Whole-energy-system transition pathways for Cuba: multi-sector optimization with EnergyScope Pathway

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Abstract:
As global energy systems evolve, isolated island states face significant vulnerabilities resulting from their dependence on fossil fuels and deteriorating infrastructure. Cuba's energy sector has historically relied over 95% on fossil fuels for power generation, with more than 50% of primary energy imported. Following the national grid collapses of 2024 and 2025, identifying a technically resilient and sovereign energy pathway has become an urgent national priority. This study tackles this issue using a comprehensive bottom-up pathway optimization approach to assess multi-sectoral transition roadmaps from 2020 to 2055, applying the open-source EnergyScope Pathway framework. Because standard formulations assume permanent plant decommissioning, a novel discrete repowering module is introduced to explicitly model the life-extension of aging thermal assets. Two scenarios are compared: an NDC-pace electrification pathway and an accelerated electrification scenario (ACCEL) that doubles the adoption rate of electric vehicles, cooking, and heat pumps. The results demonstrate that accelerating electrification reduces total discounted system costs by 1.3% (1.8 B USD) through the elimination of gasoline, diesel, and LPG imports by 2055. Both pathways achieve an 83% renewable electricity share. Ultimately, these findings offer a data-driven roadmap demonstrating that accelerated end-use electrification is an economically superior strategy for achieving energy sovereignty and deep decarbonization.

Keywords:
Whole-energy-system, End-use electrification, MILP, EnergyScope Pathway, Cuba, Energy transition.

1. Introduction

The global imperative to transition toward sustainable, decarbonized energy systems presents a particularly complex challenge for island nations, which must balance climate goals with extreme economic and infrastructural vulnerabilities. Cuba's energy sector is currently at a critical crossroads, characterized by an acute structural crisis and heavy historical dependence on fossil fuels, which accounted for approximately 95% of its electricity generation up until 2024 [9–11]. The National Electric System (SEN) suffers from frequent and severe blackouts, driven by a fleet of centralized, baseload thermoelectric power plants that are over 40 years old and severely degraded by the corrosive effects of burning domestic high-sulfur crude oil [27, 28].
To address these vulnerabilities, Cuba's initial Nationally Determined Contribution (NDC) under the Paris Agreement proposed a roadmap to install 2.14 GW of renewable capacity by 2030, which included a target of 0.7 GW of solar photovoltaic (PV) generation [25, 28]. However, facing severe fuel shortages and grid instability stemming from a loss of subsidized oil imports, the Cuban government was forced to drastically accelerate this timeline [32, 33]. In 2025 alone, backed by international cooperation, Cuba synchronized between 0.75 GW and 1.0 GW of new solar PV capacity to the grid, effectively surpassing its 2030 NDC solar target five years ahead of schedule [32–34]. Consequently, the share of renewables in the nation's electricity generation jumped from 2% in 2024 to 10% by the end of 2025 [32]. Building on this accelerated momentum, the government has updated its ambitions, aiming to reach 2 GW of installed solar PV capacity by 2028 [33], while progressing toward a 100%

renewable system by 2050 [29, 30]. Moreover, the updated NDC further specifies that 10% of public transport should be electric by 2030 [24].

Prior energy system studies for Cuba have relied predominantly on simulation and accounting frameworks. Vázquez et al. used the LINDA model to assess renewable integration potential for the power sector [8]. Korkeakoski et al. applied EnergyPLAN to analyze 100% renewable scenarios for Isla de la Juventud [9]. Luukkanen et al. developed the CubaLinda model to explore full renewable penetration pathways [16, 17]. However, CubaLinda is an accounting framework that requires the user to manually input assumed investment portfolios and technology mixes, rather than endogenously optimizing investment decisions [30]. Pehrs and Partanen applied a CLEWs framework to study energy–water–land interactions [18], representing the only prior multi-resource analysis for Cuba.

More recently, researchers have deployed energy system optimization models (ESOMs) to identify least-cost pathways. Brandts et al. employed the open-source `oemof` framework to investigate cost-optimal capacity expansion for the Cuban power sector, identifying wind and biomass as critical bridging technologies [10]. Rojas Plana et al. used OSeMOSYS to model long-term generation capacity expansion scenarios to 2050, demonstrating that sugarcane biomass would be a crucial technology to achieve high renewable penetration as it will replace the aging thermoelectric fleet [31]. Guevara-Luna et al. evaluated the progressive introduction of intermittent solar and wind sources, highlighting the environmental and economic benefits of reducing fossil fuel imports [11]. At the broader Caribbean scale, Bogdanov et al. demonstrated that full energy sector transitions integrating power, heat, transport, and industry are technically and economically feasible [6], and Oyewo et al. provided the most comprehensive multi-sector, multi-node analysis of Caribbean carbon-neutrality pathways, albeit without country-specific granularity for Cuba [7].

Despite these advances, a significant gap remains. Previous optimization studies for Cuba focus on the power sector in isolation rather than the whole energy system, and they treat the aging thermoelectric fleet either as liabilities to be rapidly decommissioned or as static backups forced to run at minimum thresholds [10, 11]. Alternative proposals to replace these plants with new CCGT capacity would require entirely new, capital-intensive gas import infrastructure [10, 27]. No study has modeled the option of repowering these plants to serve as flexible transitional assets within a whole-system optimization.

This study addresses this gap by applying the EnergyScope Pathway framework [12] to the Cuban energy system. Because the standard formulation assumes permanent decommissioning at end-of-life and does not represent the option to extend plant operational life through discrete repowering decisions, we introduce a novel discrete repowering module. We leverage this enhanced framework to evaluate two scenarios: an NDC-pace electrification pathway, where end-use electrification follows gradual adoption trajectories consistent with Cuba's updated NDC 3.0 [24], and an accelerated electrification pathway (ACCEL) with approximately twice the NDC adoption pace across all end-use sectors. Consequently, this paper makes two contributions: (i) developing the first whole-energy-system pathway optimization for Cuba, featuring a novel discrete repowering module and must-run constraints to accurately model the aging thermoelectric fleet; and (ii) providing a quantitative assessment of the macroeconomic and environmental value of accelerating end-use electrification beyond current NDC targets.

2. Methodology

2.1. The EnergyScope Pathway framework

EnergyScope Pathway [12] is an open-source mixed-integer linear programming (MILP) model formulated in AMPL and designed to optimize the transition of a regional whole-energy system over a multi-phase planning horizon. Unlike snapshot models that optimize a single target year, EnergyScope Pathway simultaneously determines investment timing, technology deployment, and hourly dispatch for every phase within the horizon, thereby capturing the path-dependence of infrastructure

decisions.
The model minimizes the total discounted system cost:

$$\min \; C_{\text{tot}} = \sum_{p \in \mathcal{P}} (C_{\text{inv},p} + C_{\text{maint},p} + C_{\text{op},p}) \cdot \alpha_p - \sum_{i \in \mathcal{I}} C_{\text{salvage},i} \tag{1}$$

where $\mathcal{P}$ is the set of planning phases, $C_{\text{inv},p}$, $C_{\text{maint},p}$, and $C_{\text{op},p}$ are the investment, maintenance, and operating costs at phase p, α_p is the phase-specific discount factor, and $C_{\text{salvage},i}$ is the salvage value of technology i remaining at the horizon end.
At each phase, the installed capacity of technology i evolves according to:

$$F_i^{p,\text{end}} = F_i^{p,\text{start}} + F_{\text{new},p,i} - F_{\text{old},p,i} - \sum_{p'} F_{\text{decom},p,p',i} \tag{2}$$

where F_{new} is new-build capacity, F_{old} is mandatory retirement triggered when a vintage's lifetime expires, and F_{decom} is voluntary early decommissioning.
The model enforces energy balance through a layer structure. Each technology produces or consumes energy in one or more layers (e.g. ELECTRICITY, HEAT_HIGH_T, COOKING_DECEN, MOB_PUBLIC). At every timeslice, the sum of production minus consumption must equal the exogenous demand for that layer. This structure enables the model to capture sector coupling, since a technology such as an electric bus simultaneously consumes electricity and produces passenger mobility. Storage technologies are modelled with explicit charge, discharge, and standing loss dynamics at the timeslice level, subject to cyclic boundary conditions within each typical day.
Hourly dispatch within each year is resolved through typical days (TDs). Rather than representing all 8 760 hours, a MILP clustering algorithm selects N_{TD} representative calendar days from the full year that minimize the weighted approximation error across multiple daily profile series (electricity demand, solar capacity factor, wind capacity factor, biomass availability). Each representative day retains its full 24-hour resolution, yielding $N_{\text{TD}} \times 24$ timeslices per year. Each typical day carries a weight equal to the number of calendar days it represents.

2.2. Cuba-specific model adaptations

Several extensions and modifications were introduced to adapt the standard EnergyScope Pathway formulation to Cuba's specific conditions.
The most significant addition is a MILP repowering module. A defining feature of Cuba's electricity system is the dominance of eight crude-oil-fired thermal plants, collectively 2.50 GW. These plants retire in a staggered sequence from 2024 to 2031. The standard EnergyScope formulation treats end-of-life capacity as permanently retired. To capture the option of extending plant operational life at reduced cost, a MILP repowering module was developed.
The module introduces three new decision variables per phase and repowerable technology: $F_{\text{rec},p,i}$ (repowered capacity in GW), $N_{\text{rec},p,i}$ (integer number of repowered units, for technologies with discrete unit sizes), and $F_{\text{rec,old},p,i}$ (repowered capacity whose operational life extension has expired). For technologies with known unit sizes $\kappa_i > 0$, repowering occurs in integer multiples:

$$F_{\text{rec},p,i} = \kappa_i \cdot N_{\text{rec},p,i}, \quad N_{\text{rec},p,i} \in \mathbb{Z}_{\geq 0} \tag{3}$$

This integer constraint is physically motivated: a 0.317 GW turbine is either repowered or not. Repowering at phase p is bounded by the retiring capacity available for repowering:

$$F_{\text{rec},p,i} \leq F_{\text{old},p,i} + F_{\text{rec,old},p,i} \tag{4}$$

where $F_{\text{rec,old}}$ accumulates repowered capacity whose operational life extension L_{ext} has expired, thereby enabling re-repowering. The capacity evolution equation (2) is extended accordingly:

$$F_i^{p,\text{end}} = F_i^{p,\text{start}} + F_{\text{new},p,i} - F_{\text{old},p,i} - \sum_{p'} F_{\text{decom},p,p',i} + F_{\text{rec},p,i} - F_{\text{rec,old},p,i} \tag{5}$$

The investment cost computation and the salvage value at the horizon end are also modified. Unlike the original EnergyScope formulation, which uses linear salvage depreciation, the repowering module employs an annuity-based salvage formula:

$$C_{\text{salvage},p,i} = C_{\text{inv}} \cdot \frac{(1+r)^{L_{\text{rem}}} - 1}{(1+r)^{L} - 1} \tag{6}$$

where L_{rem} is the remaining useful life at the horizon end and L is the full lifetime. This formulation better reflects the economic value of partially depreciated assets. Each of the eight crude oil plants is modelled as a separate technology with its own unit size, retirement year, and capacity factor trajectory. This granularity is essential for the integer repowering decisions and allows the optimizer to selectively repower some plants while letting others retire.
The model also introduces an annual investment cap per technology and phase. This constraint, not present in the original EnergyScope Pathway formulation, prevents unrealistically large capacity additions in a single phase and represents supply chain, permitting, and construction time limitations.

$$F_{\text{new},p,i} \leq f_{\text{max,new},p,i} \tag{7}$$

The 2020–2024 period serves as calibration years, where installed capacity for all technologies is fixed to the observed 2020 fleet ($f_{\text{min}} = f_{\text{max}} = F_{\text{installed,2020}}$), and no new investment is allowed. This ensures the model reproduces the known system state before optimization decisions begin in 2025.
A must-run constraint was introduced as well to prevent large thermal plants from cycling on and off or being dispatched only to cover peak demand. Where μ_j is the minimum stable load fraction (0.3–0.5 for crude oil and fuel oil plants). This constraint is activated only during timeslices where the hourly capacity factor $c_{p,t} > 0$, so it does not force dispatch when the technology is physically unavailable (e.g. sugar mill plants outside the harvest season). The constraint reflects the operational reality that steam turbines cannot economically start up and shut down on an hourly basis.

$$F_t[y, j, h, \text{td}] \geq \mu_j \cdot F[y, j] \cdot c_{p,j} \tag{8}$$

3. Case study: the Cuban energy system

3.1. System characterization

Figure 1 presents a Sankey diagram of Cuba's 2022 whole-energy balance, constructed from official ONEI data [1]. The diagram traces every energy carrier (crude oil, natural gas, biomass, and renewable sources) from extraction or import through refining, power generation, and transmission to final consumption in all end-use sectors.
Several structural features are immediately apparent. Import dependence is prevalent, particularly for refined products where diesel and heavy fuel oil imports act as major vulnerabilities. Meanwhile, renewable sources constitute less than 1% of the primary energy supply despite excellent solar irradiance (5.5 kWh/m^2/day) and favorable coastal wind resources [4, 5]. The transport system relies entirely on imported petroleum products, and residential cooking depends predominantly on imported LPG. Since early 2025, US sanctions has become more severe targeting countries that supply petroleum to Cuba, curtailing fuel imports [36], accelerating a shift toward electric mobility as a practical necessity. Chinese–Cuban joint ventures now assemble electric motorcycles, tricycles, and quadricycles domestically [37], and the government has procured electric vehicles for medical transport, electric ambulances, and electric tricycles for public services [38]. Community-scale solar charging stations (*solineras*) have begun operating off-grid, supplying both vehicle charging and electric cooking [39]. These developments confirm that end-use electrification is already emerging as Cuba's primary adaptation strategy to the fossil fuel access crisis, and they motivate the scenario framing of this study.

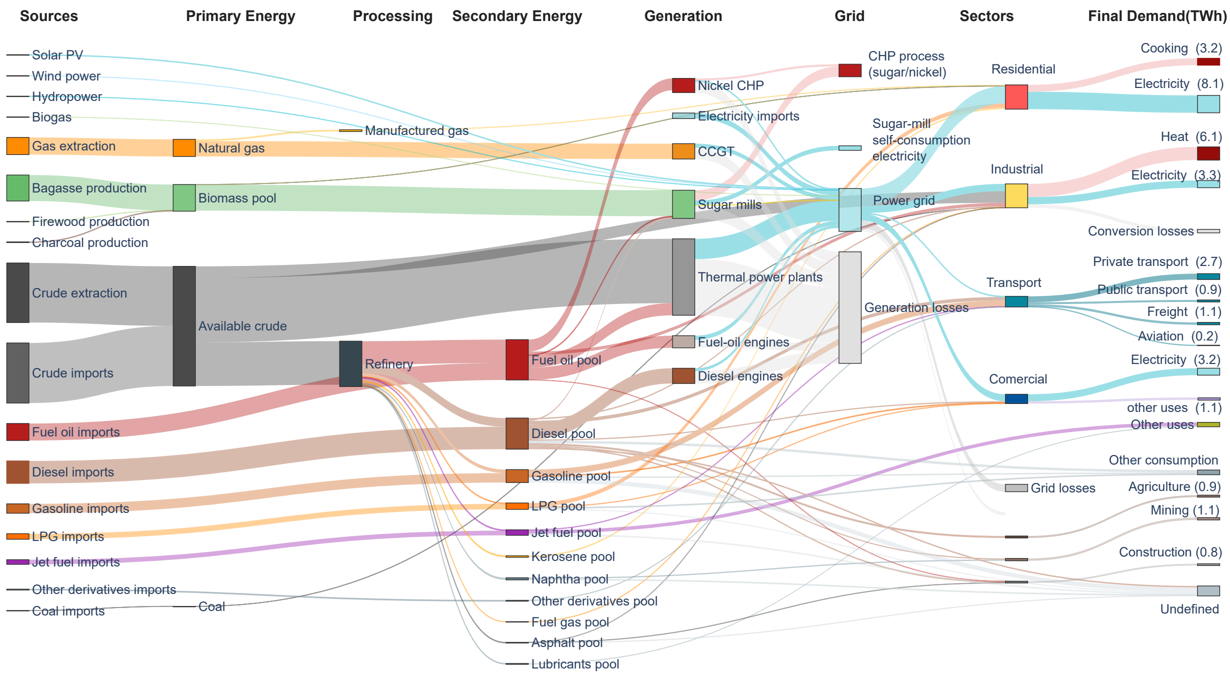

Figure 1: Sankey diagram of Cuba's whole energy system (2022). All carriers are traced from primary resources through refining, power generation, and distribution to sectoral final demand. Constructed from ONEI data [1].

Table 1 summarizes the primary energy supply and electricity generation mix. Total primary supply and direct imports of secondary energy carriers reached 124.01 TWh. The largest structural components are imported crude oil (22.68%) and domestic crude oil (22.26%), followed closely by biomass (19.78%). Furthermore, direct imports of refined products (HFO, diesel, jet fuel, gasoline, and LPG) total 33.06 TWh. When combined with imported crude oil, Cuba depends on external sources for nearly 50% of its total energy requirements.

Table 1: Primary energy supply and electricity generation in Cuba [1].

Primary Source	**TWh**	**%**
Imported Crude Oil	28.12	22.68
Domestic Crude Oil	27.60	22.26
Biomass	24.53	19.78
HFO (Imported)	15.63	12.60
Natural Gas	9.89	7.98
Diesel (Imported)	8.68	7.00
Jet Fuel (Imported)	4.38	3.53
Gasoline (Imported)	2.72	2.19
LPG	1.65	1.33
Other[a]	0.81	0.66
Total Supply	**124.01**	**100.0**

[a] Charcoal (0.48), solar and wind (0.31), firewood (0.02).

3.2. Technology and resource data

Table 2 summarizes the key generation and storage technologies, with investment costs expressed in USD showing both 2025 and 2055 values to illustrate learning-curve effects. Solar PV capacity factors are derived from hourly Global Solar Atlas data for Cuba (annual average $c_p = 0.218$); onshore wind profiles from the Global Wind Atlas ($c_p = 0.322$) [4,5]. Sugar cane biomass availability follows the seasonal *zafra* (harvest) pattern. Two categories of biomass generation are modelled: traditional sugar mill CHP plants, which are sized to meet process heat demand and export surplus electricity during the six-month harvest season (November–April), and dedicated bioelectric plants, which burn forestry biomass year-round for dispatchable generation. Hourly capacity factor time series for sugar mill CHP are set to zero outside the harvest season, restricting their dispatch accordingly. Moreover an important detailed is that this plants consumes almost all the electricity generated during the harvest season, exporting a small amount of electricity to the grid.

Table 2: Key generation and storage technology parameters

Technology	$c_{\mathrm{inv},2025}$ ($/kW)	$c_{\mathrm{inv},2055}$ ($/kW)	c_{maint} ($/kW/yr)	Life (yr)
PV	900	450	23	25
Wind onshore	1 400	700	39	25
CCGT (natural gas)	1 600	1 600	20	30
Biomass plant	2 700	2 700	38	30
Diesel generator	750	750	10	25
Crude oil plants	2 000	2 000	21	30
Hydro run-of-river	2 500	2 500	88	30
Li-ion battery[a]	426	108	5	10

[a] Battery cost in $/kWh (energy capacity); 4h charge/discharge; η = 0.92.

The existing fleet at the start of the horizon comprises 2.50 GW of crude oil plants (eight individual units, retirement years 2024–2031), 0.70 GW of legacy diesel generators (retiring 2025), 0.66 GW of fuel-oil plants (retiring 2040), 0.48 GW of CCGT natural gas (retiring 2040), 0.40 GW of biomass sugar mills (retiring 2030), 0.18 GW of HFO powerships, and 0.17 GW of industrial CHP. Additionally, 0.16 GW of PV and 0.011 GW of wind are installed.

The resource portfolio comprises 24 active resources. Domestic crude oil extraction is capped at 25.3 TWh/yr following ONEI production data, and natural gas at 4.9 TWh/yr. Bagasse availability scales with sugar production up to 22.0 TWh/yr. Forestry biomass is capped at 12.0 TWh/yr based on sustainable harvest estimates from the Cuban Ministry of Agriculture. Solar and wind resources have unlimited annual volume but are constrained by hourly capacity factor time series. All imported fuels (crude, fuel oil, HFO, LPG, diesel, gasoline) are available at exogenous international prices.

A Value of Lost Load (VOLL) technology priced at 3 000 $/MWh is included for simulating electricity shortages. Its activation indicates insufficient installed capacity to meet the demand and does not represent an actual technology.

3.3. Demand projections

End-use demands across eleven categories are projected from 2020 to 2055 (Table 3) using GDP and population scaling factors. GDP follows a recovery trajectory indexed to 2019 (0.70 in 2020, 1.00 in 2030, 1.35 in 2055), reflecting Cuba's desired economic recovery assumptions. Population declines from 11.18 million in 2020 to 8.42 million in 2055, following national demographic projections. Electricity demand at the low-voltage bus grows from approximately 17.55 TWh in 2020 to 24.49 TWh in 2055, split into a flat baseload component (40%) and a time-varying component (60%) following normalized hourly load shapes. Industrial heat is disaggregated into four layers: high-temperature process heat, low-temperature industrial heat, cement kiln heat, and sugar mill heat. The latter follows a seasonal profile matching the five-month *zafra* (harvest) season. Transport demand in passenger-km and tonne-km grows with GDP, while cooking demand is scaled jointly by GDP and population.

A real discount rate of 12% is applied. This value reflects Cuba's constrained access to international capital markets and high opportunity cost of capital, consistent with official investment guidelines and rates used in prior Cuban economic and energy studies [20–23]. Other Latin America and the Caribbean countries have similar discount rates [35], but this value is higher than the 5% typical of European EnergyScope applications.

Transmission and distribution (T&D) losses are represented through the standard EnergyScope approach: a single grid technology that adds a loss factor to the electricity demand at each timeslice. The

Table 3: End-use demand projections from 2020 to 2055.

Demand category	**2020**	**2030**	**2040**	**2055**
Electricity & buildings (TWh)				
Electricity[a]	17.55	18.91	20.99	24.49
Hot water	0.32	0.30	0.28	0.24
Cooking	1.19	1.70	2.01	2.30
Industrial heat (TWh)				
High temperature	3.08	4.41	5.20	5.95
Low temperature	2.10	3.00	3.54	4.05
Cement kilns	0.78	1.12	1.32	1.51
Sugar mills	6.72	9.60	11.3	13
Transport				
Passenger (Gpkm)	7.0	10.0	11.8	12.8
Freight (Gtkm)	2.45	3.50	4.13	4.73

[a] Sum of flat baseload (40%) and time-varying (60%) components.

combined loss rate of 20.6% aggregates separately estimated high-voltage transmission losses (4.8%) and low-voltage distribution losses (16.7%), consistent with ONEI's reported T&D loss rate [1].

3.4. Scenario definition

Two scenarios are analyzed over the 2020–2055 horizon, sharing identical resource availability, technology costs and demand projections. They differ solely in the maximum pace at which electric technologies can replace fossil-fuelled end uses in transport, cooking, and industrial heat. The PV installation yearly limits are set to 1 GW for the first 3 years, then 0.5 GW for the rest of the horizon. In the case of wind, the yearly limits are set to 0.05 GW for the first 5 years, then 0.2 GW for the rest of the horizon. For biomass the yearly limits are set to 0.05 GW until 2040, then 0.1 GW for the rest of the horizon. This assumptions are based on the current trends in the country and the expected economic development. Key limitations include the single copper-plate node representation, which does not capture inter-provincial transmission constraints that may be relevant for eastern wind resources serving western demand centres; GDP-dependent demand projections subject to macroeconomic uncertainty; and the disaggregation of industrial heat into high and low temperature categories using an assumed 60/40 split, as detailed census data are unavailable.

NDC-pace electrification (NDC). End-use electrification proceeds at the gradual pace implied by Cuba's updated NDC 3.0 [24]. In transport, maximum installed capacity for electric vehicles is bounded by technology-specific S-curves calibrated to the NDC targets: approximately 15% of public transport electric by 2030, growing progressively thereafter. For cooking, electric stove capacity is capped at levels reaching approximately 35% of demand by 2055. For industrial heat, electric furnace and heat pump capacity grows gradually ($\sim$1 pp/yr from 2035), reaching approximately 30% of process heat demand by 2055. Cement kilns continue to consume domestic crude oil as a non-substitutable industrial process. The optimizer freely determines the pace and extent of adoption within these bounds, subject to cost-optimality.

Accelerated electrification (ACCEL). The technology portfolio and demand projections are identical to NDC; the electrification S-curves for *all* end-use sectors are approximately doubled. In transport: 31% of public transport electric by 2030 and 100% by 2040. In cooking: electric stoves reach full penetration ($\sim$100%) by 2055. In industrial heat: electric furnaces and heat pumps serve up to 100% of process heat demand by 2055. This reflects a policy-push scenario with accelerated procurement of electric vehicles and buses, liberalised EV imports, earlier deployment of charging infrastructure through international cooperation, and a comprehensive programme to electrify cooking and industrial heat through heat pump deployment.

4. Results and discussion

The following subsections compare the NDC and ACCEL pathways across key indicators, such as total transition cost, RE share of generation, battery power and energy requirements, installed power capacity and CO2 emissions. It further discuss the power sector composition, end-use transitions, and emissions in more detail.

4.1. Key indicators

Table 4 provides a comparison of the two scenarios.Over the 35-year horizon, ACCEL achieves a total discounted system cost of 134.4 B USD, compared to 136.2 B USD for NDC, a saving of 1.8 B USD which is a very significant amount of money for a country like Cuba. The cost advantage arises from the comprehensive displacement of imported fossil fuels across all end-use sectors. This impact directly on energy emission with a reduction of 1.7 MtCO2 in 2055. In term of power capacity, ACCEL requires 2.5 GW more installed capacity than NDC, with the difference being primarily in PV and battery installations.

Table 4: Key performance indicators for the NDC and ACCEL scenarios by 2055.

Indicator	**NDC**	**ACCEL**	**Difference**
Total transition cost (B USD)	136.2	**134.4**	−1.8 (−1.3%)
CO_2 emissions, 2055 (Mt)	9.7	**7.9**	−1.7 (−18%)
CO_2 reduction vs. 2020 (%)	−43%	**−53%**	10 pp
RE share of generation, 2055 (%)	82.8	83.1	+0.3 pp
Installed power capacity, 2055 (GW)	15.4	17.9	+2.5
PV capacity, 2055 (GW)	2.9	**6.9**	+4.0
Battery power / energy, 2055	2.0 GW / 7.8 GWh	**5.5 GW / 22.1 GWh**	+3.5 GW

ACCEL eliminates LPG, gasoline, and diesel imports by 2055 and reduces HFO by 61% (3.64 vs. 9.24 TWh)

4.2. Power sector transformation

Under both scenarios, the power sector undergoes a structural transformation from a fossil-dominated fleet to a renewables-led system by 2055 (Figure 2). NDC reaches 15.4 GW of total installed generation capacity, with 2.88 GW of PV, 4.42 GW of wind and 2.25 GW of biomass. ACCEL deploys 17.9 GW, dominated by 6.95 GW of PV (2.4× NDC), 5.11 GW of wind and 2.44 GW of biomass. Battery storage reaches 2.0 GW / 7.8 GWh in NDC and 5.5 GW / 22.1 GWh in ACCEL, providing 4-hour dispatch flexibility for managing variability. Moreover, the share of renewables in terms of installed capacity reaches 87% in NDC and 91% in ACCEL. It is worth mentioning that by 2030 the country could reach more than the 24% of renewable installed capacity established in the NDC, following the PV installation trends of the last years. However, this is not the case for wind power and biomass power. There is an important detail regarding solar power which is the fact that by 2027 it is expected to reach more and less the 3 GW of installed capacity. These plants will be decommisioned after 25 years of operation and it will produce what is observed in the chart, a decrease in the installed solar capacity by 2055 until it reach an equilibrium with the new installed capacity.
The repowering module plays a key role in smoothing the transition. In both scenarios, the optimizer repowers crude plants in sequential cycles, maintaining 1.0–1.5 GW of crude plant capacity through the mid-horizon. By 2055, NDC retains 0.74 GW and ACCEL 0.97 GW of crude capacity due to surge in demand from end uses electrification. Fuel oil plants and the CCGT are also repowered when eligible. Diesel generators were repowered only to overcome the energy deficit in the short term and from 2029 onwards they are not used as fuel cost is too high. On top, we also gave the option

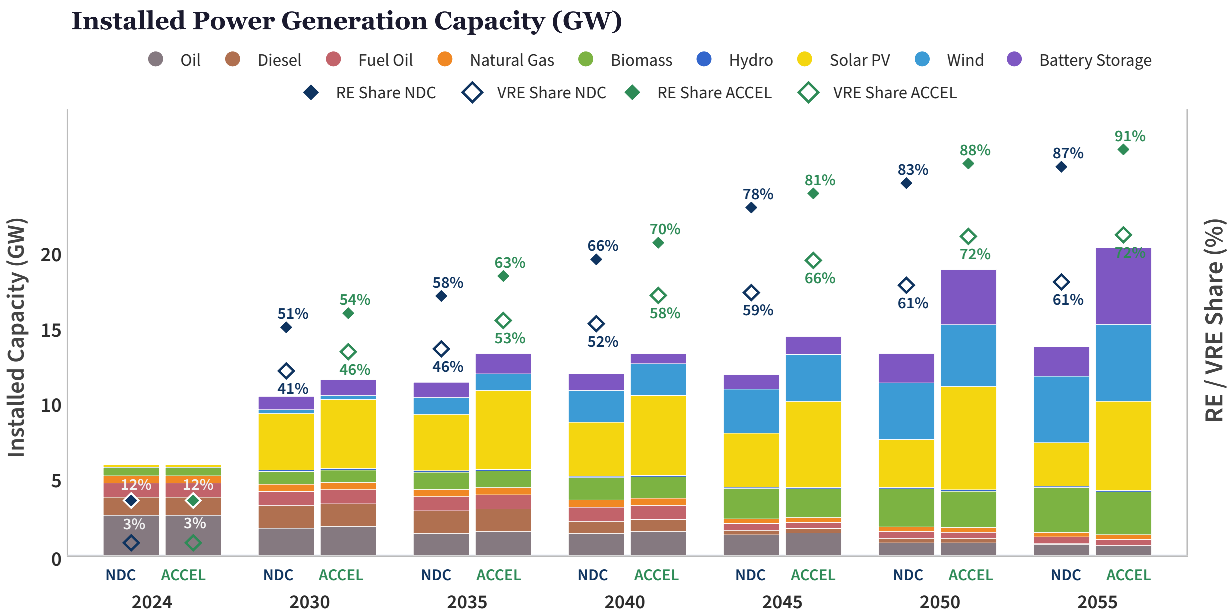

Figure 2: Installed power generation capacity by technology for selected years. RE share markers indicate the renewable contribution to annual generation.

to repower the new capacity installed by the model, specifically wind turbines, which could be an interesting option for the country in the future and has been applied in other countries [40, 41].

4.3. End-use sector and electricity generation

The two scenarios produce sharply divergent end-use electrification outcomes, reflected in both the sectoral energy balances and the electricity generation mix needed to serve them.

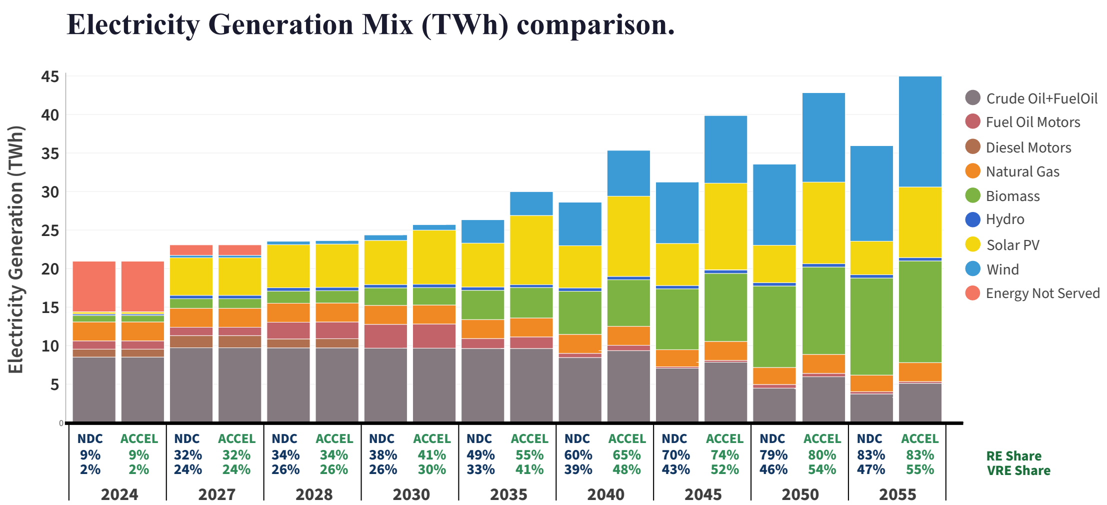

Figure 3: Annual electricity generation mix by technology for selected years.

Figure 3 shows the generation mix evolution. Both scenarios exhibit significant energy shortages during 2020–2027, with the deficit peaking at 6.6 TWh in 2024 reflecting the reality of the country where almost 50% and sometimes more, of the population does not have access to electricity. New renewable installations and repowered thermal plants progressively close this gap, eliminating energy shortages entirely by 2028, under the assumption made in the model. As it can be seen in Figure 3, NDC generates 36.0 TWh at 2055 with a renewable share of 82.8%, while ACCEL reaches around 45TWh at 83.1% renewable. Despite the near-identical RE percentages, the absolute renewable generation differs substantially: ACCEL produces 37.7 TWh of renewable electricity compared to 29.8 TWh in NDC, reflecting the much larger electricity demand from the electrified end-use sectors.
Regarding the final energy use, the electrification of sectors shows different behaviours shown in

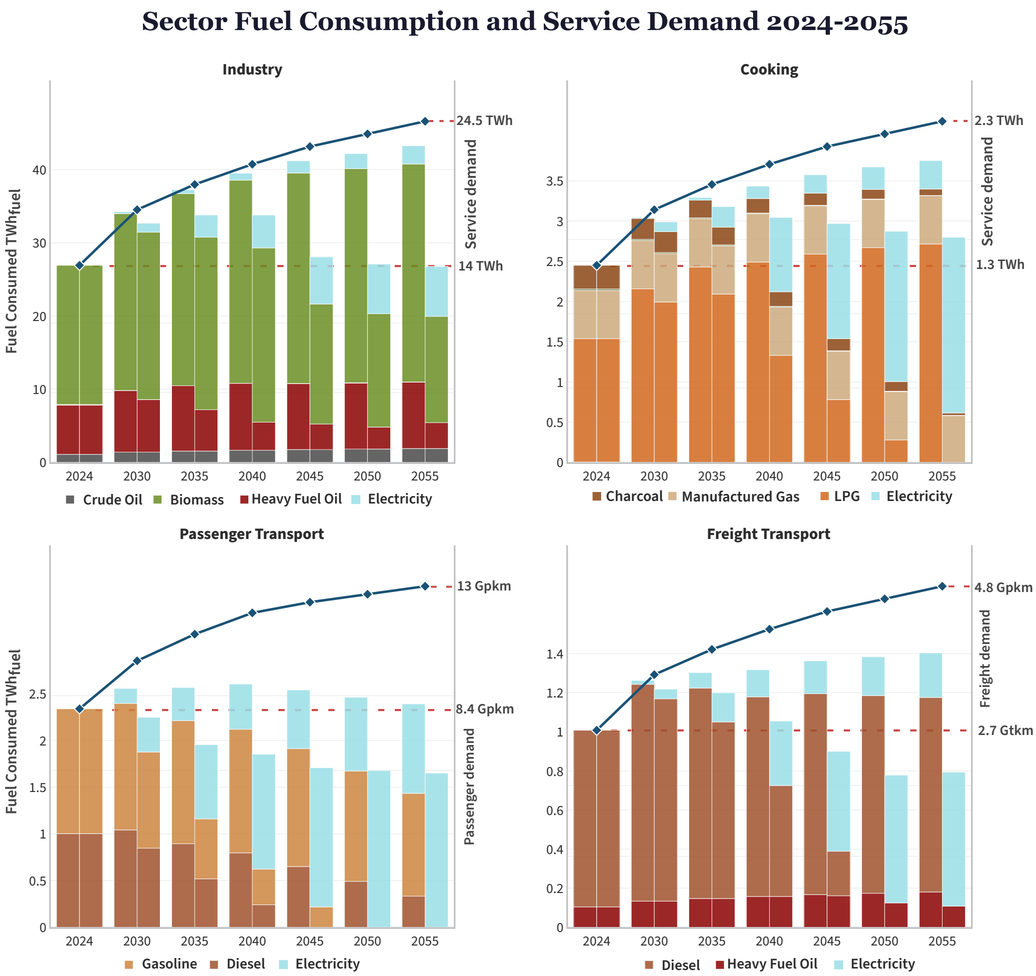

Figure 4: End-use electrification trajectories by sector and scenario.

Figure 4. In the case of cooking, the NDC, by using a gradual expansion of electrification, achieves that 14% of the total energy used comes from electricity. In ACCEL, the sector is 95% electrified by 2055, completely reducing LPG imports. It still uses an small portion of manufacturated gas which is localy produced and cheaper.

In passenger transport, by 2030 ACCEL achieves 37% electrification of private mobility and 31% of public transport, compared to 17% and 15% respectively in NDC. By 2050, ACCEL reaches 100% electric passenger transport while NDC reaches only 31% (private) and 45% (public). NDC does *not* converge to full transport electrification by 2055, where private mobility remains at only 47% electric and public transport at 79%. Freight transport also diverges. ACCEL achieves 78% electric freight compared to 29% in NDC in 2050. ACCEL reaches almost 100% by 2055, while NDC reaches only 42%. The small heavy fuel oil portion in the ACCEL scenario is related to maritime transport which no alternative was modeled. A final remark from the charts above is that electrification of end-use demands avoids the energy inefficiencies of conventional technologies and hence reduces the overall energy demand and the needs for primary energy.

Industrial heat follows a similar pattern. In NDC, oil boilers continue to dominate, with heat pump capacity reaching only 0.25 GW for sugar mill and 0.13 GW for general industrial by 2055. ACCEL, in contrast, deploys substantially more electric capacity: 3.04 GW of sugar mill heat pumps, 0.80 GW of general industrial heat pumps, and 1.18 GW of electric furnaces. Despite we gave freedom to install electric furnances, oil boilers persist in this scenario for high-temperature industrial heat.

All aforementioned explains ACCEL's much larger electricity demand (45.4 vs. 36.0 TWh at 2055) and its lower fuel import dependence.

4.4. Emissions and resource consumption

CO_2 emissions decline in both scenarios (Figure 5), but the trajectories diverge substantially. In NDC, emissions fall from 16.83 Mt in 2020 to 9.65 Mt in 2055. ACCEL achieves deeper reductions, from 16.83 Mt to 7.94 Mt, with a persistent gap opening from 2035 onward aligned with the electrification of end-use sectors. Notably, power sector still the main source of emissions. In this particullar case, the electrification of end-use sectors reduces overall emission, but increases the power sector emissions as it decides to use cheaper crude oil to generate electricity for other sectors instead of importing more expensive fuels. This could be avoided by setting a carbon tax or a cap on emissions, but how much would it cost to the country? Should Cuba renounce to their natural resources such as crude oil and natural gas to leapfrog to a green economy? The questions raised here it is important for developing countries as it highlights the trade-offs between economic development and environmental sustainability.

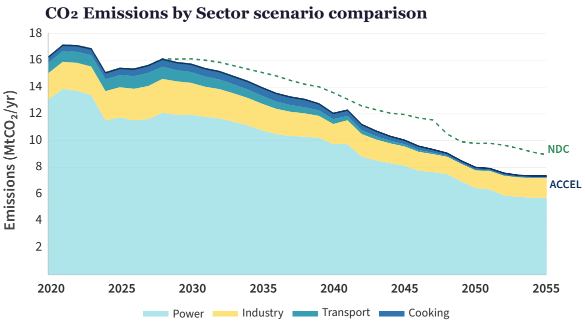

Figure 5: CO_2 emission trajectories by scenario, decomposed by emitting sector.

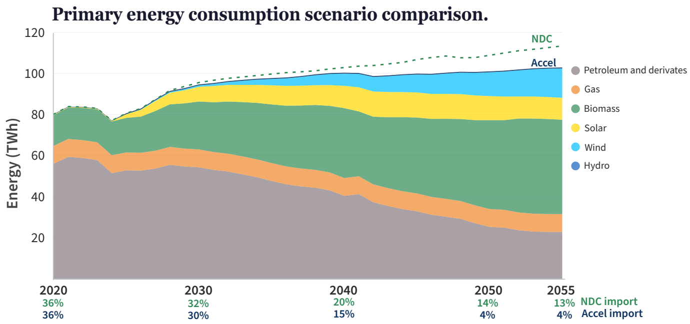

Figure 6: Primary energy trajectories by scenario.

Regarding resource consumption, the ACCEL scenario needs less primary energy than the NDC scenario resulting in a more efficient energy system. As shown in Figure 6, shifting from petroleum will required a considerable amount of biomass. Part of it will be produced by the sugar production process, but it will not be enough to cover the demand. Therefore, Cuba will use forestal biomass and speacially a tree called marabú (Dichrostachys cinerea) which is an invasive species in the island. This will require special attention as the logistic of collecting and processing this biomass could be a challenge. By using electric heat pumps in sugar mills reduces biomass requirements went off by 22% from 58 TWh/yr in NDC to 48 TWh/yr in ACCEL.

5. Conclusions

This study presents the first whole-energy-system pathway optimization for Cuba, covering electricity, transport, cooking, and industrial heat over 2020–2055 using EnergyScope Pathway with annual phase resolution and a novel discrete repowering module for aging plants and new capacity such as wind power. Rewpoering results highlight critical strategic interventions for policymakers. First, extending the operational lifecycle of existing thermal plants emerges as a financially optimal bridging strategy. For capital-constrained developing economies, strategic repowering offers a pragmatic avenue to maximize existing infrastructure and capital utilisation while variable renewable deployment scales up. However, thorough technical audits must dictate this process, as severely deteriorated units may lack viable repowering potential.

The central finding is that accelerated end-use electrification is simultaneously cheaper, cleaner, and more resource-efficient than the NDC-pace pathway. It reduces the total discounted system cost by 1.3% (1.8 B USD), lowers CO_2 emissions by 53% relative to 2020 (vs. 43% for NDC), and imports only 3% of the primary energy by 2055. In a country where foreign exchange for fuel imports constitutes a binding macroeconomic constraint, reducing them represents a strategic benefit well beyond the headline cost saving.

Another relevant result is that the 24% target set by the government is surpassed by more than 50%

of renewables in both scenarios by 2030. That target is looking only at the power sector without a holistic view where synergies between all sectors could allow the system to increase renewables. In addition both scenarios converge to approximately 83% renewable electricity shares, yet through fundamentally different means. One is that ACCEL scenario has almost two and a half times more PV and battery capacity, compared to NDC scenario. The other one is in terms of energy generation, where around 21% more was generated in the accelerated scenario from renewables.

Any delay in annual installation capacities in technologies such as solar, biomass, and wind, may adversely affect the energy system, resulting in prolonged blackouts on the island. This impacts all productive sectors of the nation, which are currently in a condition of stagnation. Consequently, faster electrification should be regarded not merely as an environmental objective but also as a macroeconomic stability tool.

On the other hand, shifting the heat production from bagasse to electric heat pumps during the sugar harvesting season reduces biomass requirements; therefore, it reduces the need for forestall biomass, making biomass plants more self-sufficient by avoiding extra logistic energy consumption.

Future work could extend this analysis in four directions. Spatial disaggregation using EnergyScope Multi-Cell [19] to capture inter-provincial transmission constraints. Sensitivity analysis to discount rate and better demand representation for all sectors – both aspects are uncertain in Cuba's current conditions. Additionally, including EV smart charging and vehicle-to-grid strategies for reducing battery storage requirements. Net-zero scenarios incorporating cement kiln fuel switching and green hydrogen production.

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Nomenclature

Symbols

- α_p Phase discount factor
- C_{inv} Investment cost, M USD
- C_{tot} Total discounted system cost, M USD
- c_{inv} Specific investment cost, \$/kW
- c_{rep} Specific repowering cost, \$/kW
- c_p Annual capacity factor
- F Installed capacity, GW
- F_{new} New-build capacity, GW
- F_{old} Mandatory retirement, GW
- F_{decom} Voluntary decommissioning, GW
- F_{rec} Repowered capacity, GW
- $F_{\text{rec,old}}$ Expired repowered capacity, GW
- F_t Dispatched power at timeslice t, GW
- κ Unit size, GW
- L_{ext} Operational life extension, years
- μ Minimum stable load fraction
- N_{rec} Number of repowered units (integer)
- N_{TD} Number of typical days

Abbreviations

- *CCGT* Combined-Cycle Gas Turbine
- *CHP* Combined Heat and Power
- *LPG* Liquefied Petroleum Gas
- *NDC* Nationally Determined Contribution
- *ONEI* Oficina Nacional de Estadística e Información
- *RE* Renewable Energy
- *SEN* Sistema Electroenergético Nacional
- *T&D* Transmission and Distribution
- *TD* Typical Day
- *VOLL* Value of Lost Load
- *VRES* Variable Renewable Energy Sources

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