits of electricity and steam	A set of unit cost, prices and profits of both electricity and steam for each group of customers.
2	Developing a spreadsheet-based economic load dispatch program for profit maximisation	A comprehensive strategic tool for economic dispatch management that helps NPS make decisions better
3	Conducting sensitivity analysis of factors affecting profitability	An understanding on factors affecting profitability and recommendations for practice

3.8 Project Risk Assessment and Mitigation Plans

To systematically manage project risks, risk identification, risk assessment and risk mitigation will be done step-by-step according to the risk management process.

Here are five risks associated with the research project execution:

(1) Lack of technical knowledge and experience in the power plant business

(2) Confidentiality corporate policy on data disclosure to general public

(3) Excessive scope of the initial project under the time available.

(4) Inaccurate estimation of unit cost, prices and profits of electricity and steam

(5) Freeze of the notebook computer while working on program development

To assess the project risks, a probability-impact matrix can be applied (Lester, 2014). The risks identified are placed in the matrix based on two relative criteria: probability and impact, to evaluate the overall risk score indicating how severe each risk is by multiplying the value of probability with the value of impact. Figure 49 shows a 3x3 probability-impact matrix for assessing the risks related to the project execution.

3 × 3 Risk Matrix		IMPACT		
		1 Limited	2 Serious	3 Severe
PROBABILITY	3 Almost Certain			
	2 Possible	Excessive scope of the initial project under the time available	Confidentiality corporate policy on data disclosure to general public	Inaccurate estimation of unit cost, prices and profits of electricity and steam
	1 Rare		Freeze of the notebook computer while working on the program development	Lack of enough technical knowledge and experience in the power plant business

Max. Risk Tolerance	Legend: Risk Tolerance Threshold Line								
6	Risk Matrix Scoring Range = 1 to 9								
Threshold Value	1	2	3	4	5	6	7	8	9
	Low Risk (1-3)			Moderate Risk (4-6)			High Risk (7-9)		

Figure 49: Probability-Impact Matric for Project Risk Assessment

After computing the risk scores, the scores are then prioritised for further qualitative analysis and mitigation plan development. Table 28 shows the summary of project risk assessment by risk ID, description, probability, impact, risk score and ranking.

Table 28: Summary of Project Risk Assessment

Risk ID	Description	Probability	Impact	Risk Score	Rank
A	Lack of enough technical knowledge and experience in the power plant business	1	3	3	3
B	Confidentiality corporate policy on data disclosure to general public	2	2	4	2
C	Excessive scope of the initial project under the time available	2	1	2	4
D	Inaccurate estimation of unit cost, prices and profits of electricity and steam	2	3	6	1
E	Freeze of the notebook computer while working on the program development	1	2	2	4

A risk response framework can be applied to develop mitigation plans if each risk should be controlled, avoided, transferred or accepted (Vose, 2008). Figure 50 shows the risks on the framework, and Table 29 shows the summary of mitigation plans.

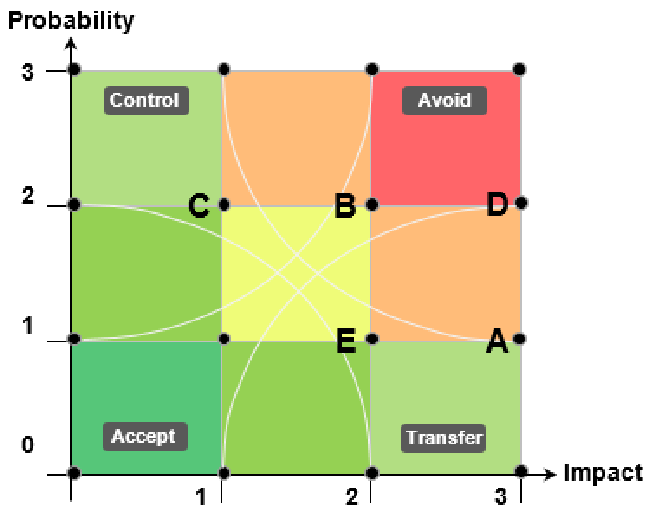


Figure 50: Risk Response Framework and Mitigation Strategies

Table 29: Summary of Project Risk Mitigation Strategies and Plans

Risk ID	Description	Mitigation Strategy	Mitigation Plan
A	Lack of enough technical knowledge and experience in the power plant business	Transfer	Studied more about the power plant business operations and technical terms
B	Confidentiality corporate policy on data disclosure to general public	Avoid	Try not to use the firm's confidential data but use applicable public data instead
C	Excessive scope of the initial project under the time available	Control	Redefined the scope of project to suit to the time available
D	Inaccurate estimation of unit cost, prices and profits of electricity and steam	Avoid	Consulted with the experts both before and after the estimation
E	Freeze of the notebook computer while working on the program development	Transfer	Used auto-save function and backed up the program using external storages

3.9 Summary of the Research Methodology Chapter

In summary, the research subjects are two cogeneration power plants of NPS whose profitability has been declining during the last few years. The job is to investigate on how the company can strategically manage economic dispatch of these two plants to achieve the maximum profit. The research is justified based on quantitative methods dealing with a set of decision variables and parameters to be used for formulating an LP model and developing the spreadsheet-based program to help make better management decisions about economic dispatch problem. The mathematical LP model was chosen due to its capability to optimise management decisions, to transform a non-linear cost function of ED problem into a linear, and to provide effective solutions, yet less complex, relative to other methods. The program was developed using Microsoft Excel since it is a user-friendly human-software interface that requires only minimum knowledge in computer operations and application platform of the users. The research design can be separated into three consecutive phases, which are (1) estimating quantitative determination for unit cost, prices and profits of electricity and steam, (2) developing a spreadsheet-based economic load dispatch program for profit maximisation and (3) conducting sensitivity analysis of factors affect profitability. Results and discussion of these three research phases will be presented in the next chapter.

CHAPTER 4 RESULTS AND ANALYSIS

This chapter presents results and analysis of the research phases as explained in the previous chapter. First, quantitative determination of costs, prices and profits of electricity and steam was estimated. Second, a spreadsheet-based economic dispatch program for profit maximisation, namely *NPS Economic Dispatcher*, was developed. Last, sensitivity of influential factors affecting profitability was analytically investigated.

4.1 Quantitative Determination for Costs, Prices and Profits

4.1.1 Estimation of Unit Cost of Production

To estimate the cost per unit of electricity and steam generated, the cost data set in Table 23 is required. It is composed of coal, biomass, demineralised water, sand, chemicals, ash disposal, lime, sea freight and land freight. Referring to the assumption of the study, variable cost (fuels and consumable raw materials) is assumed to cover 100% of the unit cost. Equation 24 shows the components of total unit cost:

$$\boxed{\text{Total Unit Cost} = \text{Total Fuel Cost} + \text{Total Consumable Raw Material Cost}} \quad (24)$$

Figure 51 depicts the estimation process flowchart for total unit cost.

(1) Start: The start of estimation process for total unit cost of production.

(2) Calculate the amount of coal required for one unit of output:

According to the definition of heat rate, it is the amount of energy required to generate one unit of electrical output. The NPS heat rate is 9,839 kJ/kWh, meaning the heat value of 9,839 kJ is required to generate 1 kWh of electricity. However, fuels used in both Plant A and Plant B are currently mixed with 95% of coal and 5% of biomass.

Heat energy from 95% of coal = $0.95 \times 9{,}839\ \dfrac{kJ}{kWh} = 9{,}347$ kJ

1 kg of coal equals to heat value of 21,700 kJ/kg

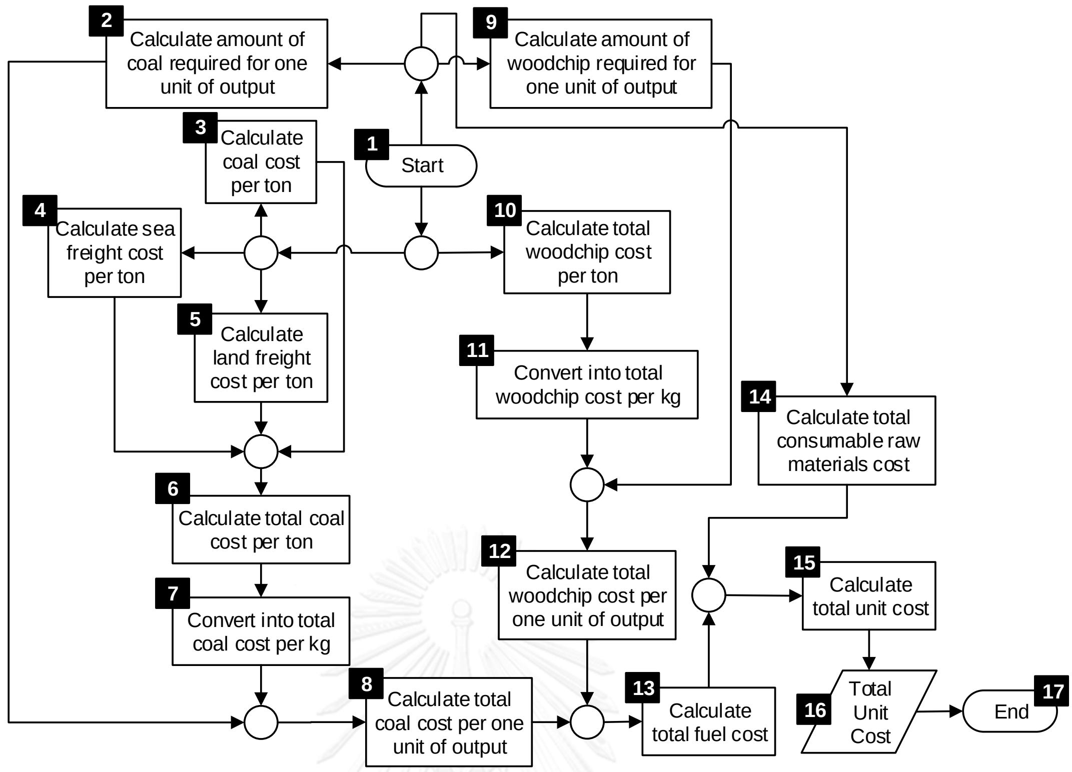


Figure 51: Estimation Process Flowchart for Total Unit Cost of Production

Therefore, the amount of coal required for 1 kWh = $\dfrac{9{,}347}{21{,}700}\ \dfrac{kJ}{kJ/kg}$ = 0.43 kg

(3) Calculate the coal cost per ton:

61.8 USD/ton × 34.6251 THB/USD = 2,139.83 THB/ton

(4) Calculate the sea freight cost per ton:

13.5 USD/ton × 34.6251 THB/USD = 467.44 THB/ton

(5) Calculate the land freight cost per ton:

180.00 THB/ton

(6) Calculate the total coal cost per ton:

Total coal cost/ton = Coal cost/ton + Freight cost/ton + Land cost per ton

= 2,139.83 + 467.44 + 180.00

= 2,787.27 THB/ton

(7) Convert into the total coal cost per kg:

$$\text{Total coal cost/kg} = \frac{2{,}787.27}{1{,}000}\frac{THB/ton}{kg/ton} = 2.787 \text{ THB/kg}$$

(8) Calculate the total coal cost per one unit of output:

= Amount of coal required/unit of output × Total coal cost/unit of output

= 0.43 kg × 2.787 THB/kg

= 1.201 THB/kWh

(9) Calculate the amount of woodchip required for one unit of output:

$$\text{Heat energy from 5\% of woodchip} = 0.05 \times 9{,}839 \ \frac{kJ}{kWh} = 492 \text{ kJ}$$

1 kg of woodchip equals to heat value of 8,800 kJ/kg

$$\text{So, the amount of woodchip required for 1 kWh} = \frac{492}{8{,}800}\frac{kJ}{kJ/kg} = 0.06 \text{ kg}$$

(10) Calculate the total woodchip cost per ton:

1,200 THB/ton

(11) Convert into the total woodchip cost per kg:

$$\text{Total woodchip cost/kg} = \frac{1{,}200}{1{,}000}\frac{THB/ton}{kg/ton} = 1.200 \text{ THB/kg}$$

(12) Calculate the total woodchip cost per one unit of output:

= Amount of woodchip required/unit of output × Total woodchip cost/ unit of output

= 0.06 kg × 1.200 THB/kg

= 0.067 THB/kWh

(13) Total fuel cost:

Total fuel cost = Total coal cost + Total woodchip cost

= 1.201 + 0.067

= 1.268 THB/kWh

(14) Total consumable raw material cost:

It is the summation of costs of consumable raw materials, see Table 30.

Table 30: Total Consumable Raw Materials Cost

Consumable List	Cost (THB/kWh)
Demineralised water	0.104
Sand	0.003
Chemicals	0.005
Ash disposal	0.002
Lime	0.001
Total cost	0.115

(15) Total unit cost of production: Referring to Equation (24)

= Total fuel cost + Total consumable material cost

= 1.268 + 0.115

= 1.383 THB/kWh

(16) Total unit cost: The total unit cost is 1.383 THB/kWh.

(17) End: The end of estimation process for total unit cost of production.

4.1.2 Estimation of Prices for Products, Customers and Times of Use

In this section, the prices are 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). Equation (1) to Equation (13) will be used to estimate electricity prices based on those differences, but steam prices have been directly provided by the company database without any use of formula due to the confidentiality policy on data disclosure to general public as discussed in Section 3.8 of the previous chapter.

4.1.2.1 Electricity Price for EGAT during Peak Hours

To estimate electricity price sold to EGAT during peak hours ($Electricity_{EGAT,\,P}$), Equation (1) to Equation (12) illustrated in Section 2.1.4.1 of the Literature Review chapter are used. Figure 52 shows the estimation process flowchart for $Electricity_{EGAT,\,P}$.

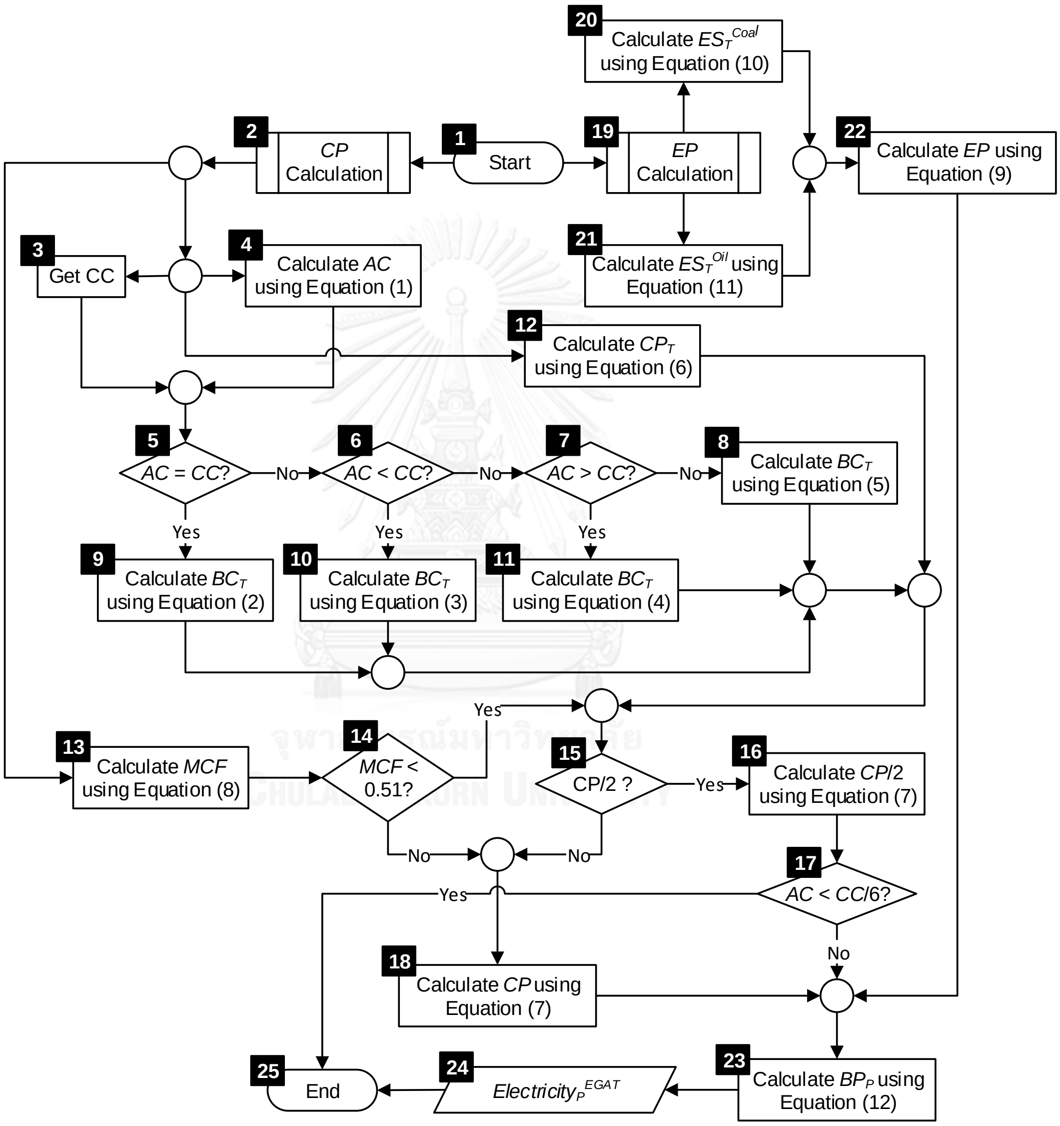


Figure 52: Estimation Process Flowchart for the Price of $Electricity_{EGAT,\,P}$

<u>Numerical Example of Estimation Procedure when *AC* = *CC* (90,000 kW)</u>

(1) Start: The start of estimation process for the price of $Electricity_{EGAT,\,P}$

(2) CP Calculation: The CP calculation sub-process

(3) Get CC: $CC_{\text{Electricity, EGAT, Plant A}}$ and $CC_{\text{Electricity, EGAT, Plant B}}$ = 90,000 kW

(4) Calculate AC using Equation (1):

From Equation (1), AC = CC = 90,000 kW

(5) Check AC = CC?: If yes, go to Step 9. Otherwise, go to Step 6.

Yes, AC = CC. Go to Step 9

(6) Check AC < CC?: If yes, go to Step 10. Otherwise, go to Step 7.

(7) Check AC > CC?: If yes, go to Step 11. Otherwise, go to Step 8.

(8) Calculate BC_T using Equation (5):

(9) Calculate BC_T using Equation (2):

From Equation (2), if AC = CC; BC_T = CC = 90,000 kW

(10) Calculate BC_T using Equation (3):

(11) Calculate BC_T using Equation (4):

(12) Calculate CP_T using Equation (6):

From Equation (6), $CP_T = CP_0 \times \left(FP \times \frac{FX_T}{FX_0} + DP \right)$

$$= 422 \times \left(0.7 \times \frac{34.6251}{27} + 0.3 \right)$$

$$= 505.42 \text{ THB/kW}$$

(13) Calculate MCF using Equation (8):

From Equation (8), when AC = CC; MCF always equals to 1.

If 0.51 ≤ MCF ≤ 1, *CP* will not be halved.

(14) Check MCF < 0.51?: If yes, go to Step 15. Otherwise, go to Step 18.

(15) Check CP/2?: If yes, go to Step 16. Otherwise, go to Step 18.

No, go to Step 18.

(16) Calculate CP/2 using Equation (7):

(17) Check AC < CC/6?: If yes, go to Step 25. Otherwise, go to Step 23.

(18) Calculate CP using Equation (7):

From Equation (7), Capacity Payment = $BC_T \times CP_T$

= 90,000 kW × 505.42 THB/kW

= 45,488,133 THB

(19) EP Calculation: The EP calculation sub-process

(20) Calculate ES_T^{Coal} using Equation (10):

From Equation (10), $ES_T^{Coal} = \frac{1}{26.5877 \times 10^6} \times \left[\left(P_T \times FX_T\right) - P_0\right] \times \text{Heat Rate}$

$= \frac{1}{26.5877 \times 10^6} \times \left[(61.6 \times 34.6251) - 1{,}007\right] \times 8{,}600$

$= 0.3642$ THB/kWh

(21) Calculate ES_T^{Oil} using Equation (11):

From Equation (11), $ES_T^{Oil} = \frac{1}{39{,}400} \times \left[P_T - P_0\right] \times \text{Heat Rate}$

$= \frac{1}{39{,}400} \times [13.2658 - 2.9242] \times 8{,}600$

$= 2.2573$ THB/kWh

(22) Calculate EP using Equation (9):

From Equation (9), Energy Payment

$= EP_0^{Coal} + \left[\left(0.75 \times ES_T^{Coal}\right) + \left(0.25 \times ES_T^{Oil}\right)\right]$

$= 0.62 + \left[(0.75 \times 0.3642) + (0.25 \times 2.2573)\right]$

$= 1.4575$ THB/kWh

(23) Calculate BP_P using Equation (12):

From Equation (12), $BP_P = \frac{CP}{EGG_P} + EP = \frac{45{,}488{,}133}{90{,}000 \times 13.5 \times 30} + 1.4575$

= 2.705 THB/kWh

(24) **$Electricity_{EGAT, P}$:**

The price of electricity sold to EGAT during peak hours is 2.7055 THB/kWh.

(25) **End:** The end of estimation process for the price of $Electricity_{EGAT, P}$

<u>Numerical Example of Estimation Procedure when *AC* (45,500 kW) < *CC* (90,000 KW)</u>

(1) **Start:** The start of estimation process for the price of $Electricity_{EGAT, P}$

(2) **CP Calculation:** The CP calculation sub-process

(3) **Get CC:** $CC_{\text{Electricity, EGAT, Plant A}}$ and $CC_{\text{Electricity, EGAT, Plant B}}$ = 90,000 kW

(4) **Calculate AC using Equation (1):**

Given AC = 45,500 kW

(5) **Check AC = CC?:** If yes, go to Step 9. Otherwise, go to Step 6.

No, AC ≠ CC. Go to Step 6

(6) **Check AC < CC?:** If yes, go to Step 10. Otherwise, go to Step 7.

Yes, AC < CC. Go to Step 10

(7) **Check AC > CC?:** If yes, go to Step 11. Otherwise, go to Step 8.

(8) **Calculate BC_T using Equation (5):**

(9) **Calculate BC_T using Equation (2):**

(10) **Calculate BC_T using Equation (3):**

From Equation (3), if AC = CC; $BC_T = AC - 0.2 \times (CC - AC)$

$= 45{,}500 - 0.2 \times (90{,}000 - 45{,}500)$

$= 36{,}600$ kW

(11) **Calculate BC_T using Equation (4):**

(12) Calculate CP_T using Equation (6):

From Equation (6), $CP_T = CP_0 \times \left(FP \times \frac{FX_T}{FX_0} + DP \right)$

$$= 422 \times \left(0.7 \times \frac{34.6251}{27} + 0.3 \right)$$

$$= 505.42 \text{ THB/kW}$$

(13) Calculate MCF using Equation (8):

From Equation (8), when AC < CC; MCF = $\frac{45{,}500}{90{,}000}$ = 0.51.

If 0.51 ≤ MCF ≤ 1, *CP* will not be halved.

(14) Check MCF < 0.51?: If yes, go to Step 15. Otherwise, go to Step 18.

(15) Check CP/2?: If yes, go to Step 16. Otherwise, go to Step 18.

(16) Calculate CP/2 using Equation (7):

(17) Check AC < CC/6?: If yes, go to Step 25. Otherwise, go to Step 23.

(18) Calculate CP using Equation (7):

From Equation (7), Capacity Payment = $BC_T \times CP_T$

= 36,600 kW × 505.42 THB/kW

= 18,498,507 THB

(19) EP Calculation: The EP calculation sub-process

(20) Calculate ES_T^{Coal} using Equation (10):

From Equation (10), $ES_T^{Coal} = \frac{1}{26.5877 \times 10^6} \times \left[\left(P_T \times FX_T \right) - P_0 \right] \times \text{Heat Rate}$

$$= \frac{1}{26.5877 \times 10^6} \times \left[(61.6 \times 34.6251) - 1{,}007 \right] \times 8{,}600$$

$$= 0.3642 \text{ THB/kWh}$$

(21) Calculate ES_T^{Oil} using Equation (11):

From Equation (11), $ES_T^{Oil} = \frac{1}{39{,}400} \times [P_T - P_0] \times \text{Heat Rate}$

$$= \frac{1}{39{,}400} \times [13.2658 - 2.9242] \times 8{,}600$$

$$= 2.2573 \text{ THB/kWh}$$

(22) Calculate EP using Equation (9):

From Equation (9), Energy Payment

$$= EP_0^{Coal} + \left[\left(0.75 \times ES_T^{Coal}\right) + \left(0.25 \times ES_T^{Oil}\right)\right]$$

$$= 0.62 + [(0.75 \times 0.3642) + (0.25 \times 2.2573)]$$

$$= 1.4575 \text{ THB/kWh}$$

(23) Calculate BP_P using Equation (12):

From Equation (12), $BP_P = \frac{CP}{EGG_P} + EP$

$$= \frac{18{,}498{,}507}{45{,}500 \times 13.5 \times 30} + 1.4575$$

$$= 2.461 \text{ THB/kWh}$$

(24) $\text{Electricity}_{\text{EGAT, P}}$:

The price of electricity sold to EGAT during peak hours is 2.461 THB/kWh.

(25) End: The end of estimation process for the price of $\text{Electricity}_{\text{EGAT, P}}$

<u>**Numerical Example of Estimation Procedure when *AC* (0 kW) < *CC*/6 (15,000 kW)**</u>

(1) Start: The start of estimation process for the price of $\text{Electricity}_{\text{EGAT, P}}$

(2) CP Calculation: The CP calculation sub-process

(3) Get CC: $CC_{\text{Electricity, EGAT, Plant A}}$ and $CC_{\text{Electricity, EGAT, Plant B}}$ = 90,000 kW

(4) Calculate AC using Equation (1):

Given AC = 0 kW

(5) Check AC = CC?: If yes, go to Step 9. Otherwise, go to Step 6.

No, AC ≠ CC. Go to Step 6

(6) Check AC < CC?: If yes, go to Step 10. Otherwise, go to Step 7.

Yes, AC < CC. Go to Step 10

(7) Check AC > CC?: If yes, go to Step 11. Otherwise, go to Step 8.

(8) Calculate BC_T using Equation (5):

(9) Calculate BC_T using Equation (2):

(10) Calculate BC_T using Equation (3):

From Equation (3), if AC < CC; BC_T = AC − 0.2 × (CC − AC)

$$= 0 - 0.2 \times (90{,}000 - 0)$$

$$= -\ 18{,}000 \text{ kW}$$

This is when $BC_T < 0$, it means that EGAT will charge a penalty fee.

(11) Calculate BC_T using Equation (4):

(12) Calculate CP_T using Equation (6):

From Equation (6), $CP_T = CP_0 \times \left(FP \times \dfrac{FX_T}{FX_0} + DP \right)$

$$= 422 \times \left(0.7 \times \frac{34.6251}{27} + 0.3 \right)$$

$$= 505.42 \text{ THB/kW}$$

(13) Calculate MCF using Equation (8):

From Equation (8), when AC < CC; MCF = $\dfrac{-18{,}000}{90{,}000} = -\ 0.2$

If MCF < 0.51, *CP* will be halved.

(14) Check MCF < 0.51?: If yes, go to Step 15. Otherwise, go to Step 18.

Yes, MCF < 0.51. Go to Step 15

(15) Check CP/2?: If yes, go to Step 16. Otherwise, go to Step 18.

Yes, CP/2. Go to Step 16

(16) Calculate CP/2 using Equation (7):

From Equation (7), Capacity Payment $= BC_T \times \frac{CP_T}{2}$

$$= -18{,}000 \text{ kW} \times \frac{505.42}{2} \text{ THB/kW}$$

$$= -4{,}548{,}813 \text{ THB}$$

This means NPS will be charged a penalty fee of 4,548,813 THB by EGAT.

(17) Check AC < CC/6?: If yes, go to Step 25. Otherwise, go to Step 23.

Yes, AC < CC/6. Go to Step 25.

(18) Calculate CP using Equation (7):

(19) EP Calculation: The EP calculation sub-process

(20) Calculate ES_T^{Coal} using Equation (10):

(21) Calculate ES_T^{Oil} using Equation (11):

(22) Calculate EP using Equation (9):

(23) Calculate BP_P using Equation (12):

(24) $\text{Electricity}_{\text{EGAT, P}}$:

(25) End: The end of estimation process for the price of $\text{Electricity}_{\text{EGAT, P}}$

The reason for demonstrating three numeral examples is because they are the often cases happening in practical; however, the case when AC < CC is the most frequent case.

4.1.2.2 Electricity Price for EGAT during Off-Peak Hours

To estimate electricity price sold to EGAT during off-peak hours ($Electricity_{EGAT, OP}$), Equation (9) to Equation (11) and Equation (13) in Section 2.1.4.1 of the Literature Review chapter are used. Figure 53 illustrates the estimation process flowchart for $Electricity_{EGAT, OP}$.

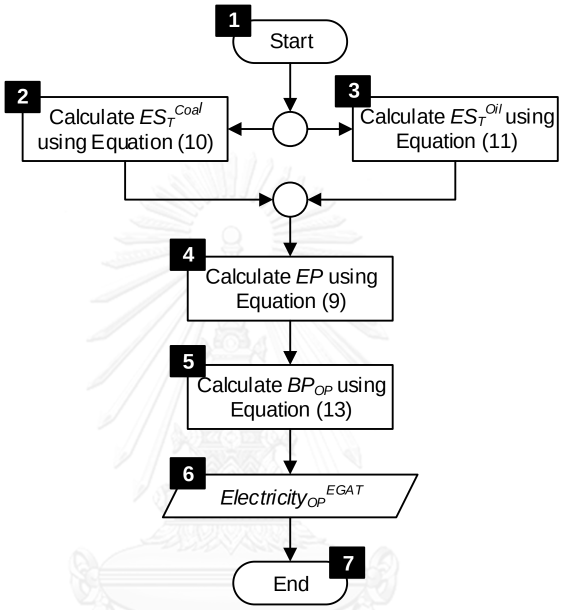


Figure 53: Estimation Process Flowchart for the Price of $\text{Electricity}_{\text{EGAT, OP}}$

<u>Numerical Example of Estimation Procedure</u>

(1) **Start:** The start of estimation process for the price of $\text{Electricity}_{\text{EGAT, OP}}$

(2) **Calculate ES_T^{Coal} using Equation (10):**

From Equation (10), $ES_T^{Coal} = \frac{1}{26.5877 \times 10^6} \times \left[(P_T \times FX_T) - P_0 \right] \times \text{Heat Rate}$

$$= \frac{1}{26.5877 \times 10^6} \times \left[(61.6 \times 34.6251) - 1{,}007 \right] \times 8{,}600$$

$= 0.3642$ THB/kWh

(3) Calculate ES_T^{Oil} using Equation (11):

From Equation (11), $ES_T^{Oil} = \frac{1}{39{,}400} \times [P_T - P_0] \times \text{Heat Rate}$

$$= \frac{1}{39{,}400} \times [13.2658 - 2.9242] \times 8{,}600$$

$$= 2.2573 \text{ THB/kWh}$$

(4) Calculate EP using Equation (9):

From Equation (9), Energy Payment

$$= EP_0^{Coal} + \left[\left(0.75 \times ES_T^{Coal}\right) + \left(0.25 \times ES_T^{Oil}\right)\right]$$

$$= 0.62 + [(0.75 \times 0.3642) + (0.25 \times 2.2573)]$$

$$= 1.457 \text{ THB/kWh}$$

(5) Calculate BP_{OP} using Equation (13):

From Equation (13), $BP_{OP} = EP = 1.457$ THB/kWh

(6) $Electricity_{EGAT,\ OP}$:

The price of electricity sold to EGAT during off-peak hours is 1.457 THB/kWh.

(7) End: The end of estimation process for the price of $Electricity_{EGAT,\ OP}$

4.1.2.3 Electricity Prices for AA and Industry during Peak Hours

To estimate electricity prices for AA ($Electricity_{AA,\ P}$), Industry ($Electricity_{Industry,\ P}$) during peak hours, Equation (14), Equation (15), Equation (17), Table 12 and Table 13 in Section 2.1.4.2 of the Literature Review chapter will be used. However, transmission lines to AA and Industry customers are at voltage level 22-23 kV. Table 31 illustrates the TOU rate for the large general service at the voltage level 22-23 kV.

Table 31: TOU Rate for Large General Service at Voltage Level 22-23 kV

Time of Use (TOU) Rate	Demand Charge (Baht/kW)	Energy Charge (Baht/kWh)		Service Charge (Baht/Month)
	Peak	*Peak*	*Off-Peak*	
At voltage level 22-23 kV	132.93	4.2097	2.6295	312.24

Remark: Peak Hours 09.00 – 22.00 Monday to Friday
Off-Peak Hours 22.00 – 09.00 Monday to Friday and 00.00 – 24.00 Saturday & Sunday

The electricity tariff for large industrial customers consists of three parts: (1) Demand Charge, (2) Energy Charge and (3) Service Charge before being adjusted by *Ft* charge to reflect the actual fuel cost for power generation over a specific period of time. In estimation process, the Service Charge of 312.24 THB/month can be neglected since it covers a very small amount when the price per unit is estimated. Hence, only Demand Charge and Energy Charge will be considered in the estimation process of this research study.

Moreover, both peak hours and off-peak hours between EGAT and PEA are different in terms of duration and days as illustrated in Table 32. Energy Charge can be affected by this difference, so it would be better if they are all made equivalently but still precise.

Table 32: Time of Use Differences between EGAT and PEA

Time of Use	EGAT	PEA	
Peak Duration	08.00-21.30 (13.5 hrs)	09.00-22.00 (13 hrs)	
Peak Days	Everyday	Monday-Friday	
Off-Peak Duration	21.30-08.00 (10.5 hrs)	22.00-09.00 (11 hrs)	00.00-24.00 (24 hrs)
Off-Peak Days	Everyday	Monday-Friday	Saturday-Sunday

The following calculation procedure show how to determine the values of equivalent Energy Charges for both peak hours and off-peak hours, based on TOU of EGAT, to be later used in estimating the unit price of electricity sold to AA and Industry.

(1) Find the average of energy charge for peak and off-peak hours in a month:

$$= \frac{\left(EC_P \times Hour_P^{Mon-Fri} \times Day_P^{Mon-Fri}\right) + \left[\left(Hour_{OP}^{Mon-Fri} \times Day_{OP}^{Mon-Fri}\right) + \left(Hour_{OP}^{Sat-Sun} \times Day_{OP}^{Sat-Sun}\right)\right] \times EC_{OP}}{Hours\ /\ Day \times Days\ /\ Month}$$

$$= \frac{(4.2097 \times 13 \times 22) + \left[(11 \times 22) + (24 \times 8)\right] \times 2.6295}{24 \times 30}$$

$= 3.2572$ THB/kWh

(2) Find the equivalent energy charge for off-peak hours by substituting the average of energy charge in the following formula:

$$EC_{P\&OP}^{Average} = \frac{\left[\left(EC_{OP}^{Equi} + (EC_P - EC_{OP})\right) \times Hour_P^{EGAT}\right] + \left(Hour_{OP}^{EGAT} \times EC_{OP}^{Equi}\right)}{Hours\ /\ Day}$$

$$3.2572 = \frac{\left[\left(EC_{OP}^{Equi} + (4.2097 - 2.6295) \times 13.5\right) + \left(10.5 \times EC_{OP}^{Equi}\right)\right]}{24}$$

$EC_{OP}^{Equi} = 2.3683$ THB/kWh

(3) Find the equivalent energy charge for peak hours:

$EC_P^{Equi} = 2.3683 + 1.5802$

$= 3.9485$ THB/kWh

Therefore, the modified (equivalent) Energy Charges for estimating the unit prices of electricity sold to AA and Industry during peak hours (08.00-21.30 of everyday) and off-peak hours (21.30-08.00 of everyday) can be presented in Table 33 below. Please note that both Demand Charge and Energy Charge are included in the unit price for peak period, but only Energy Charge is included in the unit price for off-peak period.

Table 33: Modified Time of Use Rate for Large General Service

Time of Use (TOU) Rate	Demand Charge (Baht/kW)	Energy Charge (Baht/kWh)	
	Peak	*Peak*	*Off-Peak*
At voltage level 22-23 kV	132.93	3.9485	2.3683

Remark: Peak Hours 08.00 – 21.30 Everyday
Off-Peak Hours 21.30 – 08.00 Everyday

In addition to Demand Charge and Energy Charge, Fuel Transfer (Ft) Charge is also included in the unit price of electricity sold to AA and Industry during both peak hours and off-peak hours. The current Ft charge is at –0.3729 THB/kWh, see Table 13.

Figure 54 shows the estimation process flowchart for $Electricity_{AA,\ P}$.

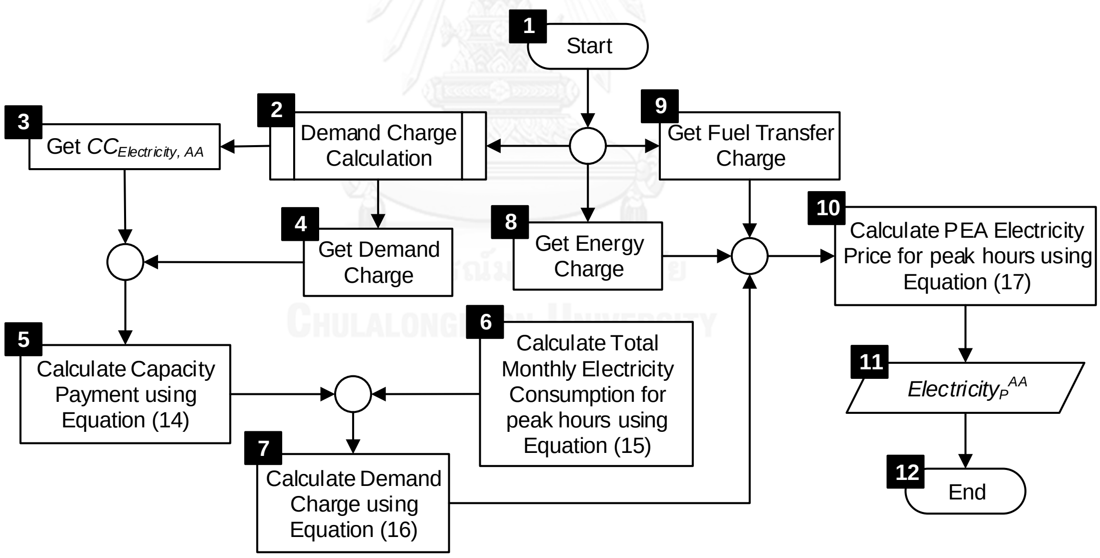


Figure 54: Estimation Process Flowchart for the Price of $Electricity_{AA,\ P}$

<u>Numerical Example of Estimation Procedure for $Electricity_{AA,\ P}$</u>

(1) Start: The start of estimation process for the price of $Electricity_{AA,\ P}$

(2) Demand Charge Calculation: The Demand Charge Calculation sub-process

(3) **Get $CC_{Electricity, AA}$:** The contracted electric capacity of AA is 60,000 kW.

(4) **Get Demand Charge:** The Demand Charge is 132.93 THB/kW

(5) **Calculate Capacity Payment using Equation (14):**

$$\text{Capacity Payment} = CC_{Electricity, AA} \times \text{Demand Charge}$$
$$= 60{,}000 \text{ kW} \times 132.93 \text{ THB/kW}$$
$$= 7{,}975{,}800 \text{ THB}$$

(6) **Calculate Total Monthly Electricity Consumption for peak hours using Equation (15):**

$$\text{Total Monthly Consumption} = CC_{Electricity, AA} \times Hours_P \times Days_P$$
$$= 60{,}000 \text{ kW} \times 13.5 \text{ hrs} \times 22 \text{ days}$$
$$= 17{,}820{,}000 \text{ kWh}$$

(7) **Calculate Demand Charge using Equation (16):**

$$\text{Demand Charge} = \frac{\text{Capacity Payment}}{\text{Total Monthly Electricity Consumption}}$$
$$= \frac{7{,}975{,}800}{17{,}820{,}000}$$
$$= 0.4476 \text{ THB/kWh}$$

(8) **Get Energy Charge:** The Energy Charge is 3.9485 THB/kWh

(9) **Get Fuel Transfer Charge:** The Ft charge is –0.3729 THB/kWh

(10) **Calculate PEA Electricity Price for peak hours using Equation (17):**

$$\text{PEA Electricity Price}_P = \text{Demand Charge} + \text{Energy Charge} + \text{Ft Charge}$$
$$= 0.4476 + 3.9485 + (-0.3729)$$
$$= 4.023 \text{ THB/kWh}$$

(11) **$Electricity_P^{AA}$:**

The price of electricity sold to AA during peak hours is 4.023 THB/kWh.

(12) **End:** The end of estimation process for the price of $Electricity_{AA, P}$

Figure 55 shows the estimation process flowchart for Electricity$_{Industry,\ P}$.

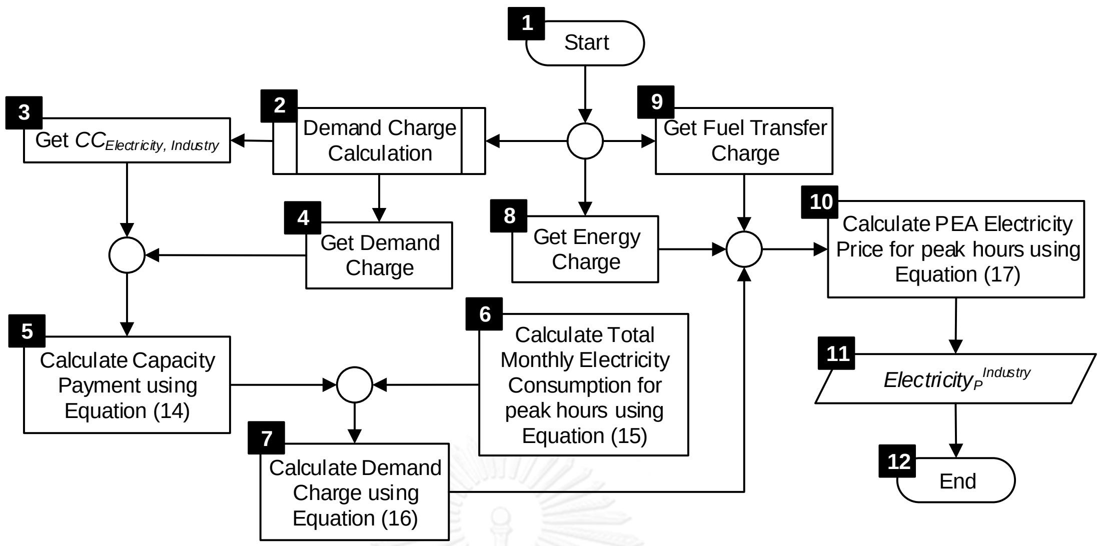


Figure 55: Estimation Process Flowchart for the Price of Electricity$_{Industry,\ P}$

<u>Numerical Example of Estimation Procedure for Electricity$_{Industry,\ P}$</u>

(1) **Start:** The start of estimation process for the price of Electricity$_{Industry,\ P}$

(2) **Demand Charge Calculation:** The Demand Charge Calculation sub-process

(3) **Get CC$_{Electricity,\ Industry}$:**

The contracted electric capacity of Industry is 140,000 kW.

(4) **Get Demand Charge:** The Demand Charge is 132.93 THB/kW

(5) **Calculate Capacity Payment using Equation (14):**

Capacity Payment = CC$_{Electricity,\ Industry}$ × Demand Charge

= 140,000 kW × 132.93 THB/kW

= 18,610,200 THB

(6) **Calculate Total Monthly Electricity Consumption for peak hours using Equation (15):**

$$\text{Total Monthly Consumption} = CC_{Electricity,\ Industry} \times Hours_P \times Days_P$$

$$= 140{,}000 \text{ kW} \times 13.5 \text{ hrs} \times 22 \text{ days}$$

$$= 41{,}580{,}000 \text{ kWh}$$

(7) **Calculate Demand Charge:**

$$\text{Demand Charge} = \frac{\text{Capacity Payment}}{\text{Total Monthly Electricity Consumption}}$$

$$= \frac{18{,}610{,}200}{41{,}580{,}000}$$

$$= 0.4476 \text{ THB/kWh}$$

(8) **Get Energy Charge:** The Energy Charge is 3.9485 THB/kWh

(9) **Get Fuel Transfer Charge:** The Ft charge is –0.3729 THB/kWh

(10) **Sum Demand Charge, Energy Charge and Fuel Transfer Charge:**

$$\text{PEA Electricity Price}_P = \text{Demand Charge} + \text{Energy Charge} + \text{Ft Charge}$$

$$= 0.4476 + 3.9485 + (-0.3729)$$

$$= 4.023 \text{ THB/kWh}$$

(11) **$Electricity_P^{Industry}$:**

The price of electricity sold to Industry during peak hours is 4.023 THB/kWh.

(12) **End:** The end of estimation process for the price of $Electricity_{Industry,\ P}$

4.1.2.4 Electricity Price for AA and Industry during Off-Peak Hours

To estimate the unit prices for AA ($Electricity_{AA,\ OP}$) and Industry ($Electricity_{Industry,\ OP}$) during off-peak hours, Equation (18), Table 12 and Table 13 will be used. Figure 56 illustrates the estimation process flowchart for $Electricity_{AA,\ OP}$.

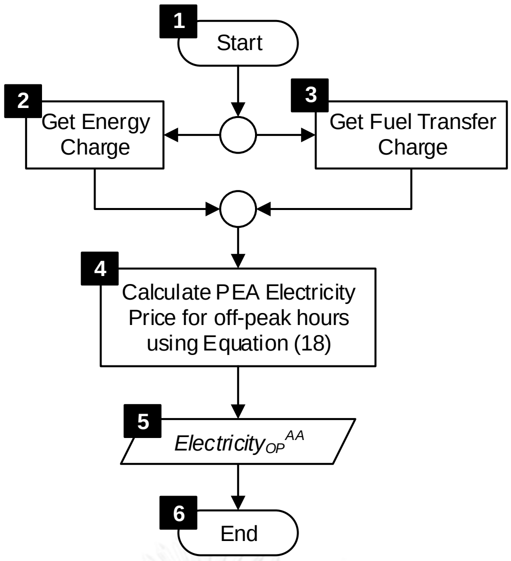


Figure 56: Estimation Process Flowchart for the Price of Electricity$_{AA,\ OP}$

<u>Numerical Example of Estimation Procedure for Electricity$_{AA,\ OP}$</u>

(1) **Start:** The start of estimation process for the price of Electricity$_{AA,\ OP}$

(2) **Get Energy Charge:** The Energy Charge is 2.3683 THB/kWh

(3) **Get Fuel Transfer Charge:** The Ft charge is –0.3729 THB/kWh

(4) **Calculate PEA Electricity Price for off-peak hours using Equation (18):**

PEA Electricity Price$_{OP}$ = Energy Charge + Ft Charge

= 2.3683 + (–0.3729)

= 1.995 THB/kWh

(5) **Electricity$_{OP}^{AA}$:**

The price of electricity sold to AA during off-peak hours is 1.995 THB/kWh.

(6) **End:** The end of estimation process for the price of Electricity$_{AA,\ OP}$

Figure 57 illustrates the estimation process flowchart for Electricity$_{Industry,\ OP}$.

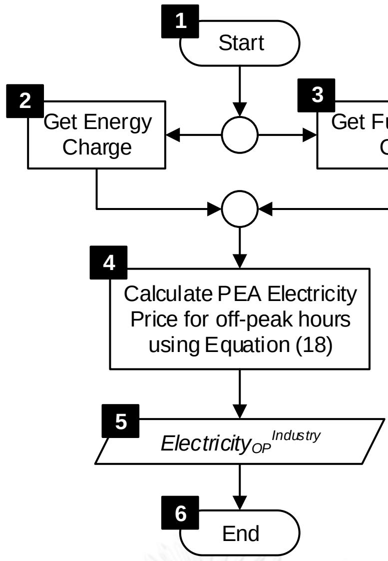


Figure 57: Estimation Process Flowchart for the Price of $\text{Electricity}_{\text{Industry, OP}}$

<u>Numerical Example of Estimation Procedure for $\text{Electricity}_{\text{Industry, OP}}$</u>

(1) **Start:** The start of estimation process for the price of $\text{Electricity}_{\text{Industry, OP}}$

(2) **Get Energy Charge:** The Energy Charge is 2.3683 THB/kWh

(3) **Get Fuel Transfer Charge:** The Ft charge is –0.3729 THB/kWh

(4) **Calculate PEA Electricity Price for off-peak hours using Equation (18):**

PEA Electricity Price_{OP} = Energy Charge + Ft Charge

= 2.3683 + (–0.3729)

= 1.995 THB/kWh

(5) **$\text{Electricity}_{\text{OP}}^{\text{Industry}}$:**

The price of electricity sold to Industry during off-peak hours is 1.995 THB/kWh.

(6) **End:** The end of estimation process for the price of $\text{Electricity}_{\text{Industry, OP}}$

4.1.2.5 LP Steam Price for AA during Peak and Off-Peak Hours

The LP steam price is based on either of fuel oil price, natural gas price or coal price, and CPI. The formula used to estimate the price of LP steam is confidential and cannot be disclosed. However, from the company database, the selling price per unit of LP steam is 450 THB/ton or 2.813 THB/kWh in the equivalent unit of electricity, and it is the same for both peak hours and off-peak hours as presented in Table 34.

Table 34: LP Steam Price for Peak Hours and Off-Peak Hours

LP Steam	Unit	Peak	Off-Peak
Price Per Ton	THB/ton	450	450
Price Per kWh	THB/kWh	2.813	2.813

4.1.2.6 MP Steam Price for AA during Peak and Off-Peak Hours

The MP steam price is also based on either of fuel oil price, natural gas price or coal price, and CPI. The formula used to estimate the price of MP steam is confidential and cannot be disclosed. However, from the company database, the selling price per unit of MP steam is 570 THB/ton or 2.780 THB/kWh in the equivalent unit of electricity, and it is the same for both peak hours and off-peak hours as shown in Table 35 below.

Table 35: MP Steam Price for Peak Hours and Off-Peak Hours

MP Steam	Unit	Peak	Off-Peak
Price Per Ton	THB/ton	570	570
Price Per kWh	THB/kWh	2.780	2.780

4.1.3 Estimation of Profits for Products, Customers and Times of Use

Profit can be calculated by directly subtracting cost from selling price. Due to different products, different groups of customers and different times of use, this section is then divided into sub-sections to demonstrate how to estimate each of the profits.

4.1.3.1 Electricity Profit for EGAT during Peak Hours

The profit from selling electricity to EGAT during peak hours depends on selling price per unit, and the selling price per unit will be cheap or expensive based on AC. This means that the selling price per unit will be more expensive when AC is exactly equal to CC, and it will be cheaper when AC is far below CC.

Nevertheless, the selling price per unit can be zero if AC is less than CC/6 or even zero, meaning that the company generates and sells electricity of only 15,000 kW or chooses to sell nothing to EGAT at all in that particular month, respectively. In these cases, BC_T will become negative, meaning that EGAT will charge penalty fee, and the penalty fee will be greatest if AC is zero relative to positive values of AC.

Accordingly, NPS will have to generate and sell electricity of at least 15,000 kW to EGAT in order to avoid being penalised and to make some profit. Table 36 shows different profit levels in different cases when $AC = CC$ and $CC/6 \leq AC < CC$:

Table 36: Different Profit Levels Gained from EGAT during Peak Hours

AC (kW)	CC (kW)	Price (THB/kWh)	Cost (THB/kWh)	Profit (THB/kWh)
90,000	90,000	2.705	1.383	1.322
75,000	90,000	2.656	1.383	1.273
60,000	90,000	2.581	1.383	1.198
45,500 [1]	90,000	2.461	1.383	1.078
30,000	90,000	1.832	1.383	0.449
15,000 [2]	90,000	1.457	1.383	0.074

Remark: [1] MCF = 0.51 [2] BC_T = 0 (Break-even to not be charged)

From Table 36, first, the price decreases as *AC* decreases leading the profit to decrease. Second, the price gap between *AC* of 45,500 kW and *AC* of 30,000 kW is very large. This is because *CP*, one of the pricing components, is halved when *MCF* is below 0.51. Lastly, the price when *AC* is at 15,000 kW is significantly low and very close to the cost resulting the profit of only 0.074 THB/kWh.

4.1.3.2 Electricity Profit for EGAT during Off-Peak Hours

The profit from selling electricity to EGAT during off-peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned}\text{Profit}_{EGAT,OP}^{Electricity} &= \text{Price}_{EGAT,OP}^{Electricity} - \text{Unit Cost}\\ &= 1.457 - 1.383\\ &= 0.074 \text{ THB/kWh}\end{aligned}$$

4.1.3.3 Electricity Profit for AA and Industry during Peak Hours

The profit from selling electricity to AA during peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned}\text{Profit}_{AA,P}^{Electricity} &= \text{Price}_{AA,P}^{Electricity} - \text{Unit Cost}\\ &= 4.023 - 1.383\\ &= 2.640 \text{ THB/kWh}\end{aligned}$$

The profit from selling electricity to Industry during peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned}\text{Profit}_{Industry,P}^{Electricity} &= \text{Price}_{Industry,P}^{Electricity} - \text{Unit Cost}\\ &= 4.023 - 1.383\\ &= 2.640 \text{ THB/kWh}\end{aligned}$$

4.1.3.4 Electricity Profit for AA and Industry during Off-Peak Hours

The profit from selling electricity to AA during off-peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned} Profit^{Electricity}_{AA,OP} &= Price^{Electricity}_{AA,OP} - Unit\ Cost \\ &= 1.995 - 1.383 \\ &= 0.612 \text{ THB/kWh} \end{aligned}$$

The profit from selling electricity to Industry during off-peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned} Profit^{Electricity}_{Industry,OP} &= Price^{Electricity}_{Industry,OP} - Unit\ Cost \\ &= 1.995 - 1.383 \\ &= 0.612 \text{ THB/kWh} \end{aligned}$$

4.1.3.5 LP Steam Profit for AA during Peak and Off-Peak Hours

The profit from selling LP steam to AA during peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned} Profit^{LP}_{AA,P} &= Price^{LP}_{AA,P} - Unit\ Cost \\ &= 2.813 - 1.383 \\ &= 1.430 \text{ THB/kWh (in equivalent unit of electricity)} \end{aligned}$$

The profit from selling LP steam to AA during off-peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned} Profit^{LP}_{AA,OP} &= Price^{LP}_{AA,OP} - Unit\ Cost \\ &= 2.813 - 1.383 \\ &= 1.430 \text{ THB/kWh (in equivalent unit of electricity)} \end{aligned}$$

4.1.3.6 MP Steam Profit for AA during Peak and Off-Peak Hours

The profit from selling MP steam to AA during peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned}\text{Profit}^{MP}_{AA,P} &= \text{Price}^{MP}_{AA,P} - \text{Unit Cost}\\ &= 2.780 - 1.383\\ &= 1.397 \text{ THB/kWh (in equivalent unit of electricity)}\end{aligned}$$

The profit from selling MP steam to AA during off-peak hours can be calculated by subtracting the unit cost of production from the unit price as follows:

$$\begin{aligned}\text{Profit}^{MP}_{AA,OP} &= \text{Price}^{MP}_{AA,OP} - \text{Unit Cost}\\ &= 2.780 - 1.383\\ &= 1.397 \text{ THB/kWh (in equivalent unit of electricity)}\end{aligned}$$

Please note that the profits calculated from Section 4.1.3.2 to Section 4.1.3.6 do not vary with AC, but these profits tend to increase as their units sold increase. The quantitative determination for unit cost, prices and profits of electricity and steam performed in this section will be further used for program development discussed in the next section.

4.2 Spreadsheet-Based Economic Load Dispatch Program for Profit Maximisation (*NPS Economic Dispatcher*)

The purpose of this section is to demonstrate how to develop the spreadsheet-based economic load dispatch program for profit maximisation, namely *NPS Economic Dispatcher*. Initially, conceptual design was described. Next, a mathematical LP model was formulated to solve ED program with the goal of maximising profit. Then, the program was developed to simulate ED management under a set of possible scenarios to see which scenarios provides the maximum profit to the company.

4.2.1 Conceptual Design

4.2.1.1 Functionality

NPS Economic Dispatcher 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.

4.2.1.2 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 about the computation algorithm and the data entry procedure should be simple without spending excessive physical and mental efforts.

4.2.1.3 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.

4.2.2 Computation Program

4.2.2.1 Required Input Data

NPS Economic Dispatcher needs five sets of input data of its computation algorithm to generate optimal ED management solutions. They are:

(1) Price: The unit price is used to estimate the unit profit along with the cost. The unit price for each product, each group of customers and each time of use has already been estimated (see Section 4.1.2), but its estimation procedure is still required by the algorithm embedded in the program.

(2) **Cost:** The unit cost of production is used to estimate the unit profit along with the price. The unit cost of production has already been estimated (see Section 4.1.1), but its estimation procedure is still required by the computation algorithm.

(3) **Profit:** The unit profit calculated by subtracting the cost from the price is used as the coefficient of a decision variable (number of electricity or steam produced). The profit for each product, each group of customers and each time of use has already been estimated (see Section 4.1.3), but that is just a demonstration. It cannot also be immediately entered into cells of the spreadsheets, especially the electricity price for EGAT during peak hours since it changes as AC changes. Thus, its estimation procedure is still required by the computation algorithm.

(4) **Sales Contracts:** The contracted capacity of electricity and/or steam specified on the sales contracts between NPS and EGAT/AA/Industry is used to form a set of equality and inequality constraints.

(5) **Parameters:** There are several parameters required by the program including foreign exchange rate, coal reference price, fuel oil reference price, related base rates, NPS heat rate, SPP cogeneration rule, coal-to-biomass ratios, maximum capacities of Plan A and Plant B and more.

4.2.2.2 Formulation of Linear Optimisation Model

Prior to starting the LP model formulation, two versions of mathematical modelling steps proposed by Carson & Cobelli (2001) and Taylor III (2010) (shown in Figure 39 and Figure 40 of the Literature Review chapter) were modified to suit to the research and shown in Figure 58. It also acts as the framework towards completion of this research project.

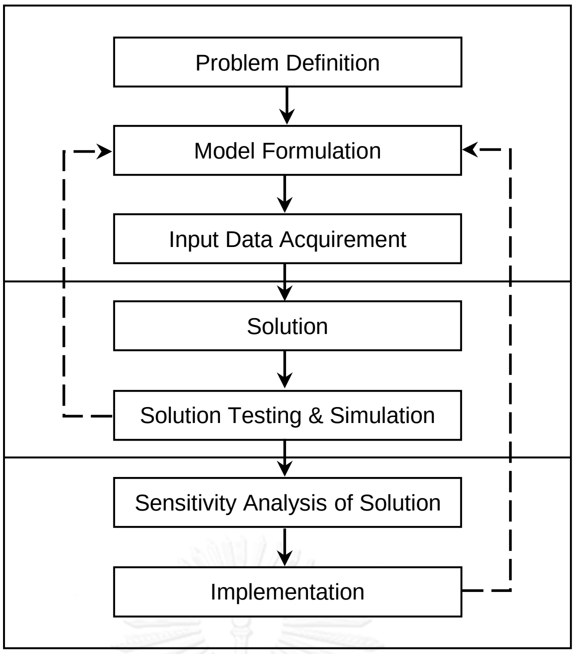


Figure 58: Modified Framework for Model Formulation, Solution and Analysis

Sources: Modified from Carson & Cobelli (2001) and Taylor III (2010)

The facing problem is decreased profit arising from independent management among the power plants and some root-causes (see Section 1.3 of the Introduction chapter). The underlying ED principle is applied to solve this problem with the aim of maximising the profit by determining how much electricity and steam should be optimally generated by each of the power plants while satisfying various constraints.

Referring to the formulation steps for LP problems proposed by Hillier & Lieberman (2014) in the Literature Review chapter, three steps include (1) defining decision variables, (2) setting objective function and (3) assigning model constraints.

Define 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

<u>Set Objective Functions</u>

A. Maximise the Profit during Peak Hours

$$\text{Maximise} \quad p_{EGAT,P}^{Electricity} X_{EGAT,A}^{Electricity} + p_{EGAT,P}^{Electricity} X_{EGAT,B}^{Electricity} + p_{AA,P}^{Electricity} X_{AA,A}^{Electricity} + p_{AA,P}^{Electricity} X_{AA,B}^{Electricity} + p_{Industry,P}^{Electricity} X_{Industry,A}^{Electricity} + p_{Industry,P}^{Electricity} X_{Industry,B}^{Electricity} + p_{AA,P}^{LPSteam} X_{AA,A}^{LPSteam} + p_{AA,P}^{LPSteam} X_{AA,B}^{LPSteam} + p_{AA,P}^{MPSteam} X_{AA,A}^{MPSteam} + p_{AA,P}^{MPSteam} X_{AA,B}^{MPSteam} \quad (25)$$

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

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

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

B. Maximise the Profit during Off-Peak Hours

$$\text{Maximise} \quad p_{EGAT,OP}^{Electricity} X_{EGAT,A}^{Electricity} + p_{EGAT,OP}^{Electricity} X_{EGAT,B}^{Electricity} + p_{AA,OP}^{Electricity} X_{AA,A}^{Electricity} + p_{AA,OP}^{Electricity} X_{AA,B}^{Electricity} + p_{Industry,OP}^{Electricity} X_{Industry,A}^{Electricity} + p_{Industry,OP}^{Electricity} X_{Industry,B}^{Electricity} + p_{AA,OP}^{LPSteam} X_{AA,A}^{LPSteam} + p_{AA,OP}^{LPSteam} X_{AA,B}^{LPSteam} + p_{AA,OP}^{MPSteam} X_{AA,A}^{MPSteam} + p_{AA,OP}^{MPSteam} X_{AA,B}^{MPSteam} \quad (26)$$

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

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

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

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

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

Assign Model Constraints

Subject to $CC_{EGAT,A}^{Electricity}$: $0 \le X_{EGAT,A}^{Electricity} \le 91{,}800$ (27)

$CC_{EGAT,B}^{Electricity}$: $0 \le X_{EGAT,B}^{Electricity} \le 91{,}800$ (28)

$CC_{AA}^{Electricity}$: $X_{AA,A}^{Electricity} + X_{AA,B}^{Electricity} = 60{,}000$ (29)

$CC_{Industry}^{Electricity}$: $X_{Industry,A}^{Electricity} + X_{Industry,B}^{Electricity} = 140{,}000$ (30)

$CC_{AA}^{LPSteam}$: $X_{AA,A}^{LPSteam} + X_{AA,B}^{LPSteam} \ge 11{,}184$ (31)

$CC_{AA}^{MPSteam}$: $X_{AA,A}^{MPSteam} + X_{AA,B}^{MPSteam} \ge 906$ (32)

SPP Cogeneration Rule: (33)

$$\frac{X_{AA,A}^{LPSteam} + X_{AA,B}^{LPSteam} + X_{AA,A}^{MPSteam} + X_{AA,B}^{MPSteam}}{X_{EGAT,A}^{Electricity} + X_{EGAT,B}^{Electricity} + X_{AA,A}^{Electricity} + X_{AA,B}^{Electricity} + X_{Industry,A}^{Electricity} + X_{Industry,B}^{Electricity} + X_{AA,A}^{LPSteam} + X_{AA,B}^{LPSteam} + X_{AA,A}^{MPSteam} + X_{AA,B}^{MPSteam}} \ge 0.10$$

Max. Capacity$_A$: $X_{EGAT,A}^{Electricity} + X_{AA,A}^{Electricity} + X_{Industry,A}^{Electricity} + X_{AA,A}^{LPSteam} + X_{AA,A}^{MPSteam} \le 149{,}000$ (34)

Max. Capacity$_B$: $X_{EGAT,B}^{Electricity} + X_{AA,B}^{Electricity} + X_{Industry,B}^{Electricity} + X_{AA,B}^{LPSteam} + X_{AA,B}^{MPSteam} \le 149{,}000$ (35)

Total Capacity : (36)

$$X_{EGAT,A}^{Electricity} + X_{EGAT,B}^{Electricity} + X_{AA,A}^{Electricity} + X_{AA,B}^{Electricity} + X_{Industry,A}^{Electricity} + X_{Industry,B}^{Electricity} + X_{AA,A}^{LPSteam} + X_{AA,B}^{LPSteam} + X_{AA,A}^{MPSteam} + X_{AA,B}^{MPSteam} \le 298{,}000$$

The dual objectives illustrated in Equation (25) and Equation (26) 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. They cannot be combined into a single objective function because 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.

For the constraints, the description is presented in tabular form as Table 37.

Table 37: Description for Model Constraints

Equation	Constraint Description
Equation (27)	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.
Equation (28)	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.
Equation (29)	The sum of electricity units produced and sold to AA by Plant A and Plant B must exactly equals to 60,000 kW. Zero unit is not allowed since AA needs electricity for its manufacturing and office buildings.
Equation (30)	The sum of electricity units produced and sold to Industry by Plant A and Plant B must exactly equals to 140,000 kW. Zero unit is not allowed since Industry needs electricity for its manufacturing and office buildings.
Equation (31)	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 equivalent unit of electricity). The upper limit is not specified since AA requires tons of steam for its manufacturing.
Equation (32)	The sum of MP steam units produced and sold to AA by Plant A and Plant B must be at least 906 kW (in equivalent unit of electricity). The upper limit is not specified since AA requires tons of steam for its manufacturing.
Equation (33)	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 EGG.

Equation	Constraint Description
Equation (34)	To ensure that 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 consumed by its station service.
Equation (35)	To ensure that the sum of electricity units 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 consumed by its station service.
Equation (36)	To ensure that the sum of electricity units and steam units produced and sold to all customers must not surpass the total maximum capacity of both Plant A and Plant B of 298,000 kW. Please note that the total installed generating capacity of Plant A and Plant B is 328,000 kW but 30,000 kW is consumed altogether by their station services.

4.2.2.3 Computation Algorithm

NPS Economic Dispatcher utilises the quantitative determination procedure created in Section 4.1 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. Figure 59 presents a flowchart of the algorithm.

This flowchart can be applied to solve the models for peak and off-peak periods. The computation algorithm starts from 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 maximising 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 summarise the model results in terms of ED solution management and profit.

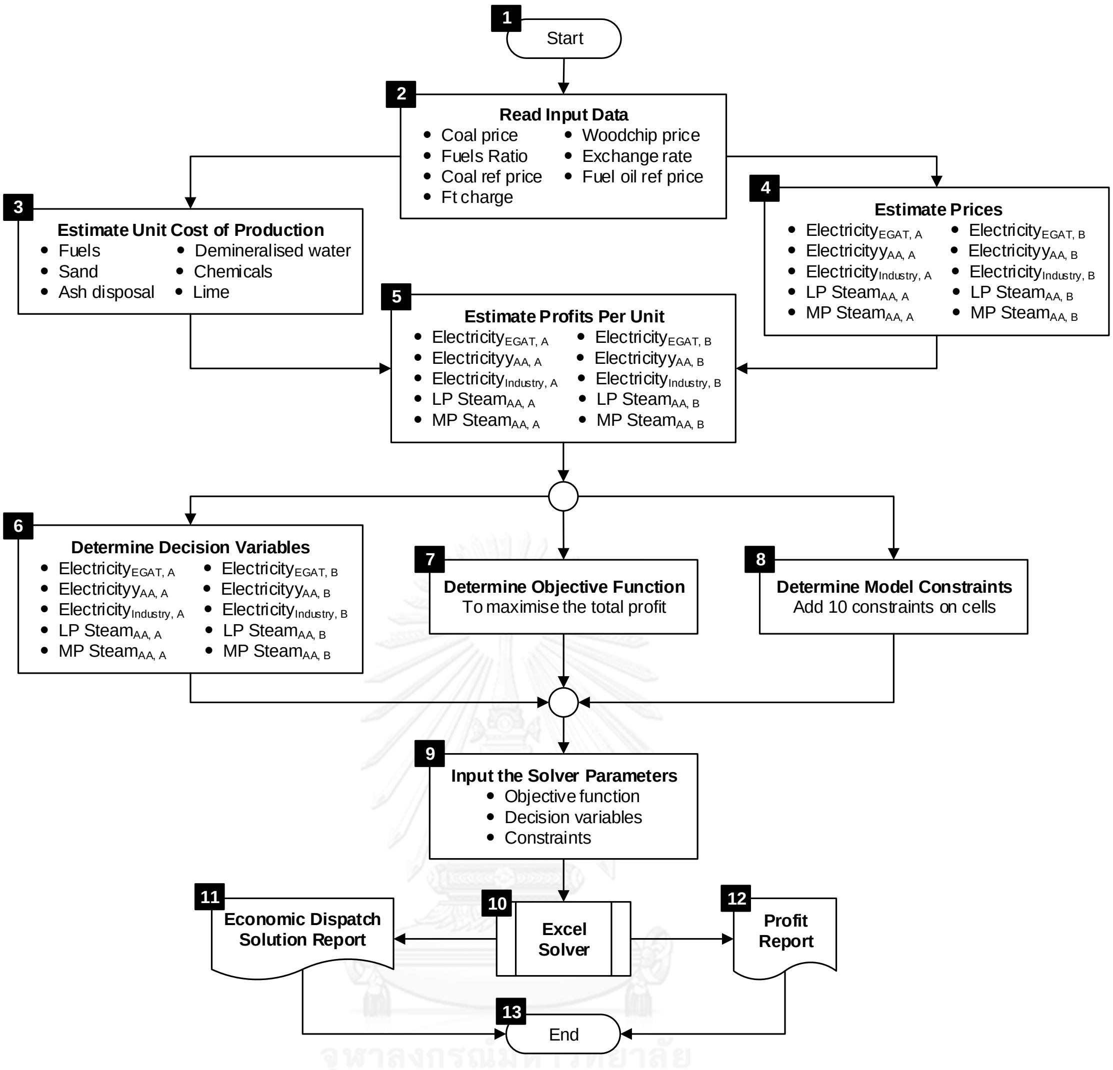


Figure 59: Flowchart of the Computation Algorithm

4.2.2.4 Computed Results from Excel Solver

For practicality, *NPS Economic Dispatcher* summarises the ES solutions on how to manage ED of dual cogeneration power plants while achieving the maximum. Specifically, the computed results from Excel Solver should help make a decision how much electricity and steam should be optimally generated by each plant while satisfying all the constraints of power system, SPP regulation and sales contracts with the customers.

4.2.2.5 Assumptions of the Program

NPS Economic Dispatcher 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 model variables and parameters 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. No other type of profit is 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 specific time is not allowed.
- The SPP cogeneration regulation of minimum 10% heat output remains unchanged.

4.2.2.6 Feasible Scenarios towards Maximum Profit Achievement

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 38, were thereby created and used replace the original constraints of $CC_{EGAT,A}^{Electricity}$ and $CC_{EGAT,B}^{Electricity}$. A simulation was performed in the next section to see which of the two allows NPS to achieve the maximum profit.

Table 38: 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 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 company 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 sells electricity between 15,000 kW and 45,500 kW to EGAT, where the value of *MCF* is below 0.51, resulting *CP* is halved.

4.2.3 Illustrative Simulation of *NPS Economic Dispatcher*

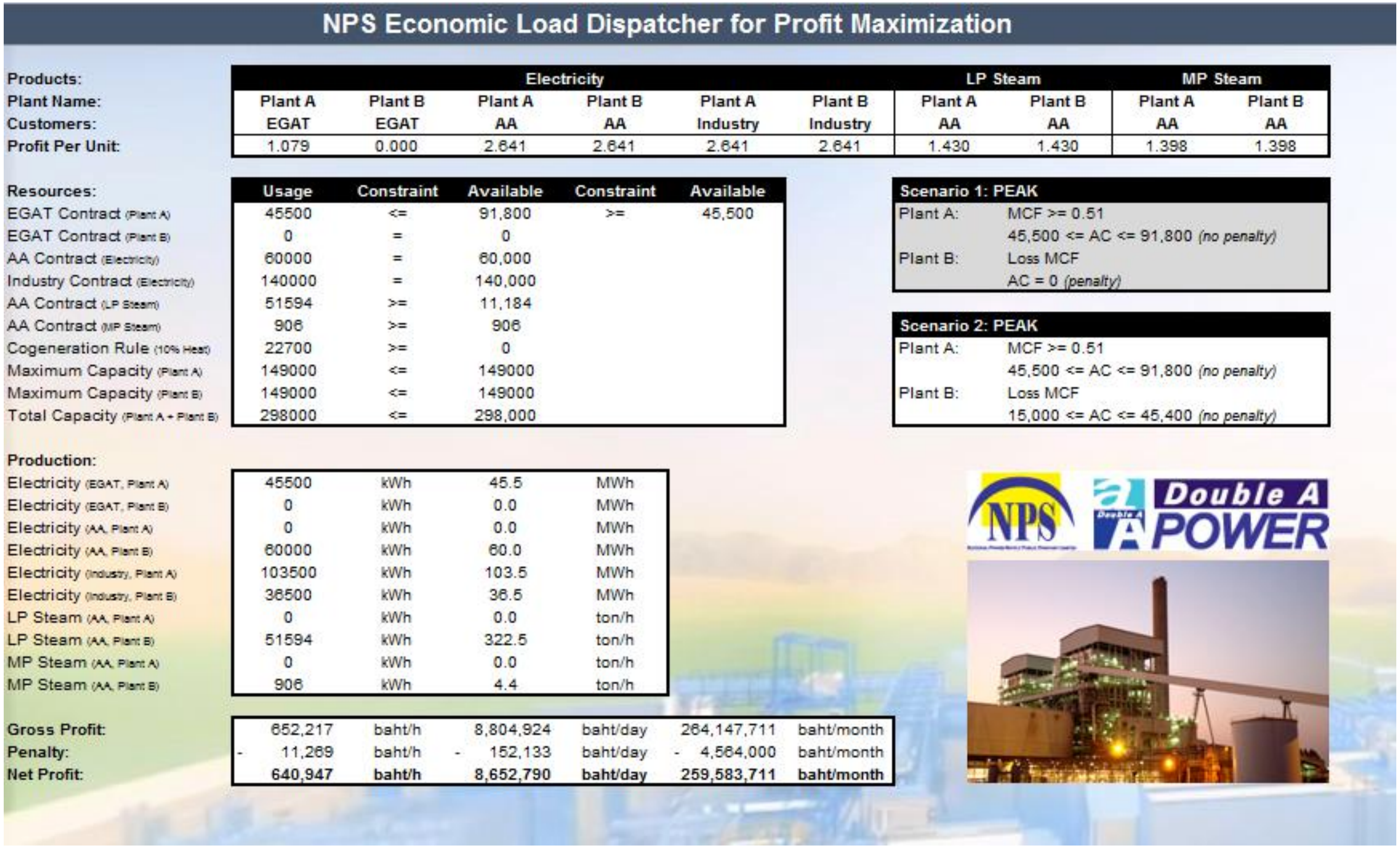
NPS Economic Dispatcher was developed and simulated using Microsoft Excel 2013 (64-bit) on a notebook computer with Microsoft Windows 10 Pro Operating System and Intel Core i5 Central Process Unit. The users are not required to enable a 'Macro' option before running the program, simply just working with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

Those four spreadsheets function the screens displays for different periods and different scenarios. They are (1) Peak (Scenario 1) sheet, (2) Peak (Scenario 2) sheet, (3) Off-Peak (Scenario 1) and (4) Off-Peak (Scenario 2). The reasons for having up to four sheets are as follows: First, the LP model is not able to run dual objective functions given the same set of constraints due to different profits per unit in different periods of times of use. Second, the optimal solutions regarding ED management should be obtained during different periods. Specifically, how much electricity and steam should be produced and sold to each group of customers in both periods.

Figure 60, Figure 61, Figure 62 and Figure 63 illustrate the display screens and the results of Peak Hours under Scenario 1, Peak Hours under Scenario 2, Off-Peak Hours under Scenario 1 and Off-Peak Hours under Scenario 2, respectively.

4.2.3.1 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	0.000	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)	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: 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)	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:	652,217	baht/h	8,804,924	baht/day	264,147,711	baht/month
Penalty:	- 11,269	baht/h	- 152,133	baht/day	- 4,564,000	baht/month
Net Profit:	**640,947**	**baht/h**	**8,652,790**	**baht/day**	**259,583,711**	**baht/month**

Figure 60: NPS Economic Dispatcher for Peak Hours under Scenario 1

4.2.3.2 Peak Hours under Scenario 2

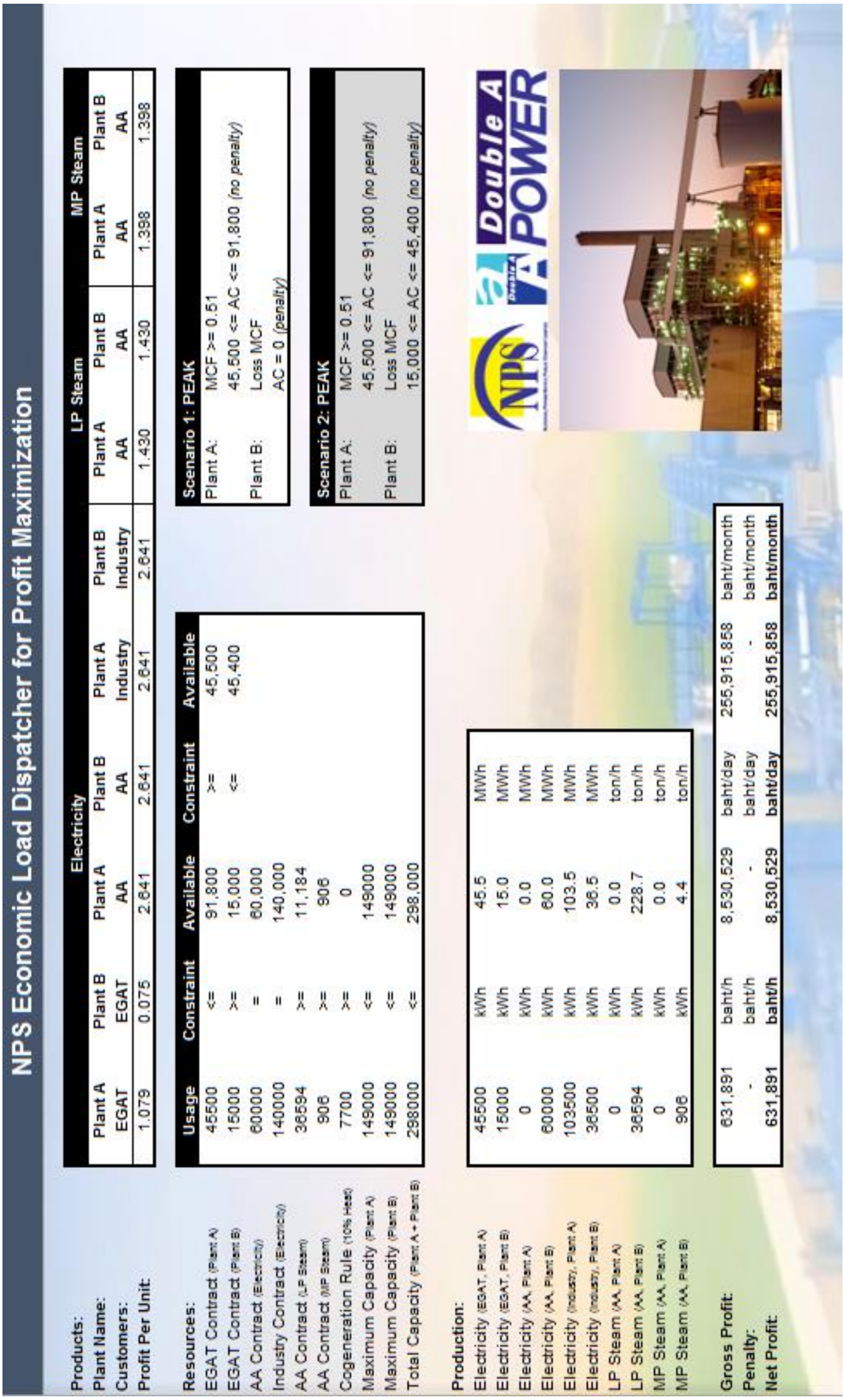
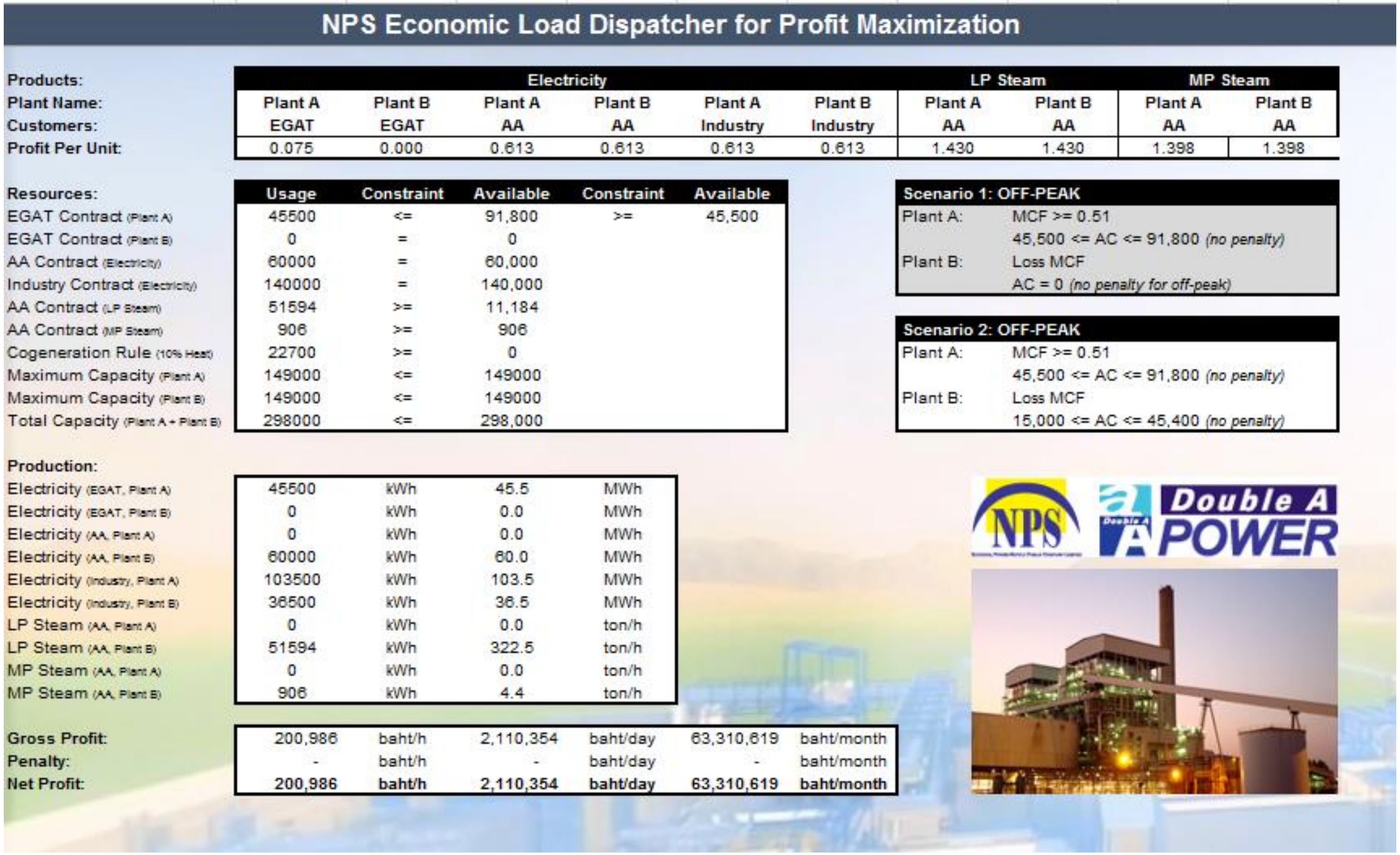


Figure 61: NPS Economic Dispatcher for Peak Hours under Scenario 2

4.2.3.3 Off-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:	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)*

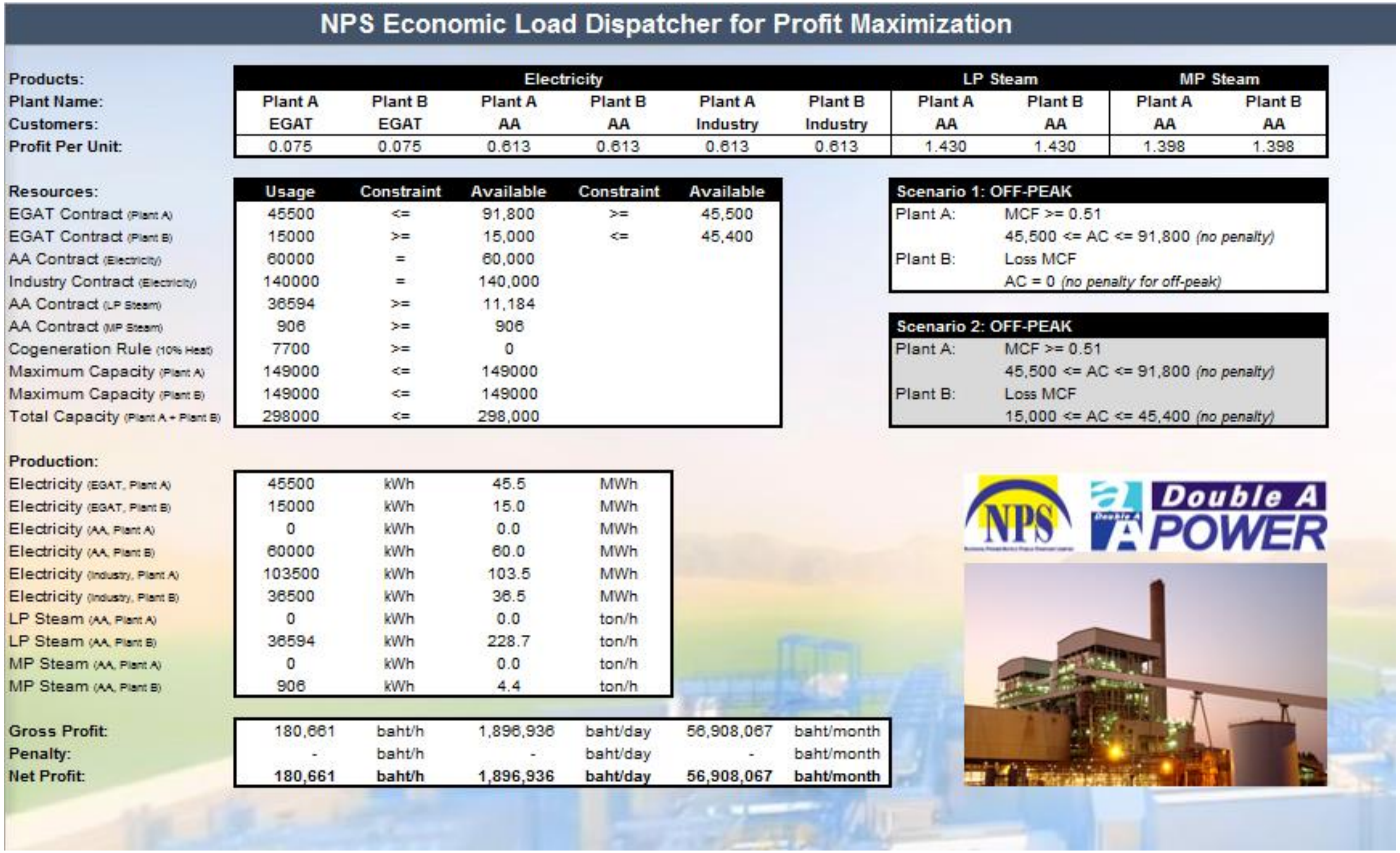
Scenario 2: OFF-PEAK	
Plant A:	MCF >= 0.51
	45,500 <= AC <= 91,800 *(no penalty)*
Plant B:	Loss MCF
	15,000 <= AC <= 45,400 *(no penalty)*

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**

Figure 62: NPS Economic Dispatcher for Off-Peak Hours under Scenario 1

4.2.3.4 Off-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	0.075	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)	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: 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)	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:	180,661	baht/h	1,896,936	baht/day	56,908,067	baht/month
Penalty:	-	baht/h	-	baht/day	-	baht/month
Net Profit:	**180,661**	**baht/h**	**1,896,936**	**baht/day**	**56,908,067**	**baht/month**

Figure 63: NPS Economic Dispatcher for Off-Peak Hours under Scenario 2

4.2.3.5 Summary of the Illustrative Simulation

Considering the profit report shown in Table 39. 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 39: Profit Report

Time of Use	Peak Hours		Off-Peak Hours		24 Hours
Scenario	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 40 illustrates 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 Industry are 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 40: Economic Dispatch Management Report

Time of Use	Peak Hours		Off-Peak Hours	
Scenario	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 minimising total cost together with the proposed program, the performances of NPS should be improved in terms of ED and financial return.

4.3 Sensitivity Analysis of Factors Affecting Profitability

When the LP models were formulated in Section 4.2.2, they were implicitly assumed to be deterministic that is the parameters of the models were known with certainty. These parameters include the coefficients of objective function, such as profit per unit of electricity sold and profit per unit of steam sold. In practicality, the model parameters are simply estimates or best guesses that are subject to change. For this reason, this section is intended to examine to what extent the profitability is affected by changes in major factorial parameters through sensitivity analysis.

4.3.1 Identification of Influential Factors

Referring the Literature Review chapter, it was discovered that many external factors could affect the revenue of power plant companies, such as coal price, natural gas price, fuel oil price and foreign exchange. Ft charge could also be another factor as it is included when pricing electricity for the consumers in the provincial areas. Moreover, an internal factor, such as the ratio of fuels used, is influential to the cost.

In this context, five major influential factors considered in the analysis based on the literatures and interview from the experts of the company include (1) exchange rate, (2) coal reference price, (3) fuel oil reference price, (4) coal-to-biomass fuel ratio and (5) Ft charge. The natural gas price was excluded because it is not involved in the pricing determination, and the power plants studied are driven by the mixed fuel of coal and biomass.

4.3.1.1 Foreign Exchange Rate

Foreign exchange rate is regarded as the value of Thailand's currency in relation to the United States' currency determined by buyers and sellers trading in the foreign exchange market. For example, an exchange rate of 35 Thai baht (THB) to the United States dollar (USD) means 35 THB will be exchanged for each 1 USD.

A change in the exchange rate will affect the EGAT electricity prices for both peak and off-peak periods since the exchange rate is one of the pricing components of both *CP* and *EP*. To remind, EGAT peak-hour price equals to the sum of *CP* and *EP* and EGAT off-peak price equals to EP. Also, a change in the exchange rate has the effects on the unit cost because the costs of coal and sea freight are based on the US currency. Hence, the changes in the EGAT prices and the unit cost will consequently result the profit per unit to change.

4.3.1.2 Coal Reference Price

Coal reference price is used to compute the electricity tariff for SPP firm contract as shown in Section 2.1.4.1 of the Literature Review chapter. The coal reference price is based on Barlow Jonker: Japanese Power Utilities (BJ JPU) announced by the PPA Division, EGAT.

A change in the coal reference price will affect EGAT electricity prices for both peak and off-peak periods since the coal reference price is one of the pricing components of *EP*, see the term ES_T^{Coal} in both Equation (9) and Equation (10). Accordingly, the changes in the coal reference price will lead the profit per unit gained from EGAT to change.

4.3.1.3 Fuel Oil Reference Price

Fuel oil reference price is also another factor used to compute the electricity tariff for SPP firm contract as shown in Section 2.1.4.1 of the Literature Review chapter. The fuel oil reference price is determined and officially declared by the PPA Division, EGAT every month.

A change in the fuel oil reference price will affect the EGAT electricity prices for both peak and off-peak period since the fuel oil reference price is one of the pricing components of *EP*, similarly to the case of coal reference price, see the term ES_T^{Oil} in both Equation (9) and Equation (11). Thereby, the changes in the fuel oil reference price will cause the profit per unit obtained from EGAT to change in the end.

4.3.1.4 Coal-to-Biomass Fuel Ratio

Coal-to-biomass fuel ratio is the combination of coal and woodchip used as primary fuels for generating electricity and steam simultaneously. For Plant A and Plan B of NPS, the acceptable range of coal fuel is between 85% and 95%, and the acceptable range of biomass fuel is between 5% and 15%. The current fuel ratio is to use coal of 95% and biomass of 5%. If either coal or biomass is input outside its boundaries, there might cause troubles impacting the overall power plants, such as less productivity and even machine breakdown.

A change in the coal-to-biomass fuel ratio will directly affect the total unit cost since the costs of coal and woodchip represents the total fuel cost, which covers the major portion of the total unit cost, see Equation (24). As a result, the changes in the coal-to-biomass fuel ratio will ultimately cause all profits per unit of both electricity and steam during both peak hours and off-peak hours to change.

4.3.1.5 Fuel Transfer (Ft) Charge

Ft charge is the rate included in the electricity bill, adjusted by a mechanism to reflect the actual price of electricity over a specific of time. The Ft charge is determined and officially declared by Energy Regulatory Commission (ERC) every four months. The current Ft charge used from January 2017 to April 2017 is at –0.3729 THB per kWh.

A change in the Ft charge will affect the electricity prices sold to AA and Industry for both peak hours and off-peak hours because the Ft charge is one of the pricing components, see Equation (17) and Equation (18). Therefore, the profits per unit gained from selling the electricity to AA and Industry will be affected as the Ft charges alter.

4.3.2 Numerical Examples of Sensitivity Analysis

Referring to Taylor III (2010) in Section 2.7 of the Literature Review chapter, the most obvious way to ascertain the effect of a change in the parameter of a model is to make the change in the original model by resolving the model and comparing the solution results with the original ones. Notwithstanding, in some cases the effect of changes on the model can be determined without solving the problem again.

Using a statistical regression technique on which this research project rely should be appropriate as Hillier & Lieberman (2014) suggested that linear regression approach is the most suitable if the model response is actually linear, and because it is relatively simple and requires low computation time. The following sections demonstrate the numerical examples of the analysis of those factors identified and their effects on the profitability.

4.3.2.1 Sensitivity Analysis of Foreign Exchange Rate

Figure 64 shows the regression model for the exchange rate and the unit cost. The relationship between the two is perfect positive correlation (r^2 = 1), indicating that 100% of the total variation is explained by the regression equation. An average unit cost of 0.0324 THB is expected to increase for an increase in 1 USD.

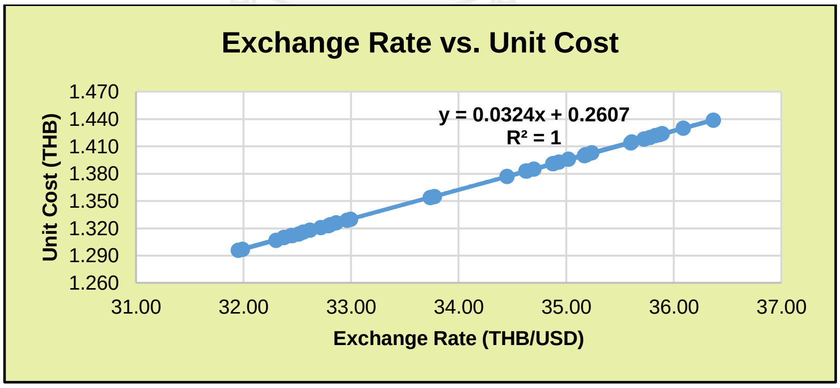


Figure 64: Regression Model for Exchange Rate and Unit Cost

Figure 65 shows the regression model for the exchange rate and the unit prices. The relationship between exchange rate and EGAT price for peak hours is also perfect positive correlation (r^2 = 1). An average EGAT price for peak hours of 0.0367 THB is expected to increase for an increase in 1 USD. Whereas, the relationship between exchange rate and EGAT price for off-peak hours is positive correlation (r^2 = 0.9998). An average EGAT price for off-peak hours of 0.0149 THB is expected to increase for an increase in 1 USD.

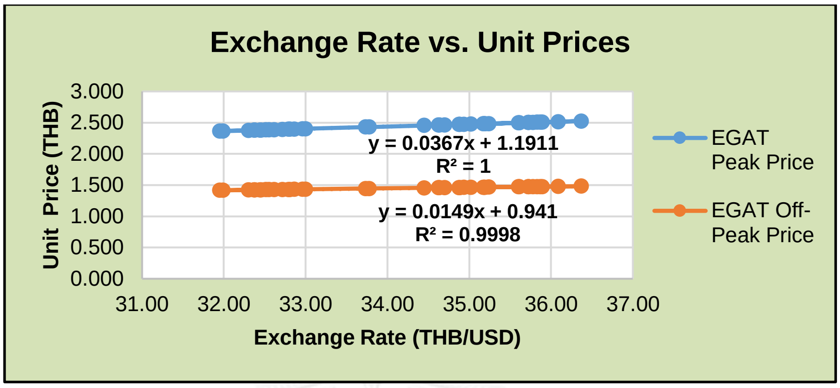


Figure 65: Regression Model for Exchange Rate and Unit Prices

Figure 66 shows the regression model for the exchange rate and the unit profits. The relationship between exchange rate and EGAT profit for peak hours is perfect positive correlation (r^2 = 0.9961). An average EGAT profit for peak hours of 0.0043 THB is expected to increase for an increase in 1 USD. Conversely, the relationship between exchange rate and EGAT profit for off-peak hours is very close to perfect positive correlation (r^2 = 0.9997). However, an average EGAT profit for off-peak hours of 0.0175 THB is expected to decrease for an increase in 1 USD due to the negative coefficient.

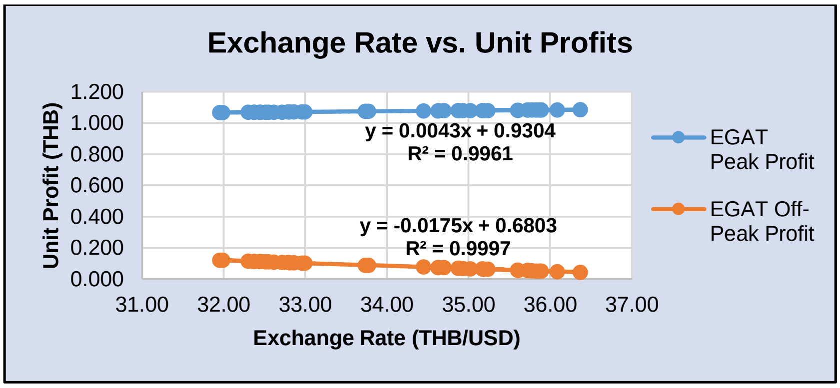


Figure 66: Regression Model for Exchange Rate and Unit Profits

Considering how sensitive the unit cost, the prices and the profits of the electricity sales to EGAT in peak and off-peak hours to the variations of exchange rate, as illustrated in Table 41 below.

Table 41: Sensitivity Results from Changes in Foreign Exchange Rate

Statistic	FX[1]	Unit Cost	EGAT			
			Peak Hours		Off-Peak Hours	
			Price	Profit	Price	Profit
Max	36.3696	1.439	2.525	1.086	1.484	0.045
Mean	34.1409	1.367	2.444	1.077	1.450	0.083
Min	31.1409	1.296	2.363	1.067	1.418	0.122

Remark: [1] Monthly data collected from January 2014 to April 2017.

It can be clearly seen that the exchange rate has the strong effect on the changes in all of the parameters. For instance, the unit cost of production increased up to 1.439 THB when the exchange rate hit 36.3696 THB/USD but decreased to 1.296 THB if the exchange rate was at 31.1409 THB/USD. The reason for this is because the costs of coal and its sea freight used as the main fuel are both based on USD.

4.3.2.2 Sensitivity Analysis of Coal Reference Price

Figure 67 shows the regression model for the coal reference price and the unit prices. The relationship between the coal reference price and EGAT price for peak period is perfect positive correlation (r^2 = 1), indicating that 100% of the total variation is explained by the regression equation. Likewise, the relationship between the coal reference price and EGAT price for off-peak hours. This means the average EGAT prices for both periods of 0.0084 THB is expected to increase for an increase in 1 USD in the coal reference price.

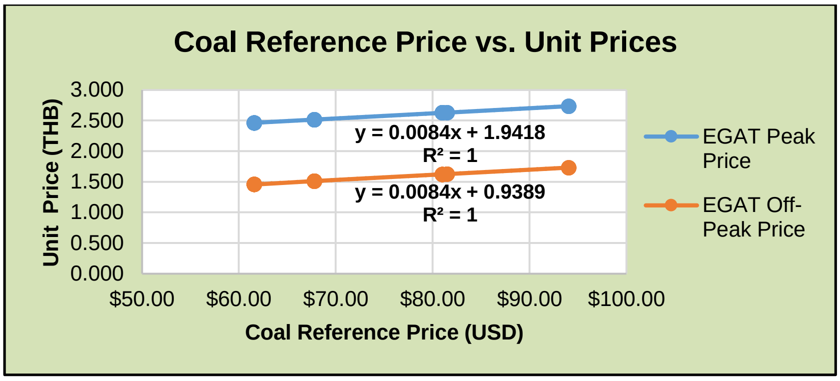


Figure 67: Regression Model for Coal Reference Price and Unit Prices

Figure 68 shows the regression model for the coal reference price and the unit profits. Similarly, the relationships between the coal reference price and EGAT profits for peak hours and off-peak hours are perfect positive correlation (r^2 = 1). An increase in the coal reference price of 1 USD will lead EGAT profits for peak and off-peak hours to increase by 0.0084 THB.

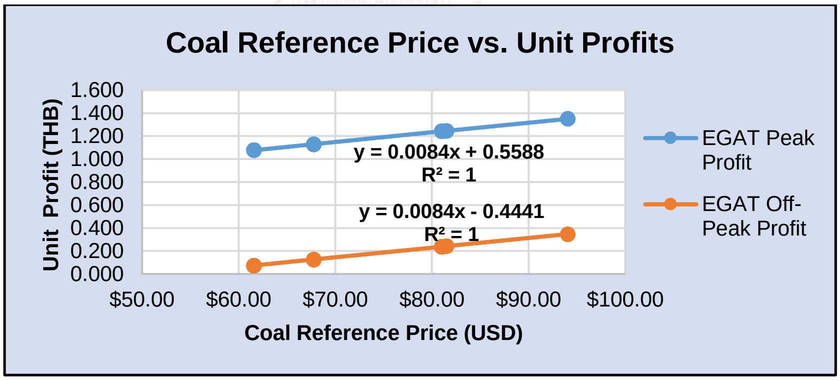


Figure 68: Regression Model for Coal Reference Price and Unit Profits

Considering the effects of the coal reference price on the unit cost, the prices and the profits of the electricity sales to EGAT in peak and off-peak hours in Table 42 below. The unit cost is not affected since the coal price reference is not involved in the estimation of the unit cost, but the electricity prices sold to EGAT during both periods are based on the coal reference price. This can be observed from the variations in the prices as they increased if the coal reference prices increased. The profits obtained from EGAT also varied as the electricity prices varied although the unit cost remained constant, remembering that the profit is directly calculated from the subtraction of the unit cost from the price,

Table 42: Sensitivity Results from Changes in Coal Reference Price

Statistic	Coal Price	Unit Cost	EGAT			
			Peak Hours		Off-Peak Hours	
			Price	Profit	Price	Profit
Max	$94.06	1.383	2.734	1.351	1.750	0.347
Mean	$61.60	1.383	2.592	1.209	1.589	0.206
Min	$77.20	1.383	2.461	1.078	1.457	0.074

Remark: [1] Monthly data collected from January 2014 to April 2017.

4.3.2.3 Sensitivity Analysis of Fuel Oil Reference Price

Figure 69 illustrates the regression model for the fuel oil reference price and the unit prices. The relationships between the coal reference price and EGAT prices for peak period and off-peak periods are both perfect positive correlation (r^2 = 1), indicating that 100% of the total variation is explained by the regression equation. The average EGAT prices for both periods of 0.0546 THB is expected to rise for a rise in 1 THB in the fuel oil reference price.

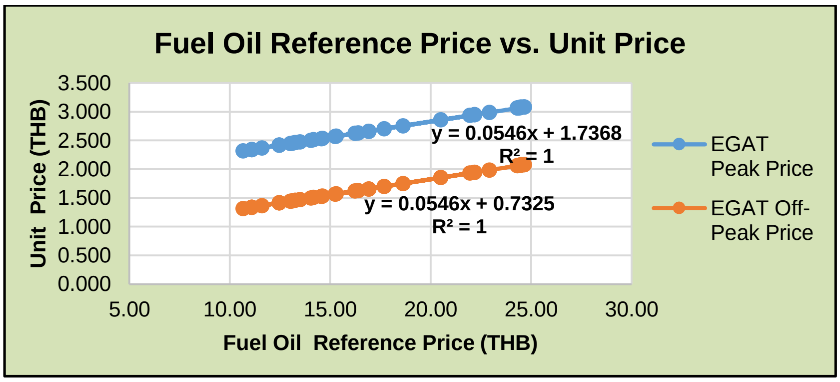


Figure 69: Regression Model for Fuel Oil Reference Price and Unit Prices

Figure 70 illustrates the regression model for the fuel oil reference price and the unit profits. Likewise, the relationships between the fuel oil reference price and EGAT profits for peak and off-peak hours are also perfect positive correlation (r^2 = 1). A rise in the fuel oil reference price of 1 THB will cause EGAT profits for both periods to rise by 0.0546 THB.

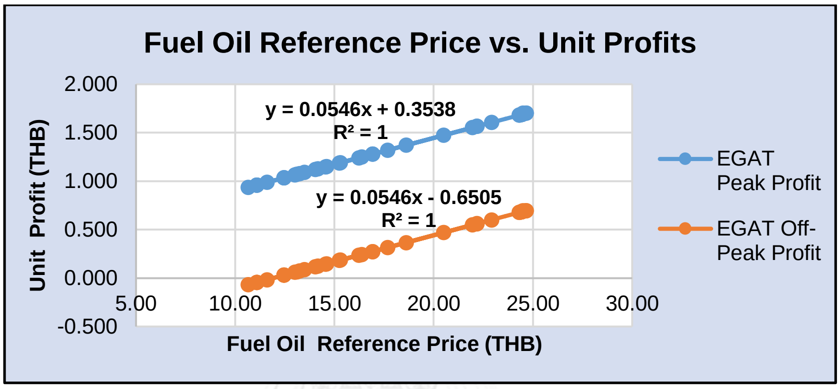


Figure 70: Regression Model for Fuel Oil Reference Price and Unit Profits

Considering how sensitive the unit cost, the prices and the profits of the electricity sold to EGAT in peak period and off-peak period to the variations of fuel reference price in Table 43. The same as the coal reference price that the fuel oil reference price has no effect on the unit cost because it is not used to estimate the unit cost, but the electricity prices sold to EGAT during both periods partly rely on the fuel oil reference price. This can be seen from the variations in the prices as they increased if the fuel oil reference prices increased. The profits obtained from EGAT also varied as the electricity prices varied.

Table 43: Regression Results from Changes in Fuel Oil Reference Price

Statistic	Fuel Oil Price	Unit Cost	EGAT			
			Peak Hours		Off-Peak Hours	
			Price	Profit	Price	Profit
Max	24.6691	1.383	3.084	1.701	2.080	0.697
Mean	10.6613	1.383	2.714	1.331	1.710	0.327
Min	17.8868	1.383	2.319	0.936	1.315	(0.068)

Remark: [1] Monthly data collected from January 2014 to April 2017.

4.3.2.4 Sensitivity Analysis of Coal-to-Biomass Fuel Ratio

Figure 71 illustrates the regression model for coal fuel ratio and the unit cost. Note that if the ratio is at 90%, it means that the fuel is mixed with 90% of coal and 10% of woodchip.

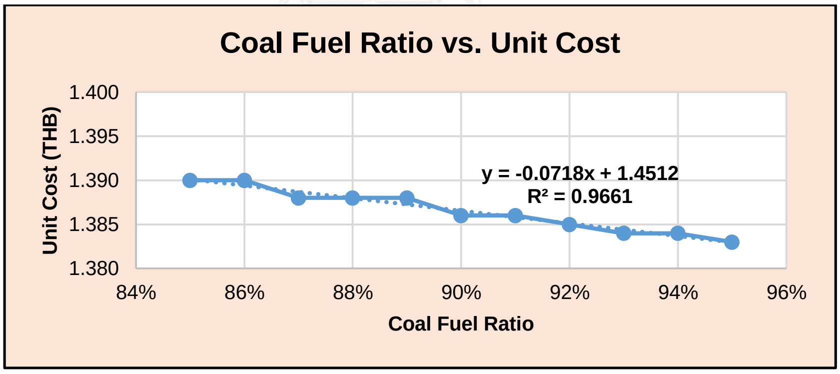


Figure 71: Regression Model for Coal Fuel Ratio and Unit Cost

The relationship between the coal fuel ratio and the unit cost tends to be negative, meaning that the unit cost continually decreases as more coal and less woodchip are used. However, the correlation between the two is positive due to the r^2 value of 0.9661, indicating that approximately 96% of the total variation can be explained by the regression equation. From the regression equation, it is expected that the unit cost will decrease by 0.0718 THB for a 1% increase in the use of coal fuel.

Figure 72 depicts the regression model for the coal fuel ratio and the unit profits from selling electricity and steam to all groups of customers at both times of use. The relationships between the coal fuel ratio and the unit profits are positive correlation (r^2 = 0.9661), indicating that about 96% of the total variation is explained by the regression equation. Considering the coefficients of the regression equations, they are entirely the same at 0.0718. This is similar to the case of coal fuel ratio vs. unit cost, so it can be expected that the profits per unit from selling electricity and steam to all groups of customers at both times of use will increase by 0.0718 THB for a 1% increase in the use of coal fuel.

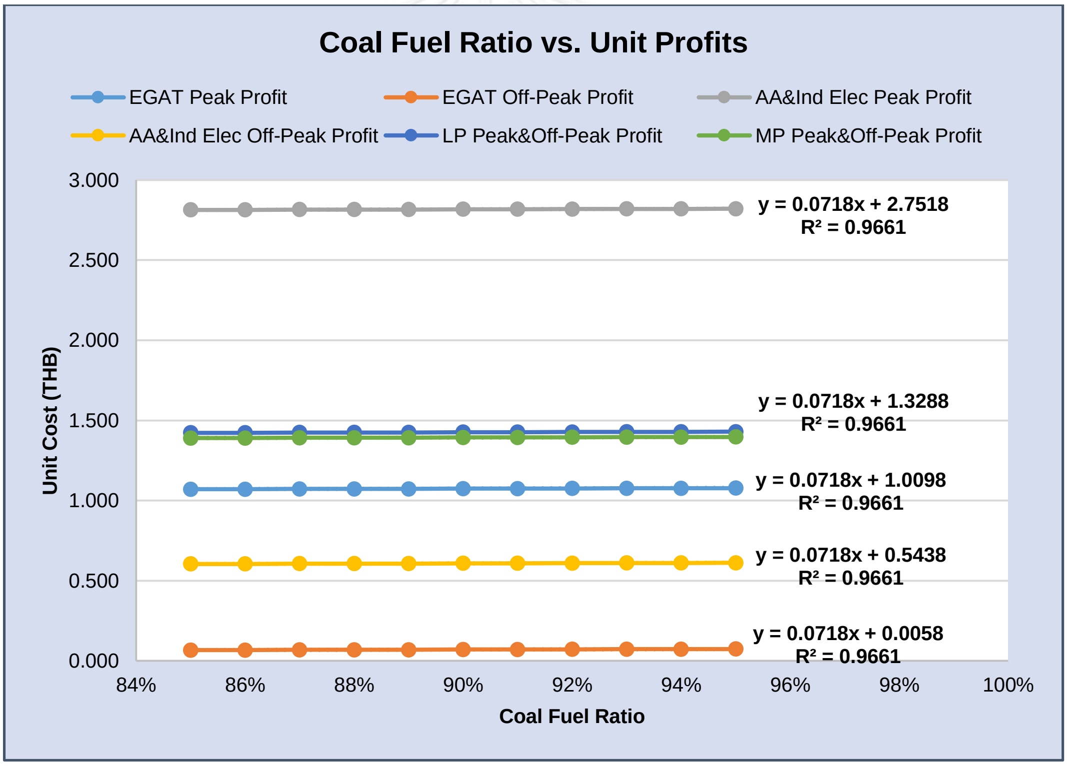


Figure 72: Regression Model for Coal Fuel Ratio and Unit Profits

See Table 44 for the sensitivity results from changes in coal-to-biomass fuel ratio. It is crystal clear that a change in the fuel ratio has very strong effects on the entire set of the parameters. One key benefit from the results allows NPS to know how much of the coal and the woodchip should be mixed optimally. It was found that the optimal and most economic strategy is to mix the fuels using 95% of coal and 5% of woodchip. Apart from this benefit, the company can also gain maximum profit per unit of electricity and steam sold.

Table 44: Sensitivity Results from Changes in Coal-to-Biomass Fuel Ratio

Statistic	Coal: Wood-chip	Unit Cost	Electricity						LP Steam		MP Steam	
			EGAT		AA		Industry		AA		AA	
			Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
			Profit	Profit	Profit	Profit	Profit	Profit	Profit	Profit	Profit	Profit
Max	85 : 15	1.390	1.078	0.074	2.820	0.612	2.820	0.612	1.430	1.430	1.397	1.397
Mean	90 : 10	1.387	1.704	0.070	2.816	0.608	2.816	0.608	1.426	1.426	1.393	1.393
Min	95 : 5	1.383	1.071	0.067	2.813	0.605	2.813	0.605	1.423	1.423	1.390	1.390

4.3.2.5 Sensitivity Analysis of Ft Charge

Figure 73 shows the regression model for the fuel transfer charge and the unit prices. The relationship between the Ft charge and the electricity prices sold to AA and Industry during peak hours is perfect positive correlation (r^2 = 1). For 1 THB increase in the Ft charge, an average 1.0001 THB increase in the profit per unit.

However, the relationship between the Ft charge and the electricity prices sold to AA and Industry during off-peak hours is just moderately positive correlation as the r^2 value is only 0.7145, indicating that approximately 71% of the total variation can be explained by the regression equation. This means that the average profits per unit for off-peak hours are expected to increase by 0.9562 THB for an increase in 1 THB in the Ft charge.

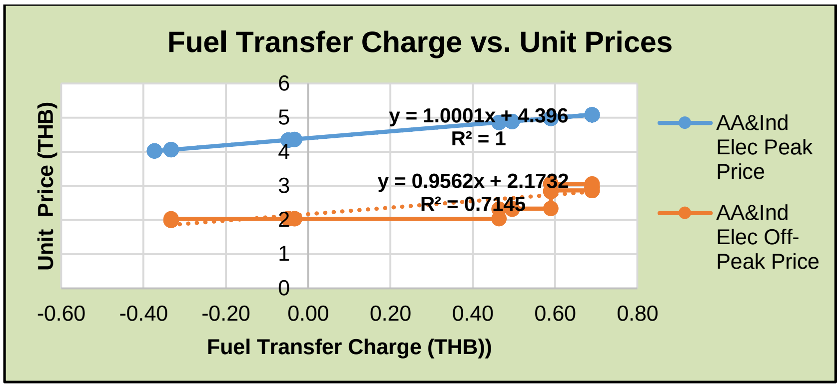


Figure 73: Regression Model for Fuel Transfer Charge and Unit Prices

Figure 74 illustrates the regression model for the fuel transfer charge and the unit profits. The relationships between the fuel transfer charge and the unit profits gained from selling electricity to AA and Industry during peak and off-peak hours are both perfect positive correlation (r^2 = 1). This is similar to the case of Ft charge vs. unit prices during off-peak time. Hence, it can be expected that the profits per unit from selling electricity to AA and Industry at both times of use will increase by about 1 THB when the Ft charge increases by 1 THB. To sum up, the Ft charge has a very strong positive relationship to the profit per unit obtained from selling electricity to AA and Industry in both peak and off-peak hours.

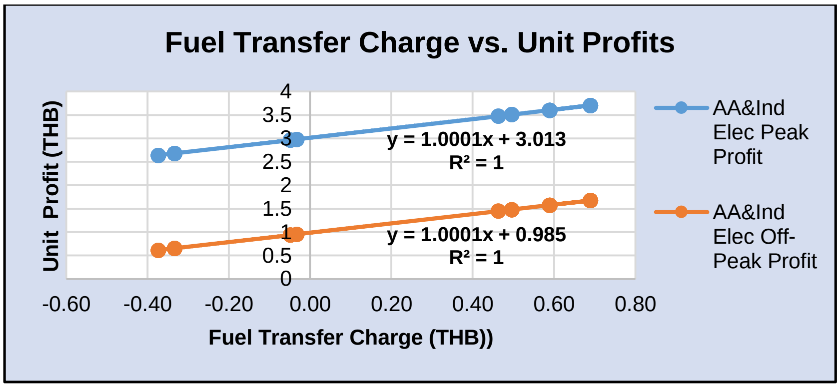


Figure 74: Regression Model for Fuel Transfer Charge and Unit Profits

Considering how sensitive the unit cost, the unit prices and the profits per unit of the electricity sold to AA and Industry in peak and off-peak periods to the variations of Ft charge in Table 45. The Ft charge has no effect on the unit cost since it is not used to estimate the unit cost; however, the electricity prices sold to AA and Industry during both periods strongly depend on the Ft charge. This can be observed from the variations in the prices as they increased if the Ft charge increased, while the profits per unit gained from AA and Industry also varied as the electricity prices varied. For instance, the prices and the profits per unit in peak hours reached 5.086 THB and 3.703 THB, respectively, when the Ft charge reached 0.6900 THB per kWh. On the other hand, the prices and the profits per unit in peak hours lowered to 4.203 THB and 2.640 THB, respectively, when the Ft charge was at minimum of –0.3782 THB per kWh.

Table 45: Sensitivity Results from Changes in Fuel Transfer Charge

Statistic	Ft Charge	Unit Cost	AA				Industry			
			Peak Hours		Off-Peak Hours		Peak Hours		Off-Peak Hours	
			Price	Profit	Price	Profit	Price	Profit	Price	Profit
Max	0.6900	1.383	5.086	3.703	3.058	1.675	5.086	3.703	3.058	1.675
Mean	0.2182	1.383	4.614	3.231	2.586	1.203	4.614	3.231	2.586	1.203
Min	–0.3782	1.383	4.023	2.640	1.995	0.612	4.023	2.640	1.995	0.612

Remark: [1] Monthly data collected from January 2014 to April 2017.

For more sensitivity analysis results of the foreign exchange rate, the coal reference price, the fuel oil reference price, the coal-to-biomass fuel ratio and the Ft charge can be found in Appendix A, and the ANOVA tables for linear regression analysis can be found in Appendix B.

As mentioned earlier that, in practical, the model parameters are simply estimates or best guesses that are subject to change. The operations managers are normally interested in more than the optimal solution to the LP problem, they would like to know how sensitive the answers are to changes in input parameters.

Typically, there are two approaches to determining how sensitive an optimal solution is to changes. One is simply a trial-and-error by resolving the whole problem as previously shown through using the linear regression, but this approach took a long time to investigate a series of possible changes in the identified factors. The second approach is the analytic post-optimality method using Excel Solver when the LP problem has already been solved to find a range of changes in the parameters that will not cause the optimal solution changes.

Figure 75 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 helps a decision maker know if the solution is relatively insensitive to reasonable changes in one or more of the parameters of the problem.

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

Figure 75: Sensitivity Report for Peak Hours under Scenario 1

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 any consequences.

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.

Figure 76 illustrates 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 all 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 that 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.

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

Figure 76: Sensitivity Report for Off-Peak Hours under Scenario 1

4.3.2.6 Summary of Numerical Examples of Sensitivity Analysis

Five influential factors of exchange rate, coal reference price, fuel oil reference price, coal-to-biomass fuel ratio and Ft charge were chosen based on the literatures and interview from the experts to examine how sensitive the profitability is to changes in these key factors. The first approach using linear regression revealed that, in overall, the entire factors have strong effects and positive correlations with the profit because of most extreme r^2 value of 1. Nevertheless, these factors do matter and are influential to the profit differently. For instance, an increase in the exchange rate affects the profit gained from EGAT to increase only during peak hours, while increases in the remaining factors positively result the profit to increase. The second approach is to analyse information from the sensitivity report for both Peak and Off-Peak under Scenario 1 (the most optimal case obtained from *NPS Economic Dispatcher* compared against Scenario 2). The results help the decision makers to investigate a series of possible changes that will not affect the optimal solution of ED management.

4.4 Summary of the Results and Analysis Chapter

In summary, the analytical results and the discussion of three research phases were presented. In Phase 1, the unit cost, the prices, the profits of electricity and steam for each group of customers at different times of use were determined. A number of the estimation process flowcharts were created to help understand the calculation procedure hierarchically. These quantitative determination of unit cost, prices and profits were then used to embed in developing spreadsheet-based program called *NPS Economic Dispatcher* in Phase 2. The underlying objective of this program development is to help make a management decision on economic dispatch of electricity and steam for the dual power plants to achieve the maximum profit. Two feasible scenarios for each time of use, peak hour period and off-peak hour period, towards achieving the optimal profit were simulated using Microsoft Excel. It was found that Scenario 1 is the optimal solution and applicable to both periods since it yielded the total maximum profit and was able to satisfy the power constraints and not severely violate the customers' agreement. This brings to a conclusion that although the best alternative is perhaps when all demands should not be essentially fully met, the maximum profit can be achieved by the power plants with good economic dispatch management.

CHAPTER 5 DISCUSSION

This chapter discusses whether the project objective has been achieved and the research question has been answered. Key research findings, comparisons of the findings with existing literatures, investigation of the findings to support the developed hypothesis, impacts of limitations on validity of the results and recommendations for practicality are critically discussed.

5.1 Overview of the Significant Research Findings

To remind that the research objective is to develop a spreadsheet-based optimisation program for strategically managing economic dispatch (ED) of electricity and steam for the dual power plants to ultimately gain the maximum profit. This objective has been successfully achieved by supportive executions of the following research steps. They are investigating the current status of the production and operations systems, formulating the estimation processes for the unit cost, price and profit of electricity and steam for different customers at different times of use, simulating ED management for profit maximisation, and to identifying and analysing major factors affecting profitability.

The research question has been clearly answered that NPS can strategically manage ED of electric power and steam for the dual power plants to achieve the maximum profit by the aid of the developed program called *NPS Economic Dispatcher*.

After completing the research, here is the summary of the significant findings:

(1) The spreadsheet-based program (*NPS Economic Dispatcher*) was developed for ED management and profit optimality in the power plant business.

(2) The program was basically developed from consolidation of mathematical LP models, literature survey and analytical factors applicable to NPS.

(3) The program was simulated using two comparative scenarios, and the obtained results were validated by a panel of production planning experts in the company.

(4) The best scenario providing the optimal profit is when NPS chooses not to satisfy all electricity demands for EGAT, but under acceptable contractual allowance.

(5) Changes in factors of exchange rate, coal reference price, fuel oil reference price, coal-to-biomass fuel ratio and Ft charge significantly affect the profitability.

(6) The research has generated a user-friendly strategic tool for production planning in dual CHP power plants, unavailable elsewhere, at least in the public domain.

(7) NPS will be able to use this program for strategically managing ED and retaining at much superior profit levels than presently obtained.

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.

Figure 77 and Figure 78 show the revenue and the cost, respectively of electricity and steam by Plant A and Plant B under the best ED solution (Scenario 1), given that their installed capacity accounts for 45.18% of the total (328 out of 726.05 MW, see Table 2), and therefore the revenue and the cost should represent by about the same percent of the installed capacity (see Table 3 and Table 5).

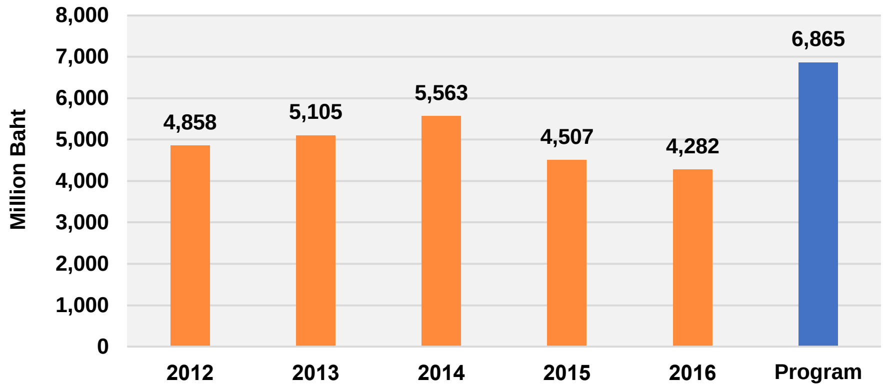


Figure 77: Revenue from Electricity and Steam by Plant A and Plant B

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.

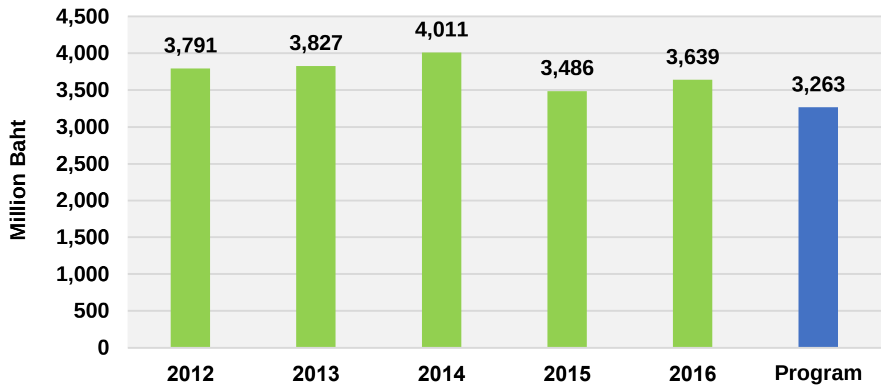


Figure 78: Cost of Electricity and Steam Production by Plant A and Plant B

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.

Figure 79 illustrates the profit received from the sales of electricity and steam. Since 2014, the profit has decreased continuously from 1,552 million THB to only 644 million THB in 2016, decreasing by 58.51%. With the program results, the company's profit should be maximised to 3,552 million THB if Scenario 1 for both peak and off-peak periods is executed.

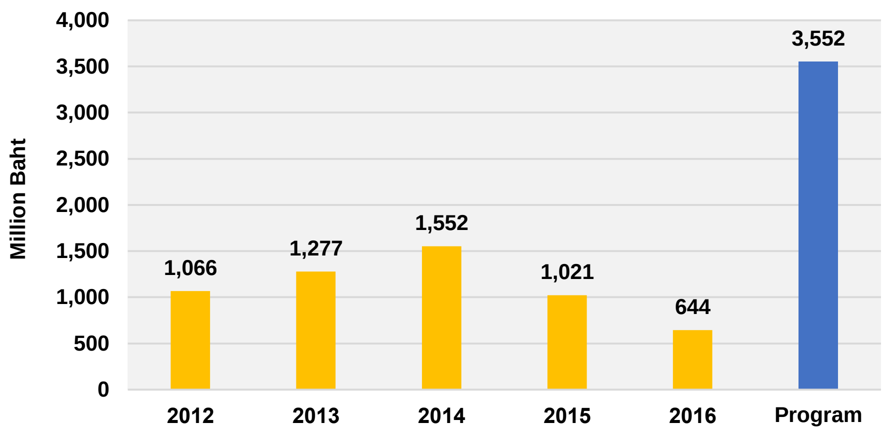


Figure 79: Profit from Electricity and Steam by Plant A and Plant B

Table 46 below summarises the revenue, the cost, the 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 (see the Profit Report in Section 2.3.4.5 of the Results and Analysis chapter for the comparison of profit obtained between Scenario 1 and Scenario 2).

Table 46: 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 47 below shows the revenue per unit, the cost per unit, the 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 47: 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

In addition to profit maximisation, some of the KPIs for measuring operational efficiency could also be greatly improved as depicted in Table 48 in tabular form and in graphical form for Availability Factor, FMO and PMO in Figure 80.

Table 48: Improved Key Performance Indicators for Operational Efficiency

KPI	Unit	2012	2013	2014	2015	2016	Program[3]
Availability Factor[1]	%	83.29	86.02	88.52	84.79	85.70	90.41
FMO[1]	%	5.26	4.03	3.63	6.43	5.38	N/A
PMO[1]	%	11.46	9.95	6.80	7.30	8.92	9.59
EGG[1]	'000 MWh	3,526	3,786	3,930	3,713	3,893	2,360
MCF[2]	%	> 51					~ 25

Remark: [1] Weighted average of the total installed capacity of the company
[2] Indicator determined by the power purchase agreement (PPA)
[3] Research subject (Plant A and Plant B)

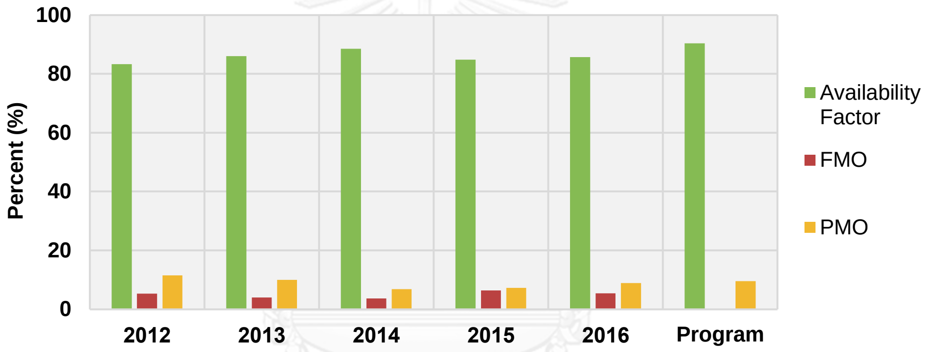


Figure 80: Improved Availability Factor, FMO and PMO by the Program

It can be observed there were improvements in all KPIs, excluding MCF. Given that both Plant A and Plant B operate 330 days a year (about 30 days are scheduled for PMO), the result from the program shows that the availability factor is expected to significantly increase and be the highest compared with the ones in the past years. The PMO is reduced to only 9.59% since the duration is only 30 days when the power plant stops the operations. The expected EGG is relatively high as the installed capacity of both plants is about 45% of the total. Nevertheless, NPS will not be able to retain an MCF of 51% at minimum because non-deliverability of electricity according to the contracted capacity with EGAT.

In terms of how much of electricity and steam should be generated and sold to which of the customers during peak hours and off-peak hours can be discussed using the Economic Dispatch Management Report of Scenario 1 as shown in Table 49.

Table 49: Economic Dispatch Management Report of Scenario 1

Scenario 1		
Time of Use	Peak Hours	Off-Peak Hours
$Electricity_A^{EGAT}$	45.5 MWh	45.5 MWh
$Electricity_B^{EGAT}$	0	0
$Electricity_A^{AA}$	0	0
$Electricity_B^{AA}$	60 MWh	60 MWh
$Electricity_A^{Industry}$	103.5 MWh	103.5 MWh
$Electricity_B^{Industry}$	36.5 MWh	36.5 MWh
$LPSteam_A^{AA}$	0	0
$LPSteam_B^{AA}$	322.5 ton/h	322.5 ton/h
$MPSteam_A^{AA}$	0	0
$MPSteam_B^{AA}$	4.4 ton/h	4.4 ton/h

Overall, Scenario 1 generated the same optimal ED management decision for both times of use. EGAT was 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 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.

5.2 Consideration of the Findings in Light of Existing Researches

Referring to the Literature Review chapter, a number of researches have studied and come up with diverse findings regarding the strategic and operations management in power plants. Some of them developed the managerial and production strategies for power plants (Huang *et al*., 2004; Lazzaretto & Carraretto, 2006;). While, some of them investigated the problems faced by the power plants and proposed the planning (Cerri *et al*., 2009; Kragelund *et al*., 2012), and built the production models under assumptions (Latifoğlu *et al*., 2013).

Considering the existing research studies in the field of ED, it can be obviously seen from Table 17 in Section 2.3.5 of the Literature Review chapter that almost of them aimed to apply ED for minimising either the total fuel cost or the total cost of generation according to the underlying principle of ED by Happ (1977). The findings of those research studies have altogether proven that ED can be used for lowering the cost although different solutions were be applied to solve the ED problems with various constraint characteristics.

There is only one research study by Tsai *et al*. (2015) that was intended to solve the ED problem with the goal of maximising the profit; nevertheless, their operational and power system constraints were relatively holistic and indifferent from those found in common ED problem solving. More importantly, the existing research studies totally relied on complex computation programs to solve ED problems. None of them have produced a comprehensive and user-friendly program that requires minimum computer operation knowledge of users.

This research study, on the other hand, has produced a spreadsheet-based program for ED management that has a user-friendly human interface and needs only minimum knowledge in computer operation and application platform of users (Section 4.2.1). The users are not required to understand the computation algorithm and the complicated data entry procedure, so it should be simple without spending excessive physical and mental efforts while still providing effective results. The developed program was simulated (Section 4.2.3), the simulation results were satisfying since it is capable to help make an ED management decision to achieve maximum profit in the end (Section 4.2.3.5).

The key findings of this study have filled the research gap by applying the underlying principle of ED along with the mathematical LP models (Section 4.2.2.2) as well as proving that ED principle is not only applicable to minimising the total cost of generation, but also to maximising the total profit, especially in the CHP plant system where local constraints are involved and none of the previous research studies have done before (Section 2.3.5). In addition, the results from conducting the sensitivity analysis as one of the significant findings of this research study (Section 4.3.2) also revealed exchange rate, coal reference price, fuel oil reference, mixed-fuels ratio and Ft charge can all have impacts on the profitability before providing recommendations for further practicality (Section 5.5).

5.3 Examination of the Findings and the Developed Hypotheses

Referring to the hypothesis underpinning the research question in Section 1.5 of the Introduction chapter, it is “*NPS strategically manages economic dispatch of electricity and steam for the dual power plants to achieve the maximum profit by virtue of developing a spreadsheet-based optimisation program*”. To elaborately discuss the examination on how the findings summarised in Section 5.1 support the hypothesis, these two phrases of the hypothesis statement need to be separated:

"strategically manages ED of electricity and steam for the dual power plants"

A spreadsheet-based optimization program, namely *NPS Economic Dispatcher*, was developed to help make a management decision on how to economically dispatch electricity and steam produced by the dual power plants under restrictions in terms of power systems, sales contract and regulation. Figure 81 shows the screenshot of NPS Economic Dispatcher.

There are five major areas on the screen as follows:

(1) Objective Function

(2) Constraints

(3) Scenarios

(4) Economic Dispatch Management Report

(5) Profit Report.

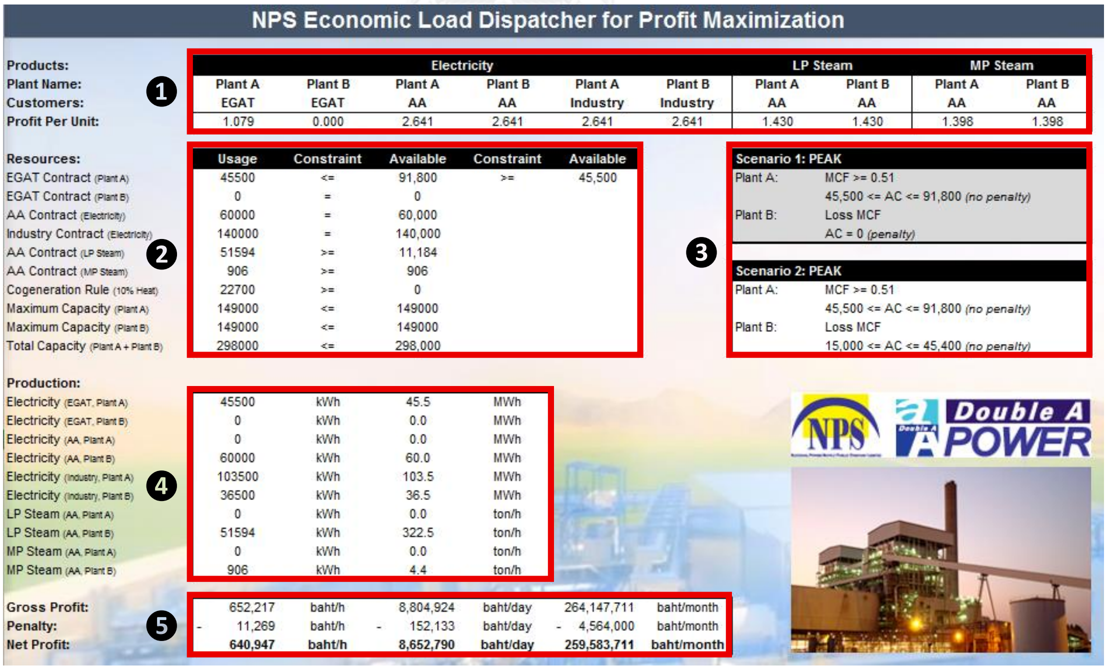


Figure 81: Screenshot of NPS Economic Dispatcher

The program generates an Economic Dispatch Management Report which helps the users to make a decision better how many electricity units and steam units to be produced by which plant before being sold to the customers. For example, 45.5 MWh and 0 MWh of electricity should be produced by Plant A and Plant B, respectively, and sold to EGAT, even EGAT Contracts for both plants allows up to 91,800 kW each to be delivered as indicated in the Constraints under Scenario 1.

Although the program is relatively suitable for operational level, it can be also used by the planning managers to assists them make such decision strategically. Moreover, the users are not required to have high skill in computer operation, but a universal basic software Microsoft Excel is needed that should have already been installed by most enterprises.

"to achieve the maximum profit"

Apart from the Economic Dispatch Management Report, *NPS Economic Dispatcher* also generates a Profit Report showing estimated gross profit, net profit and, if necessary, penalty. The figures of gross profit and net profit are already maximum based on the numbers of electricity units and steam units to be generated and sold to the customers specified on the Economic Dispatch Management Report. In this case, the gross profit expected to be obtained is 264,147,177 THB per month when those numbers of electricity and steam are delivered. However, a penalty fee of 4,564,000 THB is charged by EGAT due to zero *AC* of Plant B, leaving the expected net profit of 259,583,711 THB per month.

Hence, after examining the whole significant findings of the research, it was found out that they altogether successfully support the above hypothesis statement.

5.4 Limitations of the Research on Generalisation of the Results

The limitations on generalization of the results are summarised as follows:

(1) The spreadsheet economic dispatch program for profit maximisation can be directly applicable to Plant A and Plant B of NPS as designed and developed; nonetheless, it could be used by any NPS power plants with modifications of the LP models.

(2) The program was developed using input monthly data gathered in April of 2017, including foreign exchange rate of 34.6251 THB/USD, coal reference price of 61.60 USD/ton, fuel oil reference price of 13.2658 THB/litre, fuels ratio of 95% coal and 5% woodchip and Ft charge of −0.3729 THB/kWh. If any piece of these information changes slightly, the program will generate different results in terms of both ED management solution and profit.

(3) The program was developed based on SPP contract with EGAT where there should not be changes in the SPP regulations, such as minimum 10% of total outputs must be heat instead of pure power. This research is limited to that, so such changes will affect the generalisation of the results.

(4) The estimation process and pricing formula for both LP steam and MP steam are trade secret. The researcher could collect the final numbers of steam prices and entered them into the sheets, so they are constant. Even though they can be changed easily, precision should not be very much.

(5) There might be some variations in terms of the total unit cost and profit per unit since the total unit cost is represented by only variable costs (fuels, consumable raw materials and freight). Nonetheless, the variations should not be significant because such variable costs cover almost of 100% unit cost.

(6) Discount rates are excluded in the profit per unit of all products for all groups of customer in both peak hours and off-peak hours. In reality, there should be the discount rates for some customers under their own contract agreements. Thus, any discount should be considered separately at the end of billing payment.

(7) The final number of electricity and steam outputs are entirely generated from the exact amount of heat energy from mixed fuels before dispatching to each of the customers. This means that heat loss and power loss are neglected in this research study, even the loss is actually very small in the practicality.

5.5 Recommendations for Practical Implementation

The recommendations for practical implementation are summarised as follows:

(1) Coal should be purchased when the market coal price is reasonable and attractive, long-term fuel sourcing should be considered last because the freight cost is not fixed but varies to the number of tons shipped.

(2) The company should maintain the current mixed fuels ratio that is to use 95% of coal and 5% of woodchip as this ratio provides the most economic unit cost, see more details about the sensitivity analysis of coal-to-biomass fuel ratio in Section 4.3.2.4 of the Results and Analysis chapter.

(3) Research and development programs on the energy trees, such as eucalyptus, should be continued to seek for the ones with higher heating values, so that the productivity can be further improved.

(4) The company should consider to sign sales contracts with the customers whose electricity demand is sustainable to minimise the risk of decreased revenue and to reduce the chance of hitting below the break-even point.

(5) A financial instrument should be continually utilised in managing the risk from exchange rate volatility, such as making 1-year buying and selling contracts of forward exchange rate with domestic financial institutions.

5.6 Summary of the Discussion Chapter

In summary, the research objective has been attained. The program can be used as a strategic tool for managing ED while allowing NPS to obtain the optimal profit. The research gap has been filled through applying the basic principle of ED together with the mathematical LP models to prove that the ED is applicable beyond only cost minimisation but also profit maximisation where many local constraints are concerned. The hypothesis is fully supported after the careful examination. The validity and the generalisation of the results limited by the research were clarified, and the recommendations for practicality was proposed at the end. The next chapter will conclude the completion of this research project.

CHAPTER 6 CONCLUSIONS

This chapter concludes what this research project has conducted, discovered and accomplished. These include general research findings, practical challenges and limitations, implications of the research, research contributions and future work.

6.1 General Conclusions

The main objective of this research project is to develop a spreadsheet-based optimisation 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 cogeneration power plants. The company had to excessively stock up the fuels, unintentionally schedule force maintenance outage, encounter decreases in the productivity and choose not to deliver the electrical outputs to some customers. As a consequence, the revenue has been affected and the profit has been declining consecutively for the last few years.

The corporate annual report revealed that electricity and steam is the major source of revenue, ranging from 75% to 90% over the past five years. The decreases in revenue were partially because of the external effects from the monopolised pricing determined by the regulator in the electricity market. Moreover, the business environment is highly dynamic and depends on some holistic economic factors, such as exchange rate, coal price, fuel oil price and more, but NPS and other SPPs are not allowed to directly adjust the selling prices as to the alterations in those volatile macroeconomic factors.

Apart from the decreases in revenue, lack of coordination among the power plants results the cost of goods sold to increase even more units of electricity and steam could be sold over years. This is contrast to what it should have actually been in both theory and real practices. Figure 82 illustrates the comparison between the profit from selling electricity and steam over the last five years and the profit generated by the developed program.

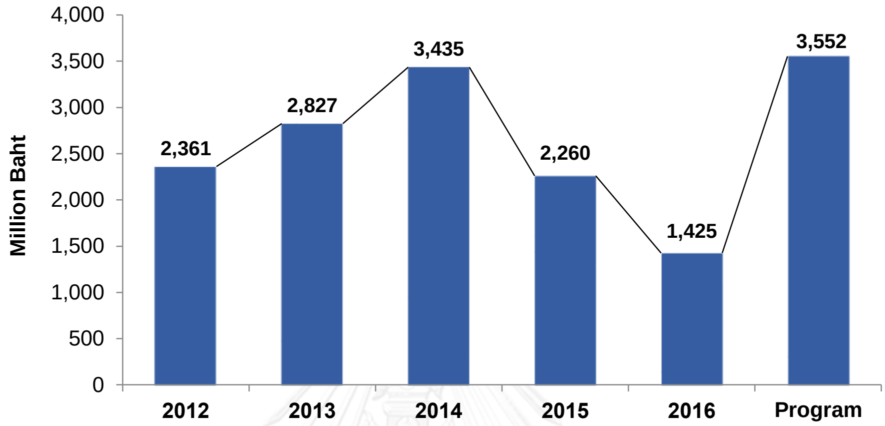


Figure 82: Summary of Profit from Electricity and Steam

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.

This research project was completed successfully as intended. The research method, the results and the conclusions can be summarised in Table 50.

Table 50: Summary of the Research Project Completion

RESEARCH OBJECTIVE	To develop a spreadsheet-based optimisation program for strategically managing economic dispatch of electricity and steam for the dual power plants to ultimately achieve the maximum profit	
Research Method	**Results**	**Conclusion**
Investigating the Current Status of Electricity and Steam Generation and Operations		
• Exploration of the current business operations and strategies • Observation of the current practices and problems by plant visits, meetings, interviews and corporate annual report study • Drawing the electricity and steam generation process diagram	✓ Relatively strong competitive business position (Chapter 1.2.1) ✓ Cost leadership, Miles & Snow's analyser corporate strategies (Chapter 1.2.4) ✓ Electricity and steam generation process diagram (Chapter 1.2.5) ✓ Decreased profit problem and causes were found (Chapter 1.3)	✓ The company is facing with the problem of decreased profit continuously over the past few years (Chapter 6.1) ✓ The decreased profit was mainly due to independent management without economic dispatch consideration (Chapter 6.1)
Formulating Quantitative Determination for Costs, Prices and Profits of Electricity and Steam		
• Literature survey • Collection of required data sets • Drawing the estimation process flowcharts for cost, prices and profits of electricity and steam • Computational procedures for unit cost, prices and profits of electricity and steam	✓ NPS has to rely on the pricing formula for SPP (Chapter 2.1.4) ✓ Revenue, cost, formula, sales contract and parameter data sets are required (Chapter 3.5) ✓ Estimation process flowcharts were drawn and computational procedures were illustrated (Chapter 4.1)	✓ The quantitative determination for costs, prices and profits of both electricity and steam can be used and embedded in to the developed program (Chapter 5.1)
Developing the Spreadsheet-Based Optimisation Program for Economic Dispatch		
• Brainstorming conceptual design • Literature survey on mathematical LP modelling • Coding and debugging the spreadsheets using Microsoft Excel program	✓ Functionality, usability and validity is the conceptual design (Chapter 4.2.1) ✓ Simple LP models were constructed and the program was developed (Chapter 4.2.2)	✓ *NPS Economic Dispatcher* was developed and can be used to management economic load dispatch of the dual power plants (Chapter 5.1 & Chapter 5.3)
Simulating Economic Dispatch Management for Profit Maximisation		
• Creation of plausible comparative scenarios towards profit maximisation achievement • Simulation of the developed program under the plausible comparative scenarios	✓ The program was simulated under two scenarios: - Peak (Scenario 1) - Peak (Scenario 2) - Off-Peak (Scenario 1) - Off-Peak (Scenario 2)	✓ The best scenario towards profit maximisation achievement is to execute Scenario 1 for both Peak Hours and Off-Peak Hours periods (Chapter 5.1)
Identifying and Analysing Major Influential Factors Affecting Profitability		
• Factors specific to power plant business and pricing identified • Examination of the effects of the factors on the profitability	✓ The profitability was strongly affected by changes in exchange rate, coal price, fuel oil price, fuel ratio and Ft charge.	✓ NPS should seek for a mitigation plan arising from such changes in the factors as suggested (Chapter 5.5)

6.2 Practical Challenges and Limitations

NPS Economic Dispatcher was applied in a case study company of the SPP with cogeneration system, where electricity and steam are generated at the same time. In practicality, heat loss is usually occurred during the production process, but in a very small amount. This means that it is relatively easy when planning how much electricity and steam to be produced and sold for maximum profit, but it should also be often difficult to rely on the program and expect that certain amount of input fuels will entirely be converted to the final products. Likewise, in the case of power loss in the transmission and the distribution lines, which results in less electricity to delivered to the final users and eventually causes some variations in the profits obtained between reality and simulation.

Since the program was developed to limit its application for the coal and biomass-fired power plants of NPS, it is therefore not directly applicable to other power plants fuelled by black liquor or even pure biomass within NPS and outsiders without some adjustments. However, the majority of elements is still applicable to other SPPs, particularly the estimation process flowcharts for the electricity prices sold to EGAT during both peak period and off-peak period. Besides, the developed program cannot be effectively used without entering new input data, such as exchange rate, coal price and more, before solving the model. This is because the sets of initial input data embedded in the program is based on the set of data in that particular month.

6.3 Implications of the Research

This research project has filled the gap in the literature by extending the application and underlying principle of ED to maximise the profit from selling electricity and steam by the dual power plants with consideration of local constraints in terms of power system, demand-supply balances and SPP contractual agreements. Based on extensive reading on journals, conference and articles, ED is mostly focused on the goal of minimising total cost instead of maximising profit. The spreadsheet-based economic load dispatch program was developed using Microsoft Excel as it enables the problem in an attractive format for reporting and presentation purposes. The program is intended to assist solve the particular ED problem of decreases in profit and challenges in satisfying the customer demands for electricity and steam without violating the contract agreements.

6.4 Research Contributions

In the context of the research discovery, contributions can be added to both academic perspectives and practical and industrial aspects described as follows:

6.4.1 Academic Contributions

The academic contribution of this research project is a succinct, it is a comprehensive collection of tools, mathematical techniques and methodologies for profit maximisation in the cogeneration power plant business and manufacturing operations in other companies in the energy sector experiencing similar challenges. The general method and techniques applied in this research study can also be used for other types of situations where there is a lack of published know-how, especially in this case where the heat rate, research and development on fuel energy and the profit strategy are closely guarded trade secrets. Last but not least, a this research study and its findings will be complied into a manuscript to be further submitted for publication at a journal and/or a conference.

6.4.2 Practical and Industrial Contributions

The research output in the form of a spreadsheet program acts as a comprehensive strategic tool for economic dispatch management assisting in making a decision on how to optimally deliver electricity and stream to the customers. As a consequence of the program implementation, the revenue of the company from selling electricity and steam is expected to increase while the profit is thereby maximised. Furthermore, managing the production and the operations for the dual power plants can be improved and more effective when the proposed program is utilised in a certain and suitable way. The findings of research study can also be extended to provide an in-depth understanding of profit analysis, so that a set of operations strategies could be developed and in align with the corporate business strategies and other functional strategies across the whole organisation.

Beyond, those practical contributions will also be added towards the advancement of the body of knowledge in the power plant industry. The reason for this is because profit maximisation strategy is typically proprietary and party confidential for the majority of firms in the industry, where know-how and technical expertise is not generally propagated.

6.5 Future Work

A great deal of work remains some rooms for further researches. Up to this point of completing the research project, three future works are proposed as follows:

6.5.1 Extension of the Scope by Covering More or Entire Power Plants

The current program could be extended by including more or all power plants of NPS since their fuels are different from each other. The results of ED management solution from the revised version and the original version could be compared to see whether the ED management of more plants is better and the profit achieved is higher.

6.5.2 Revision of the Model for New Possible Constraints and Scenarios

Due to the dynamic business environment and changing in relevant parameters, the model could be revised by incorporating new constraints. For instance, there is an electricity contract from a new customer or the existing customer's contract terminates, the constraints in the model should be up-to-date to provide timing accurate results. Alternatively, more new scenarios toward achieving optimal profit could be created, simulated, and then compared to the previous ones to investigate which of the scenarios the company should strict to follow.

6.5.3 Development of the Program Using Visual Basic for Applications

As Microsoft Excel is an electronic worksheet which can also be used for a variety of purposes, such as automating the tasks by using Visual Basic for Applications (VBA). Attractive home screen, sub-screens and buttons for presenting ED management and profit reports could be designed using a macro. Also, the macro can also be written to automatically update changing values of parameters, such as exchange rate, coal price, fuel oil price and more, without manual data entry by the program users.

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APPENDICES

Appendix A: Sensitivity Analysis Tables of Major Influential Factors

Table 51: Sensitivity Analysis Table of Exchange Rate vs. Unit Cost & Price & Profit

Month	FX	UNIT COST	UNIT PRICE		UNIT PROFIT									
			EGAT		EGAT		AA Electricity		Industry Electricity		LP Steam		MP Steam	
			Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Jan 2014	32.9975	1.330	2.402	1.433	1.072	0.103	2.873	1.450	1.450	0.665	1.483	1.483	1.450	1.450
Feb 2014	32.6180	1.318	2.388	1.427	1.070	0.109	2.885	1.462	1.462	0.677	1.495	1.495	1.462	1.462
Mar 2014	32.4432	1.312	2.381	1.425	1.069	0.113	2.891	1.468	1.468	0.683	1.501	1.501	1.468	1.468
Apr 2014	32.3033	1.307	2.376	1.423	1.069	0.116	2.896	1.473	1.473	0.688	1.506	1.506	1.473	1.473
May 2014	32.7912	1.323	2.394	1.430	1.071	0.107	2.880	1.457	1.457	0.672	1.490	1.490	1.457	1.457
Jun 2014	32.4550	1.312	2.382	1.425	1.070	0.113	2.891	1.468	1.468	0.683	1.501	1.501	1.468	1.468
Jul 2014	31.9902	1.297	2.365	1.418	1.068	0.121	2.906	1.483	1.483	0.698	1.516	1.516	1.483	1.483
Aug 2014	31.9521	1.296	2.363	1.418	1.067	0.122	2.907	1.484	1.484	0.699	1.517	1.517	1.484	1.484
Sep 2014	32.3733	1.310	2.379	1.424	1.069	0.114	2.893	1.470	1.470	0.685	1.503	1.503	1.470	1.470
Oct 2014	32.5131	1.314	2.384	1.426	1.070	0.112	2.889	1.466	1.466	0.681	1.499	1.499	1.466	1.466
Nov 2014	32.8085	1.324	2.395	1.430	1.071	0.106	2.879	1.456	1.456	0.671	1.489	1.489	1.456	1.456
Dec 2014	32.9630	1.329	2.400	1.433	1.071	0.104	2.874	1.451	1.451	0.666	1.484	1.484	1.451	1.451
Jan 2015	32.7195	1.321	2.391	1.429	1.070	0.108	2.882	1.459	1.459	0.674	1.492	1.492	1.459	1.459
Feb 2015	32.3771	1.310	2.379	1.424	1.069	0.114	2.893	1.470	1.470	0.685	1.503	1.503	1.470	1.470
Mar 2015	32.5551	1.316	2.385	1.427	1.069	0.111	2.887	1.464	1.464	0.679	1.497	1.497	1.464	1.464
Apr 2015	32.8634	1.326	2.397	1.431	1.071	0.105	2.877	1.454	1.454	0.669	1.487	1.487	1.454	1.454
May 2015	33.7359	1.354	2.429	1.444	1.075	0.090	2.849	1.426	1.426	0.641	1.459	1.459	1.426	1.426
Jun 2015	33.7768	1.355	2.430	1.445	1.075	0.090	2.848	1.425	1.425	0.640	1.458	1.458	1.425	1.425
Jul 2015	35.1715	1.400	2.481	1.466	1.081	0.066	2.803	1.380	1.380	0.595	1.413	1.413	1.380	1.380
Aug 2015	35.8696	1.423	2.507	1.476	1.084	0.053	2.780	1.357	1.357	0.572	1.390	1.390	1.357	1.357
Sep 2015	36.3696	1.439	2.525	1.484	1.086	0.045	2.764	1.341	1.341	0.556	1.374	1.374	1.341	1.341
Oct 2015	35.6023	1.414	2.497	1.472	1.083	0.058	2.789	1.366	1.366	0.581	1.399	1.399	1.366	1.366
Nov 2015	35.8944	1.424	2.508	1.476	1.084	0.052	2.779	1.356	1.356	0.571	1.389	1.389	1.356	1.356
Dec 2015	36.0886	1.430	2.515	1.479	1.085	0.049	2.773	1.350	1.350	0.565	1.383	1.383	1.350	1.350
Jan 2016	35.7802	1.420	2.504	1.475	1.084	0.055	2.783	1.360	1.360	0.575	1.393	1.393	1.360	1.360
Feb 2016	35.7252	1.418	2.502	1.474	1.084	0.056	2.785	1.362	1.362	0.577	1.395	1.395	1.362	1.362
Mar 2016	35.2392	1.403	2.484	1.467	1.081	0.064	2.800	1.377	1.377	0.592	1.410	1.410	1.377	1.377
Apr 2016	34.9337	1.393	2.473	1.462	1.080	0.069	2.810	1.387	1.387	0.602	1.420	1.420	1.387	1.387
May 2016	35.7263	1.418	2.502	1.474	1.084	0.056	2.785	1.362	1.362	0.577	1.395	1.395	1.362	1.362
Jun 2016	35.1802	1.401	2.482	1.466	1.081	0.065	2.802	1.379	1.379	0.594	1.412	1.412	1.379	1.379
Jul 2016	34.8754	1.391	2.470	1.461	1.079	0.070	2.812	1.389	1.389	0.604	1.422	1.422	1.389	1.389
Aug 2016	34.6341	1.383	2.462	1.458	1.079	0.075	2.820	1.397	1.397	0.612	1.430	1.430	1.397	1.397
Sep 2016	34.6999	1.385	2.464	1.459	1.079	0.074	2.818	1.395	1.395	0.610	1.428	1.428	1.395	1.395
Oct 2016	35.0210	1.396	2.476	1.463	1.080	0.067	2.807	1.384	1.384	0.599	1.417	1.417	1.384	1.384
Nov 2016	35.6113	1.415	2.497	1.472	1.082	0.057	2.788	1.365	1.365	0.580	1.398	1.398	1.365	1.365
Dec 2016	35.8307	1.422	2.506	1.475	1.084	0.053	2.781	1.358	1.358	0.573	1.391	1.391	1.358	1.358
Jan 2017	35.1908	1.401	2.482	1.466	1.081	0.065	2.802	1.379	1.379	0.594	1.412	1.412	1.379	1.379
Feb 2017	34.8819	1.391	2.471	1.461	1.080	0.070	2.812	1.389	1.389	0.604	1.422	1.422	1.389	1.389
Mar 2017	34.4501	1.377	2.455	1.455	1.078	0.078	2.826	1.403	1.403	0.618	1.436	1.436	1.403	1.403
Apr 2017	34.6251	1.383	2.461	1.457	1.078	0.074	2.820	1.397	1.397	0.612	1.430	1.430	1.397	1.397

Table 52: Sensitivity Analysis Table of Coal Reference Price vs. Price & Profit

Period	Month	Coal Price	UNIT COST	UNIT PRICE		UNIT PROFIT	
				EGAT		EGAT	
				Peak	Off-Peak	Peak	Off-Peak
Jan 2014 - Mar 2014	Jan 2014	$94.06	1.383	2.734	1.730	1.351	0.347
	Feb 2014	$94.06	1.383	2.734	1.730	1.351	0.347
	Mar 2014	$94.06	1.383	2.734	1.730	1.351	0.347
Apr 2014 - Dec 2014	Apr 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	May 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	Jun 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	Jul 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	Aug 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	Sep 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	Oct 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	Nov 2014	$81.03	1.383	2.625	1.621	1.242	0.238
	Dec 2014	$81.03	1.383	2.625	1.621	1.242	0.238
Jan 2015 - Mar 2015	Jan 2015	$81.52	1.383	2.629	1.625	1.246	0.242
	Feb 2015	$81.52	1.383	2.629	1.625	1.246	0.242
	Mar 2015	$81.52	1.383	2.629	1.625	1.246	0.242
Apr 2015 - Mar 2016	Apr 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	May 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Jun 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Jul 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Aug 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Sep 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Oct 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Nov 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Dec 2015	$67.80	1.383	2.513	1.510	1.130	0.127
	Jan 2016	$67.80	1.383	2.513	1.510	1.130	0.127
	Feb 2016	$67.80	1.383	2.513	1.510	1.130	0.127
	Mar 2016	$67.80	1.383	2.513	1.510	1.130	0.127
Apr 2016 - Present	Apr 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	May 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Jun 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Jul 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Aug 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Sep 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Oct 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Nov 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Dec 2016	$61.60	1.383	2.461	1.457	1.078	0.074
	Jan 2017	$61.60	1.383	2.461	1.457	1.078	0.074
	Feb 2017	$61.60	1.383	2.461	1.457	1.078	0.074
	Mar 2017	$61.60	1.383	2.461	1.457	1.078	0.074
	Apr 2017	$61.60	1.383	2.461	1.457	1.078	0.074

Table 53: Sensitivity Analysis Table of Fuel Oil Reference Price vs. Price & Profit

Month	Fuel Oil Price	UNIT COST	UNIT PRICE		UNIT PROFIT	
			EGAT		EGAT	
			Peak	Off-Peak	Peak	Off-Peak
Jan 2014	24.6691	1.383	3.084	2.080	1.701	0.697
Feb 2014	24.6691	1.383	3.084	2.080	1.701	0.697
Mar 2014	24.4993	1.383	3.084	2.080	1.701	0.697
Apr 2014	24.4663	1.383	3.073	2.069	1.690	0.686
May 2014	24.4663	1.383	3.073	2.069	1.690	0.686
Jun 2014	24.3948	1.383	3.069	2.065	1.686	0.682
Jul 2014	24.4279	1.383	3.070	2.067	1.687	0.684
Aug 2014	24.4279	1.383	3.070	2.067	1.687	0.684
Sep 2014	24.4279	1.383	3.070	2.067	1.687	0.684
Oct 2014	24.3286	1.383	3.065	2.061	1.682	0.678
Nov 2014	24.3180	1.383	3.064	2.061	1.681	0.678
Dec 2014	22.1911	1.383	2.948	1.945	1.565	0.562
Jan 2015	20.5106	1.383	2.857	1.853	1.474	0.470
Feb 2015	15.2505	1.383	2.570	1.566	1.187	0.183
Mar 2015	13.1204	1.383	2.453	1.450	1.070	0.067
Apr 2015	22.9231	1.383	2.988	1.984	1.605	0.601
May 2015	18.6239	1.383	2.754	1.750	1.371	0.367
Jun 2015	14.5614	1.383	2.532	1.528	1.149	0.145
Jul 2015	17.6961	1.383	2.703	1.699	1.320	0.316
Aug 2015	15.3059	1.383	2.573	1.569	1.190	0.186
Sep 2015	14.1686	1.383	2.511	1.507	1.128	0.124
Oct 2015	13.4944	1.383	2.474	1.470	1.091	0.087
Nov 2015	10.6613	1.383	2.319	1.315	0.936	-0.068
Dec 2015	16.2316	1.383	2.623	1.619	1.240	0.236
Jan 2016	16.3913	1.383	2.632	1.628	1.249	0.245
Feb 2016	13.0178	1.383	2.448	1.444	1.065	0.061
Mar 2016	21.9632	1.383	2.936	1.932	1.553	0.549
Apr 2016	22.1875	1.383	2.948	1.944	1.565	0.561
May 2016	14.6126	1.383	2.535	1.531	1.152	0.148
Jun 2016	16.9300	1.383	2.661	1.657	1.278	0.274
Jul 2016	16.9300	1.383	2.661	1.657	1.278	0.274
Aug 2016	11.6099	1.383	2.371	1.367	0.988	-0.016
Sep 2016	11.0920	1.383	2.343	1.339	0.960	-0.044
Oct 2016	11.0920	1.383	2.343	1.339	0.960	-0.044
Nov 2016	11.0920	1.383	2.343	1.339	0.960	-0.044
Dec 2016	12.4685	1.383	2.418	1.414	1.035	0.031
Jan 2017	12.4685	1.383	2.418	1.414	1.035	0.031
Feb 2017	12.4685	1.383	2.418	1.414	1.035	0.031
Mar 2017	14.0475	1.383	2.504	1.500	1.121	0.117
Apr 2017	13.2658	1.383	2.461	1.457	1.078	0.074

Table 54: Sensitivity Analysis Table of Coal-to-Biomass Fuel Ratio vs. Unit Cost

Fuel Ratio		UNIT COST				
		Fuel Cost				Total
Coal	Woodchip	Coal	Woodchip	Total	Consumable	Unit Cost
95%	5%	1.201	0.067	1.268	0.015	1.383
94%	6%	1.188	0.081	1.269	0.015	1.384
93%	7%	1.175	0.094	1.269	0.015	1.384
92%	8%	1.163	0.107	1.270	0.015	1.385
91%	9%	1.150	0.121	1.271	0.015	1.386
90%	10%	1.137	0.134	1.271	0.015	1.386
89%	11%	1.125	0.148	1.273	0.015	1.388
88%	12%	1.112	0.161	1.273	0.015	1.388
87%	13%	1.099	0.174	1.273	0.015	1.388
86%	14%	1.087	0.188	1.275	0.015	1.390
85%	15%	1.074	0.201	1.275	0.015	1.390

Table 55: Sensitivity Analysis Table of Coal-to-Biomass Fuel Ratio vs. Unit Price

Fuel Ratio		UNIT PRICE									
		EGAT		AA Electricity		Industry Electricity		LP Steam		MP Steam	
Coal	Wood	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
95%	5%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
94%	6%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
93%	7%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
92%	8%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
91%	9%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
90%	10%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
89%	11%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
88%	12%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
87%	13%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
86%	14%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780
85%	15%	2.461	1.457	4.203	1.995	4.203	1.995	2.813	2.813	2.780	2.780

Table 56: Sensitivity Analysis Table of Coal-to-Biomass Fuel Ratio vs. Unit Profit

Fuel Ratio		UNIT PROFIT									
		EGAT		AA Electricity		Industry Electricity		LP Steam		MP Steam	
Coal	Wood	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
95%	5%	1.078	0.074	2.820	0.612	2.820	0.612	1.430	1.430	1.397	1.397
94%	6%	1.077	0.073	2.819	0.611	2.819	0.611	1.429	1.429	1.396	1.396
93%	7%	1.077	0.073	2.819	0.611	2.819	0.611	1.429	1.429	1.396	1.396
92%	8%	1.076	0.072	2.818	0.610	2.818	0.610	1.428	1.428	1.395	1.395
91%	9%	1.075	0.071	2.817	0.609	2.817	0.609	1.427	1.427	1.394	1.394
90%	10%	1.075	0.071	2.817	0.609	2.817	0.609	1.427	1.427	1.394	1.394
89%	11%	1.073	0.069	2.815	0.607	2.815	0.607	1.425	1.425	1.392	1.392
88%	12%	1.073	0.069	2.815	0.607	2.815	0.607	1.425	1.425	1.392	1.392
87%	13%	1.073	0.069	2.815	0.607	2.815	0.607	1.425	1.425	1.392	1.392
86%	14%	1.071	0.067	2.813	0.605	2.813	0.605	1.423	1.423	1.390	1.390
85%	15%	1.071	0.067	2.813	0.605	2.813	0.605	1.423	1.423	1.390	1.390

Table 57: Sensitivity Analysis Table of Ft Charge vs. Unit Profit & Price & Profit

Period	Month	Ft	UNIT COST	UNIT PRICE				UNIT PROFIT			
				AA Electricity		Industry Electricity		AA Electricity		Industry Electricity	
				Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Jan - Apr 2014	Jan 2014	0.5900	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
	Feb 2014	0.5900	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
	Mar 2014	0.5900	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
	Apr 2014	0.5900	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
May - Aug 2014	May 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
	Jun 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
	Jul 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
	Aug 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
Sep - Dec 2014	Sep 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
	Oct 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
	Nov 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
	Dec 2014	0.6900	1.383	5.086	3.058	5.086	3.058	3.703	1.675	3.703	1.675
Jan - Apr 2015	Jan 2015	0.5896	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
	Feb 2015	0.5896	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
	Mar 2015	0.5896	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
	Apr 2015	0.5896	1.383	4.986	2.958	4.986	2.958	3.603	1.575	3.603	1.575
May - Aug 2015	May 2015	0.4961	1.383	4.892	2.864	4.892	2.864	3.509	1.481	3.509	1.481
	Jun 2015	0.4961	1.383	4.892	2.864	4.892	2.864	3.509	1.481	3.509	1.481
	Jul 2015	0.4961	1.383	4.892	2.864	4.892	2.864	3.509	1.481	3.509	1.481
	Aug 2015	0.4961	1.383	4.892	2.864	4.892	2.864	3.509	1.481	3.509	1.481
Sep - Oct 2015	Sep 2015	0.4638	1.383	4.860	2.832	4.860	2.832	3.477	1.449	3.477	1.449
	Oct 2015	0.4638	1.383	4.860	2.832	4.860	2.832	3.477	1.449	3.477	1.449
Nov - Dec 2015	Nov 2015	-0.0323	1.383	4.364	2.336	4.364	2.336	2.981	0.953	2.981	0.953
	Dec 2015	-0.0323	1.383	4.364	2.336	4.364	2.336	2.981	0.953	2.981	0.953
Jan - Apr 2016	Jan 2016	-0.0480	1.383	4.348	2.320	4.348	2.320	2.965	0.937	2.965	0.937
	Feb 2016	-0.0480	1.383	4.348	2.320	4.348	2.320	2.965	0.937	2.965	0.937
	Mar 2016	-0.0480	1.383	4.348	2.320	4.348	2.320	2.965	0.937	2.965	0.937
	Apr 2016	-0.0480	1.383	4.348	2.320	4.348	2.320	2.965	0.937	2.965	0.937
May - Aug 2016	May 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
	Jun 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
	Jul 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
	Aug 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
Sep - Dec 2016	Sep 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
	Oct 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
	Nov 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
	Dec 2016	-0.3329	1.383	4.063	2.035	4.063	2.035	2.68	0.652	2.68	0.652
Jan - Apr 2017	Jan 2017	-0.3729	1.383	4.023	1.995	4.023	1.995	2.64	0.612	2.64	0.612
	Feb 2017	-0.3729	1.383	4.023	1.995	4.023	1.995	2.64	0.612	2.64	0.612
	Mar 2017	-0.3729	1.383	4.023	1.995	4.023	1.995	2.64	0.612	2.64	0.612
	Apr 2017	-0.3729	1.383	4.023	1.995	4.023	1.995	2.64	0.612	2.64	0.612

Appendix B: ANOVA Tables of the Linear Regression Analysis

Exchange Rate

Table 58: ANOVA Table of Regression Analysis (FX vs. Unit Cost)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 59: ANOVA Table of Regression Analysis (FX vs. EGAT Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.1077	0.1077	1,240,505	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.1077			

Table 60: ANOVA Table of Regression Analysis (FX vs. EGAT Off-Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0178	0.0178	213,353	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0178			

Table 61: ANOVA Table of Regression Analysis (FX vs. EGAT Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0015	0.0015	9,811	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0015			

Table 62: ANOVA Table of Regression Analysis (FX vs. EGAT Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0245	0.0245	119,388	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0245			

Table 63: ANOVA Table of Regression Analysis (FX vs. AA Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 64: ANOVA Table of Regression Analysis (FX vs. AA Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 65: ANOVA Table of Regression Analysis (FX vs. Industry Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 66: ANOVA Table of Regression Analysis (FX vs. Industry Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 67: ANOVA Table of Regression Analysis (FX vs. LP Steam Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 68: ANOVA Table of Regression Analysis (FX vs. LP Steam Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 69: ANOVA Table of Regression Analysis (FX vs. MP Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

Table 70: ANOVA Table of Regression Analysis (FX vs. MP Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.0840	0.0840	1,144,829	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.0840			

<u>Coal Reference Price</u>

Table 71: ANOVA Table of Regression Analysis (Coal Price vs. EGAT Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.2898	0.2898	48,844,406	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.2898			

Table 72: ANOVA Table of Regression Analysis (Coal Price vs. EGAT Off-Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.2890	0.2890	2,095,265	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.2890			

Table 73: ANOVA Table of Regression Analysis (Coal Price vs. EGAT Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.2898	0.2898	48,844,406	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.2898			

Table 74: ANOVA Table of Regression Analysis (Coal Price vs. EGAT Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	0.2890	0.2890	2,095,265	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	0.2890			

Fuel Oil Reference Price

Table 75: ANOVA Table of Regression Analysis (Fuel Oil Price vs. EGAT Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	3.0980	3.0980	1,294,502	< 0.0001
Residual	38	0.0001	0.0000		
Total	39	3.0981			

Table 76: ANOVA Table of Regression Analysis (Fuel Oil Price vs. EGAT Off-Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	3.1008	3.1008	1,397,768	< 0.0001
Residual	38	0.0001	0.0000		
Total	39	3.1009			

Table 77: ANOVA Table of Regression Analysis (Fuel Oil Price vs. EGAT Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	3.0980	3.0980	1,294,502	< 0.0001
Residual	38	0.0001	0.0000		
Total	39	3.0981			

Table 78: ANOVA Table of Regression Analysis (Fuel Oil Price vs. EGAT Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	3.1008	3.1008	1,397,768	< 0.0001
Residual	38	0.0001	0.0000		
Total	39	3.1009			

<u>Coal-to-Biomass Fuel Ratio</u>

Table 79: ANOVA Table of Regression Analysis (Fuel Ratio vs. Unit Cost)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 80: ANOVA Table of Regression Analysis (Fuel Ratio vs. EGAT Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 81: ANOVA Table of Regression Analysis (Fuel Ratio vs. EGAT Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 82: ANOVA Table of Regression Analysis (Fuel Ratio vs. AA Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 83: ANOVA Table of Regression Analysis (Fuel Ratio vs. AA Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 84: ANOVA Table of Regression Analysis (Fuel Ratio vs. Industry Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 85: ANOVA Table of Regression Analysis (Fuel Ratio vs. Industry Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 86: ANOVA Table of Regression Analysis (Fuel Ratio vs. LP Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 87: ANOVA Table of Regression Analysis (Fuel Ratio vs. LP Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 88: ANOVA Table of Regression Analysis (Fuel Ratio vs. MP Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

Table 89: ANOVA Table of Regression Analysis (Fuel Ratio vs. MP Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	2	0.0000	0.0000	256	< 0.0001
Residual	9	0.0000	0.0000		
Total	11	0.0000			

<u>Fuel Transfer Charge</u>

Table 90: ANOVA Table of Regression Analysis (Ft Charge vs. AA Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

Table 91: ANOVA Table of Regression Analysis (Ft Charge vs. AA Off-Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

Table 92: ANOVA Table of Regression Analysis (Ft Charge vs. Industry Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

Table 93: ANOVA Table of Regression Analysis (Ft Charge vs. Industry Off-Peak Price)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

Table 94: ANOVA Table of Regression Analysis (Ft Charge vs. AA Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

Table 95: ANOVA Table of Regression Analysis (Ft Charge vs. AA Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

Table 96: ANOVA Table of Regression Analysis (Ft Charge vs. Industry Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

Table 97: ANOVA Table of Regression Analysis (Ft Charge vs. Industry Off-Peak Profit)

	df	Sum of Squares	Mean Square	*F*	*P* value
Regression	1	7.5535	7.5535	329,012,308	< 0.0001
Residual	38	0.0000	0.0000		
Total	39	7.5535			

GLOSSARY

Actual Capacity the total amount of actual capacity sold to EGAT during peak hours or off-peak hours

Adder an additional buying price paid to generators determined based on fuel types and conditions

Availability Factor the ratio of actual hours of operating a generator, excluding the plant maintenance hours and force maintenance hours, to total hours in a year

Billing Capacity the amount of billing capacity at the end of month

Capacity Payment electricity tariff includes EGAT's investment costs depending on the contractual period with SPP

Combined Heat and Power an electric power plant is capable to generate both electricity and steam simultaneously

Commercial Operation initiation date when a seller starts generating electricity for sale after all testing and commissioning processes have been finished

Consumer Price Index annual price changes in the price level of acquiring a basket of goods and services paid by households

Contracted Capacity the amount of electric power or steam capacity between NPS and the customer

Demineralised Water the water used for the demineralization and cooling process

Electricity Generating Authority of Thailand the leading state-owned power enterprise of Thailand under the Ministry of Energy, which was founded in 1969

Energy Payment the electricity tariff for fuel costs covering generation and maintenance variable cost

Enhanced Single Buyer the model of Thailand's electricity supply industry where EGAT is the only buyer responsible for generating and transmitting electric power for most of the country

Equivalent Gross Generation the total amount of electricity and steam, in an equivalent unit of kWh, over actual hours of operating a generator. The amount of steam included in equivalent gross generation is 10 percent.

Force Maintenance Outage the ratio of the number of force maintenance outage hours, excluding planned maintenance hours, to total hours in a calendar year

Fuel Saving payment is earned when a certain level of cogeneration efficiency is achieved

Fuel Transfer Charge the rate included in an electricity bill, adjusted by a mechanism to reflect actual price of electricity over a specific period of time

Gross Power Output the total amount of electric power generated over actual hours of generator operations

Heat Rate the amount of heat energy from fuel used to generate one unit of electricity

Independent Power Producer a large-scale private power producer with installed capacity of over 90 MW

Metropolitan Electricity Authority the state-owned enterprise responsible for exclusively distributing electricity bought from EGAT to end-users in Bangkok Metropolitan area and two satellite provinces: Nonthaburi and Samut Prakarn

Monthly Capacity Factor the ratio of units of electricity sold to EGAT to the electric energy specified on the contract between NPS and EGAT

National Power Supply a subsidiary company of Double A Power Group whose business is to generate and sell electricity and steam

Output Factor the ratio of total amount of electricity made over actual hours of operating a generator to total amount of electricity to installed generating capacity over actual hours of operating a generator

Plant Maintenance Outage the ratio of the number of planned maintenance hours to total hours in a calendar year

Power Development Plan Thailand's master investment plan for power development

Power Purchase Agreement a legal principle contract between two parties: a seller who generates electricity and a buyer who desires to purchase electricity

Provincial Electricity Authority the state-owned power enterprise responsible for the distribution of electric power purchased from EGAT to end-users in provincial areas

Renewable Energy Promotion adder income under government support to encourage SPPs to employ renewable energy

Request Capacity total amount of electric capacity requested by EGAT more than the amount of contracted capacity during either peak hours or off-peak hours

Small Power Producer the private power producer who uses either cogeneration system or renewable energy technology to produce and sell electricity to EGAT of up to 90 MW for each PPA contract

Time of Use a certain time period of electricity consumption by final users, such as peak hour period or off-peak hour period

Very Small Power Producer the smallest-scale private power producer with installed capacity of less than 10 MW connecting to the national grid system

REFERENCES

APPENDIX

VITA

Sorajak Chanjirawittaya was born on April 6, 1991. He finished a high school degree in science-math program from Triam Udom Suksa School in 2009. In 2013, he completed a Bachelor’s Degree in Engineering Management with honours from Sirindhorn International Institute of Technology, Thammasat University. After graduating, he decided to study a dual degree program to pursue a Master of Engineering in Engineering Management from Faculty of Engineering, Chulalongkorn University and a Master of Science in Engineering Business Management from Warwick Manufacturing Group, the University of Warwick.

Throughout his education life, he has published academic papers in journals and conferences at both international and national arenas as follows:

(1) “Novel Method of Computing Recommended Settings of Notebook Computer and Office Workstation for Ergonomic Work Posture” (2016), Maejo International Journal of Science and Technology

(2) “Spreadsheet-Based Program for Ergonomic Adjustment of Notebook Computer and Workstation Settings” (2015), Journal of Human Ergology, Tokyo, Japan

(3) “Comparison of Work Postures during Notebook Computer Use between User-Preferred and Recommended Workstation Settings” (2013), Proceedings of the 4th International Conference on Engineering, Project, and Production Management (EPPM 2013)

(4) “ErgoNBC – A Computer Program for Recommending Notebook Computer, Workstation, and Accessories Settings” (2013), Proceedings of the 4th International Conference on Engineering, Project, and Production Management (EPPM 2013)