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Proposal of Zero-Emission Tug in South Korea Using Fuel Cell/Energy Storage System: Economic and Environmental Long-Term Impacts

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Abstract: This study presents the results of economic and environmental analysis for two types of zero-emission ships (ZESs) that are receiving more attention to meet strengthened environmental regulations. One of the two types of ZES is the ZES using only the energy storage system (All-ESS), and the other is the ZES with fuel cell and ESS hybrid system (FC–ESS). The target ship is a tug operating in South Korea, and the main parameters are based on the specific circumstances of South Korea. The optimal capacity of the ESS for each proposed system is determined using an optimization tool. The total cost for a ship's lifetime is calculated using economic analysis. The greenhouse gas (GHG) emission for the fuel's lifecycle (well-to-wake) is calculated using environmental analysis. The results reveal that the proposed ZESs are 1.7–3.4 times more expensive than the conventional marine gas oil (MGO)-fueled ship; however, it could be reduced by 1.3–2.4 times if the carbon price is considered. The proposed ZESs have 58.7–74.3% lower lifecycle GHG emissions than the one from the conventional ship. The results also highlight that the electricity- or hydrogen-based ZESs should reduce GHG emissions from the upstream phase (well-to-tank) to realize genuine ZESs.

Keywords: zero-emission ship (ZES); fuel cell (FC); energy storage system (ESS); greenhouse gas (GHG); well-to-wake (WtW); economic and environmental analysis; optimal capacity; total cost

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1. Introduction

Harmful emissions from ships cause significant health and environmental problems, particularly for inhabitants near ports and coastal areas. One of the most representative regulations for this environmental issue is in emission control areas (ECAs), where ships must comply with more stringent air quality standards designated by the International Maritime Organization (IMO).

Numerous countries are strengthening their domestic environmental regulations to comply with international standards. For example, South Korea's Ministry of Oceans and Fisheries (MOF) declared a Korean version of the ECA that limits sulfur emissions to 0.1% m/m (mass by mass) for all ships anchored in major ports in South Korea as of 1 January 2022. In addition, the Korean government officially announced its green ship strategy named the "2030 Green Ship-K Promotion Strategy" in December 2020 to achieve carbon neutrality in the shipping industry [1].

In order to respond to these environmental policies in the marine sector, most ship owners have tried to utilize low-carbon fuel or exhaust gas after-treatment devices for their ships as a short-term measure. However, all ships should ultimately be converted to zero-emission ships (ZESs) in the long run. Significantly, the tugs (tugboats), which help maneuver other large ships to nearby ports, emit a large amount of greenhouse gas

(GHG) emissions while maneuvering and are the largest contributor among inland ships [2]. Therefore, it is regarded as needing to be converted to a ZES urgently.

For a ZES, renewable energy sources (solar or wind energy) are not preferred as the onboard power source due to their highly weather-dependent characteristics. Since weather can change quickly and unpredictably, their power could not supply continuously and stably. Moreover, while they require a large installation volume, a tug possesses a limited space in which only optimized and compact equipment would fit.

In the meanwhile, according to references [3,4], oil fuels will fade out, and ammonia, hydrogen, and biofuels are taking the lion's share for ocean-going vessels with efforts to employ such fuels in internal combustion engines (ICE). However, in the short-sea segment (such as tugs, offshore, and passenger ships/ferries), fuel cells and energy storage systems (ESSs) represent promising power sources [5] because of the shorter voyage time and smaller power demands than ocean-going ships.

In the past, in most cases, ESSs with small capacity have been used for a peak load or transient load supply to overcome the oversized main engine capacity problems [6]. Recently, however, large-capacity of ESS has become the main power source for tugs due to technological development. Combined with ESS, fuel cells (FCs) have also been adopted as the main power source to extend the voyage distance for ships.

A lifetime cost analysis is required to determine the optimal power system among various options when applying these alternative FC or ESS power sources to a ship. In addition, for an alternative power system, its fuel's lifecycle GHG emissions are becoming more prominent because the alternative fuel (e.g., hydrogen, electricity) is primarily laid in the upstream phase [7]. Therefore, this study provides new insights into alternative power systems' long-term economic and environmental impacts.

The remainder of this paper is organized as follows: Section 2 presents a relevant literature review. Section 3 describes the target ship and its conventional power systems. Section 4 presents the lifecycle emission factors of hydrogen and electricity based on the long-term policies of the Korean government. Section 5 introduces the two proposed zero-emission systems with formulations for economic and environmental analyses. Section 6 presents the analysis results, and finally, Section 7 presents the concluding remarks.

2. Literature Review

With the current trend of adopting greener technologies in the maritime industry, the economic and environmental impacts of FC- or ESS-powered tugs have been investigated over the past decades.

Kumar et al. [8] suggested a tug with a generator–flywheel hybrid system to reduce fuel consumption. They reported that adopting the 50 kWh flywheel offers a 25.6% reduction in fuel consumption compared with the conventional generator-only power system. Yuan et al. [9] introduced a power management control strategy for a generator–battery hybrid system for a tug. The proposed power management strategy promises a 17.6% reduction in fuel consumption compared with the conventional strategy.

Shiraishi et al. [10] introduced Japan's first hybrid tug (TSUBASA), which uses two shaft generators (S/G), two diesel generators, and two sets of lithium-ion batteries. It achieves a 20% reduction in carbon dioxide (CO_2) emissions compared with the conventional tug.

Additionally, C. Mulder and M. Mulligan [11] employed a hybrid power system for tugs. For normal low-power operations, the FC and ESS were operated in parallel; however, for infrequent high-power operations, they were combined with a single diesel generator to obtain a boost power supply. Reportedly, the hybrid tug could reduce emissions by 67% compared with the conventional tug.

As presented in Table 1, various trials have been conducted to develop zero- or low-emission tugs using FC or ESS. The hybridization of the FC and ESS is believed to be very promising in the shipping industry because they can compensate for each other's shortcomings. First, the ESS can supply the cold-up starting power for the FC. Additionally, the ESS has a faster response performance than FC. For the FC, the frequent changing load conditions are the main reason leading to its life attenuation due to the difficulties of water management and insufficient supply of reactive gases [12]. By contrast, the ESS's size is limited in a tug's smaller space, hindering the long-distance voyage [13]. As a solution to this, when FC is used together, it can extend the ships' voyage distance because FC is an energy converter rather than an energy storage device.

Table 1. List of low- or zero-emission tugs using FC/ESS power.

No.	Project Name /Owner	Ship Name	Bollard Full (ton)	Power System Configuration	Power Source Capacity			Country	Built Year	Ref.
					G/E (kW)	FC (kW)	ESS (kWh)			
1	Foss Maritime Company [1]	Carolyn Dorothy	58	Generator + ESS	620	-	0.3	U.S.	2009	[14,15]
2	E-KOTUG [1]	RT Adriaan	84	Generator + ESS	-	-	117	Netherlands	2012	[16]
3	NYK Bulk & Projects Carrier Ltd. [1]	Tsubasa	55	Generator + ESS	800	-	300	Japan	2013	[10]
4	Luleå Hamn AB [1]	Vilja	100	Generator + ESS	Unknown	-	600	Sweden	2019	[17,18]
5	GISAS Shipbuilding Industry	Gisas Power	32	All-ESS	-	-	2900	Turkey	2020	[19,20]
6	ELEKTRA project	Elektra	-	FC + ESS	-	300	2500	Germany	2021	[21,22]
7	Lianyungang Port Holding Group	Yungang Electric No. 1	-	All-ESS	-	-	5000	China	2021	[23]
8	Sembcorp Marine	-	65	M/E + ESS	-	-	904	Singapore	2021	[24]
9	Ports of Auckland	Sparky	70	All-ESS	-	-	2784	New Zealand	2021	[25]
10	e5 Tug/Tokyo Kisen	Taiga	50	Generator + ESS	Unknown	-	Unknown	Japan	2022	[26]
11	Crowley	eWolf	70	All-ESS	-	-	6000	U.S.	(expected) 2023	[27]
12	HaiSea Marine	Unknown	70	All-ESS	-	-	5240	Canada	(expected) 2023	[28]
13	Svitzer (Maersk)	Unknown	80	FC + ESS	-	Unknown	Unknown	Europe	(expected) 2024	[29]
14	DSME	Unknown	Unknown	FC + ESS (total 3 MWh)	-	Unknown	Unknown	South Korea	(expected) 2026	[30]

Note. Data are from references of [10,14–30]. [1] The S/G is not included in this Table.

Based on the studies described above and reference ships (Table 1), the market demand for FC- or ESS-powered tugs is increasing, primarily because of the evident environmental benefits. However, in the previous studies, lifetime costs for a tug have not been analyzed in depth under the government's long-term energy policy. In addition, previous studies on environmental analysis have not focused on the lifecycle impact of alternative fuels, which is more crucial than before because of their high dependency on the upstream phase.

This study attempts to fill this gap by investigating the long-term potential economic and environmental impacts of the ZES based on two types: the ZES using only the ESS (All-ESS) and the ZES with FC and ESS hybrid system (FC–ESS). The FC–ESS is further divided into two cases: one consists of two sets of FC and one set of ESS, while the other, conversely, consists of one set of FC and two sets of ESS. For the proposed systems, the optimal capacity of the ESS was determined to minimize the total lifetime cost, and the total lifecycle GHG emissions were analyzed based on South Korea's energy policies. Korea's energy policy to achieve net zero by 2050 is not significantly different from other global energy policies. Hence, this study's methodology and analysis results can be easily applied to cases in other countries.

3. Target Ship

The vessel system considered in this study was a 31 m long tug with a bollard pull of 200 tons. This target ship is powered by two 1400 kW main engines (M/Es) and two 100 kW generator engines (G/Es), which are fueled by marine gas oil (MGO), as shown in Figure 1. Each M/E is connected through a mechanical drive shaft to one propeller, and two G/Es are used for hotel loads, lighting, air conditioning, and winch motors. The general specifications of the target ship are listed in Table 2, and the assumed cost data for the main equipment are listed in Table 3. MGO and O&M costs were assumed to increase annually, with an inflation rate of 2%.

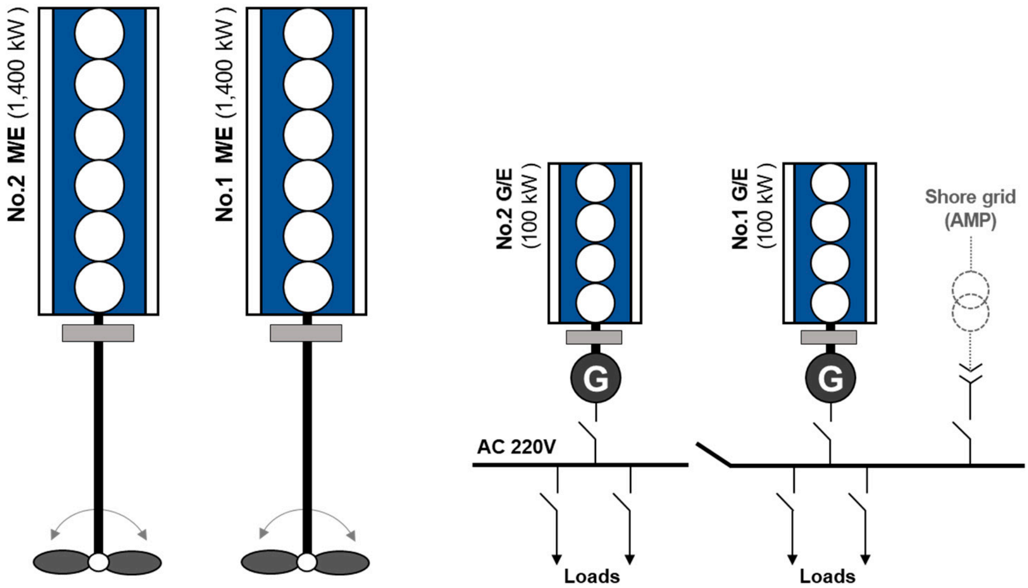


Figure 1. System layout of the conventional system of a target ship.

Table 2. General specifications of the target ship.

Item	Specification
Length overall (LOA)	31 m
Gross tonnage	200 ton
Bollard full	46 ton
Working hours	160 min./trip
The number of trips per day	9 times/day
Annual operation days	313 days/yr [1]
M/E power	1400 kW × 2 (4-stroke medium-speed)
G/E power	100 kW × 2 (AC 220 V)
Propulsion efficiency	51% [2]
Electric power supply efficiency	48% [3]
Fuel type	MGO
Lifespan	25 years

[1] The rest of the year (52 days) is the cold standby state when the ship is inoperable for repair, maintenance, inspection, etc. [31]. [2] The efficiencies of M/E (52%) and shafting (99%) are included [32]. [3] The efficiencies of G/E (50%), alternator (98%), and switchboard (98%) are included [32].

Table 3. Assumed cost data for the conventional MGO-fueled system.

Category		Cost Data	Reference
Investment cost	M/E	USD 300/kW	[33]
	G/E	USD 350/kW	[34]
	M/E auxiliaries	USD 90/kW [1]	[35]
O&M cost	O&M (M/E, G/E, aux.)	2.5% of CAPEX/year	-
	Fuel (MGO)	USD 1.19/kg [2]	[36]

Note. Data are from references of [33–36]. [1] It is assumed to be approximately 30% against the M/E cost. [2] It is the average cost for the year 2021 in South Korea (VAT included), applied unit conversion factors for petroleum product of 0.92 kg/L [37].

In a conventional system for a tug, the M/E power is typically based on the tug's rated bollard pull operation, where ships do not spend much time. According to the reference of [15], the average M/E load (expressed as a percentage of full power) over the monitoring period was only 16%.

Herein, the typical load profile shown in Figure 2, which has five operation modes (Table 4) based on references [9,10,38–40], was applied. For simplicity and practical reasons, rapid dynamics and transient power demands were not considered. The ship service load (or hotel load) of 70 kW was assumed to be constant throughout its operating cycle.

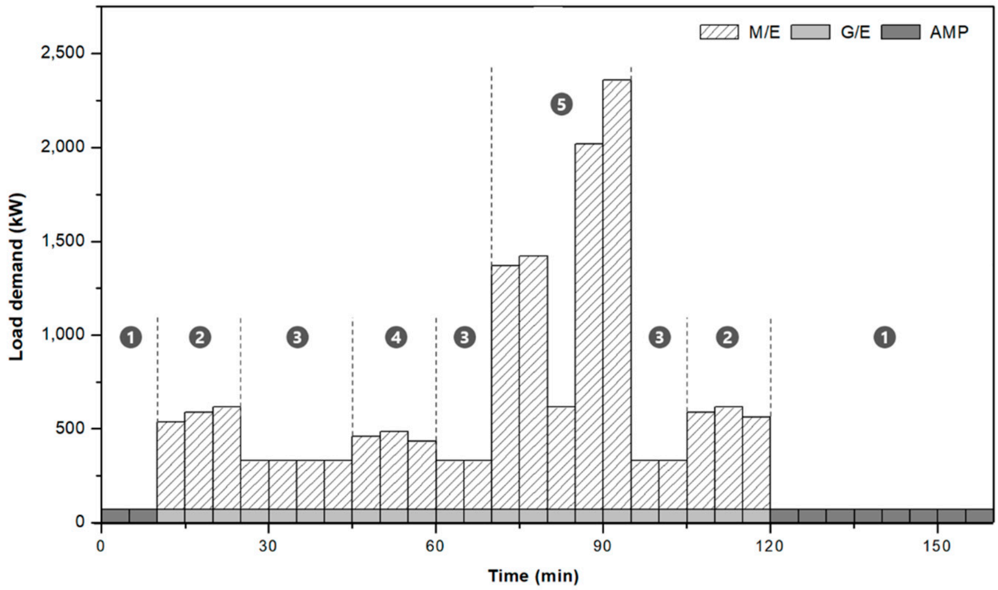


Figure 2. Typical load profile of a tug (M/E: main engine; G/E: generator engine; AMP: alternative maritime power).

Table 4. Description of each operation mode of a target ship.

No.	Operation Mode	Description
①	Harbor standby	Idling in the water waiting for a call.
②	Transit	Movement of the tug between to or from a ship.
③	Waiting	Waiting for a while for the next job preparation.
④	Close to the ship	Close movement of the tug to a ship for a ship assisting.
⑤	Ship assist (towing)	Assisting a ship from berth to sea and vice-versa.

4. Environmental Parameters

To analyze the ship fuel's lifecycle GHG emissions, a well-to-wake (WtW) analysis, which is similar to the well-to-wheel concept in the automotive industry, could be performed. WtW analysis can be divided into two groups: well-to-tank (WtT) and tank-to-wake (TtW). The WtT emission is the sum of all emissions from the fuel production to a ship's fuel tank, including fuel transmission, distribution, storage, and refueling. In contrast, the TtW emission is the sum of emissions from the fuel tank of a ship to fuel consumption to operate a ship. A simplified WtW process for ships powered by hydrogen or electricity is shown in Figure 3 and can differ between countries.

4.1. Conventional Fuel

Marine gas oil (MGO), one fuel type of marine diesel oil (MDO), is still the most preferred alternative for responding to stricter environmental regulations. The WtT and TtW GHG emission factors of the MGO are listed in Table 5, in which the unit "kWh" refers the mechanical or electrical energy output of M/E or G/E.

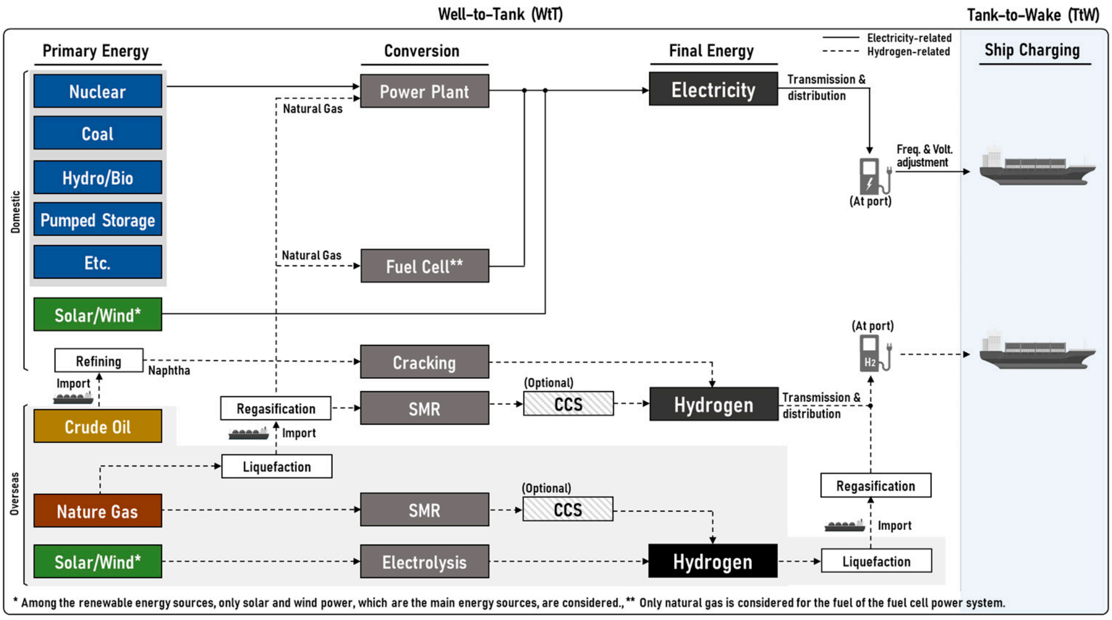


Figure 3. Simplified WtW process for ships powered by hydrogen or electricity.

Table 5. Assumed technical specifications and GHG emission factors for MGO.

Type	Specific Fuel Consumption (g/kWh) [2]	Energy Density Assumption (kJ/kg) [2]	GHG Emission Factor ($gCO_2{}^{-eq.}/kWh$)		
			WtT	TtW	Total (WtW)
M/E	175	42,700	107.60 [41]	569.30 [2]	676.90
G/E	185	42,700	113.75 [41]	602.95 [2]	716.70

Note. Data are from references of [2,41].

Here, GHG emissions were expressed as carbon dioxide equivalent ($CO_2{}^{-eq.}$), which aggregates the three pollutants based on their century-long global warming potentials (GWPs), as determined by the Fifth Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC). Therefore, the 100-year GWPs are assumed to be 1 for CO_2, 30 for fossil CH_4, and 265 for N_2O [42] for the MGO fuel.

4.2. Hydrogen

The GHG emissions from hydrogen fuel differ between countries, depending on the hydrogen production pathway of each country. In general, hydrogen can be produced using the following four methods.

- Byproduct hydrogen in the petrochemical industry, predominantly through naphtha cracking;
- Hydrogen produced using steam methane reforming (SMR), typically sourced from natural gas;
- Hydrogen from SMR together with the carbon capture and storage (CCS) process;
- Hydrogen produced in the electrolysis process using electricity from renewable energy.

In addition, a certain proportion of hydrogen fuel used in each country may be imported from abroad. In this study, all imported hydrogen is assumed to be liquid hydrogen (LH_2), and the electrolysis efficiency is assumed to be 64% [43]. The GHG emission factors of the WtT process for each hydrogen production method are shown in Table 6.

Table 6. Hydrogen fuel's GHG emission factors for a ship according to its production method in S. Korea.

Phase	Domestic Production ($gCO_2{}^{-eq.}/kWh$)				Overseas Production ($gCO_2{}^{-eq.}/kWh$)	
	Naphtha Cracking	**SMR**	**SMR+CCS**	**Electrolysis**	**SMR+CCS**	**Electrolysis**
Upstream (fuel)	36.00 [44]	200.15 [1] [45]	200.15 [1] [45]	54.23 [3]	200.15 [45]	54.23 [3]
H_2 production	108.00 [44]	350.28 [2] [46]	158.06 [2] [46]	0	158.06 [2] [46]	0
CCS process	0	0	81.36 [46]	0	81.36 [46]	0
Liquefaction	0	0	0	0	171.45 [47]	171.45 [47]
Regasification	0	0	0	0	15.15 [47]	15.15 [47]
H_2 transport/distribution [4]	8.58	8.58	8.58	8.58	8.58 [5]	8.58 [5]
Total	**152.58**	**559.01**	**448.15**	**62.81**	**634.75**	**249.41**

Note. Data are from references of [44–47]. [1] The imported LNG, which has 200.15 $gCO_2{}^{-eq.}/kWh$ [45] during the NG upstream phase is applied. [2] Assumed that the CCS rate is 85% in the SMR process, and 65% in energy to drive SMR. Moreover, its methane leakage rate is assumed to be 3.5%. [3] The electrolyzer's operation is assumed to be driven only by local solar and wind power. [4] The only pipeline is applied as the inland H_2 transport/distribution method because it occupies a relatively large proportion of 93% [48,49]. However, contrary to reference [47], the distance is applied twice because ports are farther away than inland charging stations. [5] A LH_2 carrier could use boil-off gas (BOG) in storage tanks for its propulsion fuel; therefore, it is assumed that the ship would not incur additional GHG emissions during seagoing [43].

Currently, the hydrogen used in South Korea is derived primarily from byproducts through naphtha cracking in the petrochemical process or from the SMR process using natural gas. However, the government aims to achieve 100% green hydrogen by 2050 [50]. In this regard, the hydrogen mix in South Korea is expected to be changed, as shown in Table 7.

Table 7. Current and expected future hydrogen mixes in South Korea.

H_2 Production Region	H_2 Production Method	Current Mix in 2021 (%) [51] [1]	Future Mix in 2050 (%) [50] [2]
Domestic	Naphtha cracking	56.42	0
	SMR	33.61	0
	SMR+CCS	0	0
	Electrolysis	9.98	20.07
Overseas	SMR+CCS	0	0
	Electrolysis	0	79.93
Total	**-**	**100**	**100**

Note. Data are from references of [50,51]. [1] Byproduct hydrogen produced and consumed by oil refineries is excluded. [2] Plan A scenario in the reference [50] is applied, which is the complete transition to 100% green hydrogen by 2050.

Based on Tables 6 and 7, the WtT GHG emission factor of hydrogen in 2021 was approximately 280.24 $gCO_2{}^{-eq.}/kWh$, and it is expected to decrease to 211.96 $gCO_2{}^{-eq.}/kWh$ by 2050, with a rate of about -0.96% per year. If the same rate is applied to the subsequent period, the emission factor is expected to be 220.29 $gCO_2{}^{-eq.}/kWh$ in 2046, when the ship's lifespan is over.

4.3. Electricity

Shore power or alternative maritime power (AMP) is the electric power supplied from shoreside electrical power to a ship at berth while its onboard power source is shut down. The emission from AMP is highly dependent on its land-side electricity generation mix. Therefore, it is expected to be lower if land-side electricity is generated by more renewable power sources.

Under the draft 2050 carbon-neutral scenarios [50] announced in 2021, coal will be phased out before 2050. Hence, the GHG emission factors and the electricity generation mix for each power source in South Korea are expected to be changed, as presented in Table 8.

Table 8. GHG emission factors and the electricity generation mix by each power source in S. Korea.

Power Source		GHG Emission Factor (gCO_2 $^{-eq.}$/kWh)	Current Mix in 2021 (%) [52,53]	Future Mix in 2050 (%) [50] [6]	Reference
Nuclear [1]		12.00	27.00	6.10	[54]
Coal [2]		1251.5	34.00	0.00	[55]
Natural gas (NG) [3]		564.15	29.00	0.00	[45,56]
Renewable energy	Solar	52.42	3.42	34.85 [7]	[57]
	Wind	17.00	0.44	34.85 [7]	[54]
	Hydro	24.40	0.42	0.00	[57]
	Biofuel	53.00	1.63	1.00 [7]	[57]
New energy	Fuel cell [4]	588.00 (2021), 325.89 (2050)	0.67	1.40	[44]
	Hydrogen turbine [4]	278.95 (2021), 210.69 (2050)	0.00	21.50	Section 4.2, [58]
Pumped storage		256.63	1.00	0.00	[59]
Etc. [5]		1422.00	2.42	0.30	[44]

Note. Data are from references of [44,45,50,52–59]. [1] Only pressurized water reactor (PWR) nuclear power plant, which accounts for most in South Korea, is considered. [2] The average value of the installed and new-build coal power plant in South Korea is applied. [3] The imported LNG, which has 200.15 gCO_2 $^{-eq.}$/kWh [45] during the NG upstream phase is applied. [4] In 2021, fuel cells were primarily fueled by imported natural gas. However, by 2050, fuel cells and hydrogen turbines will be fueled by 100% hydrogen, with a carbon emission intensity of ~0% g/kWh in the downstream phase [58]. [5] In the Etc., only byproduct gas plants are applied due to lack of accurate data. [6] Plan A scenario in the reference [50] is applied, which is the cessation of thermal power generation. [7] Renewable energy generation is assumed to be achieved using solar and wind power (excluding 1% of biofuel) [60].

Based on Table 8 and an electric power transmission and distribution (T&D) loss of 3.6% [61], the WtT GHG emission factor of electricity in 2021 was approximately 659.86 gCO_2 $^{-eq.}$g/kWh, which is expected to be reduced to 82.55 gCO_2 $^{-eq.}$/kWh by 2050, with a rate of about −6.92% per year. If the same reduction rate is applied to the subsequent period, the emission factor is expected to be 109.96 gCO_2 $^{-eq.}$/kWh in 2046.

5. Proposed Systems

This study proposed three different power systems using FC or ESS to realize a zero-emission tug. The proton-exchange membrane fuel cell (PEMFC) and the lithium-ion battery (LIB) were selected as the types of FC and ESS, respectively, as they are among the most commonly used types on the market. Moreover, it is assumed that the PEMFC is supplied its fuel by onboard hydrogen fuel tanks, and LIB is charged from onshore electricity in the port. They offer an expected lifetime based on the marine manufacturer's references. Furthermore, the capacity loss (capacity fading) factor is considered to determine the appropriate installation capacity of PEMFC and LIB. The detailed assumptions for the design parameters of the PEMFC and LIB are presented in Table 9. The other assumptions for this study are listed below:

- Korea's carbon-neutral policy will be achieved successfully by 2050.
- The hydrogen/electricity charging infrastructure for a tug is prepared.
- The tug can return to port safely even though one power source is out of service.
- Only a tug's main equipment is considered for the economic analysis.
- The carbon price will be imposed on WtW emissions from a ship after 2026.

Table 9. Assumed specifications of PEMFC and LIB for the proposed systems.

Type	Item	Specification	Reference
PEMFC	Efficiency (PEMFC)	45% [1]	[62]
	Efficiency (System)	43% [2]	[62]
	Lifetime	31,500 h [3]	[63–65]
	Specific fuel consumption (SFC) [4]	62 g/kWh	[63,66]
	Capacity loss/fading	10% (at end-of-life)	[67,68]
	Fuel storage	Compressed tanks (700 bar)	Assumption
	H_2 charging cycle	Once a day	Assumption
LIB	Efficiency (LIB)	98%	[69]
	Efficiency (System)	94% [2]	[69]
	Lifetime	8600 cycles [3] (DoD 80%)	[70–72]
	Capacity loss/fading	30% (at end-of-life)	[73]
	Operating C-rate	2C	Assumption
	Depth of Discharge (DoD)	80%	Assumption
	SoC operating range	10–90%	Assumption
	Electricity charging cycle	3 times per day	Assumption

Note. Data are from references of [62–73]. [1] The efficiency of a PEMFC varies with its load factor. However, for simplicity, it is assumed to have a fixed value of 0.45 [62]. [2] The efficiency of a converter (98%) and onboard switchboard (98%) are added. [3] Average values based on references from marine PEMFC or LIB (nickel manganese cobalt (NMC) or lithium iron phosphate (LFP) type) manufacturers are considered. The lifetime is assumed to increase (approximately 25%) for each replacement according to technology development [74–76]. [4] Average value based on degradation factor (0.3%/1000 h [77]) is considered because the reference values are based on the beginning of life (BoL).

5.1. System Layout

The first ship power system considered in this study was powered by only two sets of ESS (Case 1), as shown in Figure 4. The others were FC–ESS hybrid systems, as shown in Figure 5: (a) a system with two ESS sets and one FC set (Case 2), and (b) a system with two FC sets and one ESS set (Case 3). All cases were based on the DC-grid system, and each power source should be connected to the main bus bar through a DC/DC converter.

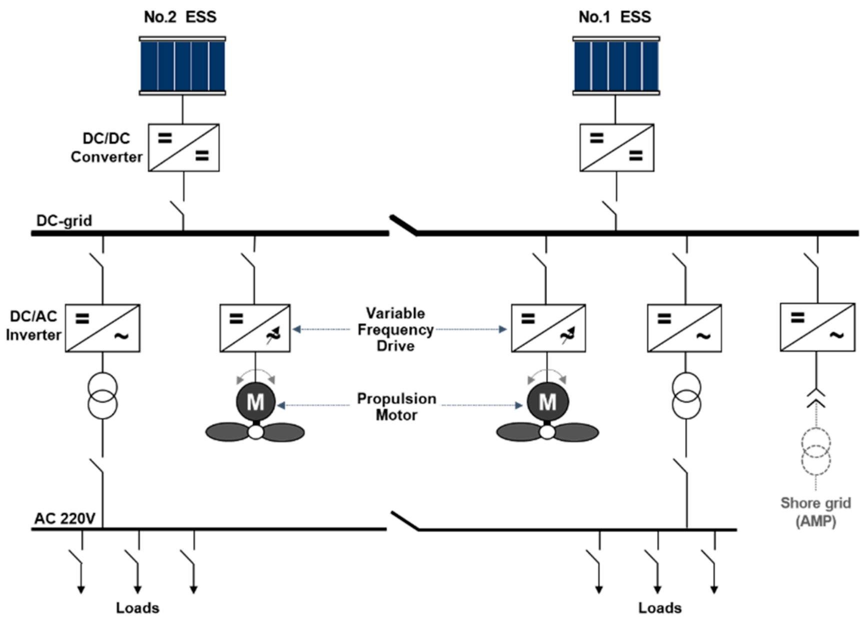


Figure 4. Proposed system concept of All-ESS (Case 1).

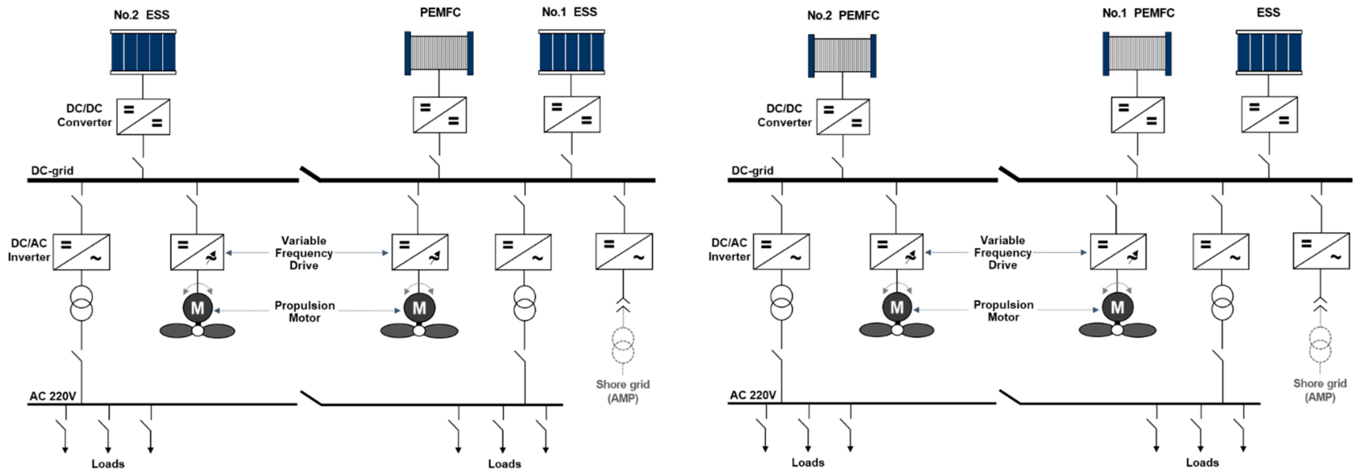


Figure 5. Proposed system concept of the FC–ESS: (**a**) Case 2 that has one FC set and two ESS sets; (**b**) Case 3 that has two FC sets and one ESS set.

In the FC–ESS systems, the capacity of one FC set was determined to be 730 kW (including a 15% sea margin) such that the FC could supply power by itself during all operating modes, except for the towing mode, in which the ESS can assist in supplying the peak power. Electricity is assumed to be charged after three voyage cycles, and hydrogen fuel is charged once daily during a standby period at a port.

Each system must have remaining spare energy to deal with cases of worst situations (e.g., loss of one power source and loss of one main switchboard). Essentially, the ship must be able to return to the port safely using the spare energy, even if any worst situation occurs. In case of Case 3, it has two separate FC power sources; hence, it can satisfy the requirement without the reserved energy in the ESS. However, the other systems (Cases 1 and 2) should retain spare energy in the ESS during one ESS charging cycle.

5.2. Cost Assumptions

The cost data for the proposed system are presented in Table 10. One USD is assumed to be approximately 1145 Korean Won based on the average exchange rate in 2021 [78].

Table 10. Assumed cost data for the proposed systems.

Category	Equipment	Cost	Reference
Investment cost	PEMFC	USD 1000/kW	[79]
	LIB	USD 500/kWh	[80]
	Converter/VFD [1]	USD 200/kW	[81]
	Propulsion motor	USD 135/kW	[82]
	H_2 storage tank (Type IV, 700 bar)	USD 18/kWh [2]	[43]
O&M cost	PEMFC	USD 13/kW/year	[83]
	LIB	USD 5/kWh/year	[83]
	Converter/VFD [1]	USD 2/kW/year	[84]
	Propulsion motor	1% of CAPEX/year	[85]

Note. Data are from references of [43,79–85]. [1] Variable frequency drive (VFD) (also known as the motor drive) for a propulsion motor. [2] Maritime tank is more expensive than the one used for cars or trucks, which are approximately USD 14−15/kWh [43,86,87].

In general, when replacing PEMFC and LIB at the end of their lifespan, only the stack parts of the PEMFC and cell parts of the LIB are to be replaced. In this study, it is assumed that stack parts account for 72% [88] of the initial PEMFC system cost, and cell parts account for 82% [89] of the initial LIB system cost. Moreover, replacement costs may decrease because of future market growth, as presented in Table 11. Moreover, the lifespan of PEMFC and LIB was assumed to increase by 25% for each replacement, considering technological developments [74–76].

The assumptions for electricity and hydrogen costs, which were based on the inland standards in 2021, are summarized in Table 12. The hydrogen cost was USD 7.42/kg [90,91] in 2021 in Korea; it was assumed to decrease by 4.13% annually and become USD 2.18/kg by 2050, according to the Korean government plan [92].

Table 11. Assumed replacement cost parameters for PEMFC and LIB.

Parameter	PEMFC		LIB		Ref.
Cost change for each replacement	1st (6th year) 2nd (13th year) 3rd (23rd year)	75% of the initial cost 40% of the initial cost 30% of the initial cost	1st (9th year) 2nd (20th year) -	50% of the initial cost 27% of the initial cost -	[93]

Note. Data are from references of [93].

Table 12. Assumed hydrogen and electricity cost for ships.

Type	Current Fee (2021)	Annual Change Rate	Reference
Hydrogen	USD 7.42/kg-H_2	−4.13%/year	[90–92]
Electricity [1]	USD 6.31/kW/month, USD 0.08/kWh	+ 5%/year	[94–97]

Note. Data are from references of [90–92,94–97]. [1] For the sake of simplicity, the other specific cost factors with high volatility were not considered.

For electricity cost, the inland commercial rate was applied, and as of 2021, it was composed of a fixed cost of USD 6.31/kW/month and a variable cost of USD 0.08/kWh [94]. In addition, the rate was expected to increase annually by approximately 5%, which is higher than that in the past decades due to the increase in new and renewable energy in coming decades [95–97].

5.3. Objective Function

In this study, the proposed systems were assumed to minimize the total lifetime cost of a target ship. To satisfy this assumption, the lifetime costs were calculated using the optimization problem based on the net present value (NPV) method described below.

Generally, the total lifetime cost (*TC*) comprises the investment cost (*IC*), variable cost (*VC*), and replacement cost (*RC*) of the PEMFC and LIB, as follows.

$$TC = IC + VC + RC \tag{1}$$

The annual values of each cost were discounted to the base year, and the discount rate was arbitrarily set to 5%. The assumed parameters used in this study are listed in Table 13. First, the IC mainly comprised the main equipment costs, as expressed in the following equation, where UC refers to each unit cost of the main equipment: PEMFC (UC_{fc}), LIB (UC_{lib}), converter or VFD (UC_{con}), hydrogen tank (UC_{tk}), and propulsion motor (UC_{mt}). Additionally, time-step t is from 0 to the end of three voyages with the interval (Δt_s) of 5 min, as shown in Figure 2.

$$\begin{aligned} IC = {} & (UC_{fc} \times FC0/C_{f\_fc}) + (UC_{lib} \times ESS0/C_{f\_ess}) + \{UC_{con} \times (FC0 + (C_r \times ESS0) + P_{prop})\} + UC_{tk} \times Fr \\ & \times \left(\frac{\Delta t_s}{60} \times \sum\nolimits_t \frac{p\_FC(t)}{\eta_{fc}}\right) + (UC_{mt} \times P_{prop}) \end{aligned} \tag{2}$$

where FC0 (kW) is the minimum rated power of the PEMFC; ESS0 (kWh) is the minimum rated capacity of the LIB; C_{f_fc} and C_{f_ess} are the remaining capacity at the end-of-life (EoL) against the initial capacities of the FC and LIB, respectively; P_{prop} (kW) is the total rated power of the propulsion motors; $p\_FC(t)$ (kW) is the power generated by the PEMFC; C_r is the operating C-rate of the LIB; F_r is the number of LIB charging per day; and η_{fc} is the efficiency of the PEMFC system. In Equation (2), the PEMFC and hydrogen tanks were only applied to the FC–ESS system.

Table 13. Assumed parameters for analysis in this study.

Parameter	Symbol	Value	Source
The operating days of a tug per year	D	313 days/yr	Table 2
The number of LIB charging	F_r	3 times/day	Table 9
The number of ship trips for one day	T_r	9 times/day	Table 2
The minimum rated power of PEMFC	FC0	0 kW (Case 1) 730 kW (Case 2) 1460 kW (Case 3)	Section 5.1
The specific fuel consumption (SFC) of the PEMFC	SFC_{fc}	62 g/kWh	Table 9
The operating C-rate of the LIB	C_r	2	Table 9
The remaining capacity against its initial capacity of FC (@ EoL)	C_{f_fc}	0.9	Table 9
The remaining capacity against its initial capacity of LIB (@ EoL)	C_{f_ess}	0.7	Table 9
The sum of the propulsion power	P_{prop}	2800 kW	Table 2
The shore power used by a ship at berth	P_{amp}	70 kW	Figure 2
The energy consumption for AMP at berth	C_{amp}	58.33 kWh/voyage [1]	Figure 2
The remaining LIB spare energy for safety	R_{load}	466 kWh (Case 1) 233 kWh (Case 2) 0 kWh (Case 3)	Figure 2
Annual discount rate	d	5%/yr	Assumption
Annual inflation rate	r	2%/yr	Assumption
The annual rate of change of hydrogen cost	f	−4.13%/yr	Table 12
The annual rate of change of electricity cost	e	+ 5%/yr	Table 12
FC system efficiency	η_{fc}	0.43	Table 9
ESS discharging efficiency	η_{ess}	0.94	Table 9
The efficiency of LIB charging from shore power	η_{ch}	0.94	Assumption
The efficiency of AMP at berth	η_{amp}	0.92	Assumption
The unit cost of the PEMFC	UC_{fc}	USD 1000/kW	Table 10
The unit cost of the LIB	UC_{lib}	USD 500/kWh	Table 10
The unit cost of the converter/VFD	UC_{con}	USD 200/kW	Table 10
The unit cost of the propulsion motor	UC_{mt}	USD 135/kW	Table 10
The unit cost of the hydrogen tank	UC_{tk}	USD 18/kWh	Table 10
The O&M cost of the PEMFC	w	USD 13/kW/yr	Table 10
The O&M cost of the LIB	x	USD 5/kWh/yr	Table 10
The O&M cost of the converter/VFD	z	USD 2/kW/yr	Table 10
The O&M cost of the propulsion motor	mt	USD 1.35/kW/yr	Table 10
The annual average cost of hydrogen fuel in 2021	UC_{h2}	USD 7.42 × 10^{-3}/g	Table 12
The annual average fixed cost of electricity in 2021	EC1	USD 6.31/kW/month	Table 12
The annual average variable cost of electricity in 2021	EC2	USD 0.08/kWh	Table 12
The ratio of the PEMFC stack cost against its system cost	a	72%	Table 11
The ratio of the LIB cell cost against its system cost	b	82%	Table 11
GHG emission factor of hydrogen in 2021	GHG_{h2}	280.24 $gCO_2{}^{-eq\cdot}$/kWh	Sections 4.2 and 4.3
GHG emission factor of electricity in 2021	GHG_{elec}	659.86 $gCO_2{}^{-eq\cdot}$/kWh	Sections 4.2 and 4.3
Annual reduction rate of the hydrogen emission factor	m	0.96%/yr	Sections 4.2 and 4.3
Annual reduction rate of the electricity emission factor	n	6.92%/yr	Sections 4.2 and 4.3

[1] C_{amp} is calculated by multiplying the P_{shore} and harboring standby time of 50 min. (70 kW × 50 min.).

The replacement costs, or *RC*, are expected to decrease according to the assumed rates noted in Table 11 and can be expressed as follows.

$$RC = \{UC_{fc} \times \frac{FC0}{C_{f\_fc}} \times a \times (\frac{0.75}{(1+d)^6} + \frac{0.40}{(1+d)^{13}} + \frac{0.30}{(1+d)^{23}})\} + \{UC_{lib} \times \frac{ESS0}{C_{f\_ess}} \times b \times (\frac{0.50}{(1+d)^9} + \frac{0.27}{(1+d)^{20}})\} \quad (3)$$

where *d* is the annual discount rate; a is the ratio of the PEMFC stack cost against its entire system cost; and b is the ratio of the LIB cell cost against its entire system cost.

The *VC* comprises the total hydrogen cost (*HC*), total electricity cost of shore charging (*EC*), and total O&M cost (*OC*). Hence, *VC* can be formulated as follows.

$$VC = \sum_{y=1}^{25} \left[\left\{ HC(1+f)^y + EC(1+e)^y + OC(1+r)^y \right\} / (1+d)^y \right] \tag{4}$$

where *f* is the annual rate of change in the hydrogen cost; *e* is the annual rate of change in the electricity cost; and *r* is the annual inflation rate. First, *HC* was calculated based on the annual hydrogen consumption as follows.

$$HC \left\{ \mathrm{D} \times \mathrm{F}_r \times \mathrm{UC}_{h_2} \times \left(\frac{\Delta \mathrm{t_s}}{60} \times \sum_{\mathrm{t}} p\_\mathrm{FC}(t) \right) \right\} \times \mathrm{SFC}_{fc} \tag{5}$$

where D is the working day of a tug per year; UC_{h2} (USD/g) is the annual average cost of hydrogen fuel in 2021; and SFC_{fc} (g/kWh) is the specific fuel consumption (SFC) of the PEMFC.

In addition, the *EC* was calculated by summing the fixed and the variable electricity cost as below. The fixed electricity cost, which is related to the maximum allowable contracted power, was assumed to have a 10% margin.

$$EC = \left[\left\{ 12 \times \mathrm{EC1} \times \left(\frac{C_r \times \mathrm{ESS0}}{\eta_{ch}} + \frac{\mathrm{P}_{amp}}{\eta_{amp}} \right) \times 1.1 \right\} + \left\{ \mathrm{D} \times \mathrm{EC2} \times \left(\mathrm{F}_r \times \frac{\mathrm{C}_{ch}}{\eta_{ch}} + \mathrm{T}_r \times \frac{C_{amp}}{\eta_{amp}} \right) \right\} \right] \times 1.137 \tag{6}$$

where EC1 (USD/kW/month) is the average fixed cost of electricity; EC2 (USD/kWh) is the average variable cost of electricity; P_{amp} (kW) is the shore power used by a ship at berth; C_{amp} (kWh) is the energy consumption for AMP at berth; C_{ch} (kWh) is the charging capacity for LIB from the fully discharged state to the maximum limit of SOC (up to 90%); η_{ch} is the efficiency of LIB charging from shore power; η_{amp} is the efficiency of AMP at berth; and T_r is the number of ship trips per day. All cost parameters needed to calculate the above equation are based on Table 12, adding a 13.7% tax.

OC, which is the sum of each O&M cost for the main equipment, was calculated as follows.

$$OC = (\mathrm{w} \times \mathrm{FC0}/\mathrm{C}_{\mathrm{f}\_fc}) + (\mathrm{x} \times \mathrm{ESS0}/\mathrm{C}_{\mathrm{f}\_ess}) + \{\mathrm{z} \times (\mathrm{FC0} + (\mathrm{C}_r \times \mathrm{ESS0}) + \mathrm{P}_{prop}) + (\mathrm{mt} \times \mathrm{P}_{prop}) \tag{7}$$

where w (USD/kW/year) is the O&M cost of the PEMFC; x (USD/kWh/year) is the O&M cost of the LIB; z (USD/kW/year) is the O&M cost of the converter/VFD; and mt (USD/kW/year) is the O&M cost of the propulsion motor.

The GHG emissions during a ship's lifetime are the sum of the emissions from hydrogen (EM_{h2}) and electricity (EM_{elec}) based on each GHG emission factor (GHG_{h2}, GHG_{elec}) mentioned in Section 3. According to the Korean government's green policies, these emission factors will decrease by a certain percentage (m, n) every year, as follows.

$$EM_{h2} \sum_{\mathrm{y}=1}^{25} \mathrm{D} \times \mathrm{F}_r \times \left(\frac{\Delta \mathrm{t_s}}{60} \times \sum_{\mathrm{t}} \frac{p\_FC(t)}{\eta_{fc}} \times \mathrm{GHG}_{h_2} \times (1-\mathrm{m})^y \right. \tag{8}$$

$$EM_{\mathrm{elec}} = \sum_{\mathrm{y}=1}^{25} \mathrm{D} \times \left(\mathrm{F}_r \times \frac{\mathrm{C}_{ch}}{\eta_{ch}} + \mathrm{T_r} \times \frac{\mathrm{C}_{amp}}{\eta_{amp}} \times \mathrm{GHG}_{elec} \times (1-\mathrm{n})^y \right. \tag{9}$$

5.4. Constraints

The power outputs of the ESS (*p*_ESS (t)) and PEMFC (*p*_FC (t)) should satisfy the upper and lower bounds, as follows.

$$0 \le p\_\mathrm{ESS}\,(\mathrm{t}) \le (\mathrm{ESS0} \times \mathrm{C}_r) \tag{10}$$

$$(\mathrm{FC0} \times 0.1) \le p\_\mathrm{FC}\,(\mathrm{t}) \le (\mathrm{FC0} \times 0.9) \tag{11}$$

The ESS capacity (c_ESS (t)) also has upper and lower bounds considering its DoD (80%) and minimum spare energy (R_{load}) for safety, as follows.

$$(\text{ESS0} \times 0.1) + \frac{R_{load}}{\eta_{ess}} \leq c\_\text{ESS0}\ (t) \leq (\text{ESS0} \times 0.9) \tag{12}$$

where η_{ess} is the efficiency of the ESS discharging. For the All-ESS system with two separate ESS sets, each ESS set must have its spare energy in preparation for the failure of the other set of ESS. The update function for the stored energy in the ESS is dependent on the energy at the prior time (t −1), as follows.

$$c\_\text{ESS}\ (\text{t}) = c\_\text{ESS}\ (\text{t} - 1) - \left(\frac{\Delta \text{t}_\text{s}}{60} \times \frac{p\_\text{ESS(t)} \times \text{C}_r}{\eta_{ess}}\right)\ (\text{t} > 1) \tag{13}$$

$$c\_\text{ESS}\ (\text{t}) = (\text{ESS0} \times 0.9) - \left(\frac{\Delta \text{t}_\text{s}}{60} \times \frac{p\_\text{ESS(t)} \times \text{C}_r}{\eta_\text{ess}}\right)\ (\text{t} = 1) \tag{14}$$

For the proposed optimization problem, the demand load (demand (t)) must be met by the power supplied from both the PEMFC (p_FC (t)) and ESS (p_ESS (t)), as follows.

$$(\text{C}_r \times p\_\text{ESS (t)}) + p\_\text{FC (t)} = \text{demand (t)} \tag{15}$$

The operating strategies for the proposed systems are derived based on a solution from a nonlinear programming problem with discontinuous derivatives (DNLP). The mathematical model described above was implemented using the CONOPT solver, which is one of the typical solvers available with the general algebraic modeling system (GAMS) (http://www.gams.com, 10 January 2023).

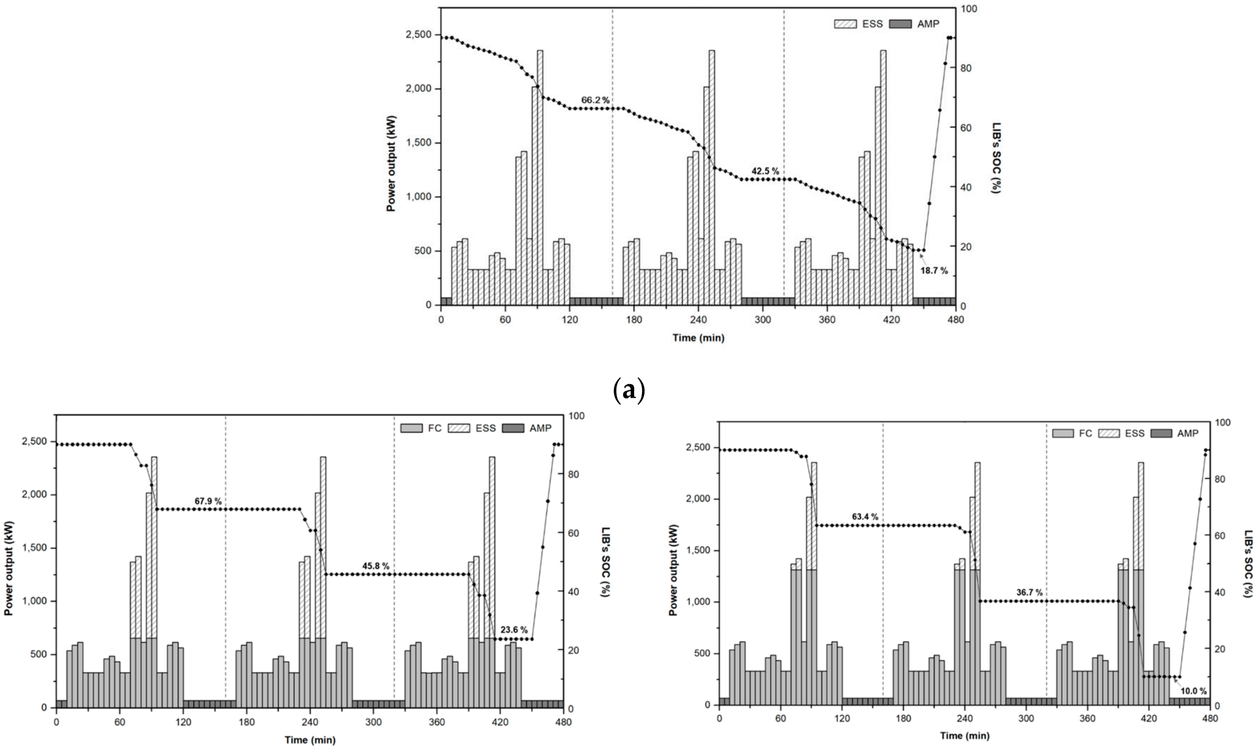
6. Results

Through the simulation studies, the optimal ESS capacity was determined to be 8162 kWh for the All-ESS (Case 1) system, and 2600 kWh (Case 2) and 910 kWh (Case 3) for the FC–ESS systems. The comparison results for the proposed systems (Cases 1–3) against the conventional MGO-fueled system are listed in Table 14.

Table 14. Comparisons of the conventional and proposed systems based on a defined load scenario.

Category		Conventional System (MGO-Fueled)	Proposed Systems		
			Case 1(All-ESS)	Case 2(FC–ESS)	Case 3(FC–ESS)
Power capacity	M/E (kW)	2800	-	-	-
	G/E (kW)	200	-	-	-
	FC (kW)	-	-	812	1624
	ESS (kWh)	-	8162	2600	910
Cost (Million USD)	Investment cost	1.16	7.30	4.26	3.98
	O&M cost	0.51	1.28	0.73	0.71
	Fuel cost (MGO/H_2)	12.44	-	10.97	13.64
	Electricity cost	0.60	39.33	12.73	5.07
	Replacement cost (ESS/FC)	-	1.41	0.96	1.17
	Carbon price	6.69	1.72	2.56	2.76
	Total	**21.40**	**51.04**	**32.21**	**27.33**
GHG emissions (ton CO_2-eq.)	MGO	120831	-	-	-
	Hydrogen	-	-	36,451	45,334
	Electricity	1321	31,431	10,249	5087
	Total	**122,152**	**31,431**	**46,700**	**50,421**

The simulation results for each power dispatch in the proposed system are shown in Figure 6.



(**a**)

(**b**) (**c**)

Figure 6. Power dispatch and LIB's SOC for proposed systems based on a defined load scenario: (**a**) Case 1 (All-ESS); (**b**) Case 2 (FC–ESS) that has one FC set and two ESS sets; (**c**) Case 3 (FC–ESS) that has two FC sets and one ESS set.

In the case of the All-ESS system, only the ESS covered the entire load except for the harbor standby mode. However, for the FC–ESS system, the ESS acted as a supplement for the peak loads.

6.1. Economic Comparison

Figure 7 shows the total lifetime costs of the conventional and proposed systems. Evidently, all the proposed systems had a higher lifetime cost compared with the conventional system. First, the lifetime cost of the All-ESS (Case 1) system was 3.4 times more than that of the conventional one, and it was the highest value among the proposed systems. In the case of the FC–ESS system, the lifetime cost of Case 2 was 2.0 times, and that of Case 3 was 1.7 times more than that of the conventional one.

In the meantime, there have been discussions in the IMO meeting [98] that a WtW approach should be taken for the carbon pricing system. In this regard, if the carbon price is imposed on the WtW phase, the proposed ZESs could be 1.3–2.4 times more expensive than the conventional one (Figure 7). In this study, it is assumed that the carbon price would be imposed starting from 2026, and would increase step by step for a 2050 target of full decarbonization (-100% scenario) with the average carbon price of around USD 191/ton [99].

The hydrogen and electricity costs occupy the largest share of the total lifetime cost. In this regard, considering the volatility in future costs, the total lifetime cost of the proposed systems could be changeable. For example, as shown in Table 15, if the future hydrogen cost changes, the total lifetime cost against the "MGO-fueled" in Case 2 and Case 3 have slight deviations. On the other hand, if the future electricity cost changes (4–6%/year), Case 1 shows the most significant variations among the proposed systems.

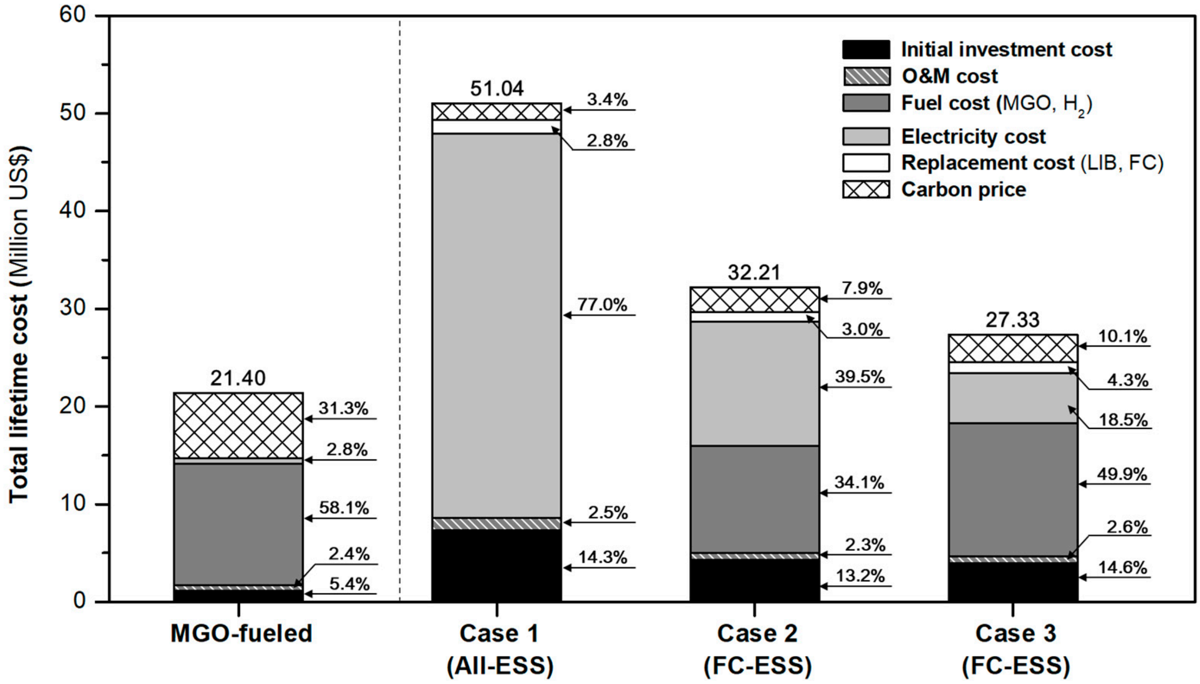


Figure 7. Distribution of the total lifetime costs for the conventional and proposed systems.

Table 15. The different results of the total lifetime costs according to fuel cost's variations.

Expected Annual Cost Change Rate of Fuel's Cost		Total Lifetime Cost (Million USD)			
		MGO-Fueled	Case 1 (All-ESS)	Case 2 (FC–ESS)	Case 3 (FC–ESS)
Hydrogen	−3.30%/year (−20% lower)	21.40	51.04	33.07	28.41
	−4.13%/year (base value)	21.40	51.04	32.21	27.33
	−4.96%/year (+20% higher)	21.40	51.04	31.43	26.37
Electricity	+4%/year (−20% lower)	21.33	46.53	30.74	26.76
	+5%/year (base value)	21.40	51.04	32.21	27.33
	+6%/year (+20% lower)	21.48	56.31	33.91	28.02

6.2. Environmental Comparison

Figure 8 presents the total lifecycle (WtW) GHG emissions for the conventional and the three proposed systems. The results revealed that the proposed systems are greener options even though they have higher WtT emissions than the conventional system. First, for the All-ESS system (Case 1), the WtW GHG emission was reduced by 74.3% compared with the conventional one. Additionally, for the FC–ESS system, the emission was reduced by 61.8% (Case 2) and 58.7% (Case 3).

Additionally, the total WtW GHG emissions could be changeable depending on the future hydrogen and electricity emission factors. For example, as shown in Table 16, if hydrogen's emission factor changes (−0.77% to −1.15%/year), the GHG reduction against the "MGO-fueled" would be 61.0–62.5% for Case 2, and 57.8–59.6% for Case 3. On the other hand, if electricity's emission factor changes (−5.54% to −8.30%/year), the GHG reduction in Case 1 against the "MGO-fueled" is 70.3–77.5%, which is a significant difference.

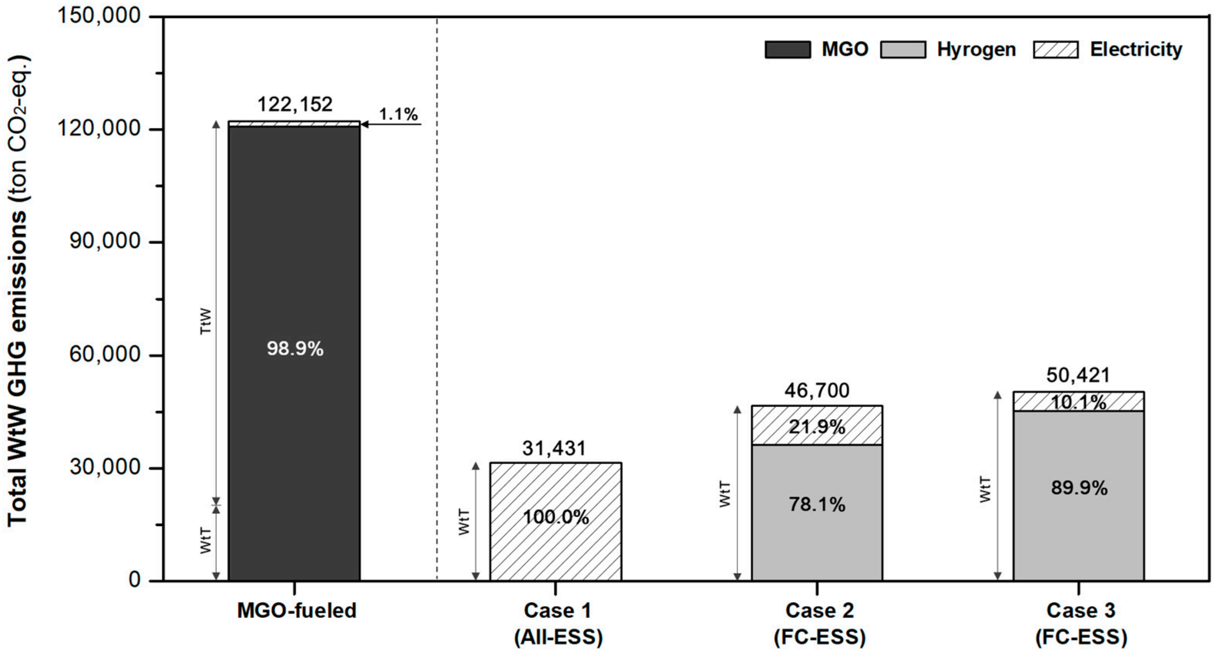


Figure 8. Distribution of the total WtW GHG emissions for the conventional and proposed systems.

Table 16. The different results of the total WtW GHG emissions according to emission factor's variations.

Expected Annual Change Rate of Fuel's Emission Factor		Total WtW GHG Emissions (ton $CO_2{}^{-eq.}$)			
		MGO-Fueled	Case 1 (All-ESS)	Case 2 (FC–ESS)	Case 3 (FC–ESS)
Hydrogen	−1.15%/year (−20% lower)	122,152	31,431	45,839	49,350
	−0.96%/year (base value)	122,152	31,431	46,700	50,421
	−0.77%/year (+20% higher)	122,152	31,431	47,587	51,525
Electricity	−8.30%/year (−20% lower)	121,984	27,424	45,394	49,773
	−6.92%/year (base value)	122,152	31,431	46,700	50,421
	−5.54%/year (+20% higher)	122,357	36,304	48,289	51,210

7. Conclusions and Future Work

This study proposed alternative power systems (All-ESS and FC–ESS) to realize a zero-emission tug and compared their economic and environmental impacts with those of the conventional system. For these systems, the optimal ESS capacity was determined by minimizing the lifetime cost of a ship. And in this study, lifecycle GHG emissions were investigated based on long-term policies in South Korea, which is not rich in renewable energy and is expected to increase green hydrogen imports from overseas. Although some assumptions and limited scope were employed, the following conclusions were drawn based on the analysis results.

For a ship's lifetime cost, the proposed ZESs were 1.7–3.4 times more expensive than the conventional one; however, it could be reduced by 1.3–2.4 times when the carbon price is considered.

From the fuel's lifecycle GHG emissions, the proposed ZESs had 58.7–74.3% lower than the conventional one, despite their higher WtT emissions.

Among the proposed ZESs, Case 3 (FC–ESS) would be the most economical option, whereas Case 1 (All-ESS) would be the most eco-friendly option.

The analysis results revealed that reducing the ship fuel's lifecycle GHG emissions is a step in the right direction. However, many institutional challenges still exist and need to be solved for the ZES, as follows.

Insufficient onshore electricity/hydrogen charging infrastructure for ZESs.

Unestablished electricity/hydrogen fee standard (or subsidies) for ZESs.
Undecided carbon pricing scheme for non-ZESs.

First, South Korea has been trying to expand its electricity- and hydrogen-charging infrastructure at ports [100,101]. In addition, the Korean Government is considering lowering hydrogen fuel fees to facilitate shipping companies adopting greener technologies [1]. And the IMO suggests that entry into the force of the carbon pricing might be in 2026 at the earliest [102]. Moreover, there are many technological or economic challenges that still exist for the FC or ESS, including:

Long-lifetime technologies with low-degradation rates for reducing replacement cost.
Safety-enhanced technologies for marine applications.
Competitive market price than other alternative solutions.

First, FC and ESS have a limited operating lifetime and must be replaced several times during a ship's lifetime. Therefore, extending their lifetime and reducing degradation rates to a reasonable level represent important priorities. Moreover, it is essential to ensure safe passage throughout a ship's voyage, requiring a safety-enhanced design for the FC and ESS. Additionally, FC and ESS for maritime applications are still expensive compared with the other industries because they have fewer production systems and higher requirements for the product. Nevertheless, the FC and ESS cost for ships is expected to drop further in the coming years as ZESs become more demanding in the market [5].

Lastly, since this study was conducted based on future assumptions, the following further research is needed to prove the effectiveness of this proposed system:

Economic/environmental comparison with other alternative measures for the ZES (ammonia, biofuel, etc.).
Environmental comparison with various hydrogen supply scenarios.
Environmental comparison, including the emissions from the manufacturing/production phase of FC or LIB.
Economic comparison with various institutional GHG emission reduction measures (GHG levy, incentives, etc.).

This study can be used to determine the optimal ZES options considering long-term economic and environmental impacts. In addition, it can contribute to deciding the level of subsidy for ZESs or the carbon price for non-ZESs. Finally, we hope that genuine ZESs will soon become common in South Korea upon overcoming the aforementioned challenges.

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