การศึกษาระบบการผลิตพลังงานไฟฟ้าความร้อนร่วมกับระบบการผลิตก๊าซจากวัสดุเหลือทิ้งทางการเกษตรในประเทศไทย

นางสาวสิริวิกร ศิริโยธิพันธุ์

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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STUDY OF BIOMASS-BASED INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) FROM AGRICULTURAL RESIDUES IN THAILAND

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A Thesis Submitted in Partial Fulfillment of the Requirements
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Thesis Title	STUDY OF BIOMASS-BASED INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) FROM AGRICULTURAL RESIDUES IN THAILAND
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สิริวิกร ศิริโยธิพันธุ์ : การศึกษาระบบการผลิตพลังงานไฟฟ้าความร้อนร่วมกับระบบการผลิตก๊าซจากวัสดุเหลือทิ้งทางการเกษตรในประเทศไทย (STUDY OF BIOMASS-BASED INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) FROM AGRICULTURAL RESIDUES IN THAILAND) อ. ที่ปรึกษา: ดร. สุรเทพ เขียวหอม, 138 หน้า.

งานวิจัยนี้ทำการศึกษาระบบการผลิตไฟฟ้าความร้อนร่วมกับระบบการผลิตก๊าซจากชีวมวล ซึ่งเลือกใช้แก๊สซิไฟเออร์ประเภทฟลูอิดไดซ์เบดชนิดบับเบิลแบบเป่าอากาศ ที่สภาวะความดันต่ำ โดยใช้โปรแกรมสำเร็จรูปในการเลียนแบบกระบวนการ โดยในงานวิจัยนี้พิจารณาการใช้วัสดุเหลือทิ้งทางการเกษตรในประเทศไทยซึ่งมีศักยภาพในการใช้เป็นวัตถุดิบป้อน และศึกษาถึงสภาวะการดำเนินงานที่เหมาะสม เพื่อให้เกิดประสิทธิภาพทางความร้อนของการผลิตกระแสไฟฟ้าสูงและมลพิษต่อสิ่งแวดล้อมต่ำ ซึ่งตัวแปรการดำเนินงานที่ทำการศึกษาในครั้งนี้คือ อัตราการป้อนวัตถุดิบ อุณหภูมิของแก๊สซิไฟเออร์ อัตราการป้อนอากาศในแก๊สซิไฟเออร์ และอัตราการป้อนอากาศในกังหันก๊าซ จากผลการศึกษาพบว่า การเปลี่ยนแปลงสภาวะการดำเนินงานของการผลิตกระแสไฟฟ้าความร้อนร่วมกับระบบการผลิตก๊าซส่งผลอย่างชัดเจนต่อประสิทธิภาพทางความร้อน ปริมาณกระแสไฟฟ้าสุทธิ และสมรรถนะด้านสิ่งแวดล้อม การใช้กะลาปาล์มเป็นวัตถุดิบป้อนจะให้ปริมาณกระแสไฟฟ้าสุทธิมากที่สุด และการใช้ฟางข้าวเป็นวัตถุดิบป้อนจะให้ประสิทธิภาพทางความร้อนสูงที่สุด โดยทางเลือกที่ดีที่สุดในงานวิจัยครั้งนี้คือ การเลือกใช้ฟางข้าวเป็นวัตถุดิบป้อนในสภาวะอุณหภูมิของแก๊สซิไฟเออร์ 700-860 °C สัดส่วนอัตราการป้อนอากาศต่ออัตราการป้อนวัตถุดิบในแก๊สซิไฟเออร์ 2.4 เท่า และ สัดส่วนอัตราการป้อนอากาศต่ออัตราการป้อนก๊าซเชื้อเพลิงในกังหันก๊าซ 5 เท่า

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SIRIVIKORN SIRIYOTHIPHAN: STUDY OF BIOMASS-BASED INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) SYSTEM FROM AGRICULTURAL RESIDUES IN THAILAND. THESIS ADVISOR: SOORATHEP KHEAWHOM, Ph.D., 138 pp.

In this work, the production of electricity from biomass-based integrated gasification combined cycle (IGCC) with low pressure air-blown bubbling fluidized bed gasifier is investigated using a multi-criteria analysis framework, where commercial software is used to perform a simulation. We consider potential raw materials based on agricultural residues in Thailand, and operating condition of the IGCC in order to achieve high thermal efficiency with low emissions. The operating variables considered include feedstock flow rate, gasifier temperature, air to gasifer ratio and air to gas turbine ratio. We found that the change of operating condition of IGCC drastically affect to thermal efficiency, net power and environmental performance. Net power obtained from the cycle with palm oil shell feedstock is highest. Rice straw feedstock has highest thermal efficiency. Further, the most promising option is rice straw feedstock with 700-860 °C gasifier temperature, 2.4 air to gasifier ratio and 5 air to gas turbine ratio.

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NOMENCLATURE

ACFB	Atmospheric Circulating Fluidized Bed
BCL/FERCO	Battelle Columbus Laboratory/FERCO
BFB	Bubbling Fluidized Bed
BGL	British Gas/Lurgi
CFB	Circulating Fluidized Bed
CFM	Cubic Feet per Minute
CRRs	Crop-to-Residue Ratios
DEA	Diethanolamine
DGA	Diglycolamine
DOE	Department of Energy
ESPs	Electrostatic Precipitators
EPI	Energy Products of Idaho
FB	Fluidized Bed
GE	General Electric
GTI	Gas Technology Institute
HCN	Hydrogen Cyanide
HR	Infinite impulse response
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MHI	Mitsubishi Heavy Industries
MTCI	Manufacturing and Technology Conversion International
NREL	National Renewable Energy Laboratory
PC	Pulverized Combustion
PCC	Pulverised Coal Combustion
PCFB	Pressurized Circulating Fluidized Bed
PPM	Part Per Million (unit)
PRIMES	Producer Rice Mill Energy Systems
PSI	pound per square inch (unit)
RFTC	Reverse Flow Tar Cracking

SCOT	Shell Claus Off-gas Treatment
SEI	Southern Electric International
TCPDU	Thermochemical Pilot Development Unit
TPD	Tones Per Day (unit)
TPS	Termiska Processor AB

CHAPTER 1

INTRODUCTION

1.1 Importance and Reason of Research

Thailand is facing a critical energy problem due to the increasing of energy consumption and rising of energy prices, Table 1.1 shows the amount of energy consumption, production and importation in Thailand in 2005 [12]. The majority of the power sources are imported. The energy utilization from biomass resources has received considerable attention. The energy obtained from agricultural wastes or agricultural by-products is a form of renewable energy; in principle, utilizing this energy does not add carbon dioxide, which is a greenhouse gas, to the atmospheric environment, in contrast to fossil fuels. Like other biomass wastes, agricultural wastes contain a high amount of organic constituents (i.e., cellulose, hemicellulose and lignin) and possess a high-energy content. Therefore, it can be recognized as a potential source of renewable energy based on benefits of both energy recovery and environmental protection. Due to the lower contents of sulfur and nitrogen in biomass wastes, its energy utilization also creates less environmental pollution and health risk than fossil fuel combustion [28]. While biomass from agricultural residues in Thailand such as byproducts from rice, oil palm, sugar and wood processing mills are plentiful, but using these material as alternative energy sources has not yet much investigated and implemented. Biomass technology includes numerous ways of using organic matter to directly generate power or be processed into fuel [10].

Technologies for transformation and utilization of biomass cover a wide range, from well-established technologies to those in the research stage. All of these technologies have been steadily developed and improved. The biomass conversion technologies have been concentrated in gasification technology, densification technology, pyrolysis technology, combustion technology and biogas technology. Co-generation system is of the biomass technology, and also attractive to many industries from combined heat and power facilities providing process heating and electricity for their own consumption and sell surplus electricity.

Table 1.1 Energy overview in Thailand in 2005.

	Total energy consumption	Energy Production	Value of Import
	(Thousand barrel of crude oil per day)		(million baht)
Total	1,525	742	774,282
Oil	695	114	658,651
Condensate	-	67	-
Natural gas	568	412	63,845
Coal	105	-	15,268
Lignite	125	125	
Hydro Electricity	32	25	6,518

A range of advanced power plant technologies has been developed and continues to be enhanced to make further reductions in the emissions of pollutants and to improve efficiencies such as Pulverized Combustion (PC), Fluidized Bed Combustion and Integrated Gasification Combined Cycle (IGCC). Table 1.2 shows the comparison of various coal combustion technologies. Biomass-based IGCC system has various advantages over other technologies. It can efficiently replace the traditional combustor. Exhaust heat from the gas turbine is used to produce steam for a conventional steam turbine. The steam turbines can be combined with gas turbine into a combined single cycle. An IGCC power system can produce electricity efficiently and cleanly [17].

From the advantages of IGCC that detail above, this study investigates biomass-based IGCC system with low pressure air-blown bubbling fluidized bed gasifier using a multi-criteria analysis framework in order to present a way to improve the energy management system of electricity production. Further, we consider potential raw materials based on agricultural residues in Thailand, and operating condition of the IGCC in order to achieve high thermal efficiency with low emissions.

1.2 Research Objective

To investigate the potential of alternative energy sources from agricultural residues in Thailand and identify suitable raw material and optimizes operating variables to achieve high efficiency of Biomass-based Integrated Gasification Combined Cycle (IGCC) system. Moreover, the effect of variability on various operating parameters related to power and environmental performances is also studied and discussed.

Table 1.2 Coal Combustion Technology Comparisons.

Base Processes	**PCC**	**Supercritical PCC**	**AFBC**	**PFBC**	**IGCC**
Rank (1=Best, 5=Worst)					
Efficiency/GHG Ranking	5	3	4	2	1
Sulphur Removal Ranking	5	4	3	2	1
NO_x Control Ranking	5	4	2	3	1
PM Emission Ranking	5	4	3	2	1
Mercury Emission Ranking	5	4	3	2	1
CO_2 Sequestration Ranking	More Difficult	More Difficult	More Difficult	Less Difficult	Less Difficult
Capital Cost Ranking	1	2	3	4	5
Operating Cost Ranking	5	4	3	2	1
Overall Cost to Produce Ranking	3	2	1	4	5

1.3 Scope of Research

The production of electricity from biomass-based integrated gasification combined cycle (IGCC) system is investigated. This study identifies suitable raw materials which is based on agricultural residues in Thailand, and determines the optimal operating variables, which are type of feedstock, feedstock flow rate, gasifier temperature, air to gasifer ratio, air to gas turbine ratio, to achieve the highest efficiency and the lowest emissions. We consider a low pressure, air–blown bubbling fluidized bed gasification. Aspen Plus [2] is used to perform a simulation in this study.

1.4 Contribution of Research

We present a way to improve the energy management system of electricity production from agricultural residues in Thailand by using the information obtained from the simulation and optimization of the developed mathematical models.

CHAPTER 2

THEORY AND LITERATURE REVIEWS

2.1 Introduction to IGCC

IGCC technology enables the use of solid fuels (coal, petroleum coke, biomass, waste products) or liquids in a thermal power plant, with the efficiency and environmental benefits of combined cycles [6]. This involves the integration of the three technologies. The fuel is gasified using the oxygen or air, and the synthetic gas produced is cooled and exhaustively cleaned of solid particles and contaminants for its combustion in the combined cycle gas turbine. IGCC uses a combined cycle format with a gas turbine driven by the synthetic gas, while the exhaust gases are heat exchanges with water/steam to generate superheated steam to drive a steam turbine. Using IGCC, more of the power comes from the gas turbine. Typically 60-70% of the power comes from the gas turbine with IGCC, compared with about 20% using Pressurized Fluidized Bed Combustion (PFBC). For coal gasification takes place in the presence of a controlled shortage of air/oxygen thus maintaining reducing conditions. The process is carried out in am enclosed pressurized reactor, and the product is mixture of CO and H_2 (called synthesis gas, syngas or fuel gas). The product gas is cleaned and then burned with either oxygen or air, generating combustion products at high temperature and pressure. The sulfur present mainly forms H_2S but there is also a little COS. The H_2S can be more readily removed than SO_2. Although no NO_x is formed during gasification, some is formed when the fuel gas or syngas is subsequently burned. IGCC plants can be configured to facilitate CO_2 capture. The new gas is quenched and cleaned. Syn-gas is shift using steam to convert CO to CO_2., which is then separated for possible long-term sequestration. Comparision of thermal efficiency with PFBC, the driving force behind the development is to achieve high thermal efficiencies together with low levels of emissions. With all power generation routes, it is important to assess and compare thermal efficiencies under normal load following conditions, and not just when the unit is operating under full load. It is hoped to reach efficiencies of over 40%. And possibly as high as 45% with IGCC. Higher efficiencies are possible when high gas inlet temperature to the gas turbine can be achieved. At the moment, the gas cleaning stages for particulates and sulfur removal can only be carried out at relatively low temperatures, which restricts the overall efficiency obtainable. The main incentive for IGCC development has been that units may be able to achieve high thermal efficiencies than Pulverised Coal Combustion (PCC) plant, and be able to match the environmental performance of gas-fired plants. During the development phase, the thermal efficiencies of new PCC plants using superheated steam have also increased. The emissions of particulates, NO_x and SO_2 from IGCC units is expected to meet, and possibly to better, all current standards. On most units, sulfur is produced in elemental form as a by-product [16]. A typical configuration of an IGCC power plant, and its integration possibilities are shown in Figure 2.1.

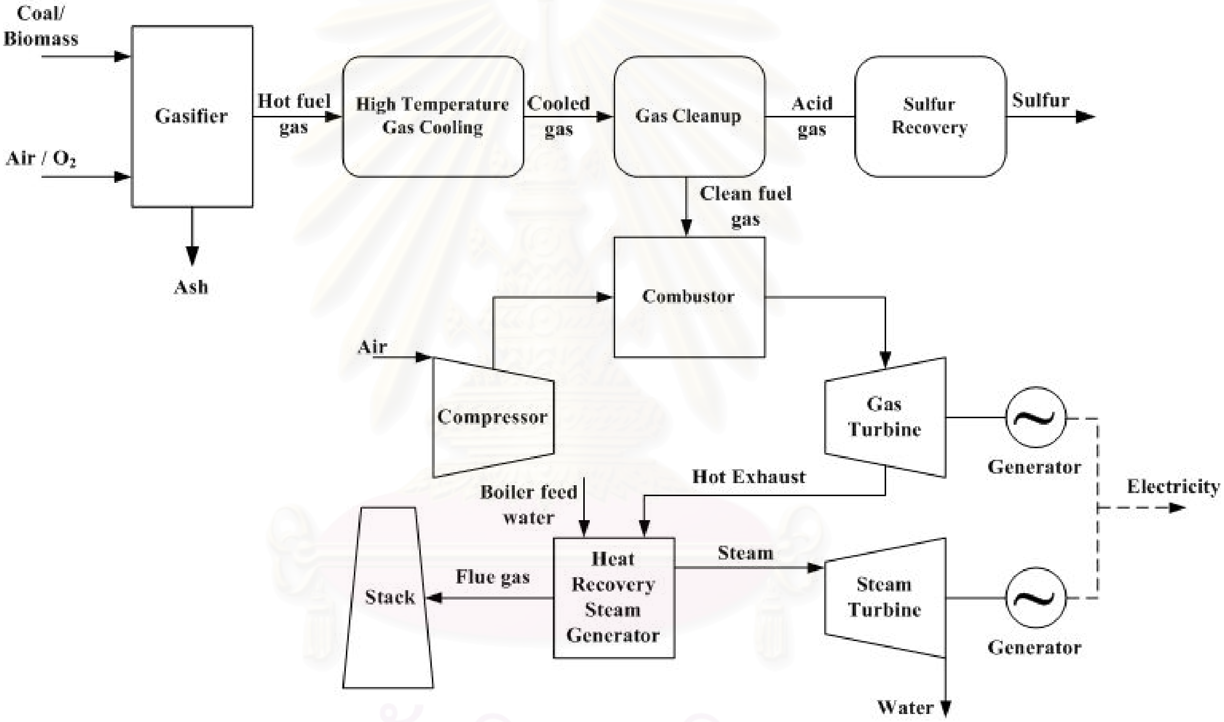

Figure 2.1 Block diagram and integrated options for an IGCC plant.

Table 2.1 Database of IGCC plants

Plant Name	Year	Country	Technology Name	Feed Class	Production (MW)
Delaware Clean Energy Cogeneration Project	2002	United States	GE	Petcoke	160
Wabash River Energy Ltd.	1995	United States	E-GAS (ConocoPhillips)	Petcoke	262
Polk County IGCC Project	1996	United States	GE	Coal	250
api Energia S.p.A. IGCC Plant	2001	Italy	GE	Petroleum	287
ISAB Energy IGCC Project	1999	Italy	GE	Petroleum	512
SARLUX IGCC Project	2000	Italy	GE	Petroleum	551
Buggenum IGCC Plant	1994	Netherlands	Shell	Coal	253
Puertollano GCC Plant	1997	Spain	Krupp Koppers PRENFLO	Coal	335
Lima Energy IGCC Plant	2010	United States	E-GAS (Destec/Dow)	Petcoke	540
Schwarze Pumpe Power/Methanol Plant	1992	Germany		Petroleum	75
Negishi IGCC	2003	Japan	GE	Petroleum	342
Sanghi IGCC Plant	2002	India	GTI U-GAS	Coal	52.5
Schwarze Pumpe Power/Methanol Plant	1964	Germany	Lurgi Dry Ash	Biomass/Waste	75
Americentrale Fuel Gas Plant	2000	Netherlands	Lurgi CFB	Biomass/Waste	85
Schwarze Pumpe Power/Methanol Plant	1999	Germany	BGL	Biomass/Waste	75
Chawan IGCC Plant	2001	Singapore	GE	Petroleum	173
Vresova IGCC Plant	1996	Czech Republic	Lurgi Dry Ash	Coal	350
VÃ¤rnamo IGCC Demonstration Plant	1993	Sweden	Foster Wheeler PCFB	Biomass/Waste	6
Schwarze Pumpe Power/Methanol Plant	1968	Germany	Lurgi Multi Purpose	Petroleum	75
KymijÃ¤rvi ACFBG Plant	1998	Finland	Foster Wheeler ACFB	Biomass/Waste	42
Sulcis IGCC Project	2009	Italy	Shell	Coal	450
Agip IGCC	2006	Italy	Shell	Petroleum	
Fondotoce Gasification Plant	1999	Germany	ThermoSelec	Biomass/Waste	12.5
Mesaba Energy Project	2013	United States	E-GAS (ConocoPhillips)	Coal	530
Schwarze Pumpe Power/Methanol Plant	2000	Germany	BGL	Biomass/Waste	-
Nakoso IGCC	2007	Japan	MHI Air-blown Gasifier	Coal	250
BP Hydrogen Power	2012	United States	GE	Petcoke	630
Edwardsport IGCC	2011	United States	GE	Coal	630
Taylorville Energy Center	2012	United States	GE	Coal	630
Orlando Gasification Project	2010	United States	KBR Transport Reactor	Coal	285

2.2 Description of Biomass IGCC Plant

The biomass-based IGCC electric generating plants considered consist of the following process sections:

- Fuel receiving, sizing, preparation, and drying
- Gasifier and Gas Cleanup (Gasification Island)
    - Gasifier

  - Tar cracker
  - Gas cooling
  - Particulate removal
  - Acid gas removal
- Combined Cycle
- General plant utilities and facilities

2.3 Gasification Island

2.3.1 Definition of Gasification.

Gasification is generally carried out by reacting fuel such as coal, biomass, petroleum coke, or heavy oil, with a restricted amount of oxygen and often in combination with steam. Heat evolved from the exothermic reaction of oxygen with the fuel serves to maintain the gasifier at the operating temperature and drives certain endothermic reaction taking place inside it. Steam can be the sole gasification medium if an external source can provide the heat necessary for the endothermic gasification reactions [22].

Gasification of coal offers certain important advantages over direct combustion. For example, for given throughout of fuel processed, the volume of gas obtained from gasification is much less compared to that obtained from a combustion system. The reduced volume of gas needs smaller equipment, and hence results in lower overall costs. For small capacity power packs, a unit comprised of a gasifier and a compression-ignition engine is less expensive than one comprising a boiler, condenser, steam engine, etc. Thus, gasification provides an attractive option for remote locations.

There is, however, one important shortcoming of the gasifier: the carbon conversion efficiency is rarely 100%. As a result, a useful part of the fuel energy remains in the char. Furthermore, for cold gas application, the sensible heat of the gas could be lost unless a heat recovery system is used.

Clean gas obtained from a gasifier can fuel a large combined cycle system for electricity generation, where the gasified fuel is first burnt in a combustion turbine-generator unit, and then the hot exhaust gas from its gas turbine is used for generating steam to produce further power in a steam turbine-generator unit. The combination of a gasifier and a combined cycle is called the integrated gasification combined cycle (IGCC). Such a system results in greater reduction in emissions from coal-based energy systems compared to that with direct combustion of the coal for power generation. An IGCC system offers a generating efficiency (~ 40%), higher than that for a conventional direct combustion pulverized coal fired plant (~ 34%). The target efficiency of gasification-based combined-cycle electricity generation of the Department of Energy of the United State of America is 52% on HHV basis, which is even higher than the efficiency of modern supercritical pulverized coal-fired plants (~ 40%).

Another emerging application of gas from solid fuels is high-efficiency production of electricity using fuel cells. Coal can be gasified to produce syngas – a gas containing CO and H_2. This gas, after a high degree of purification can be substituted for natural gas in fuel cells, which could help enhance the power generation efficiency to above 50%.

Coal gas can be further converted to transportable liquid fuels, or used in chemical and fertilizer. Thus, as petroleum and natural gas reserves are depleted, coal gasification may emerge as a vital process for developing alternatives to these fuels.

2.3.2 Type of Gasifiers.

Depending upon the gasification medium, gasifier can be broadly classified into two groups:

1. Air blown, where air is the gasification medium
2. Oxygen-blown, where pure oxygen is the gasification medium

Air gasification produces a low heating value (5000 to 6000 kJ/kg or 3 to 6 MJ/m^3, LHV) gas, which contains about 50% nitrogen and can fuel engines and furnaces.

Oxygen blowing is free from diluents like nitrogen. As a result it produces higher (15,000 kJ/kg or 10 to 12 MJ/m^3, LHV) heating value gas, which is, however, still leaner than natural gas typically having a heating value of 50,000 kJ/kg (40 MJ/m^3).

Depending upon how the gas and fuel contact each other, gasifier can be further divided into following three types :

1. Entrained bed
2. Fluidized bed (Bubbling and Circulating)
3. Fixed or moving bed

The following section provides a brief description of each of the above type of gasifers.

- **Entrained Bed Gasifier**

  Entrained-flow systems gasify pulverized fuel particles suspened in a stream of oxygen (or air) and steam. Ash in the coal melts at the high operating temperature of the gasifier and is removed as liquid slag. A number of manufacturers offer commercial entrained-bed gasifiers for large-scale applications, such as Texaco, Shell, and Koppers-Totzek. These gasifiers typically operate at pressure up to 35 bar and use oxygen as the gasifier medium. Many IGCC plants utilize entrained bed gasifiers.

Entrained bed gasifiers are available in much larger capacities (>100 MWe) than other types, but these are more commonly used for fossil fuels like coal, refinery wastes, etc. Their use for biomass gasification is rather limited, as it requires the fuel particles to be very fine (in the order of 80 to 100 μm).

- **Fluidized Bed Gasifier**

In the case of a fluidized bed gasifier , the fuel is gasified in a bed of small particles fluidized by a suitable gasification medium such as air or steam. Fritz Winkler or Gemany, who invented the “fluidized bed” in 1921, built a commercial air-blown fluidized bed gasifier, which was used for powering gas engines in 1926. By 1929, a total of five such gasifier units produced about 100 MW of power. The energy crisis of the 1970s triggered an interest in fluidized bed, which resulted in the development of a new generation of bubbling fluidized bed gasifier. The concern for climate change has increased the interest in biomass gasification for which fluidized bed gasifiers are particularly popular, occupying nearly 20% of their market.

Fluidized bed gasifiers are divided into the following two major types:

  - **Bubbling fluidized bed gasifier**

    A bubbling fluidized bed consists of fine, inert particles of sand or alumina, which have been selected for size, density, and thermal characteristics. As gas (oxygen, air or steam) is forced through the inert particles, a point is reached when the frictional force between the particles and the gas counterbalances the weight of the solids. At this gas velocity (minimum fluidization), bubbling and channeling of gas through the media occurs, such that the particles remain in the reactor and appear to be in a “boiling state”. The fluidized particles tend to break up the biomass fed to the bed and ensure good heat transfer throughout the reactor.

  - **Circulating fluidized bed gasifier**

    Circulating fluidized bed gasifiers operate at gas velocities higher than the minimum fluidization point, resulting in entrainment of the particles in the gas stream. The entrained particles in the gas exit the top of the reactor, are separated in a cyclone and returned to the reactor.

- **Fixed / Moving Bed**

  In a fixed or moving bed gasifier, the gasification medium flows through, and thus comes into contact with, a fixed bed of solid fuel particles. Depending upon the flow direction of the gasifying medium through the bed of fuel, this type of gasifier can be of three types: updraft (medium flows upwards), downdraft (medium flows downward) and sidedraft (fuel is fed from the top and gas flows sideways through it)

  The best-know and most widely used large, moving bed system is the Lurgi gasifier, which has been used in South America for indirect liquefaction of coal since 1955. The technology for building small moving bed gasifiers is more than a century old and was well established by 1999. During the World War II, more than one million such gasifiers were in use in different parts of the world for operating trucks, buses, taxis, boats, trains and other vehicles. Downdraft gasifiers are very popular, especially for biomass gasification. They are typically used for small particles (<1.5 MWth) and occupy more than 75% of the biomass gasification market.

Tables 2.2 compares relative strengths and weaknesses of different types of gasifiers. More detailed comparison of their performance is presented in Table 2.3.

2.3.3 Theory of Gasifier

In typical gasifier the following physicochemical processes take place at temperature indicated within brackets

1. Drying	(> 150 ^{o}C)
2. Pyrolysis (devolatilization)	(150-700 ^{o}C)
3. Combustion	(700-1500 ^{o}C)
4. Reduction	(800-1100 ^{o}C)

Process 1,2 and 4 absorb heat provided by the exothermic combustion process. In the drying process, the moisture in the solid fuel evaporates. The pyrolysis process separate the water vapor, organic liquid and noncondensable gases from the char or solid carbon of the fuel. The combustion process oxidizes fuel constituents in an exothermic reaction, while the gasification process reduces them to combustible gases in an endothermic reaction.

Table 2.2 A Comparison of Fixed, fluidized and Entrained Bed Gasfiers with Specific Reference to Coal Gasification

Strength and Weakness			
Class	**Types**	**Strength/Weakness**	**Power Production**
Fixed bed	(a) Downdraft	Low heating value, moderate dust, low tar	Small to medium scale
	(b) Updraft	Higher heating value, moderate dust, high tar	
	(c) Crossdraft	Low heating value, moderate dust, high tar	
Fluidized bed	Bubbling or Circulating	Higher than fixed bed throughout, improved mass and heat transfer from fuel, higher heating value, higher efficiency	Medium scale
Entrained flow		Can gasify all types of coal, large sensible heat in flue gas, large capacity, involves slagging of ash	

Operational characteristics			
Parameters	**Fixed / Moving bed**	**Fluidized bed**	**Entrained bed**
Feed size	< 51 mm	< 6 mm	< 0.15 mm
Tolerance for fines	Limited	Good	Excellent
Tolerance for coarse	Very good	Good	Poor
Exit gas temperature	450-650 ^{o}C	800-1000 ^{o}C	> 1260 ^{o}C
Feed stock tolerance	Low-rank coal	Low-rank coal and excellent for biomass	Any coal including caking but unsuitable for biomass
Oxidant requirement	Low	Moderate	High
Reaction zone temperature	1090 ^{o}C	800-1000 ^{o}C	>1990 ^{o}C
Nature of ash produced	Dry	Dry	Slagging
Cold gas efficiency	Small capacities	Medium-size units	Large capacities
Problem areas	Tar production and utilization of fines	Car conversion	Raw gas cooling

Table 2.3 Comparison of basic characteristics of different types of gasifiers

	Fixed Beds Types			Fluidized Beds	
	Updraft	Downdraft	Side-Draft	Bubbling	Circulating
Sensitivity to:					
- Fuel specification	Moderate	Specific	Moderate	Flexible	Flexible
- Fuel size	Very good	Good	Good	Fair	Fair
- Moisture content	Very good	Fair	Good	Good	Good
Ash content	Poor	Poor	Poor	Very good	Very good
Reaction temperature	1000 ^oC	1000 ^oC	900 ^oC	850 ^oC	850 ^oC
Fuel mixing	Poor	Poor	Poor	Very good	Excellent
Gas exit temperature	250 ^oC	800^oC	900 ^oC	800 ^oC	850 ^oC
Tar in gas	Very high	Very low	Very high	Moderate	Low
Dust in gas	Good	Moderate	High	Very high	Very high
Turndown ratio	Good	Fair	Good	Very good	Good
Scale-up potential	Good	Poor	Poor	Good	Very good
Start-up facility	Poor	Poor	Poor	Good	Good
Control facility	Fair	Fair	Fair	Very good	Very good
Carbon conversion	Very good	Very good	Poor	Fair	Very good
Thermal efficiency	Excellent	Very good	Good	Good	Very good
LHV od gas	Poor	Poor	Poor	Poor	Fair

2.3.3.1 Pyrolysis or Devolatilization

Pyrolysis (also called partial gasification) was first observed in the 17th century and was later used by Murdoch in 1797 to produce town gas for street lighting, and then by Gesner in 1846 to produce clean, transportable oil homes and other uses. Presently, there is renewed interest in partial gasification for advanced combined-cycle power generation from coal.

A series of complex physical and chemical processes occur during the devolatilization or pyrolysis processes, which start slowly at less than 350 ^oC, accelerating to an almost instantaneous rate above 700 ^oC. The composition of the evolved products is a function of the temperature, pressure, and gas composition during devolatilization. The pyrolysis process is initiated at around 230 ^oC, when the thermally unstable components, such as lignin in biomass, and volatile components. This process can be represented by the following general reaction:

$$\text{Coal (or biomass)} + \text{Heat} \rightarrow \text{Char} + \text{Gases} + \text{Vapors or Liquid} \qquad \text{(R2.1)}$$

The vaporized liquid product contains tar and polyaromatic hydrocarbon (PAH,). The tar, being sticky, represents a great challenge to downstream machines like filter, engines, etc. If the pyrolysis product could be made to pass through a high temperature (1100 to 1200 ^oC) zone, a large fraction of the would break down to smaller hydrocarbons. The heating value of the gas produced in pyrolysis is low (3.5 to 9 MJ/m^3). Pyrolysis generally produces the following three products:

1. Light gases such as H_2, CO, CO_2, H_2O, CH_4
2. Tar, a black, various and corrosive liquid composed of heavy organic and inorganic molecules
3. Char, a solid residue mainly containing carbon

Composition of the pyrolysis product depends on several factors including the temperature and rate of heating. The tar and gas content of coal pyrolysis product increases with temperature up to 900 to 1000 ^oC

2.3.3.2 Combustion

The oxidation or combustion of char is one of the most important chemical reaction taking place inside a gasifier, providing practically all the thermal energy needed for the endothermic reactions. Oxygen supplied to the gasifier reacts with the combustible substances present, resulting in the formation of CO_2 and H_2O, which subsequently undergo reduction upon contact with the char produced from pyrolysis.

$$C + O_2 = CO_2 \text{ (+393.77 kJ / mol carbon)} \qquad \text{(R2.2)}$$

The other combustion reaction is the oxidation of hydrogen in fuel to produce steam.

$$H_2 + \tfrac{1}{2} O_2 = H_2O \text{ (+742 kJ / mol } H_2\text{)} \qquad \text{(R2.3)}$$

2.3.3.3 Gasification

Gasification involved a series of endothermic reaction supported by the heat produced from the combustion reaction described above. Gasification yields combustible gases such as hydrogen, carbon monoxide, and methane through a series of reactions. The following are four major gasification reactions:

i. Water-gas reaction
ii. Boudouard reaction
iii. Shift conversion
iv. Methanation

Brief description of these reactions are given below.

- **Water-Gas Reaction**

Water-gas reaction is the partial oxidation of carbon by steam, which could come from a host of different sources, such as water vapor associated with the incoming air, vapor produced from the evaporation of water, and pyrolysis of the solid fuel. Steam reacts with the hot carbon according to the heterogeneous water-gas reaction:

$C + H_2O = H_2 + CO$ (-13138 kJ/kg mol carbon) (R2.4)

In some gasifiers, steam is supplied as the gasification medium with or without air or oxygen.

- **Boudouard Reaction**

The carbon dioxide present in the gasifier reacts with char to produce CO according to the following endothermic reaction, which is known as the Boudouard reaction:

$CO_2 + C = 2CO$ (-17258 kJ/kg mol carbon) (R2.5)

- **Shift Conversion**

The heating value of hydrogen is higher than that of carbon monoxide. Therefore, the reduction of steam by carbon monoxide to produce hydrogen is highly desirable reaction.

$CO + H_2O = CO_2 + H_2$ (-4198 kJ/mol) (R2.6)

This endothermic reaction, known as water-gas shift, results in an increase in the ratio of hydrogen to carbon monoxide in the gas, and is employed in the manufacture of synthesis gas.

- **Methanation**

Methane could also form in the gasifier through the following overall reaction:

$C + 2H_2 = CH_4$ (+7490 kJ/kg mol carbon) (R2.7)

This reaction can be accelerated by nickel-based catalysts at 1100 ^{o}C and 6 to 8 bar. Methane formation is preferred especially when the gasification products are to be used as a feedstock for other chemical process. It is also preferred in IGCC application due to methane’s high heating value.

2.3.4 Fluidized Bed Gasification

In a fluidized bed gasifier, air and fuel are mixed in a hot bed of granular solids such as sand. Due to the intense gas-solid mixing in a fluidized bed, the different zones -- drying, pyrolysis, oxidation, reduction – cannot be distinguished, but the temperature is uniform throughout the bed. Contrary to fixed bed gasifiers the air-to-fuel ratio can be changed, and as a result the bed temperature can be controlled easily. The product gas will however, always contain some tar, which needs to be removed.

Unlike fixed bed gasifier, which need a fairly specific feedstock, fluidized bed are more tolerant. Updraft moving bed gasifier, however, suffer from high tar yields in the product gases and their inability to maintain uniform radial temperature profiles and to avoid local slagging problems makes the moving bed unsuitable for large installation. fluidized bed, on the other hand, are free from these problems and as a result find wide application in biomass gasification.

A bubbling fluidized bed, however, cannot achieve high solids conversion, due to the back-mixing of solids, The high degree of solid mixing help gasification, but owing to the intimate mixing of fully gasified fuels with partially gasified any waste solid stream will contain some partially gasified solids reducing the solid conversion. Particle entrainment from bubbling bed also contributes to the loss in a gasifier. The other important problem with fluidized bed gasifiers is the slow diffusion of the oxygen from the bubbles to the emulsion phase, which creates oxidizing conditions in the whole bed decreasing the gasification efficiency.

The circulating fluidized bed (CFB) can get around this problem by providing longer solid residence time within its solid circulation loop.

Fluidized bed gasifiers have several advantaged over other types of gasifiers, which include:

1. Higher throughput than fixed bed gasifiers
2. Improved heat and mass transfer from fuel
3. High heating value
4. Reduced char

Another important advantage of fluidized bed gasifiers is that the ash does not melt, which makes its removal relatively simple. A comparison of fluidized bed gasifiers with fixed bed gasifiers is given in Table 2.2.

In a typical fluidized bed gasifier, solid fuel particles are brought into contact with a restricted supply of oxygen by feeding them into an oxygen- or air-starved fluidized bed. The fuel particles are quickly heated to the bed temperature and undergo rapid drying and pyrolysis.

Fluidized bed is especially good for biomass gasification. So far as coal gasification is concerned, fluidized beds have found only limited application because of their low carbon-conversion efficiency, which results from the relatively low bed temperature (800 to 1000^{o}C) needed to avoid ash agglomeration. However, fluidized beds are attractive for other reactive fuels, such as, municipal solid waste and lignite, which can be gasified satisfactorily at lower temperatures compared to high-rank coal.

Since fluidized bed gasifiers operate at relatively low temperatures, most high-ash content fuels, depending on ash chemistry, can be gasified in such beds without the problem of ash sintering and agglomeration. Also, fluidized bed gasifiers can be operated on different types of fuels or a mixture of different fuels. This feature is especially attractive for biomass fuels, such as agricultural residues and wood, that maybe available for gasification at different times of the year. Because of these advantages, a great deal of current development activities on large-scale biomass gasification are focus on fluidized bed technologies.

2.3.5 Comparison of Bubbling and Circulating Fluidized Bed Gasifiers

There are two type of fluidized bed gasifiers: bubbling and circulating. Due to the back-mixing of solids as well as particle entrainment, a single bubbling fluidized bed (BFB) cannot achieve high solid conversion. A circulating fluidized bed (CFB), which is known for is excellent heat and mass transfer and longer residence time, can achieve better conversion. Advantages of CFB over BFB for gasification are listed as follows :

1. High gas-solid slip velocity ensures good mixing and excellent heat and mass transfer.
2. A CFB can process a wider range of feed particles without the penalty of entrainment loss. In a CFB, small particles are converted in singles-pass, or are entrained, separated form the gas, and returned to the gasifier via an external recycke loop. Large particles, which are converted slowly, are recycled internally inside the fast bed until they are small enough for external recycling.
3. High recirculation rate of solids provide CFBs with a solid heating rate higher than that in bubbling fluidized bed, which in turn reduces the tar production during the heating of the fuels.
4. CFBs have less restriction on the size and shape of fuel than that for bubbling or entrained bed gasifiers. For this reason CFB gasifier are preferred for biomass or waste-product gasification.
5. CFBs use relatively fine (< 400 μm) particles. Such fine particles provide the gasification reactions with very large specific gas-solid contact-surface areas.
6. Gas by-passing through the bubbles in a bubbling fluidized bed does not occur in CFB gasifiers. Thus, in a CFB gasifier, excellent gas-solid contact, large contact

surface area, and long residence time all provide favorable conditions for efficient gasification.

7. A CFB gasifier operates at high velocities (4 to 7 m/sec), several times larger than those (1 to 1.5 m/sec) used in a fluidized bed gasifier. Therefore, for a given bed area , one can expect a much larger throughout in a CFB unit. For example, for sawdust a CFB gasifier had a throughput of 28 GJ/m^2/h in compared to 4.5 GJ/m^2/h in a fixed bed.
8. The continuous formation and breakdown of clusters in the fast bed enhances the gas-solid contact and therefore provides good carbon conversion in a CFB boiler.
9. CFB gasifier are easy to scale-up and are reliable over a wider range a feedstock.

2.3.6 Review of Gasification Modeling Research

Nadge Richard and Henrik Thunman [25] founded general equations expressing biomass properties. The biomass was supposed to be pyrolyzed in a temperature range of 573 K -1173 K. Pyrolysis is a thermal decomposition of a product without any oxygen at high temperature (more than 473 K). It gives volatile gases, char and tar. The equations founded for the amount of tar (2.1), the amount of char (2.2) and the composition of char (2.3), (2.4), (2.5) could be considered as reliable and had been checked as being valid for a large variety of biomass.

$$Ytar = 55.19 - 11.5\ T^* - 21.69\ T^* \tag{2.1}$$

$$T^* = (T-833) / 160$$

$$\text{model 1: } Y_{char} = 180 \times \exp[-0.0037 \times (T-273)] \tag{2.2a}$$

$$\text{model 2: } Y_{char} = 90 \times \exp[-0.0027 \times (T-273)] \tag{2.2b}$$

$$\text{model 3: } Y_{char} = 5 / (1 - 1.25 \times \exp[-5 \times 0.0002 \times (T-273)]\ ) \tag{2.2c}$$

$$\text{model 1: } X'_{C,char} = 0.069 \times (T-273) + 28.38 \tag{2.3a}$$

$$\text{model 2: } X'_{C,char} = 98 \times (1 - 0.7 \times \exp[-0.0018 \times (T-273)]\ ) \tag{2.3b}$$

$$\text{model 3: } X'_{C,char} = 98 / (1 + \exp[-98 \times 0.00035 \times (T-273)]\ ) \tag{2.3c}$$

$$\text{model 1: } X'_{H,char} = -0.048 \times (T-273) + 50 \tag{2.4a}$$

$$\text{model 2: } X'_{H,char} = 53 \times \exp[-0.00177 \times (T-273)] \tag{2.4b}$$

$$\text{model : } X'_{O,char} = 25 \times \exp[-0.0027 \times (T-273)] \tag{2.5}$$

when T* is a dimensionless temperature and T the temperature of the reactor in Kelvin.

In addition, many researches [27,24,19] considered tar that produced in gasifier and definition of tar is $C_{10}H_8$. In typically, product composition from gasification reaction that founded in those researches are H_2, CO_2, CO, H_2O, CH_4, C_2H_2, C_2H_4, C_6H_6, Tar ($C_{10}H_8$), NH_3, H_2S and char.

2.3.7 Review of Biomass Gasification Technologies

Jared P. Ciferno and John J. Marano [5] searched on biomass gasification technology was completed to determine the current status of biomass gasification commercialization, identify near-commercial processes and collect reliable gasification data. More than 40 sources, including a number of web sites, provided data. Data were organized into the following four categories: gasification operating conditions, syngas composition, emissions and capital cost that summary in Table 2.4 to 2.6. This information provided a reasonable basis for determining which biomass gasifiers seem most appropriate for any given application.

Moreover, research of HM Associates Inc. was identifying the most likely and least resistant path to commercialization for small-scale integrated gasification systems while meeting environmental constraints [13]. This objective is based on the premise that the development of a commercially acceptable product would lead to evolutionary product improvements over time as commercialization of gas turbine and other energy products have proven. Table 2.7 presented operating parameters and the current status including feedstock used and demonstration and/or commercial plant sizes

Table 2.4 Individual Gasifier Operating Conditions

	EPI	**Stein**	**Tampella**	**ISU**	**GTI**	**SEI**	**Purox**	**Sofresid**
Type	BFB	BFB	BFB	BFB	BFB	BFB	FB	FB
Primary Feedstock	Wood	Wood	Wood	Corn	Wood	Wood	MSW	MSW
Throughput (tonne/day)	100	60	45	4.5	12	181	181	195
Pressure (bar)	1	15	20-23	1	35	1	1	1
Temperature (^{o}C)	650	700-750	850-950	730	816	650-815	-	1300-1400
Reactant 1	Air	O_2	Air	Air	O_2	Air	O_2	Air
Input (kg/kg feed)	2.0	0.6	0.4	-	0.27	1.45	-	-
Reactant 2	-	Steam	Steam	-	Steam	-	-	-
Input (kg/kg feed)	-	0.4	0.5	-	0.64	-	-	-
	TPS	**Aerimp -ianti**	**Foster Wheeler**	**Lurgi**	**Sydkraft**	**BCL / FERCO**[a]	**MTCI**[b]	
Type	CFB	CFB	CFB	CFB	CFB	CFB	BFB	
Primary Feedstock	Wood	RDF	Wood	Bark	Wood	Wood	Pulp	
Throughput (tonne/day)	9	45-100	14.5	84-108	-	24	7	
Pressure (bar)	1	1	1	1	18	1	1	
Temperature (^{o}C)	700-950	850-900	900	800	950-1000	600-1000	790-815	
Reactant 1	Air	Air	Air	Air	Air	Air	-	
Input (kg/kg feed)	-	1.7	1.7	1.25	-	0.08	-	
Reactant 2	-	-	-	-	-	Steam	Steam	
Input (kg/kg feed)	-	-	-	-	-	0.31	2.2	

[a] Indirectly Heated CFB with separate combustor

[b] Indirectly-Heated BFB with separate combustor

[c] Fluid Bed - Entrained Flow (no circulation)

"- " indicates unknown or not reported

Table 2.5 Syngas Compositions Summary

	BFB Range	CFB Range	BCL/ FERCO[a]	MTCI [b]	Fixed Bed Purox	Shell[c]
Feedstock	Various	Various	Wood	Pulp	MSW	Coal
H_2	5-26	7-20	14.9	43.3	23.4	24
CO	13-27	9-22	46.5	9.22	39.1	67
CO_2	12-40	11-16	14.6	28.1	24.4	4
H_2O	<18	10-14	dry	5.57	dry	3
CH_4	3-11	<9	17.8	4.73	5.47	0.02
C_2+	<3	<4	6.2	9.03	4.93	0
Tars	<0.11	<1	-	Scrubbed	-	0
H_2S	~0	~0	-	0.08	0.05	1
O_2	<0.2	0	0	0	-	0
NH_3	0	0	0	0	-	0.04
N_2	13-56	46-52	0	0	-	1
H_2/CO Ratio	0.2-1.6	0.6-1.0	0.3	4.6	0.6	0.36
Heating Value (MJ/m^3)	4-13	4-7.5	18.0	16.7	-	9.51

[a] Indirectly Heated CFB with separate combustor
[b] Indirectly-Heated BFB with separate combustor
[c] Fluid Bed - Entrained Flow (no circulation)
"- " indicates unknown or not reported

Table 2.6 Gasification Capital Costs

Technology Type	Type	Size (tonne/day)	Capital Cost ($ 10^6)	Capital Cost ($ 10^3 /tPD)	Capital Cost ($/GJ/h Syngas)
BFB Range	BFB	170-960	2-36	13-45	21,600-54,900
BFB Average	BFB	615	16.1	25.0	29,500
BCL/FERCO[a]	CFB	740-910	18-26	24.5-28.4	33,000-48,000
MTCI[b]	BFB	44	1.1	25.2	-
Shell Coal Gasifier[c]	-	2,200	80.5	37.3	1,400

2.4 Tar Reforming

If the end use of the gas requires cooling to near ambient temperatures it is possible to use a number of physical removal methods, including wet scrubbing and filtration, to remove tars. Wet scrubbing is an effective gas conditioning process that condenses the tars out of the product gas [8]. This technology is available and can be optimized for tar removal. A disadvantage of wet scrubbing for product gas conditioning is the formation and accumulation of wastewater. This technique does not eliminate tars but merely transfers the problem from the gas phase to the condensed phase. Wastewater minimization and treatment are important considerations when wet scrubbing is used for tar removal. Also, when tar is removed from the product gas stream, its fuel value is lost and the overall efficiency of the integrated gasification process is reduced. These issues associated with wet scrubbing can be reduced when it is used in conjunction with some level of catalytic hot gas conditioning.

If the end use requires that the product gas remain at high temperature, at or slightly below the gasifier exit temperature, then some method of hot gas cleaning will be needed for tar elimination. Wet scrubbing is still an option; however, a severe thermodynamic penalty will result from cooling and reheating the conditioned product gas, reducing the overall efficiency of the process. Hot gas conditioning eliminates tars by converting them into desired product gas components thus retaining their chemical energy in the product gas and avoiding treatment of an additional waste stream. Thermal cracking is a hot gas conditioning option but it requires temperatures higher than typical gasifier exit temperatures (> 1100ºC) to achieve high conversion efficiencies. Increased temperatures for thermal cracking tars can come from adding oxygen to the process and consuming some of the product gas to provide additional heat. Thermal destruction of tars may also produce soot that is an unwanted impurity in the product gas stream.

An attractive hot gas conditioning method for tar destruction is catalytic steam reforming. This technique offers several advantages:

1) catalyst reactor temperatures can be thermally integrated with the gasifier exit temperature

2) the composition of the product gas can be catalytically adjusted

3) steam can be added to the catalyst reactor to ensure complete reforming of tars.

Table 2.7 Key Operating Characteristics Of Gasification Technologies

Reference No, Developer/ Process Name	Reactor Type	Feedstock	Application	Feed Rate (tpd)	Reactor		Reactant	Gas Exit Temperature (^oC)
					Pressure (psi)	Temperature (^oC)		
Wellman Process Engineering	FB	Wood	Engine	10	NA	600-1000	Air/Steam	100
Volund (Ansaldo)	FB	Straw	Heat	13	atm.		Air/Steam	250
Union Carbide (Purox Process)	FB	MSW	IGCC	200		750-1100	Oxygen	180-300
Sofresid-Caliqua	FB	MSW	Steam for district heating and electricity	215	14.5	1300-1400	Hot air	
Gas Technology Institute (GTI)	BFB	Woody biomass	Fuel gas, syngas	3.6-12	479	816	O_2/Steam	816
MTCI	BFB	Pulp, Paper mill sludge, black liqueur, Coal	Steam	200	15	790-815	Steam	
Alternate Gas (Citicorp Ind. Credit)	BFB	Wood Chips	Lime kiln, Boiler and drier fuel	200	14.7	649-815	Hot Air	745-801
Energy Products of Idaho (formerly JWP Energy Products)	BFB	Wood Chips	Steam for power production Methanol	110	14.7	650	Air	621
ASCAB/Stein Industrie	BFB	Wood Chips	production, Electricity (*Process has been abandoned)*	50	220.5	716	Steam/O_2	
Tampella Power Inc.	BFB	Biomass, Coal	Fuel for gas turbines, Boiler fuel	40	290-334	850-950	Air	300-350
BECON (Biomass Energy Conservation Facility)	BFB	Shelled Corn	IGCC	5	14.7	730	Air	
BCL/FERCO	CFB	Wood	Fuel gas (200 considered min. acceptable size)	26-200	15	600-1000	Air /Steam	820
TPS-Thermal Process Studsvik (Studsvik Eneriteknik AB)	CFB	Woody biomass	Fuel gas	13-78	14.7	700-900	Air	
Lurgi Energy	CFB	Bark	Lime kiln firing	120	14.7	800	Air	600
Aerimpianti (subsidiary of Ansaldo)	CFB	RDF	Cement kiln firing	48-110	7.25	850-900	Air	800-900
Foster Wheeler (formerly Ahlstrom)	CFB	Wood	Lime kiln firing, Electricity production	16	14.7	905	Air	700
Sydkraft AB (in cooperation with Foster Wheeler)	CFB	Wood	IGCC - electricity and district heating (6 MWe and 9 MWt)		261	950-1000	Air	

Catalytic reforming of biomass tars is a developing technology for tar removal from syngas streams. The concept of this technology is to reform tar in a fluidized reactor bed, or tar cracker, into lighter gases using a proprietary catalyst. In addition to tar, light hydrocarbons (C_1 to C_5), benzene, and ammonia are also removed. A few large-scale biomass gasification facilities, such as Carbona in Denmark and the FERCO gasifier in Vermont, have demonstrated a novel catalyst in their tar crackers since commercial catalysts are too friable for this application. The FERCO tar cracker removed 90% of the tar in the syngas stream using a novel catalyst known as DN34. In both of these processes, a wet scrubber was used downstream of the tar cracker to remove residual tars and impurities.

A tar cracker known as the Reverse Flow Tar Cracking (RFTC) reactor developed by BTG uses the steam reforming process with a commercial nickel catalyst [14]. The nickel catalyst is very sensitive to sulfur impurities; therefore, a syngas stream containing sulfur contaminants has to be desulfurized prior to entering the RFTC reactor. Due to the cooling requirement for the desulfurization process, the syngas is fed to the reactor at a temperature from 660 -1200 ^oF and is heated to the reaction temperature of 1650 -1740 ^oF in the reactor entrance section. The heated gas passes through a bed of nickel catalyst where tar, light hydrocarbons, and ammonia are removed by steam reforming. The main reactions of the RFTC reactor are:

$C_nH_m + nH_2O \leftrightarrow nCO + (\frac{1}{2}m+n)H_2$ Hydrocarbon reforming (R2.8)

$2NH_3 \leftrightarrow N_2 + 3H_2$ Reverse ammonia synthesis (R2.9)

$CO + H_2O \leftrightarrow CO_2 + H_2$ Water-gas shift (R2.10)

A small amount of the syngas is combusted to counterbalance the endothermic tar reforming reactions:

$H_2 + \frac{1}{2} O_2 \rightarrow H_2O$ (R2.11)

$CO + \frac{1}{2} O_2 \rightarrow CO_2$ (R2.12)

$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$ (R2.13)

The typical conversion for the RFTC reactor is shown in Table 2.8:

Furthermore, simulation from P. Spath et al. [26] and Nexant Inc. [20] used tar reformer was modeled using NREL’s “goal design” reactor conversion for the Thermochemical Pilot Development Unit (TCPDU). Table 2.9 shown the assumed reactor conversion rate as provided by NREL. In the tar reformer operates at 870 ^oC, tars (mono and polyaromatic compounds) and light hydrocarbons such as methane, ethylene, and ethane are converted to H_2 and CO. Ammonia is converted to N_2 and H_2.

Table 2.8 Tar reformer performance of RFTC reactor

Compound	Percent Conversion to CO & H_2
Benzene	82%
Napthalele	99%
Phenol	96%
Total Aromatics	94%
Total Phenols	98%
Total Tar	96%
Ammonia	99%

Table 2.9 Tar reformer performance of NREL's "goal design" reactor

Compound	Percent Conversion to CO & H_2
Methane (CH_4)	80%
Ethane (C_2H_6)	99%
Ethylene (C_2H_4)	90%
Tars (C_{10+})	99.9%
Benzene (C_6H_6)	99%
Ammonia (NH_3)*	90%

* Converts to N_2 and H_2

Syngas exiting the tar reformer enters another cyclone to separate both entrained reforming catalyst and any residual char. The solids are then sent to a catalyst regenerator. The catalyst is sent to a regenerator vessel, where char and residual carbon is combusted. The hot, regenerated catalyst is then recycled back to the reactor vessel, acting as the heat source for the reforming reactions.

2.5 Gas Cleanup

2.5.1 Chemical components of raw syngas

The major components of the syngas at the outlet of an entrained flow slagging gasifier are CO, H_2, CO_2 and H_2O. Some N_2, Ar and small amounts of CH_4 will also be present. This section will consider some of the other components which may be present in the raw syngas to different extents [18].

Sulfur compounds:

The major part (>90 %) of the sulfur components in the feed are converted to hydrogen sulfide (H_2S) and the rest to carbonyl sulfide (COS). Compounds such as SO_x and CS_2 are essentially absent in the syngas. Up to 99.8 % of the coal sulfur can be removed in the acid gas removal process. As COS in not easily removed, a hydrolysis unit (or shift reactor in case of CO_2 capture) is required to convert the COS to H_2S prior to the acid gas removal.

Nitrogen compounds:

Nitrogen enters the gasifier both as molecular nitrogen (supplied with the coal or oxygen stream) and as fuel bound nitrogen. It has been found that gasifiers normally produce some hydrogen cyanide (HCN) and ammonia (NH_3), but negligible amounts of NO_x because O_2 is not in surplus (reducing conditions). It seems that most HCN and NH_3 originate from fuel bound nitrogen and not from the molecular nitrogen which has strong chemical bonds. The proportions of HCN and NH_3 are dependent on the coal characteristics. One should also consider two potential problems with HCN: 1) it can react with amines and degrade it, and 2) it acts as a poison for some catalytic processes (e.g. Fischer-Tropsch synthesis). Both HCN and NH_3 have very high solubilities in water, and may therefore be removed in water scrubbing.

Chlorine compounds:

Most of the chlorine content of the coal will be converted to hydrogen chloride (HCl) gas. Metals in the coal will also form chlorides such as ammonium chloride (NaCl) with melting points in the range 350-800 °C. Chlorine compounds from the coal will also react with ammonia to form ammonium chloride (NH_4Cl) which becomes a solid at around 280 °C. The chlorides may foul the syngas cooler surfaces if not addressed in the design. Much of the chlorides may be removed in a water scrubber.

Solid carbon and ash:

Some amount of char (unconverted carbon) and ash will always be entrained in the exit flow of the gasifier. The quench ensures that these particles will be non-sticky to prevent fouling issues. After capture in a filter or scrubber, these particles may be recycled to the gasifier to increase the carbon conversion efficiency.

Other trace components:

Besides the major components of the coal feed, which is covered by the ultimate analysis, it has been found that a substantial part of the periodic table is represented in coals. Examples of such trace elements which are present at the ppmw level are lead (Pb), mercury (Hg) and arsenic (As). The formation of metal carbonyls such as nickel carbonyl ($Ni(CO)_4$) and iron carbonyl ($Fe(CO)_5$) also seems probable. Also, some hydrogen fluoride (HF) is formed in the gasifier.

2.5.2 Particulate Removal

During the gasification process, the mineral matter contained in the biomass feedstock will form inorganic ash, and the unconverted biomass will form char. These particulates are entrained in the syngas stream as it exits the gasifier. The concentration of particulates produced is often influenced by the gasifier design. These particulates can present emissions problem and can cause abrasion to downstream equipment. Therefore, the particulates concentration must be reduced using various technologies [14,30] discussed in the following paragraphs.

- **Cyclone Separators**

  Cyclones use centrifugal forces to separate the bulk of large size particulates from a gas stream. In gasification systems, cyclones are normally used as the first step in the gas cleanup process. They are relatively inexpensive to manufacture and easy to operate which translate to low capital and maintenance costs. In general, 90-98% of particulates 10 µm or larger in diameter can be removed, but the removal efficiency decreases significantly for smaller particulates .The removal efficiency also decreases as the operating temperatures increases. Cyclones are capable of handling operating temperatures up to 2000^{o}F and can be designed to operate at pressures normally encountered in gasifiers. Cyclones are usually made from carbon steel and are refractory lined to withstand high temperature environments. A flow range from 300 to 13,000 CFM is typical for cyclones. This flow range is within the parameter of the syngas flow rate specified by NREL for this project.

- **Barrier Filters**

  Barrier filters remove particulates by capturing the particulates on the filter surfaces as the gas stream passes through the filter medium. The particulates accumulated on the filter surfaces form a cake, which can be dislodged by initiating a blowback flow. The blowback gas flows in the reverse direction of normal process flow and dislodges the filter cake, which is then removed from the system. Barrier filters include high-temperature filters, such as *ceramic and metal candle filters, and low-temperature filters,* such as *baghouse filters*.

- **Ceramic Candle Filters**

  Ceramic filters are designed to remove particulate matter from gas streams at elevated temperatures. Ceramic filters can be designed for any flow requirement and can remove 90% of particulates larger than 0.3 µm. In theory, the ceramic filter elements, normally made of aluminosilicate or silicon carbide powder with a sodium aluminosilicate binder, have exceptional physical and thermal properties, and should be able to withstand high temperature operations of up to 1800 ^{o}F. However, commercial operations using ceramic filters at this temperature range have not been successful due to the susceptibility of the filter elements to cracking. Advances in composite filter element materials that have resistance to crack propagation at high temperatures are being developed and tested . At temperatures below 850 ^{o}F, ceramic filters have demonstrated satisfactory operational reliability.

  In operations where tars are formed in the gasifier, ceramic filters should be operated at temperatures above the dew point of the tars (usually about 700-750 ^{o}F) to avoid tar condensation. Condensed tar accumulates on filter surfaces and leads to plugging which will reduce the lifetime of the filter and impact process flowrates.

- **Metal Candle Filters**

  Metal filters are used in high temperature cleanup systems to remove particulate matter and can achieve filtration level as low as 1 µm. They can be designed to meet any flow requirement and can operate over a wide range of temperatures depending on the material of construction. Metal filters made from stainless steel can be used in cleanup systems for temperatures below 650 ^{o}F while Inconel or alloy HR filters are suitable for operating temperatures up to 1100 ^{o}F. At even higher temperatures, Fercalloy can withstand temperatures up to 1800 ^{o}F , although commercial operation at this temperature has not been demonstrated. Commercial operation of metal filters operating at a maximum temperature of 915 ^{o}F has been successful at a few gasification facilities in Europe .

Some operational considerations for metal filters are the corrosion rate and tar deposition on filter elements. Under similar stream compositions and conditions, the corrosion rate of metal filter elements is ten times that of the surrounding piping; thus, a regular maintenance schedule is essential to ensure operational reliability. Additionally, in operations where filter elements are subjected to frequent cleaning cycles due to tar deposition, the lifetime of the filter will be reduced. Therefore, it is recommended that the filter be operated at a temperature above the dew point of the tars in the syngas stream to avoid tar condensation and deposition.

- **Baghouse Filters**

Baghouse filters are made of a woven fabric or felted (non-woven) material to remove particulate matter from an air or gas stream and can remove particulates down to 2.5 µm . For woven fabric filters, the removal efficiency increases as the thickness of filter cake increases; thus, the removal efficiency of these systems is constantly changing. Felted filter systems have a constant removal efficiency that does not depend on the thickness of the filter cake . Baghouse filters are modular in design and thus can accommodate a wide flow range from 1,500 to 150,000 CFM. The air-to-cloth ratio, or ratio of the volumetric flow to cloth area, sets the size of a baghouse unit. The bag fabric can be made from various materials including polyester, acrylic, NOMEX, Teflon, Ryton, and fiberglass . The operating temperature range of an application influences the selection of bag material. For example, materials such as polyester or acrylic are suitable for applications with operating temperatures below 300 ^{o}F, while NOMEX, Teflon, Ryton, or fiberglass is recommended for temperatures up to 500 ^{o}F. Due to the temperature limits of the filter fabric, baghouse filters are only used in the low-temperature cleanup systems. They are often used downstream of the cyclones so that the particulate loading on the filters can be reduced.

Disadvantages of baghouse filters include the need for periodic bag replacement that can result in high maintenance costs and the potential for bag fire or explosion. A spark detection and extinguishment system, along with bag grounding strips, are recommended safety measures to mitigate the fire potential. Additionally, the performance of the filter fabrics degrades drastically with tar deposition on the fabric surface, so fabric surface treatments such as Teflon coating and pre-coating with limestone or other compatible filter aids is recommended. Such pre-coats can also be used to adsorb mercury and other contaminants.. Industry experience suggests that either ceramic or metal filters should be used in place of baghouse filters in high temperature operations.

- **Electrostatic Precipitators (ESPs)**

ESPs are commonly used in large power plants to control fly ash emissions. ESPs consist of discharge electrodes centered between positively grounded collection plates. As the gas stream laden with particulates passes through the ESP, the discharge electrodes provide a negative charge to the particulates. The positively grounded collection plates act as a magnet for the negatively charged particulates, which collect on the plates. The collected particulates are transported into the collection hopper by the rapper or vibrator system.

ESPs are classified as either wet or dry processes. In wet ESPs, a water quench is applied either intermittently or continuously to the collection plates. The purpose of the water quench is to prevent possible fires that have occasionally resulted from the use of dry ESPs. The wastewater from wet ESPs must be treated prior to disposal.

For dry ESPs, the removal efficiency decreases for particulates with a high electrical resistivity since these particulates can introduce positive ions into the gas space resulting in reduced attraction of the negatively charged particulates to the collection plates. Particulates with a high resistivity are commonly produced from combustion of low-sulfur coals. Flow ranges of 10,000 – 300,000 CFM are typical for dry ESPs. Dry ESPs operate in the pressure range from vacuum conditions up to 150 psi and can operate at temperatures up to 75 ^{o}F .

Wet ESPs can achieve 99.9% removal of sub-micron particulates down to 0.01 µm. Particulate resistivity does not affect removal efficiency of wet ESPs since the humid operating environment often reduces the resistivity of particulates. These systems are generally designed for gas flow range from 1,000 to 100,000 CFM. Gas streams with particulate sizes larger than 2 µm or with an exceptionally high particulate loading should be pretreated to reduce the load on the ESP. Wet ESPs operate in the pressure range from vacuum conditions up to 150 psi, with operating temperatures limited to 170-190 ^{o}F .

The type of ESP selected for an application is largely influenced by the operating parameter and the type of particulates to be removed. However, the use of ESPs is limited in gasification systems due to the significant capital costs compared to other systems. Additionally, the removal efficiency of ESPs is sensitive to fluctuations in process conditions, such as changes in temperatures and pressures, gas compositions, and particulate loading. Therefore, ESPs are not suitable for biomass gasification applications that have highly variable syngas compositions from different feedstocks.

- **Wet Scrubber**

Wet particulate removal is not as powerful as filters and ESPs when it comes to removal efficiency for sub-micron particles, wet scrubbers are able to effectively remove fine particles and also certain gaseous components from a gas stream by selecting a proper washing liquid. By far the most common is the venturi scrubber.

The capital costs of a wet scrubber are lower than for a baghouse filter or ESP. Operation and maintenance costs, however, are much higher due to high pressure drops and problems related to corrosion, abrasion, solids build-up, failure of rotating parts and re-start problems after a shut-down. Despite the advantage of high inlet gas velocities of ~ 100 m/s, a collection efficiency of ~ 99% overall is obtained with system pressure drops of the order of 1 bar. The latter is less problematic when used in high pressure processes such as PFBC-CC or IGCC.

For conventional power plants as much as 3% of the net output may be needed to operate the wet scrubber, which is also due to the re-heat of the outlet gas to stack conditions.

The major drawback of wet particulate scrubbers is that a gas cleaning problem is transformed in a water treatment problem. Table 2.10 lists the features of different wet particulate scrubbers.

Table 2.10 Typical operating conditions for wet particulate scrubbers

Category	Particle capture mechanism	Type of scrubber	Number of stages	Pressure drop per stage,Pa	Liquid-to-gas ratio,l/m^3
Performed spray	Inertial impaction	Spray towers	1	800-1100	1.3-1.7
		Cyclone spray towers		1000-2000	0.7-1.3
		Vane type cyclonic towers			
Packed bed	Inertial impaction	Standard pack-bed scrubber	1	1300-1600	1.3-2.0
		Moving-bed scrubbers	3-5	800-1300	2.0-8.0
		Cross-blow scrubbers	4	-2500	-2.5
		Fiber-bed scrubbers		50-800	
Tray-type scrubbers	Inertial impaction	Perforated plate		-400	
	Diffusional impaction	Impingement-plate		250-2000	0.4-0.7
		Horizontal impingement plate			
Mechanically aided scrubbers	Inertial impaction	Wet fans	1	1000-2000	
		Disintegrator scrubbers			
Venturi and Orifice scrubbers	Inertial impaction	Standard venture scrubber	1	1000-18000	0.8-2.0
	Diffusional impaction	Variable throat venture (flooded disc, plumb bob, movable blade, radial flow, variable rod)	1		
		Orifice scrubbers	1	800-400	

2.5.3 Acid Gas Removal

Sulfur contaminants such as H_2S, COS, CO_2, mercaptans, and HCN poison catalysts used in liquid fuel synthesis. Therefore, the syntheses of methanol and FT liquids from syngas require that the sulfur be removed from the syngas to a residual level of 0.10 ppm or less. Acid gas removal technologies can be categorized as *amine-based, physical solvent, liquid phase oxidation, or catalytic absorbent processes.* The type of technology selected is largely influenced by the system operating conditions, the sulfur level in the syngas stream, and the desired purity of the treated syngas. Brief descriptions to explain the overall process for each system [14, 30] are given in the following paragraphs.

- **Amine-based system**

Amine processes are proven technologies for the removal of H_2S and CO_2 from gas streams by absorption. Amine systems generally consist of an absorber, a stripper column, a flash separator, and heat exchangers. This is a low-temperature process in which the gas to be treated usually enters the absorber at approximately 110^{o}F. In the absorber, acid gases are removed from the gas stream by chemical reactions with the amine solution. The sweet gas stream exits at the top of the absorber. Regeneration of the rich amine is accomplished through the flash separator to remove absorbed hydrocarbons followed by a stripper column to remove the H_2S and CO_2 from the amine solution. The lean amine solution is cooled and returned to the absorber. The stripped acid gas stream is cooled to recover water and then sent to a sulfur recovery unit.

Amine systems normally operate in the low to medium pressure range of 70-360 psi, although higher pressures can be accommodated with a specific amine solvent. However, in applications where the partial pressure of acid gases is high, the economy of an amine system declines in comparison to other systems. Amine systems can be designed to meet specific flow range and sulfur removal requirements. A sulfur removal level as low as 1 ppm can be achieved but at the expense of operating cost due to the large solvent circulation rate required .

There are a variety of amine solutions available. Each offers distinct advantages based on the specific treating condition. Commercially available amine solutions include :

MEA – Monoethanolamine removes both H_2S and CO_2 from gas streams and is generally used in low-pressure systems and in operations requiring stringent sulfur removal.

DGA – Diglycolamine is used when there is a need for COS and mercaptan removal in addition to H_2S. DGA can hydrolyze COS to H_2S; thus, a COS hydrolysis unit is not needed in the cleanup system.

DEA - Diethanolamine is used in medium- to high-pressure systems (above 500 psi) and is suitable for gas stream with a high ratio of H_2S to CO_2.

MDEA - Methyldiethanolamine has a higher affinity for H_2S than CO_2. MDEA is used when there is a low ratio of H_2S to CO_2 in the gas stream so that the H_2S can be concentrated in the acid gas effluent. If a Claus plant is used for sulfur recovery, a relatively high concentration of H_2S (>15%) in the acid gas effluent is required for optimal Claus operation.

After prolonged use, MEA, DGA, and MDEA solutions accumulate impurities that reduce the H_2S removal efficiency of the solutions. A reclaim unit is needed to remove the impurities in order to improve system efficiency.

One major operating concern for amine systems is corrosion. In water, H_2S dissociates to form a weak acid while CO_2 forms carbonic acid. These acids attack and corrode metal. Therefore, equipment in the amine systems may be clad with stainless steel to improve equipment life.

- **Physical solvent system**

This acid gas removal technology uses an organic solvent to remove acid gases from gas streams by physical absorption without chemical reaction. The driving force of this process is the high solubility of acid gases in the organic solvent. In most cases, solubility increases as the temperature decreases and the pressure increases. Thus, physical absorption is a low-temperature, high-pressure process, with high partial pressure of acid gases required for the economy and efficiency of this process. The temperature of the solvent should be as low as possible while the temperature of the gas to be treated usually enters the absorber at about 100 ^{o}F. Physical solvent systems normally operate at pressures above 150 psi .

In general, physical solvent systems consist of an absorber, a stripper column, a series of flash separators, and heat exchangers. In the absorber, acid gases in the syngas stream are absorbed into the solvent solution. The sweet syngas stream exits the top of the absorber. Regeneration of the rich solvent stream is accomplished through a series of flash separators at reduced pressures to remove absorbed hydrocarbons followed by the stripper column to remove the acid gases from the solvent. The lean solvent solution is cooled and returned to the absorber. The stripped acid gas stream is cooled to recover water and then sent to a sulfur recovery unit.

The two common physical systems are Rectisol and Selexol. The Rectisol process, which uses methanol at temperatures < 32 ^{o}F, can achieve a sulfur removal level as low as 0.1 ppm. The Selexol process, which uses mixtures of dimethyl ethers of polyethylene glycol, can achieve a sulfur removal level of 1ppm .

Selection of material of construction depends on the solvent used. For example, stainless steel is required for much of the Rectisol process equipment, contributing to a significant capital cost. In the Selexol process, carbon steel is the standard material of construction, except for those areas with high severity where stainless steel will be used.

The choice for physical sorbent or amine-based (chemical sorbent) processes depends on the gases that are to be removed (H_2S and/or CO_2 plus others, such as NH_3, HCN, water), the required selectivity and the allowable energy input. Chemical sorption involves a stronger bond between the species that may require more energy (*i.e.* steam) during the regeneration step. The most common use of physical solvent processes is for bulk removal of carbon dioxide or selective H_2S removal. Sorbents for physical solvent are expensive. chemical sorbent processes are mainly based on alkanolamines (“amines”), used in aqueous solutions (15 - 50%) to absorb H_2S and CO_2. For H_2S the reactions with all amines are very fast; for CO_2 the reactions are much slower. Carbonyl sulphide (COS), which often accompanies H_2S is not removed very well by amines, and it is therefore usually catalytically hydrolyzed to H_2S and CO_2 at low temperatures.

- **Liquid phase oxidation process - LO-CAT^{TM}**

LO-CAT^{TM} is an oxidation process that uses iron catalyst held in a chelating agent to oxidize H_2S to elemental sulfur. H_2S is the only acid gas being removed in this process but a high CO_2 concentration in the feedgas requires caustic for pH adjustment. A LO-CAT^{TM} process consists of 3 sections that include an absorber, an oxidizer for catalyst regeneration, and a sulfur handling unit. When the gas stream comes in contact with the LO-CAT^{TM} solution in the absorber, H_2S in the gas stream is converted to elemental sulfur. The spent catalyst along with the elemental sulfur exit the absorber, then enter the oxidizer where the spent catalyst is regenerated by contact with oxygen in air, and the elemental sulfur is concentrated into a sulfur slurry. The sulfur slurry moves to the sulfur handling unit where it is washed to recover any entrained catalyst. The sulfur recovered from a LO-CAT^{TM} process contains a small amount of entrained residual catalyst and is considered low-value sulfur that is suitable for agricultural purposes but is undesirable as a chemical feedstock.

The LO-CAT^{TM} process is suitable for small-scale applications that require less than 20 TPD of sulfur recovery capacity, making the LO-CAT^{TM} a candidate process for this study, which has less than 5 TPD of sulfur recovery. This process can achieve 99.9%+ of H_2S removal efficiency . This process can operate over a wide range of pressures from atmospheric up to 600 psi, but most are low-pressure applications in amine acid gas service. The operating temperature is normally maintained at about 110 ^{o}F since high temperatures degrade the LO-CAT^{TM} solution that can affect removal efficiency. Advantages of this process include the ability to treat a wide range of gas compositions, a significant turndown flexibility, and less capital costs in comparison to the Claus process with the associated tail gas treating unit.

Since LO-CAT^{TM} only removes H_2S, a COS hydrolysis unit upstream of the LO-CAT^{TM} is needed to hydrolyze any COS in the gas stream to H_2S. Other acid gases, such as HCN and mercaptans, would have to be removed by wet scrubbing.

The standard material used for LO-CAT^{TM} systems is stainless steel. Under certain conditions where there is build-up of chloride ions from the feed gas, FRP (fiberglass reinforced plastic) material is used to provide added stability for the stainless steel components .

- **Catalytic absorbent—ZnO**

ZnO is often used as a polishing step for sulfur removal in gas streams where the sulfur level is below 20 ppmv. In a traditional purification system, ZnO is used in conjunction with hydrogenation catalysts based on cobalt, molybdenum and nickel. This system involves the hydrogenation of sulfur compounds such as mercaptans to H_2S, and halides such as chlorides to HCl. These compounds are then reacted with the ZnO absorbent where H_2S is converted to zinc sulfide, and HCl forms a stable chloride. Additionally, ZnO also removes COS by hydrolysis to form H_2S which is then adsorbed to form zinc sulfide. The general reactions are summarized below :

Hydrogenation reactions:

$$RSH + H_2 \rightarrow RH + H_2S \quad (R2.14)$$

$$RCl + H_2 \rightarrow RH + HCl \quad (R2.15)$$

Reaction with ZnO:

$$ZnO + H_2S \leftrightarrow ZnS + H_2O \quad (R2.16)$$

$$ZnO + COS \leftrightarrow ZnS + H_2O \quad (R2.17)$$

A sulfur removal below 50 ppm is attainable with ZnO. Since the sulfur specifications for alcohols and FT liquids are 0.10 ppm or less, ZnO will be used to achieve these requirements. However, a hydrogenation reactor will not likely be required since the syngas stream given by NREL does not contain halogens or any other sulfur compounds other than H_2S.

ZnO is active over a wide range of temperatures from ambient to 750 ^{o}F; however, operating temperatures range between 660 ^{o}F and 750 ^{o}F are normally used to maximize absorption efficiency. Operating pressure limits are not a concern for the use of ZnO absorbent. The ZnO reactor is normally constructed from carbon steel clad with stainless steel to prevent corrosion caused by acid gases.

One drawback of this process is the significant operating costs contributed by frequent replacement and disposal of ZnO absorbent since it cannot be regenerated.

- **H_2S control by the Claus process**

In the Claus process H_2S is oxidised to sulphur and water. It is a very important process for the treatment of the concentrated H_2S streams (preferably > 50..60%) that result from oil and natural gas processing, *i.e.* typically from amine sorption. The Claus reaction is

$2H_2S + O_2$ W $2/x\ S_x\ (s) + 2H_2O$ (R2.18)

The same result is obtained by oxidation of a of the incoming H_2S, and mixing it with the rest:

$2\ H_2S + O_2$ W $SO_2 + 2\ H_2O$ (R2.19)

$2\ H_2S + SO_2$ W $3/x\ S_x\ (s) + 2\ H_2O$ (R2.20)

Other reactions taking place, depending on the presence of CO_2 and NH_3 are

H_2S W $H_2 + 1/x\ S_x\ (s)$ (R2.21)

$H_2S + CO_2$ W $H_2O + COS$ (R2.22)

$COS + H_2S$ W $H_2O + CS_2$ (R2.23)

$2\ NH_3 + 3\ O_2$ W $2\ NO + 3\ H_2O$ (R2.24)

Depending on the concentration of the H_2S, three types of Claus processes can be distinguished:

I. > 50 % H_2S in the gas Straight-through Claus process

II. 15...50 % H_2S in the gas Split-flow Claus process

III. < 15 % H_2S in the gas Direct oxidation Claus process

A catalyst is used to reach high conversions with sufficient speed: typically an activated alumina, activated bauxite or cobaltmolybdenum hydrogenation catalyst are used. The process involves a partial oxidation step with air at 1000 – 1400 ^{o}C, followed by cooling in a waste heat boiler where also liquid sulphur product is obtained. After cooling to 200 – 350 ^{o}C the gas is led to the catalytic Claus reactor. Since a single Claus stage does not give sufficient H_2S conversion, two- or three-stage processes are used which give conversions of ~ 95 % and ~97 %, respectively. Several improvements give conversions higher than that: the Superclaus 99 and 99.5 process give corresponding %-conversions by using special catalysts (preventing the formation of SO_2) and a separate hydrogenation reactor between the second and third stage. Oxygen enrichment of the air to the burner in the final Claus stage improves flame stability and reduces soot formation and poisoning of the catalyst beds.

For gases containing ammonia, burner modifications and/or air enrichment with oxygen are applied to prevent the formation of ammonium salts, e.g. the Oxyclaus process. In general this gives higher burner temperatures of ~ 1500 °C.

For the tail-gas cleanup, the SCOT (Shell Claus Off-gas Treatment) process is often used, which is based on oxidation of all remaining sulphur to SO_2 and returning that to the inlet of the Claus unit.

2.5.4 Ammonia Removal

Two methods for removing ammonia include catalytic tar reforming and wet scrubbing [14]. Tar cracker catalysts have been demonstrated to be effective at reducing ammonia in the syngas stream by conversion to N_2 and H_2. A tar cracker can be used to remove ammonia followed by gas cooling and a wet scrubber to remove residual ammonia. This cleanup configuration should achieve complete removal of ammonia.

- **Alkali removal**

Alkali removal is normally accomplished by cooling the syngas stream below 1100°F to allow condensation of alkali species followed by barrier filtration or wet scrubbing. Corrosion potential should be taken into consideration when using metal or ceramic candle filters due to possible reactions between the alkali and filter materials at high temperatures. Several demonstration facilities had used barrier filters to removal alkali along with other impurities. For example, ceramic filters were used at the Lahti facility in Finland and Varnamo in Sweden. The Varnamo facility experienced breakage of the ceramic filter elements and replaced them with sintered metal filters, which operated successfully. Baghouse filters were used in Lahti's low-pressure gasification system and the FERCO facility in Vermont.

Alkali can easily be removed by wet scrubbing, thus it is often the preferred method for alkali removal. Descriptions of operating and cleanup parameters for barrier filters and wet scrubbing are given earlier in this Appendix.

- **Removal of other contaminants**

Contaminants such as halides or metals (i.e. nickel or iron) are not typical, but may exist in syngas produced from biomass gasification. If present, these impurities can be removed by wet scrubbing or purification by hydrogenation and ZnO absorption.

2.5.5 Syngas Quenching

At the outlet of the gasifier reactor the temperature of the syngas is around 1500 °C and the fly ash (or slag) is in liquid form. To protect downstream process equipment from fouling, a quench is needed to solidify the slag and make it non-sticky. There are four main alternatives for quenching [24] :

- Radiant syngas cooling
- Water quench
- Gas recycle quench
- Chemical quench

2.5.6 Syngas coolers

Unless the hot syngas has been totally quenched with water, it typically has a temperature of around 900 °C and therefore needs further cooling before downstream gas clean up processes. There are two classes of syngas coolers for steam production [24]:

- Fire tube boilers
- Water tube boilers

Both types have been operated successfully in different plants. Of the two types, fire tube boilers are lower in cost. In this design, the hot raw syngas flows inside the tubes, while high pressure steam is generated on the outside. This means that the tubes are subjected to an external pressure. Depending on the design, maximum steam pressure is between 100 and 150 bar. Water tube boilers can handle higher steam pressure. The Tampa plant has good experience with their fire tube boilers, but bad experience with their gas to gas heat exchangers which were used to recover low temperature syngas heat (after the fire tube boiler) to preheat clean syngas to the gas turbine. Deposits were building up in the gas-gas exchanger and this led to corrosion and cracking of the tubes which caused raw syngas to enter the gas turbine and damage the blades. It was the decided to remove this gas-gas exchanger.

2.6 Combined Cycle

2.6.1 Steam turbine power plants, Rankine cycle

In traditional power plants the energy from combustion is transferred to a sealed water/steam circuit in which the cycle’s upper temperature corresponds to the temperature of the steam superheated upon entering the turbine (530-600ºC), and the lower temperature is that of the ambient temperature of the refrigeration water used in the condenser [6]. Current net efficiencies range from 35-37%, with a limited potential for improvement, which is based on the development of special materials that can withstand more extreme conditions of steam. These power plants, called supercritical and ultra-supercritical plants, have current net efficiencies of 37-40% and potential net efficiencies of 42-45%, although with high costs.

2.6.2 Gas turbine power plants, Brayton cycle

These power plants operate using an air compression cycle, the internal combustion of a liquid or gaseous fuel, and the expansion of the combustion gases at high temperatures (Brayton cycle). The gas turbines operate using a very high inlet temperature, up to 1200ºC, but at the same time the temperatures of the exhaust gases are very high, between 500-600ºC. This means that the process is not optimized from an efficiency point of view. For the more modern units, efficiency is 35-38%.

2.6.3 The Combined Cycle

A combined cycle system is composed of a gas turbine and a bottoming steam cycle. Both the gas turbine and the steam turbine provide shaft energy to a generator for production of electricity. The gas turbine primarily consists of a compressor, a combustor, and an expander. The compressor supplies required air to the combustor. The combustor is divided into a section for stoichiometric adiabatic combustion of the fuel gas and a subsequent section for quench of the primary combustion products with secondary air. The gases exiting the quench stage of the combustor are at the turbine inlet temperature. The hot exhaust gases from the gas turbine combustors are sent to the gas turbine expanders, which in turn drive the generators.

The hot gas turbine exhaust gases enter the heat recovery steam generator (HRSG) process area. The HRSG consists of a superheat system including reheaters, high pressure evaporators, and boilers. High pressure steam is generated in the superheat steam system using the heat recovered from the hot turbine exhaust gases. The exhaust gases that have been cooled flow out of the heat recovery steam generators. Most of the steam generated in the HRSGs is sent to the steam turbines where it is expanded and more electric power is generated. A portion of steam is sent to the fuel gas saturation unit. Hence, the advantages of the thermodynamic cycles of gas and steam are brought together as a high absorption temperature in the cycle of the gas turbine and a low transfer temperature in the steam cycle are achieved, managing to increase the efficiency to values in excess of 55%.

For the simulation model of IGCC system, many researcher were developed for various of gasifier technology to generate power in IGCC system using coal or biomass feedstock. Akunuri, Naveen Venkata [1] focused on modeling and assessment of three Texaco gasifier-based systems using ASPEN Plus. The gas turbines represented in the model are assumed to be heavy duty "F" class systems similar to a General Electric MS7001F. Further, Craig K.R. and Mann M.K. [7] described the cost and performance potential of three biomass-based IGCC systems. The three gasifier systems chosen for this study were a high pressure air-blown (IGT gasifier), a low pressure indirectly heated (BCL gasifier), and a low pressure air-blown (TPS gasifier). The MS-6101FA gas turbine was used to low pressure air-blown IGCC system. In addition, the researches of Pickett, Mathew Michael [21] and Xie, Chi [29] developed simulation model for IGCC system.

CHAPTER 3

BIOMASS RESIDUES IN THAILAND

Thailand is the one of world leaders in the agricultural production and export. The biomass resources, especially agricultural residues, are abundant in the country. The use of biomass is relatively clean and considered neutral on CO_2 emission. Advanced biomass energy technologies have also been developed in many countries. Biomass is therefore one of the clean energy resources that shows high potential to accommodate the increasing energy demand and substitute fossil fuels. Many researchers in Thailand have investigated the potential energy of agricultural residues and other types of biomass in Thailand for supporting alternative energy and reducing the energy imports.

The EC-ASEAN COGEN Program [10] focuses on the major biomass sectors which are potential energy sources from the wood and agricultural sectors of Thailand. The sugar, rice and oil palm sectors are three major potential biomass energy resources. A summary of the existing power potential from biomass based on proven technology in Thailand is shown in Table 3.1. Moreover, Boonrod Sajjakulnukit et. al. [4] estimated that total potential energy of biomass from agricultural residues, animal manure, fuelwood conservation, fuel substitution, municipal solid wastes, industrial wastewater, black liquor and palm oil mill effluent in 1997 was 479 PJ (10^{15} Joules) and potential energy from the agricultural residues was 479 PJ which trends to be 558 and 620 PJ in 2005 and 2010 respectively. The potential energy was approximately 17% of the total primary energy consumed in 1997.

Table 3.1 The summary of the existing power potential from biomass in Thailand

Sector	Residue	Theoretical Power Potential (GWh/hr)	No. of mills in Thailand		Structural Power Potential (MW)
			Total	Above Threshold	
Sugar	Bagasse	5797	46	46	1900
Rice	Rice Husk	2422	>44000	78	66
Oil Palm	EFB+Shell+Fiber	379	15	15	69
Wood	From log production	86	777	-	-
	From rubber wood	-	About 200	-	950

3.1 Avaliability of Biomass Residues in Thailand

From this study, The sugar cane, rice, palm oil, cassava and corn sectors are the major potential biomass energy resources. Crop-to-Residue Ratios (CRRs) are the estimates of residues derived from the production of agricultural crops. Studies on the determination of CRRs for various agricultural crops in Thailand have been done in the past. Department of Alternative Energy Development and Efficiency [3] investigated CRRs of agricultural residues in Thailand that are present in Table 3.2.

Table 3.2 CRRs of agricultural residues in Thailand.

Type	Biomass	Moisture (%)	LHV MJ/kg	Crop-to-residue ratios	
				Per production (%)	Tons / Rai
Paddy	Rice husk	12	13.52	21	
	Rice straw	10	12.33	49	
Sugar cane	Bagasse	50.73	7.37	28	
	Sugar cane Trash	9.2	15.48	17	
Palm oil	Palm oil fiber	38.5	11.4	19	
	Palm oil Shell	12	16.9	4	
	Palm oil empty bunch	58.6	7.24	32	
	Frond	78	1.76	141	
	Palm oil trunk	48.4	7.54		10
Cassava	Cassava slurry	80	1.47	37	
	Cassava peel	67	1.49	0.06	
	Cassava rhizome	59.4	5.49	20	
Corn	Corn cob	40	9.62	24	
	Corn stalk	42	9.83	82	

Biomass is an important renewable source of energy and has been used to provide energy for human activities since time immemorial. In the rural areas of Thailand where energy markets do not exist, biomass fuels are not traded and are mostly home-grown or collected by family labor. In energy markets where modern technology and competition dictate the use of more efficient and clean fuels, biomass is gaining an increased commercial value.

This chapter shall focus on the major biomass sectors as potential energy sources from the agricultural sectors of Thailand. The detail of biomasses are described from Energy for Environmental of Foundation [11] and resources of harvesting and processing of agricultural per province in Thailand were investigated by Department of Agricultural Extension [9]. The production of agriculture can see in Appendix A. % Efficiency was calculated by :

$$\%\ \text{Efficiency} = \frac{\text{Net Power(MW)}}{\text{LHV(kJ/kg)} \times \text{Feed flowrate(tons/s)}} \times 100\% \qquad (3.1)$$

3.1.1 Paddy Residues

Biomass from this sector have two major residues are husk and straw.

- **Rice husk**

Properties	small (less than 5 mms long and 2mms thick), yellow, 15 %of moisture
Sources	rice mills
Utilizations	fuel, soil preparation before cultivation, chickens' litter
Strengths	low moisture, small size, suitable for using as fuel. Husk ash can sell
Weaknesses	16-18 % of ash after incineration and transportation arguably may not be worth the expense due to its light weight (1 m^3 = 123 kg)

- **Rice straw**

Properties	long lean small and hollow, collected after harvest
Sources	Labor-harvested straw piled at the villages' threshing floor but machinery-harvested straw left in the farms
Utilizations	animals' food, soil preparation before cultivation, mushroom plant nursery, wreath making and paper industry but one out of three of straw left unused and awaiting burning
Strengths	potential for various utilization
Weaknesses	hard to collect, need to use a straw baler for gathering

Based on a CRRs for paddy residues , residues generated and residues available energy in 2006 for Thailand are calculated and shown in Table 3.3.

3.1.2 Sugar Cane Residues

Sugar cane residues are basically of two types: the cane residues made up of leaves and tops of cane plants (also known as cane trash) that remain behind in the field after the harvest, and bagasse which is the fibrous residue delivered after the extraction of the juice from the sugar cane mills.

- **Sugar cane bagasse**

Properties	flaky. In raw sugar making process, sugar canes are squeezed for sap and bagasse will be separated
Sources	altogether 46 sugar refineries in Thailand
Utilizations	80 % used as fuel in refineries and 20 % used to make paper and MDF boards
Strengths	yet to use to best potential
Weaknesses	light weight and high moisture

- **Sugar cane trash**

Properties	long, lean, cut and left in the farms during December-April, mostly await for open burning
Sources	sugar cane fields
Utilizations	tops can be made animals' food
Strengths	Leafs and tops are yet to be used to best potential
Weaknesses	Available only during December-April, hard to collect and machinery required

Based on a CRRs for bagasse and sugar cane trash, residues generated and residues available energy in 2006 for Thailand are calculated and shown in Table 3.4.

Table 3.3 Residues available energy and processing of paddy per region in Thailand, 2006

Region	Production (tons)	Residue Generated (10^6 kg)	Residue Available Energy (10^6 MJ)	Power (Eff. 30%) (MW)
Rice husks	**29,592,379**	**6,214**	**84,019**	**1066**
Central	9,363,127	1,966	26,584	337
Northeastern	10,612,251	2,229	30,130	382
North	8,723,600	1,832	24,768	314
South	893,401	188	2,537	32
Rice straws	**29,592,379**	**14,500**	**178,788**	**2268**
Central	9,363,127	4,588	56,569	718
Northeastern	10,612,251	5,200	64,116	813
North	8,723,600	4,275	52,705	669
South	893,401	438	5,398	68
Summary	**59,184,758**	**20,715**	**262,807**	**3333**

Table 3.4 Residues available energy and processing of sugar cane per region in Thailand, 2006

Region	Production (tons)	Residue Generated (10^6 kg)	Residue Available Energy (10^6 MJ)	Power (Eff. 30%) (MW)
Bagasses	**47,658,097**	**13,344**	**98,347**	**1247**
Central	18,317,053	5,129	37,799	479
Northeastern	15,666,587	4,387	32,330	410
North	13,674,457	3,829	28,219	358
South	-	-	-	-
Sugar cane Trashs	**47,658,097**	**8,102**	**125,417**	**1591**
Central	18,317,053	3,114	48,203	611
Northeastern	15,666,587	2,663	41,228	523
North	13,674,457	2,325	35,986	456
South	-	-	-	-
Summary	**95,316,194**	**21,446**	**223,764**	**2838**

3.1.3 Cassava Residues

- **Cassava rhizome**

Properties	Top part is round 15 mm in diameter while the lower part is 30 cm long
Sources	Cassava plantations
Utilizations	Abundant but unexploited
Strengths	Not many competitive suppliers
Weaknesses	60 % of moisture and digestion required

- **Cassava peel and slurry**

Properties	Peel, 50 % moisture, is brown and small. Slurry is white and high moisture, 80 %.
Sources	Tapioca flour mill
Utilizations	Peel is used for fertilizer, slurry is mixed with pellet for animal feeds.
Strengths	Peel is still available.
Weaknesses	Peel has low heating value.

Based on a CRRs for cassava residues, residues generated and residues available energy in 2006 for Thailand are calculated and shown in Table 3.5

Table 3.5 Residues available energy and processing of cassava per region in Thailand, 2006

Region	Production (tons)	Residue Generated (10^6 kg)	Residue Available Energy (10^6 MJ)	Power (Eff. 30%) (MW)
Cassava slurries	**22,584,402**	**8,356**	**12,284**	**12.10**
Central	7,223,504	2,673	3,929	3.87
Northeastern	12,152,480	4,496	6,610	6.51
North	3,208,418	1,187	1,745	1.72
South	-	-	-	-
Cassava peels	**22,584,402**	**14**	**20**	**0.02**
Central	7,223,504	4	6	0.01
Northeastern	12,152,480	7	11	0.01
North	3,208,418	2	3	0.00
South	-	-	-	-
Cassava rhizomes	**22,584,402**	**4,517**	**24,798**	**6.54**
Central	7,223,504	1,445	7,931	2.09
Northeastern	12,152,480	2,430	13,343	3.52
North	3,208,418	642	3,523	0.93
South	-	-	-	-
Summary	**67,753,206**	**12,887**	**37,102**	**18.66**

3.1.4 Palm Oil Residues

- **Palm oil residues**

Properties	3 types: 1. Fiber, 2. Shell (similar to coconut shell but smaller, about 1-2 cm in diameter) and 3. Empty fruit bunches
Sources	Palm oil extraction plants
Utilizations	Fiber used as fuel in palm oil extraction plants while empty fruit bunches used in mushroom plant nursery
Strengths	Shell has a high heating value, suitable for using as fuel. empty fruit bunch ash contains high potassium.
Weaknesses	Empty fruit bunches need to be shredded because they are big. The high alkaline may cause sticky stain in the boiler's water tubes

- **Palm oil leafs and trunks**

Properties	Frond is 2-3m long and cut before taking the empty fruit bunches down. Palm oil trees will be cut after 20-25 years
Sources	Palm oil plantations
Utilizations	Frond is used for soil protection and the trees is being cut in some area.

Strengths Yet to study the variety of its utility potential

Weaknesses Frond has high moisture, 80 % and large in size

Based on a CRRs for palm oil residues, residues generated and residues available energy in 2006 for Thailand are calculated and shown in Table 3.6.

Table 3.6 Residues available energy and processing of palm oil per region in Thailand, 2006

Region	Production (tons)	Residue Generated (10^6 kg)	Residue Available Energy (10^6 MJ)	Power (Eff. 30%) (MW)
Empty bunches	**6,240,753**	**1,997**	**14,459**	**183**
Central	414,511	133	960	12
Northeastern	-	-	-	-
North	-	-	-	-
South	5,826,242	1,864	13,498	171
Palm oil fibers	**6,240,753**	**1,186**	**13,517**	**171**
Central	414,511	79	898	11
Northeastern	-	-	-	-
North	-	-	-	-
South	5,826,242	1,107	12,620	160
Palm oil shells	**6,240,753**	**250**	**4,219**	**54**
Central	414,511	17	280	4
Northeastern	-	-	-	-
North	-	-	-	-
South	5,826,242	233	3,939	50
Palm oil fronds	**6,240,753**	**8,799**	**15,487**	**196**
Central	414,511	584	1,029	13
Northeastern	-	-	-	-
North	-	-	-	-
South	5,826,242	8,215	14,458	183
Palm oil trunks	**6,240,753**	**23,742**	**179,015**	**2,271**
Central	414,511	1,686	12,714	161
Northeastern	-	-	-	-
North	-	-	-	-
South	5,826,242	22,056	166,301	2,109
Whole Kingdom	**31,203,765**	**35,974**	**226,697**	**2,875**

3.1.5 Corn Residues

- **Corncobs and stems**

Properties Corncobs are left after corns' processing and stems will be cut after harvest

Sources Corn fields

Utilizations Alcohol, fuel and animals' food mixed with Molasses

Strengths	Higher heating value, and stems are unexploited and left in the fields
Weaknesses	There are various demand for corncobs

Based on a CRRs for corn residues, residues generated and residues available energy in 2006 for Thailand are calculated and shown in Table 3.7.

Table 3.7 Residues available energy and processing of corn per region in Thailand, 2006

Region	Production (tons)	Residue Generated (10^6 kg)	Residue Available Energy (10^6 MJ)	Power (Eff. 30%) (MW)
Corn cob	**3,696,342**	**887**	**8,534**	**108**
Central	677,172	163	1,563	20
Northeastern	688,414	165	1,589	20
North	2,330,756	559	5,381	68
South	-	-	-	-
Corn stalk	**3,696,342**	**3,031**	**29,795**	**378**
Central	677,172	555	5,458	69
Northeastern	688,414	564	5,549	70
North	2,330,756	1,911	18,787	238
South	-	-	-	-
Whole Kingdom	**7,392,684**	**3,918**	**38,329**	**486**

3.1.6 Summary of Agricultural Residues

In this study, total residual available energy from paddy, corn, palm oil, sugar cane and cassava residues in 2006 was 764 PJ and total power from this energy ,when calculate the percent efficiency was 30%, was 9,552 MW . Details of data that shown in Table 3.8.

Table 3.8 Total Residual Available Energy in 2006

	Biomass	Production (tons)	Residue Generated (10^6 kg)	Residue Available Energy (10^6 MJ)	Power (Eff. 30%) (MW)
Paddy	Rice husks	29,592,379	6,214	84,019	1,066
	Rice straws	29,592,379	14,500	178,788	2,268
Corn	Corn cobs	3,696,342	887	8,534	108
	Corn stalks	3,696,342	3,031	29,795	378
Palm oil	Empty bunches	6,240,753	1,997	14,459	183
	Fibers	6,240,753	1,186	13,517	171
	Shells	6,240,753	250	4,219	54

	Biomass	Production (tons)	Residue Generated (10⁶ kg)	Residue Available Energy (10⁶ MJ)	Power (Eff. 30%) (MW)
	Fronds	6,240,753	8,799	15,487	196
	Trunks	6,240,753	23,742	179,015	2,271
Sugar cane	Bagasses	47,658,097	13,344	98,347	1,247
	Trashs	47,658,097	8,102	125,417	1,591
Cassava	Slurries	47,658,097	8,356	12,284	12
	Peels	47,658,097	14	20	0.02
	Rhizomes	47,658,097	4,517	24,798	7
Summary		**109,771,973**	**90,423**	**763,901**	**9,552**

3.2 Choosing Agricultural Residues in This Research

Criteria for select types of agricultural residues are :

- Agricultural residues must to have low % moisture content in order to decrease energy and cost for drying. Then, % moisture content of biomass is not more than 15 %.
- Agricultural residues must to have more low heating value (LHV) for given the high effectively generated power.

Then, from the Table 3.2 can be plotted between type of biomass, % moisture content and low heating value that shown in Fig. 3.1. Consideration from the criteria, the suitable feedstock for this work is rice husk, rice straw, sugar cane trash and palm oil shell.

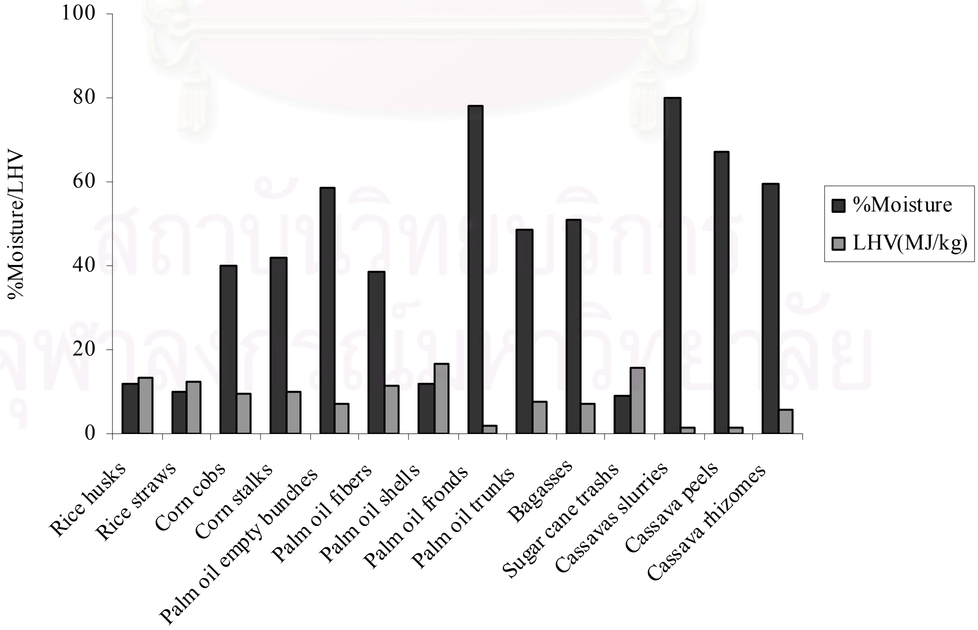

Figure 3.1 Low heating value and %moisture content of various biomasses

CHAPTER 4

PROCESS MODEL OF IGGC SYSTEM

4.1 Biomass Analysis

Rice husk, rice straw, sugar cane trash and palm oil shell are feedstock in this study. In Table 4.1 shows the data analysis of the feedstock which collected from Energy for Environmental of Foundation [3].

Table 4.1 Biomass Analysis

	Rice husk	Rice straw	Sugar cane trash	Palm oil shell
Proximate analysis				
Moisture, %	12.0	10.0	9.2	12
Fixed Carbon, %	18.88	18.9	16.9	16.3
Volatile Matter, %	56.46	60.7	67.8	68.2
Ash, %	12.65	10.39	6.1	3.5
Ultimate Analysis				
Ash, %	12.65	10.39	6.10	3.52
Carbon, %	37.48	38.17	41.60	44.44
Hydrogen, %	4.41	5.02	5.08	5.01
Nitrogen, %	0.17	0.58	0.40	0.28
Chlorine, %	0.09	0.00	0.01	0.02
Sulfur, %	0.04	0.09	0.17	0.02
Oxygen, %	33.27	35.28	37.42	34.70
Moisture, %	12.0	10.00	9.20	12.00
Other Characteristics				
Bulk Density, kg/m^3	150	125	100	400
Higher heating value, kJ/kg	14,755	13,650	16,794	18,267
Lower heating value, kJ/kg	13,517	12,330	15,479	16,900

4.2 Assumption of This Work.

The mass and energy balances for the biomass-based IGCC electric generating plants conducted based on the following assumption :

- The system in at steady state.
- All steams are well mixed.
- Negligible any leaks and losses from equipments.
- All pressure drops are considered negligible.
- There is no consideration occurring within the compressors.
- There is no heat loss from the insulated adsorption column.

- Temperature remains constant by means of heating and cooling utilities.
- Assume 100% of CO_2, H_2O, NH_3 and sulfur are removed from the systems.
- Solid are not formed within the process.
- The Peng-Robinson property method is approximate for this analysis and stream type is "MIXCINC".
- The reactions in gasifier are equilibrium composition and considered isothermal through the gasifier.

4.3 Major Process Sections in IGCC System

Each major process area of the IGCC plant is described in the following sections. For each process area, an ASPEN PLUS flowsheet, a table describing the unit operations, and a detailed description of the process area is provided.

4.3.1 Gasification and Gas Cleanup (Gasification Island)

The biomass; rice husk, rice straw, sugar cane trash or palm oil shell, is preheated to 70 ^oC and feed to the atmospheric pressure, air – blown, bubbling fluidized bed gasifier by screw feeders that are isolated from the upstream components by pressurized rotary valves. Operating parameters from the gasifier and gas cleanup are presented in Table 4.2. Tar ($C_{10}H_8$) and char are entrained with the syngas in the devolatilization zone, DECOMP. The regression model of devolatilizated products ,that collected by Nadège Richard and Henrik Thunman [26], are shown in Equation:

$$Ytar = 14 + [(973-T) \times 7 / 200] \quad (4.1)$$

$$Y_{char} = 90 \times \exp[- 0.0027 \times (T-273)] \quad (4.2)$$

$$X'_{C,char} = 98 \times (1- 0.7 \times \exp[- 0.0018 \times (T-273)]) \quad (4.3)$$

$$X'_{H,char} = 53 \times \exp[- 0.00177 \times (T-273)] \quad (4.4)$$

$$X'_{O,char} = 25 \times \exp[- 0.0027 \times (T-273)] \quad (4.5)$$

The reactions in gasifier, GASIFIER are equilibrium composition and considered isothermal through the gasifier. The equilibrium products are specified as H_2O, H_2, CO_2, CO, CH_4, C_2H_4, C_2H_6, $C_{10}H_8$, H_2S, N_2, NH_3 and CL_2. Syngas is fed to a tar reformer to remove tars, light hydrocarbons, and ammonia before any additional gas treating or cooling. The tar reformer was modeled using NREL's "goal design" reactor conversion for the Thermochemical Pilot Development Unit (TCPDU). In the tar reformer (operating at temperature = 870 ^oC), tars and light hydrocarbons such as methane, ethylene, and ethane are converted to H_2 and CO [14,20].

After exiting tar reformer, the fuel gas enters the syngas cooler. In the syngas cooler, the temperature of the fuel gas is reduced to 288 ºC [7]. The syngas is sent to remove any remaining ammonia, particulates, sulfur, metals, halides, or alkali remaining in the system. Fig. 4.1 and Table 4.3 present gasification and gas cleanup model in detail.

Table 4.2 Operating parameter of gasifier and tar reformer

Gasifier	
Temperature	700 – 900 ^{o}C
Pressure	14.7 psia (1 atm)
Air / Feed Ratio	1.0 – 2.4
Tar reformer	
Temperature	870 ^{o}C

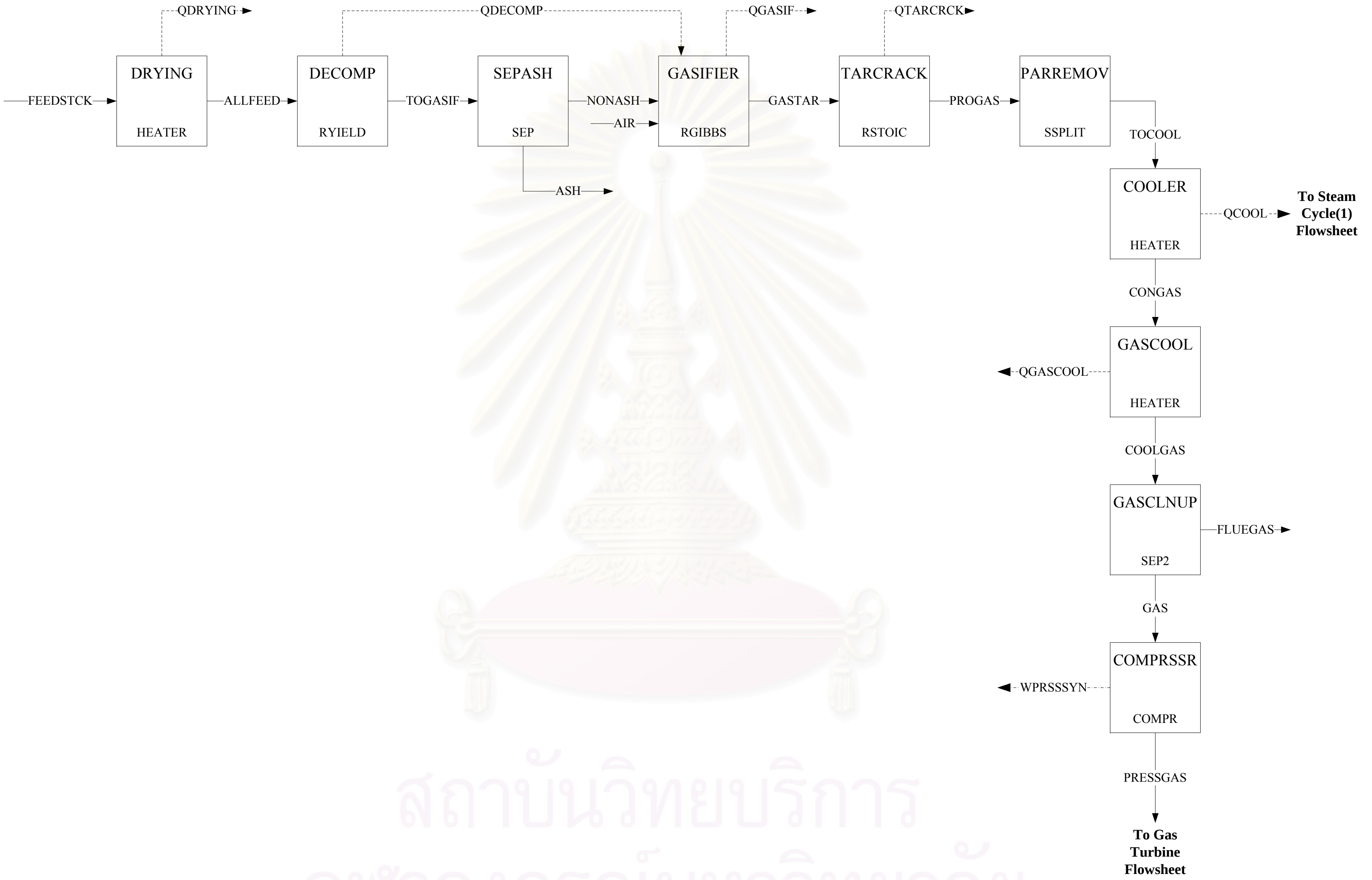

Figure 4.1 Gasification Island Flowsheet

Table 4.3 Gasification Island Section Unit Operation Description

NO	Block ID (Aspen block name)	Block parameter	Description
1	DRYING (HEATER}	TEMP=70 ^oC PRES = 14.7 psia	Preheating feedstock
2	DECOMP (RYIELD)		Yields of composition follow to regression model [6]. Temperature is varied.
3	SEPASH (SEP)	FRAC STREAM=ASH SUBSTREAM=NC COMP=ASH FRAC=1	This block separates the ash from the syngas
4	GASIFIER (RGIBBS)	PROD H_2O / H_2 / CO_2 / CO / CH_4 / C_2H_4 / C_2H_6 / $C_{10}H_8$ / H_2S / N_2 / NH_3 / HCL / NO / NO_2 / COS	This reactor simulates the gasification zone through equilibrium calculations based on minimizing Gibbs free energy. Temperature is varied.
5	TARCRACK (RSTOIC)	TEMP = 870 ^oC PRES =1 atm STOIC 1 MIXED CH_4 -1. / H_2O -1. / CO 1. / H_2 3. STOIC 2 MIXED C_2H_4 -1. / H_2O -2. / CO 2. / H_2 4. STOIC 3 MIXED C_2H_6 -1. / H_2O -2. / CO 2. / H_2 5. STOIC 4 MIXED $C_{10}H_8$ -1. / H_2O -10. / CO 10. / H_2 14. STOIC 5 MIXED NH_3 -1. / N_2 0.5 / H_2 1.5 CONV 1 MIXED CH_4 0.8 CONV 2 MIXED C_2H_4 0.9 CONV 3 MIXED C_2H_6 0.99 CONV 4 MIXED $C_{10}H_8$ 0.999 CONV 5 MIXED NH_3 0.9	The stoichiometric reactor simulates tar reforming
6	PARREMOV (SSPLIT)	FRAC MIXED PARTICLE 0. FRAC CISOLID PARTICLE 1. FRAC NC PARTICLE 1.	
7	COOLER (HEATER)	TEMP =345 ^oC PRES = 14.7 psia	
8	GASCOOL (HEATER)	TEMP =288 ^oC PRES = 14.7 psia	
9	GASCLNUP (SEP2)	FRAC STREAM=FLUEGAS SUBSTREAM=MIXED COMPS=C S O_2 HCL_2 H_2O H_2 CO_2 CO CH_4 C_2H_4 C_2H_6 $C_{10}H_8$ N_2 NO NO_2 NH_3 COS FRACS=1. 1. 0. 1. 0. 0. 1. 0. 0. 1. 1.1. 0. 1. 1. 1. 1. 1.	
10	COMPRSSR (COMPR)	TYPE=ISENTROPIC PRES=219.03 psia SEFF=0.72	
11	FLASH (FLASH2)	TEMP =255 ^oC PRES = 219.03 psia	

4.3.2 Gas Turbine

Following final fuel gas cleaning, the fuel gas is compressed for introduction into the gas turbine combustor. The gas turbines represented in the model are assumed to be heavy duty "F" class systems similar to a General Electric MS6001FA. Table 4.3 present the gas turbine model MS6001FA in detail. This compression is accomplished in a multi-stage, intercooled centrifugal compressor [7]. The 6FA gas turbine configuration includes an 18-stage compressor, six combustion chambers and a three-stage turbine [24]. Fig. 4.2 and Table 4.5 present the gas turbine model in detail.

Table 4.4 Specification of Gas turbine model MS6001FA

	Specification
Gas turbine	GE MS-6101FA
Turbine PR	14.9
Air Flow (kg/s)	196 kg/s
Turbine firing temperature, ºC (ºF)	1,288 (2,350)
Steam cycle conditions, MPa/ºC /ºC (psia/ºF/ºF)	10/538/538 (1,465/1,000/ 1,000)

Ambient conditions of the atmospheric air entering the gas turbine compressor are assumed to be 35 °C, 14.7 psia (1 atm **).** The compressor ratio is 14.9 [7], The individual compressor stage outlets for the first, second, and third stages are estimated by the following relationships, respectively [1]:

$$P_{c,1,o} = P_{ambient}\, PR^{0.33} \qquad (4.6)$$

$$P_{c,2,o} = P_{ambient}\, PR^{0.67} \qquad (4.7)$$

$$P_{c,3,o} = P_{ambient}\, PR \qquad (4.8)$$

where,

PR = pressure ratio =14.9

$P_{ambient}$ = 14.7 psia

The gas turbine model was developed by Akunuri, Naveen Venkata (1999) [1]. The compressors outlet pressures specified as 35.85 psia, 89.82 psia, and 219.03 psia allowing for some pressure loss. The isentropic efficiencies of each of the compressors are 0.81. After each stage of compression, the compressed air is split into two or more streams. One stream undergoes further compression and the other streams are used for cooling the turbine blades after each expansion stage of the gas turbine.

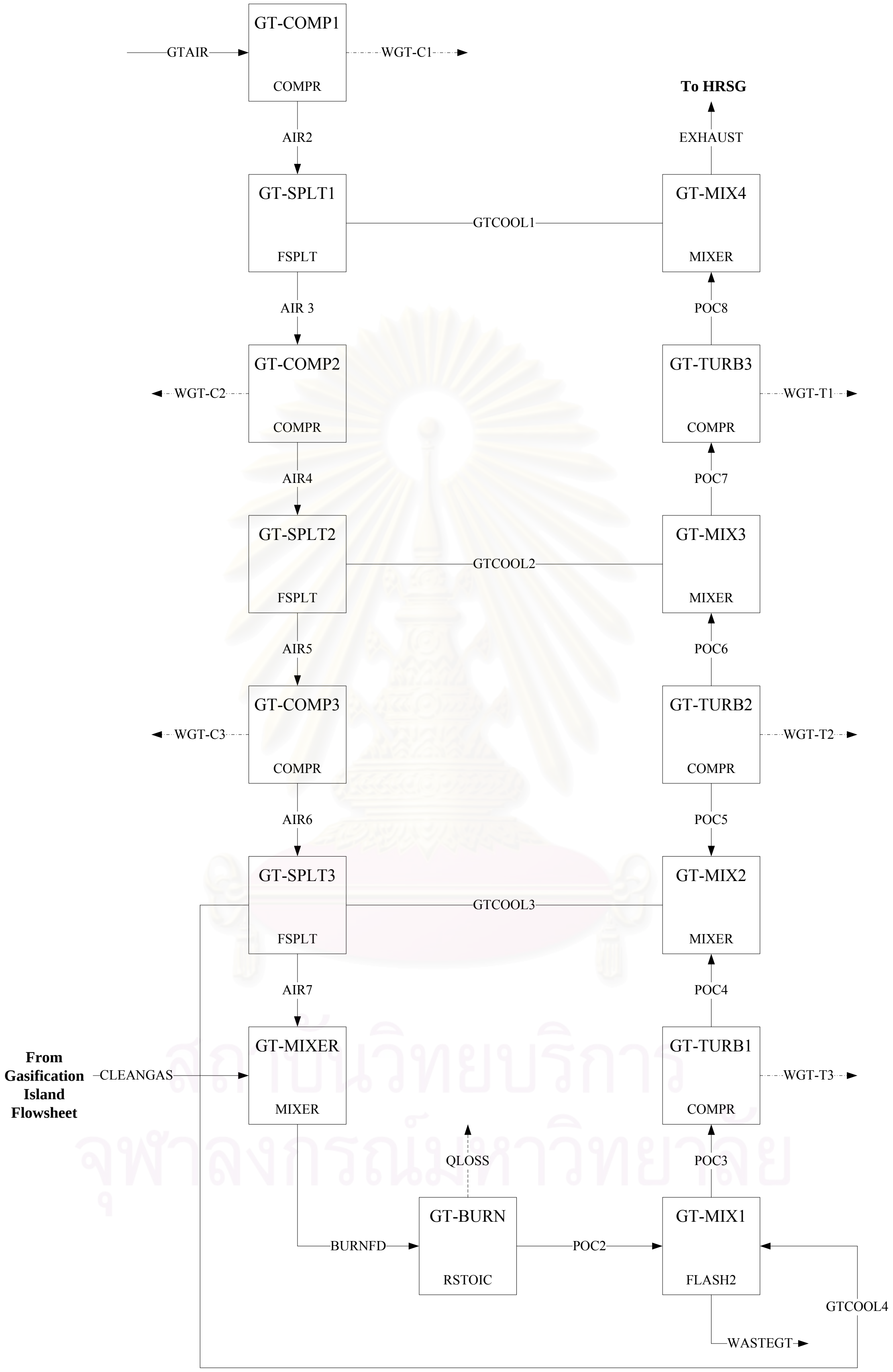

Figure 4.2 Gas Turbine Flowsheet

Table 4.5 Gas Turbine Section Unit Operation Description

NO	Block ID (Aspen block name)	Block parameter	Description
1	GT-COMP1 (COMPR)	TYPE=ISENTROPIC PRES=35.85 psia SEFF=0.81	This block simulates a compressor which compresses the air entering the Gas Turbine.
2	GT-COMP2 (COMPR)	TYPE=ISENTROPIC PRES=89.82 psia SEFF=0.81	Similar to GT-COMP1
3	GT-COMP3 (COMPR)	TYPE=ISENTROPIC PRES=219.03 psia SEFF=0.81	Similar to GT-COMP1
4	GT-SPLT1 (FSPLIT)	FRAC GTCOOL1 0.1	This block splits the compressed air coming out of the block GT-COMP1 and directs one stream is used to cool the products of combustion of the Gas Turbine. This accounts for cooling the leakages and blockages.
5	GT-SPLT2 (FSPLIT)	FRAC GTCOOL2 0.1	Similar to GT-SPLT1. This corresponds to 1st stage Rotor and 2nd stage Vane Cooling.
6	GT-SPLT3 (FSPLIT)	FRAC GTCOOL3 0.1 / GTCOOL4 0.1	Similar to GT-SPLT1. This corresponds to 1st stage Vane Cooling.
7	GT-MIXER (MIXER)		This block simulates the mixing of the compressed air and expanded fuel gas.
8	GT-BURN (RSTOIC)	TEMP=1288 ^{o}C PRES=219.03 psia STOIC 1 MIXED CO -2. / O2 -1. / CO2 2. STOIC 2 MIXED H2 -2. / O2 -1. / H2O 2. STOIC 3 MIXED CH4 -1. / O2 -1.5 / CO 1. / H2O 2. CONV 1 MIXED CO 1. CONV 2 MIXED H2 1. CONV 3 MIXED CH4 1.	Simulates the stoichiometric reactions that take place in Gas Turbine combustor.
9	GT-MIX1 (MIXER)		Simulates the mixing of cool air with the hot products of combustion.
10	GT-MIX2 (MIXER)		Simulates the mixing of cool air with the hot products of combustion.
11	GT-MIX3 (MIXER)		Simulates the mixing of cool air with the hot products of combustion.
12	GT-MIX4 (MIXER)		Simulates the mixing of cool air with the hot products of combustion.

NO	Block ID (Aspen block name)	Block parameter	Description
13	GT-TURB1 (COMPR)	TYPE=ISENTROPIC PRES=89.82 psia SEFF=0.81	Simulates a compressor for the expansion and subsequent cooling of the mixing of products of combustion and cool air.
14	GT-TURB2 (COMPR)	TYPE=ISENTROPIC PRES=35.85 psia SEFF=0.81	Simulates a compressor for the expansion and subsequent cooling of the mixing of products of combustion and cool air.
15	GT-TURB3 (COMPR)	TYPE=ISENTROPIC PRES=15.2 psia SEFF=0.81	Simulates a compressor for the expansion and subsequent cooling of the mixing of products of combustion and cool air.

The reheated fuel gas and the compressed air enter the combustor. The following chemical reactions are used in the block GT-BURN to simulate the combustion.

$2CO + O_2 \rightarrow 2CO_2$ (R4.1)

$2 H_2 + O_2 \rightarrow 2 H_2O$ (R4.2)

$CH_4 + 1.5O_2 \rightarrow CO + 2 H_2O$ (R4.3)

The assumption of this reaction is :

- CO, H_2 and CH_4 are completely conversion.
- NO_x are considered negligible.

The firing temperature of the gas turbine is constrained by the requirement that the turbine exhaust gas, 'GTPOC', has a temperature of 1288 °C or less to prevent damage to the turbine blades.When the expansion of the hot products of combustion leaving the combustor is modeled in three stages. In each of these stages, the hot gases are mixed with the cooler air and then expanded in the turbine. The first, second, and third turbines have an outlet pressures of 89.82 psia, 35.85 psia, and 15.2 psia, respectively, and each has an isentropic efficiency of 0.919. The exhaust gases enter HRSG unit.

4.3.3 Steam Cycle

The HRSG consists of a superheater at a pressure of 1465 psia and a temperature of 536 °C (997 °F), a reheater at 536 °C (997 °F), two economizers, a high pressure boiler, and a low pressure boiler. The steam cycle model was developed by Akunuri, Naveen Venkata[4]. The inlet steam to the high pressure economizer and the makeup water for steam generation is initialized in the ASPEN input file through FORTRAN block The heat losses in the HRSG process are accounted for through block ‘QSPLIT’ shown in Table 4.5 and Fig. 4.3.

The total heat is sent to the block ‘ECONOMZR’ which simulates a heat exchanger. ‘ECONOMZR’ heats a stream of water to a temperature of 290 °C (553 °F). The mass flow of the stream of water is calculated by FORTRAN block. The remaining amount of heat available is sent to block ‘HPBOILER’ which simulates a high pressure steam boiler in HRSG. The steam generated by ‘HPBOILER’ enters the superheater, SUPERHTR and generates superheated steam at a temperature of 536 °C (997 °F).

The steam generated in the HRSG section is expanded through three stages, consisting of a 350 psia pressure turbine followed by an intermediate pressure turbine of pressure 115 psia, followed by low pressure turbines of 1 psia. The output stream from ‘STEAM350’ is heated by ‘QREHEAT’ to a temperature of 536 °C (997 °F) enters the block ‘TURB115’, which generates steam at 115 psia. The details regarding the modeling of the steam cycle are given in Table 4.6 and Figure 4.3 - 4.4.

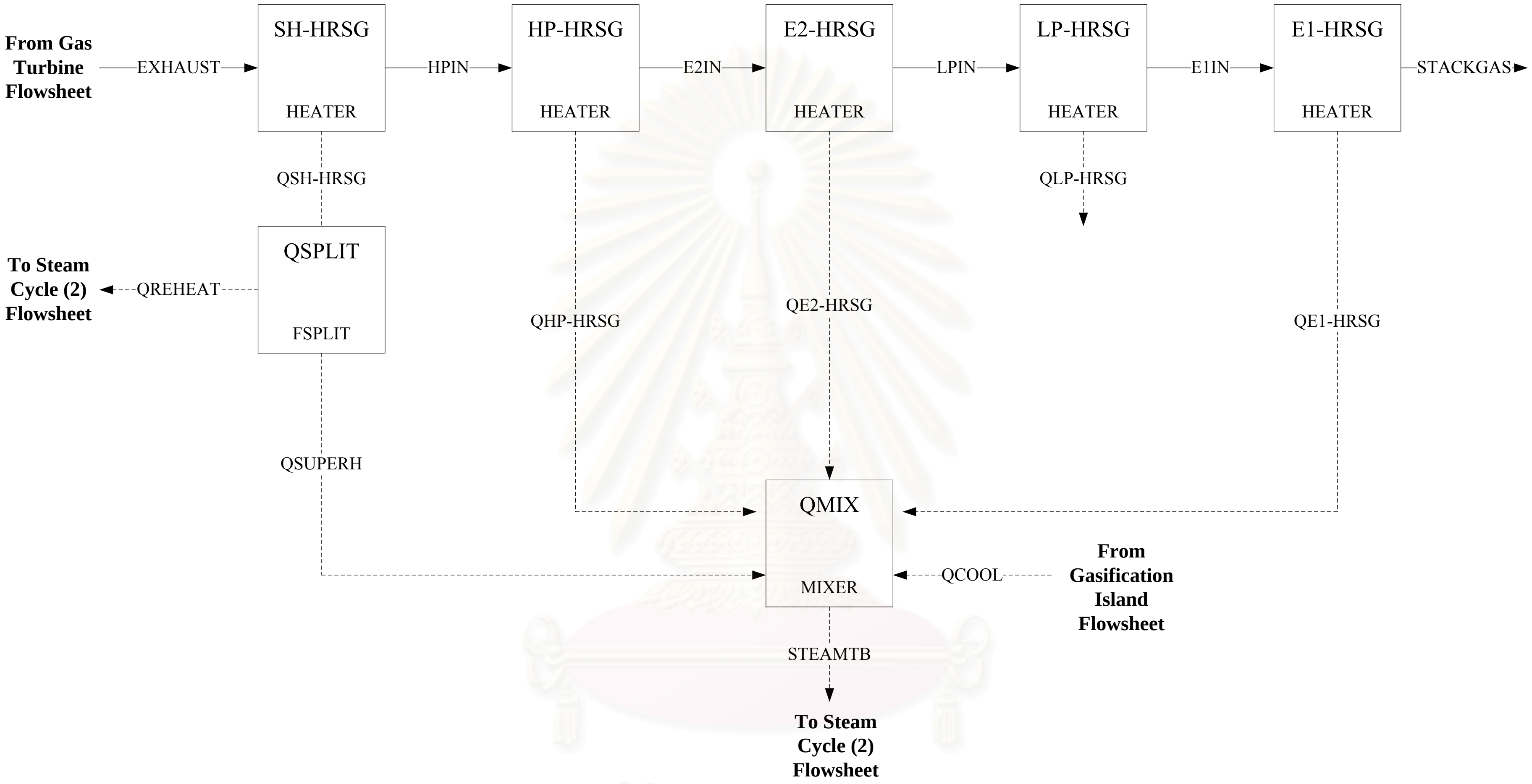

Figure 4.3 Steam Cycle (1) Flowsheet

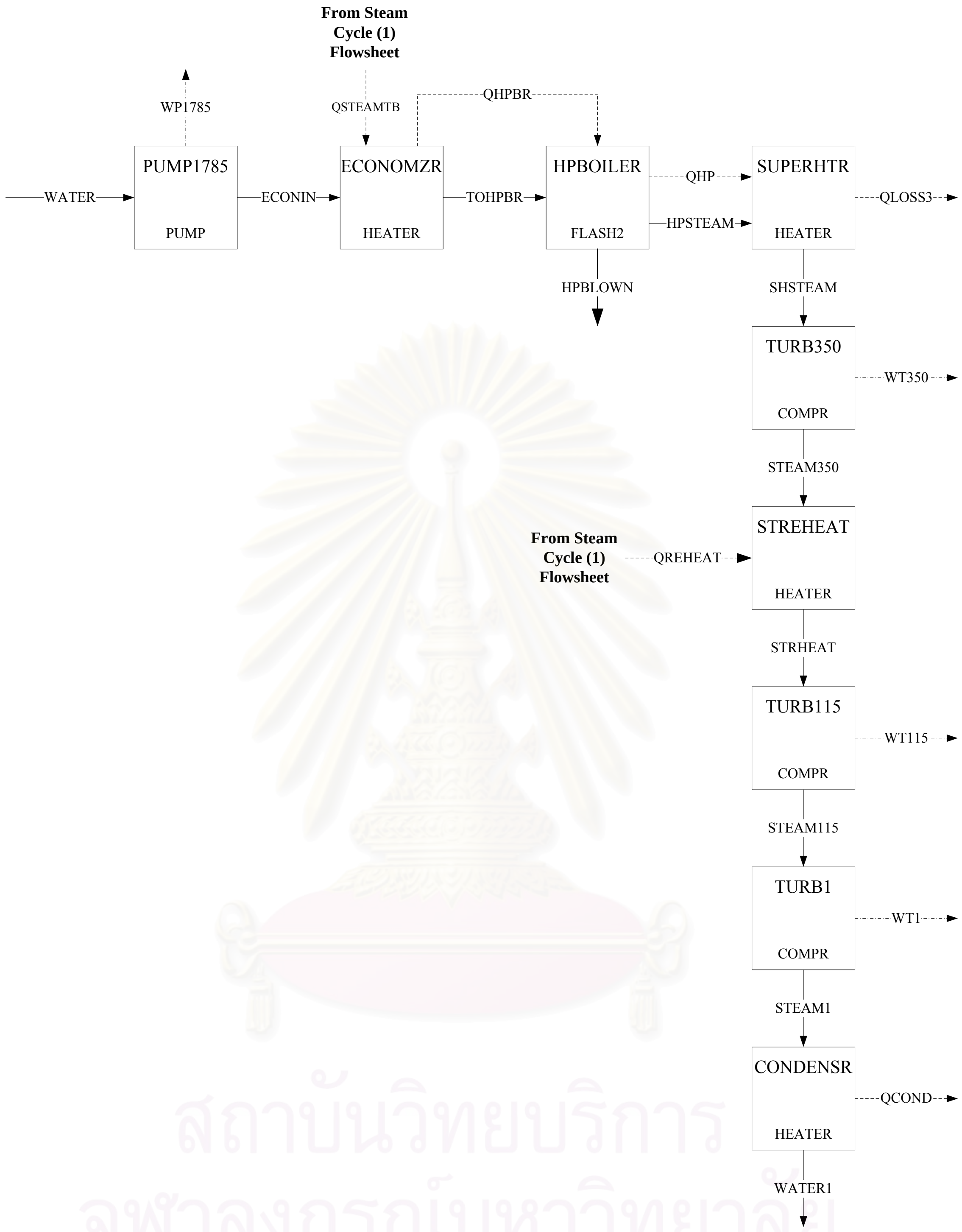

Figure 4.4 Steam Cycle (2) Flowsheet

Table 4.6 Steam Cycle Section Unit Operation Flowsheet

NO	Block ID (Aspen block name)	Block parameter	Description
1	SH-HRSG (HEATER)	PARAM TEMP=395 °C DPPARM=0.	This block is part of the Heat Recovery Steam Generation Section and removes heat from the products of combustion of the Gas Turbine.
2	HP-HRSG (HEATER)	PARAM TEMP=338 °C DPPARM=0.	This block is part of the Heat Recovery Steam Generation Section and removes heat from the products of combustion of the Gas Turbine.
3	E2-HRSG (HEATER)	PARAM TEMP=205 °C DPPARM=0.	This block is part of the Heat Recovery Steam Generation Section and removes heat from the products of combustion of the Gas Turbine.
4	LP-HRSG (HEATER)	PARAM TEMP=186 °C DPPARM=0.	This block is part of the Heat Recovery Steam Generation Section and removes heat from the products of combustion of the Gas Turbine.
5	E1-HRSG (HEATER)	PARAM TEMP=133 °C DPPARM=0.	This block is part of the Heat Recovery Steam Generation Section and removes heat from the products of combustion of the Gas Turbine.
6	QSPLIT (FSPLIT)	FRAC QREHEAT 0.0388	Simulates the radiation losses in the HRSG and diverts QREHEAT to REHEAT in HRSG section.
7	QMIX (MIXER)		Simulates the mixing of the various heat stream in the HRSG used in the calculation of superheated steam mass flow.
8	PUMP1785 (PUMP)	PARAM PRES=1785 psia	Simulates a pump which delivers condensate to the HRSG economizer.
9	ECONOMZR (HEATER)	PARAM TEMP=290 °C PRES=1625. psia	Simulates economizers 1 and 2 of HRSG.
10	HPBOILER (FLASH2)	PARAM PRES=1545 psia VFRAC=0.97	Simulates a high pressure steam boiler in HRSG.
11	SUPERHTR (HEATER)	PARAM TEMP=536 °C PRES=1465 psia	Simulates a high pressure steam boiler in HRSG.

NO	Block ID (Aspen block name)	Block parameter	Description
12	TURB350 (COMPR)	TYPE=ISENTROPIC PRES=350 psia SEFF=0.847	Simulates a high pressure steam turbine.
13	STREHEAT (HEATER)	PARAM DPPARM=0.	This block simulates the mixing of steams at 350 psia and 565 psia.
14	TURB115 (COMPR)	TYPE=ISENTROPIC PRES=115 psia SEFF=0.901	Simulates an intermediate pressure steam turbine.
15	TURB1 (COMPR)	TYPE=ISENTROPIC PRES=1 psia SEFF=0.849	Simulates a low pressure (1 psia) steam turbine.
16	CONDENSR (HEATER)	PARAM PRES=1. VFRAC=0.	

4.4 Model in FORTRAN Block

- Flowrate of stream 'AIR'

Flowrate of stream 'AIR' = Air to gasifier ratio x Flowrate of stream 'FEED' (4.9)

- Flowrate of stream 'AIRGT'

Flowrate of stream 'AIRGT' = Air to gas turbine ratio x Flowrate of stream 'FLUGAS' (4.10)

4.5 Net Power Output and Plant Efficiency

The net plant power output is the total power generated from the gas turbines and steam turbines less the total auxiliary power consumption. The gas and steam turbines have been modeled as a series of compressors and turbines in ASPEN Plus using the unit operation block COMPR. This unit operation block requires outlet pressure and isentropic efficiencies as parameters. The net power output in MW is given by

NET Power = GT Power + ST Power - Auxiliary power (4.11)

Where ,

GT Power The net gas turbine power output is calculated to be the sum of the work done by the gas turbine expanders and work required by the gas turbine compressors.

GT Power = ('WGT-C1' + 'WGT-C1' + 'WGT-C1') – ('WGT-T1' + 'WGT-T1'+ 'WGT-T1') (MW) (4.12)

ST Power The total gross output of the steam turbine is the sum of the total work done by the four steam turbines.

$$= - (\text{‘WT350’} + \text{‘WT115’} + \text{‘WT1’})\ (\text{MW}) \qquad (4.13)$$

Auxiliary Power = Auxiliary power consumption by boiler feed water section

$$\text{‘WP1785’}\ (\text{MW}) \qquad (4.14)$$

The net plant efficiency based on a higher heating value basis is given by

$$\%\ \text{Efficiency} = \frac{\text{Net Power(MW)}}{\text{HHV(kJ/kg)} \times \text{Feed flowrate(tons/s)}} \times 100\% \qquad (4.15)$$

4.6 Environmental Emissions

Emissions of process are considered from syngas product stream, ‘PROGAS’ that through the tar reforming process. In this study, the environmental emissions are specified as CO_2, NH_3 and H_2S.

CHAPTER 5

RESULTS AND DISCUSSION

The objective of the present work is to study operating variables that effect to environmental impact and power performance of IGCC system. Operating variables for this study are: the types of feedstocks are Sugar cane trash, palm oil shell, rice husk and rice straw, the feedstock flowrate is 1000- 2000 tons / day, the gasifier temperature is 700-900 °C, the air to gasifier ratio is 1 - 2.4 and the air to gas turbine ratio is 2 – 5 . The results are considered only available operating condition that none error complied and the effect of operating variables to thermal efficiency, net power and environmental performance are described below.

5.1 Effect of Operating Variables on Environmental Performance

- **Effect to CO_2 Emissions**

  Figures 5.1-5.8 describe the influences of gasifier temperature and air to gasifier ratio on concentration of CO_2 in units of mole flowrate (kmol/hr) and mole fraction. It can be shown the concentration of CO_2 in syngas products from reaction decrease with decreasing air to gasifier ratio and increasing gasifier temperature and these tend to effect in every feedstock in this study. The Reasons of the results are to increase CO_2 with increasing oxygen in the feed and at high temperatures CO_2 formation is suppressed in favor of CO [27].

- **Effect to NH_3 Emissions**

  Figures 5.9-5.16 describe the influences of gasifier temperature and air to gasifier ratio on concentration of NH_3 in units of mole flowrate (kmol/hr) and mole fraction. It can be shown the concentration of NH_3 in syngas products from reaction decrease with increasing air to gasifier ratio and decreasing gasifier temperature. Furthermore, these tend to be effect in every feedstock in this study.

- **Effect to H_2S Emissions**

  From Figures 5.17-5.24 describe the influences of gasifier temperature and air to gasifier ratio on concentration of H_2S in units of mole flowrate (kmol/hr) and mole fraction. It can be the mole fraction of H_2S in syngas products from reaction decrease when increasing air to gasifier ratio and gasifier temperature but the mole flowrate of

H_2S is constant because this study sulfur composition only come from feedstock and sulfur formation to H_2S only. Then, the mole flowrate of H_2S just is constant for every feedstock.

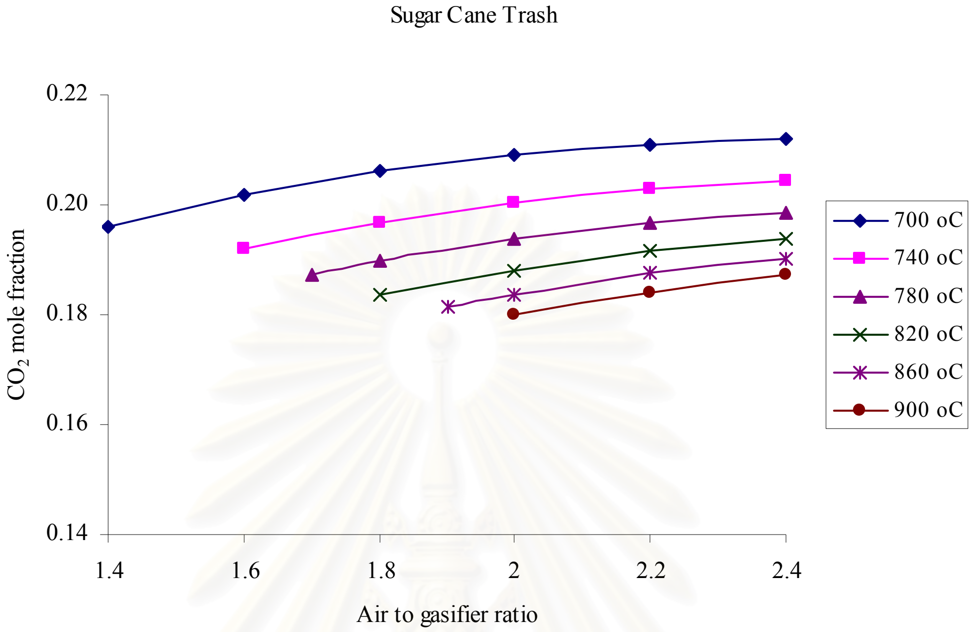

Figure 5.1 Effect of gasifier temperature and air to gasifier ratio to mole fraction of CO_2 emission for sugar cane trash

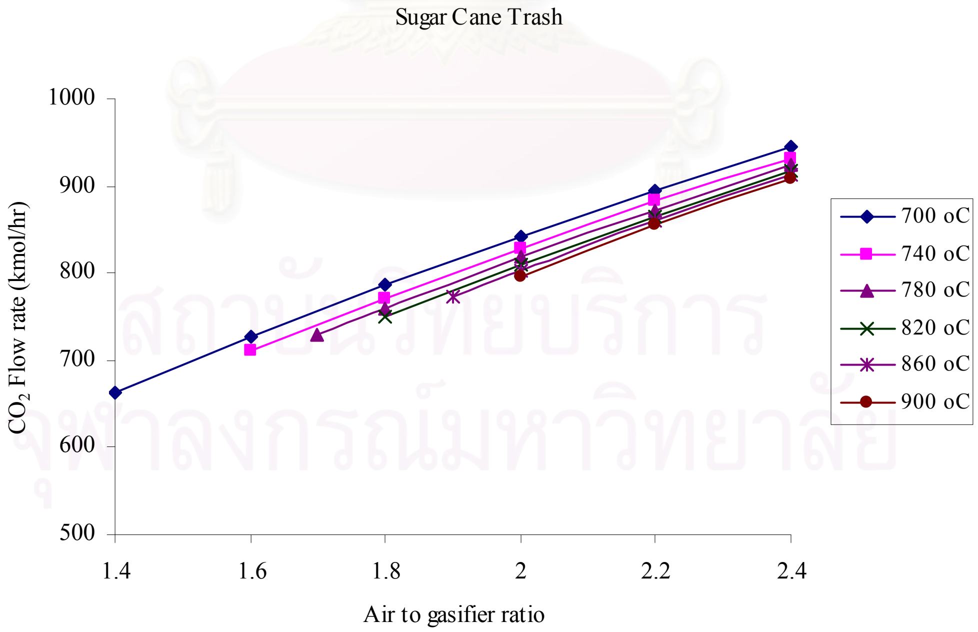

Figure 5.2 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of CO_2 emission for sugar cane trash

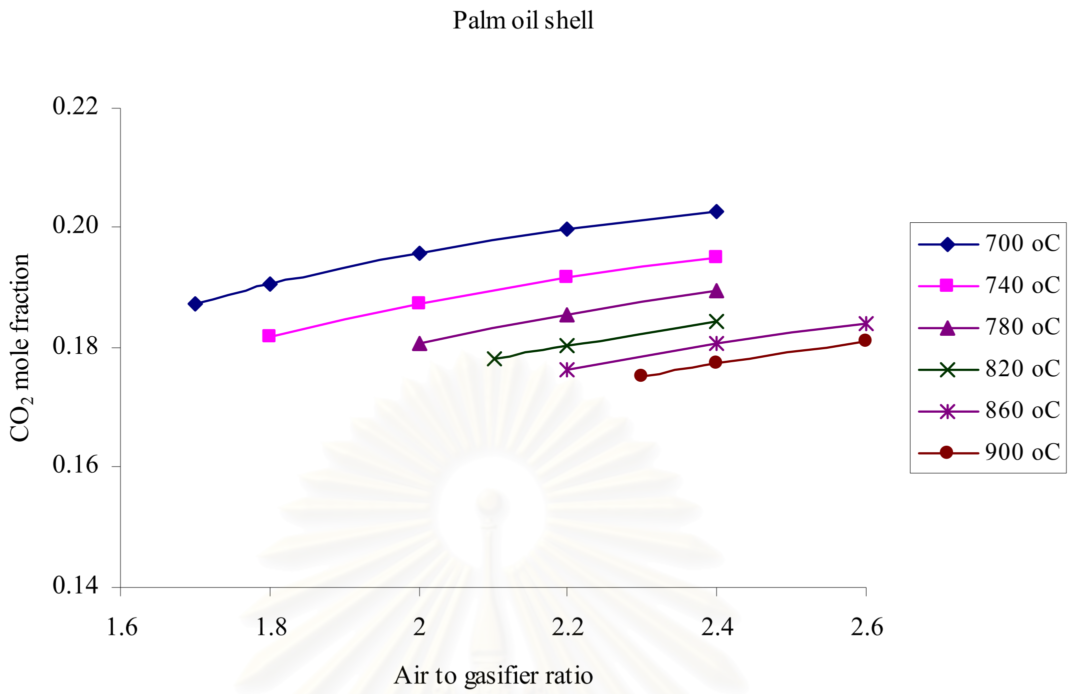

Figure 5.3 Effect of gasifier temperature and air to gasifier ratio to mole fraction of CO_2 emission for palm oil shell

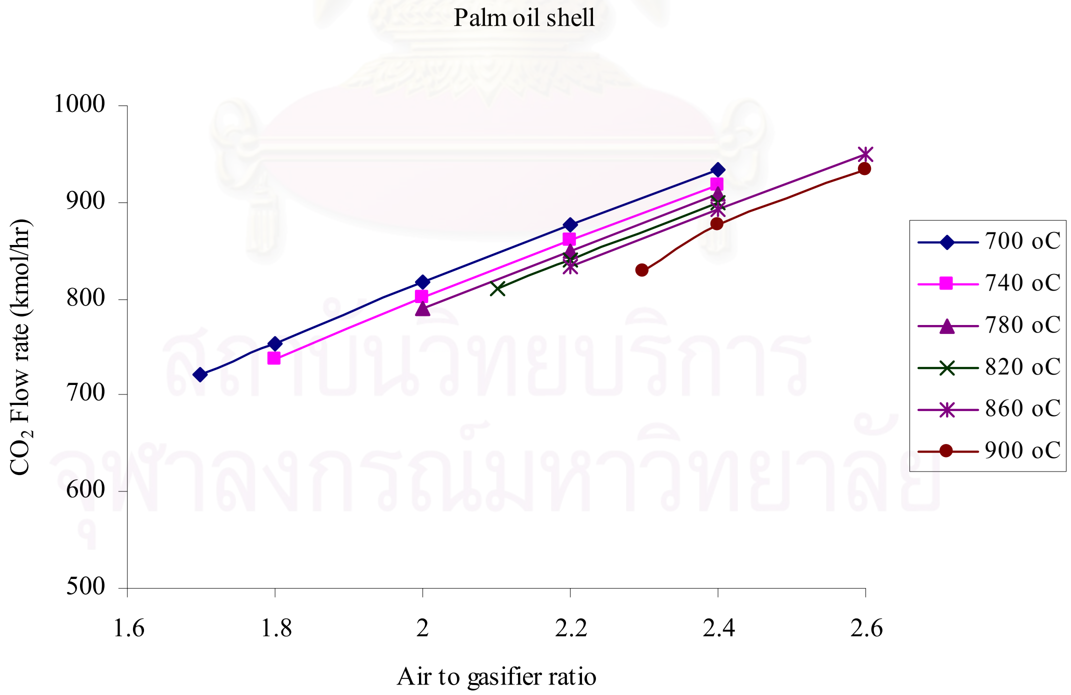

Figure 5.4 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of CO_2 emission for palm oil shell

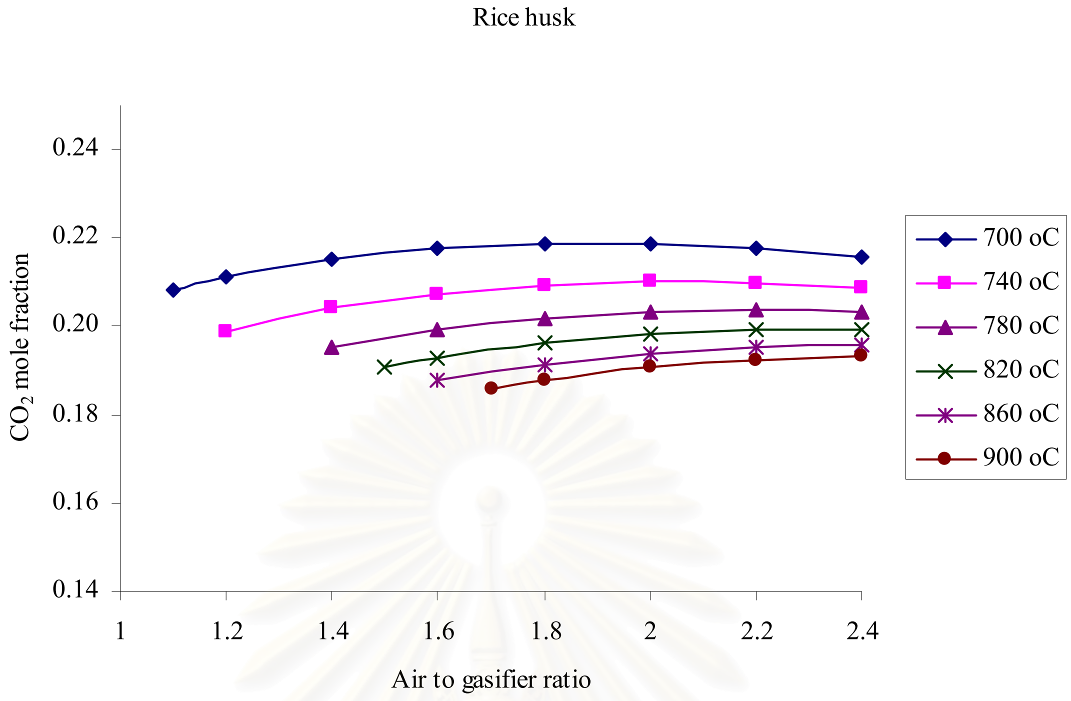

Figure 5.5 Effect of gasifier temperature and air to gasifier ratio to mole fraction of CO_2 emission for rice husk

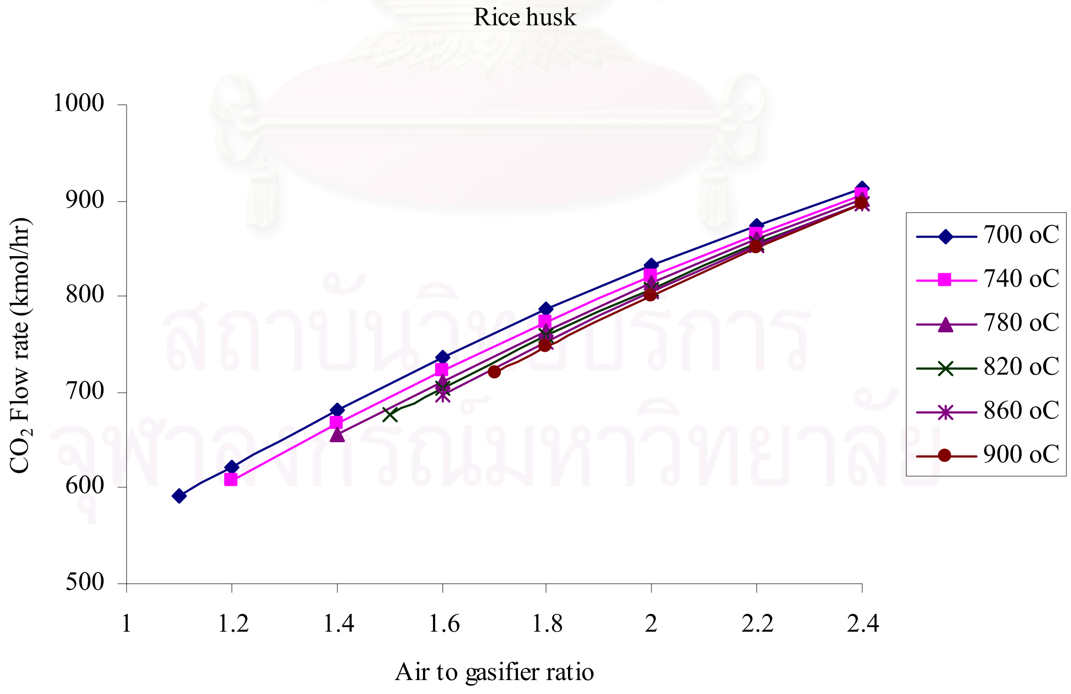

Figure 5.6 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of CO_2 emission for rice husk

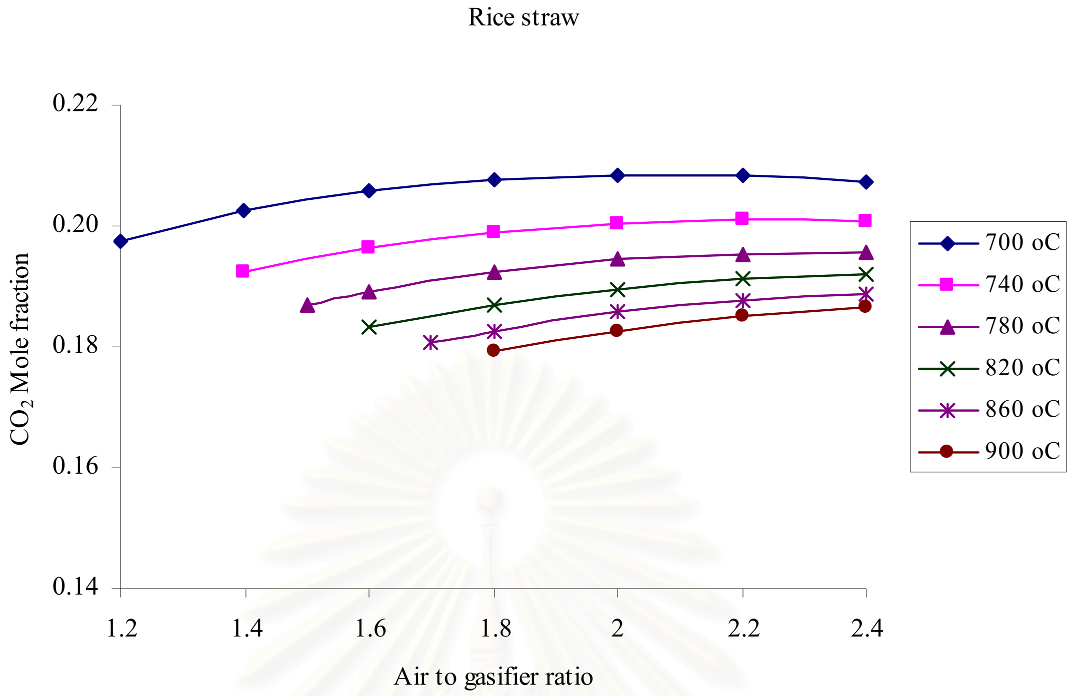

Figure 5.7 Effect of gasifier temperature and air to gasifier ratio to mole fraction of CO_2 emission for rice straw

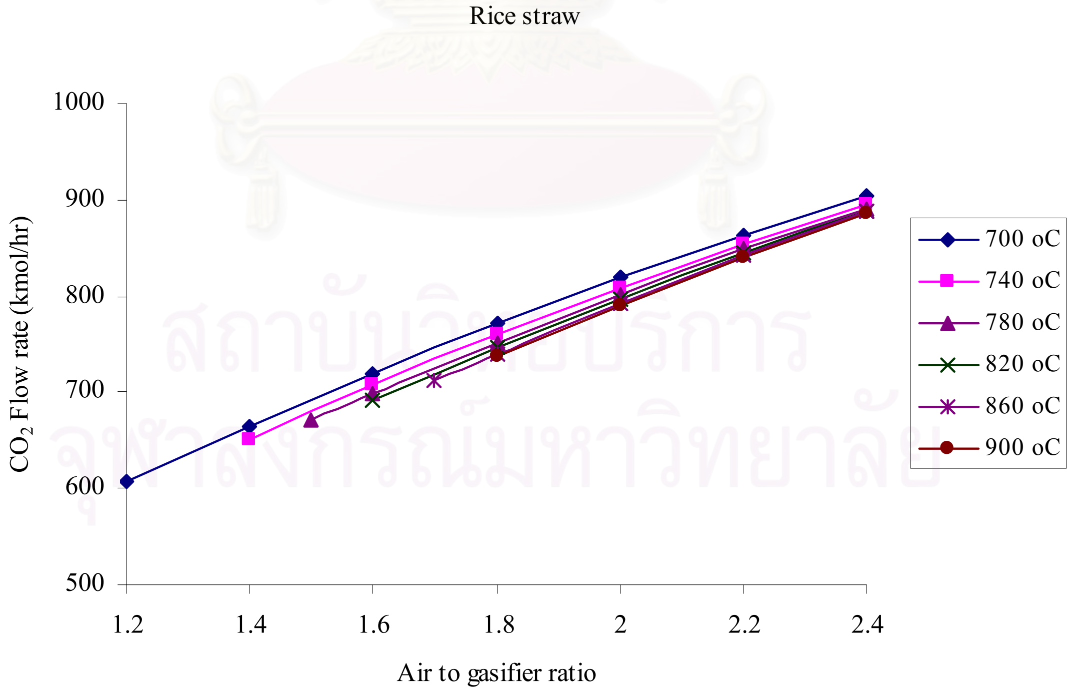

Figure 5.8 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of CO_2 emission for rice straw

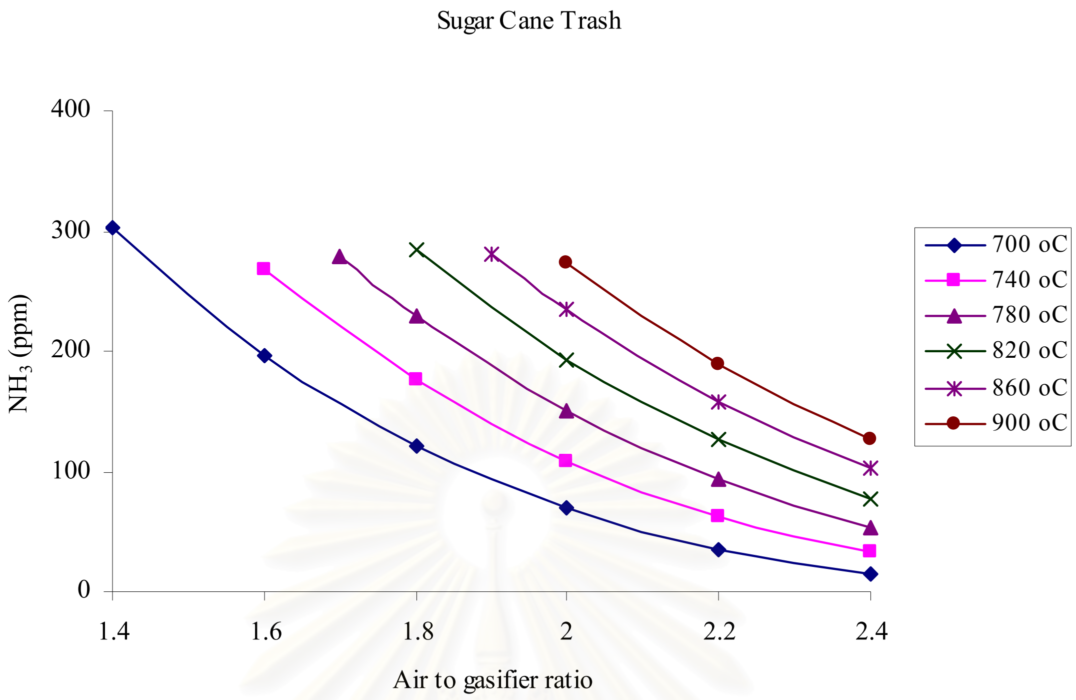

Figure 5.9 Effect of gasifier temperature and air to gasifier ratio to mole fraction of NH$_3$ emission for sugar cane trash

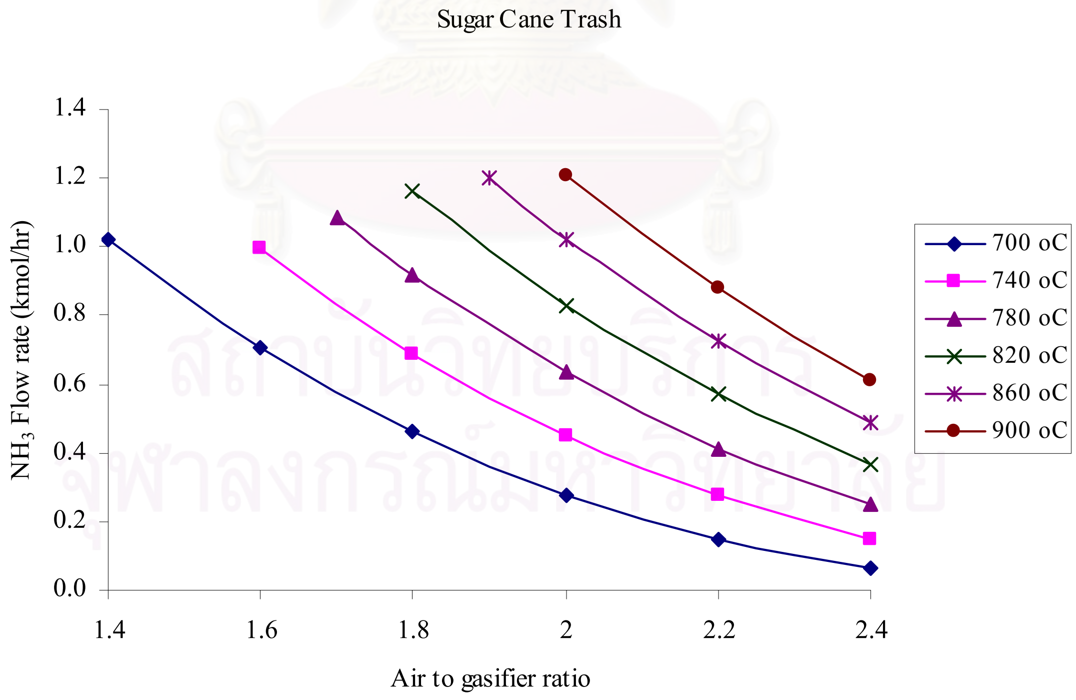

Figure 5.10 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of NH$_3$ emission for sugar cane trash

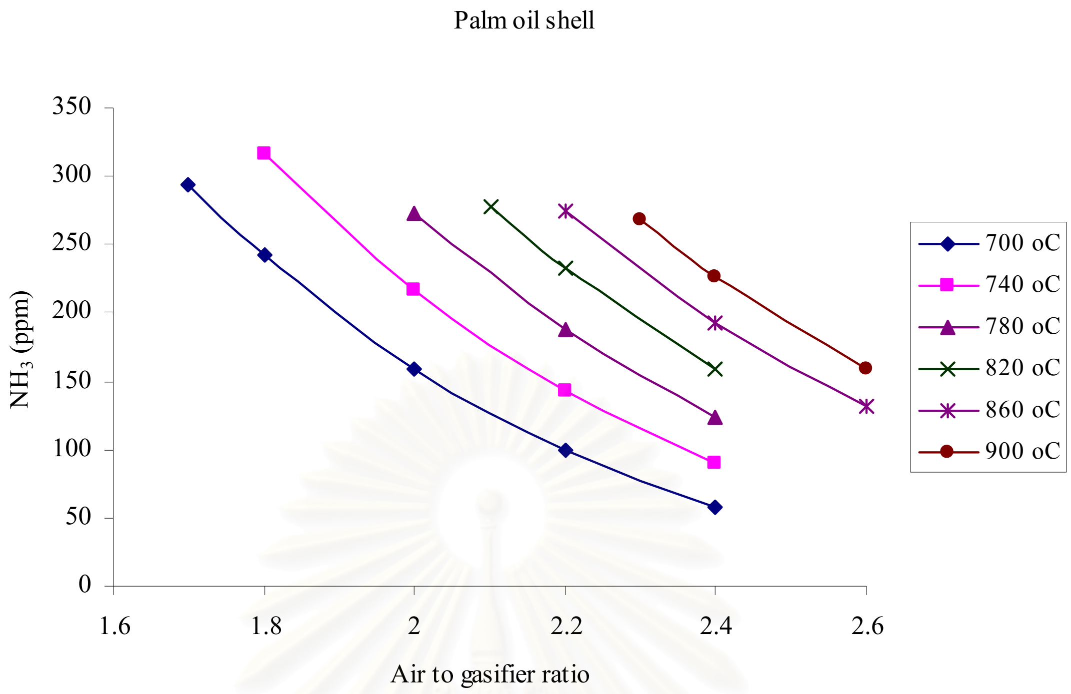

Figure 5.11 Effect of gasifier temperature and air to gasifier ratio to mole fraction of NH_3 emission for palm oil shell

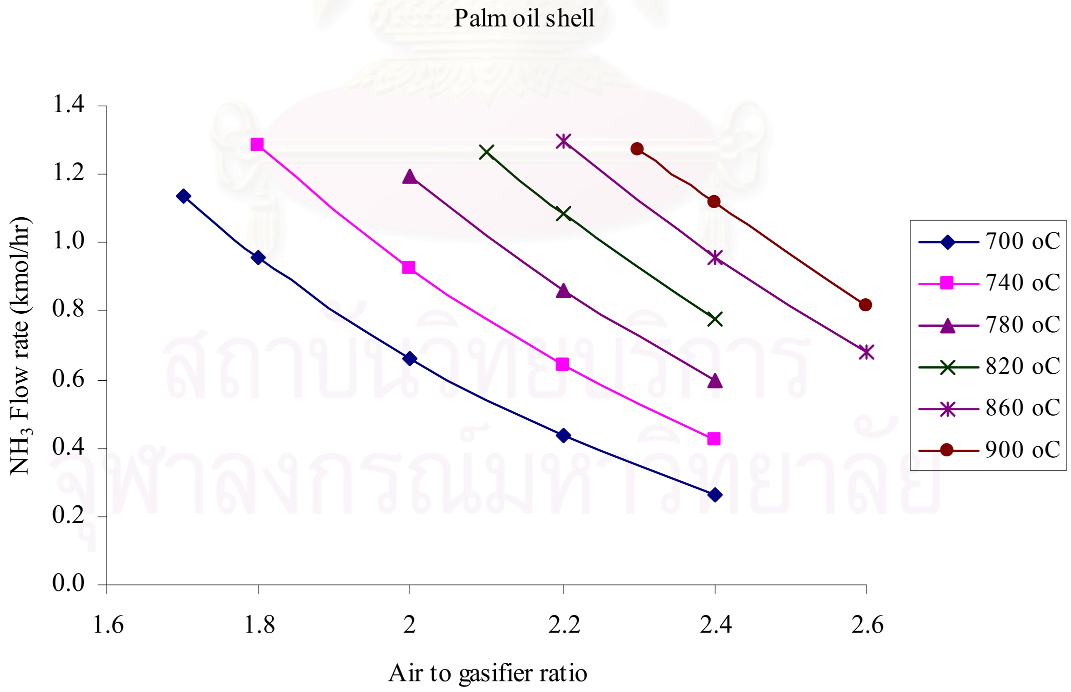

Figure 5.12 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of NH_3 emission for palm oil shell

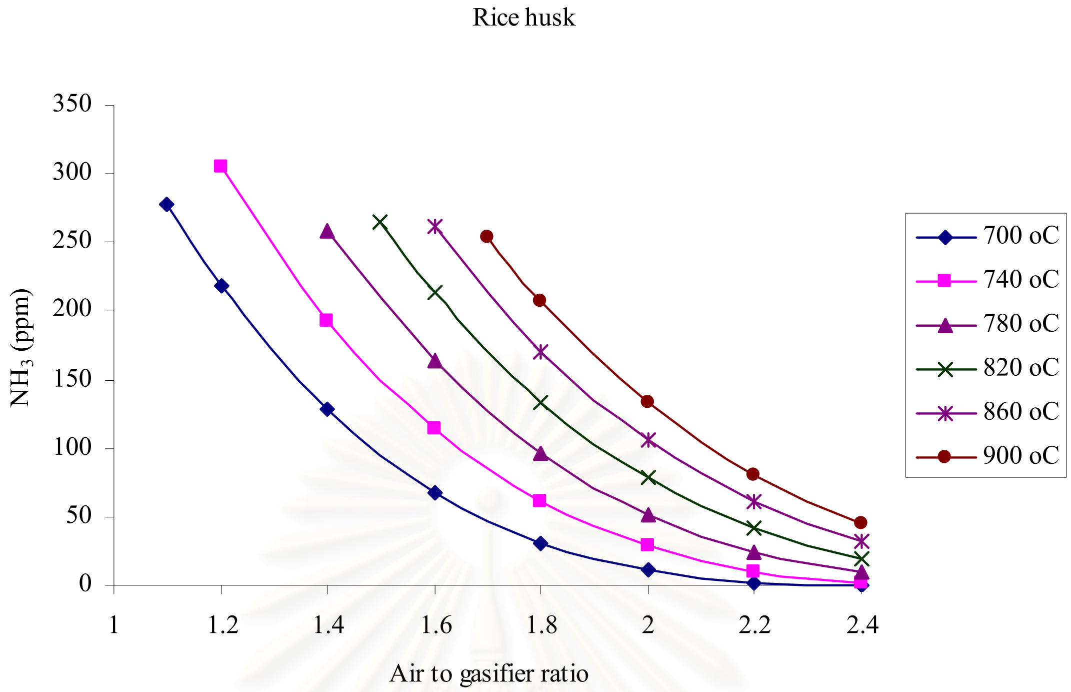

Figure 5.13 Effect of gasifier temperature and air to gasifier ratio to mole fraction of NH_3 emission for rice husk

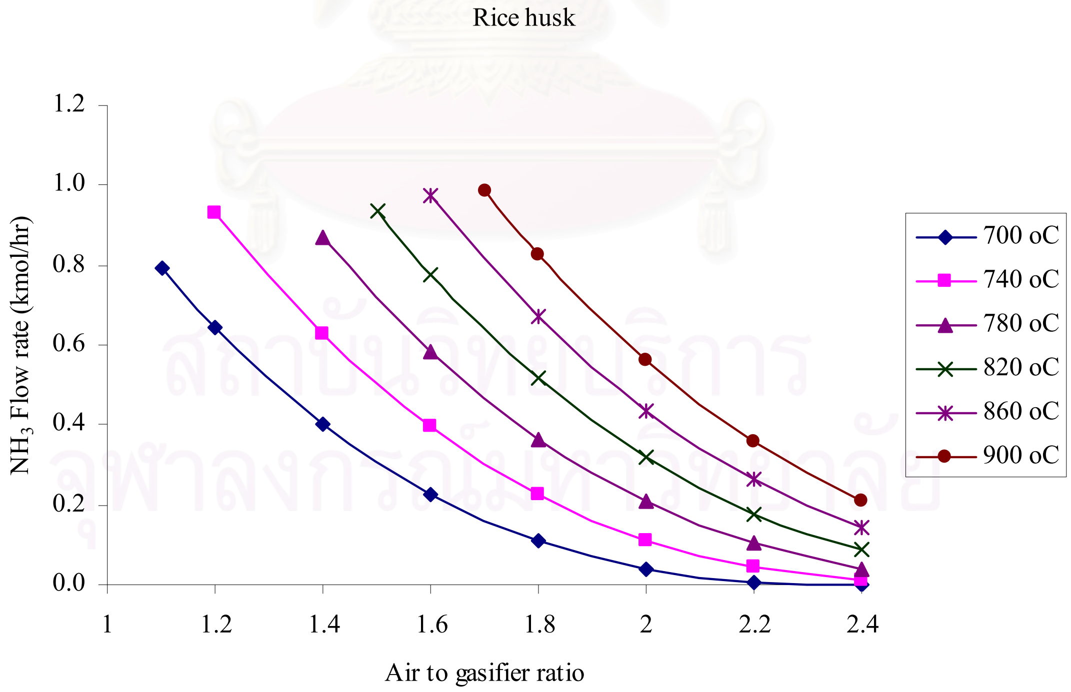

Figure 5.14 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of NH_3 emission for rice husk

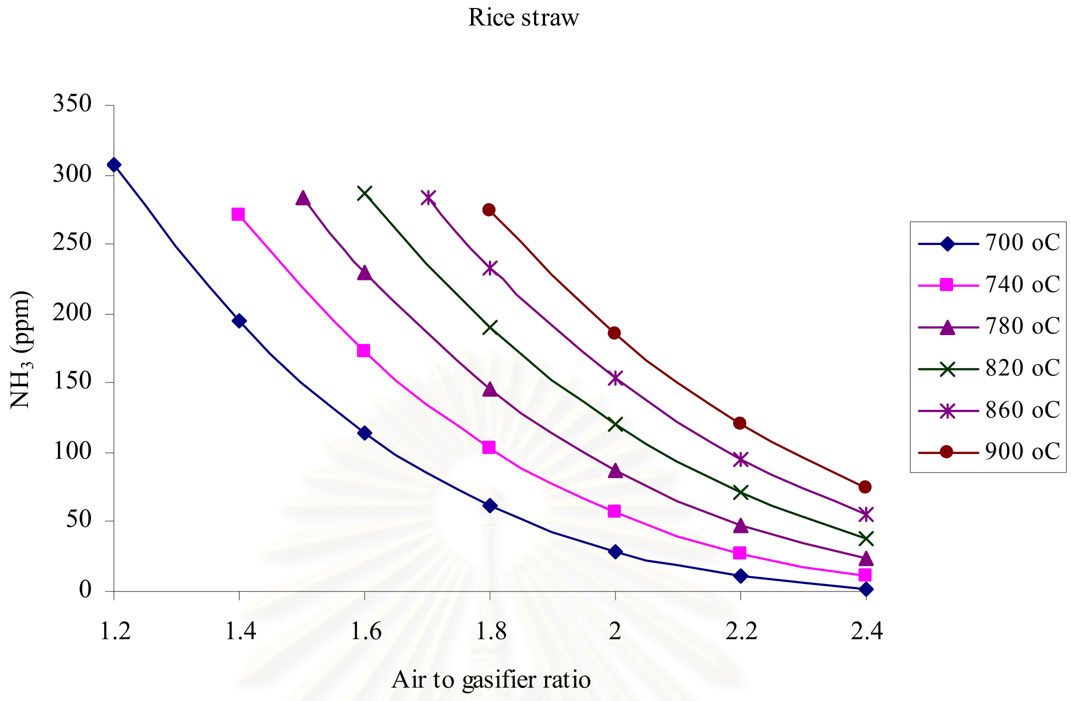

Figure 5.15 Effect of gasifier temperature and air to gasifier ratio to mole fraction of NH_3 emission for rice straw

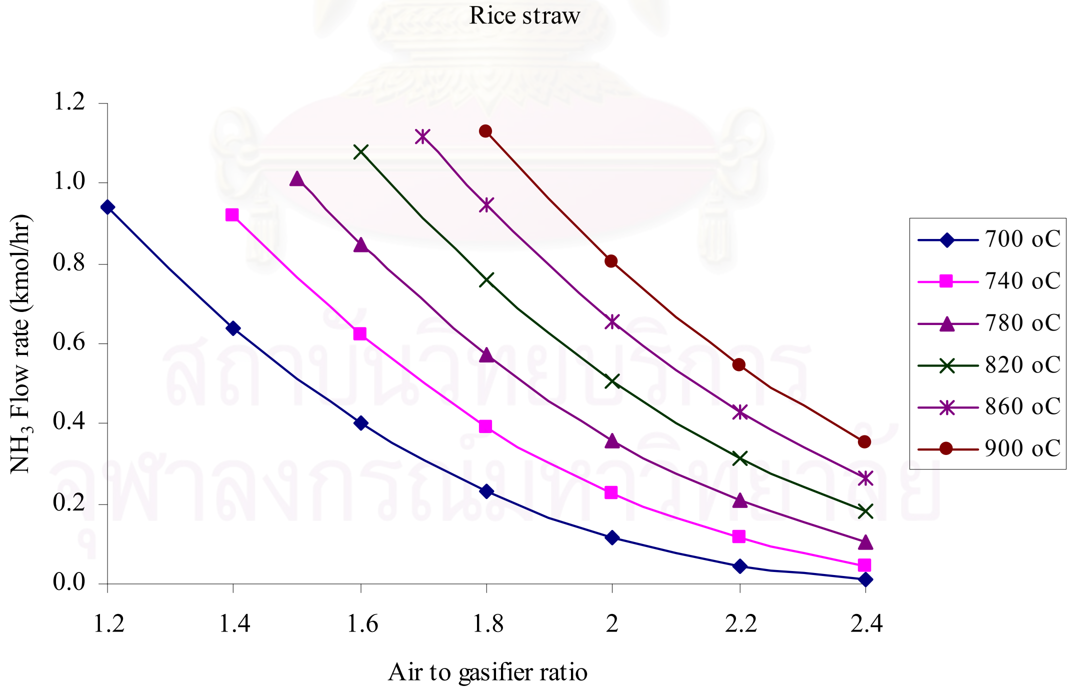

Figure 5.16 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of NH_3 emission for rice straw

Figure 5.17 Effect of gasifier temperature and air to gasifier ratio to mole fraction of H_2S emission for sugar cane trash

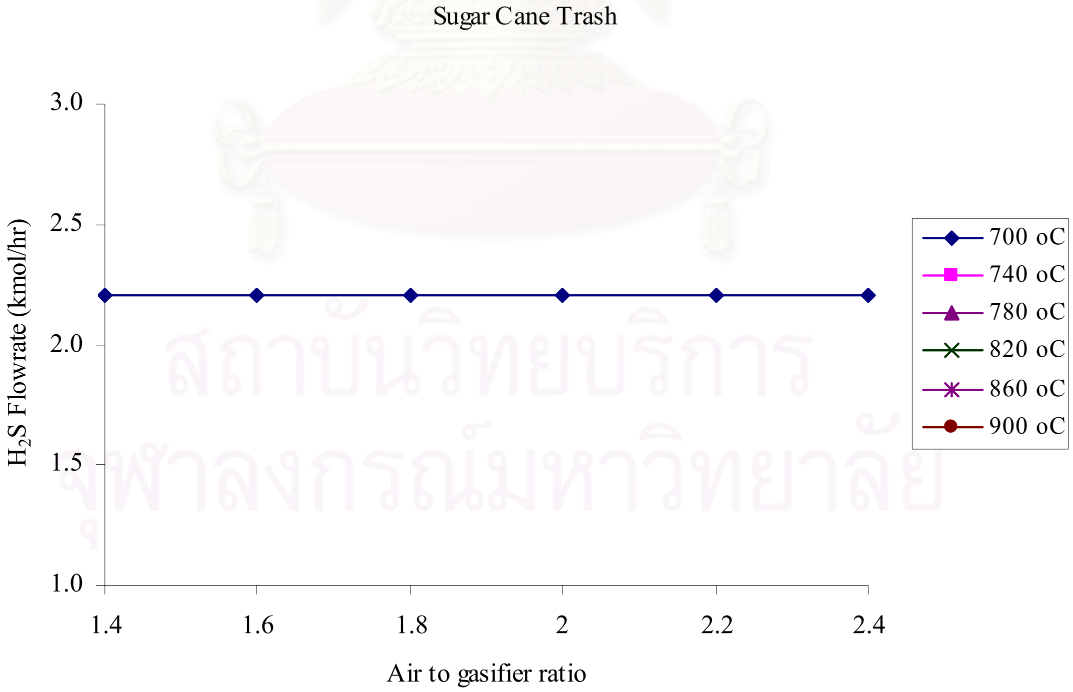

Figure 5.18 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of H_2S emission for sugar cane trash

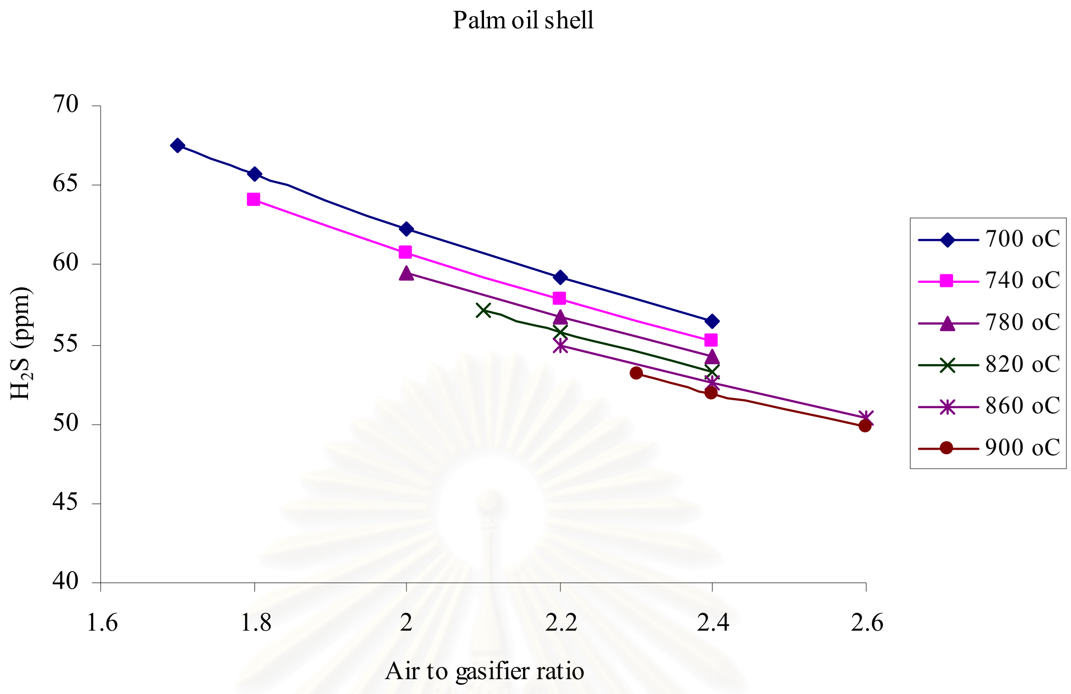

Figure 5.19 Effect of gasifier temperature and air to gasifier ratio to mole fraction of H_2S emission for palm oil shell

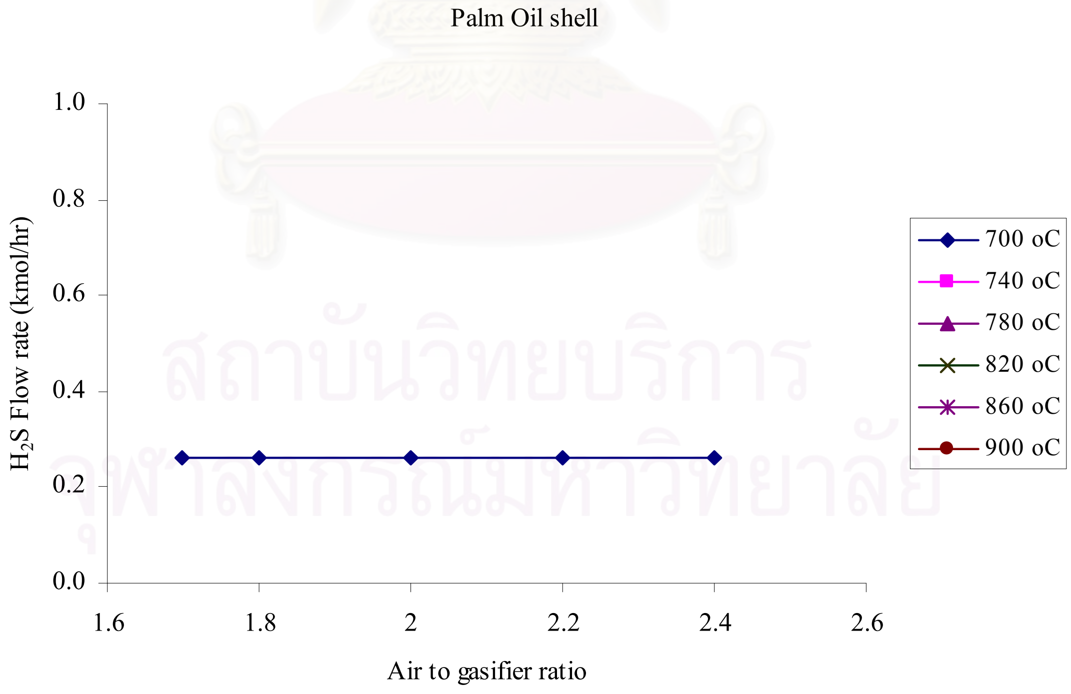

Figure 5.20 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of H_2S emission for palm oil shell

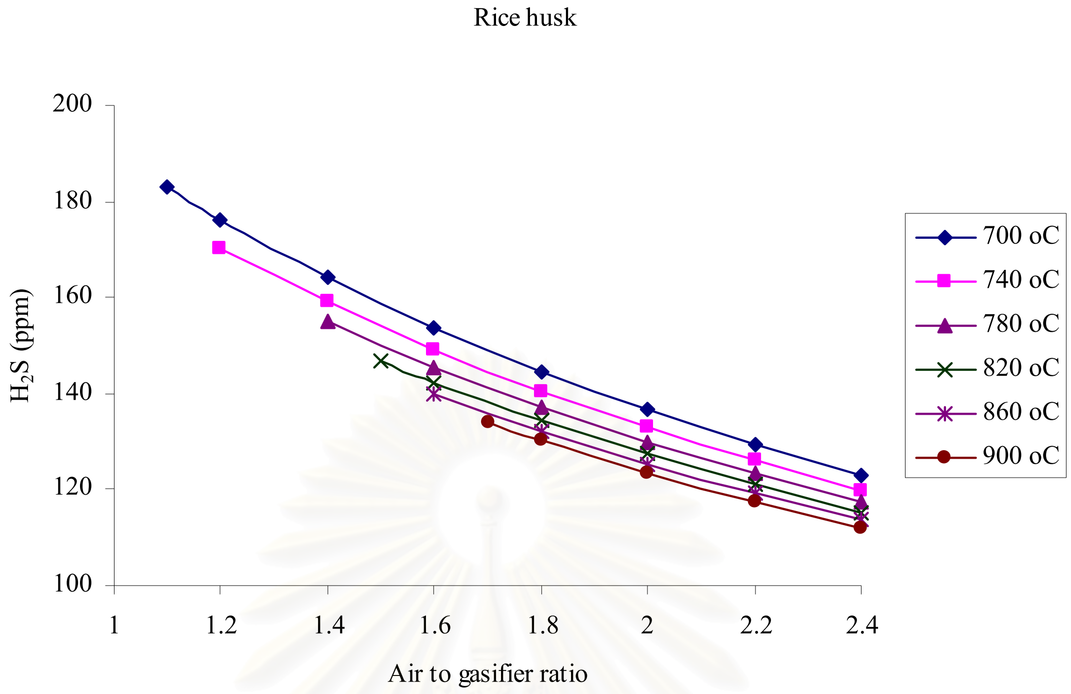

Figure 5.21 Effect of gasifier temperature and air to gasifier ratio to mole fraction of H_2S emission for rice husk

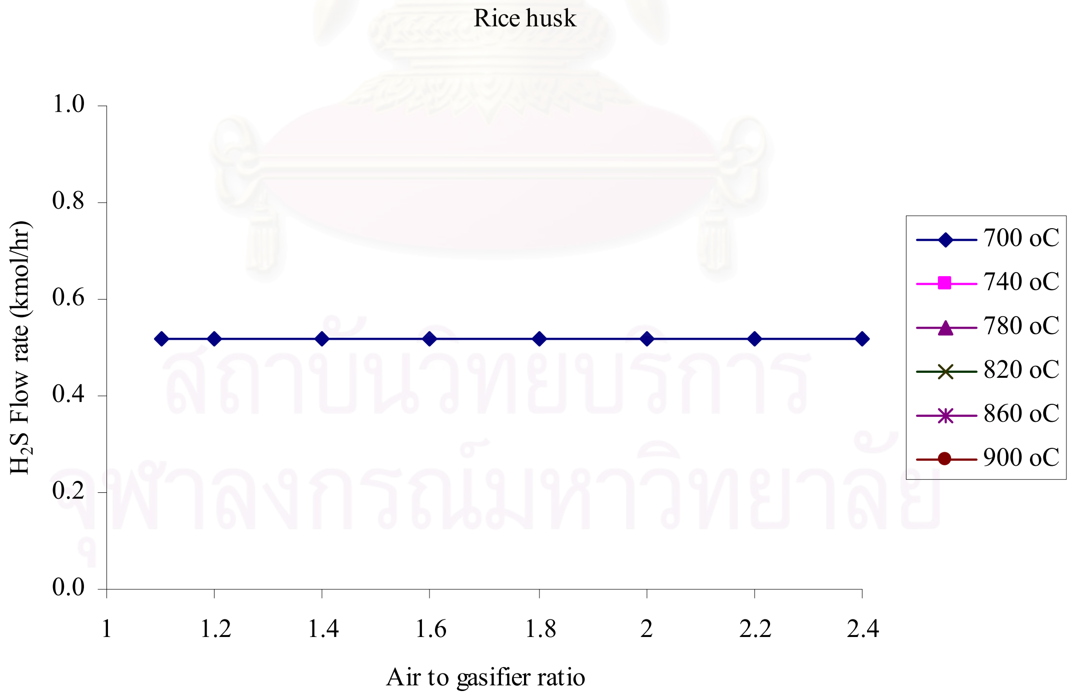

Figure 5.22 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of H_2S emission for rice husk

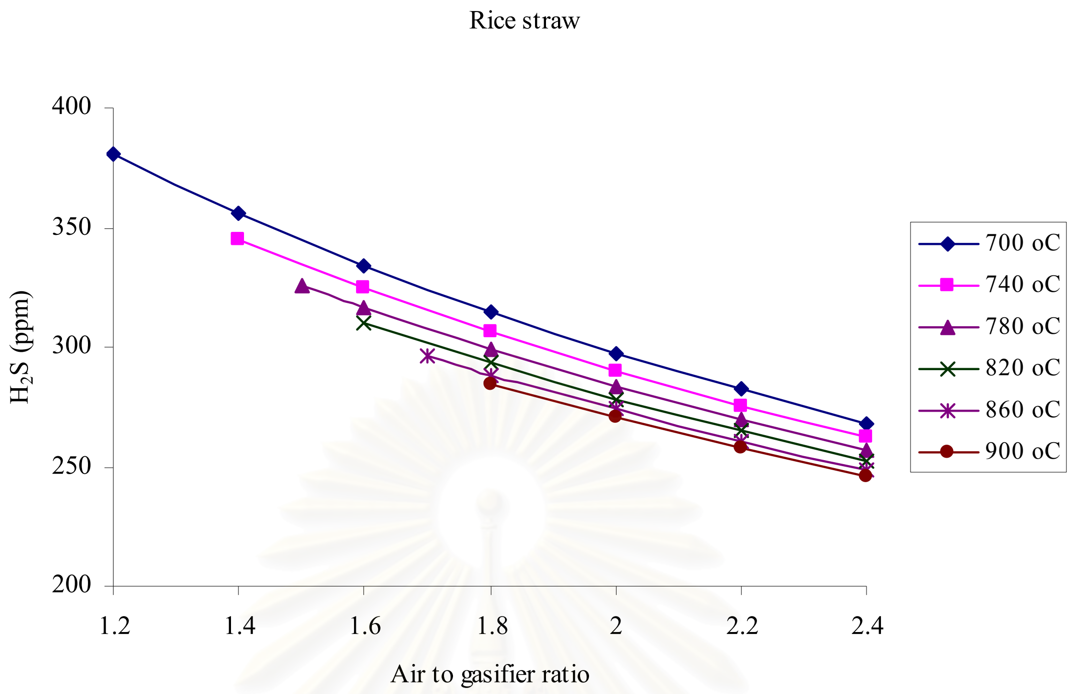

Figure 5.23 Effect of gasifier temperature and air to gasifier ratio to mole fraction of H_2S emission for rice straw

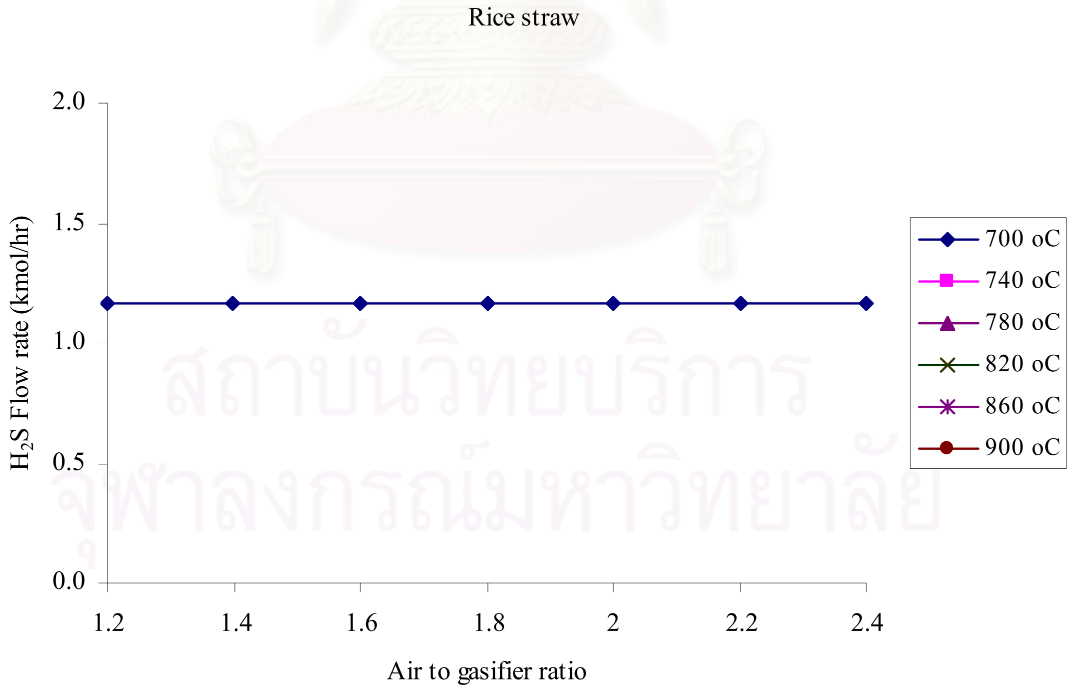

Figure 5.24 Effect of gasifier temperature and air to gasifier ratio to mole flowrate of H_2S emission for rice straw

- **Summarize the effect of operating variables to environment performance**

Actually, In generated power system must to have rarely environmental emission. Then, The influence of gasifier temperature and air to gasifier ratio to emissions are summarized in Table 5.1. Furthermore, Type of feedstock is small effect to these emissions to maintain the same gasifier temperature and air to gasifier ratio.

Table 5.1 Effect of operating variables to environmental emissions

	Temperature increasing	Air to gasifier ratio increasing
CO_2 emission	↓	↑
NH_3 emission	↑	↓
H_2S emission	↓	↓

5.2 The Influence of Operating Variables to the Efficiency and Net Power of Biomass-Based IGCC System

5.2.1 The Influence of Gasifier Temperature

The gasifier temperature is expected to be one of the most important operating variables affecting the performance of gasifier. Then, it certainly effect to efficient of IGCC system too. From Figs. 5.25 - 5.32, it can be shown that the efficiency and net power small increase with increasing gasifier temperature. Furthermore, these tend to effect in every feedstock in this study. It cause of CO and H_2 mole fraction, called syngas, increase with increasing gasifier temperature [23] but the temperature and pressure of gasification do not appear to significantly affect overall conversion efficiencies other than by degree to which it affects the efficiency of the gasification process itself [27].

5.2.2 The Effluence of Air to Gasifier Ratio

From Figures 5.33 - 5.40, its can be shown that the efficiency and net power increase with increasing air to gasifier ratio. Moreover, these tend to be effect in every feedstock in this study. The increased air in gasifier increases the volume of gas passing through the gasification, gas cleanup and gas turbine system. For this reason is caused to higher gas for driven gas turbine and higher energy for generated steam for driving steam turbine.

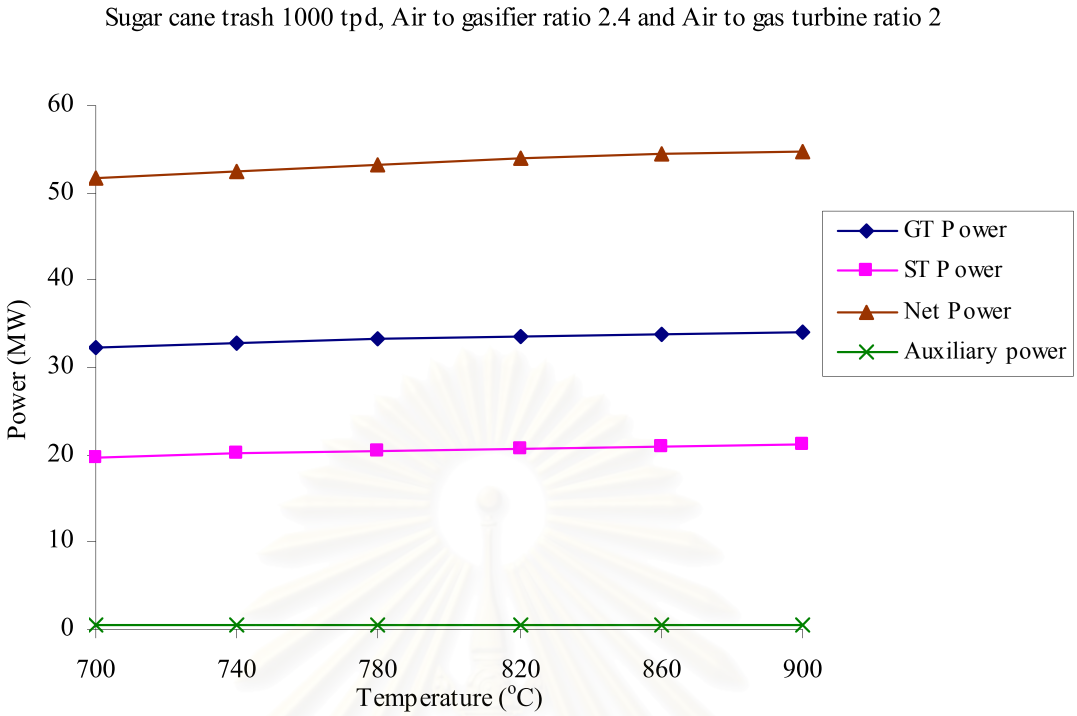

Figure 5.25 Effect of gasifier temperature to the net power for sugar cane trash

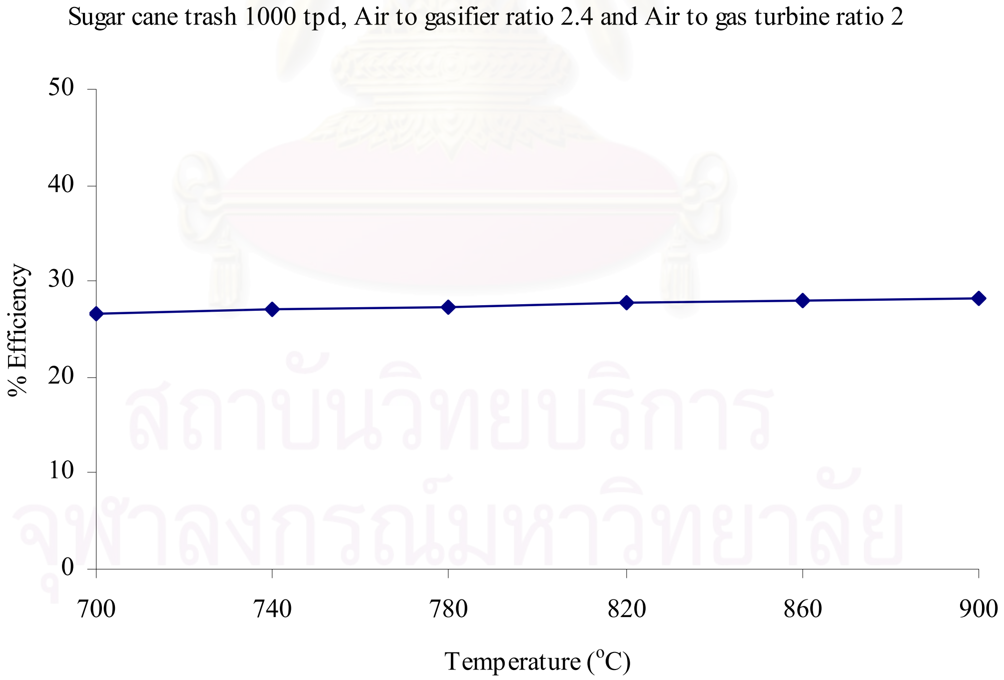

Figure 5.26 Effect of gasifier temperature to the efficiency for sugar cane trash

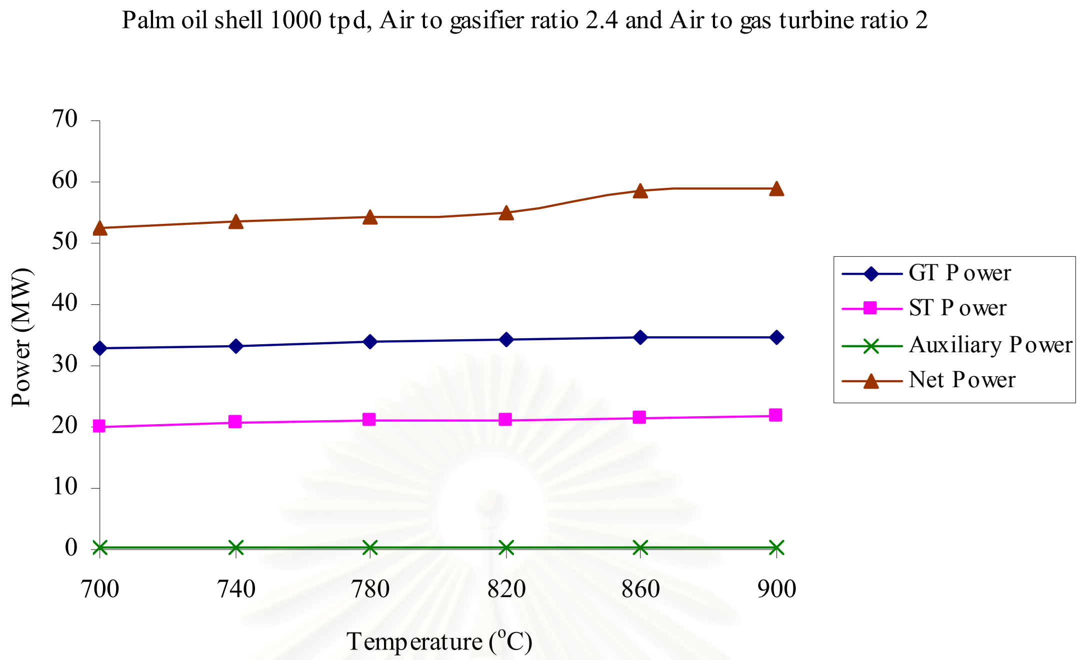

Figure 5.27 Effect of gasifier temperature to the net power for palm oil shell

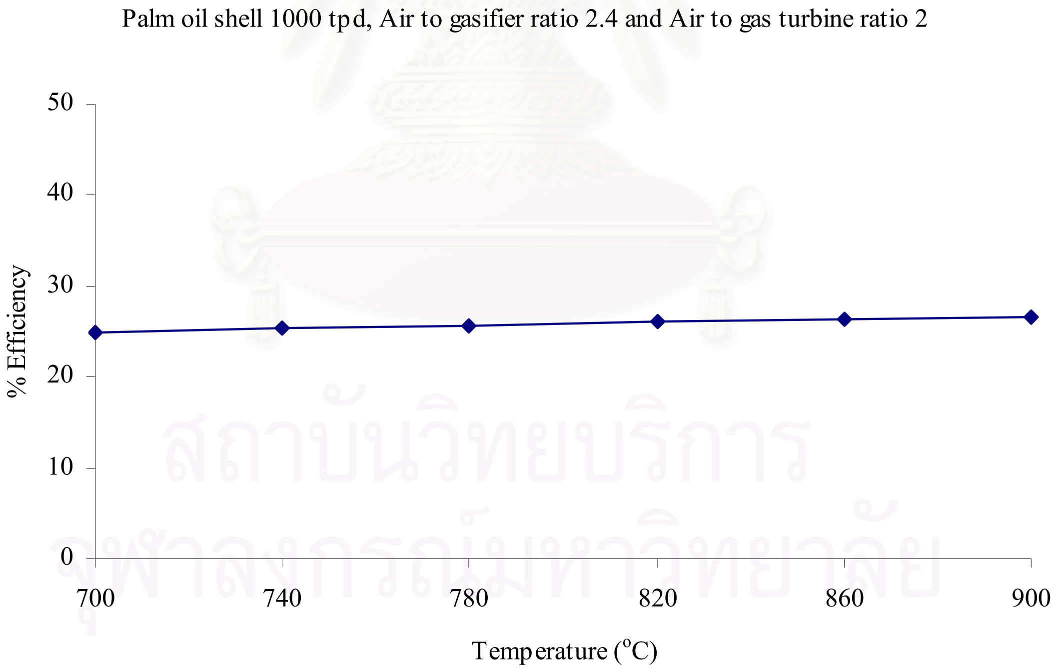

Figure 5.28 Effect of gasifier temperature to the efficiency for palm oil shell

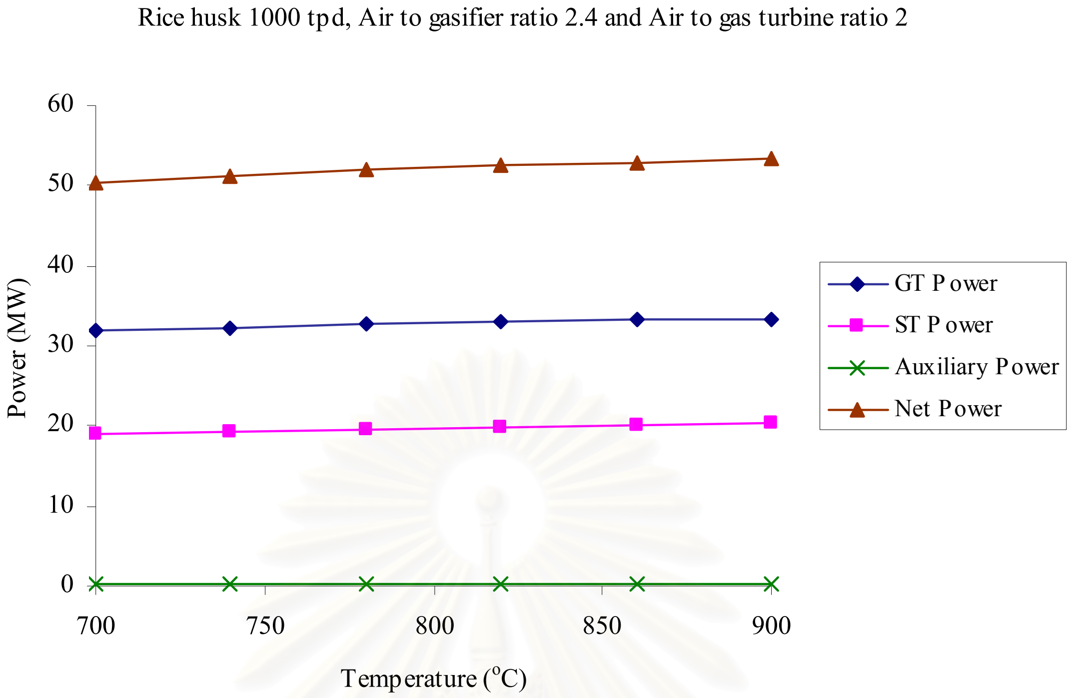

Figure 5.29 Effect of gasifier temperature to the net power for rice husk

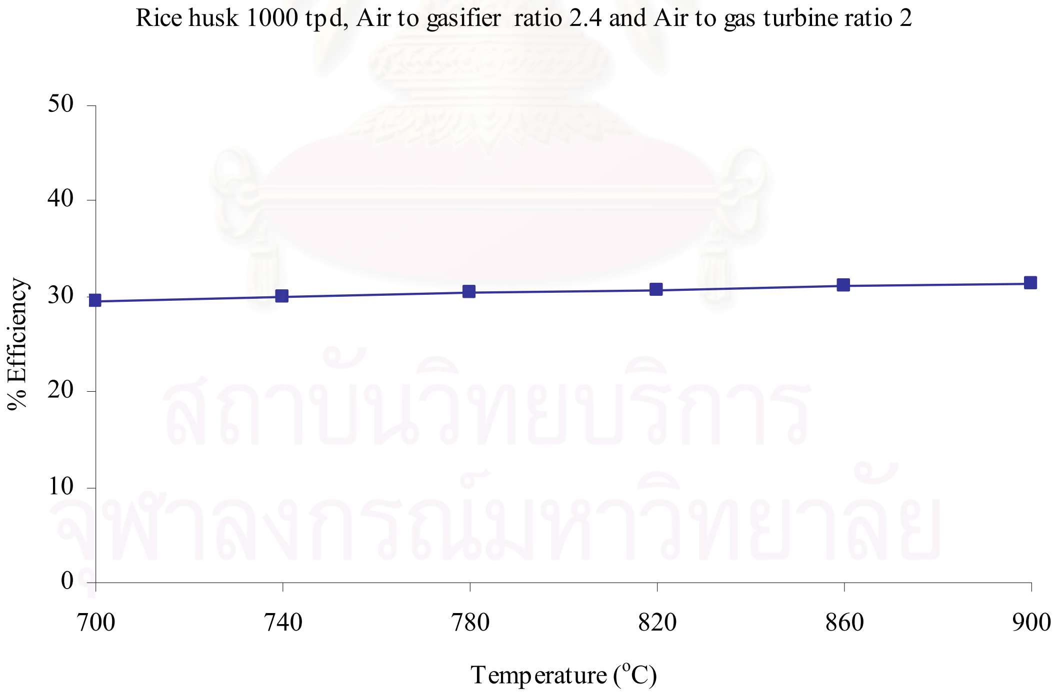

Figure 5.30 Effect of gasifier temperature to the efficiency for rice husk

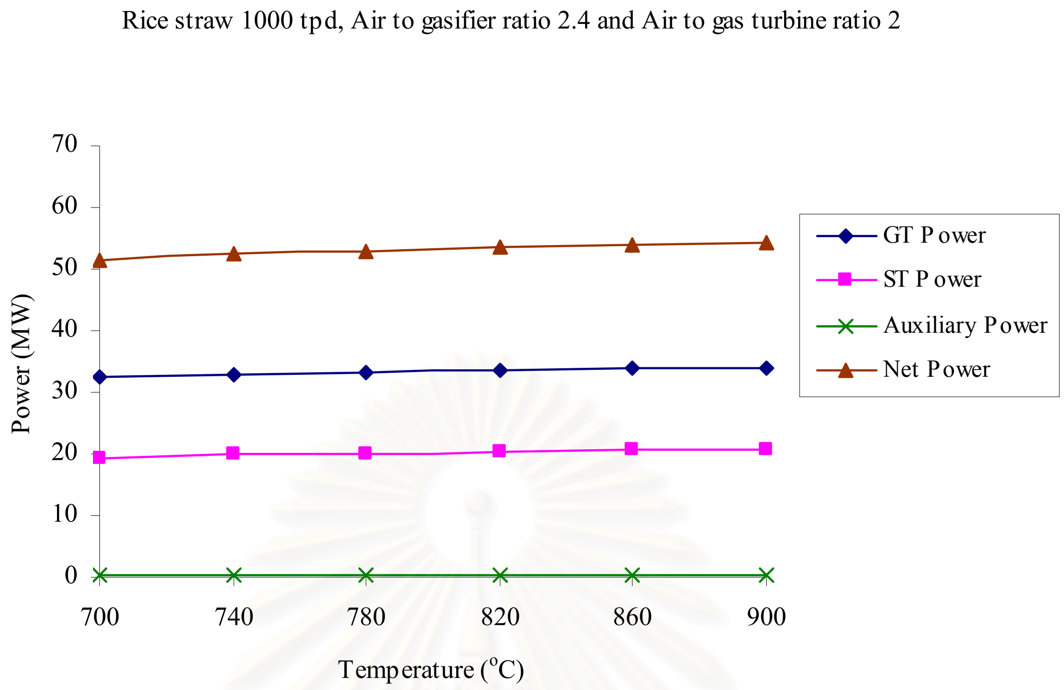

Figure 5.31 Effect of gasifier temperature to the net power for rice straw

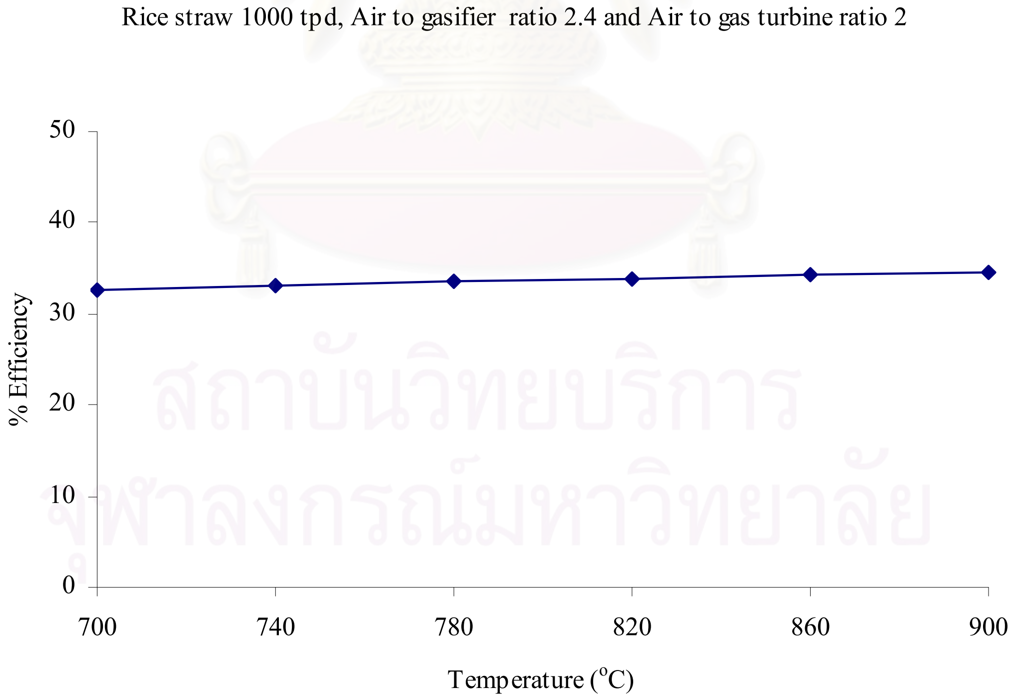

Figure 5.32 Effect of gasifier temperature to the efficiency for rice straw

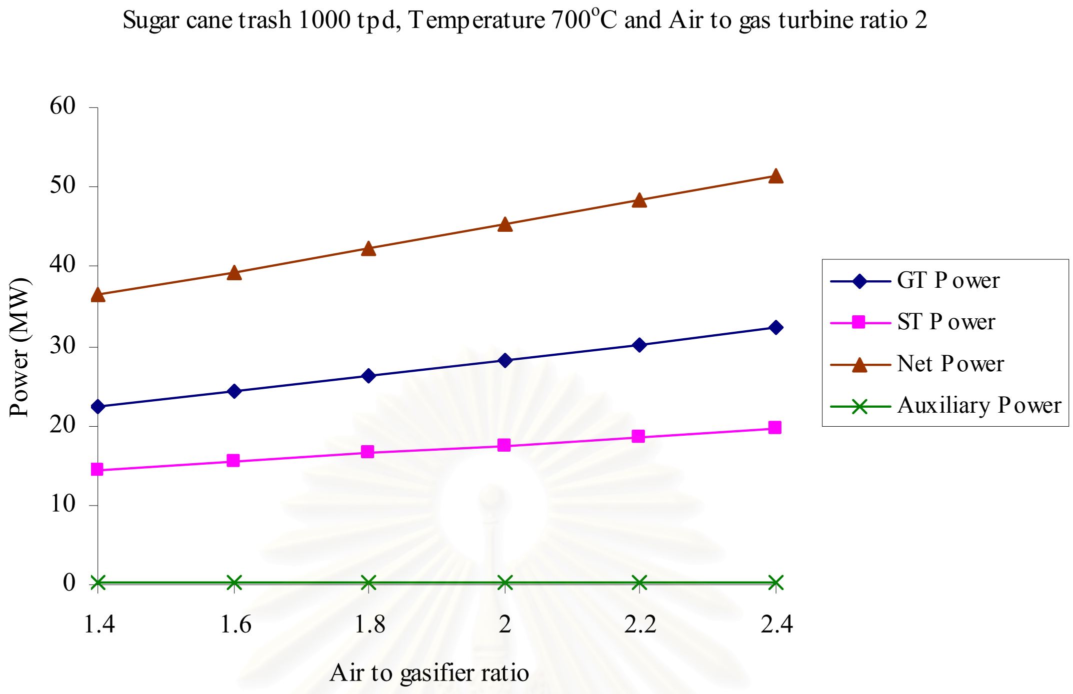

Figure 5.33 Effect of air to gasifier ratio to the net power for sugar cane trash

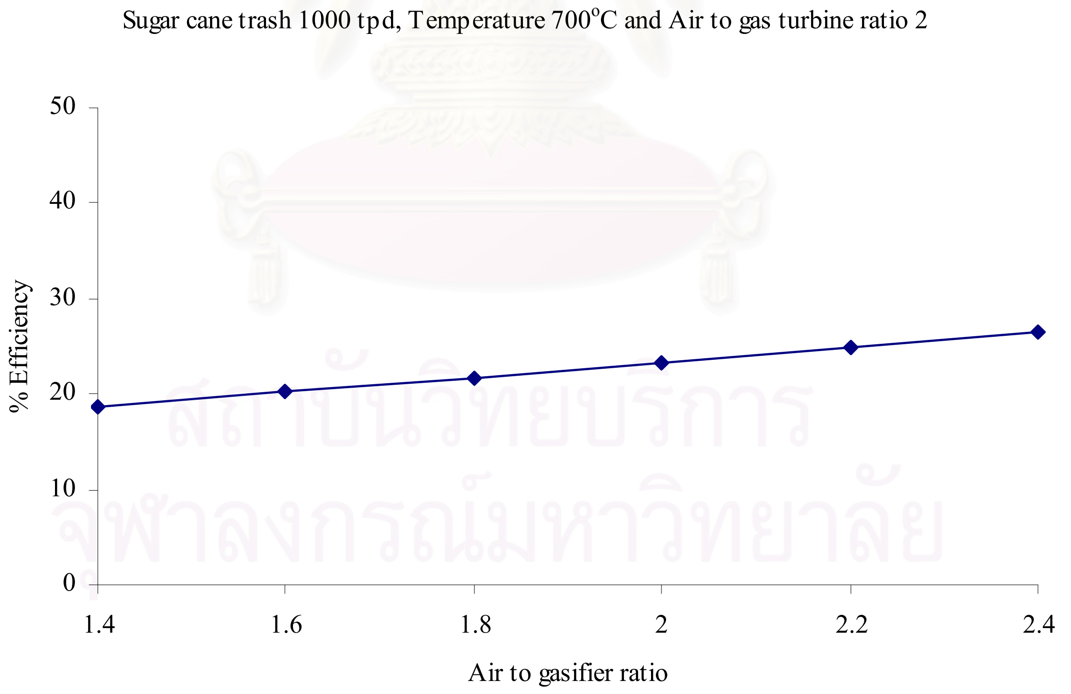

Figure 5.34 Effect of air to gasifier ratio to the efficiency for sugar cane trash

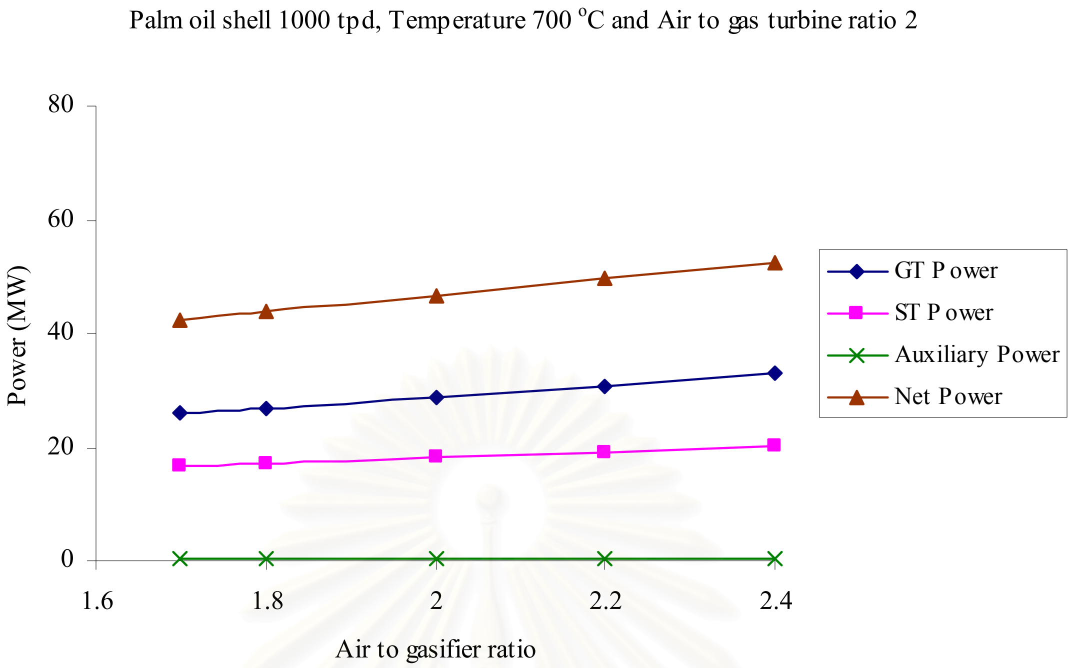

Figure 5.35 Effect of air to gasifier ratio to the net power for palm oil shell

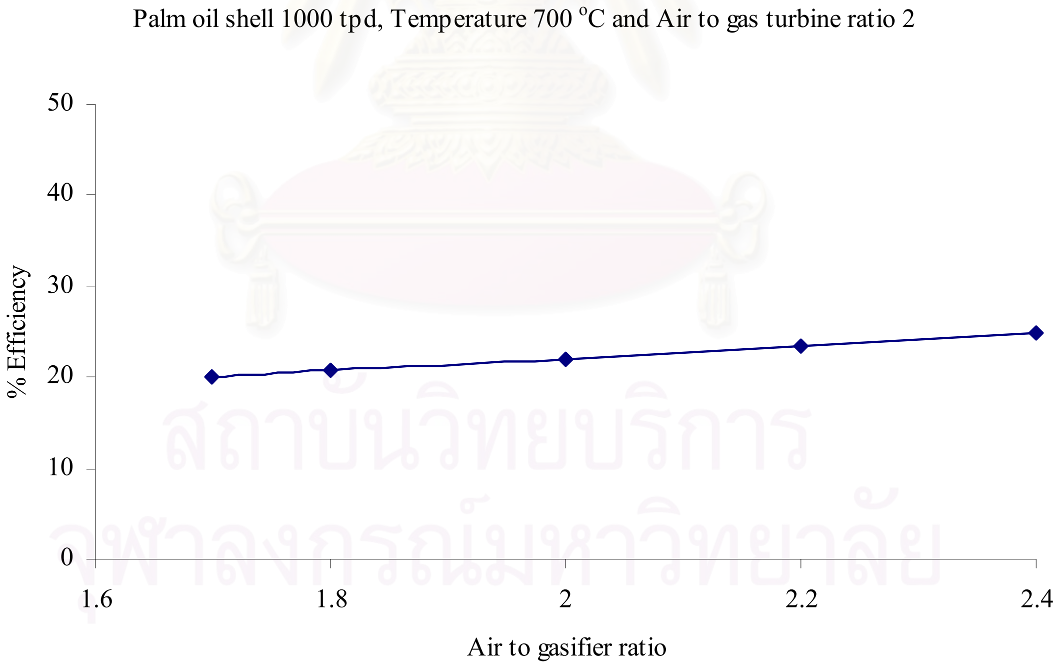

Figure 5.36 Effect of air to gasifier ratio to the efficiency for palm oil shell

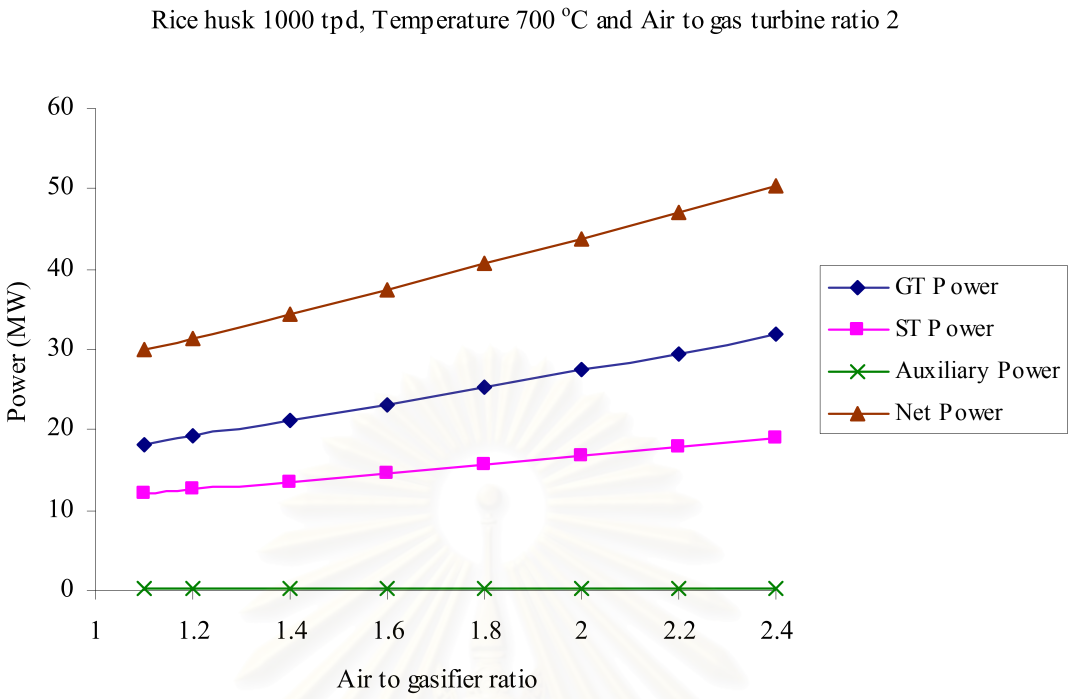

Figure 5.37 Effect of air to gasifier ratio to the net power for rice husk

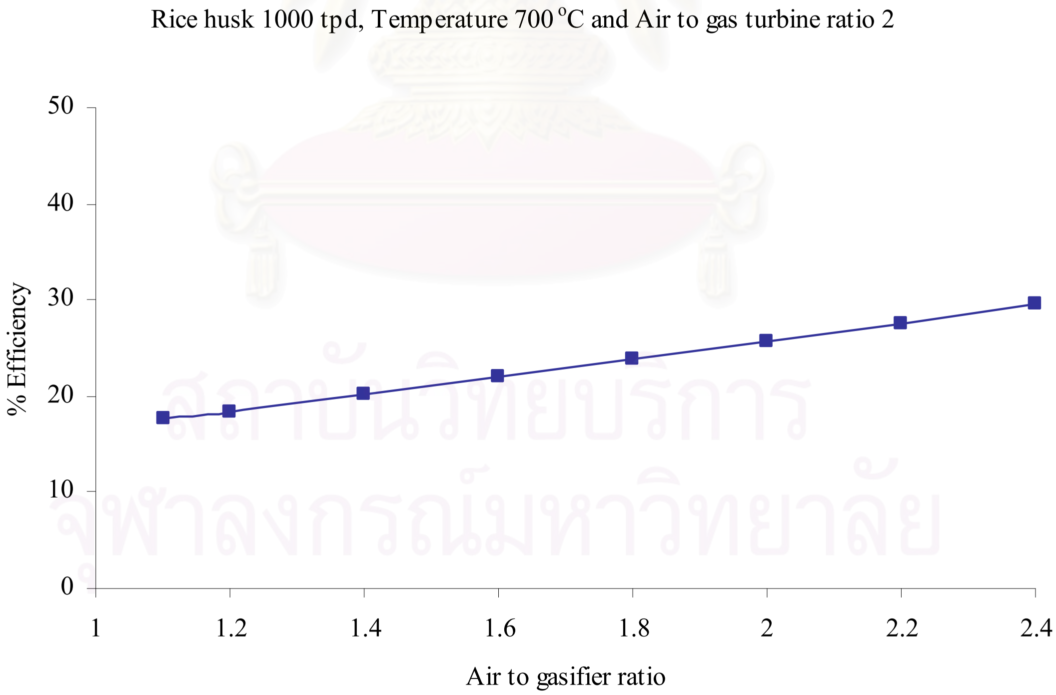

Figure 5.38 Effect of air to gasifier ratio to the efficiency for rice husk

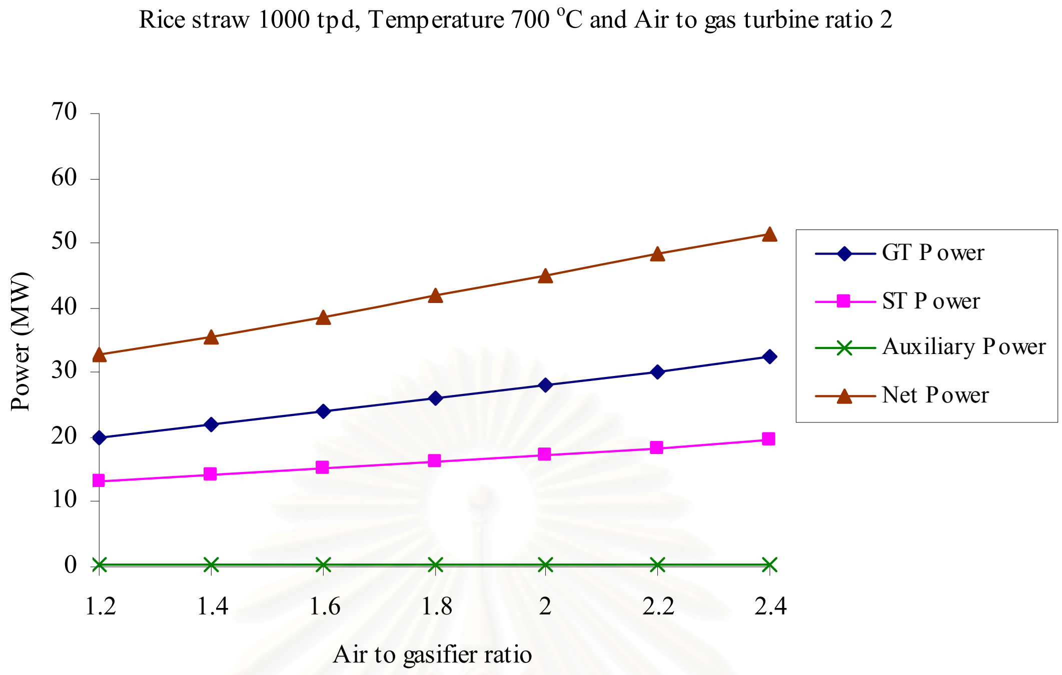

Figure 5.39 Effect of air to gasifier ratio to the net power for rice straw

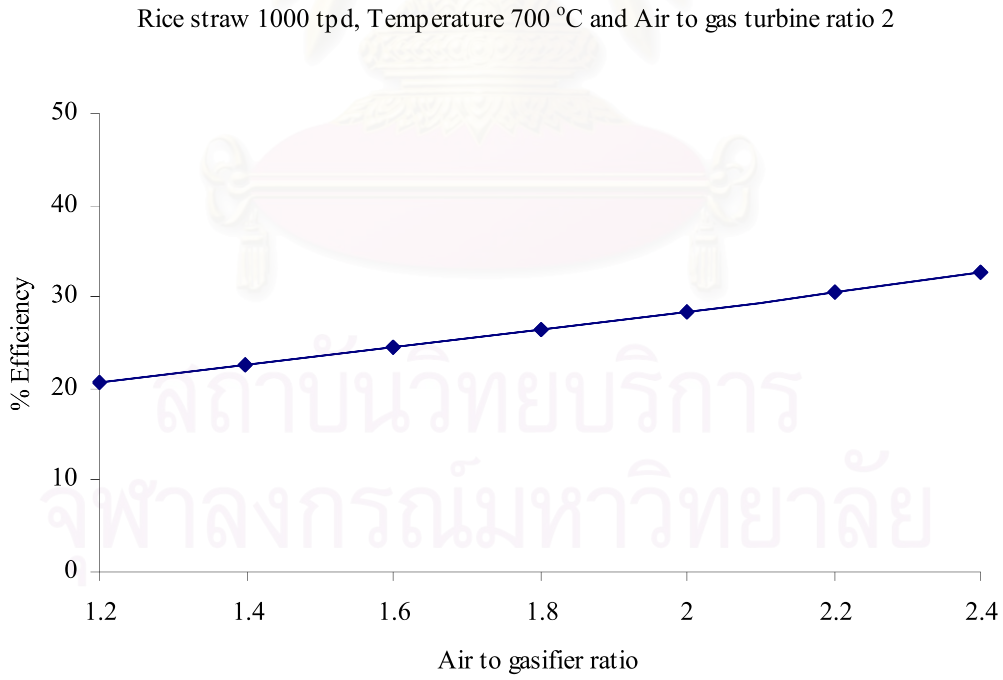

Figure 5.40 Effect of air to gasifier ratio to the efficiency for rice straw

5.2.3 The Influence of Air to Gas Turbine Ratio

From Figures 5.41 - 5.48, it can be shown that the efficiency and net power increase with increasing air to gas turbine ratio and these tends to be effect in every feedstock in this study. In the same reason with increasing air to gasifier ratio, the increased air in gas turbine increases the volume of gas passing through the gas turbine system, caused to higher gas for driven gas turbine and higher energy for generated steam for driving steam turbine.

5.2.4 The Influence of Feedstock Flowrate

The results of effect of feedstock flow rate to the net power ,shown in Figs. 5.49 and 5.56, are shown the efficiency and net power are increase when increased feedstock flowrate and this trends effect to every feedstock in this study. The increased mass flow of fuel and therefore the high mass flow rate through the turbine will lead to and increased net power output [18]. However, it doesn't increase the efficiency because calculation of the efficiency, related to Equation (4.15), based on a higher heating value basis. When the net power is increased, the energy from feedstock increases too.

5.2.5 The Influence of Types of Feedstock

The results of effect of types of feedstock to the net power and efficiency are shown in Figs. 5.57, 5.58. The most net power come from palm oil shell, and sugar cane trash, rice straw and rice husk, respectively. On the other hand, Rice straw, shown in Figure 16, is the most efficiency to produced power in this study because , comparison of feedstock and referred to Equation (4.15) , the difference of HHV of feedstock is more than the difference of net power at the same operating condition. Then the efficiency come from rice straw, and rice husk, sugar cane trash and palm oil shell, respectively.

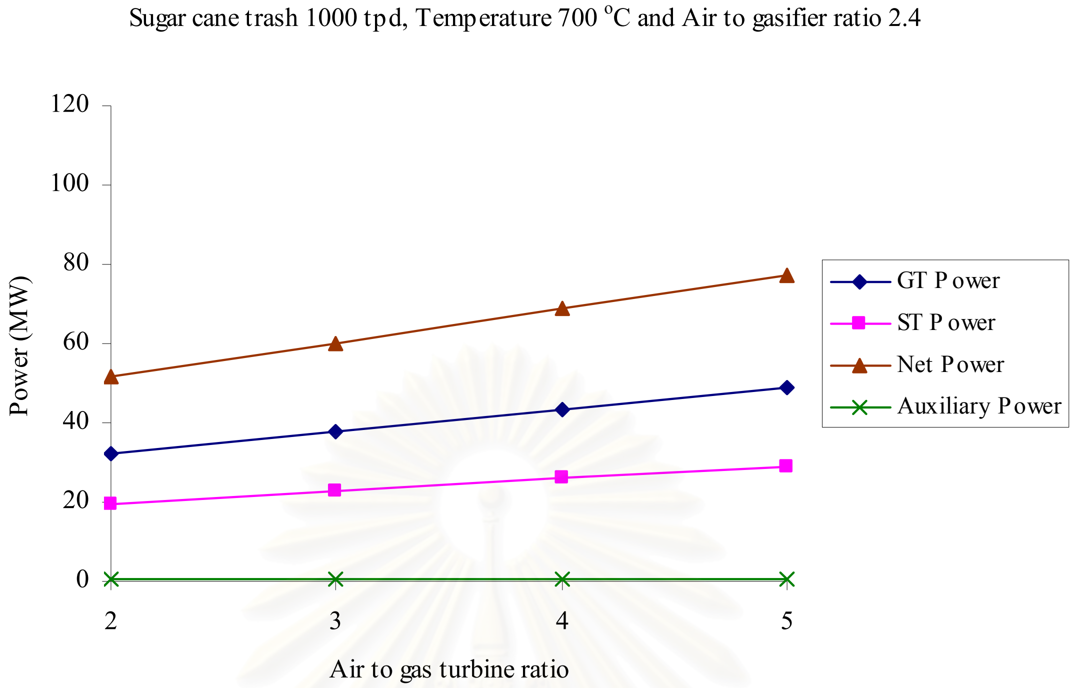

Figure 5.41 Effect of air to gas turbine ratio to the net power for sugar cane trash

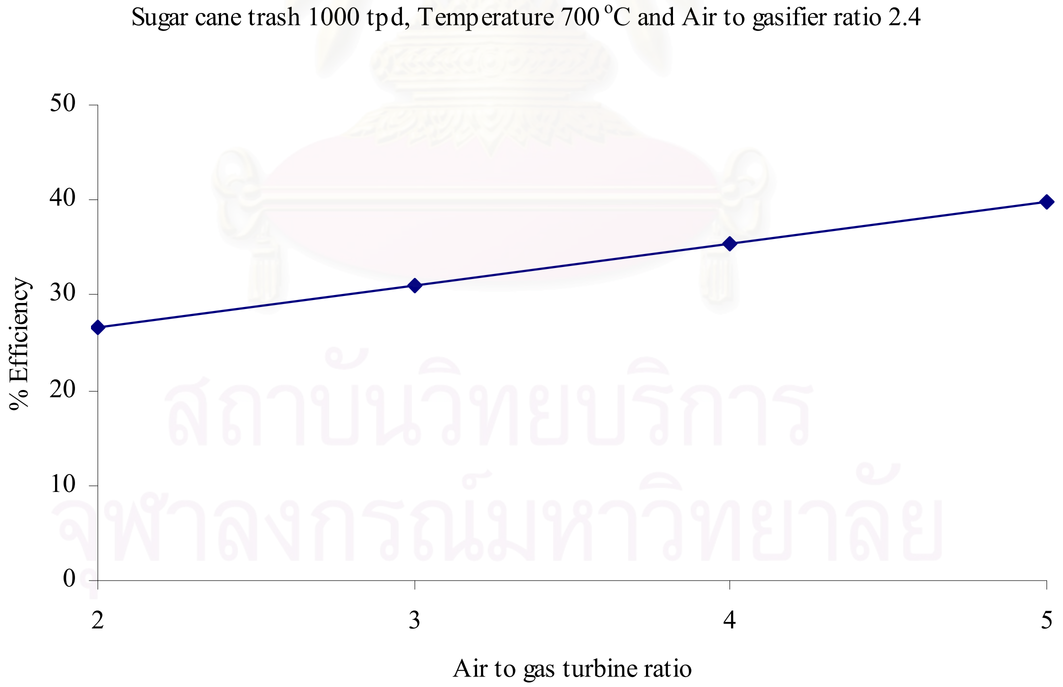

Figure 5.42 Effect of air to gas turbine ratio to the efficiency for sugar cane trash

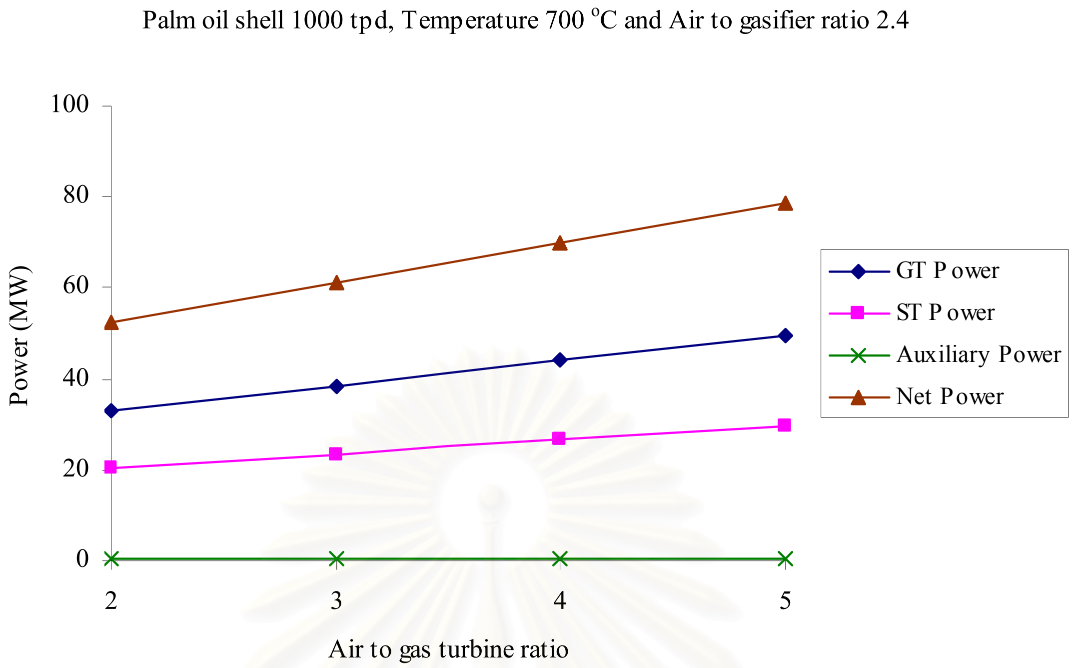

Figure 5.43 Effect of air to gas turbine ratio to the net power for palm oil shell

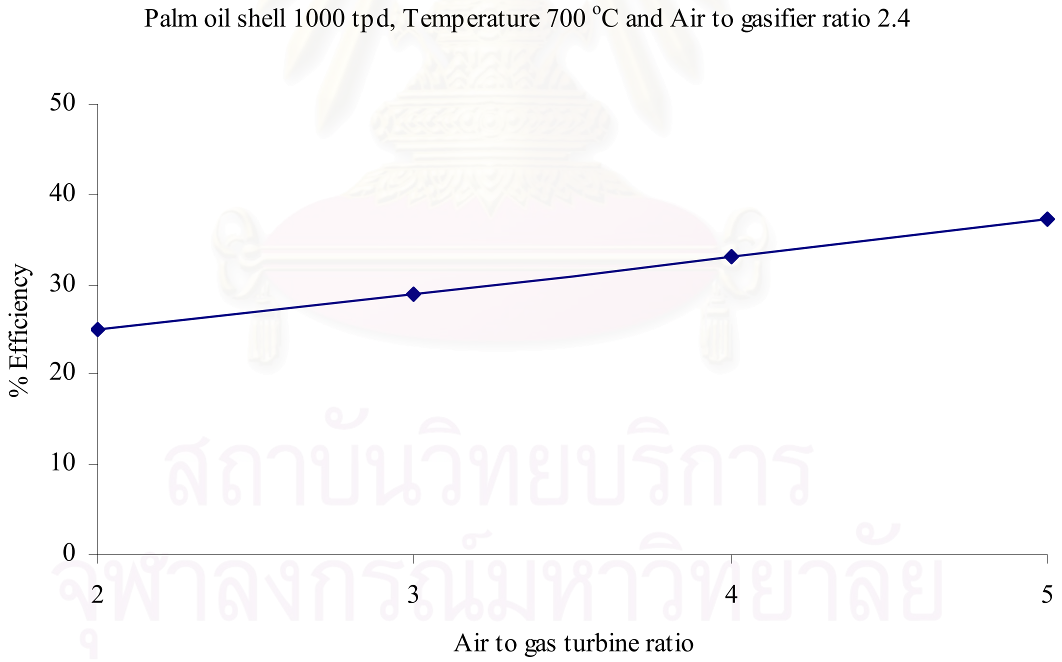

Figure 5.44 Effect of air to gas turbine ratio to the efficiency for palm oil shell

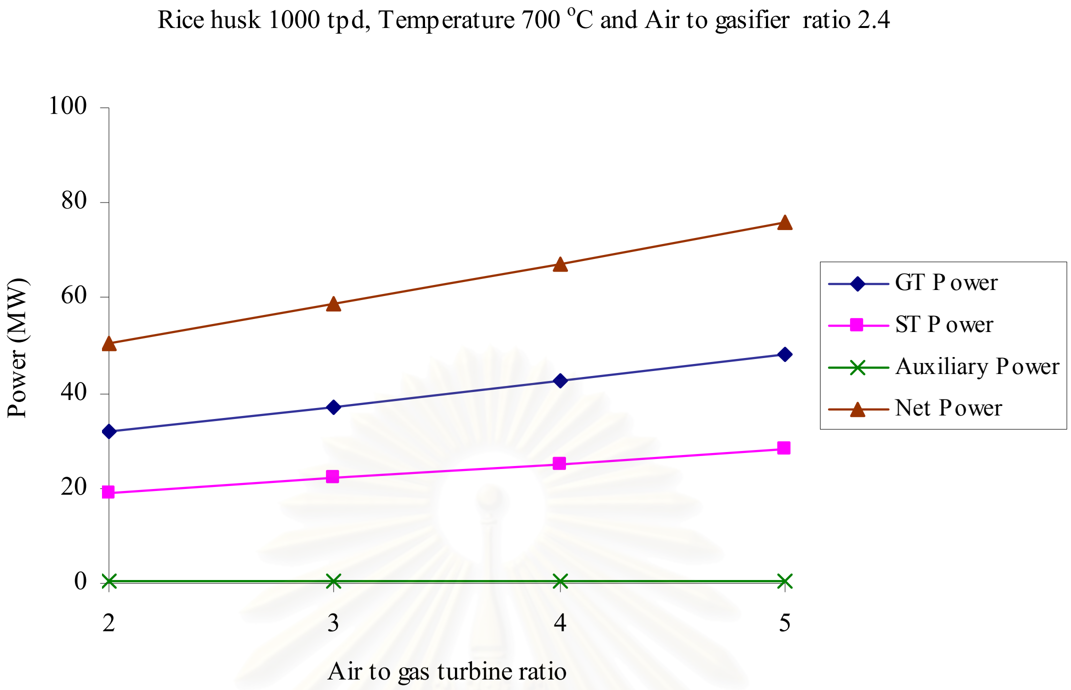

Figure 5.45 Effect of air to gas turbine ratio to the net power for rice husk

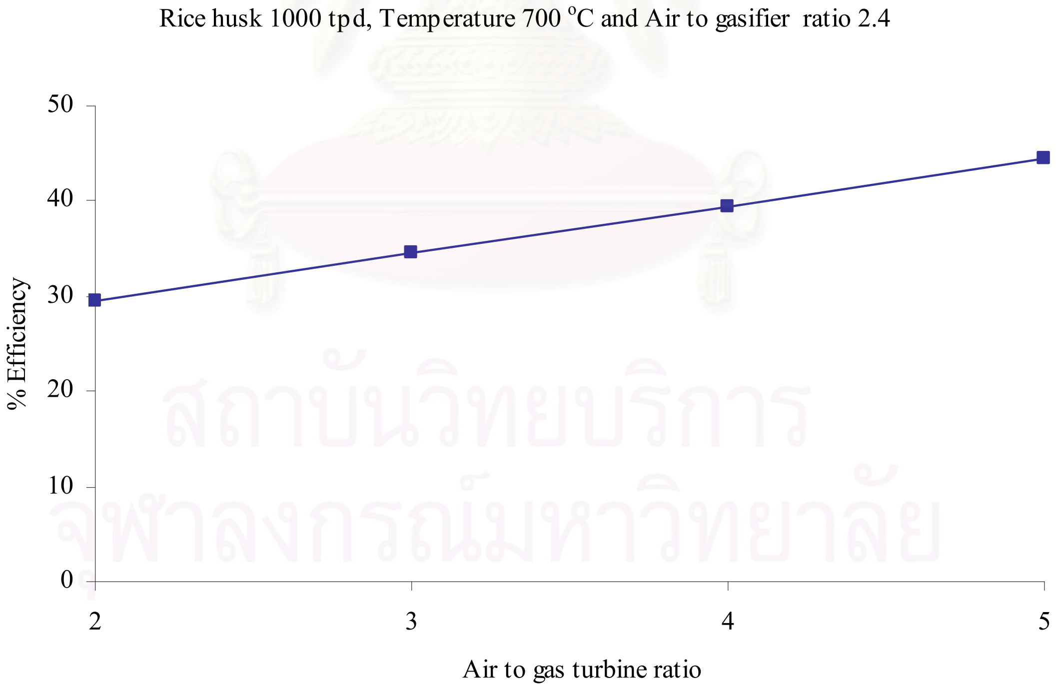

Figure 5.46 Effect of air to gas turbine ratio to the efficiency for rice husk

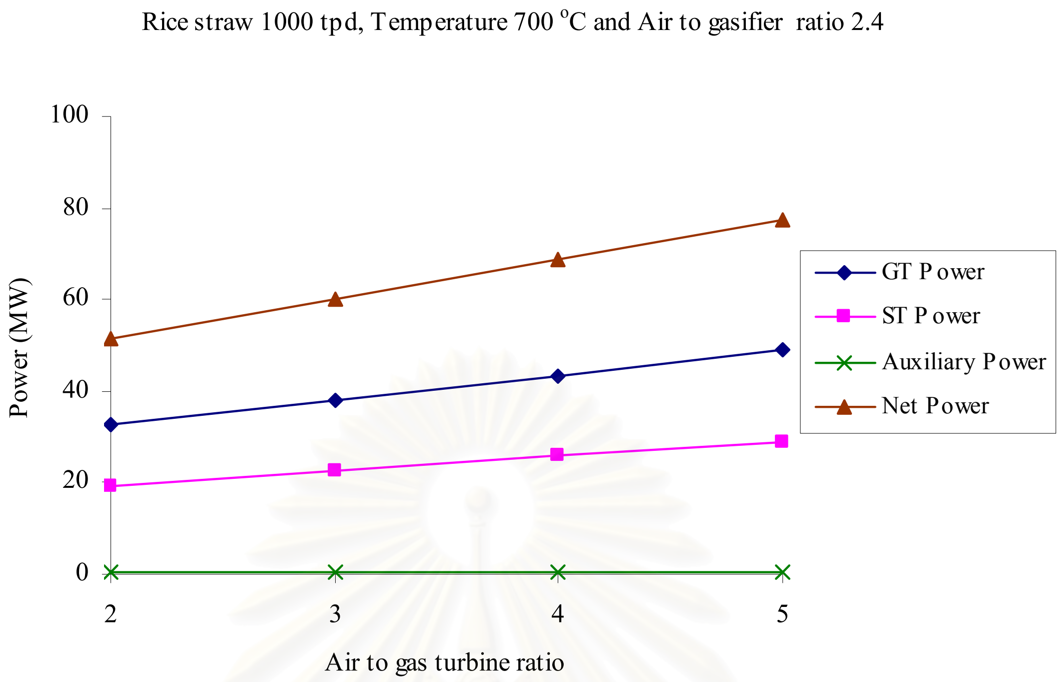

Figure 5.47 Effect of air to gas turbine ratio to the net power for rice straw

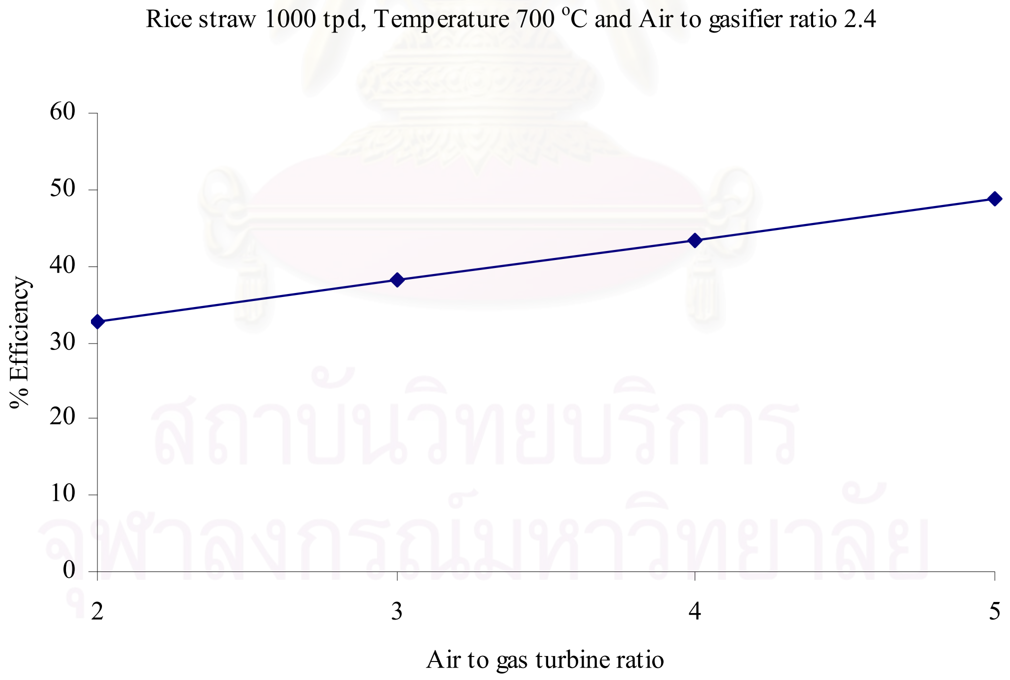

Figure 5.48 Effect of air to gas turbine ratio to the efficiency for rice straw

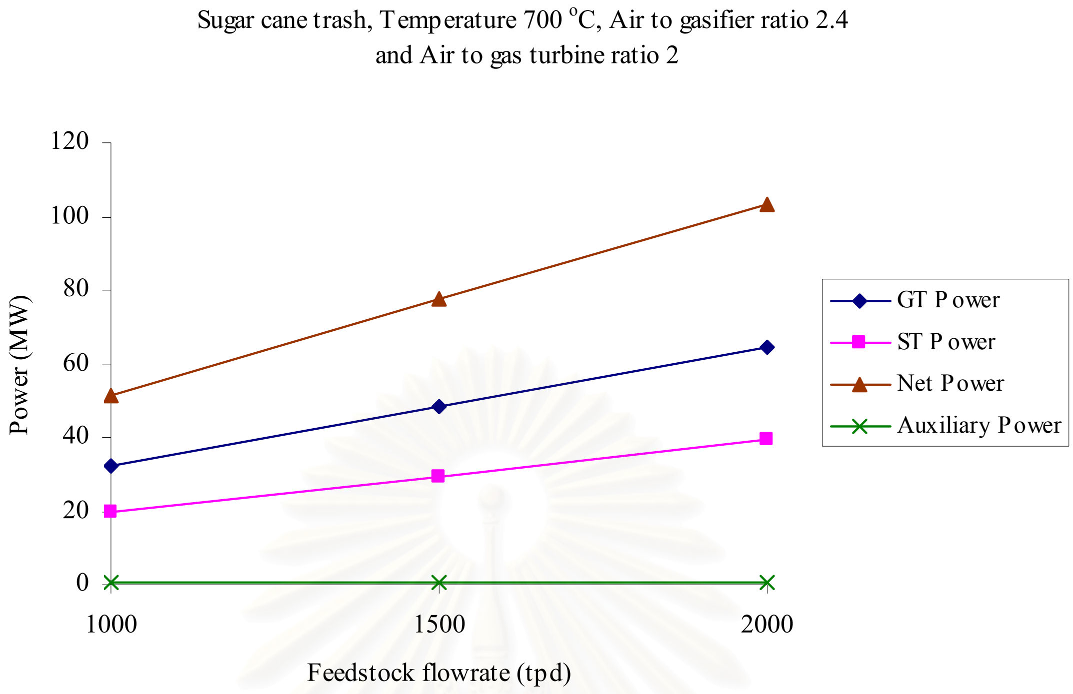

Figure 5.49 Effect of feedstock flow rate to the net power for sugar cane trash

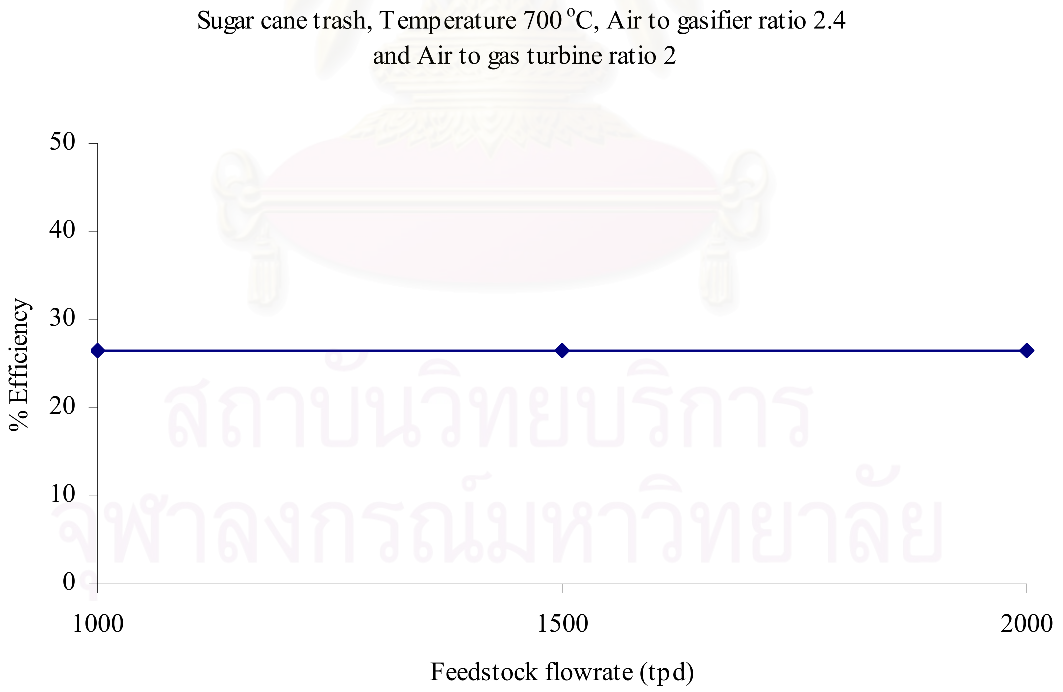

Figure 5.50 Effect of feedstock flow rate to the efficiency for sugar cane trash

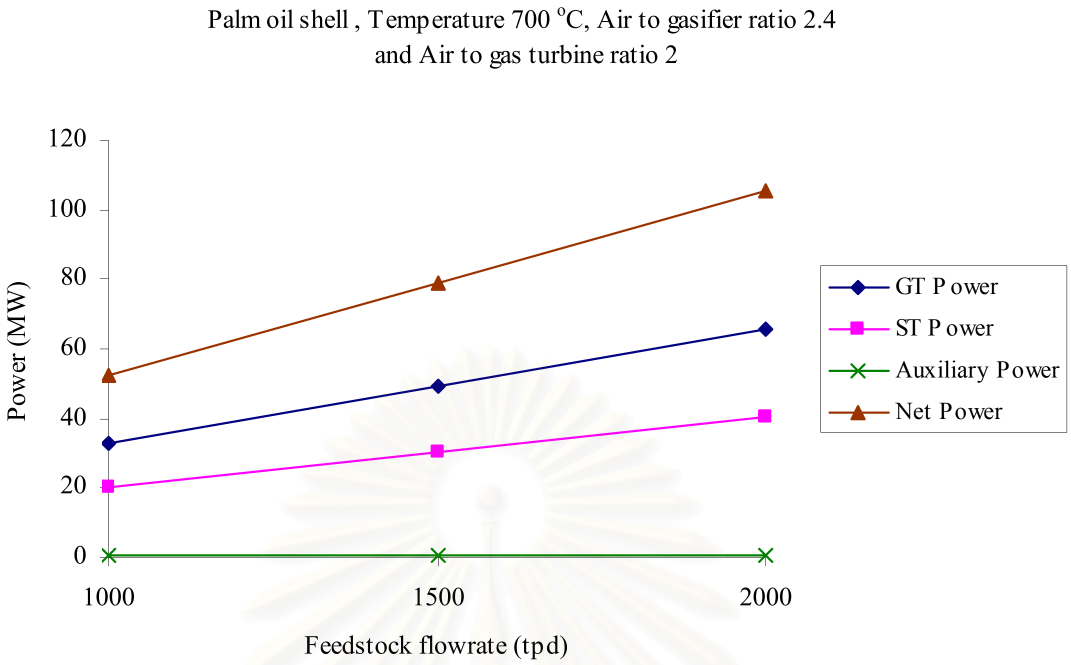

Figure 5.51 Effect of feedstock flow rate to the net power for palm oil shell

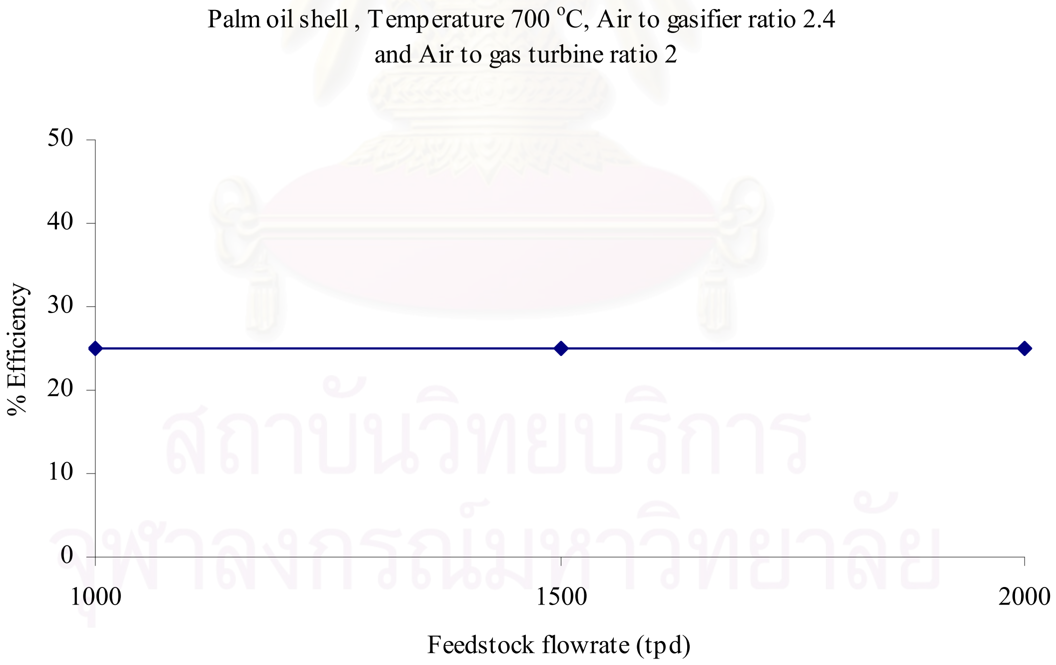

Figure 5.52 Effect of feedstock flow rate to the efficiency for palm oil shell

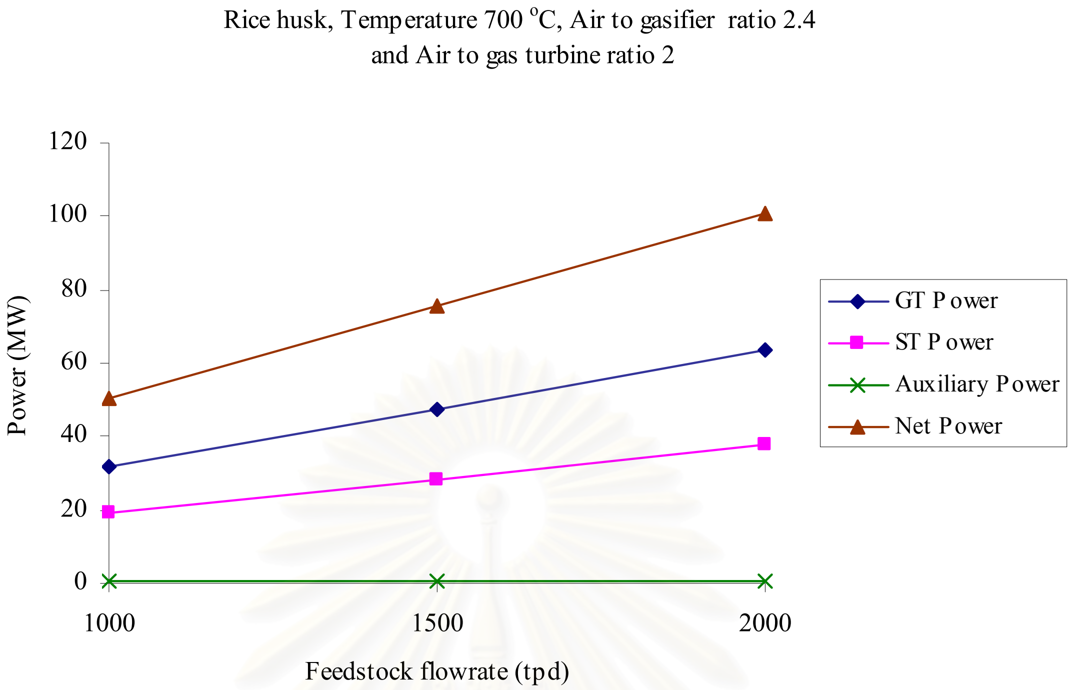

Figure 5.53 Effect of feedstock flow rate to the net power for rice husk

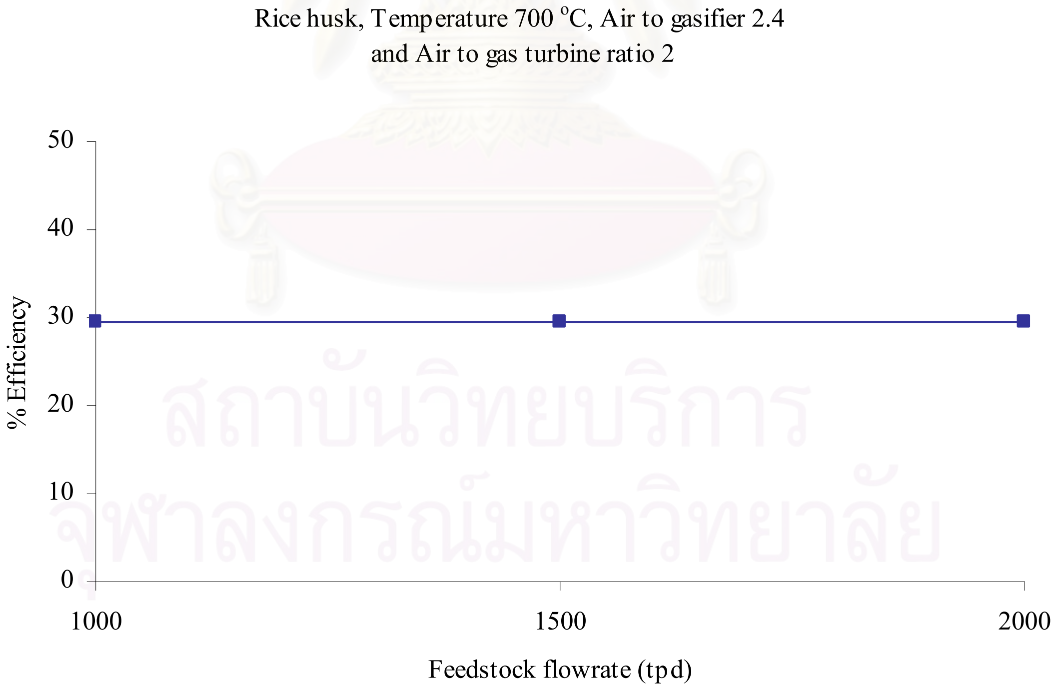

Figure 5.54 Effect of feedstock flow rate to the efficiency for rice husk

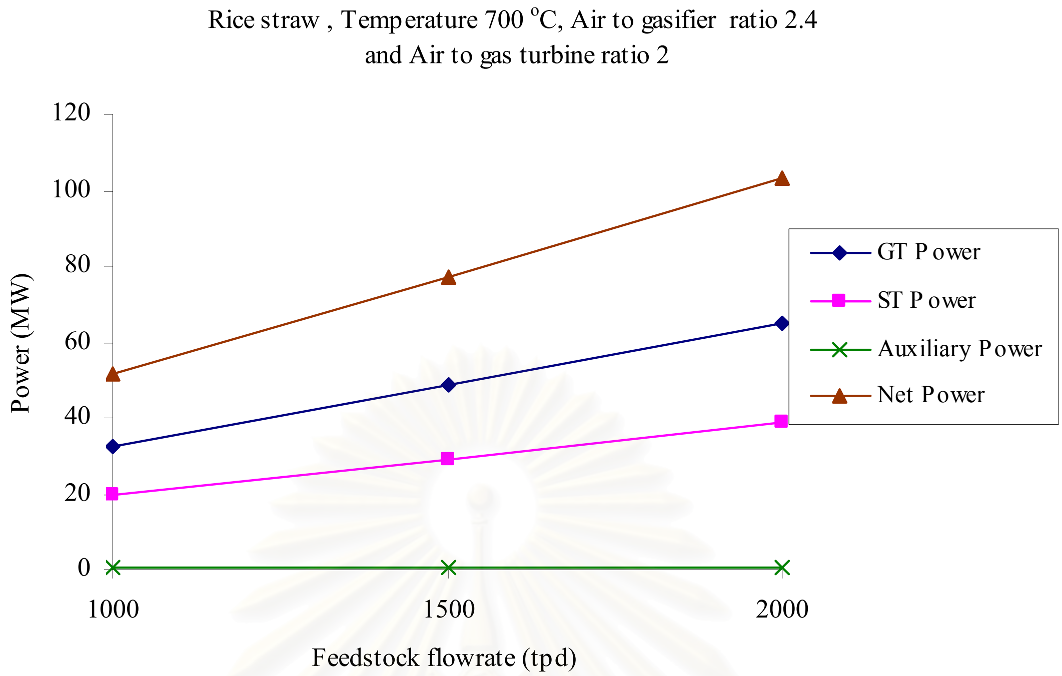

Figure 5.55 Effect of feedstock flow rate to the net power for rice straw

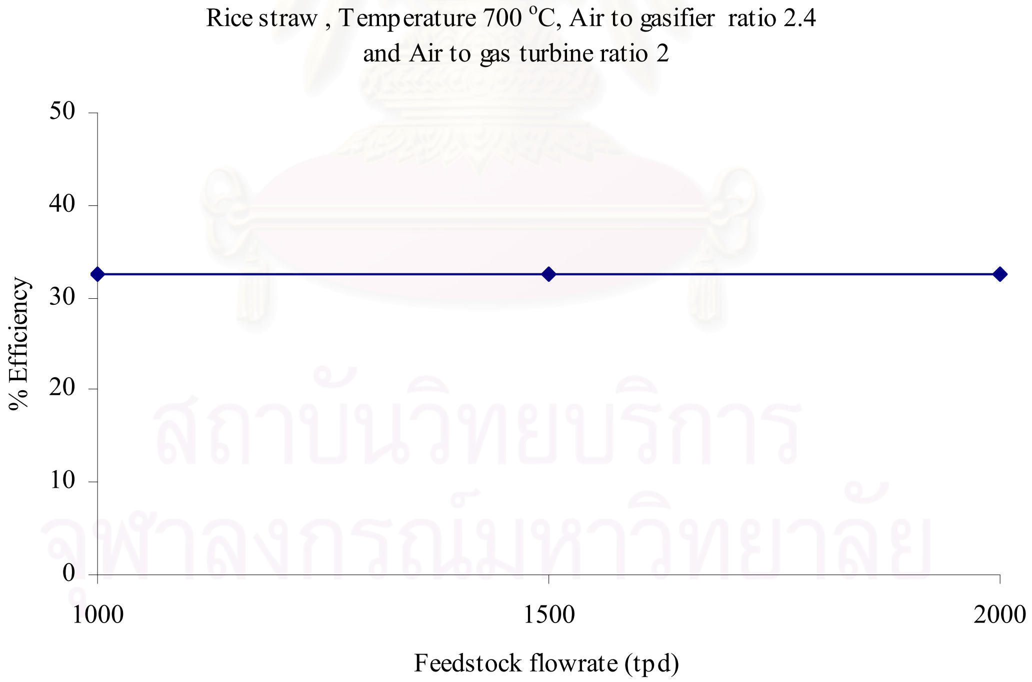

Figure 5.56 Effect of feedstock flow rate to the efficiency for rice straw

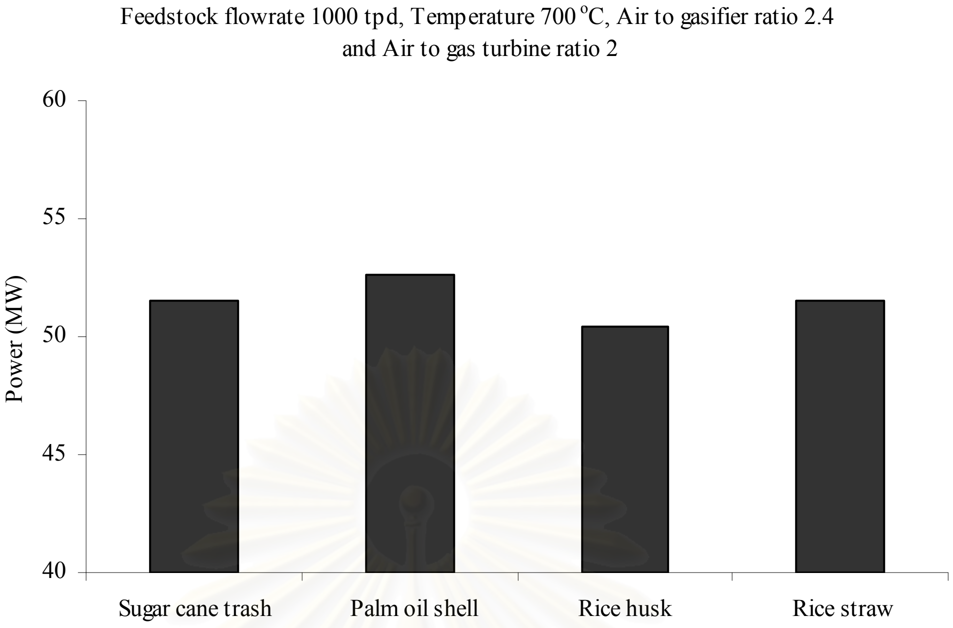

Figure 5.57 Effect of type of feedstock to the net power

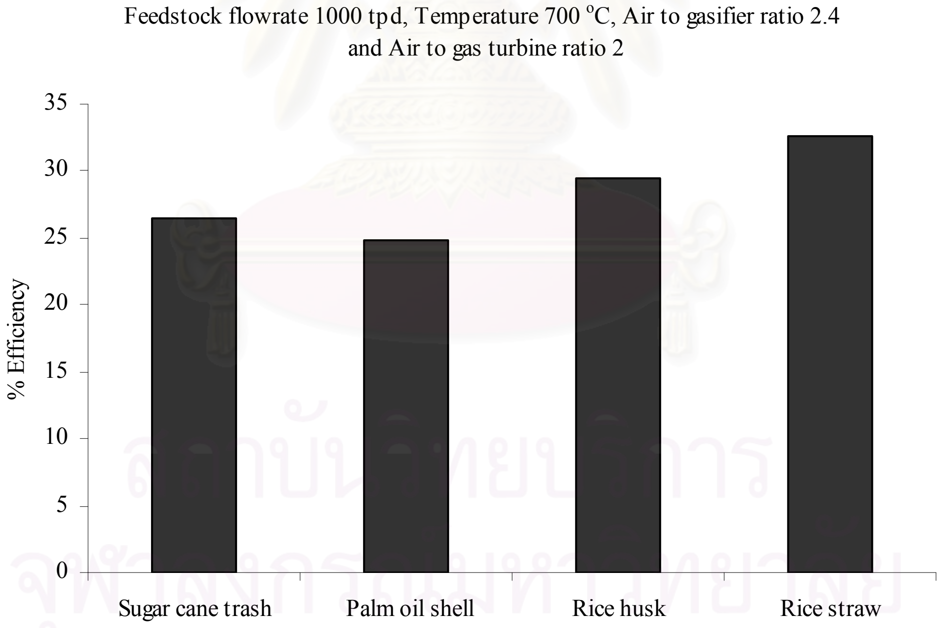

Figure 5.58 Effect of type of feedstock to the efficiency

5.3 Discussions

From the results, the change of operating condition certainly affect to the net power and thermal efficiency. Then, This research has been studied and considered the efficiency and the environmental impacts which are the essential to determine an optimal point to operate in the IGCC system. The gas turbine certainly requires such the most efficient system. First, the best efficiency from each of gasifier temperature is selected and arranged the results between 0-1 that shown in Appendix B. Then, the efficiency is plotted with CO_2, NH_3 and H_2S emissions in every cases that shown in Figs. 5.59-5.61. Related from graphs, it determine an optimal point of operating condition in IGCC system which shown in Table 5.2 and summarize the most promising option is rice straw feedstock with 700-860 °C gasifier temperature, 2.4 air to gasifier ratio and 5 air to gas turbine ratio.

Table 5.2 The best conditions for operate IGCC in this study

Biomass	Feedstock Flow Rate (tpd)	Temperature (^oC)	Air to Gas Turbine Ratio	Air to Gasifier Ratio	NET Power (MW)	Efficiency (%)	CO_2 (kmol/hr)	NH_3 (kmol/hr)	H_2S (kmol/hr)
Straw	1000	700	5	2.4	77.3	48.91	904	0.010	1.169
Straw	1000	740	5	2.4	78.4	49.59	896	0.047	1.169
Straw	1000	780	5	2.4	79.2	50.15	891	0.105	1.169
Straw	1000	820	5	2.4	79.9	50.60	889	0.179	1.169
Straw	1000	860	5	2.4	80.5	50.98	887	0.263	1.169

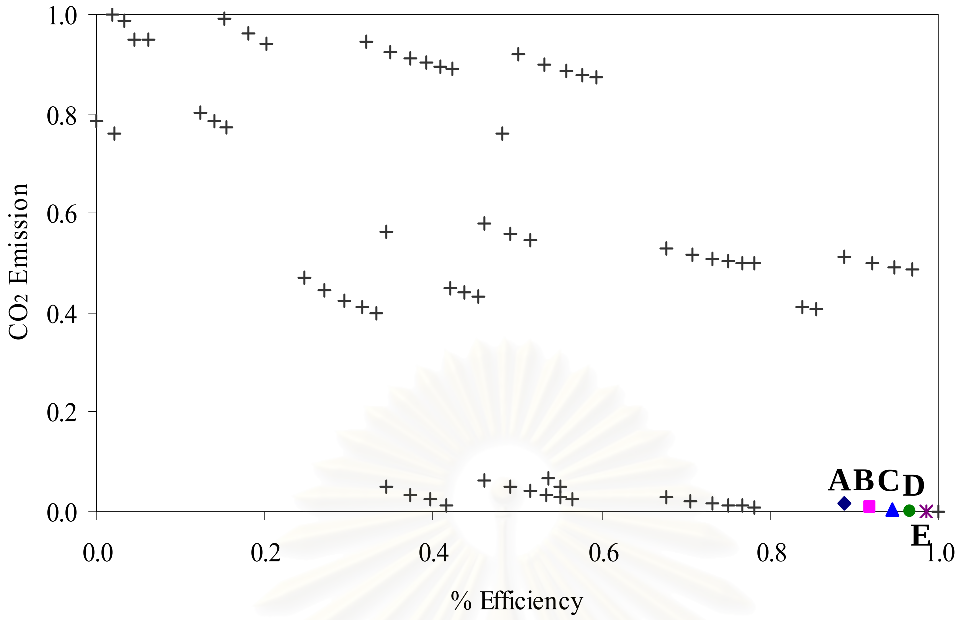

Figure 5.59 Relation between the efficiency and CO_2 emission

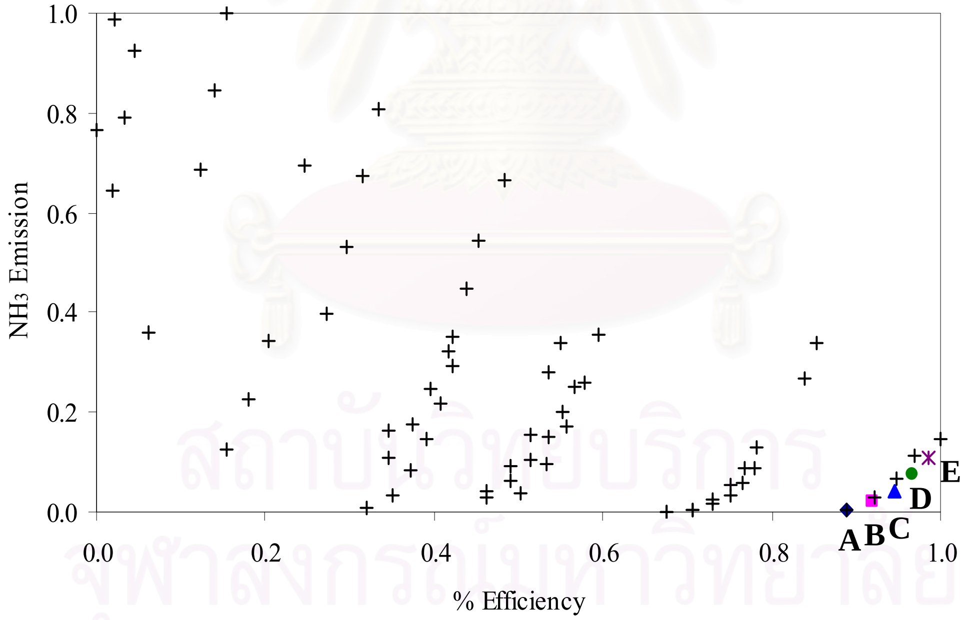

Figure 5.60 Relation between the efficiency and NH_3 emission

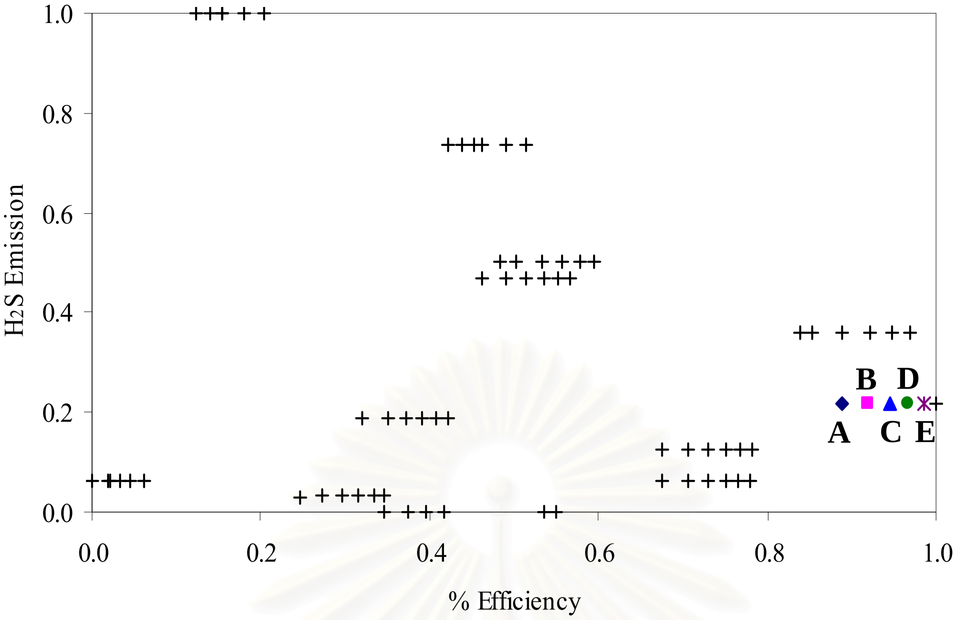

Figure 5.61 Relation between the efficiency and H_2S emission

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

In this research, we identify suitable raw material and optimum operating conditions of Biomass-based Integrated Gasification Combined Cycle (IGCC) system. Aspen Plus are used to perform a simulation. In addition, the effect of variability on various operating parameters related to efficiency and environmental performances is also discussed. From the results of this work, we can summarize that the suitable feedstock for the process considered is rice husk, rice straw, sugar cane trash and palm oil shell. The change of operating conditions certainly affect to the net power and the efficiency. Type of feedstock, gasifier temperature and air to gasifier ratio are the influence of CO_2, NH_3 and H_2S emissions. Furthermore, the efficiency and the net power increase with increasing gasifier temperature, air to gasifier ratio and air to gas turbine ratio. In the other hands, the increasing of flowrate increases the net power but does not change the thermal efficiency. The best feedstock for high net power is palm oil shell. Rice straw has highest thermal efficiency. Moreover, the optimum operating condition is straw with gasifier temperature between 700-860 ^oC, 2.4 air to gasifier ratio and 5 air to gas turbine ratio.

6.2 Recommendations

- In the future study should consider to useful of waste energy from IGCC system process for the most energy effectively such as used for heating utility or drying feedstock.
- In the future study, operating condition of gasifier should consider reactant form oxygen or air/steam or oxygen/steam and pressurized gasifier for the best power performance of IGCC system.
- In the future study, the biomass/coal feedstock should be considered for improvement of power performance of IGCC system.

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APPENDICES

APPENDIX A

AGRICULTURAL PRODUCTION IN THAILAND

Table A1 Provinces of each region

Northern	North - Eastern	Central Plain	Southern
Chiang Rai	Loei	Saraburi	Chumphon
Phayao	Nong Bua Lam Phu	Lop Buri	Ranong
Lampang	Udon Thani	Sing Buri	Surat Thani
Lamphun	Nong Khai	Chai Nat	Phangnga
Chiang Mai	Sakon Nakhon	Suphan Buri	Phuket
Mae Hong Son	Nakhon Phanom	Ang Thong	Krabi
Tak	Mukdahan	Ayutthaya	Trang
Kamphaeng Phet	Yasothon	Nonthaburi	Nakhon Si Thammarat
Sukhothai	Amnat Charoen	Bangkok	Phatthalung
Phrae	Ubon Ratchathani	Pathum Thani	Songkhla
Nan	Si Sa Ket	Nakhon Nayok	Satun
Uttaradit	Surin	Prachin Buri	Pattani
Phitsanulok	Buri Ram	Chachoengsao	Yala
Phichit	Maha Sarakham	Sa Kaeo	Narathiwat
Nakhon Sawan	Roi Et	Chanthaburi	
Uthai Thani	Kalasin	Trat	
Phetchabun	Khon Kaen	Rayong	
	Chaiyaphum	Chon Buri	
	Nakhon Ratchasima	Samut Prakan	
		Samut Sakhon	
		Nakhon Pathom	
		Kanchanaburi	
		Ratchaburi	
		Samut Songkhram	
		Phetchaburi	
		Prachuap Khiri Khan	

Table A2 Second Rice : Area, production and yield by province, 2006

Province	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**9,902,785**	**9,872,431**	**6,752,684**	**684**
Chiang Rai	111,464	111,464	76,585	687
Phayao	1,755	1,755	1,007	574
Lampang	8,251	8,120	4,610	568
Lamphun	5,253	5,253	3,840	731
Chiang Mai	34,447	34,447	22,253	646
Mae Hong Son	20	20	8	400
Tak	19,062	18,756	11,761	627
Kamphaeng Phet	480,131	478,560	301,299	630
Sukhothai	285,362	273,059	191,763	702
Phrae	2,976	2,976	1,732	582
Nan	1,750	1,750	991	566
Uttaradit	151,144	150,646	112,451	746
Phitsanulok	622,349	618,883	446,542	722
Phichit	677,810	674,210	460,911	684
Nakhon Sawan	718,594	717,508	495,112	690
Uthai Thani	196,482	196,082	129,678	661
Phetchabun	14,236	14,195	7,660	540
Loei	1,658	1,648	771	468
Nong Bua Lam Phu	6,826	6,738	3,467	515
Udon Thani	23,710	23,478	10,134	432
Nong Khai	45,750	45,642	19,710	432
Sakon Nakhon	15,755	15,559	5,393	347
Nakhon Phanom	13,937	13,937	5,129	368
Mukdahan	137	137	55	401
Yasothon	21,312	21,312	9,618	451
Amnat Charoen	1,259	1,259	462	367
Ubon Ratchathani	58,956	58,956	19,161	325
Si Sa Ket	12,406	12,329	5,161	419
Surin	1,729	1,724	778	451
Buri Ram	1,037	1,032	368	357
Maha Sarakham	68,293	67,995	40,441	595
Roi Et	65,933	65,851	37,054	563
Kalasin	244,211	243,957	121,981	500
Khon Kaen	39,266	38,956	19,982	513
Chaiyaphum	10,291	10,160	4,590	452
Nakhon Ratchasima	25,592	25,454	15,037	591
Saraburi	164,475	164,172	108,894	663
Lop Buri	309,861	309,666	218,520	706
Sing Buri	343,463	343,463	263,436	767
Chai Nat	613,265	613,194	467,225	762
Suphan Buri	1,172,252	1,171,247	868,414	741
Ang Thong	337,658	337,658	232,309	688

Province	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Ayutthaya	592,202	592,202	418,176	706
Nonthaburi	130,983	130,983	100,441	767
Bangkok	73,049	73,049	49,893	683
Pathum Thani	294,914	294,914	203,793	691
Nakhon Nayok	64,082	63,992	35,787	559
Prachin Buri	126,312	126,312	73,829	584
Chachoengsao	339,387	336,823	218,053	647
Sa Kaeo	5,923	5,664	3,400	600
Trat	1,594	1,594	631	396
Rayong	9,167	9,167	4,842	528
Chon Buri	4,725	4,725	2,295	486
Samut Prakan	25,622	25,622	20,385	796
Samut Sakhon	10,895	10,895	7,615	699
Nakhon Pathom	379,413	379,413	283,849	748
Kanchanaburi	170,952	170,893	125,505	734
Ratchaburi	277,291	277,237	191,197	690
Samut Songkhram	3,315	3,315	2,551	770
Phetchaburi	226,002	226,002	151,707	671
Prachuap Khiri Khan	39,909	39,909	18,966	475
Chomphon	4,269	4,269	2,266	531
Surat Thani	10,257	10,257	5,213	508
Nakhon Si Thammarat	99,015	98,817	49,954	506
Phatthalung	43,773	43,554	19,369	445
Songkhla	16,342	16,342	8,301	508
Satun	246	246	92	374
Pattani	22,387	22,387	8,037	359
Yala	149	149	50	336
Narathiwat	492	492	194	394

Table A3 Second Rice : Area, production and yield by region, 2006

Region	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**9,902,785**	**9,872,431**	**6,752,684**	**684**
Northern	3,331,086	3,307,683	2,268,203	686
North - Eastern	658,058	656,124	319,292	487
Central Plain	5,716,711	5,712,112	4,071,713	713
Southern	196,930	196,513	93,476	476

Table A4 Major Rice : Area, production and yield by province, 2006

Province	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**57,541,825**	**53,500,163**	**22,839,695**	**427**
Chiang Rai	1,234,079	1,207,997	652,366	540
Phayao	596,088	569,091	296,716	521
Lampang	416,095	407,240	217,782	535
Lamphun	148,804	144,474	81,679	565
Chiang Mai	518,590	505,428	303,863	601
Mae Hong Son	116,488	110,145	53,416	485
Tak	221,525	205,831	94,784	460
Kamphaeng Phet	1,127,363	1,042,770	573,409	550
Sukhothai	792,698	720,914	355,450	493
Phrae	249,886	243,235	139,286	573
Nan	206,283	201,363	104,963	521
Uttaradit	437,626	409,183	255,576	625
Phitsanulok	1,244,063	1,062,197	575,978	542
Phichit	1,442,007	1,283,110	715,211	557
Nakhon Sawan	2,349,636	2,127,328	1,181,489	555
Uthai Thani	525,585	486,828	257,700	529
Phetchabun	1,159,533	1,055,548	595,729	564
Loei	413,403	384,752	134,919	351
Nong Bua Lam Phu	918,701	889,915	267,751	301
Udon Thani	1,850,459	1,800,076	562,750	313
Nong Khai	1,084,502	1,047,298	329,710	315
Sakon Nakhon	1,834,390	1,750,672	566,649	324
Nakhon Phanom	1,038,730	978,357	284,513	291
Mukdahan	360,281	351,626	110,054	313
Yasothon	1,040,614	972,527	292,184	300
Amnat Charoen	912,251	879,530	275,547	313
Ubon Ratchathani	3,182,153	3,044,758	948,936	312
Si Sa Ket	2,261,120	2,185,797	818,717	375
Surin	2,616,518	2,538,840	956,807	377
Buri Ram	2,755,739	2,593,929	892,826	344
Maha Sarakham	1,805,003	1,617,113	568,645	352
Roi Et	2,581,056	2,419,911	818,529	338
Kalasin	1,294,888	1,188,707	463,669	390
Khon Kaen	2,400,642	2,208,937	727,015	329
Chaiyaphum	1,257,116	1,103,076	355,799	323
Nakhon Ratchasima	3,103,818	2,777,518	917,939	330
Saraburi	381,820	364,604	191,632	526
Lop Buri	885,969	828,275	446,521	539
Sing Buri	390,178	315,508	231,376	733
Chai Nat	899,672	824,875	583,887	708
Suphan Buri	1,073,679	988,704	705,407	713
Ang Thong	352,276	171,801	153,945	896

Province	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Ayutthaya	838,679	736,456	476,370	647
Nonthaburi	102,061	93,456	77,056	825
Bangkok	115,997	98,397	71,338	725
Pathum Thani	306,063	291,604	213,632	733
Nakhon Nayok	451,025	418,687	206,118	492
Prachin Buri	754,393	680,562	274,316	403
Chachoengsao	862,727	817,467	453,868	555
Sa Kaeo	803,577	737,083	269,996	366
Chanthaburi	45,369	39,485	14,110	357
Trat	38,051	35,845	13,813	385
Rayong	23,599	22,396	9,015	403
Chon Buri	126,741	117,047	52,978	453
Samut Prakan	36,876	35,349	27,178	769
Samut Sakhon	20,281	19,303	12,858	666
Nakhon Pathom	361,212	345,518	219,978	637
Kanchanaburi	366,155	338,254	182,345	539
Ratchaburi	312,243	298,617	203,895	683
Samut Songkhram	2,798	2,714	1,592	587
Phetchaburi	338,557	331,789	174,357	526
Prachuap Khiri Khan	56,077	54,246	23,833	439
Chumphon	50,235	47,935	17,833	372
Ranong	3,856	3,649	1,134	311
Surat Thani	61,077	56,340	24,983	443
Phangnga	8,973	8,772	2,764	315
Phuket	1,312	1,268	436	344
Krabi	32,951	31,924	11,434	358
Trang	61,188	59,091	20,376	345
Nakhon Si Thammarat	642,342	581,181	226,744	390
Phatthalung	413,661	394,715	178,288	452
Songkhla	372,546	357,562	158,230	443
Satun	78,683	76,554	29,034	379
Pattani	196,698	187,588	65,697	350
Yala	65,356	63,248	22,809	361
Narathiwat	109,139	106,273	40,163	378

Table A5 Major Rice : Area, production and yield by region, 2006

Region	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**57,541,825**	**53,500,163**	**22,839,695**	**427**
Northern	12,786,349	11,782,682	6,455,397	548
North - Eastern	32,711,384	30,733,339	10,292,959	335
Central Plain	9,946,075	9,008,042	5,291,414	587
Southern	2,098,017	1,976,100	799,925	405

Table A6 Corn : Area, production and yield by province, 2006

Province	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**6,081,656**	**5,613,372**	**3,696,341**	**658**
Chiang Rai	329,343	324,333	209,750	647
Phayao	213,548	206,368	140,155	679
Lampang	31,514	28,060	21,114	752
Lamphun	53,248	47,800	32,535	681
Chiang Mai	47,143	46,100	32,812	712
Mae Hong Son	2,547	2,335	1,172	502
Tak	442,133	434,375	281,012	647
Kamphaeng Phet	194,664	184,783	129,924	703
Sukhothai	73,660	68,616	41,107	599
Phrae	59,843	57,070	32,674	573
Nan	151,654	150,900	90,537	600
Uttaradit	41,487	36,940	24,726	669
Phitsanulok	225,442	221,990	148,183	668
Phichit	48,483	45,107	33,801	749
Nakhon Sawan	485,401	368,193	300,385	816
Uthai Thani	245,395	176,744	164,433	930
Phetchabun	990,377	933,553	646,436	692
Loei	262,329	250,914	129,602	517
Nong Bua Lam Phu	60,213	53,286	28,786	540
Udon Thani	22,798	20,110	10,920	543
Nong Khai	3,494	3,433	1,702	496
Ubon Ratchathani	25,505	24,780	16,349	660
Si Sa Ket	73,199	67,240	44,066	655
Buri Ram	522	495	294	595
Khon Kaen	7,613	7,135	4,035	566
Chaiyaphum	120,457	116,400	62,999	541
Nakhon Ratchasima	721,593	676,938	389,660	576
Saraburi	161,725	153,200	95,418	623
Lop Buri	478,696	466,342	280,995	603
Chai Nat	16,466	15,660	8,101	517
Suphan Buri	65,015	61,990	30,427	491
Prachin Buri	23,443	20,980	14,699	701
Chachoengsao	18,393	17,250	11,220	650
Sa Kaeo	252,068	198,030	162,836	822
Chanthaburi	33,274	32,650	21,695	664
Chon Buri	1,406	1,369	759	555
Kanchanaburi	84,007	79,080	45,112	570
Ratchaburi	8,024	7,679	3,426	446
Phetchaburi	3,083	2,792	1,360	487
Prachuap Khiri Khan	2,451	2,352	1,125	478

Table A7 Corn : Area, production and yield by region,2006

Region	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**6,081,656**	**5,613,372**	**3,696,341**	**658**
Northern	3,635,882	3,333,267	2,330,756	699
North - Eastern	1,297,723	1,220,731	688,414	564
Central Plain	1,148,051	1,059,374	677,172	639

Table A8 Palm oil: Harvested area, production and yield by province, 2006

Province	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**2,374,202**	**6,240,753**	**2,629**
Trat	18,816	43,879	2,332
Raypmg	12,934	30,291	2,342
Chon Buri	65,269	167,219	2,562
Prachup Khiri Khan	71,597	173,122	2,418
Chumphon	478,656	1,214,350	2,537
Ranong	36,483	98,978	2,713
Surat Thani	657,853	1,726,864	2,625
Phangnga	66,356	150,031	2,261
Krabi	693,424	1,999,141	2,883
Trang	87,713	230,159	2,624
Nakhon Si Thammarat	45,476	102,912	2,263
Songkhla	16,982	37,428	2,204
Satun	90,993	202,732	2,228
Narathiwat	19,065	43,945	2,305
Others	12,585	19,702	1,566

Table A9 Palm oil: Harvested area, production and yield by region, 2006

Region	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**2,374,202**	**6,240,753**	**2,629**
Central Plain	168,616	414,511	2,458
Southern	2,205,586	5,826,242	379

Table A10 Cassava : Area, production and yield by province, 2006

Province	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**6,933,418**	**6,692,537**	**22,584,402**	**3,375**
Chiang Rai	5,855	5,608	16,162	2,882
Phayao	532	507	1,350	2,663
Lampang	598	582	1,574	2,704
Tak	1,674	1,478	4,353	2,945
Kamphaeng Phet	386,628	378,552	1,335,910	3,529
Sukhothai	1,068	1,036	2,744	2,649
Phrae	1,172	1,126	2,943	2,614
Nan	-	-	-	-

Province	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Uttaradit	4,241	4,024	12,664	3,147
Phitsanulok	158,480	153,532	519,552	3,384
Phichit	3,606	3,483	10,648	3,057
Nakhon Sawan	194,893	187,458	644,106	3,436
Uthai Thani	185,191	176,712	584,563	3,308
Phetchabun	23,779	22,860	71,849	3,143
Loei	138,942	131,366	371,634	2,829
Nong Bua Lam Phu	41,582	39,957	128,142	3,207
Udon Thani	152,696	145,907	510,675	3,500
Nong Khai	46,288	44,119	128,607	2,915
Sakon Nakhon	64,326	59,847	171,043	2,858
Nakhon Phanom	11,191	10,239	28,710	2,804
Mukdahan	92,789	87,715	239,023	2,725
Yasothon	45,103	42,964	139,762	3,253
Amnat Charoen	33,147	31,045	90,558	2,917
Ubon Ratchathani	82,869	76,378	234,633	3,072
Si Sa Ket	56,866	53,518	154,774	2,892
Surin	44,018	40,114	110,474	2,754
Buri Ram	190,083	186,872	589,394	3,154
Maha Sarakham	120,595	114,136	338,185	2,963
Roi Et	115,679	109,537	329,487	3,008
Kalasin	309,485	294,402	1,050,426	3,568
Khon Kaen	216,131	206,557	695,477	3,367
Chaiyaphum	354,887	339,197	1,136,649	3,351
Nakhon Ratchasima	1,697,732	1,669,054	5,704,827	3,418
Saraburi	21,958	20,787	73,669	3,544
Lop Buri	94,432	91,294	346,917	3,800
Chai Nat	71,841	70,170	225,947	3,220
Suphan Buri	28,177	27,187	83,410	3,068
Prachin Buri	152,887	146,524	516,497	3,525
Chachoengsao	295,387	282,944	1,028,501	3,635
Sa Kaeo	363,625	357,454	1,344,027	3,760
Chanthaburi	248,379	235,643	784,927	3,331
Rayong	230,315	222,520	808,860	3,635
Chon Buri	297,342	284,295	970,299	3,413
Kanchanaburi	252,163	243,018	760,646	3,130
Ratchaburi	91,857	87,980	271,330	3,084
Phetchaburi	2,929	2,839	8,474	2,985

Table A11 **Cassava : Area, production and yield by region, 2006**

Region	Planted Area (Rai)	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**6,933,418**	**6,692,537**	**22,584,402**	**3,375**
Northern	967,717	936,958	3,208,418	3,424
North-Eastern	3,814,409	3,682,924	12,152,480	3,300
Central Plain	2,151,292	2,072,655	7,223,504	3,485

Table A12 **Sugar cane : Planted area, production and yield by province, 2006**

Province	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**6,033,331**	**47,658,097**	**7,899**
Chiang Rai	1,007	6,787	6,740
Lampang	41,160	248,195	6,030
Chiang Mai	2,596	19,260	7,419
Tak	9,137	73,379	8,031
Kamphaeng Phet	320,214	2,809,237	8,773
Sukhothai	158,113	1,144,738	7,240
Phrae	3,328	23,775	7,144
Uttaradit	90,745	674,598	7,434
Phitsanulok	146,454	1,226,992	8,378
Phichit	39,438	311,442	7,897
Nakhon Sawan	531,434	4,668,116	8,784
Uthai Thani	178,130	1,256,707	7,055
Phetchabun	168,484	1,211,231	7,189
Loei	65,534	469,944	7,171
Nong Bua Lam Phu	25,453	176,338	6,928
Udon Thani	370,582	2,638,914	7,121
Nong Khai	7,564	54,302	7,179
Sakon Nakhon	18,224	131,377	7,209
Nakhon Phanom	8,088	66,969	8,280
Mukdahan	65,396	517,544	7,914
Yasothon	5,018	39,251	7,822
Amnat Charoen	4,138	31,854	7,698
Surin	15,734	111,287	7,073
Buri Ram	72,738	494,837	6,803
Maha Sarakham	31,128	244,604	7,858
Roi Et	14,865	117,106	7,878
Kalasin	231,428	1,867,161	8,068
Khon Kaen	428,132	3,449,460	8,057
Chaiyaphum	275,098	2,074,789	7,542
Nakhon Ratchasima	441,662	3,180,850	7,202
Saraburi	175,137	1,350,657	7,712
Lop Buri	143,223	1,040,658	7,266
Sing Buri	80,151	741,798	9,255
Chai Nat	31,381	291,498	9,289

Province	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Suphan Buri	471,349	3,965,459	8,413
Ang Thong	12,818	121,117	9,449
Prachin Buri	5,375	41,153	7,656
Chachoengsao	60,283	455,963	7,564
Sa Kaeo	107,948	844,115	7,820
Chanthaburi	17,593	140,163	7,967
Rayong	28,317	216,229	7,636
Chon Buri	109,240	866,492	7,932
Nakhon Pathom	90,928	804,986	8,853
Kanchanaburi	640,553	5,580,498	8,712
Ratchaburi	200,541	1,309,332	6,529
Phetchaburi	28,871	180,386	6,248
Prachuap Khiri Khan	58,601	366,549	6,255

Table A13 Sugar cane : Planted area, production and yield by region, 2006

Region	Harvested Area (Rai)	Production (Tons)	Yield per Rai (kgs.)
Whole Kingdom	**6,033,331**	**47,658,097**	**7,899**
Northern	1,690,240	13,674,457	8,090
North - Eastern	2,080,782	15,666,587	7,529
Central Plain	2,262,309	18,317,053	8,097

APPENDIX B

SUMMARY OF THE OPTIMAL OF OPERATING CONDITIONS FOR EACH FEEDSTOCK

Table B1 The best operating conditions for sugar cane trash feedstock

Feedstock Flow Rate(tpd)	Temp. (^oC)	Air GT Ratio	Air Gasifier Ratio	NET Power (MW)	Efficiency (%)	CO_2 (kmol/hr)	NH_3 (kmol/hr)	H_2S (kmol/hr)	Efficiency (%)	CO_2	NH_3	H_2S
1000	700	5	2.4	77.3	39.76	945	0.067	2.209	0.461	0.063	0.028	0.469
	740	5	2.4	78.5	40.40	932	0.150	2.209	0.491	0.050	0.062	0.469
	780	5	2.4	79.5	40.90	924	0.251	2.209	0.514	0.041	0.104	0.469
	820	5	2.4	80.4	41.34	917	0.369	2.209	0.535	0.033	0.152	0.469
	860	5	2.4	81.1	41.70	912	0.489	2.209	0.552	0.028	0.202	0.469
	900	5	2.4	81.6	42.00	909	0.612	2.209	0.566	0.024	0.253	0.469
1500	700	5	2.4	116.0	39.77	1417	0.101	3.313	0.462	0.581	0.042	0.735
	740	5	2.4	117.8	40.41	1398	0.225	3.313	0.492	0.561	0.093	0.735
	780	5	2.4	119.3	40.91	1386	0.376	3.313	0.515	0.547	0.155	0.735
	820	5	2.2	113.4	38.89	1297	0.854	3.313	0.421	0.450	0.353	0.735
	860	5	2.2	114.5	39.26	1289	1.086	3.313	0.438	0.440	0.449	0.735
	900	5	2.2	115.4	39.58	1282	1.315	3.313	0.453	0.433	0.544	0.735
2000	700	4	2.2	128.9	33.15	1791	0.299	4.418	0.153	0.991	0.124	1.000
	740	4	2.2	131.2	33.75	1764	0.549	4.418	0.181	0.961	0.227	1.000
	780	4	2.2	133.0	34.22	1745	0.827	4.418	0.203	0.941	0.342	1.000
	820	4	2	126.4	32.52	1618	1.662	4.418	0.123	0.802	0.687	1.000
	860	4	2	127.8	32.87	1605	2.045	4.418	0.140	0.787	0.846	1.000
	900	4	2	129.0	33.18	1594	2.419	4.418	0.154	0.775	1.000	1.000

Table B2 The best operating conditions for palm oil shell feedstock

Feedstock Flow Rate(tpd)	Temp. (^oC)	Air GT Ratio	Air Gasifier Ratio	NET Power (MW)	Efficiency (%)	CO_2 (kmol/hr)	NH_3 (kmol/hr)	H_2S (kmol/hr)	Efficiency (%)	CO_2	NH_3	H_2S
1000	700	5	2.4	78.8	37.27	933	0.264	0.260	0.345	0.051	0.109	0.001
	740	5	2.4	80.1	37.88	919	0.424	0.260	0.374	0.035	0.175	0.001
	780	5	2.4	81.1	38.38	908	0.595	0.260	0.397	0.023	0.246	0.001
	820	5	2.4	82.0	38.81	899	0.777	0.260	0.417	0.014	0.321	0.001
	860	5	2.4	87.5	41.36	949	0.678	0.260	0.536	0.069	0.280	0.001
	900	5	2.4	88.1	41.67	934	0.816	0.257	0.550	0.051	0.337	0.000
1500	700	5	2.4	118.2	37.28	1400	0.396	0.390	0.346	0.562	0.164	0.032
	740	5	2.2	113.2	35.70	1292	0.966	0.390	0.272	0.445	0.399	0.032
	780	5	2.2	114.8	36.20	1276	1.290	0.390	0.295	0.426	0.533	0.032
	820	5	2.2	116.2	36.65	1261	1.626	0.390	0.316	0.411	0.672	0.032
	860	5	2.2	117.4	37.01	1250	1.949	0.390	0.333	0.398	0.806	0.032
	900	4	2.4	111.5	35.17	1315	1.680	0.385	0.247	0.469	0.695	0.031
2000	700	4	2.2	132.0	31.21	1754	0.867	0.520	0.062	0.950	0.359	0.063
	740	4	2	126.3	29.88	1603	1.855	0.520	0.000	0.785	0.767	0.063
	780	4	2	128.3	30.35	1579	2.387	0.520	0.022	0.759	0.987	0.063
	820	3	2.4	128.1	30.29	1799	1.554	0.520	0.019	1.000	0.643	0.063
	860	3	2.4	129.3	30.58	1786	1.910	0.520	0.033	0.986	0.790	0.063
	900	3	2.4	130.4	30.84	1753	2.241	0.513	0.045	0.950	0.926	0.062

Table B3 The best operating conditions for rice husk feedstock

Feedstock Flow Rate(tpd)	Temp. (^oC)	Air GT Ratio	Air Gasifier Ratio	NET Power (MW)	Efficiency (%)	CO_2 (kmol/hr)	NH_3 (kmol/hr)	H_2S (kmol/hr)	Efficiency (%)	CO_2	NH_3	H_2S
1000	700	5	2.4	75.8	44.36	914	0.000	0.52	0.676	0.029	-	0.063
	740	5	2.4	76.9	45.01	906	0.010	0.52	0.706	0.021	0.004	0.063
	780	5	2.4	77.7	45.53	901	0.039	0.52	0.730	0.015	0.016	0.063
	820	5	2.4	78.5	45.95	898	0.086	0.52	0.750	0.012	0.035	0.063
	860	5	2.4	79.1	46.30	896	0.144	0.52	0.767	0.011	0.059	0.063
	900	5	2.4	79.6	46.60	896	0.209	0.520	0.780	0.010	0.086	0.063
1500	700	5	2.4	113.7	44.37	1371	0.000	0.78	0.677	0.530	0.000	0.126
	740	5	2.4	115.3	45.02	1358	0.015	0.78	0.707	0.517	0.006	0.126
	780	5	2.4	116.6	45.54	1351	0.059	0.78	0.731	0.509	0.024	0.126
	820	5	2.4	117.7	45.96	1347	0.128	0.78	0.751	0.504	0.053	0.126
	860	5	2.4	118.6	46.31	1345	0.215	0.78	0.767	0.502	0.089	0.126
	900	5	2.4	119.4	46.61	1344	0.313	0.78	0.781	0.501	0.130	0.126
2000	700	4	2.2	125.5	36.75	1750	0.016	1.04	0.321	0.946	0.007	0.188
	740	4	2.2	127.6	37.37	1731	0.086	1.04	0.350	0.925	0.036	0.188
	780	4	2.2	129.3	37.87	1718	0.204	1.04	0.373	0.911	0.084	0.188
	820	4	2.2	130.7	38.28	1710	0.356	1.04	0.392	0.902	0.147	0.188
	860	4	2.2	131.9	38.62	1705	0.529	1.04	0.408	0.897	0.219	0.188
	900	4	2.2	132.9	38.91	1701	0.713	1.04	0.422	0.893	0.295	0.188

Table B4 The best operating conditions for rice straw feedstock

Feedstock Flow Rate(tpd)	Temp. (^oC)	Air GT Ratio	Air Gasifier Ratio	NET Power (MW)	Efficiency (%)	CO_2 (kmol/hr)	NH_3 (kmol/hr)	H_2S (kmol/hr)	Efficiency (%)	CO_2	NH_3	H_2S
1000	700	5	2.4	77.3	48.91	904	0.010	1.169	0.888	0.018	0.004	0.219
	740	5	2.4	78.4	49.59	896	0.047	1.169	0.920	0.010	0.019	0.219
	780	5	2.4	79.2	50.15	891	0.105	1.169	0.946	0.005	0.043	0.219
	820	5	2.4	79.9	50.60	889	0.179	1.169	0.968	0.002	0.074	0.219
	860	5	2.4	80.5	50.98	887	0.263	1.169	0.985	0.001	0.109	0.219
	900	5	2.4	81.0	51.30	887	0.351	1.169	1.000	0.000	0.145	0.219
1500	700	5	2.4	115.9	48.92	1355	0.015	1.754	0.889	0.514	0.006	0.360
	740	5	2.4	117.6	49.60	1344	0.070	1.754	0.921	0.501	0.029	0.360
	780	5	2.4	118.9	50.16	1337	0.158	1.754	0.947	0.493	0.065	0.360
	820	5	2.4	119.9	50.61	1333	0.269	1.754	0.968	0.489	0.111	0.360
	860	5	2.2	113.4	47.83	1263	0.644	1.754	0.838	0.412	0.266	0.360
	900	5	2.2	114.2	48.17	1261	0.819	1.754	0.854	0.410	0.339	0.360
2000	700	4	2.2	128.4	40.63	1726	0.089	2.339	0.502	0.920	0.037	0.500
	740	4	2.2	130.4	41.28	1708	0.230	2.339	0.532	0.901	0.095	0.500
	780	4	2.2	132.1	41.82	1697	0.416	2.339	0.557	0.888	0.172	0.500
	820	4	2.2	133.5	42.26	1689	0.631	2.339	0.578	0.879	0.261	0.500
	860	4	2.2	134.7	42.62	1684	0.859	2.339	0.595	0.874	0.355	0.500
	900	4	2	127.1	40.23	1581	1.604	2.339	0.483	0.761	0.663	0.500

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