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Investigating a Retrofit Thermal Power Plant from a Sustainable Environment Perspective—A Fuel Lifecycle Assessment Case Study

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Abstract: Retrofitting thermal power plants is a valuable opportunity to guide Taiwan's electricity generation towards sustainability. Using an existing power plant nearing decommissioning as a case study, we hypothesized about fuel source options for retrofitting the power plant and compared the resulting impact on lifecycle atmospheric emissions. Our use of the lifecycle assessment (LCA) methodology reflected Taiwan's heavy reliance on the imports and shipping of primary energy sources. We found that after accounting for the contribution of liquefaction and regasification (17%), gas-fired electricity still has significantly lower lifecycle greenhouse gases (GHGs) than coal or fuel oil (FO). In addition, we found that if natural gas (NG) is selected to achieve the greenhouse gas reduction of thermal power, the co-benefit of air pollution reduction can also be achieved at the same time.

Keywords: atmospheric emissions; greenhouse gases; air pollution; LCA; lifecycle assessment; thermal power plant; natural gas

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1. Introduction

1.1. Policy of Energy Transition in Taiwan

Relying on imports for more than 98% of its energy use, it is critically important for Taiwan to have a sustainable energy system. Taiwan's electricity demand has grown from 134.3 terawatt-hours (TWh) in 1996 to 274 TWh in 2019 following the development of the economy [1]. Taiwan's electricity generation sources consist of thermal power (81.5%), nuclear power (11.8%), renewable energy (including hydropower) (5.6%), and pumped-storage hydroelectricity (1.2%). In thermal power, coal has the largest share (approximately 46.1%) of electricity generation in Taiwan, followed by natural gas (33.3%) and oil (2.1%) [1]. With the percentage of electricity generated from thermal power plants increased from 66.4% in 1996 to 81.5% in 2019, much atmospheric emission was generated, including particulate matter (PM), nitrogen oxides (NO_x), sulfuric oxides (SO_x), and greenhouse gases (GHGs). The carbon dioxide (CO_2) emission from electricity generation alone accounted for more than 47% of Taiwan's total CO_2 emissions from fuel combustion, which was approximately 0.82% of the global amount and ranked 21st among other countries in the world [2,3]. Finding the optimal energy mix is a must for this urgent issue.

The current central government issued the "Sustainable Energy Policy Convention" vowing to reduce carbon emissions by 50% from the business-as-usual level by 2030 [4]. On the other hand, the government has declared making Taiwan a "nuclear-free homeland" by 2025. Rapid growth in clean energy including renewables is crucial in the route to greater energy security if Taiwan is to achieve both goals. Taiwan is continuing its energy transition, to achieve a 20% share of installed capacity for renewables by 2025 [4].

1.2. Use NG for Electricity Generation

Energy efficiency is one of the major factors in determining whether the above-mentioned energy transition will become real as expected. Combined cycle power plants play an important role in electricity production with their relatively high efficiency and low GHG emissions [5–9].

Natural gas (NG) is seen as a flexible and cleaner fuel in power generation, to comply with the growing awareness of environmental issues and climate change. Control technologies applied at NG combined cycle (NGCC) plants have contributed to lower NO_x, SO_x, and PM emissions during operations. Kong et al. [10] compared the energy efficiency of a coal gasification project with that of imported NG based on an energy return on investment analysis. The results indicated that imported NG generally has a better energy return on investment than coal-based synthetic NG regardless of whether the environmental inputs are considered. Holladay and LaRiviere [11] found that NG generation has displaced coal-fired generation as the marginal fuel source owing to decreased NG prices, resulting in a significant change in the marginal emissions profile of electricity generation across U.S. regions.

Further improvement in efficiency in NG-fueled plants is possible, as has been suggested in the literature. The study result of Arsalis and Alexandrou [12] suggested decentralized, NG-fueled trigeneration plants as alternatives to centralized, electricity-only plants to improve efficiency and minimize operating costs. Ghasemiasl et al. [13] proposed a multigeneration system for an existing combined cycle power plant and reported an exergy efficiency of 49.64% and an energy efficiency of 57.36%, resulting in lower emissions and fuel costs. Javadi et al. [14] suggested improved performance and a possible further reduction in emissions achievable by adding a multi-effect desalination cycle and parabolic solar collectors to a combined cycle power plant. In addition to lower NG prices, the existence of sufficient gas infrastructures, or a competitive market environment, or both of them is needed in order to couple retail electricity prices with the cost of natural gas [15].

1.3. Environmental Footprint of Power Generation

Environmental accounting approaches such as LCA and the carbon footprint have been commonly applied in recent year for decision-making on energy selection. LCA addresses the potential environmental impact of a product or service from a cradle-to-grave perspective. The process of conducting an LCA includes the goal and scope definition, inventory analysis, impact assessment, and interpretation [16–19]. The type of LCA that is chosen depends on the goal of the study [20]. Material and energy balances can be used to calculate the emissions and energy use in the generation of electricity. It encompasses all upstream and downstream processes associated with the generation of 1 kWh of electricity. A fuel lifecycle analysis (or fuel LCA) is often used in the study of atmospheric emissions from energy use. A fuel LCA quantifies emissions along the entire fuel pathway, considering fuel extraction, production, transporting, processing, conversion, and distribution [21,22]. For example, electricity generated from NG requires the acquisition and transport of NG from sources, which can result in a comparatively large amount of emission. The results are then used to evaluate the environmental impacts of the process.

Vandani, Joda, and Bozorgmehry Boozarjomehry [9] used the LCA method to investigate the effect of using diesel instead of NG for electricity generation. Their results showed that a power plant using diesel could lead to a higher adverse environmental impact. Applying the LCA method, Rajović et al. [23] concluded that using the associated petroleum gas via combined heat and power plants and heat boilers can provide a significant reduction in GHG emissions and resource depletion. Meng and Dillingham [24] compared lifecycle atmospheric emissions of NG power plants with distributed or centralized systems. Dalir et al. [25] developed an LCA model focusing on the carbon footprint of three types of fossil fuel power plants and demonstrated its use in facilitating energy portfolio decision making. Jordaan et al. [26] performed a systematic review of 251 research papers that conducted carbon LCA for electricity generation and emphasized the need for further research on the spatial, temporal, or spatiotemporal issues of LCA.

Other studies conducted a comparative LCA focusing on atmospheric emissions from power generation systems on a regional basis, for example: Šerešová et al. [27] conducted research for the Czech Republic; Hondo [28] performed a study for Japan; Ou et al. [29] focused on power generation and supply in China. The LCA method has also been used to assess the impact of renewable energies including wind [30,31] and solar [32–35]. Furthermore, Ling-Chin and Roskilly [36] used the LCA methodology via scenario analysis to investigate a retrofit power plant on board a cargo ship from a sustainability perspective. They concluded that retrofitting power plants with suitable emerging technologies could significantly mitigate the environmental impacts. Hua et al. [37] also used LCA for atmospheric emissions from marine shipping operating on FO and on liquefied natural gas (LNG). Their findings indicated possible improvement in total lifecycle GHG emissions from the use of LNG to power ships. Arteconi, Brandoni, Evangelista, and Polonara [32] compared the lifecycle GHG emissions of diesel and liquefied natural gas (LNG) used as fuels for heavy-duty vehicles in the European market, considering two possible LNG procurement strategies. The study found that the use of LNG enables a 10% reduction in GHG emissions by comparison with diesel if purchasing LNG directly from the regasification terminal, while the emissions are only comparable with those of diesel if producing LNG locally (at the service station) with small-scale plants.

1.4. Purpose of the Study

The state-owned Taipower Company (TPC) has recently completed the retrofitting of a power plant with three ultra-supercritical units, at 800 MW each, operating successively from 2016 to 2019. Meanwhile, the company underwent active planning for further power plant development, as more existing units are approaching decommissioning [38]. It is expected to play a crucial role to help boost the total electricity supply, while at the same time contributing to atmospheric emissions and other environmental impacts.

The objective of this study is to provide a preliminary assessment of the influence on atmospheric emissions from the choices of the energy sources for power generation. We selected one oil-fueled power plant, Hsieh-ho Power Plant, as a study case, as it is approaching decommissioning in the near future. We compared the fuel lifecycle atmospheric emissions of possible fuel choices for the power plant, including coal and NG, given that NG is a widely used energy option in complying with the growing awareness of energy transition. Specifically, we give a comparison considering the upstream processes and transportation of the fuel, due to the fact that Taiwan relies on imports for all its primary energy sources for electricity and marine shipping plays an important role in the trade routes. The results from this study provide valuable information for the power sector to aggressively pursue possible approaches to optimize the energy mix and further introduce alternative fuels, for example NG, for power generation.

2. Materials and Methods

With reference to the transition of power generation in Taiwan, we compared the fuel lifecycle atmospheric emissions of FO, coal, and NG as fuels for power plant operation. A 2 GW power plant, which is scheduled to be decommissioned in the next few years, was chosen as the subject of comparison. The following section provides a description of the processes and technologies included in each process stage in order to understand what is represented by the results of the study presented in Section 3.

2.1. Object and Scope of the Study

We used the Hsieh-ho Power Plant (HHPP), an oil-fueled power plant located on the north coast of Taiwan (25°9′26.38″ N 121°44′21.57″ E), as a target case in this study, considering its foreseeable transition to other fuels in response to decommission in the next few years. Figure 1 provides a general idea of the location of the target power plant.

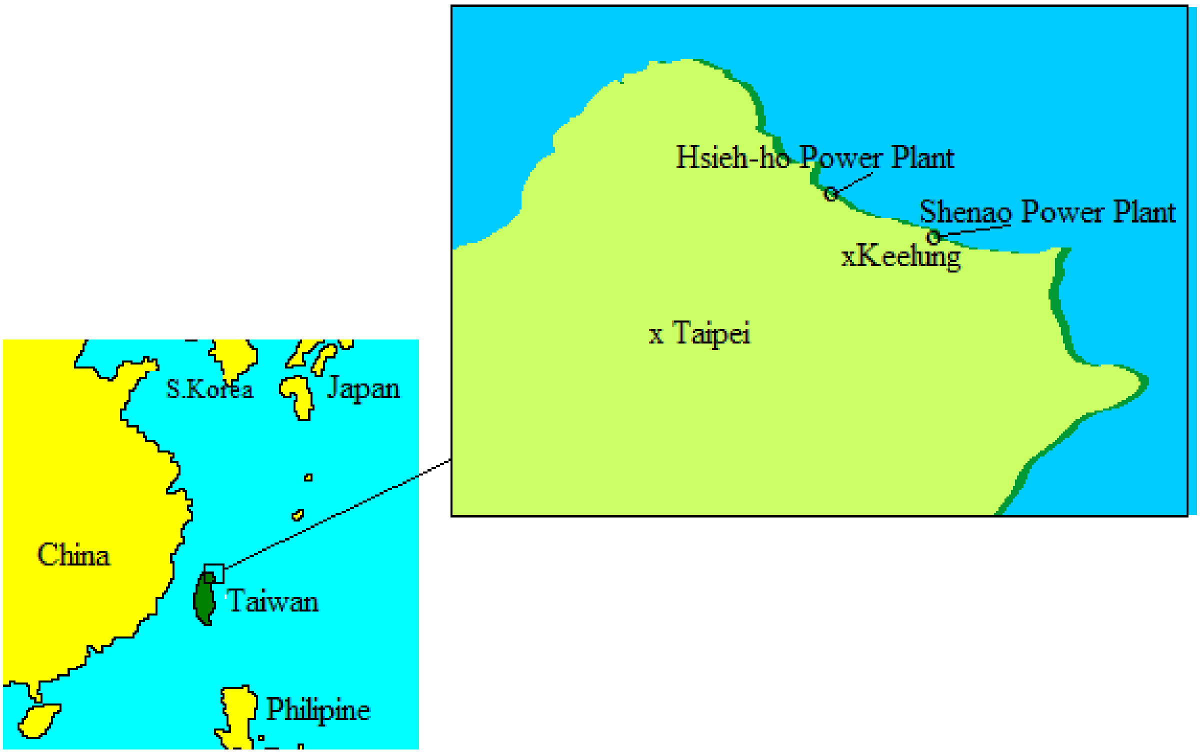

Figure 1. Relative locations of Keelung City, Hsieh-ho Power Plant, and Shenao Power Plant.

Table 1 defines the case for the energy study. The target 2 GW power plant comprises four identical 500 MW units, each consisting of a steam turbine coupled to an air-cooled generator unit, step-up transformers, and a seawater condenser. Each has its own auxiliaries (piping, pumps, and so on). The plant has been in service for nearly forty years. We postulated that the plant is to be rebuilt after decommissioning soon, with alternative energy sources for the new design. This study considered coal-fired power generation as one of the retrofitting alternatives for HHPP, given that the technology is still an important choice for TPC's recent retrofitting. In addition to coal and oil, this study evaluated the NGCC power technology. The presumed NGCC power plant uses two parallel NG-fired combustion turbines, followed by a heat recovery steam generator (Figure 2).

Table 1. Definition of the study case—Hsieh-ho Power Plant.

Current—Fuel-Oil-Fired	Alternative 1—Coal-Fired [1]	Alternative 2—NGCC [2]
• Generating capacity: 2000 MW (4 × 500 MW) • Primary fuel: FO • Commission date: 1977–1985 • Boiler: rated 1701 tonnes/h, 176 kg/cm^3, 542 °C • Generator units: steam turbine, 3600 rpm single reheat with throttle steam conditions of 166 kg/cm^2, 538 °C • Mean annual energy output: 4,356,329 MWh	• Generating capacity: 2400 MW (4 × mix of 100 MW and 500 MW units) • Primary fuel: hard coal • Startup fuel: fuel oil • SO_x retention: FGD • NO_x retention: SCR	• Generating capacity: 2600 MW (2 × 1300 MW CCGT) • Primary fuel: natural gas • 100% natural gas firing

[1] Model based on an average hard coal power plant in the North American Electricity Reliability Corporation (NERC), as adopted in the process "Electricity Generation—Hard coal, burned in power plant/NPCC U" in the Ecoinvent database v.2.2. [2] Model based on the average of installed NG fired power plants in the United States, as adopted in the process "Natural gas, burned in power plant/US U" in the Ecoinvent database v.2.2.

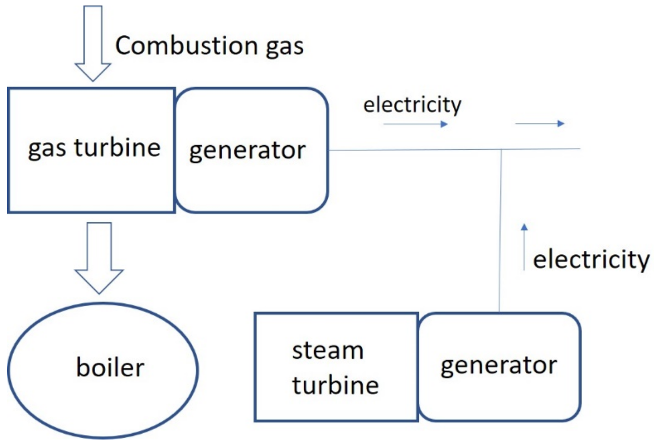

Figure 2. Basic NG combined cycle power generation.

2.2. Fuel LCA for Power Generation

This study used a fuel LCA model to assess the atmospheric emissions from the power plant. In addition to the direct emissions from the power plant, a fuel LCA also considers those associated with the fuel extraction, production, transporting, process, conversion, and distribution. This approach is especially useful for comparison across fuel supply chains [21,22,39].

In this study, the functional unit was defined as 1 kWh of electricity produced at the gate of the power plant, at the point of delivery to the electricity grid. This functional unit served as a reference to which the input and output data were normalized, and all environmental emissions considered in this study were compared across the system [19].

The system boundaries determine which unit processes shall be included within the LCA [19]. In this study, the scope and system boundaries for each of the various power generation scenarios covered power plant operation, including its infrastructure and all related process stages and technologies, plus the upstream production and transportation of the fuels to the gate of the power plant. The system boundary does not extend to the transmission and distribution, nor the usage of electricity, as our study focuses on the comparison of the production of electricity under various fuel technology, and we assumed the electricity output would be connected to the same grid for distribution. Given that it is a fuel lifecycle analysis, we did not consider upstream emissions from the procurement of other material inputs. In this study, we limited ourselves to the atmospheric emissions of GHGs and pollutants only, as the issue is currently of much concern in Taiwan, although there may still be other environmental issues related to electricity generation as well.

As an example, Figure 3 illustrates the NG scenario system boundaries. NG supply starts with the construction and installation of wells. Following that, NG is extracted as a mixture of raw NG, condensed higher hydrocarbons, water, and particles. The raw gas is then sent to a processing plant where it undergoes various purifying processes including dehydration and acid gas removal [40]. Once purified, NG is compressed and transferred to the power plants. Given that the transport involves marine shipping, the transferring system requires storage facilities, as well as a liquefaction and regasification process in a terminal along the coastline, so that NG can be easily and safely transported across oceans [41–43].

Following the approach adopted by previous studies, the upstream supply chain in a fuel LCA study covers the environmental impacts associated with the extraction, production, and transportation of all fuels used in the operation of the power plant. The operation stage considers the environmental impacts associated with the normal operation and maintenance of the power plant, including air pollution control. Waste management refers to the handling of solid and liquid wastes, of which the overall contribution was assumed to be negligible in comparison to the total lifecycle emissions following the practice of previous studies [24,27,40,44].

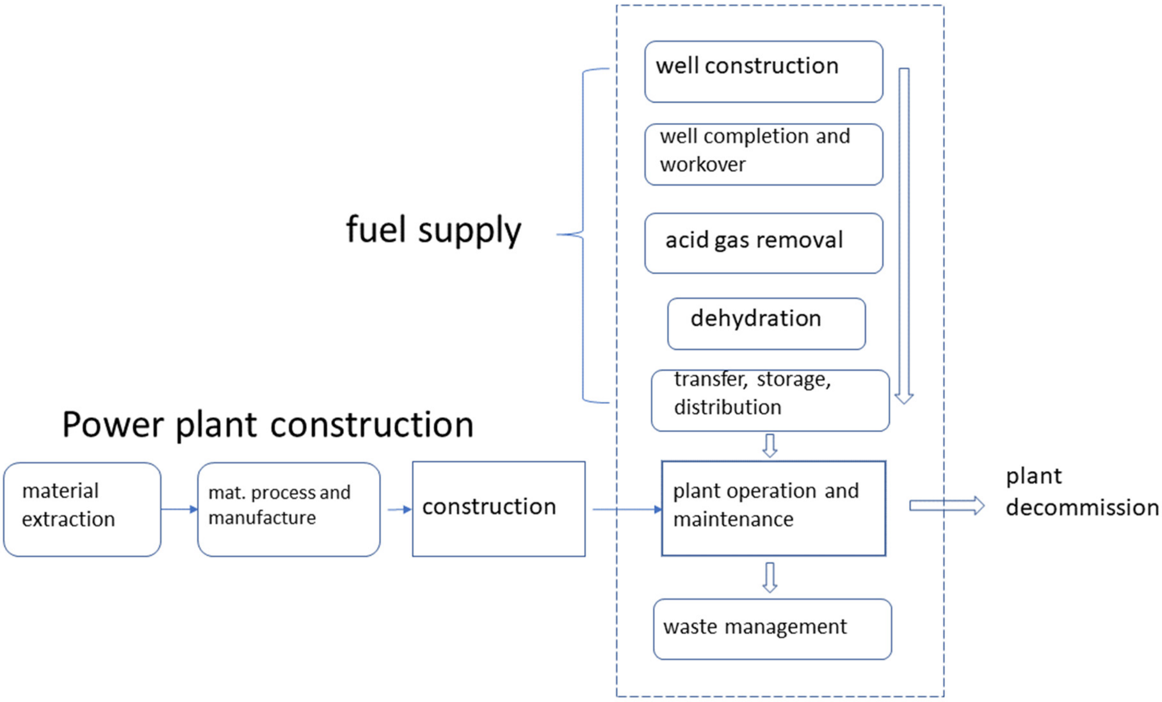

Figure 3. System boundaries of the natural gas scenario.

2.3. Energy Supply and Use

2.3.1. Scenarios of Energy Supply

In a fuel lifecycle assessment for thermal power generation, it is necessary to consider the atmospheric emissions prior to the fuels' arrival at the gate of the power plant. This includes emissions derived from the upstream production of fuel, as well as from the transportation, handling, and storage of the fuels. Taiwan relies heavily on imports for almost all of its energy supplies. Taiwan imports bituminous and sub-bituminous coal for power generation, currently procured mainly from Australia, as Figure 4 shows. Based on the 2019 data, the crude oil sources were mainly from Saudi Arabia, Kuwait, and Indonesia, while NG was mainly from Qatar and Australia [1].

We developed three fuel supply chain scenarios for the target power plant based on the most likely fuel import sources and routes in the Taiwan scenario (Table 2). In addition, we also considered a fourth scenario where combined fuel sources are used to generate electricity in the target power plant, 50% coal and 50% LNG. As summarized in Table 2, the fuel supply chain includes all upstream and on-site processes related to the normal operation of the power plant. Shipping distance in this study was estimated based on the most efficient trade route between the assumed fuel extraction site and the power plant.

In the scenario for coal, we assumed coal from Australia. It is then transported to the unloading wharf at Port Keelung, Taiwan, by bulk carriers and discharged via conveyors to the coal storage areas. In the scenarios for FO, we assumed crude oil is produced in Eastern Province, Saudi Arabia, and shipped to Taiwan from Yanbu Port. Imported crude oil is then unloaded at Taoyuan Refinery for FO production. The refined FO is then transferred to HHPP for interim storage and fed through a piping system for use.

As for the scenarios for NG, we assumed Dampier, Australia, to be the source of imported LNG for HHPP, given that Australian LNG import has long been key to meeting Taiwan's industrial needs. LNG is shipped to the LNG terminal located at the coast outside HHPP, near Keelung Port, and then is fed to the power plant directly from the regasification plant at the coast.

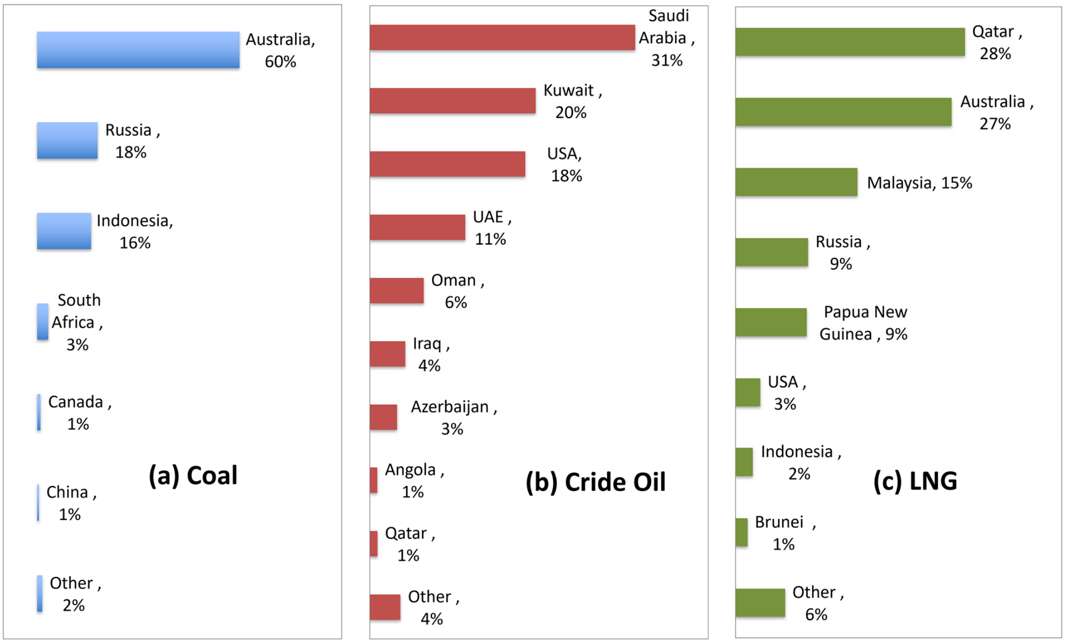

Figure 4. Breakdowns of sources of fuel import to Taiwan. Panel (**a**) shows the breakdown for coal imported for electricity generation; Panel (**b**) displays the breakdown for crude oil imports which was used to produce fuel oil; Panel (**c**) the breakdown of LNG imports. All based on 2019 data.

Table 2. Scenarios for fuel supply.

Scenario Number	Fuel	Route	Means of Transport	Distance (km)
Scenario 1	FO	Crude imported from Yanbu, Saudi Arabia, unloaded at Taoyuan, and refined FO piped to the power plant	Pipeline, Hawiyah (in Ghawer oil field), to Abqaiq, Saudi Arabia	158
			Pipeline, Abqaiq plant to Port of Yanbu (746 miles, 56-inch pipeline)	1200
			Crude oil tanker from King Fahad Industrial Port (Yanbu) to Ta-Lin-Pu Offshore Oil Terminal (Kaohsiung)	12,823
			Crude oil pipeline from Ta-Lin-Pu Offshore Oil Terminal (Kaohsiung) to Ta-Lin Refinery, round trip	4
			FO tanker from Ta-Lin-Pu Offshore Oil Terminal (Kaohsiung) to HHPP	414
			Oil pipeline from the terminal at Hsieh-ho (Keelung) to the power plant	1
Scenario 2	Coal	Coal imported from Hunter Valley, Australia, unloaded at Keelung	Rail freighter average distance from Hunter Valley Coal Area to Kooragang coal terminal of the port of Newcastle	128
			Bulk carriers from Newcastle, Australia, to Keelung, Taiwan	7848
			Coal conveyer form the terminal at Hsieh-ho (Keelung) to the power plant	0.2
Scenario 3	NG	LNG imported from Australia, unloaded and stored at the LNG terminal near Keelung port, then piped to HHPP	Pipe from the Northwest Shelf to the liquefaction facility in Port Dampier	150
			The LNG carrier from Port Dampier to the LNG terminal at HHPP, near Keelung port	6358
			LNG pipeline from the terminal to HHPP	0.2

2.3.2. Scenarios of Energy Use

The amount of fuel used to generate electricity depends on the energy efficiency of the power plant and the heat value of the fuel. We also considered energy efficiency in standard load mode to reflect differences in operating efficiency between fuels. Power plant efficiencies (heat rates) vary by generators, emission controls, and other factors, for example the cleanness of the heat exchangers. Fuel heat contents also vary. We adopted the weighted average heat content value based on real data published in 2015 by the Bureau of Energy, Taiwan [45]. For the heart rates, our assumption was based on Energy Information Administration (EIA) data published in the Electric Power Annual 2015 [46], given that the real heat rate data from Taipower Company are not publicly available. EIA published the year-average operating heat rate data for U.S. electric power plants in the utility and independent power producer sectors, which we believe should be an achievable yardstick for a new retrofitted thermal power plant. The formula we used to calculate the amount of fuel used to generate 1 kWh of electricity is shown in Equation (1). Table 3 summarizes the assumption for energy consumption during power generation.

$$\text{Fuel used per kWh} = \frac{\text{Heat rate (in Btu per kWh)}}{\text{Fuel heat content (in Btu per unit of fuel)}} \tag{1}$$

Table 3. Assumption for energy consumption during power generation.

Fuel	Heat Content of Fuel [1]	Amount of Fuel Used to Generate 1 kWh	kWh Generated/ Fuel Used	Power Plant Heat Rates [2]
Coal	5368 kCal/kg	0.4895 kg	1853 kWh/ton	10,428 Btu/kWh
Natural Gas	9000 kCal/m^3	0.2214 m^3 (gas mode), or 0.1677 kg (LNG)	128 kWh/Mcf	7907 Btu/kWh
Fuel Oil	9600 kCal/L	0.284 L or 0.271 kg	560 kWh/barrel	10,814 Btu/kWh

[1] Weighted average heat content of energy products consumed for power generation published in Energy Statistical Annual Reports [45]. [2] Average operating heat rates of electric power systems in 2014, obtained from Electric Power Annual 2015 [46].

2.4. Fuel LCA Emissions

2.4.1. Calculation of Emissions

To facilitate a stage-by-stage comparison among the four fuel supply scenarios, we followed [37] and disaggregated the full fuel lifecycle of power generation into four stages: (1) exploration and extraction, (2) production (including compression and/or liquefaction and regasification of NG), (3) transportation, and (4) consumption in electricity generation. We used the LCA software SimaPro (v.7.24) to link the processes and lifecycle stages and to compute the lifecycle emissions. We then compared the fuel lifecycle emissions across the four fuel technology scenarios based on the SimaPro results, contrasting the environmental impact of each replacement fuel with FO, which is the fuel currently in use at HHPP.

For the electricity generation stage, we considered specific emissions from the consumption of fuels in the standard operating cycle to account for the direct emissions from HHPP. The emissions were based on the ratio of real-world and nominal-specific fuel consumption. Based on the energy consumption estimates described earlier in Section 2.3.2 (Table 3), we calculated the direct emissions from each of the four electricity generation technologies using the respective unit process in the SimaPro software. We focused only on the emissions of GHGs and major air pollutants from power plant use of fuels. Table 4 presents the emission factors of selected major emission items used for the analysis of the direct atmospheric emissions from the electricity generation process. We relied on the Ecoinvent database (v2.2), available through SimaPro, for a complete list of the emission factors for the stage, including emission factors from the power plant infrastructure.

Table 4. Emission factors for selected major atmospheric emissions items from the electricity generation process.

Types of Emissions	Fuel Source for the Power Plants		
	Fuel Oil	**Coal**	**Natural Gas**
CO_2 (kg/GJ)	74.61791	95.2	50.8
CH_4 (kg/GJ)	0.0053191	0.00076	0.00094
N_2O (kg/GJ)	0.004	0.00221	0.001
NO_x (kg/GJ)	0.187	0.119	0.0264
SO_2 (kg/GJ)	0.025	0.513	0.000646
CO (kg/GJ)	0.01	0.01	0.0351
PM_{10} (kg/GJ)	0.0050000	0.003809	0.0005

Note: Includes only the emissions from the operation of the power plant; does not include emissions from the power plant infrastructure over its lifetime. Source: Ecoinvent database, v.2.2. Emission factor for fuel-oil-fueled power plant from the process "heavy fuel oil, burned in power plant/MJ/NL", for coal-fueled from the process "hard coal, burned in power plant/NPCC U", and for natural-gas-fueled from the process "natural gas, burned in power plant/MJ/US".

Emissions from a particular upstream process k include emissions from the production of the output from the process (Y_k) plus the emissions of all inputs ($X_{j,k}$) of the process incurred in their respective upstream production. We calculated upstream stream emissions using Equation (2) as follows:

$$EM_{i,k} = \left(EFR_{i,k} + \sum_{j} EFR_{i,j,k} \times X_{j,k} \right) \times Y_k \tag{2}$$

where $EM_{i,k}$ represents the emissions of gaseous item i in kg/kWh from upstream process k; $EFR_{i,k}$ represents the emission factor of gaseous item i for one unit of output from the upstream process k; $EFR_{i,j,k}$ represents the emission factor of gaseous item i for one unit of input j used to produce the output of process k; $X_{j,k}$ represents the quantity of input j required to produce one unit of output of process k; Y_k represents the quantity of output from process k. The output of a particular process may also be the input required for the next downstream process, while similarly, the inputs of a particular process are also the output from a further upstream process.

Emissions from a particular transport process were calculated similarly, where the outputs were typically measured by the weight or volume of the fuel transported multiplied by the transport distance (in ton-miles or m^3-miles). Direct emissions from each transport process were then summed up to generate total emissions per trip of transport.

For the upstream fuel procurement stages, we also relied on the lifecycle inventory databases supplied in SimaPro to calculate well-to-gate emissions for all fuels. Emissions from the fuel transport stage were computed according to the fuel supply chain scenarios described in Table 2, based on modal choices specific to, and as realistic as possible for, Taiwan's fuel import route.

2.4.2. GHGs

Global warming potential (GWP) is a total measure of the atmospheric heat-trapping (greenhouse) effect of air emissions (GHGs) contributing to climate change, typically over a 100-year period. The most significant GHGs associated with power generation are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6), associated with the combustion of fuels for electricity production and transportation [40,47,48].

We used the IPCC 2007 method [49] to assess the global warming potential (GWP) from the emission inventory result, assuming a timeframe of 100 years. Each emitted airborne substance was converted to CO_2 equivalent (CO_2e) according to its GWP, which were then summed up to arrive at total GHG emissions.

2.4.3. Air Pollutants

In addition to GHGs, major air pollutant emissions from the power generation system considered in this study were PM10, SO_x, NO_x, and CO. We used the IMPACT 2002+ method equipped with the SimaPro software to create the inventory report for fuel lifecycle airborne emissions from each of the four fuel choice scenarios. The lifecycle inventory report includes a detailed listing of all airborne pollutants across various stages of the fuel lifecycle, expressed in terms of their respective physical units.

3. Results

This study quantifies the GHG and air pollutant emissions from the full fuel lifecycle of electricity generation, including the production, transformation, liquefaction, shipping, and regasification phases of the supply chain, as well as the end-use of the fuel in the target electricity generation plant. These lifecycle atmospheric emission results are discussed in the context of retrofitting existing FO-fueled power plants with alternative fuel sources, including coal and NG imported from other countries. The results are organized into three sections: First, Section 3.1 focuses on the result of fuel lifecycle GHG emissions, including a comparison of total GHG emissions across fuel choices, the analysis of the relative contribution from fuel lifecycle stages, as well as a detailed analysis of four major GHGs. Section 3.2 presents the result for four air pollutants, NO_x, SO_x, CO, and PM10, displaying the respective result of fuel lifecycle emissions across fuel choices, as well as for their respective relative contribution from four fuel lifecycle stages. Finally, we report the uncertainty analysis of our results in Section 3.3.

3.1. GHG Emissions

GHG emissions are always an important concern in the retrofitting decision of a power plant. In fact, the main focus of the Taiwan government's recent "Sustainable Energy Policy Convention" is the mitigation of GHGs while maintaining a sufficient and stable electricity supply for the economy and household consumption. Our study case is still concerned with fossil-fuel-fired power technologies, which remain a main component of the baseload power supply in Taiwan. A comparison is nevertheless worthwhile, as the choice of fuel source and the technological efficiency may still result in a variation in the GHG impact.

3.1.1. Comparison of Major GHG Emissions across Fuel Choices

Figure 4 compares full fuel lifecycle total GHG emissions from electricity generation among four fuel scenarios. We found that total GHG emissions from a fuel lifecycle perspective will likely increase if we change the fuel source of electricity generation from FO, which is the existing choice for the case power plant, to coal. When FO is used as the fuel for electricity generation in HHPP (Scenario 1), the fuel lifecycle GHG emissions is 944 gCO_2e/kWh. When coal is used (Scenario 2) as an alternative to FO, the lifecycle GHG emissions increase by 18.45% to 1158 gCO_2e/kWh.

On the other hand, total GHG emissions from a fuel lifecycle perspective will substantially decrease if we change the fuel source of electricity generation from FO to natural gas (Scenario 3). Lifecycle total GHG emission can be lowered to 564 gCO_2e/kWh, which is a 40.25% reduction compared to the FO-fueled case. A net emission reduction benefit still exists even if the power plant were to use both coal and natural gas, on a half-and-half basis (Scenario 4). The reduction is approximately 8.7%, compared to FO-fueled cases.

Figure 5 also demonstrates that CO_2 is the dominant GHG under either fuel choice scenario, with GH_4 and N_2O being the next two major gases, though nearly negligible compared to CO_2. As a result, the difference in CO_2 emission among the four fuel choice scenarios is almost identical to that in total GHGs.

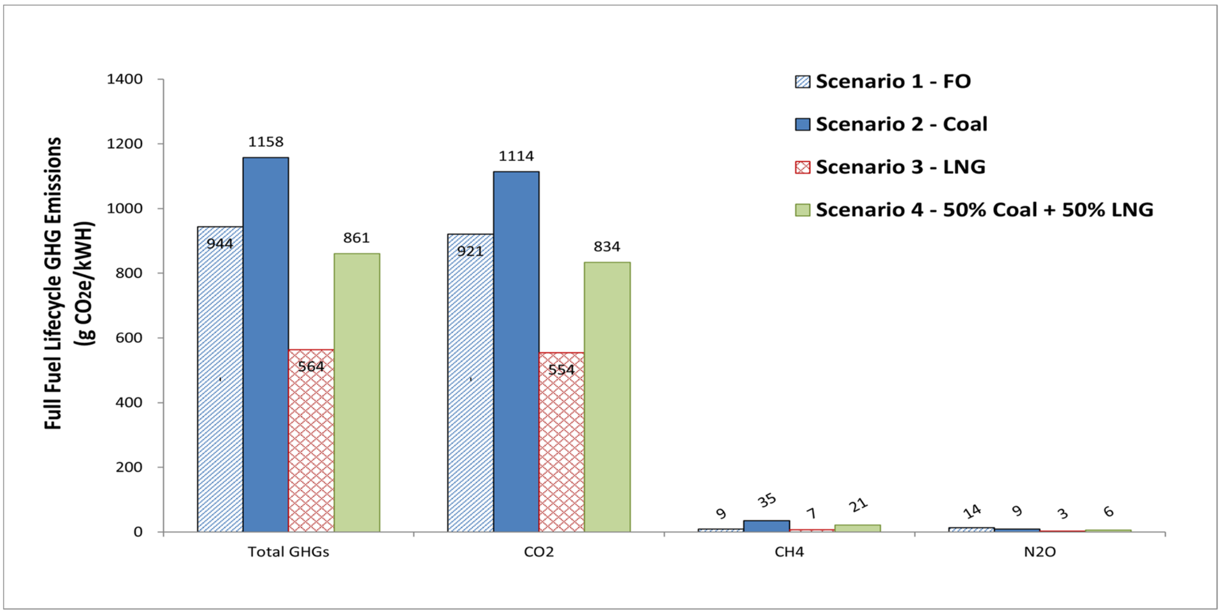

Figure 5. Comparison of full fuel lifecycle GHG emissions from electricity generation among four fuel scenarios.

CH_4 is the next important GHG for Scenarios 2, 3, and 4 and the third important one for Scenario 1. We noticed a very drastic increase in the emission of CH_4 when switching from FO to coal. CH_4 increases to 3.8-times when switching from FO-fueled to coal-fueled, while increasing to 2.3-times when switching to 50% coal and 50% NG. When switching from FO to natural gas, however, full fuel lifecycle CH_4 can be reduced by about 24%, despite the usual criticism of large CH_4 emissions in the upstream production and preparation of natural gas. The reduction in CH_4 emissions under this case (Scenario 3) is much more significant (reduced by nearly 80%) if compared to the case of a coal-fired power plant (Scenario 2).

The importance of N_2O is comparable to that of CH_4, being the next important GHG for Scenario 1 and the third important GHG for Scenarios 2, 3, and 4, though similarly almost negligible compared to CO_2. Our result indicates that changing the fuel source of HHPP away from FO is likely to reduce the full fuel lifecycle emissions of N_2O. Replacement of coal-fired and NG-fired technology reduces the N_2O emissions by around 36% and 80%, respectively. Switching to 50% coal and 50% natural gas is also likely to result in about a 58% reduction in N_2O emissions.

3.1.2. Relative Contribution of Total GHG Emissions from Four Fuel Lifecycle Stages

Through an analysis of the relative contributions of total GHG emissions from the four fuel lifecycle stages, we found that electricity generation dominates among all stages under all four fuel choice scenarios (Figure 6). It is worth noting that the total lifecycle GHG emissions can be cut by nearly half for gas-fueled power plants in comparison to coal and oil, mainly due to much cleaner combustion in power generation. The contribution of GHG emissions due to fuel transportation and transformation is much more significant when gas is used (22%) as a replacement for oil and coal (8% and almost 4%, respectively) to fuel the power plant. This is not surprising given that Taiwan needs to import natural gas from abroad (Australia, as modeled in this study), which requires natural gas to be liquefied to LNG for safe and efficient sea freight transportation and then being regasified upon arrival before use as a fuel. Liquefaction and regasification demand a large energy input and thus result in high GHG emissions during the transformation stage. Nevertheless, the gas-fueled power plant still emits much less total GHG emissions, even after taking into account the additional emissions due to the complication of the cross-ocean transportation of LNG.

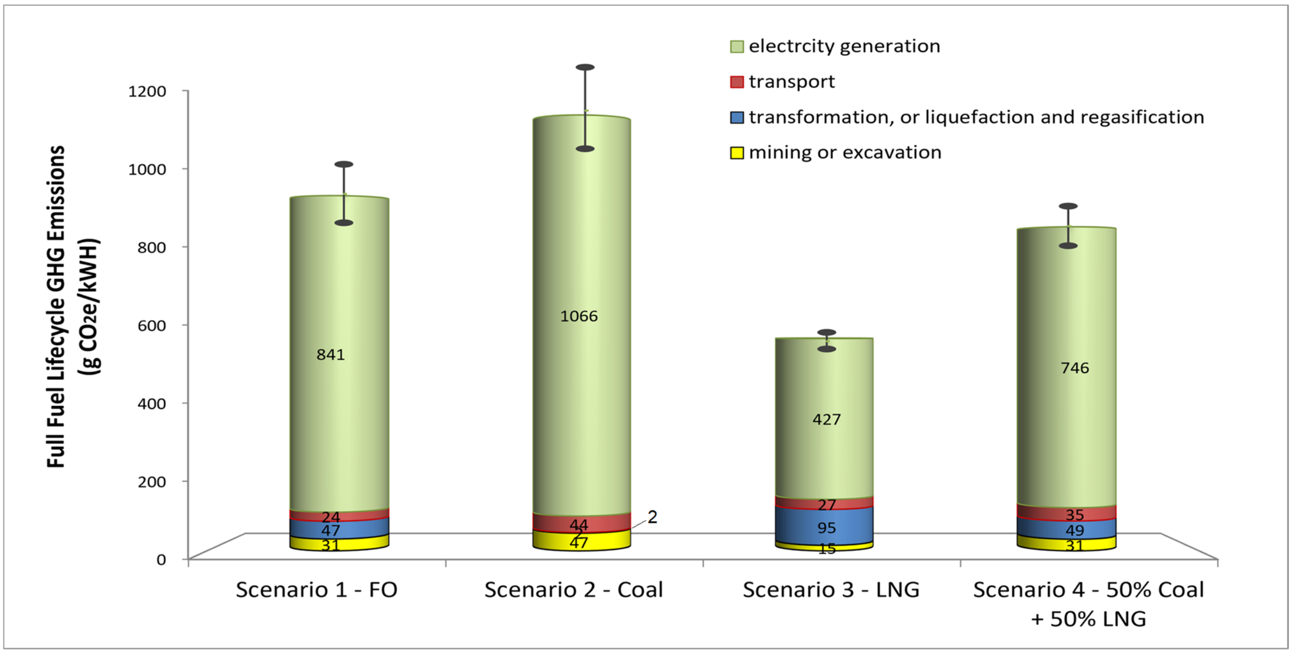

Figure 6. Comparison of the relative contribution of full fuel lifecycle total GHG emissions from four fuel lifecycle stages among four fuel scenarios for electricity generation.

Table 5 provides further details of the emissions of GHGs from the full fuel lifecycle of electricity generation across various fuel supply scenarios, broken down into four fuel lifecycle stages. Using FO (produced from crude oil imported from Saudi Arabia), 89% of GHG emissions are contributed by electricity generation. The other three stages account for only a small portion of the GHG emissions. Crude production, refining, and transport contribute only 5%, 3%, and 3%, respectively. The results of CO_2 and N_2O show similar breakdowns. As far as methane (CH_4) emission (approximately 1% of total GHG in this case) is concerned, the major contributors switched to crude production (60%) followed by refining (17%) and electricity generation (17%). For SF_6, the major contributors are transport (47%) and refining (42%).

Table 5. Comparison of the emissions of major GHGs from the full fuel lifecycle of electricity generation across various fuel supply scenarios, broken down by four fuel lifecycle stages (Unit: g-CO_2 equivalent/kwh).

Scenario 1—FO Produced from Crude Imported from Saudi Arabia										
	Total	**%**	**Crude Production**	**%**	**Refining**	**%**	**Transport**	**%**	**Electricity Generation**	**%**
GHG	943.811	(100%)	31.484	(3%)	47.244	(5%)	24.094	(3%)	840.990	(89%)
CO_2	920.616	(100%)	25.571	(3%)	45.525	(5%)	23.294	(3%)	826.226	(90%)
CH_4	9.280	(100%)	5.539	(60%)	1.539	(17%)	0.587	(6%)	1.614	(17%)
N_2O	13.729	(100%)	0.254	(2%)	0.150	(1%)	0.185	(1%)	13.141	(96%)
SF_6	0.049	(100%)	0.005	(9%)	0.020	(42%)	0.023	(47%)	0.001	(2%)
Scenario 2—Coal Imported from Australia										
	Total	**%**	**Mining**	**%**	**Transformation and Storage**	**%**	**Transport**	**%**	**Electricity Generation**	**%**
GHG	1158.079	(100%)	47.014	(4%)	1.872	(0%)	43.633	(4%)	1065.560	(92%)
CO_2	1113.821	(100%)	12.114	(1%)	1.770	(0%)	42.425	(4%)	1057.512	(95%)
CH_4	35.202	(100%)	33.551	(95%)	0.079	(0%)	0.845	(2%)	0.727	(2%)
N_2O	8.824	(100%)	1.196	(14%)	0.017	(0%)	0.327	(4%)	7.284	(83%)
SF_6	0.036	(100%)	0.002	(6%)	0.006	(16%)	0.024	(67%)	0.004	(11%)

Table 5. *Cont.*

Scenario 3—LNG Imported from Australia										
	Total	**%**	**Excavation**	**%**	**Liquefaction and Regasification**	**%**	**Transport**	**%**	**Electricity Generation**	**%**
GHG	564.015	(100%)	14.740	(3%)	95.420	(17%)	26.857	(5%)	426.997	(76%)
CO_2	554.133	(100%)	14.017	(3%)	89.711	(16%)	26.111	(5%)	424.294	(77%)
CH_4	7.081	(100%)	0.633	(9%)	5.641	(80%)	0.599	(8%)	0.208	(3%)
N_2O	2.771	(100%)	0.081	(3%)	0.062	(2%)	0.139	(5%)	2.489	(90%)
SF_6	0.012	(100%)	0.004	(34%)	0.004	(36%)	0.003	(29%)	0.000	(1%)
Scenario 4—50% Coal and 50% LNG										
	Total	**%**	**Mining or Excavation**	**%**	**Transformation, Liquefaction and Regasification**	**%**	**Transport**	**%**	**Electricity Generation**	**%**
GHG	861.047	(100%)	30.877	(4%)	48.646	(6%)	35.245	(4%)	746.279	(87%)
CO_2	833.977	(100%)	13.066	(2%)	45.741	(5%)	34.268	(4%)	740.903	(89%)
CH_4	21.141	(100%)	17.092	(81%)	2.860	(14%)	0.722	(3%)	0.467	(2%)
N_2O	5.797	(100%)	0.638	(11%)	0.039	(1%)	0.233	(4%)	4.886	(84%)
SF_6	0.024	(100%)	0.003	(13%)	0.005	(21%)	0.014	(58%)	0.002	(8%)

When coal is used (Scenario 2) to replace FO for electricity generation, the contribution to total GHG emissions during electricity generation increases slightly (from 89% to 92%). Mining and transport of coal contribute equally (4%) to total GHG emissions. When LNG (Australia imported) is used for power generation (Scenario 3), however, the contribution to total GHG emission in the electricity generation stage is reduced markedly (to 76%), while the contribution of liquefaction and regasification accounts for a significant portion (17%).

3.1.3. Analysis of the Four Major Specific GHGs

Table 5 also provides the detailed emissions of four major specific GHGs, arising from each of the four scenarios of fuel supply, broken down by four fuel lifecycle stages. CO_2 is the dominant GHG under either fuel choice scenario, consistent with what is displayed in Figures 5 and 6. The amounts of the three next important GHGs, CH_4, N_2O, and SF6, are all relatively small. We noticed differences in the pattern of the relative contribution from the fuel lifecycle stages for these four major GHGs, through the comparison across fuel choice scenarios. The findings may provide useful insights for GHG mitigation policy, specifically for Taiwan's case.

Electricity generation is a much more significant contributor to CO_2 than other stages for all four fuel choice scenarios. It accounts for 90% when using FO to fuel the power plant (Scenario 1), but its share becomes even larger, 95%, when coal is used (Scenario 2), while decreasing to 89% where 50% coal and 50% NG are used as the fuel (Scenario 4). On the other hand, the contribution to CO_2 emission is the lowest (77%) for Scenario 3 when using NG to fuel HHPP. The upstream process contributes more to the relative share when FO is used as the fuel (Scenario 1), as refining is an energy-intensive process. In the case of NG, the contribution of CO_2 during liquefaction and regasification (16%) is relatively significant in comparison to stages other than electricity generation for all scenarios. In either of the scenarios, the contribution from the transport stage is relatively stable, accounting for about 3–5%.

In the case of CH_4, upstream production, instead of electricity generation, becomes the most important source of emission. The four fuel supply scenarios exhibit again different patterns of relative contribution from the four stages. When using FO to fuel HHPP (Scenario 1), the most significant source is crude production, which accounts for 60%. The contributions of CH_4 from electricity generation are much less, only 17%. Refining can be considered an important stage for the emissions of CH_4 (contributes 17%). As for

Scenario 2, where coal is used to fuel HHPP, the contribution to CH_4 during electricity generation is much less, only 2%. In contrast, the CH_4 emission is virtually all attributed to coal mining. For Scenario 3, where NG is used to fuel HHPP, similar to combusting coal, contribution to CH_4 during electricity generation is much less. In contrast, most of the CH_4 emission is contributed during liquefaction and regasification. As for Scenario 4, where 50% coal and 50% NG are used to fuel HHPP, the contribution to CH_4 during electricity generation is similarly much less. Upstream production under this scenario accounts for a larger proportion of the CH_4 emission, with most of the emission being contributed during mining or excavation (81%). Transformation, liquefaction, and regasification also account for 14%, given that this scenario considers NG as the fuel as well.

The lifecycle distribution of N_2O emissions resembles that of CO_2. Electricity generation is a much more significant contributor than other stages for all four fuel choice scenarios. This concentration in the electricity generation stage is even more obvious for Scenario 1 when FO is used, with 96% of N_2O generated during the generation stage. Among the four scenarios, the contribution of generation (82%) to N_2O emission is the lowest when using coal to fuel HHPP (Scenario 2). As for stages other than electricity generation, mining and excavation are relatively significant contributors to N_2O emissions in comparison to the remaining stages for Scenarios 2 and 4 (14% and 11%, respectively). For Scenario 3, however, each of the three other stages contributes no more than 5% of N_2O emission.

For SF_6, the four fuel supply scenarios exhibit different patterns of relative contribution from the four stages again. The contribution from electricity generation is not as important as in the case of CO_2 and N_2O. Instead, transport becomes the most important source of SF_6 emissions for Scenarios 1, 2, and 4, accounting for 47%, 67%, and 58%, respectively. Transport (29%) is also an important source of SF_6 emissions for Scenario 3, where natural gas is the fuel for the power plant. Though the gas is much less important in terms of the amount in the total fuel lifecycle GHGs from the power plant, it has much more significant warming potential compared to other GHGs. Our results indicate that the transport of the fuel is a likely targeting stage to look for abatement opportunities for this specific GHG, but this could be a challenge for Taiwan, as it relies on the import and long-distance transport of fuel from abroad.

The contribution weight of other stages varies quite obviously among fuel the supply scenarios. When FO is used to fuel HHPP (Scenario 1), refining (42%) is the next major source of SF_6 emissions, while crude production and electricity generation together account for only 11%. For Scenario 2, where coal is used to fuel HHPP, SF6 emissions from stages other than transport are much less, with the next largest sources, transformation, and storage, accounting for only 16%. For Scenario 3, where NG is used to fuel HHPP, the contribution to SF_6 during electricity generation is almost negligible. In contrast, most of the SF_6 emissions are spread somewhat evenly among the other three stages, with liquefaction and regasification accounting for 36% and NG excavation accounting for 34%, both of which are more important contributors than transport (29%). For Scenario 4, where 50% coal and 50% NG are used to fuel HHPP, the next important source of SF_6 is transformation, liquefaction, and regasification (21%), then mining or excavation (13%). Electricity generation accounts for only about 8% of all SF6 emissions.

3.2. Air Pollutants' Emissions

In addition to GHGs, emissions of other air pollutants have aroused much controversy around power plants in Taiwan in recent years. This is partly due to the fact that the coal-fired power plants remain the baseload for Taiwan's power supply (constituting about 46%), but many of them are approaching decommissioning and are becoming easy targets to blame for poor regional air quality. Given that these plants will require retrofitting soon, it is worth comparing the fuel lifecycle emissions of the major air pollutants, as well as the alternative power technologies.

3.2.1. Total Fuel Lifecycle Emissions of Major Air Pollutants

Figure 7 compares major air pollutant emissions across various fuel choice scenarios. Lifecycle NO_x emissions are highest when FO (2496 mg/kWh) is used for electricity generation, followed by coal (2354 mg/kWh). When NG replaces the currently used FO to run HHPP, NO_x emissions drop to less than one-fifth (17.25%). As Scenario 4 assumes the power plant is fueled by 50% coal and 50% NG, the lifecycle NO_x emissions can be lowered by 56%. Fuel NO_x, or fuel-bound nitrogen, is often found in liquid and solid fuels, while most gaseous fuels, such as natural gas, are free of it. The excess air and the flame temperature also influence the formation of NO_x in the system [6,50–52].

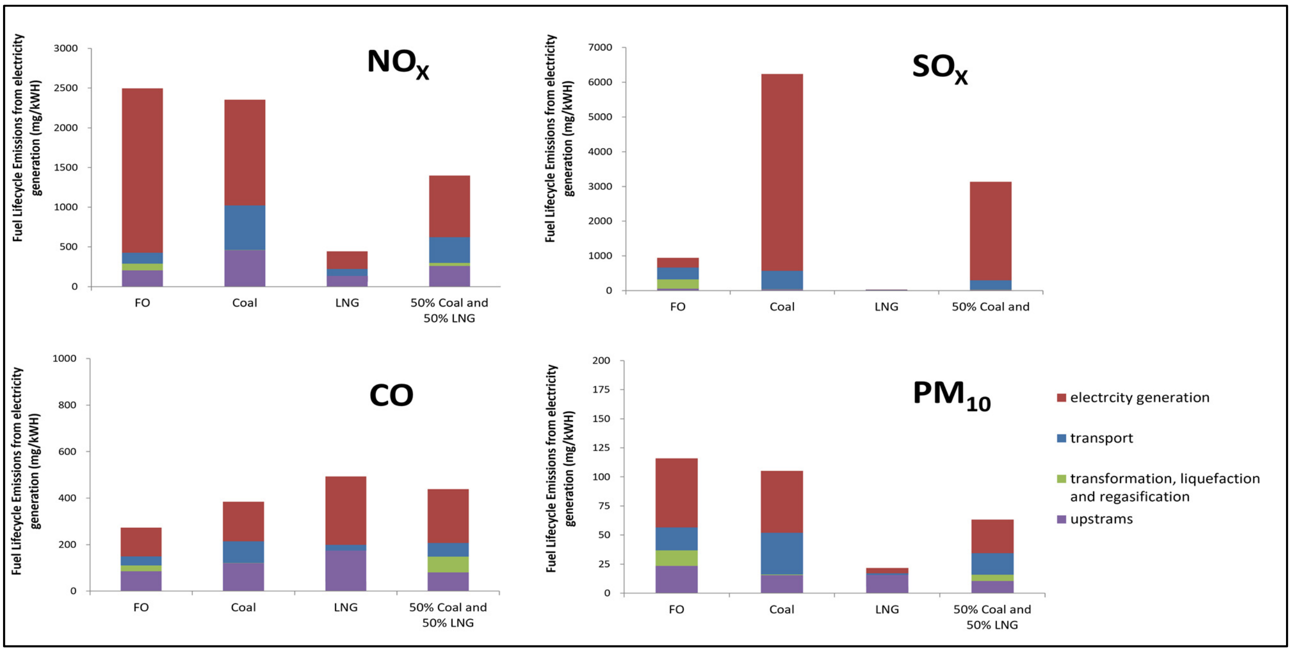

Figure 7. Comparison of major air pollutant emissions across various fuel choice scenarios, broken down by four fuel lifecycle stages.

The lifecycle SO_x emissions when coal is used (6.24 g/kWh) are tremendously higher than when other fuels are selected, as expected. The emission can be cut to one-half (3.14 g/kWh) when NG is used in combination with coal fuel. The lifecycle SO_x emissions for FO are only approximately 15% of that for coal, while for NG-fueled power plants, they are almost negligible. Although NG is considered a "clean fuel" in contrast to coal and FO, it emits the highest CO. The lifecycle CO emissions for the three scenarios from the highest to the lowest are NG (493 mg/kWh), NG and coal (439 mg/kWh), coal (384 mg/kWh), and FO (273 mg/kWh).

The pattern of PM10 is very similar to that of NO_x. Full lifecycle PM10 emissions are highest when FO (116 mg/kWh) is used for electricity generation, followed by coal (105 mg/kWh). When NG replaces the currently used FO to run the plant, PM10 emissions drop to less than one-fifth (19%). As Scenario 4 assumes the power plant is fueled by 50% coal and 50% NG, the lifecycle PM10 emissions can be lowered by 46%.

3.2.2. Contribution of Fuel Lifecycle Stages

We found that the relative contribution from the four fuel lifecycle stages varies with the choice of fuel sources, and the pattern is also not consistent when a different pollutant is involved. Figures 8–11 provide a comparison of the relative contribution from the four fuel lifecycle stages across the four fuel supply scenarios for each of the four air pollutants.

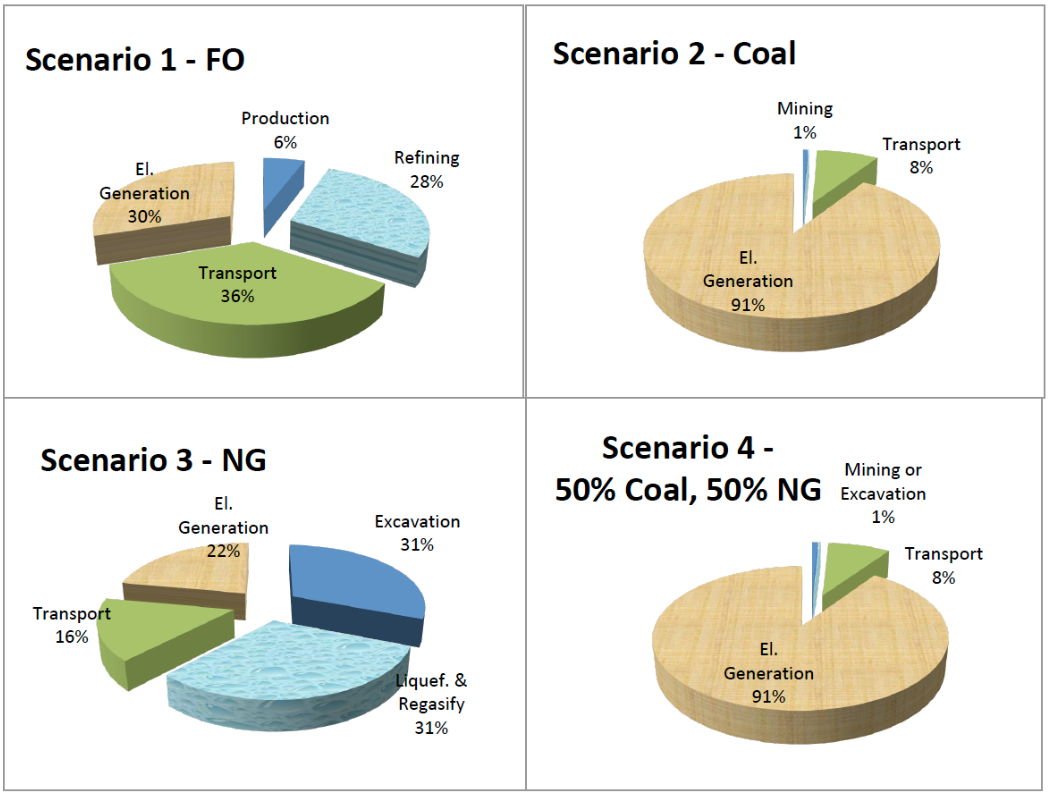

Figure 8. Comparison of the relative contribution of SO_x emissions from lifecycle stages among different fuel choice scenarios.

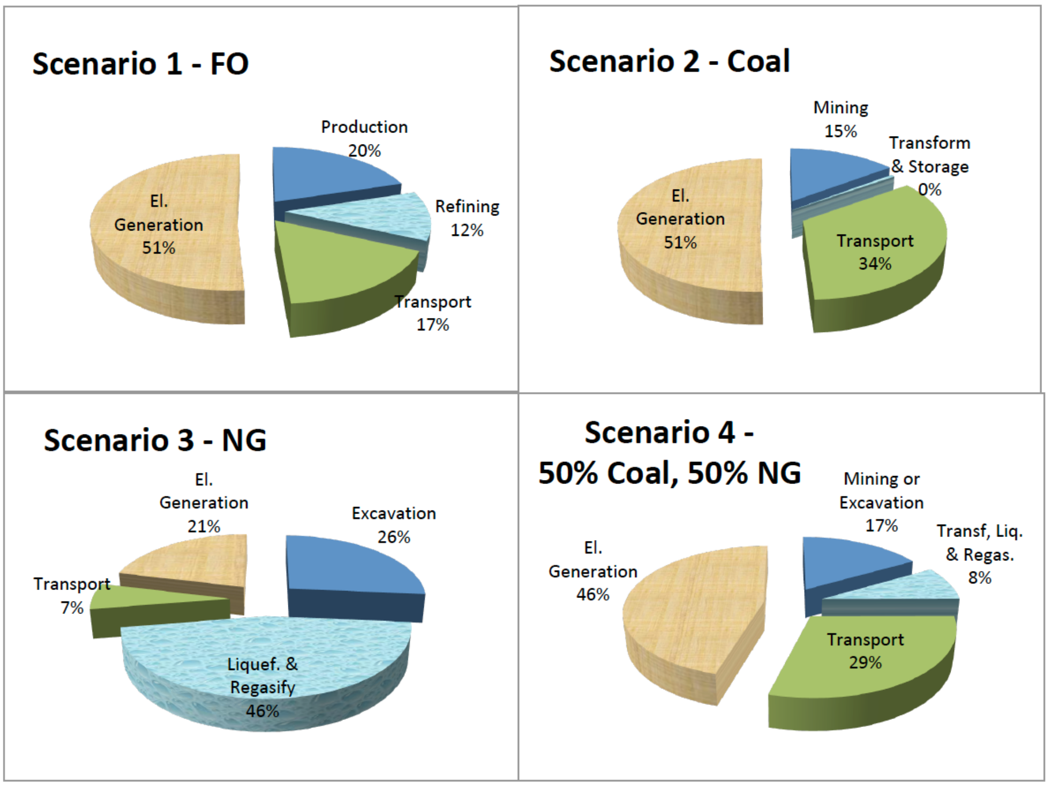

Figure 9. Comparison of the relative contribution of PM_{10} emissions from lifecycle stages among different fuel supply scenarios.

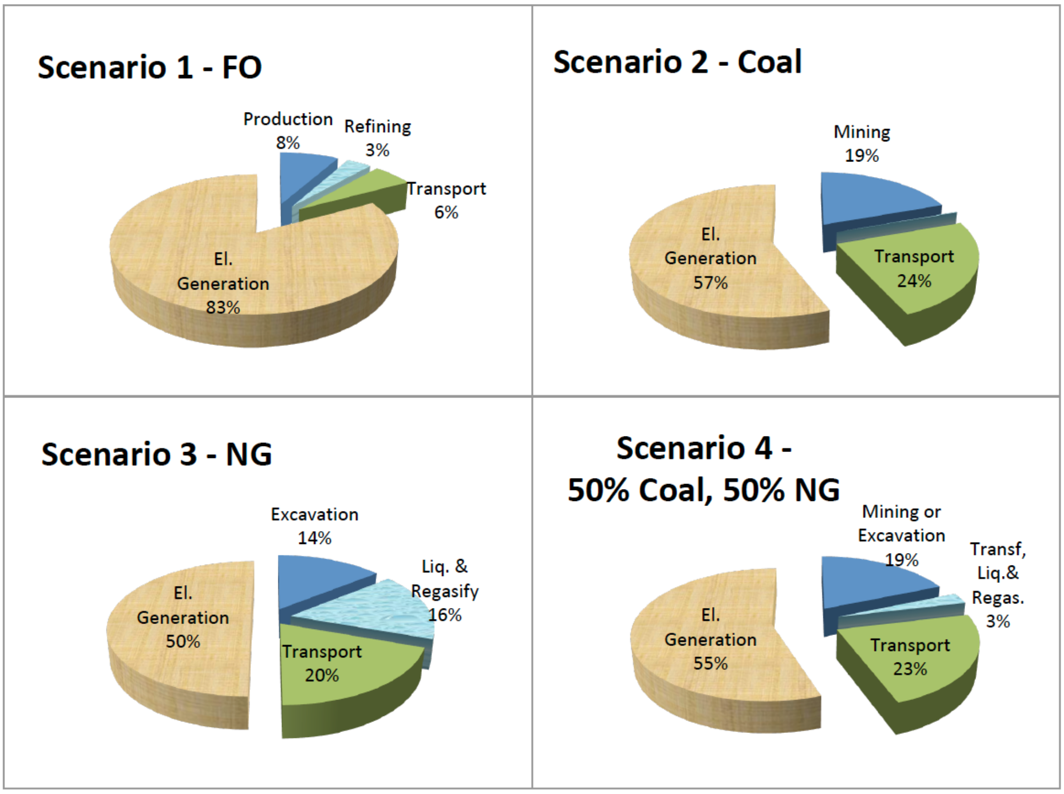

Figure 10. Comparison of the relative contribution of NO_x emissions from lifecycle stages among different fuel supply scenarios.

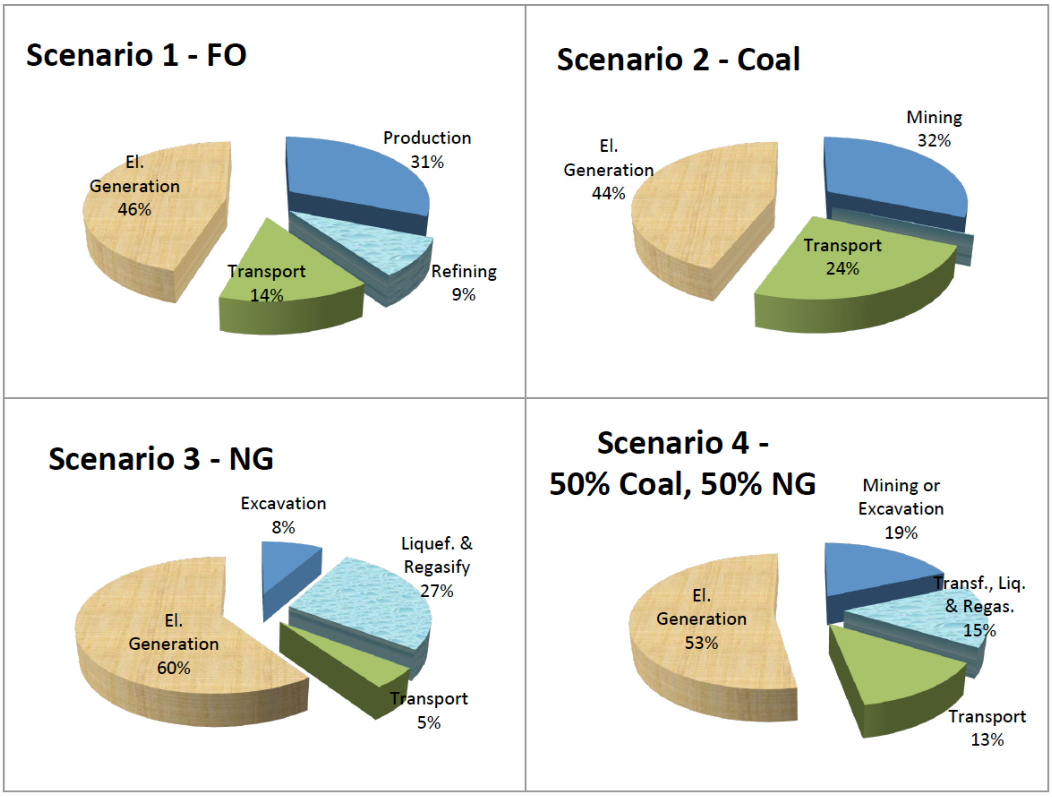

Figure 11. Comparison of the relative contribution of CO emissions from lifecycle stages among different fuel supply scenarios.

For SO_x (Figure 8), electricity generation is a much more significant contributor than the other stages, when coal is involved to fuel the plant (Scenarios 2 and 4). The two scenarios have an identical breakdown of contributions from different stages, given that the use of NG emits almost negligible lifecycle SO_x in either of the stages. Coal use in power plants mainly results in emissions including SO_2, a sulfate aerosol precursor, and black carbon particles. All the sulfur in the coal is converted to SO_2 under a combustion temperature of 920 °C or higher [53–56]. The contributions to SO_x emission in the generation stages are lower, 22% and 30%, when using NG (Scenario 3) and oil (Scenario 1) to fuel the plant, respectively. Instead, transport contributes the most (36%) to SO_x emission when oil is used (Scenario 1), while liquefaction and regasification contribute the most (31%) when using NG to fuel the plant (Scenario 3).

Figure 9 compares the relative contribution of the fuel lifecycle stages to total PM10 emissions among the four fuel choice scenarios. Again, we found a unique pattern for the NG scenario (Scenario 3) in contrast to other scenarios. Liquefaction and regasification are the most important stages contributing to PM10 emissions, similar to the case for SO_x emissions. Nearly one-half of PM10 (46%) is from liquefaction and regasification, while only 21% is from the generation stage. As a result, the transfer, liquefaction, and regasification stages gain importance when combining NG and coal to fuel the plant (Scenario 4). On the other hand, electricity generation is the most important source of PM10 emissions for Scenarios 1 and 2, contributing nearly one-half of total emissions.

As for NO_x and CO emissions (Figures 10 and 11), generation is the most important contributor among the stages in all four fuel supply scenarios. The share of NO_x emission from the generation stage is even more significant when FO is used to fuel the plant (Scenario 1), accounting for about 83% (Figure 10). The generation stage still accounts for more than one-half of total NO_x emissions when either NG or coal is used to fuel the plant (Scenarios 2 to 4). The next major source of emission comes from transport, when coal or NG is involved, accounting for about 20% to 24%. Liquefaction and regasification also account for 16% of NO_x emissions if NG is used as the fuel.

For CO emissions (Figure 11), electricity generation contributes a little less than one-half of total emissions when either FO or coal is used in fueling the plant (Scenarios 1 and 2). The next major source of CO emission is the upstream production of the fuels, which accounts for 31% when FO is used, while mining accounts for 32% when coal is used. When NG is used to fuel the plant, however, the largest two contributors of CO emissions shift to electricity generation (60%) and the liquefaction and regasification stages (27%). Furthermore, the magnitude of CO emissions from these two stages increases, given that using NG emits more CO than using either FO or coal.

As shown in Figures 8 and 9, SO_x and PM10 emissions are generated primarily from the upstream supply chain (78% and 79% of the total lifecycle, respectively) from NG-fueled plant operation. Our result deviates a little from the findings reported in other studies, which showed that upstream processes and the transport of combined cycle (CC) NG plants can contribute up to 80–90% of the lifecycle emissions of SO_2 [57]. This is probably because our study is based on the average NG power technology currently in use in Taiwan. Though most of the plants have a combined cycle, a very small portion of older plants have a single cycle (SC).

On the other hand, our result regarding NO_x emissions from NG-fueled power plants is consistent with previous studies, in which the NG scenario generates significant NO_x emission from plant operations (accounted for nearly 50%), although upstream NG production also factors in the total lifecycle emissions, as a consequence of the energy used for the extraction of NG [50,57]. Our findings of overall NO_x emissions of 0.44 kg-NO_x/MWh are within the range reported in previous studies, where overall NO_x emissions from CC plants were on the order of 0.2–1.3 kg-NO_x/MWh, with upstream production and transport (0.1–0.5 kg-NO_x/MWh) playing an important role. Studies report much higher NO_x emissions for SC plants, at approximately 1.8–3.8 kg-NO_x/MWh, due to lower efficiencies and less-efficient FGC systems [57].

3.3. Uncertainty Analysis

Since data in lifecycle models have inevitably some uncertainty, we considered in our LCA modeling the variation in the emission factor data specified in the unit process version of the Ecoinvent database. We then applied Monte Carlo techniques to handle the data uncertainty in the LCA results, using the SimaPro software. The uncertainty analysis was performed by specifying 300 runs with a 95% confidence interval for each fuel supply scenario. Table 6 presents the uncertainty analysis result of the total fuel lifecycle GHG emissions for the four fuel supply scenarios. Our result show that carbon dioxide emissions are relatively certain under each of the four scenarios and are comparable to the results reported in earlier studies. Turconi, Boldrin, and Astrup [57] performed a survey of various studies and reported lifecycle GHG emissions of 530–900 kg-CO_2e/MWh for FO-fueled power plants and 380–1000 kg-CO_2e/MWh for NG-fueled power plants. Our result for coal-fueled power plants leans toward the higher end of the results of earlier studies, which documented 660–1050 kg-CO_2e/MWh for hard coal, while 800–1300 kg-CO_2e/MWh for lignite. Our analysis reports a large variation in the estimated emission per MWh for other GHGs, indicating high uncertainty in the estimates; the coefficient of variation (CV) for N_2O tends to be larger, reaching as high as 0.630 in the case fuel-oil-fired plants and 0.546 in the case of the natural-gas-fueled plants.

Table 6. Uncertainty analysis results of the total fuel lifecycle GHG emissions for the four fuel supply scenarios (Unit: g-CO_2 equivalent/kWh).

Fuel Source	Total GHG		CO_2		CH_4		N_2O		SF_6	
FO	869–1020	(0.039)	848–997	(0.039)	5.7–14.9	(0.257)	3.9–37.8	(0.630)	0.03–0.075	(0.229)
Coal	1060–1270	(0.047)	1020–1230	(0.046)	16.8–73.0	(0.407)	4.7–15.4	(0.295)	0.02–0.06	(0.288)
LNG	544–587	(0.018)	535–577	(0.019)	5.2–9.8	(0.162)	1.1–7.8	(0.546)	0.007–0.019	(0.265)
50% Coal, 50% NG	810–912	(0.031)	785–884	(0.032)	12.1–36.6	(0.275)	3.4–9.1	(0.247)	0.014–0.041	(0.266)

Note: estimated with the 95% confidence interval; numbers in parenthesis represent the coefficient of variation.

We adopted a similar approach to perform an uncertainty analysis for the total fuel lifecycle emissions of the four pollutants. Table 7 displays the results for the four fuel supply scenarios. Again, we found moderate uncertainty in the estimated result. Except for the NO_x and SO_2 emissions involving the coal-fired plant, the CV tends to be larger for most items or scenarios. Compared to the findings summarized in [57], our results of NO_x and SO_2 for NG-fueled plants are in about the same range. We report generally higher NO_x and SO_2 emissions in the case of a coal-fired plant.

Table 7. Uncertainty analysis results of the total fuel lifecycle atmospheric emissions for the four fuel supply scenarios (Unit: mg/kWh).

Fuel Source	NO_x		SO_2		CO		PM_{10}	
FO	1740–3710	(0.195)	699–1560	(0.273)	137–540	(0.368)	64–202	(0.306)
Coal	1940–2770	(0.092)	5350–7240	(0.077)	204–758	(0.359)	62–171	(0.267)
LNG	259–843	(0.327)	21–42	(0.206)	239–915	(0.369)	12–40	(0.345)
50% Coal, 50% NG	1150–1710	(0.101)	2620–3720	(0.088)	272–735	(0.277)	40–102	(0.244)

Note: estimated with the 95% confidence interval; numbers in parenthesis represent the coefficient of variation.

4. Discussions

The future transition of Taiwan's electricity sector will be shaped by policy and economic and technological drivers whose trajectories are uncertain. We proposed a framework to help infrastructure planners and policymakers ensure a balanced energy supply and minimized risks under future variability by providing a lifecycle assessment from a sustainable environment perspective. An alternative pathway of the transition should be formulated after a careful assessment has been rendered not only of its impacts on climate change, but also the potential concerns, if any, of other pollution issues.

4.1. GHG Mitigation through the Fuel Choice for Electricity Generation

Does switching from FO to NG lower the net impact of fuel use in GWP? Using HHPP as an example, we evaluated changes in emissions of CO_2, CH_4, N_2O, and SF_6 resulting from the substitution of FO by coal or NG. Our results show that the majority of GHG emissions from power plants are generated during the operational stage when fuel is combusted, accounting for as much as 89% to 92% in the case of fuel oil and coal and 76% for natural gas (Table 5).

Unlike many other countries, Taiwan relies on imports for all types of fuels used in electricity generation. The trade route between the fuel source and the power plant tends to be long and usually requires marine shipping. Emissions related to the transport of fuels are thus an additional and potentially significant factor that warrants consideration unique to Taiwan's case. An analysis via LCA helped put the magnitude of the impact in perspective. Our study found that the transportation of imported fuel accounted for about 3–5% of total lifecycle GHG emissions across the scenarios of fuel choices (Table 5). Natural gas, however, requires an additional 17% due to liquefaction and regasification, which is inevitable in Taiwan's case, as the import typically goes through long-distance sea transport. Furthermore, as NG is comprised mostly of CH_4, fugitive emissions also contribute to the GHG footprint during extraction, processing, and transport and increase possibly with the distance of sea transport as well. Nevertheless, gas-fired power is still the one with the least GHG footprint among the scenarios, after the upstream emissions are reflected in the comparison.

An analysis of the source of emissions across the lifecycle, such as ours, provides insight on where to target strategies to optimize and reduce emissions. From the perspective of individual power producers, it is more difficult to control indirect upstream emissions compared to emissions generated directly within the power plant. Since the latter is the real major source of greenhouse gas emissions, it is necessary to target emission reduction efforts within power plants. Electricity technology choices today will determine emissions from power plants, as well as upstream fuel production and transportation, over the next 30 years or more.

Thermal power is still the major source of Taiwan's electricity (81.47%), among which nearly two-thirds are from state-owned Taipower and one-third is from private companies. Taipower remains the backbone of Taiwan's energy security, though its contribution to the total electricity supply has gradually adjusted down to no more than 70% during the past two decades [1]. The company underwent upgrades of its Linkou and Talin power plants in recent years, both adopting the ultra-supercritical coal-fired technology. The former contains three 800 MW units, and the latter has two 800 MW units, which started commercial operation successively between 2016 and 2019. Another coal-fired power generation retrofitting project of the same technology proposed, but currently shelved due to the controversy of air pollution, would build three additional units each of 800 MW in capacity. Other thermal projects of Taipower, including recently completed and ongoing one, are all-gas-fired and adopting the more efficient combined cycle technology. It is expected to achieve a net increase in the gas thermal capacity by approximately 7500 MW by 2025 while replacing or shutting down older oil-fired and coal-fired power plants [38].

With the introduction of more efficient coal-fired power technology, we expect the average GHG emission intensity from the coal-fired thermal power plant to be lower in the future in Taiwan. For example, the target CO_2 emission intensity was at 789 g/kWh in the operation stage in the Linkou power plant [58]. This is much better than our estimate of CO_2 emissions for the coal-fired plant of 1057.5 g/kWh, as our result is based on existing technology and the average thermal efficiency of the fuel. We expect that the GHG emission intensity can be improved even further if the ongoing adjustment to enlarge the weights of gas-fired units in the thermal fleets is completed in the near future, as our study clearly identified its potential in cutting down GHG emissions per output unit (kWh). Our estimate of CO_2 emissions for gas-fired plant of 424.3 g/kWh, based on existing technology and the average thermal efficiency of the fuel, is a great improvement in comparison to our estimate for the coal-fired plant and is still much better than expected from a new ultra-supercritical coal-fueled power plant. Thermal power will remain the baseload for Taiwan's electricity supply, as renewable power, though which new investment has been quickly catching up in recent years, is not expected to exceed 20% before 2025. As a result, from a GHG mitigation perspective, it is necessary for Taiwan to aggressively enlarge the share of gas power plants in its thermal fleets. It is not beneficial to retrofit a decommissioning power plant to a coal-fired one, even with updated ultra-supercritical technology.

Our findings reaffirm a necessary road map if Taiwan is to achieve the Intended Nationally Determined Contribution (INDC) announced in 2015 in response to the Paris Agreement. Taiwan has committed to reducing its greenhouse gas emissions by 50% from the business-as-usual level by 2030 [59]. As a result, Taiwan initiated the "Energy Transition Policy" in 2016 to adjust the energy structure for electricity generation. In part, Taiwan has set targets to increase the share of renewable energy generation and natural-gas-fueled power respectively to 20% and 50% by 2025. The policy also calls for no new coal-fired power plant to be built before 2025 and the existing plants to be replaced by gas-fired units after the decommissioning [60,61]. Based on our analysis, we believe the latter part of the policy shall be carried forward beyond 2025 if our intention is to optimize the GHG mitigation potentials from the fuel choice for electricity generation.

4.2. Co-Benefits of Emission Reduction

When power plants are looking for retrofit alternatives, it is important to keep in mind that measures to reduce greenhouse gas emissions may provide benefits beyond just climate change mitigation. Switching to cleaner fossil fuels, such as natural gas, is likely to reduce air pollution and its accompanying health and environmental impacts, thus substantially improving local or indoor air quality in the short term [62,63].

This study assessed the emission impact of possible fuel choices to retrofit the existing fuel-oil-based Hsieh-ho Power Plant, which is approaching decommissioning soon. We found that the co-benefits of emission reductions will likely be realized if the new technology is natural-gas-fueled. This finding is clearly documented in Figure 12, which displays the relationship between emissions of GHGs and those of four air pollutants, across the specific power technologies analyzed in this study. The emissions of SO_x, NO_x, and PM10 are all reduced along with the reduction in GHG emissions when natural-gas-based technology is chosen as the replacement. This relationship exists when counting only the emissions from electricity generation (Panels (a) and (b)), as well as when considering emissions from the total fuel lifecycle (Panels (c) and (d)). The only exception is CO emission, where we found a reverse relationship if the power technology changed from fuel-oil-based to natural-gas-based (Panel (b) and (d)).

On the other hand, emissions of SO_x and PM10 are expected to increase, while emissions of NO_x and CO are expected to decrease, along with the increase in GHG emissions, if the new technology changes from fuel-oil-based to coal-based. Nevertheless, the emissions of SO_x, NO_x, and PM10 are all much higher from coal-fueled technology, compared the natural-gas-fueled technology. These air pollutants are well known as the cause of local threats to ecosystems, crop yields, and human health [63,64].

According to our results, when the coal-based, instead of the natural-gas-based, technology is chosen as a replacement for HHPP, emissions of all three air pollutants are markedly higher in the electricity generation stage (Panels (a) and (b) of Figure 12), raising the possible immediate threats to the local environment and communities around the power plant. This increase in impact is not only limited to local areas, however. Our analysis indicates that the increase in emissions of all three air pollutants is expected to spread across the fuel lifecycle, with PM10 displaying much more evident incremental emissions (Panels (c) and (d) of Figure 12). The choice of power plant technology is in effect locked in for the upstream exploration, production, and transportation of the selected fuel for many years to come and, in turn, as in the case of coal-based power technology, is likely to increase the negative impact on ecosystems and human health far away.

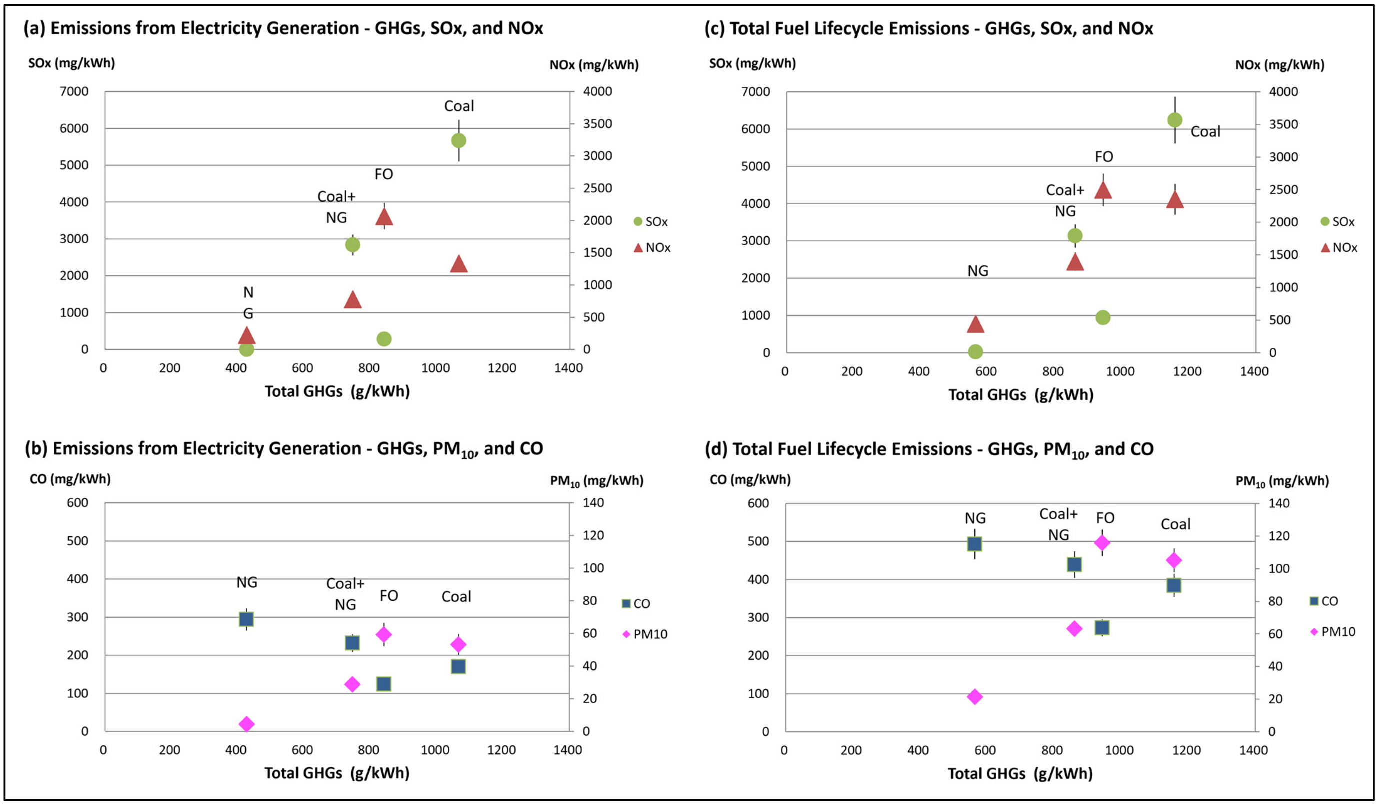

Figure 12. Relationship of emissions of GHGs and four air pollutants across specific power technologies. Panels (**a**,**b**) for the electricity generation stage only; Panels (**c**,**d**) for the total fuel lifecycle.

5. Conclusions

5.1. Sustainable Environment Perspective

The results of this study provide a bright future for the power sector to actively pursue all possible measures to optimize the energy mix and further introduce NG into power plants. Our study also confirms that GHG emissions are mainly generated directly at the power plant, accounting for as much as 89% to 92% in the case of fuel oil and coal and 76% for natural gas. It is worth prioritizing the mitigation efforts within the power plant.

This study took into consideration the unique situation of Taiwan, where all types of fuels used in electricity generation require long trade routes from the fuel sources. Our analysis via LCA found that all fuel choices studied generated about 3–5% of total lifecycle GHG emissions owing to the transportation of the imported fuel, while natural gas required an additional 17% due to liquefaction and regasification. Nevertheless, gas-fired electricity still has lower lifecycle GHGs than coal-fired or oil-fired plants, even with much higher upstream emissions from NG. A choice of power technology options today will determine the emissions from the power plant, as well as its upstream production and transportation of fuels for the next 30 or more years.

The study result regarding the four air pollutants shows a voluminous reduction in the emissions of NO_x, SO_x, and PM10 when the power plant is changed from FO-fueled to NG-fueled, though it recorded an increase in CO emissions. The emissions of NO_x, SO_x and PM10 from NG-fueled plants are also voluminously lower than from coal-fueled plants. In fact, SO_x emissions from the coal-fueled plant are about six folds those from FO-fueled and thousands of folds those from NG-fueled plant. We also found that the relative contribution from the four fuel lifecycle stages varies with the choice of fuel sources, and the pattern is also not consistent when a different pollutant is involved. For the retrofitted power plant utilizing NG as the fuel, SO_x and PM10 emissions are generated primarily from the upstream fuel supply chain (78% and 79% of the lifecycle total, respectively), while NO_x emissions from plant operations (accounting for nearly 50%). In contrast, for coal-fueled power plants, all four pollutants are generated primarily from the plant operation stage, with its contribution for SO_x being the highest (91%). These findings all indicate that for a decision in retrofitting HHPP, an NG-fueled plant is a way better choice than a coal-fueled plant from the perspective of local air quality around the power plant.

Furthermore, this study demonstrated that initiatives that reduce GHG emissions may have additional benefits. We found that co-benefits of emission reductions are likely realized if the new technology is natural-gas-fueled. The emissions of SO_x, NO_x, and PM10 all reduce along with the reduction in GHG emissions when natural-gas-based technology is chosen as the replacement. On the other hand, emissions of SO_x and PM10 are expected to increase, while emissions of NO_x and CO are expected to decrease, along with the increase in GHG emissions, if the new technology is fuel-oil-based to coal-based. This relationship exists when counting only the emissions from electricity generation, as well as when considering emissions from the total fuel lifecycle.

5.2. Uncertainties and Limitations

This study was limited to assessing GHGs, NO_x, SO_x, CO, and PM emissions for four fuel supply scenarios. The results from this study provide an important, but incomplete picture of overall environmental performance across the power generation lifecycle. This study did not consider the use of carbon capture and sequestration, which may warrant further studies.

This study gives theoretical estimates about the formation of atmospheric emissions based on the literature and data available from the Ecoinvent database. The assumptions involved in these estimates introduce many uncertainties, and discrepancies are expected between the present estimates and practical measurements. In addition, emissions considered in this study may vary enormously with combustion conditions in boilers and are also affected by, for example, the load, fuel properties, furnace temperature, and excess air in the system [65]. For a given power plant, the applied pollution control methods can also influence the overall result. Pollution control methods include a variety of pre- and post-combustion technologies, for example electrostatic precipitators, scrubbers, selected catalytic reduction, and baghouses [55,57].

The results obtained in this study identify contributions related to each lifecycle phase. As expected, CO_2 accounts for the vast majority (98–99%) of the total air emissions from each scenario examined. Three other GHGs, CH_4, N_2O, and SF_6, are also emitted from the system, but in much smaller quantities. They do not affect much of the total GHG emissions of the system, even though the GWP of these gases is much higher than that of CO_2. Nevertheless, GWP should not be used solely to represent the environmental performance of a system, as indicated by various previous studies [50,66–69].

This study found that the emissions from the liquefaction, shipping, and regasification segments of the natural gas lifecycle are fewer than 22% of the total. This percentage is expected to increase if we assume a higher methane leakage rate and/or a 20-year timeframe for GWP, as a previous study indicated that emissions resulting from upstream production are expected to increase drastically with the change in the assumptions [5].

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Abbreviations

CH_4	methane
CO_2	carbon dioxide
CO_2e	CO_2 equivalent
FO	fuel oil
GHGs	greenhouse gases
GW	gigawatt
GWh	gigawatt hour
GWP	global warming potential
HHPP	Hsieh-ho Power Plant
LCA	lifecycle assessment
LNG	Liquefied natural gas
MW	megawatt
MWh	megawatt hour
NG	natural gas
NGCC	natural gas combined cycle
N_2O	nitrous oxide
NO_x	nitrogen oxides
PM	particulate matter
SF_6	sulfur hexafluoride
SO_x	sulfuric oxide
TPC	Taipower Company

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