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Life Cycle Analysis of Integrated Gasification Combined Cycle Power Generation in the Context of Southeast Asia

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Abstract: Coal remains a major source of electricity production even under the current state of developments in climate policies due to national energy priorities. Coal remains the most attractive option, especially to the developing economies in Southeast Asia, due to its abundance and affordability in the region, despite the heavily polluting nature of this energy source. Gasification of coal running on an integration gasification combined cycle (IGCC) power generation with carbon capture and storage (CCS) represents an option to reduce the environmental impacts of power generation from coal, but the decarbonization potential and suitability of IGCC in the context of Southeast Asia remain unclear. Using Singapore as an example, this paper presents a study on the life cycle analysis (LCA) of IGCC power generation with and without CCS based on a generic process-driven analysis method. We further evaluate the suitability of IGCC with and without CCS as an option to address the energy and climate objectives for the developing economies in Southeast Asia. Findings suggest that the current IGCC technology is a much less attractive option in the context of Southeast Asia when compared to other available power generation technologies, such as solar photovoltaic systems, coal with CCS, and potentially nuclear power technologies.

Keywords: life cycle analysis; process chain; integrated gasification combined cycle; carbon capture and storage; system boundary; climate change

1. Introduction

The global greenhouse gas (GHG) emissions from human activities are continually rising due to the need for continued economic and industrial development. According to the Intergovernmental Panel on Climate Change [1], 25% of greenhouse gas emissions in 2010 came from electricity and heat generation, and carbon dioxide (CO_2) accounts for 65% of global GHG emissions. Global energy demand is expected to grow by 37% between 2014 and 2040, leading to a continued increase in the atmospheric concentration of GHGs due to the combustion of fossil fuels. A study by the International Energy Agency suggests a slow-down in the global energy demand, with a markedly improved system-level efficiency due to policy efforts world-wide [2]. However, coal is likely to continue dominating the global and Southeast Asian energy mix in the foreseeable future [3–5].

The objective is thus to evaluate technology options that would make the use of coal less environmentally damaging. Among the various methods used in the literature, life cycle analysis

(LCA) methods appear to be most popular in evaluating the system-level carbon emission of electricity generation [6], such as those of solar energy [7,8], biomass [9,10], and nuclear energy [11,12].

There is a number of LCA studies on electricity generation from coal. Nease et al. [13] performed a comparative analysis using the process chain analysis (PCA) approach. The analysis focused on ultra-supercritical (USC) and integrated gasification combined cycle (IGCC) power plants in conjunction with the use of carbon capture and storage (CCS). Chang et al. [14] combined the use of an input-output table and process level data for comparing the life cycle greenhouse gas emissions and water consumptions of sub-critical, supercritical, USC, and IGCC to those of the shale gas fired combined cycle gas turbine (CCGT) technologies. The US National Renewable Energy Laboratory (NREL) [15] conducted a comprehensive assessment on the life cycle impacts of electricity generation from coal. The NREL's detailed analysis is useful for formulating the life cycle system of electricity generation from coal in the proposed analysis. In addition, a number of studies have had a specific focus on evaluating the use of CCS technology for reducing carbon emission from coal fired power plant [16–18].

Many of the studies in the LCA literature tend to employ commercially available software, such as GaBi [19] and RETScreen [20], or follow the ISO Standards or other general frameworks. As a contribution to the literature, we propose a generic LCA-PCA method by following the energy balance principles, with particular attention to the formulation of process and system boundaries based on earlier developments, as described in [12,21–23]. As such, our study does not employ any commercial software and/or existing modelling codes.

Among other considerations, the main reason for selecting a generic LCA-PCA approach as the basis for formulating the methodology in this study is threefold. First, the method is flexible and has transparent tracking of energy input and carbon emission streams. Next, it has demonstrated robustness in producing unbiased LCA results as shown in [12]. Last and most importantly, the method can be extended to a wide range of systems, such as energy systems [10], manufacturing systems [7], and systems delivering services [24]. These advantages enable a common platform for benchmarking alternative life cycle systems for policy discussions without having to engage in a resource-intensive assessment exercise.

Findings from this study seek to provide an alternative and more up-to-date set of LCA results on IGCC with and without pre-combustion carbon capture using Singapore as an example. Findings from this study are also relevant to the developing economies situated in the tropical climatic environment in Southeast Asia. Through a comparison of environmental impacts/benefits and the cost of alternative power generation systems, we further contribute to the policy debate on the use of IGCC with CCS to meet the climate and energy objectives of the developing economies in Southeast Asia.

2. Methodology

The proposed LCA methodology is developed primarily based on earlier developments on system, process, and input-output definitions, as described in [10,12,22]. As a brief re-cap of the generic PCA framework, the methodology is conceived through a simplified representation of a life cycle electricity generation system as a black box system (Figure 1). This black-box system is characterized by energy and non-energy inputs, energy output, energy loss, and carbon emissions and is confined by a physical system boundary over a fixed timeframe. Breaking down the black box by stage or process, the resulting multi-process system can be assembled through the transformation of products across the process chain (Figure 2). All products are strictly confined within the physical boundary of the system by definition. In this case, the product refers to the fuel for the power generation process.

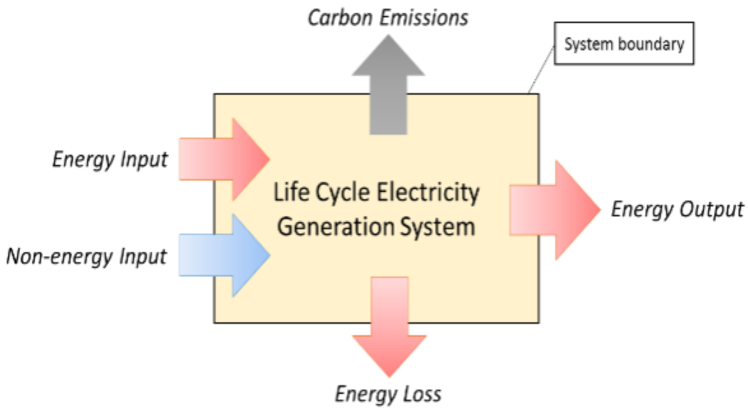

Figure 1. A generic power generation system representation.

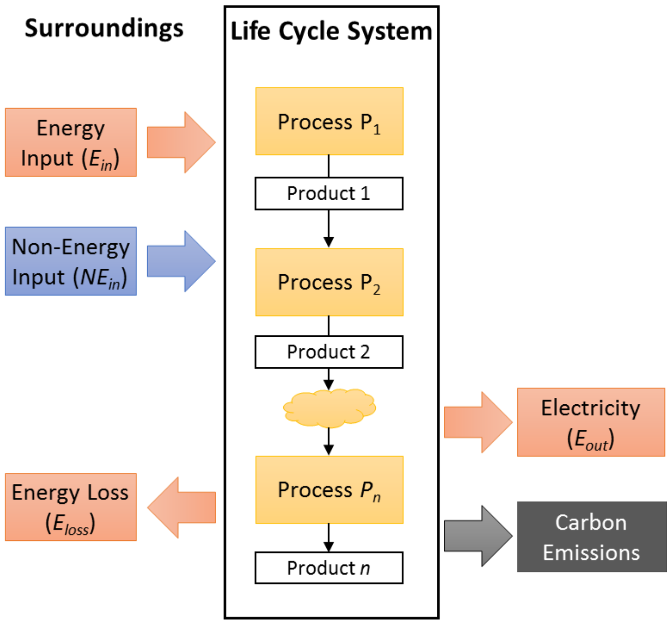

Figure 2. A generic representation of a multi-process life cycle system.

There are three dimensions governing the formulation of the system boundaries. First, there is a boundary between the life cycle system and its surroundings (Figure 2). Next, there is a boundary between the "Main System" and its "Sub-systems", which produce inputs for the "Main System" (Figure 3). Last, there are physical and temporal boundaries governing the processes to be included in an analysis and the appropriate cradle-to-grave timeframe of analysis. These dimensions can ensure consistent inclusion or exclusion of carbon emission streams, which in turn leads to unbiased LCA results [12].

In some cases, multiple systems could be interacting with one another such that the product from one system can be directly utilized by a corresponding process in a different system. In the event of an impending cross-boundary movement of products, a concept, named, "partial temporal boundary", could be applied to synchronize all interconnecting systems over a consistent timeframe for analysis [22]. In this study, the synchronization concept is not needed, since there is no potential movement of products out of the physical boundary of the Main System.

The key differences of the proposed methodology used in this study as compared to those used in other studies in the literature lie with the approach in formulating a life cycle system. Other methodologies generally conceive a life cycle system from a top-down approach by identifying the relevant processes to be included in an analysis. The physical and temporal boundaries are then defined according to the resulting system and the objectives of the analyses. Such a "top-down" approach is typically seen in commercial software, such as Simapro and GaBi. The proposed methodology conceives a life cycle system through evolving a generic power generation process, based on the fundamental energy balance principles, such as thermodynamics for power generation.

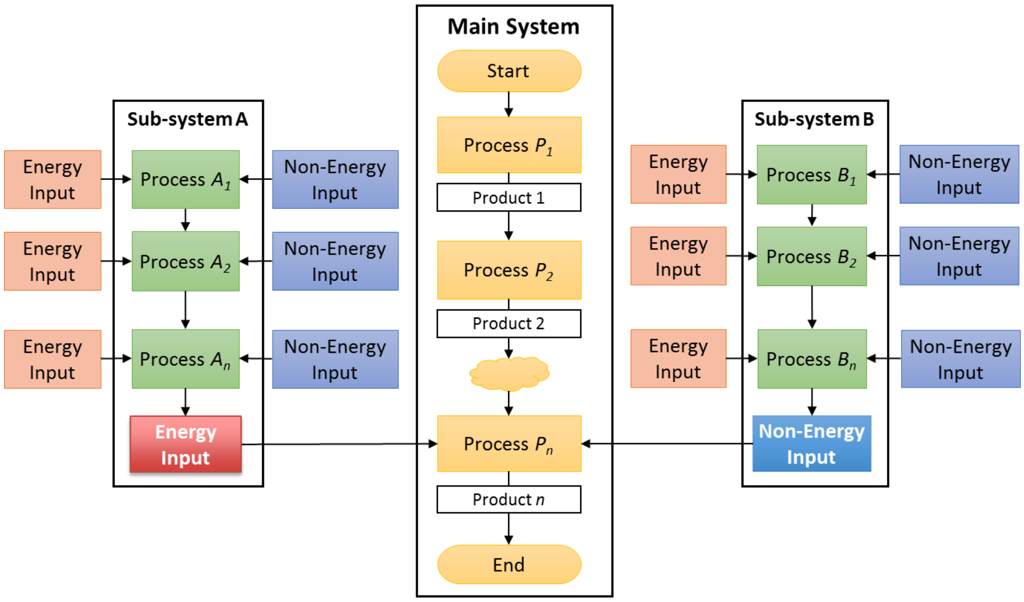

Figure 3. Boundaries between the life cycle Main System and the Sub-systems.

The basic idea is to evolve the definition of process and its energy input and output from a simple energy conversion process to a broader sense of process, such as a facility for producing a given product. The facility requires energy and non-energy input to be constructed, operated for producing the product, and decommissioned. Throughout the definition of this process and other processes in the life cycle system, the energy balance principles provide guidance on the interaction between input and output and hence the physical system boundary. The temporal boundary is determined through the fuel-to-electricity and fuel-to-fuel transformations across the process chain, which is referred to as the transformation of the "product" in this methodology [21].

The power generation process using an IGCC power plant forms the basis of the life cycle system. The system starts off with the fundamental Brayton Cycle and Rankine Cycle for defining the elementary energy input and output, and the input-output interaction across the physical system boundary. Subsequently, these working cycles are evolved into a whole power plant, thereby transforming the input definition as that for power plant construction, operation and maintenance, and decommissioning. The details of such transformation are described in [21]. As described in the preceding paragraph, the key is to broaden the definition of energy input from the input to the Brayton or Rankine Cycle to the input to the power plant, such as energy input to power plant construction, operation, and dismantling. This ensures consistency with the non-energy input, such as concrete and steel for the power plant structure, and copper and aluminum for the generator and other equipment, as discussed in [12]. The fuel-to-energy conversion process is internalized with fuel becoming the "product" for assembling the process chain of the life cycle system.

The fuel for the IGCC power plant is supplied through gasification of coal. We further consider the option of having a steam-methane reforming process followed by pre-combustion carbon capture after coal gasification. Coal is assumed to be obtained from an earlier process of coal processing, which includes cleaning, pulverizing and drying after being received from the export country. Usually, coal is mined from the ground either through an underground or open-pit mining method and transported to power plants by land and/or sea. An overview of the key processes of a life cycle system for IGCC power generation is shown in Figure 4.

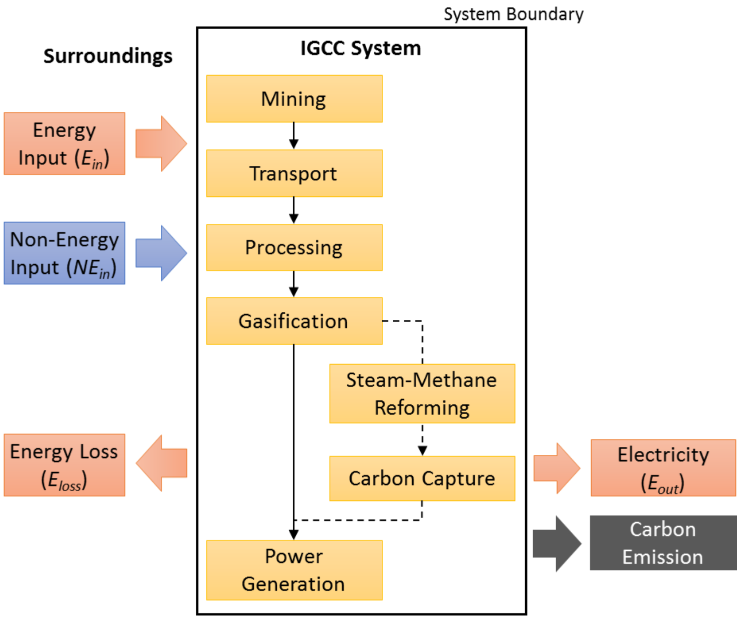

Figure 4. Life cycle system of the integrated gasification combined cycle (IGCC) power generation from with pre-combustion carbon capture.

2.1. System Boundaries and Accounting

The selection of system boundaries and the accounting of carbon emissions are usually referred to as assumptions in a typical LCA study. The proposed method uses a different approach in which the physical system boundary is identified through observations of the governing equations as the scope of calculation expands from the Main System to its Sub-systems mathematically. Thus, instead of assuming a set of system boundaries to subjectively determine the processes to be included and/or excluded, the quantitative formulations govern the inclusion and/or exclusion of the processes, as described in [21]. The proposed method is thus more restrictive as compared to other methods, but the stringent governance of system and boundary formulations enables the framework to expand beyond the LCA of a standalone system towards a large-scale global energy systems analysis tool through systematic expansion across the Sub-systems.

The primary objective of this study is, then, to apply the framework to formulate the methodology for the proposed analysis, which is to evaluate the life cycle carbon emissions of IGCC for policy discussions. The key formulations required to conduct the proposed analyses are presented in this section.

With reference to [12], the energy and non-energy input to each process of the system can be expressed respectively as

$$E_n = \sum_{i=1,2,\ldots} E_{n,i} \tag{1}$$

$$NE_n = \sum_{i=1,2,\ldots} NE_{n,i} \tag{2}$$

where $E_{n,i}$ represents energy input by type such as diesel or electricity to each process (or nth process) of the system; and $NE_{n,i}$ represents non-energy input by type such as chemicals, metals, or other materials to each process (or nth process) of the system.

In a multi-process power generation life cycle system, the total system energy and non-energy inputs can be expressed respectively as

$$E_{sys} = \sum_{n=1,2,\ldots} E_n = \sum_{n=1,2,\ldots} \left(\sum_{i=1,2,\ldots} E_{n,i} \right) = \sum_{n=1,2,\ldots} \left(p_n \times \sum_{i=1,2,\ldots} e_i \right) \tag{3}$$

$$NE_{sys} = \sum_{n=1,2,\ldots} NE_n = \sum_{n=1,2,\ldots} \left(\sum_{i=1,2,\ldots} NE_{n,i} \right) = \sum_{n=1,2,\ldots} \left(p_n \times \sum_{i=1,2,\ldots} ne_i \right) \tag{4}$$

where E_{sys} and NE_{sys} represent the total system energy and non-energy inputs, respectively; p_n represents the product made by each process of the system; e_i represents energy input per unit of p_n produced; and ne_i represents the non-energy input per unit of p_n produced. The "product" refers to coal and/or syngas, depending on the stage/process.

The process carbon emissions due to energy and non-energy inputs can be expressed respectively as

$$C_E = \sum_{i=1,2,\ldots} c_{ne,i} \times E_i = \sum_{n=1,2,\ldots} \left(p_n \times \sum_{i=1,2,\ldots} c_{e,i} \times e_i \right) \tag{5}$$

$$C_{NE} = \sum_{i=1,2,\ldots} c_{ne,i} \times NE_i = \sum_{n=1,2,\ldots} \left(p_n \times \sum_{i=1,2,\ldots} c_{ne,i} \times ne_i \right) \tag{6}$$

where C_E represents carbon emissions due to energy input; C_{NE} represents carbon emissions due to non-energy input; $c_{e,i}$ represents the carbon content of energy input; and $c_{ne,i}$ represents the carbon content of non-energy input. Thus, the total carbon emissions over the lifetime of the system can be expressed as

$$C_{sys} = C_E + C_{NE} + C_{Fuel} = \sum_{n=1,2,\ldots} \left(p_n \times \left(\sum_{i=1,2,\ldots} c_{e,i} \times e_i + \sum_{i=1,2,\ldots} c_{ne,i} \times ne_i \right) \right) + C_{Fuel} \tag{7}$$

where C_{sys} represents the life cycle carbon emissions of the main system; and C_{Fuel} represents the life cycle carbon emissions due to the combustion of syngas. The use of carbon capture is implied and thus not explicitly explained in this equation.

Following the physical system boundary conditions governed by the mathematical formulations described in [12], the LCA main system is only responsible for carbon emissions due to the direct conversion of its inputs' carbon content, such as the combustion of fossil fuel and/or chemical/physical reactions. Carbon emissions due to the production of the inputs are excluded to ensure consistency with the physical boundary conditions. Since the LCA main system of IGCC does not involve direct conversion of its non-energy inputs' carbon content, C_{NE} is removed from the final equation describing the life cycle carbon emissions of the life cycle system as shown in Equation (8)

$$C_{sys} = C_E + C_{Fuel} = \sum_{n=1,2,\ldots} \left(p_n \times \sum_{i=1,2,\ldots} c_{e,i} \times e_i \right) + C_{Fuel} \tag{8}$$

2.2. Power Plant Fuel Requirements

The lifetime carbon emissions due to the combustion of fuel is calculated based on the quantity and carbon content of syngas. First, the lifetime electricity generation by the power plant can be expressed as

$$ELC = P_e \times \phi \times 8760 \times T \tag{9}$$

where, ELC represents the amount of electricity generated; P_e represents the power generating capacity of the power plant; ϕ represents the availability factor of the power plant; and T represents the lifetime of the power plant.

Usually, the amount of thermal energy (Q) required over the lifetime of the power plant can be expressed as

$$Q = \frac{ELC}{\eta_{th}} \tag{10}$$

where η_{th} represents the thermal efficiency of the power plant.

The amount of fuel (M_{Fuel}) required over the lifetime of the power plant can be expressed as

$$M_{Fuel} = \frac{Q}{H_{Fuel}} \tag{11}$$

where H_{Fuel} represents the heating value of the fuel.

In our study, we use a different approach in computing the lifetime power plant fuel requirement. As will be discussed in Section 3.1, we assume a set of reference specifications for the IGCC power plant. These reference parameters allow for the computation of the flow rate of the syngas fuel (in kg/s) based on the heating value of the fuel. The lifetime fuel requirement M_{Fuel} is thus obtained by multiplying the lifetime of the power plant considering the annual availability factor of the plant. This is the approach in calculating the lifetime carbon emissions from the combustion of fuel by the IGCC plant without carbon capture. The lifetime carbon emissions due to fuel combustion in the presence of pre-combustion carbon capture is explained in Section 2.4.

The amount of coal (M_{Coal}) required over the lifetime of the IGCC power plant can be computed based on the atomic mass balance of carbon between syngas and coal. This computation follows the earlier assumption that only carbon reacts with H_2O to produce syngas. However, carbon is not the only element in coal in its natural form or in syngas when produced. There are other elements, such as volatile compounds, hydrogen, and ash in coal, and hydrogen and oxygen elements in syngas in addition to carbon. Thus, the atomic mass conversion is needed to ensure accurate tracking of the input coal and output syngas during the chemical reaction process. The simple conversion equation can thus be as expressed as

$$M_{Coal} = \left(\frac{M_{Fuel}}{C_{Fuel}}\right) / c_{Coal} \tag{12}$$

where M_{Coal} represents the amount of coal needed over the lifetime of the IGCC power plant; M_{Fuel} represents the amount of syngas as fuel needed over the lifetime of the IGCC power plant; c_{Coal} represents the carbon content of coal (usually in weight percentage); and c_{Fuel} represents the carbon content of fuel (also in weight percentage). In this equation, the term $\frac{M_{Fuel}}{C_{Fuel}}$ is effectively the total amount of carbon (C) atoms required over the lifetime of the IGCC power plant. This amount of carbon atoms is assumed to be supplied from coal in the gasification process. The total amount of coal is computed based on the carbon content depending on the type of coal assumed in the analysis.

The amount of coal (M_{Coal}) is then used as *product* to compute the process and hence system energy and non-energy inputs using Equations (1)–(4) followed by carbon emissions using Equations (5)–(8) over the lifetime of the whole system.

2.3. Coal Gasification

IGCC power plants make use of synthetic gas or syngas which is converted from gasification of coal. A typical IGCC power plant consists of a few key components, namely, gasifier, gas turbine, steam turbine, and a heat recovery steam generator (HRSG). Coal is heated with a mixture of steam and oxygen to produce syngas consisting of carbon monoxide (CO), hydrogen (H_2) and methane

(CH_4), as shown in Equation (13) with reference to [25]. This partial combustion of coal generates heat that can be used to drive the steam turbine to generate electricity.

$$C + O_2 + H_2O \rightarrow CO + H_2 + CH_4 \tag{13}$$

The composition of syngas can be computed through balancing the chemical reaction equation as shown in Equation (13). For illustration, the theoretical weight of the products after the reaction assuming 1 kg of carbon (C) inside the coal is reacted in the gasifier can be obtained as shown in Table 1.

Table 1. Reaction in the gasifier.

Items	Reactants			Products		
Substance	C	O_2	H_2O	CO	H_2	CH_4
Mole	6	1	3	5	1	1
Total Molar Mass	72	32	54	140	2	16
Weight (kg)	1	0.44	0.75	1.94	0.03	0.22

In the absence of pre-combustion carbon capture, the products shown in Table 1 are the composition of syngas to be used as fuel input to the IGCC power plant. The percentage of carbon in syngas is calculated using the atomic mass ratio of carbon in all gaseous products. The final weight percentage of carbon in the syngas can be computed as shown in Table 2.

Table 2. Overall carbon content of syngas upon gasification.

Final Products	CO	H_2	CH_4
Weight (kg)	1.94	0.03	0.22
Weight percentage (%)	89%	1%	10%
Weight of carbon	0.83	0.00	0.17
Percentage of carbon in syngas (%)		45.57%	

The final percentage of carbon content in the syngas is then used to calculate the amount of coal required for the whole lifetime of the power plant based on atomic mass balance principles. In our case studies, we assume that the carbon content of coal is fully converted in the gasification process. In the absence of carbon capture, the syngas mixture is then combusted in the gas turbine for further electricity generation, while the waste heat from the gas turbine exhaust is recovered in the HRSG to raise steam for driving a steam turbine for power generation [26]. Under the condition of high carbon conversion, two additional reactions—namely, the water-gas shift reaction and methane reforming—take place. These two reactions can facilitate the removal of CO_2 emission streams, as explained in the next sub-section.

2.4. Steam-Methane Reforming and Carbon Capture

The analysis on carbon capture is entirely based on assumptions, as there is no existing commercial or demonstration IGCC plant with pre-combustion carbon capture at the moment. Removal of CO_2 emissions from IGCC through pre-combustion carbon capture can be achieved after two reactions, namely, steam-methane reforming and water-gas shift reactions [27].

With reference to [28,29], the chemical equations for steam-methane reforming and water-gas shift reactions can be expressed respectively as

$$CH_4 + H_2O \rightarrow CO + H_2 \tag{14}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{15}$$

Continuing from the gasification process, 1 kg of carbon can produce 0.22 kg of CH_4 as shown in Table 2. Assuming 90% of 0.22 kg of CH_4 is converted in the steam-methane reforming, the resulting products after steam-methane reforming are shown in Table 3.

Table 3. Steam-methane reforming reaction.

Items	Reactants		Products	
Substance	CH_4	H_2O	CO	H_2
Mole	1	1	1	3
Total Molar Mass	16	18	44	6
Weight (kg)	0.20	0.23	0.37	0.05

Since the water-gas shift reaction can also take place under the prescribed reaction conditions for steam-methane reforming, we further assume that 90% of the total amount of CO produced in the gasification and steam-methane reforming processes continue to react with H_2O. Adding up the numbers from Tables 2 and 3, 1 kg of carbon can produce a total of 2.31 kg of CO in the gasification and steam-methane reforming processes. Thus, approximately 2.09 kg of CO would participate in the water-gas shift reaction (products of the reaction are shown in Table 4).

Table 4. Water-gas shift reaction.

Items	Reactants		Products	
Substance	CO	H_2O	CO_2	H_2
Mole	1	1	1	1
Total molar mass	28	18	44	2
Weight (kg)	2.09	1.34	3.28	0.15

Post-reaction, 90% of the CO_2 is removed from the mixture of final products through carbon capture. The composition of the syngas before and after carbon capture is shown in Table 5. In comparison, the water-gas shift and steam-methane reforming reactions followed by carbon capture effectively increase the percentage of hydrogen in the syngas composition. There is also a reduction in the equivalent carbon content of syngas by about 44% after carbon capture. In addition, we further assume 90% of the CO_2 from the use of natural gas as heating fuel for the steam-methane reforming process is also removed by the carbon capture process.

Table 5. Composition of syngas before and after pre-combustion carbon capture.

Items	CO	H_2	CO_2	CH_4
Before Reforming and Carbon Capture				
Weight (kg)	1.94	0.03	0.00	0.22
Weight Percentage (%)	89%	1%	0%	10%
Carbon Content (%)	45.57%			
After Reforming and Carbon Capture				
Weight (kg)	0.23	0.23	0.33	0.02
Weight percentage (%)	27%	28%	43%	3%
Carbon Content (%)	25.37%			

The composition of syngas before and after pre-combustion capture is used to compute the gross heating value of fuel for the IGCC power plant as expressed in Equation (16).

$$H_{Syngas} = \left(\frac{M_{\mathrm{CO}}}{M_{Syngas}} \times H_{\mathrm{CO}}\right) + \left(\frac{M_{\mathrm{H2}}}{M_{syngas}} \times H_{H2}\right) + \left(\frac{M_{\mathrm{CH4}}}{W_{Syngas}} \times H_{\mathrm{CH4}}\right) \quad (16)$$

where M_{Syngas}, $M_{CO}M_{H2}$ and M_{CH4} represent the weight of syngas, CO, H_2, and CH_4 respectively; and H_{Syngas}, H_{CO}, H_{H2}, and H_{CH4} represent the heating value of syngas, CO, H_2, and CH_4, respectively.

The commonly known gross heating values for H_2, CO, and CH_4 are 141.9 MJ/kg, 100.9 MJ/kg, and 556.2 MJ/kg, respectively. These values are used to obtain the gross heating value of syngas can based on the composition of the gaseous mixture as shown in Table 5 (values presented in Table 6). The substantial increase in the gross heating value of syngas is primarily due to the increase in H_2 content in the syngas composition after steam-methane reforming and carbon capture. This can also be considered an improvement to the quality of syngas fuel when measured by the gross heating value.

Table 6. Heating value of syngas with and without pre-combustion capture (Unit: MJ/kg).

Options	Values
Without reforming	16.4
After reforming and carbon capture	44.2

The gross heating values and carbon contents of syngas with and without carbon capture are used to compute the amount of syngas needed over the lifetime of the IGCC power plant and its life cycle carbon emissions due to the combustion of fuel. The total amount of syngas consumed over the lifetime of the power plant is also used to compute the total amount of carbon required for the gasification reaction. This is done through calculating backwards from the composition of syngas presented from Table 5 back to Table 1 by following the conservation of atomic mass assuming negligible losses in the chemical reactions. The total amount of carbon is used to compute the total amount of coal needed over the lifetime of the IGCC power plant based on the carbon content of coal assumed in the case study.

2.5. Other Key Assumptions

There are a number of assumptions related to the use of the proposed method. First, this method is different from the existing commercial LCA software, such as Simapro and Gabi, mainly in the system and boundary formulations. In other words, all computations are implemented manually based on the energy and mass balance principles without the use of simulation software. Next, the method is designed to track the elementary interaction between the input and output across the system boundaries. The system boundary conditions restrict the accounting of carbon emissions that are not produced due to direct conversion of fossil fuel by the processes the Main System. In addition, the method assumes an ideal system in which there are negligible losses in the supply chain. Finally, a list of key input parameters and their reference values used in computing the life cycle carbon emissions is obtained from [10] and its referenced studies (summarized in Table 7).

Table 7. Key assumptions on the operating parameters of the IGCC cycles.

Processes	Energy Input	Reference Values	Unit
Mining	Electricity Diesel Gasoline	40,392 5876 875	GJ/t-Coal
Transport	Bunker Fuel	0.25	MJ/t-Coal-km
Processing (Pulverizing)	Electricity	9–17.5	kWh/t-Coal grinded
Processing (Drying)	Fossil Fuel	0.0735	kg-CO_2/kg-H_2O removal
Gasification	Electricity	15.74	kWh/t-Coal-processed
Steam-methane reforming	Natural gas Electricity	0.56 0.02	MJ/MJ-syngas
Power generation (Construction, operation and maintenance, and decommissioning)	Fossil fuel	15,695	Liter/MW-plant-capacity
Waste disposal	Diesel	0.001	Liter/t-solid waste

3. Case Study

3.1. Carbon Emissions due to IGCC Fuel Combustion

The combined cycle power generation is modelled through a combination of a Brayton cycle and a Rankine cycle. The main parameters assumed for calculating the combined cycle efficiency are obtained with reference to the IGCC power plant study described in [30]. The values of all relevant parameters for computing the combined cycle efficiency are presented in Table 8. The size of the IGCC power plant is assumed to be 900 MW in power generating capacity, with an annual availability factor of 85%.

Table 8. Key assumptions on the operating parameters of the IGCC cycles.

IGCC Power Plant Parameters	Quantity	Unit
Overall power plant capacity	900	MWe
Availability factor	85	%
Power plant lifetime	30	Years
Brayton Cycle (Gas Turbine)	**Quantity**	**Unit**
Inlet compressor temperature	288.00	K
Inlet compressor pressure	1.01	Bar
Inlet gas turbine temperature	1604.00	K
Outlet gas turbine pressure	1.08	Bar
Pressure ratio	18.20	-
Mass flow rate of air	683.00	kg/s
Isentropic compressor efficiency	80.00	%
Turbine efficiency	65.00	%
Combustion efficiency	90.00	%
Generator efficiency	99.00	%
Power generation from the Brayton Cycle	510.00	MW
Rankine Cycle (Steam Turbine)	**Quantity**	**Unit**
HRSG heat input	698.96	MW
HRSG efficiency	85.00	%
HRSG Pressure	140	Bar
HRSG temperature	773.15	K
Condenser pressure	0.04	Bar
Condenser temperature	302.25	K
Enthalpy of water at condenser	121.5	kJ/kg
Turbine efficiency	45	%
Generator efficiency	99	%
Power generation from the Rankine Cycle	255.00	MW

The assumed parameters as presented in Table 8 are used to compute the mass flow rate of syngas with and without carbon capture in kg/s. We recognize that the most rigorous approach to compute the mass flow rate of fuel to use computer simulation software, but a full-scale power plant simulation is outside the scope of our study. As such, we employ a manual approach by following the thermodynamic equations for the Brayton and Rankine Cycles with reference to [31]. This approach also enables the relevant energy conversion equations to be embedded in the LCA method established through the serial developments as already described in [7,12,22–24] so as to facilitate future developments, especially in case studies on power generation. The mass flow rate of syngas is used to compute CO_2 emissions due to the combustion of fuel.

Based on the assumed operational parameters as specified in Table 8, the IGCC power plant produces about 6.7 TWh of electricity annually which is about 201 TWh over its lifetime of 30 years. The equivalent efficiency of IGCC power plant is approximately 46%. As explained earlier, the overall plant efficiency can be used to compute the lifetime syngas requirement for IGCC and IGCC with carbon capture. The lifetime syngas consumption is about 96 Mt without steam-methane reforming and carbon capture and 35.6 Mt with steam-methane reforming and carbon capture. The reduced quantity in syngas consumption with carbon capture is primarily due to the higher heating value of syngas after steam-methane reforming and carbon capture. As explained in Section 2.4, a 90% conversion rate of CO and CH_4 in the gasification and steam-methane reforming processes, followed by 90% removal of CO_2 in carbon capture leave a high percentage of H_2 in the final syngas composition thereby raising the gross heating value.

The carbon emissions due to the combustion of fuel can be obtained based on the amount and equivalent carbon content of syngas consumed by IGCC at approximately 160 Mt-CO_2 and 3 Mt-CO_2 with carbon capture over the lifetime of the plant.

3.2. Carbon Emissions of Other Processes

The life cycle inventories (LCIs) for processes ranging from upstream coal supply to downstream waste disposal are taken from [10]. These include mining, transport, drying and pulverizing, power generation, and waste disposal, but exclude gasification and pre-combustion carbon capture. The energy consumption for the gasification process is 15.74 kWh/t-coal as converted from [32]. The energy input for steam-methane reforming and water-gas shift reactions is 3.93 MJ/Mt-H_2 for natural gas and 0.15 MJ/Mt-H_2 for electricity as obtained from [33]. The fuel emission factor for natural gas and grid emission factor for Singapore are drawn from [7] to compute the LCIs for gasification and steam-methane reforming with carbon capture in the Singapore context.

Using Singapore's grid emission factor as reported in [7], the LCIs for steam-methane reforming with carbon capture process and the power generation process are 217.86 t-CO_2/Mt-H_2 produced and 274.1 t-CO_2/kWe generating capacity. As such, it is noteworthy that the LCIs for these processes need to be changed if a different country is selected. The power generation process only includes energy and non-energy input for power plant construction, operations and maintenance, and decommissioning, and excludes the combustion of fuel which has been calculated using the first principle as explained in Section 2.

All coals are assumed to be imported from Indonesia with negligible losses across the supply chain. The estimated average freight distance between coal exporting ports in Indonesia and Singapore is about 660 km (with reference to https://sea-distances.org/). The annual operations and maintenance energy input for power plant operation and maintenance assumes 0.5% of the power plant construction energy use based on Singapore's average operating experience. There are four types of coal included in this study, namely, semi-anthracite, bituminous, sub-bituminous, and lignite, which are available in Indonesia. The mining method for semi-anthracite, bituminous, and sub-bituminous is usually underground mining, and the mining method for lignite is usually open-pit mining.

All LCIs obtained from [10] (as listed Table 7) are converted based on the amount of "products" leaving each process (Table 9). In this case, it refers to the amount of CO_2 emissions per million tonnes of coal and/or syngas leaving each corresponding process of the system. Waste disposal refers to the handling of residues after syngas production.

Table 9. Life cycle inventories (LCIs) for upstream processes.

Process	Values
Mining—Underground (t-CO_2/Mt-coal)	9435.62
Mining—Open-pit (t-CO_2/Mt-coal)	13,959.52
Transport (t-CO_2/Mt-coal)	13,295.10
Drying and pulverizing (t-CO_2/Mt-coal)	9011.24
Gasification (t-CO^2/Mt-coal)	7438.50
Steam-Methane Reforming with Carbon Capture (t-CO_2/Mt-H_2)	217.86
Power Generation Excluding Fuel Combustion (t-CO_2/kWe)	274.1
Waste disposal (t-CO_2/Mt-waste)	3027.38

The carbon content and the other physical compositions of the selected four types of coal are presented in Table 10. The carbon content of each type coal is used to compute the lifetime coal consumptions based on lifetime syngas consumptions assuming only one type of coal is used throughout the lifetime of the IGCC power plant.

Table 10. Physical composition of Indonesian coal by type.

Coal	Calorific Value (MJ/kg)	Composition (%)			
		Moisture	Ash	Volatiles	Carbon
Semi-Anthracite	31.41	5.23	3.54	7.48	83.75
Bituminous	30.70	3.10	7.33	42.84	46.73
Sub-bituminous	23.37	19.36	4.33	34.99	41.32
Lignite	13.74	48.27	2.99	25.42	23.32

3.3. Carbon Emissions of the Whole System

The final results are presented in life cycle carbon emission factors measured by g-CO_2/kWh. The values of the life cycle carbon emission factors and the percentage contribution by process are presented in Figure 5. As expected, the combustion of syngas fuel accounts for a major proportion of the life cycle carbon emissions of the entire system. This is consistent with other fossil-fueled power generation technologies. Our findings further suggest that 90% removal of CO_2 in the pre-combustion carbon capture process has led to approximately 71–74% reduction in the overall life cycle carbon emissions of IGCC power generation system depending on the assumed coal types. Although the life cycle carbon emission factors of IGCC with carbon capture remains many orders of magnitude higher than those of nuclear and renewable energy, IGCC with pre-combustion carbon capture can make significant contribution to reducing CO_2 emissions from fossil-fueled power generation.

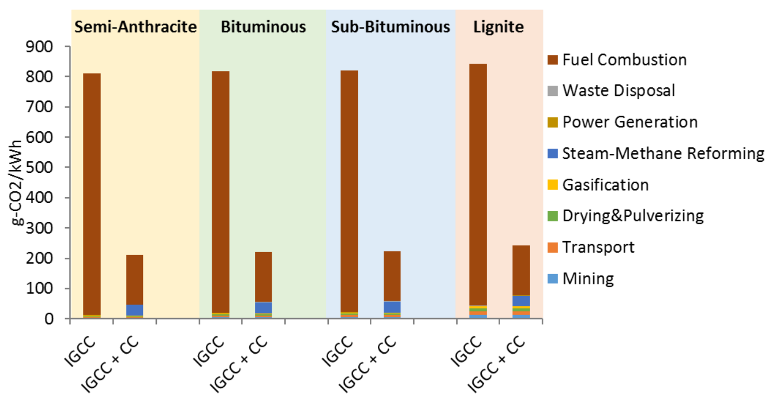

Figure 5. Life cycle carbon emissions of IGCC with and without carbon capture by input coal type. (CC denotes carbon capture).

Further decomposing the results by removing the CO_2 emissions due to the combustion of syngas reveals a distinctively different set of results. The life cycle carbon emission factors with exclusion of fuel combustion show that there is significant increase in CO_2 emissions from upstream processes. Such a drastic increase is primarily due to the energy-intensive steam-methane reforming reaction assumed to be used for a deep conversion of carbon to improve the quality of syngas. As seen from the results in our case study, the energy- and hence carbon-intensive steam-methane reforming process is responsible for drastically increasing the upstream carbon emissions.

Depending on the type of coal used in the system, the steam-methane reforming with carbon capture process can increase the upstream carbon emissions by about 82% to more than 3 times from those without carbon capture, albeit with reductions in the whole system carbon emissions.

Using coal with a higher carbon content such as semi-anthracite, the total amount of coal needed for producing the require amount of syngas is much lower than those coal types with lower carbon contents. This leads to a lower energy input, and hence lower carbon emissions for the mining, transport, drying and pulverizing, and gasification processes. The energy input and carbon emissions for the steam-reforming process are the same for all coal types because the total amount of carbon atoms needed for producing the required amount of syngas is determined by the power generation process and hence remains the same regardless the coal types. Using coal with a lower carbon content, such as lignite, the upstream process (excluding steam-reforming) energy input and carbon emissions become higher because a higher amount of coal is needed to meet the required amount of carbon atoms for the gasification process. Since the total amount of carbon emissions due to the reforming process remain unchanged, the influence of steam-reforming in the upstream process life cycle carbon emission factor appears to be different across different coal types.

As a result, the percentage of upstream life cycle carbon emissions in the total life cycle carbon emissions is increased from 1.4–5% to about 22–32%, depending on the coal types. This is a combined effect due to the added energy input and carbon emissions due to the steam-reforming process and the significant reduction in CO_2 due to the carbon capture process. In this case study, we have assumed 90% of CO_2 from the combustion of natural gas as heating fuel for the steam-methane reforming process. Without such an assumption, the values of the life cycle carbon emission factors for the upstream processes are expected to significantly increase from the obtained values, as shown in Figure 6.

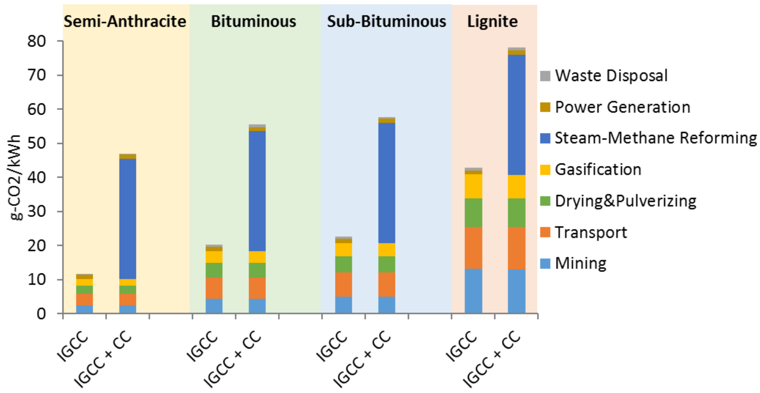

Figure 6. Life cycle carbon emission factors without accounting for the combustion of power plant fuel. (CC denotes carbon capture).

Although these results are intuitive from a mathematical accounting perspective, the results as presented in Figure 6 further imply that the steam-methane reforming with carbon capture is likely to substantially increase the running cost of IGCC. Since carbon emissions are directly linked to energy consumption in the methodology used in this study, the energy-related running costs could increase from 82% to more than 3 times that, depending on the carbon content of coal used for gasification. However, the lifetime coal consumption by the IGCC power generation system with and without carbon capture is about the same (Table 11). In addition to the mathematical explanation, a more intuitive explanation is the reduction in syngas requirement post-reforming due to a higher gross heating value. Although the carbon content of the syngas after carbon capture is reduced, the total carbon atom required with and without carbon capture to produce the needed amount of syngas is approximately the same. As such, the lifetime coal requirement with and without carbon capture is about the same.

Table 11. Lifetime coal requirement (Unit: Mt).

Type of Coal	No Carbon Capture	With Carbon Capture
Semi-Anthracite	52.29	52.17
Bituminous	93.71	93.51
Sub-bituminous	105.98	105.75
Lignite	187.78	187.37

4. Discussion

The construction cost of IGCC plant as compared to a supercritical coal fired power plant is high. The need to handle hydrogen as part of power plant fuel also poses safety concerns. Due to the need for stockpiling of coal for syngas production, the footprint of the IGCC facility could be much larger than a CCGT power plant fueled by natural gas. Although coal remains cheaper than natural gas and is abundant in Southeast Asia, land-use constraints and environmental concerns would continue to be barriers for IGCC adoption in small countries, like Singapore. However, IGCC could represent an interesting option for countries with coal resources and less constrained land space, such as Indonesia, Malaysia, and Vietnam.

The Southeast Asian region is generally well endowed with renewable energy resources, albeit with varied access to renewable technologies, among the member countries of the Association of South East Asian Nations (ASEAN). According to the International Energy Agency, the technical potential for renewable energy in ASEAN is approximately 150 GWe of hydropower, 90 GWe of bioenergy, and tens of gigawatts of wind suitable for only Vietnam and the Philippines [34]. More recent studies suggest that more renewable technologies, especially solar PV, could be deployed with the right policy and market designs [3–5]. In addition, atomic energy, especially the more advanced nuclear reactor technologies, such as the small modular reactors [35,36] and Generation IV reactor technologies [37], could also represent strategic options for ASEAN members.

In other parts of Southeast Asia, such as Indonesia and Malaysia, the deployment of IGCC could substantially increase the efficiency of coal utilization and reduce the discharge of airborne pollutants as compared to conventional coal-fired power plants. However, the life cycle carbon emissions of IGCC power generation with pre-combustion carbon capture are still much higher than renewable energy, such as solar photovoltaic (PV) systems, at about 40 to 60 g-CO_2/kWh under Southeast Asia's climatic conditions [7]. With the fast projected decline in the cost of solar cells and hence PV modules [38] and improvements in their conversion efficiencies [39], PV systems may represent a more plausible option to decarbonize the electricity sector in Southeast Asia, especially when integrated with energy storage technologies.

The cost of electricity generation, as well as the capital commitment of building new power plants, are important considerations among the developing economies in ASEAN [40]. The overnight cost of power plant construction and the levelized cost of electricity are high for IGCC and higher for IGCC with carbon capture when compared to other fossil-fueled power generation technologies [41]. With the potential need for additional land-space for stockpiling of coal and the steam-methane reforming and carbon capture facilities, the total cost of IGCC power generation could be much higher than currently reported costs in the literature. With solar PV electricity projected to reach grid parity, IGCC might face stronger barriers for adoption in ASEAN.

The intermittent nature of solar energy and the suboptimal climatic conditions in Southeast Asia makes large-scale deployment of PV systems difficult [4]. IGCC with pre-combustion carbon capture as a base load technology is much less carbon intensive than CCGT or supercritical coal-fired power plants. Theoretically, the life cycle carbon emission factors of IGCC with pre-combustion carbon capture could be further reduced with an additional post-combustion carbon capture. Assuming 90% CO_2 remove with post combustion capture and a 20% overall energy efficiency penalty, the life cycle carbon emission factor of IGCC with both pre- and post-combustion carbon capture could theoretically be reduced to about 67 to 98 g-CO_2/kWh, depending on the type of coal. However, the addition of post-combustion carbon capture is expected to further increase the overnight as well as the running costs of IGCC.

5. Conclusions

In this study, we have introduced a generic LCA-PCA method to examine the life cycle carbon emissions of IGCC power generation with and without pre-combustion carbon capture. This method is conceived based on the serial developments described in [7,10,12,22,24]. This method allows for consistent system and boundary formulations, which can help ensure accurate and unbiased LCA results. Special attention is paid to the formulation of the physical system boundaries to ensure an accurate and consistent accounting of energy input and hence carbon emission streams. Two enhancements are made to the serial developments of the LCA-PCA method. The first enhancement, with reference to earlier developments as described in [10], lies in adding the steam-methane reforming process with pre-combustion carbon capture endogenously into the mathematical formulations, rather than relying on a separate accounting approach outside of the methodology. This can help improve consistency in the system boundary formulations. Thus, the first recommendation for future research is to include post-combustion carbon capture endogenously into the formulations.

The next enhancement lies in embedding thermodynamic calculation procedures directly into the mathematical formulations. This may seem trivial from a mathematical standpoint, but it is an important step in further expanding the methodology towards being an energy systems modelling analysis tool. With reference to [42,43], the energy systems modelling tool, when developed in the future, can allow modelers to use these added formulations to estimate the technical performance of power plant technologies if no such data are available.

In addition to life cycle carbon emissions, we have further included a qualitative discussion on the economic and other dimensions in policy consideration to evaluate the suitability of IGCC with carbon capture as an option to decarbonize the electricity sector for the developing economies in ASEAN. For the purposes of this study, we were unable to secure credible and verifiable cost data on gasification, steam-methane reforming, and pre-combustion carbon capture. Due to such limitations, we were unable to quantify the economics of IGCC with pre-combustion capture, which we recognize as an important element in the cost-benefit analysis for low carbon technologies in the ASEAN context. We recommend a LCA on the cost of IGCC power generation with pre-combustion carbon capture as a second future research. This leads to our final recommendation for future research, which is to extend the current LCA methodology towards the inclusion of life cycle cost analysis endogenously in the formulation.

Author Contributions: The contribution of authors is as follows. Y.W. and V.N. designed the methodology; H.L. conducted study on gasification and steam-methane reforming; J.Y. provided analysis of data; V.N. led the team effort in the writing of the paper.

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