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Research Article

Quantitative Cost–Benefit Analysis of an Integrated HVDC and Fiber-Optic Interconnection Between the Dominican Republic and Puerto Rico

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Abstract

Island electricity systems in the Caribbean are characterized by high fuel import dependency, limited economies of scale, infrastructure vulnerability, and elevated generation costs. This paper presents a quantitative cost–benefit analysis of a proposed 700 MW voltage source converter high-voltage direct current (VSC-HVDC) submarine interconnection between the Dominican Republic (DR) and Puerto Rico (PR) over a 160 km route, incorporating the integration of fiber-optic telecommunications infrastructure under a joint public–private partnership (PPP) model. A comparative expansion-planning framework evaluates three scenarios: independent development, HVDC with localized generation in PR, and HVDC with generation expansion in DR exporting to PR. The deterministic discounted cash flow (DCF) model includes capital expenditures, fuel cost differentials, reserve sharing, avoided capacity investments, renewable integration value, and reliability monetization. Results indicate near-breakeven economics under conservative assumptions. When integrated fiber-optic revenues and diversified PPP structuring are incorporated, the project achieves positive net present value (NPV) and improved bankability. The findings demonstrate that coordinated energy–digital infrastructure deployment enhances economic viability, system resilience, and regional integration potential for Caribbean island systems. Some benefits of the interconnection between the Dominican Republic and Puerto Rico are: (1) Immediate generation of economy of scale through reserves reduction, in terms of auxiliary or peak plants and emergency centrals, and more efficient operation of electrical systems; (2) Optimal use of each country's natural resources through abundant, safe, and renewable electricity generation; (3) Increased investment in clean energy and financial support from multilateral financing banks; (4) Greater foreign exchange earnings for countries from energy sales in various electricity markets; and (5) Possibility of future interconnection with existing regional markets, such as the Electrical Interconnection System of the Countries of Central America and integration into its Regional Electrical Market.

Keywords

VSC-HVDC, Submarine Transmission, Cost–benefit Analysis, Reserve Sharing, Reliability Valuation, Fiber-optic Integration, Public–private Partnership, Island Grids

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1. Introduction

Islander power systems exhibit structural limitations including restricted generation diversity, high dependence on imported fuels, and limited reserve sharing capability [1, 2]. These conditions result in elevated levelized costs of electricity and reduced operational flexibility.

The DR–PR corridor has been identified as a technically feasible candidate for submarine HVDC interconnection [1]. Modern VSC-HVDC technology enables asynchronous interconnection, independent reactive control, and fast active power modulation, making it suitable for medium-distance submarine applications [3, 4].

Recent offshore transmission cost modeling and renewable integration studies provide updated cost benchmarks and system adequacy frameworks [5, 8]. Additionally, integrated subsea power–fiber infrastructure has been shown to improve financial viability through diversified revenue streams [6, 7].

This study develops a structured quantitative evaluation incorporating both energy system economics and telecom integration.

2. Objective

The objective is to quantify the techno-economic viability of a 700 MW, 160 km VSC-HVDC interconnection between DR and PR, incorporating integrated fiber-optic infrastructure and PPP financial structuring.

Specifically, the study:
1) Compares three expansion scenarios
2) Quantifies HVDC and generation CAPEX
3) Evaluates fuel and reserve savings
4) Monetizes reliability benefits
5) Assesses telecom revenue potential
6) Develop a PPP capital structure model

3. Methodology

3.1. Comparative Scenarios

We evaluate three structured scenarios:

Scenario A (Baseline): Independent national expansion [1]. Tables 1 and 2 present the profiles of the Dominican and Puerto Rican electricity markets. From 2019 to 2025.

Scenario B: HVDC installed: Puerto Rico expands local generation, and the Dominican Republic continue with its power system development due to the excellent growth of the country.

Scenario C: HVDC installed: Dominican Republic expands generation and exports power, while Puerto Rico pursue expansion of its renewable resources.

The evaluation adopts a total-system cost perspective consistent with regional integration principles [2].

Table 1. *Profile of the Dominican Republic's Power System [1].*

Profile of the Dominican Republic's Power System					
Year	**Total Installed Capacity (MW)**	**Peak Demand (MW)**	**Renewable Capacity (MW)**	**Renewable Share (%)**	**Notes / Source**
2019	4870	2506	1184	24,3	MEM / CNE / IRENA
2020	5000	2600	1200	24,0	MEM / IRENA
2021	5300	2800	1300	24,5	MEM
2022	5600	3000	1450	25,9	MEM / CNE
2023	5900	3200	1600	27,1	MEM
2024	6200	3640	1750	28,2	MEM Annual Report 2024
2025	6423	3252	1850	24,5	MEM Monthly Bulletin / CNE Jun-2025

MEM: Ministry of Energy and Mines; CNE: Energy National Commission; IRENA: International Renewable Energy Agency

Source: F. H. Núñez-Ramírez, "Strategic Rationale for the Interconnection of the Dominican Republic and Puerto Rico Electricity Markets Through HVDC," 2026. *American Journal of Electrical Power and Energy Systems, 2026.* https://doi.org/10.11648/j.epes.20261501.12

Table 2. *Profile of Puerto Rico's Power System [1].*

Profile of the Puerto Rico's Power System					
Year	**Total Installed Capacity (MW)**	**Peak Demand (MW)**	**Renewable Capacity (MW)**	**Renewable Share (%)**	**Notes / Source**
2019	5839	2866	307	5,2	PREPA / EIA
2020	5800	2800	320	5,5	EIA
2021	5750	2700	550	9,6	EIA / Distributed PV
2022	5900	2600	800	13,6	EIA / LUMA
2023	6100	2550	1000	16,4	LUMA / PREB
2024	6300	2512	1150	18,3	LUMA Dec-2024 Report
2025	6300	2900	1230	19,5	LUMA / DOE /PREB Mid-2025

PREPA: Puerto Rico Electric Power Authority; EIA: Energy Information Administration; LUMA Energy: Private Company of Transmission and Distributions System in Puerto Rico; DOE: Department of Energy

Source: F. H. Núñez-Ramírez, "Strategic Rationale for the Interconnection of the Dominican Republic and Puerto Rico Electricity Markets Through HVDC," 2026. *American Journal of Electrical Power and Energy Systems, 2026.* https://doi.org/10.11648/j.epes.20261501.12

3.2. Technical and Financial Assumptions

1) HVDC capacity: 700 MW
2) Route length: 160 km
3) Cable cost: $1.5M/km
4) Converter stations: $400M each
5) Generation CAPEX (CCGT): DR $1,000/kW; PR $1,300/kW
6) Capacity factor: 70%
7) Horizon: 25 years
8) Discount rate: 8% (6–10% sensitivity)
9) Fuel differential: $5/MWh base
10) VOLL: $1,000/MWh

These assumptions align with contemporary submarine HVDC cost benchmarks [5, 8].

3.3. Deterministic Economic Model Formulation

The model applies deterministic discounted cash flow (DCF) analysis.

Capital Expenditure (CAPEX)

$CAPEX_{Total} + CAPEX_{HVDC} + \sum CAPEX_{Gen,i}$

Operational Expenditure (OPEX)

$OPEX_t = Fuel_t + VOM_T + Fixed\ O\&M_t$

Net Present Value (NPV)

$$NPV = \sum_{t=1}^{25} \frac{(Benefits_t - Costs_t)}{(1+r)^t}$$

Benefit – Cost Ratio

$$BCR = \frac{\sum \frac{Benefits_t}{(1+r)^t}}{\sum \frac{Costs_t}{(1+r)^t}}$$

Avoided Capacity

$ACC = \Delta MW_{AVOIDED}\ x\ Cost_{unit}$

Fuel Savings

$Fuel\_Savings_t = Energy\_Delivered\ x\ \Delta c_{fuel}$

Expected Energy Not Served (EENS)

$$EENS = \sum_h Prob_{shortage}(h) \times Deficit_{MWh}(h)$$

Reliability Monetization

$Benefit_{reliability} = EENS\ x\ VOLL$

3.4. Reliability and Dynamic Benefits Modeling Approach

Basis for the 10 GWh/year EENS Estimate

The assumed 10 GWh/year reduction in Expected Energy Not Served (EENS) was derived from a simplified adequacy approximation consistent with probabilistic resource adequacy frameworks.

Rather than performing a full LOLE/ELCC simulation, a first-order estimate was developed using:

1) Historical outage magnitudes in Caribbean island systems
2) Typical Loss of Load Expectation (LOLE) benchmarks for isolated grids
3) Effective Load Carrying Capability (ELCC) proxy of firm HVDC transfer

Island systems comparable to PR and DR typically exhibit annual EENS levels in the range of 30–80 GWh/year under tight reserve margins (≈ 10–15%) [9, 11].

Assuming:

1) 700 MW firm interconnection capacity
2) 200 MW of effective reserve sharing contribution
3) 0.5% reduction in annual energy-at-risk

Total annual demand of PR ≈ 20 TWh

A 0.05%–0.1% reduction in annual unserved energy corresponds to:

20,000 GWh × 0.0005 = 10 GWh/year

This magnitude is consistent with adequacy improvements observed in interconnection studies for medium-sized island grids and remains intentionally conservative relative to the theoretical firm import capability of the HVDC link.

Accordingly, the 10 GWh/year assumption reflects a modest reliability gain equivalent to approximately:

One 200 MW contingency event mitigated for 50 hours/year

or

Several short-duration reserve deficit events avoided annually

This approach aligns with deterministic monetization of probabilistic adequacy improvements without overstating benefits.

Beyond deterministic cost comparison, the interconnection provides dynamic and adequacy-related benefits.

These include:

1) Reduced reserve margin requirements
2) Fast frequency response capability
3) Synthetic inertia support
4) Voltage regulation
5) Rapid contingency ramping

Dynamic benefits are conservatively monetized through:

1) Reduced spinning reserve procurement
2) Reduced EENS
3) Deferred investment in reactive compensation

While the present study uses deterministic valuation, these mechanisms are consistent with probabilistic adequacy modeling methodologies [3, 9].

4. Results

4.1. HVDC CAPEX

Submarine cable: $240M
Converters: $800M
Total: $1.04B
Consistent with NREL offshore cost modeling [5].

4.2. Generation Differential

DR CCGT (700 MW): $700M
PR CCGT (700 MW): $910M
Advantage: ≈ $210M.

4.3. Fuel Savings

$E_{ann} = 700 \times 0.70 \times 8760 = 4.29$ TWh

Annual savings:

$4.29 \times 10^6 \times 5 = 21.45$ *MUSD/year*

NPV ≈ $250MUSD

4.4. Avoided Capacity

If PR reduces local requirement by 200 MW:

200,000 x 1,300 = 260 MUSD

4.5. Reliability Benefit

10 GWh/year avoided unserved energy:

10,000 x 1,000 = 10 MUSD

NPV ≈ $10MUSD

4.6. Fiber-Optic Integration

Incremental CAPEX: $2–6M [6]

Consistent with recent global submarine cable deployment benchmarks and cost structures reported by international telecom authorities [15].

Annual telecom revenue (8 fiber pairs): 6MUSD/year, consistent with regional bandwidth demand growth trends and projected inter-island data traffic expansion [15].

6MUSD/year

NPV ≈ $6MUSD

This revenue stream effectively closes the breakeven gap identified in the base-case energy-only analysis.

The Caribbean region exhibits increasing strategic importance for submarine data corridors, and integrated power–fiber deployment reduces marginal installation costs while improving digital resilience [15].

5. Joint Energy–Telecom PPP Structure

Capital Structure

1) Energy equity: 30%
2) Telecom equity: 10%
3) Multilateral debt: 40%
4) Commercial debt: 20%

Table 3. Capital structure.

Capital Structure	
Component	**Share**
Energy Equity	30%
Telecom Equity	10%
Multilateral Debt	40%

Capital Structure	
Component	**Share**
Commercial Debt	20%
Total	100%

Source: Author

Diversified revenue improves IRR and DSCR metrics and aligns with blended financing frameworks recommended for large-scale infrastructure in Small Island Developing States (SIDS) [7, 10, 13].

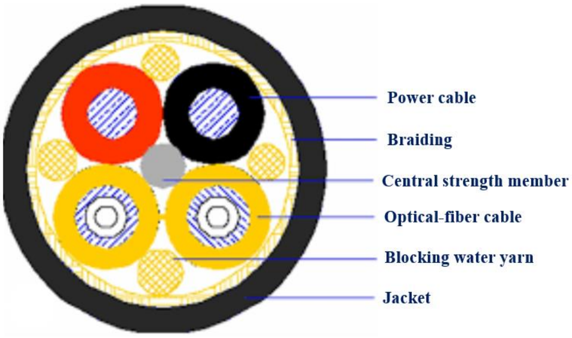

Figure 1. *Schematic cross-section of HVDC power and optical-fiber cable.*

Source: High-Voltage Submarine Power Cables: Driving the Global Energy Transition. SSC Subsea Cables. October 20, 2025. Available: https://www.subseacables.net [16].

The proposed capital structure reflects financing models commonly applied in island infrastructure projects, where multilateral development banks reduce sovereign risk exposure and improve debt tenors [13]. Such structures are particularly relevant for Caribbean SIDS seeking capital-intensive interconnection projects.

6. Dynamic Stability and Frequency Support

6.1. Asynchronous Decoupling

VSC-HVDC electrically decouples asynchronous AC systems. Frequency and phase dynamics remain local, preventing disturbance propagation and reducing oscillatory instability.

6.2. Fast Frequency Response and Synthetic Inertia

Fast frequency response capability:

$$\Delta P = K_f \Delta f$$

VSC-HVDC enhances frequency response and voltage stability [3, 4, 12].

6.3. Voltage Control

Independent reactive power control enhances voltage stability and may defer investment in synchronous condensers.

6.4. Contingency Response

Rapid HVDC ramping during contingencies redistributes imbalance within seconds, reducing cascading failure risk and lowering EENS.

7. Policy and Implementation Implications [13]

Regional optimization requires harmonized regulatory and market frameworks [2].

Multilateral financing mechanisms and structured PPP models can reduce effective discount rates, improve creditworthiness, and mitigate sovereign risk in Caribbean island systems [11, 13].

Phased deployment with scalable converter architecture enables long-term regional integration [1].

Climate-resilient infrastructure investment frameworks promoted in the Caribbean emphasize cross-sector integration, redundancy, and disaster resilience — characteristics inherent to VSC-HVDC interconnection projects [14].

8. Discussion

8.1. Interpretation of Key Findings

The results demonstrate that a 700 MW DR–PR VSC-HVDC interconnection approaches economic breakeven under conservative fuel differential and discount rate assumptions. The primary drivers of value are avoided capacity investments (≈ $260M), fuel cost differentials (NPV ≈ $250M), and reserve-sharing benefits, while reliability improvements and fiber-optic integration provide incremental but strategically relevant contributions.

Importantly, the analysis shows that even under modest $5/MWh fuel spread assumptions, system-wide optimization nearly offsets the $1.04B HVDC capital requirement. This finding suggests that the economic feasibility of Caribbean interconnections does not rely solely on high arbitrage spreads but on portfolio effects: reserve pooling, deferred peaking capacity, and cross-border generation cost asymmetry. The addition of telecom revenue shifts the project from marginal to positive NPV, demonstrating the structural importance of multi-utility infrastructure integration.

This supports the hypothesis that regional integration in island systems creates value primarily through risk diversification and adequacy enhancement rather than pure energy trading margins.

8.2. Comparison with Previous Research, Strengths, and Limitations

These findings are consistent with previous studies emphasizing the systemic benefits of HVDC interconnections in constrained systems. The coordinated frequency support and fast ramping capabilities described in [3] and [4] align with the reliability improvements monetized in this study. Similarly, hybrid subsea infrastructure analyses such as [6] demonstrate that combining power and fiber infrastructure enhances financial bankability through diversified revenue streams.

However, unlike large continental interconnection studies, where scale economies dominate, this work shows that in medium-sized island systems the economic justification relies more heavily on avoided capacity and resilience value, consistent with adequacy optimization frameworks discussed in [9] and the PR100 resilience scenarios [11].

A key strength of this study is the integrated energy–telecom PPP financial modeling, which extends beyond traditional power-only cost–benefit frameworks. At the same time, limitations must be acknowledged:

1) Deterministic DCF modeling rather than full probabilistic LOLE simulation
2) Simplified EENS estimation
3) Static fuel differential assumptions
4) No dynamic renewable penetration scenario modeling

Unexpectedly, fuel arbitrage alone does not dominate the economic case, underscoring the importance of structural adequacy benefits rather than short-term price spreads.

8.3. Broader Implications and Future Research

The study confirms that Caribbean island interconnections should be evaluated as strategic infrastructure platforms rather than conventional merchant transmission assets. The integration of energy and digital infrastructure meaningfully alters the financial profile and reduces project risk through revenue diversification.

From a policy perspective, the findings suggest that regulatory harmonization and multilateral concessional financing could shift the discount rate sufficiently to make such projects strongly positive NPV investments. This reinforces arguments in regional integration literature [2] that institutional alignment is as critical as technical feasibility.

Future research should include:

1) Full probabilistic LOLE/EENS simulations
2) Dynamic stability modeling under high renewable penetration
3) Sensitivity to LNG price volatility
4) Multi-island expansion modeling beyond the DR–PR corridor
5) Market design and cross-border settlement mechanisms

In summary, the results contribute to the emerging body of literature demonstrating that medium-scale HVDC interconnections in islanded regions can be economically defensible when evaluated through a total-system and multi-utility lens. Rather than representing merely a transmission investment, the DR–PR link constitutes a resilience-enhancing regional integration platform.

9. Conclusions

1) A deterministic techno-economic assessment of a 700 MW, 160 km VSC-HVDC interconnection between DR and PR demonstrates near-breakeven economics under conservative assumptions. Under moderate fuel differential or concessional financing, the project yields positive NPV.
2) Key quantified benefits include avoided peaker capacity, fuel savings, reserve sharing, renewable integration, and reliability improvements. Dynamic stability capabilities of VSC-HVDC provide additional resilience benefits beyond financial metrics.
3) The integration of fiber optic telecommunications infrastructure within the proposed 700 MW DR–PR VSC-HVDC interconnection materially improves the financial profile of the project.
4) From an integrated infrastructure perspective, the DR–PR HVDC interconnection evolves from a purely energy optimization project into a multi-sector strategic asset aligned with resilient Caribbean infrastructure investment principles [14].
5) From a total-system optimization perspective, the DR–PR interconnection constitutes an economically defensible and technically robust infrastructure investment for Caribbean electricity market integration.

Abbreviations

ACC	Avoided Capacity Cost
BCR	Benefit–Cost Ratio
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
DC	Direct Current
DCF	Discounted Cash Flow
DR	Dominican Republic
EENS	Expected Energy Not Served
GWh	Gigawatt-hour
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
MUSD	Millions of US Dollars
MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value

O&M	Operation and Maintenance
OPEX	Operational Expenditure
PR	Puerto Rico
VOLL	Value of Lost Load
VSC	Voltage Source Converter

Author Contributions

Francisco Nunez-Ramirez: Conceptualization, Methodology, Data curation, Investigation, Formal analysis, Data curation, Writing – original draft, Writing – review & editing

Conflicts of Interests

The author declares no conflicts of interest.

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