



Business Feasibility of LNG Distribution for Nias Gas Power Plants Using MCDM

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Abstract

Nias Island represents an isolated power system in Indonesia that still relies heavily on diesel-based generation, resulting in high operational costs and greenhouse gas emissions amid Indonesia's national energy transition toward Net Zero Emissions targets. Liquefied Natural Gas (LNG) is considered a transitional fuel to improve energy security and environmental performance in remote regions. This study aims to evaluate the business feasibility and infrastructure selection of LNG distribution for the Nias Gas Engine Power Plant by comparing an onshore terminal and a mini-Floating Storage Regasification Unit (FSRU). A quantitative decision-making approach using Multi-Criteria Decision Making (MCDM) with the Analytic Hierarchy Process (AHP) was applied, integrating technical, economic, and environmental criteria. Economic analysis includes NPV, IRR, and payback period, while environmental assessment follows IPCC 2006 emission guidelines. Findings show both alternatives are financially viable under an LNG price assumption of USD 7/MMBtu, with the FSRU generating higher NPV and IRR, while the onshore terminal demonstrates superior reliability and lower emissions. The study concludes that although both schemes are feasible, the onshore terminal is slightly preferred due to its stronger reliability and environmental performance, making it more aligned with long-term energy transition goals. Policy implications support Indonesia energy transition agenda acceleration.

INTRODUCTION

Indonesia has intensified its energy transition agenda following the ratification of the Paris Agreement, with national targets focused on reducing greenhouse gas emissions and achieving Net Zero Emission by 2060. Fossil-fuel-based power generation is a major emission contributor; accordingly, the government, through the National Energy General Plan (RUEN), plans to phase out diesel power plants (PLTD) to zero by no later than 2033.

Liquefied Natural Gas (LNG) is a relevant transition solution to replace diesel, particularly in island regions beyond the reach of gas pipeline networks. Natural gas has the lowest emission coefficient among fossil fuels (Agarwala, 2022; Balcombe et al., 2022), and liquefaction shrinks its volume roughly 600-fold, making maritime distribution to remote areas efficient. Indonesia holds significant potential for LNG development, supported by the discovery of new oil and gas reserves such as the North Ganal and South Andaman Blocks, as well as major projects including the Tangguh LNG Train-3, Indonesia Deepwater Development (IDD), and the Masela Block. Given that gas exploration is now increasingly concentrated in deepwater areas, monetization in the form of LNG is technically the more suitable pathway (Max & Johnson, 2018; Talipova & Parsegov, 2018; Yusuf & Al-Ansari, 2023).

Nias Island, part of an isolated power system under PT PLN (Persero) North Sumatra regional unit, represents the electrification challenge of 3T regions. In 2015 the island experienced an electricity crisis with a supply deficit of up to 74% following the shutdown of leased PLTD units. According to PLN's Electricity Supply Business Plan (RUPTL) 2025–2034, gas demand for the Nias PLTMG is projected to rise from 4.4 BBTUD to a peak of 7.4 BBTUD by 2034 with the addition of Nias PLTMG units 2 and 3 (PT PLN (Persero), 2025). Over the past decade, feasibility studies of LNG distribution for power generation have tended to emphasize only technical and economic aspects, without comprehensively considering environmental factors. Yet in energy infrastructure investment decisions in remote regions, these three aspects are interrelated and aligned with the spirit of the energy transition.

Previous studies on LNG distribution and receiving-terminal infrastructure have primarily focused on techno-economic optimization, route planning, and investment feasibility. Studies by Budiyanto et al. (2022; 2023) demonstrated the technical and economic feasibility of small-scale LNG distribution systems for remote power generation, while Giranza & Bergmann (2018), (Khoiriyah et al., 2023) and Ghazi et al. (2023) showed that floating LNG facilities may offer lower capital investment requirements than conventional onshore terminals. Similarly, Sommeng et al. (2023) and Pratama et al. (2025) highlighted the importance of logistics and infrastructure planning in LNG supply chains. However, these studies generally evaluated technical and economic aspects separately, with limited integration of environmental considerations into infrastructure selection decisions.

Multi-Criteria Decision Making (MCDM) has become an important approach in sustainable energy planning because infrastructure decisions often involve trade-offs among technical, economic, environmental, and operational objectives. Previous studies have shown that MCDM methods, particularly the Analytic Hierarchy Process (AHP), provide a systematic framework for evaluating energy alternatives and supporting investment decisions under uncertainty (Rezaei, 2021; Rocha et al., 2022; Sahoo et al., 2025; Siekelova et al., 2021; Zaheb et al., 2024). Recent developments have also integrated advanced techniques such as machine learning and fuzzy methods to improve decision robustness (Baran, 2026). However, most existing studies focus on energy-source selection, renewable-energy planning, or facility siting, while limited attention has been given to LNG distribution infrastructure selection that simultaneously incorporates technical reliability, economic feasibility, and environmental performance. This study addresses this gap by integrating AHP-based weighting, technical reliability indicators, and greenhouse gas emission assessment based on (Intergovernmental Panel on Climate Change, 2006) guidelines to evaluate LNG Onshore Terminal and Mini FSRU alternatives for the Nias PLTMG case.

Nias Island presents a particularly instructive case for this integration. As an isolated grid system entirely dependent on a single imported fuel source, any disruption to LNG delivery propagates immediately into generation shortfalls, unlike interconnected systems where alternative supply paths or grid balancing can absorb local disturbances. This structural vulnerability elevates the importance of distribution reliability as a decision criterion in a way that purely cost-driven feasibility studies tend to underweight. At the same time, the island's location along a monsoon-influenced shipping corridor with seasonal significant wave heights of 3–4 meters introduce a metocean constraint that interacts directly with the choice between an onshore terminal, which is shielded from open-sea transfer conditions, and an FSRU, which

depends on ship-to-ship transfer exposed to those same conditions. These context-specific factors justify treating Nias as a representative case for evaluating how technical risk, economic efficiency, and environmental performance jointly shape infrastructure recommendations in remote Indonesian island settings.

Beyond technical feasibility, LNG infrastructure development represents a strategic investment decision involving substantial capital allocation and long-term operational commitments. For isolated electricity systems such as Nias, selecting the most appropriate LNG distribution scheme requires balancing investment efficiency, operational reliability, and environmental sustainability. Therefore, infrastructure selection should be evaluated not only from an engineering perspective but also from a business feasibility and strategic decision-making perspective.

This study addresses that gap by simultaneously integrating technical, economic, and environmental aspects using the Multi-Criteria Decision Making (MCDM) method based on the Analytical Hierarchy Process (AHP). The objectives are (1) to analyze the feasibility of LNG distribution as a replacement for petroleum fuel at the Nias PLTMG across technical, economic, and environmental aspects; and (2) to apply MCDM-AHP to determine the best distribution scheme based on the established criteria weights.

METHOD

Case Study and Design Basis

The case study focused on the Nias PLTMG with a total capacity of 25–50 MW. LNG supply is planned from the Arun LNG Terminal as the nearest hub, with a shipping distance of 488.7 nautical miles through the western waters of North Sumatra. The capacity design basis is set at 7.7 BBTUD, derived from the maximum RUPTL demand projection (7.4 BBTUD) plus a 5% design margin to ensure reliable service through the end of the planning period.

The design basis parameters are organized into four groups reflecting the operating philosophy pillars established for the facility: security of supply (design capacity, margin, safety stock, shipping distance, vessel speed), operational reliability (availability, load profile, redundancy configuration), sustainability and future growth (plant lifetime, construction duration), and regulatory boundary conditions (depreciation method, corporate tax rate). These parameters, summarized in Table 1, apply identically to both the Onshore Terminal and Mini FSRU alternatives, ensuring that the subsequent technical, economic, and environmental comparisons are conducted on a consistent and unbiased basis. The selected design basis is also consistent with previous LNG infrastructure studies for the Nias power system conducted by (Wardhana, 2022), which identified LNG distribution as a technically feasible solution for supporting future electricity demand growth on the island.

The reliability philosophy adopted in both alternatives is based on the application of $n+1$ redundancy for critical equipment, ensuring that the failure of a single component does not interrupt LNG supply to the power plant. This approach is consistent with LNG receiving terminal design practices described by (Tarakad, 2000), where standby equipment is provided to maintain operational continuity and system availability.

Table 1. Design Basis and Key Parameters of the LNG Distribution Facility for the Nias PLTMG

Parameter	Unit	Value	Basis / Justification
Design capacity basis	BBTUD	7.4	Maximum RUPTL 2025–2034 demand projection
Design margin	%	+5	Best practice allowance for adequacy and future flexibility
Total design capacity	BBTUD	7.7	Design basis + margin
Safety stock	days	7	One full round-trip-time cycle under normal operation
Arun–Nias shipping distance	NM	488.7	Western North Sumatra route (Wardhana, 2022)
Design ship speed (min.)	knot	9	Conservative speed accounting for seasonal swell (Hs 3–4 m)
Plant availability	days/year	360	5 days/year planned maintenance downtime
Load profile	–	Base load	Continuous baseload operation per RUPTL 2025–2034
Critical equipment redundancy	–	n+1	Spare equipment on critical systems (Tarakad, 2000)
Plant design lifetime	years	20	Common practice for gas infrastructure projects
Construction duration	months	12	EPC duration estimate for small-scale facility in a 3T area
Corporate income tax rate	%	22	Indonesian Tax Harmonization Law No. 7/2021

Source: processed from RUPTL PLN (2025–2034) and Wardhana (2022)

Storage and ship sizing follow a bottom-up derivation from these parameters. The one-way sailing time at the minimum design speed of 9 knots over 488.7 nautical miles is 2.26 days, giving a round-trip sailing time of 4.52 days; adding a 2-day port time yields a total round trip of 6.52 days, rounded to 7 days as the conservative planning basis. The minimum buffer storage volume, equal to one full delivery cycle of daily demand ($355.2 \text{ m}^3/\text{day} \times 7 \text{ days}$), is $2,486 \text{ m}^3$, rounded up to a standard commercial tank size of $3,000 \text{ m}^3$. The corresponding carrier capacity of $2,500 \text{ m}^3$ yields an annual delivery frequency of 52 trips per year ($127,872 \text{ m}^3/\text{year} \div 2,500 \text{ m}^3/\text{trip}$), consistent with the 7-day round-trip assumption. Boil-off gas (BOG) loss during the one-way voyage, using a ship cargo tank BOG rate of 0.1%/day consistent with modern small-scale carriers as reported by Tarakad (2000), is calculated as $2,500 \times 0.001 \times 2.25 = 5.625 \text{ m}^3$, accumulating to 11.25 m^3 per round trip and $585 \text{ m}^3/\text{year}$ (0.45% of annual cargo throughput).

Distribution Scheme Alternatives

Two distribution scheme alternatives are evaluated. The first, the LNG Onshore Terminal scheme, uses a small-scale LNG carrier to an onshore receiving and regasification terminal with an independent storage tank. The second, the LNG Floating Storage Regasification Unit

(FSRU) scheme, uses a floating unit that receives cargo via ship-to-ship transfer and regasifies offshore. Both schemes are designed with identical operating philosophy, design capacity, safety standards, and performance targets to ensure objective and consistent evaluation.

In the Onshore Terminal scheme, LNG is pumped from storage tanks to an Ambient Air Vaporizer (AAV), which uses ambient heat to regasify the LNG before it is metered and piped a short distance to the power plant; boil-off gas formed in the tanks is routed through a BOG heater and compressed before injection into the gas line. In the Mini FSRU scheme, LNG is transferred from the carrier via ship-to-ship transfer to a moored floating unit equipped with its own storage, pumps, and an Open Rack Vaporizer (ORV) that uses seawater heat for regasification; gas metering is located onshore to simplify operation and monitoring. Both configurations employ n+1 redundancy on critical pumps and vaporizers (two running, one standby) and share an identical LNG carrier specification of 2,500 m³ capacity. Table 2 summarizes the principal equipment differences between the two schemes.

Table 2. Key Equipment and Facility Comparison Between the Two Distribution Schemes

Component	Onshore Terminal (Scheme A)	Mini FSRU (Scheme B)
Receiving facility	Land-based storage + regasification plant	Floating storage and regasification unit
LNG storage	3 × 1,000 m ³ tanks (3,000 m ³ total)	3 × 1,000 m ³ tanks on FSRU (3,000 m ³ total)
Vaporizer type	Ambient Air Vaporizer (AAV), 3 × 180 m ³ /day	Open Rack Vaporizer (ORV), 3 × 180 m ³ /day
LNG receiving method	Direct unloading via jetty/SPM to land tank	Ship-to-ship transfer or direct unloading to FSRU
Land requirement	Large (tank farm, regas plant, utilities)	Minimal (small onshore receiving point only)
Gas delivery to plant	Short onshore pipeline (300 m)	Subsea pipeline to shore

Source: processed from thesis design data

Assessment Criteria

Technical criteria cover LNG demand fulfilment capacity, system efficiency, operational reliability, and infrastructure readiness. Economic criteria are evaluated using Capital Expenditure (CAPEX) estimation via the six-tenths rule and Chemical Engineering Plant Cost Index (CEPCI) adjustment, Operating Expenditure (OPEX), and the feasibility indicators Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period (PBP). Environmental criteria cover distribution-chain GHG emissions (following IPCC 2006 guidelines), emission intensity, and air and marine pollution risk.

MCDM-AHP Method

The AHP is structured in three hierarchy levels: goal, main criteria with sub-criteria, and alternative ranking. Weighting is based on a literature review and theoretical considerations. The consistency of each pairwise comparison matrix is tested via the Consistency Ratio (CR), with all matrices yielding $CR \leq 0.10$, confirming consistent judgments. The final global priority score is computed by multiplying each sub-criterion's global weight by each alternative's

relative score, then summing. A sensitivity analysis across four weighting scenarios tests the robustness of the recommendation.

Pairwise comparisons follow (Saaty, 2008) nine-point intensity scale, where a value of 1 denotes equal importance, 3 denotes one criterion being slightly more important, 5 denotes moderate dominance, 7 strong dominance, and 9 extreme dominances, with reciprocal values applied for the inverse comparison. For each comparison matrix, the principal eigenvalue (λ_{max}) is estimated from the column-sum normalization procedure, and the Consistency Index is calculated as $CI = (\lambda_{max} - n) / (n - 1)$, where n is the matrix dimension. The Consistency Ratio is then obtained by dividing CI by the random consistency index for matrices of the same size ($CR = CI / RI$); a CR value at or below 0.10 indicates that the pairwise judgments are sufficiently consistent to proceed with weight extraction. Table 5 presents the pairwise comparison matrix for the three main criteria, reflecting the judgment that technical performance is slightly more important than economic performance (value 3) and moderately more important than environmental performance (value 5), while economic performance is judged slightly more important than environmental performance (value 3).

Table 3. Pairwise Comparison Matrix of Main Criteria

Criterion	Technical	Economic	Environmental
Technical	1	3	5
Economic	1/3	1	3
Environmental	1/5	1/3	1

Source: AHP scale of Saaty (2008), informed by literature review

Normalizing each column of the pairwise matrix and averaging across rows yields the priority weight vector shown in Table 6, with Technical receiving the highest weight (63.3%), followed by Economic (26.1%) and Environmental (10.6%). The same pairwise-comparison and normalization procedure is then repeated independently within each criterion to derive sub-criteria weights: for the Technical criterion, Distribution Reliability is weighted highest (58.9%) given its direct bearing on continuity of fuel supply to an isolated grid, followed by System Efficiency (25.2%) and Infrastructure Readiness (15.9%); for the Economic criterion, NPV receives the highest weight (53.9%) for its comprehensive representation of project value, followed by IRR (29.7%) and Payback Period (16.4%); and for the Environmental criterion, GHG Emissions receives the highest weight (64.8%), followed by Air Pollution Potential (23.0%) and Soil/Marine Pollution Potential (12.2%). All resulting sub-criteria matrices satisfy $CR \leq 0.10$ (Technical $CR = 0.047$; Economic $CR = 0.0079$; Environmental $CR = 0.0032$), confirming consistent judgments throughout the hierarchy.

Table 4. Main Criteria Weights ($\lambda_{max} = 3.039$, $CI = 0.020$, $CR = 0.033 \leq 0.10$)

Criterion	Priority Weight	Wi (%)
Technical	0.6333	63.3
Economic	0.2605	26.1
Environmental	0.1062	10.6

Source: Saaty (2008) AHP method; literature-based expert judgment (MCDM studies)

RESULTS AND DISCUSSION

Technical Analysis

Both schemes are technically capable of meeting the 7.7 BBTUD LNG distribution demand for the Nias PLTMG using a 2,500 m³ small-scale LNG carrier on the Arun–Nias route. The key difference lies in reliability characteristics: the LNG Onshore Terminal scheme excels in distribution reliability owing to its independent onshore safety stock and immunity to metocean conditions, whereas the LNG Floating Storage Regasification Unit scheme excels in system efficiency and infrastructure readiness due to shorter commissioning time and no requirement for extensive land acquisition.

System efficiency, assessed through boil-off gas loss, is marginally better in the Onshore Terminal scheme because shore-based cryogenic tanks achieve better thermal insulation than a floating unit exposed to seawater temperature, yielding a storage BOG rate of 0.05%/day for the Onshore Terminal versus 0.10%/day for the Mini FSRU; voyage BOG loss is identical for both schemes at 0.10%/day because both employ the same carrier specification. Reliability differences are more consequential operationally. Four structural factors distinguish the two schemes: first, IMO and classification-society rules require FSRU dry-docking every five years for 30–60 days, equivalent to roughly 6–12 days/year of planned downtime during which the Mini FSRU scheme has no terminal-side buffer, whereas the Onshore Terminal's carrier can be substituted during maintenance while the shore tank continues to supply the plant; second, ship-to-ship transfer in open water is constrained by an internationally recognized significant wave height (H_s) limit of 2.5 meters, while Nias's exposure to Indian Ocean swell of 3–4 meters during the November–March monsoon could curtail roughly 8–9 STS transfers per year under the FSRU scheme; and third, the Onshore Terminal's 3,000 m³ shore tank can be filled to capacity independently of vessel schedules, providing a genuinely independent 7-day safety stock, whereas the FSRU's safety stock resides within the same floating asset that is also the receiving point, leaving no separate buffer during disruptions. Infrastructure readiness favors the Mini FSRU, which avoids extensive land acquisition and can be commissioned faster, a material advantage in the land-constrained 3T setting of Nias.

Economic Analysis

Both schemes are financially viable at 7.7 BBTUD, indicated by positive NPV and IRR exceeding the 11% discount rate. However, their economic performance differs: the LNG Floating Storage Regasification Unit scheme shows superior performance, driven mainly by lower CAPEX despite higher OPEX. A summary of economic indicators is presented in Table 3.

CAPEX was estimated using reference cost data reported by Wardhana (2022) for a 5.17 BBTUD facility, scaled to the 7.7 BBTUD design capacity of this study. Applying the Six-Tenths Rule, $C_2/C_1 = (Q_2/Q_1)^{0.6}$, with $Q_2 = 7.7$ BBTUD and $Q_1 = 5.17$ BBTUD, yields a capacity scaling factor of 1.270. The resulting cost was then adjusted to current economic conditions using the Chemical Engineering Plant Cost Index (CEPCI), with CEPCI values of 816.0 (2022, reference year) and 800.2 (2024, projection year), giving a correction factor of 0.9806. The combined adjustment factor is therefore $1.270 \times 0.9806 = 1.245$, applied multiplicatively to the reference CAPEX values of USD 37,554,257 (Onshore Terminal) and USD 25,975,341 (Mini FSRU) to obtain the adjusted CAPEX figures of USD 46,755,050 and

USD 32,339,300 respectively. LNG carrier charter costs and OPEX were not scaled using the same factor, since these costs depend on voyage frequency, charter rate, and labor/maintenance structures that do not follow the same capacity-cost relationship as fixed plant investment; they were instead estimated directly from the operational parameters of this study. Table 3 summarizes the resulting economic indicators at the 7.7 BBTUD design capacity.

Table 5. Economic Indicators for the 7.7 BBTUD Design Capacity

Indicator	Onshore Terminal (A)	Mini FSRU (B)
CAPEX (USD)	46,755,050	32,339,300
CAPEX annuity (USD/year)	6,259,509	4,329,546
LNG carrier charter (USD/year)	8,476,464	8,476,464
OPEX (USD/year)	1,459,833	6,734,524
Gas sales price (USD/MMBtu)	7	7
NPV (USD)	11,445,577	21,439,673
IRR (%)	13	17
Payback Period (years)	12.22	8.09

Source: processed from Wardhana (2022), adjusted with Six-Tenths Rule and CEPCI

Despite a 44.6% higher CAPEX for the Onshore Terminal scheme relative to the Mini FSRU (USD 46.76 million versus USD 32.34 million), the Mini FSRU's substantially higher OPEX (USD 6.73 million/year versus USD 1.46 million/year, driven primarily by additional regasification energy consumption and floating-asset maintenance) narrows the gap in overall project economics. With an identical assumed gas sales price of USD 7/MMBtu, the lower upfront capital requirement of the Mini FSRU translates into superior capital efficiency: NPV of USD 21.44 million versus USD 11.45 million, IRR of 17% versus 13%, and a payback period of 8.09 years versus 12.22 years for the Onshore Terminal. The break-even infrastructure fee required for each scheme to reach the 11% discount-rate threshold is approximately USD 5.1477/MMBtu for the Onshore Terminal and USD 5.1655/MMBtu for the Mini FSRU a difference of only about 0.3%, indicating that on pure cost-recovery grounds the two schemes are nearly indistinguishable and that the more decisive separation in capital efficiency emerges only once full project NPV, IRR, and payback dynamics are considered jointly.

Environmental Analysis

Emission calculations were developed in accordance with the methodological framework provided by the IPCC (2006), ensuring consistency with internationally accepted greenhouse gas inventory practices.

The LNG distribution-chain GHG emissions are estimated at 180,193 tCO₂eq/year for the LNG Onshore Terminal scheme and 183,391 tCO₂eq/year for the LNG Floating Storage Regasification Unit scheme. Compared with the diesel PLTD baseline of 324,000 tCO₂eq/year, both schemes reduce emissions by 44.3% and 43.4% respectively. Emission intensities are 521 and 530 g CO₂eq/kWh; although still above the best practice of modern combined-cycle gas plants (CCGT, 400–500 g/kWh), both are far lower than diesel (938 g CO₂eq/kWh). The LNG

Onshore Terminal scheme shows slightly better emission-reduction performance and marine-pollution risk profile.

Emissions were quantified using a bottom-up GHG Protocol approach across Scope 1 (ship HFO combustion, fugitive BOG, and LNG combustion at the power plant) and Scope 2 (electricity consumption for regasification), following IPCC (2006) emission factors and AR5 100-year global warming potentials ($\text{CH}_4 = 28$, $\text{N}_2\text{O} = 265$). Table 4 disaggregates total chain emissions into five sources. Ship HFO combustion (5,782 tCO₂eq/year) and voyage BOG (3,698 tCO₂eq/year) are identical across both schemes because the carrier specification and route are unchanged. Regasification electricity consumption is the first scheme-specific source, contributing 345 tCO₂eq/year exclusively to the Mini FSRU because its Open Rack Vaporizer (ORV) requires powered seawater circulation pumps, whereas the Onshore Terminal's Ambient Air Vaporizer (AAV) relies on passive heat exchange and contributes zero. Storage BOG is the second and larger differentiator, at 2,850 tCO₂eq/year for the Onshore Terminal versus 5,703 tCO₂eq/year for the Mini FSRU a gap of 2,853 tCO₂eq/year attributable to the FSRU's higher thermal exposure to ambient seawater. Combustion of delivered LNG at the PLTMG itself, at 167,863 tCO₂eq/year, dominates the total but is identical for both schemes since electricity output and fuel consumption at the plant are unaffected by the choice of upstream distribution scheme. The cumulative effect of the two scheme-specific sources yields a net difference of 3,198 tCO₂eq/year in favor of the Onshore Terminal.

Table 4. Distribution-Chain GHG Emission Breakdown by Source (tCO₂eq/year)

Emission Source	Scope	Onshore (A)	Mini FSRU (B)	Δ (B–A)
Ship HFO combustion	1	5,782	5,782	0
Regasification electricity	2	0	345	+345
BOG – voyage	1	3,698	3,698	0
BOG – storage	1	2,850	5,703	+2,853
LNG combustion at PLTMG	1	167,863	167,863	0
Total chain GHG emission	–	180,193	183,391	+3,198
Diesel PLTD baseline	–	324,000	324,000	–
Reduction vs. diesel (%)	–	44.3	43.4	–

Source: processed using IPCC (2006) emission factors and AR5 100-year global warming potentials

Beyond GHG emissions, qualitative risk assessment of air pollution and marine/soil pollution potential favors the Onshore Terminal on both counts. For air pollution, the Onshore Terminal benefits from a permanent fire-and-gas detection system and vapor recovery unit (VRU) capability that is more difficult to replicate on a floating asset, while the Mini FSRU carries residual risk of BOG release to the open atmosphere during severe weather or onboard power disruption. For marine and soil pollution, the Onshore Terminal's near-shore transfer location allows faster spill response and avoids the open-sea ship-to-ship transfer risk inherent to the Mini FSRU, while the FSRU's seawater-based ORV regasification introduces a moderate cold-shock risk to marine biota from the discharge of chilled water, a risk absent from the Onshore Terminal's air-based vaporization. These qualitative risk differentials, together with

the quantitative emission gap, are carried forward as scored inputs into the environmental sub-criteria of the MCDM-AHP integration in the following section.

MCDM-AHP Results

Main-criteria weighting yields Technical 63.3%, Economic 26.1%, and Environmental 10.6%, with all matrices satisfying $CR \leq 0.10$. Based on the aggregation, the LNG Onshore Terminal scheme obtains a final score of 0.5118 and the LNG Floating Storage Regasification Unit scheme 0.4882. The advantage of the LNG Onshore Terminal scheme is driven by its performance on high-weight sub-criteria, namely distribution reliability and GHG emissions plus marine-pollution risk.

The sensitivity analysis across four weighting scenarios (Table 7) shows the recommendation for the LNG Onshore Terminal scheme is robust in three scenarios Base Case, Balanced, and Environment-Dominant. Only under the Economy-Dominant scenario, where the economic weight is significantly increased, does the LNG Floating Storage Regasification Unit scheme prevail. The relatively small score gap (below 0.03 in the base case) indicates both schemes compete closely and are feasible technically, economically, and environmentally.

The final global priority score for each alternative is computed by multiplying, for every sub-criterion, the global weight (main-criterion weight \times sub-criterion weight) by the alternative's normalized performance score, then summing across all nine sub-criteria. Normalized scores were obtained by dividing each alternative's raw 1–9 performance score (assigned based on the technical, economic, and environmental results above) by the sum of both alternatives' raw scores for that sub-criterion. Under this procedure, the Onshore Terminal scheme's largest score contributions arise from Distribution Reliability (0.2131, given the global weight of 0.3730 and a favorable normalized score of 0.5714) and GHG Emissions (0.0393, global weight 0.0688), while the Mini FSRU's largest contributions arise from System Efficiency (0.0851) and NPV (0.0749), reflecting its lower upfront capital requirement. Summing across all nine sub-criteria yields the final scores of 0.5118 for the Onshore Terminal and 0.4882 for the Mini FSRU, a gap of 0.0236 that, while decisive enough to produce a clear ranking, remains small relative to the total score scale underscoring that both alternatives are genuinely competitive once technical, economic, and environmental dimensions are weighed jointly rather than considered separately.

To test the robustness of this ranking against the subjectivity inherent in literature-based criteria weighting, four weighting scenarios were constructed (Table 7): the Base Case reflecting the original AHP-derived weights (Technical 63.3%, Economic 26.1%, Environmental 10.6%); an Economy-Dominant scenario representing a private-investor perspective prioritizing capital return (Technical 32.0%, Economic 55.7%, Environmental 12.3%); a Balanced scenario representing an equal-weight public-policy perspective (33.3% each); and an Environment-Dominant scenario anticipating stricter future environmental regulation (Technical 30.0%, Economic 23.3%, Environmental 46.7%). Sub-criteria weights within each main criterion were held constant across all scenarios, with only the main-criteria weights varied.

Table 5. Weighting Scenarios for Sensitivity Analysis

Criterion	Scenario 1 (Base)	Scenario 2 (Econ-Dom.)	Scenario 3 (Balanced)	Scenario 4 (Env-Dom.)
Technical	63.3%	32.0%	33.3%	30.0%
Economic	26.1%	55.7%	33.3%	23.3%
Environmental	10.6%	12.3%	33.3%	46.7%

Table 6. Final MCDM-AHP Scores Across Four Weighting Scenarios

Scenario	Score A	Score B	Gap (A–B)	Preferred
1 – Base Case (AHP)	0.5118	0.4882	+0.0236	A (Onshore)
2 – Economy-Dominant	0.4959	0.5041	–0.0082	B (Mini FSRU)
3 – Balanced	0.5163	0.4837	+0.0326	A (Onshore)
4 – Environment-Dominant	0.5268	0.4732	+0.0536	A (Onshore)

From a business feasibility perspective, the results indicate that both LNG distribution schemes are capable of generating positive economic returns while supporting the energy transition agenda. Although the difference between the final MCDM-AHP scores is relatively small, the findings suggest that investment decisions should not rely solely on financial indicators. For isolated power systems such as Nias, reliability and environmental performance play a significant role because disruptions in fuel supply may directly affect electricity generation and energy security.

The higher ranking of the LNG Onshore Terminal alternative is primarily driven by its superior distribution reliability and lower environmental impact. While the Mini FSRU alternative demonstrates stronger economic indicators, particularly NPV and IRR, its operational dependence on offshore transfer activities may expose the system to greater supply risks under adverse weather conditions. This trade-off illustrates the importance of integrating technical, economic, and environmental criteria within a unified decision-making framework.

From a strategic management perspective, the findings demonstrate that infrastructure investment decisions in remote regions require a broader evaluation framework than conventional financial feasibility analysis. The integration of technical reliability and environmental sustainability can improve long-term project resilience and support stakeholder expectations regarding energy security and decarbonization.

From a policy standpoint, the result reinforces the relevance of integrating environmental weighting into infrastructure feasibility studies as Indonesia pursues its NZE 2060 commitment. Although both schemes reduce emissions by more than 43% relative to the diesel baseline, the Onshore Terminal scheme's additional emission-reduction margin and lower marine-pollution exposure align more closely with long-term decarbonization objectives. The sensitivity analysis further shows that this recommendation only reverses when the economic weight is pushed well beyond its literature-based baseline, suggesting that the result is not an artefact of the chosen weighting but a genuinely close competition between two technically and financially viable alternatives.

CONCLUSION

Based on the results of this study, LNG distribution can be considered a feasible alternative to replace diesel fuel in the Nias Gas Engine Power Plant (PLTMG). Both evaluated distribution schemes satisfy the technical requirements of a 7.7 BBTUD demand and demonstrate positive economic feasibility under the same gas selling price assumption of USD 7/MMBtu. The LNG Onshore Terminal scheme requires a higher capital investment of USD 46.76 million, resulting in an NPV of USD 11.45 million, an IRR of 13%, and a payback period of 12.22 years. In contrast, the Mini FSRU scheme requires a lower capital investment of USD 32.34 million and provides stronger financial performance, with an NPV of USD 21.44 million, an IRR of 17%, and a payback period of 8.09 years. These results indicate that both alternatives are financially attractive, although the Mini FSRU alternative offers superior capital efficiency. However, when technical, economic, and environmental considerations are evaluated simultaneously using the MCDM-AHP framework, the LNG Onshore Terminal alternative achieves a higher overall score (0.5118) than the Mini FSRU alternative (0.4882). The result is primarily driven by its stronger distribution reliability and lower greenhouse gas emissions, which are particularly important for an isolated power system such as Nias. Therefore, the LNG Onshore Terminal scheme is recommended as the preferred long-term solution for LNG distribution to the Nias PLTMG. This study demonstrates that infrastructure investment decisions should not be based solely on financial performance indicators. The integration of technical reliability, economic feasibility, and environmental sustainability provides a more comprehensive basis for selecting energy infrastructure alternatives in remote island regions and supports Indonesia's long-term energy transition and Net Zero Emission objectives.

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