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Coal Phase-Down and Cross-Fuel Risk in Peninsular Malaysia: System-Level Trade-Offs among Thermal Retention, Co-Firing and Renewable-Storage Deployment

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Abstract

Coal phase-down can lower power-sector emissions while shifting fuel-security exposure from coal to natural gas. This study quantifies that cross-fuel risk in Peninsular Malaysia using full-year hourly modelling in EnergyPLAN 16.22, MATLAB-based scenario automation and a controlled counterfactual that holds the wider national pathway constant while varying the treatment of an anonymised 1,600 MW Study Thermal Asset. The 2025 demand scale is externally checked against the Energy Commission's recorded system peak, with a difference of 0.076%. Four cases are evaluated for 2030, 2035 and 2040: managed phase-down (PD), temporary retention (RET), retention with co-firing (RET-CF), and renewable-plus-storage deployment comprising 3,200 MW of solar PV and a 1,600 MW/6.4 GWh four-hour battery system (RE-ST). Relative to PD, RET reduces system natural-gas requirements by 9.35–12.45 TWh/yr but increases operational CO_2 emissions by 1.35–1.79 Mt/yr. A fuel-substitution ratio of 0.999–1.001 indicates near one-for-one coal-for-gas substitution on an input-energy basis. RET-CF preserves the gas reduction while moderating the emissions penalty. RE-ST changes the substitution mechanism more fundamentally, reducing both coal and gas use and lowering operational CO_2 emissions by 1.65–3.00 Mt/yr. It also lowers modelled annual system cost by USD 393–405 million under the adopted solar and battery cost assumptions. A 120-case sensitivity programme distinguishes the physical robustness of these effects from exposure to gas, carbon and substitute-fuel prices and retained-capacity availability. The results show that coal phase-down does not automatically reduce total fossil-fuel exposure: its resilience and decarbonisation outcomes depend on the portfolio that replaces the withdrawn coal contribution.

Keywords: coal phase-down; cross-fuel risk; natural-gas exposure; thermal retention; co-firing; renewable-plus-storage; Energy PLAN

Nomenclature

Symbol / label	Definition
STA	Study Thermal Asset (STA), anonymised system intervention
PD	Managed phase-down scenario
RET	Temporary thermal-retention scenario
RET-CF	Thermal retention with co-firing
RE-ST	Additional 3,200 MW solar plus 1,600 MW / 6.4 GWh BESS package
Fgas	Annual system natural-gas fuel requirement (TWh)

Symbol / label	Definition
Fcoal	Annual system coal-fuel requirement (TWh)
ECO_2	Annual operational CO_2 emissions (Mt/yr)
Csys	Annual modelled system cost (MUSD/yr)
RRE	Renewable share of electricity production (%)
λgas	Gas-price multiplier relative to the year-specific baseline price
pc	Carbon price (USD/tCO_2)
α	Deterministic retained-capacity factor used in the derating sensitivity
ρ	RET fuel-substitution ratio, −ΔFgas/ΔFcoal (input-energy basis)

1. Introduction

Malaysia's power-sector transition now has a clearer coal-retirement trajectory. In 2025, the Ministry of Energy Transition and Water Transformation stated an objective to reduce coal-fired capacity by 50% by 2035 and fully retire coal-fired power plants by 2044 [1]. The National Energy Transition Roadmap (NETR) had already ruled out new coal-fired generation, raised the long-term renewable-capacity ambition and retained natural gas as a transition fuel [2]. The planning challenge is therefore one of sequencing: coal capacity must decline while electricity demand grows, variable renewable energy expands and the system continues to require dispatchable and flexible supply.

This challenge is regional as well as national. Southeast Asian electricity demand is growing rapidly, while fossil-fuel price and import exposure remain important energy-security concerns [3]. For Malaysia and other mid-stage variable-renewable systems, the IEA emphasises improved forecasting and operations, flexibility procurement, storage and stronger grids as renewable penetration rises [4]. The 2026 Southeast Asia Energy Outlook identifies a continuing role for gas-fired generation while also highlighting regional exposure to imported gas and international market conditions [5]. The model used here does not convert each incremental unit of gas consumption into LNG imports, but it does quantify the additional gas requirement that future fuel-supply planning would need to accommodate.

Coal phase-down is therefore not only an emissions decision. Withdrawing coal can shift energy production toward gas, renewable electricity, storage, imports or other resources depending on the replacement portfolio. Recent regional work on power-system modernisation beyond coal similarly stresses that existing coal units provide energy and operational services that must be replaced during transition [6]. At the same time, greater dependence on gas can create new prices, infrastructure and carbon-lock-in risks if its role is not explicitly bound [7]. A system-level assessment should therefore track cross-fuel substitution alongside emissions and cost rather than assume that coal retirement automatically reduces total fossil-fuel exposure.

Malaysia-focused studies provide an increasingly strong basis for such analysis. IRENA's national outlook evaluates renewable expansion, electrification, batteries and regional integration [8]. Recent high-temporal-resolution national modelling studies examine Malaysian renewable deployment, storage, transmission, trade and long-term generation pathways. EnergyPLAN is applied in [9,10], while [11] uses a complementary LEAP–NEMO framework. Recent storage reviews further identify grid integration, market design and technical standards as conditions for larger BESS deployment [12,13]. These studies inform national pathway design, but they do not isolate the incremental whole-system effect of changing the transition treatment of one large thermal asset while holding the wider national pathway fixed.

The broader literature indicates that coal-transition sequencing involves at least three distinct system questions: what flexible service is temporarily retained, which fuel or technology replaces withdrawn coal energy, and how the replacement portfolio changes longer-term exposure to fuel prices, emissions and infrastructure lock-in. Lin and Liu [14], using hourly modelling, compare flexible coal operation with BESS and find a short-term role for coal flexibility but stronger long-term value from storage as renewable penetration rises. For an importing system, Lee et al. [15] shows that coal-to-gas substitution can reduce direct combustion emissions while creating upstream LNG and supply-chain dependencies that are invisible in plant-level accounting. Together, these studies reinforce the need to evaluate coal retirement as a portfolio substitution problem rather than as a stand-alone capacity withdrawal.

A second strand concerns transitional use of existing thermal assets. Malaysian bioenergy modelling finds that biomass co-firing can reduce decarbonisation cost relative to building only dedicated bioenergy capacity, but that the result is sensitive to feedstock and supply-chain costs [16]. Techno-economic and system-level studies similarly show that co-firing economics depend strongly on fuel price, logistics and carbon conditions [17,18]. The implication is that physical retention, fuel substitution within a retained unit, and non-fossil replacement should be separated analytically; combining them can obscure whether an observed benefit comes from retained capacity, lower-carbon fuel substitution or a different system portfolio.

Existing Malaysian studies provide strong national pathway evidence on renewable expansion, storage and long-term generation development [8–13], but the literature still leaves a narrower causal question unresolved: when the wider national pathway is held fixed, how does changing the treatment of one large thermal asset redistribute gas use, coal use, emissions and cost across the whole system? The present study is designed around that marginal system response. It therefore complements pathway-optimisation and national-scenario studies rather than replacing them.

This study addresses that gap through a controlled counterfactual design. The intervention is asset-specific, but the outcomes are system-wide. Peninsular Malaysia demand, the non-study generation fleet, renewable assumptions, hydropower, storage outside the intervention, and electricity exchange settings are held common between compared cases. Only the treatment of the anonymised 1,600 MW Study Thermal Asset (STA) and the explicitly defined renewable-plus-storage alternative are varied. Differences in gas requirement, coal use, operational CO_2, renewable share and modelled system cost can therefore be interpreted as conditional consequences of the transition intervention rather than as a new national forecast.

The paper makes three contributions. First, it quantifies whether managed coal phase-down transfers fuel exposure toward natural gas and measures the associated carbon-cost trade-off. Second, it separates physical-capacity retention from co-firing, allowing the emissions effect of fuel substitution to be distinguished from the system effect of retained dispatchable capacity. Third, it tests an alternative solar-plus-storage package and evaluates the robustness of the main results across 120 gas-price, carbon-price, co-firing and thermal-derating cases. The methodological novelty is the controlled counterfactual: unlike comparisons between independently evolving national pathways, the wider year-specific system is held constant so that the marginal cross-fuel response to the STA intervention can be isolated. Price-only sensitivities are interpreted as cost-exposure screens because the adopted technical-regulation configuration does not economically redispatch generation in response to price changes. The novelty therefore lies not in proposing another national transition pathway, but in isolating the marginal system-wide fuel, emissions and cost consequences of alternative treatments of the same thermal asset under an otherwise common national pathway.

The analysis addresses four research questions:

RQ1. How does managed phase-down change whole-system gas requirements relative to temporary retention, and what CO_2 trade-off accompanies that change?

RQ2. How much can co-firing reduce the retention emissions penalty and how sensitive is its system-cost effect to substitute-fuel price?

RQ3.) How does additional solar plus four-hour battery storage compare across gas use, coal use, CO_2, renewable share and system cost? and

RQ4. Which conclusions remain robust to fuel-price, carbon-price and retained-capacity sensitivities without imposing subjective weights on competing objectives?

2. Methodology

2.1 Modelling framework and computational workflow

EnergyPLAN 16.22 was used as the core simulation model for the Peninsular Malaysian electricity system. The model is appropriate for this research question because it resolves full-year hourly energy balances while representing electricity generation, storage, fuel use, renewable integration, exchange, emissions and socio-economic system cost within one

consistent framework [19–22]. This makes it suitable for controlled portfolio comparisons in which the wider system is held constant, and the marginal effect of a defined intervention is traced across multiple system outcomes.

Scenario preparation, automated execution, input modification and output retrieval were managed in MATLAB using the EnergyPLAN MATLAB Toolbox (MaT4EnergyPLAN) [19], with custom scripts used for scenario generation, batch execution, validation, post-processing, sensitivity management and comparative analysis. EnergyPLAN produced the chronological and annual system outputs for fuel use, electricity production, renewable contribution, storage, electricity exchange, operational CO2 emissions and annual system cost [20–22].

MATLAB was then used to calculate scenario differences, cost-parity estimates, Pareto classifications and quality-assurance diagnostics from the EnergyPLAN outputs. The framework is not used as a substitute for security-constrained unit commitment or dynamic network simulation; those questions are explicitly outside the analytical boundary.

The workflow separates simulation from analytical post-processing. EnergyPLAN determines the physical system response under the adopted technical-regulation configuration, while MATLAB organises controlled scenario changes and derives comparative indicators without altering EnergyPLAN dispatch. The same year-specific national assumptions and chronological structure are therefore retained across paired scenarios. The term Study Thermal Asset (STA) and generic scenario labels are used to protect plant-identifying information while preserving the intervention logic required for reproducibility.

2.2 Data sources and input construction

The model database combines public policy and system information with technical and economic inputs provided by relevant Malaysian energy-sector stakeholders. Hourly electricity-demand, hydropower and solar distributions were derived from the high-temporal-resolution GSO data used in the controlled Peninsular Malaysia model, consistent with the data provenance reported in recent national modelling [910]. Technology-performance, fuel-price, capital-cost and operating-cost assumptions were compiled from published sources and controlled stakeholder or project inputs. Institution-, plant- and contract-specific values are not identified; common assumptions are applied across paired scenarios so that observed differences reflect the intervention being tested rather than changes in the underlying national dataset.

Each assessment year is represented at hourly resolution using full-year chronological profiles for electricity demand, hydropower and solar availability. The same chronological structure is retained across all paired scenarios to preserve hour-to-hour consistency in comparative analysis. Annual demand, capacity, fuel and economic assumptions are specified separately for each planning year.

As an external demand-scale check, the controlled 2025 model peak is 21,065 MW, compared with the Energy Commission's recorded Peninsular Malaysia maximum demand of 21,049 MW on 28 May 2025 [23]. The 16 MW difference is approximately 0.076%. This check supports the overall demand scale of the controlled dataset but is not presented as a full calibration of hourly dispatch, adequacy or dynamic system behaviour.

2.3 System boundary and analytical scope

The system boundary includes electricity demand, installed generation capacity, hourly renewable availability, dispatchable thermal generation and fuel consumption, battery charging and discharging, electricity exchange, critical excess electricity production (CEEP), operational CO_2 emissions and annual system cost. The analysis is a deterministic portfolio-level energy-system assessment rather than a security-constrained unit-commitment, production-cost or dynamic-stability simulation.

Accordingly, the model is used to compare whole-system fuel, emissions, renewable-share and cost consequences of the controlled transition interventions. It does not resolve domestic gas production, LNG contracts, pipeline constraints, unit-specific commitment constraints, AC power flow, frequency stability or project-level financing. Battery nameplate capacity is likewise not interpreted as a formal capacity-credit or reliability measure. These boundaries are retained throughout the interpretation of the results and sensitivity cases.

2.4 Scenario design and controlled intervention

The scenario design preserves a common year-specific Peninsular Malaysia pathway while varying only the STA treatment or the explicitly defined renewable-plus-storage intervention. The intervention window comprises 2030, 2035

and 2040 because these are the planning years in which the controlled scenarios differ. Managed phase-down (PD) follows the common pathway with no incremental retained STA block. Temporary retention (RET) adds 1,600 MW of STA capacity in 2030, 2035 and 2040.

RET-CF retains the same 1,600 MW physical block as RET while shifting a defined share of its coal fuel to the configured substitute-fuel slot. RE-ST instead adds 3,200 MW of solar PV and a 1,600 MW/6.4 GWh four-hour BESS package. The RE-ST sizing is intentionally transparent rather than optimisation derived. Solar nameplate capacity is set at twice the retained STA capacity, BESS power equals the 1,600 MW STA nameplate, and four-hour duration gives 6.4 GWh of energy capacity.

The purpose is to create a reproducible screening comparator with enough renewable energy and intra-day storage to test whether the coal-to-gas substitution mechanism can be structurally changed, not to claim thermal-equivalent capacity or a least-cost design. This choice is consistent with the wider literature that treats BESS as an increasingly important flexibility resource as renewable penetration rises [12–14], while preserving a clear distinction between energy-shifting capability and probabilistic firm capacity.

The 2:1 solar-to-thermal and 1:1 BESS-power scaling rules are therefore experimental design choices that keep the intervention proportional to the 1,600 MW STA and make the comparison auditable across years. All non-intervention assumptions remain on the same year-specific basis, and the package is incremental to the evolving national renewable and storage pathway. Post-2040 convergence is a scenario-design condition rather than a statement that physical assets necessarily disappear at that date.

Table 1. Controlled scenario architecture and intervention boundaries.

Scenario	Public description	Intervention boundary	Analytical role
PD	Managed phase-down	No incremental STA retention; common national pathway retained.	Counterfactual for incremental system effects.
RET	Temporary thermal retention	+1,600 MW STA retention in 2030, 2035 and 2040.	Tests gas substitution and the value of temporary dispatchable capacity.
RET-CF	Retention + co-firing	Same +1,600 MW retained block as RET; a defined coal-fuel share is shifted to the substitute-fuel slot.	Separates the co-firing fuel effect from the physical retention effect.
RE-ST	Additional RE + storage	+3,200 MW solar PV and +1,600 MW / 6.4 GWh four-hour BESS.	Alternative portfolio for fuel use, emissions, renewable share and system cost.

2.5 Core outcome metrics

For scenario s and planning year y, the incremental effect relative to the managed phase-down scenario (PD) is defined as

$$\Delta X_{s,y} = X_{s,y} - X_{PD,y} \tag{1}$$

where

$$X \in \left\{F^{\mathrm{gas}}, F^{\mathrm{coal}}, E^{\mathrm{CO_2}}, R^{\mathrm{RE}}, C^{\mathrm{sys}}\right\} \tag{2}$$

Here, F^{gas} denotes the annual system natural-gas fuel requirement (TWh), F^{coal} the annual system coal-fuel requirement (TWh), E^{CO_2} annual operational CO_2 emissions (Mt/yr), RRE the renewable share of electricity production (%), and C^{sys} the annual modelled system cost (MUSD/yr).

The change in annual natural-gas requirement is calculated as

$$\Delta F^{\mathrm{gas}}_{s,y} = F^{\mathrm{gas}}_{s,y} - F^{\mathrm{gas}}_{PD,y} \tag{3}$$

while the change in annual coal-fuel requirement is

$$\Delta F_{s,y}^{\text{coal}} = F_{s,y}^{\text{coal}} - F_{PD,y}^{\text{coal}} \tag{4}$$

The corresponding change in annual operational CO_2 emissions is

$$\Delta E_{s,y}^{\text{CO}_2} = E_{s,y}^{\text{CO}_2} - E_{PD,y}^{\text{CO}_2} \tag{5}$$

Changes in renewable share and annual system cost are calculated as

$$\Delta R_{s,y}^{\text{RE}} = R_{s,y}^{\text{RE}} - R_{PD,y}^{\text{RE}} \tag{6}$$

and

$$\Delta C_{s,y}^{\text{sys}} = C_{s,y}^{\text{sys}} - C_{PD,y}^{\text{sys}} \tag{7}$$

The sign of each incremental indicator is interpreted as:

$$\boldsymbol{\Delta X_{s,y}} \begin{cases} < \mathbf{0}, & \textbf{scenario } \boldsymbol{s} \textbf{ produces a lower value than } \boldsymbol{PD}, \\ = \mathbf{0}, & \textbf{scenario } \boldsymbol{s} \textbf{ produces the same value as } \boldsymbol{PD}, \\ > \mathbf{0}, & \textbf{scenario } \boldsymbol{s} \textbf{ produces a higher value than } \boldsymbol{PD}. \end{cases}$$

For $\boldsymbol{R^{\text{RE}}}$ the change should be reported in percentage points, whereas the remaining indicators retain their respective physical or monetary units.

2.6 Baseline fuel prices and emissions treatment

Baseline fuel prices are taken from the project-supplied Malaysian power-sector technical dataset (Table 2). Source values in RM/GJ were converted to USD/GJ using the project exchange-rate assumption of RM4.28/USD, providing a consistent monetary basis for the EnergyPLAN cost inputs used in this study. The resulting coal prices are 5.369, 5.374 and 6.308 USD/GJ and gas prices are 12.070, 14.110 and 15.129 USD/GJ for 2030, 2035 and 2040, respectively. These are controlled scenario assumptions rather than market-price forecasts.

No explicit carbon charge is imposed in the controlled baseline cases:

$$p_c = 0 \text{ USD/tCO}_2$$

The zero value denotes the absence of an explicit carbon-price term in the baseline EnergyPLAN simulations. Carbon-price exposure is tested separately in Section 2.7 and should not be interpreted as a forecast of future Malaysian carbon-pricing policy.

The controlled model applies direct-combustion CO_2 factors of 96.1 $kgCO_2/GJ$ for the aggregated coal representation and 56.1 $kgCO_2/GJ$ for natural gas. These values correspond to the 2006 IPCC default factors for sub-bituminous coal and natural gas [24] and are consistent with the factor convention used in Malaysia's Renewable Energy Roadmap [25].

The coal factor is retained as a source-controlled system-model assumption rather than interpreted as a plant-specific inventory factor. The IPCC default for other bituminous coal is 94.6 $kgCO_2/GJ$, compared with 96.1 $kgCO_2/GJ$ for sub-bituminous coal [24]. Because the STA is associated with bituminous-coal procurement, the aggregate factor introduces a small fuel-type approximation in asset-level interpretation. Preserving the controlled factor, however, maintains consistency across the whole-system scenario comparison.

RET-CF uses baseline co-firing shares of 5%, 10% and 20% in 2030, 2035 and 2040, respectively. The controlled baseline assigns a zero price to the substitute-fuel slot, so the baseline RET-CF cost result is treated as a bounding case rather than evidence that co-firing is intrinsically low cost.

Malaysian co-firing research shows that supply-chain and feedstock costs can materially affect deployment economics [17], while broader techno-economic work similarly identifies fuel and carbon-price conditions as important to co-firing viability [18]. Substitute-fuel price is therefore varied explicitly in the sensitivity analysis.

Annual system cost is reported in EnergyPLAN's MUSD output and is interpreted comparatively. Consistent with the EnergyPLAN socio-economic accounting framework [20–22], the controlled cost representation combines annualised investment, fixed and variable operation and maintenance, fuel, electricity-exchange and, where imposed, CO_2-price components. The controlled cost framework uses a real calculation interest rate of 2.7%; investment costs are annualised internally using economic lifetimes of 20 years for central thermal generation, 10 years for BESS, 21 years for solar PV and 60 years for interconnection infrastructure. Technology-specific CAPEX and OPEX values are drawn from project planning inputs and are subject to confidentiality restrictions; the same source-controlled assumptions are applied consistently across paired scenarios. Accordingly, the reported cost differences are system-level comparative indicators rather than project NPV, PPA value, retail-tariff effects or guaranteed avoided costs. Appendix A summarises the non-confidential controlled assumptions used to interpret the scenario comparison.

Table 2. Baseline fuel- and carbon-price assumptions for the controlled cases.

Year	Coal price (USD/GJ)	Gas price (USD/GJ)	Carbon price (USD/tCO_2)
2030	5.369	12.070	0
2035	5.374	14.110	0
2040	6.308	15.129	0

Note: Original fuel-price values were taken from the project-supplied technical dataset in RM/GJ and converted using RM4.28/USD. A carbon price of zero denotes the absence of an explicit carbon charge in the controlled baseline simulations.

2.7 Sensitivity design

Sensitivity analysis tests whether the relative performance of the four pathways remains robust when uncertain economic and technical assumptions are varied. Four dimensions are examined: natural-gas price, carbon price, co-firing share jointly with substitute-fuel price, and deterministic availability of the retained thermal block. Each sensitivity preserves the year-specific national demand, non-intervention capacity and renewable development assumptions.

The ranges are designed as structured stress tests rather than probabilistic forecasts. The 0.75-1.50 gas-price multipliers span a broad downside-to-upside fuel-cost envelope around each year-specific baseline; carbon prices of 0-100 USD/tCO2 test whether the economic ordering changes as the emissions externality becomes progressively material; the co-firing trajectories bracket low, base and higher fuel-substitution shares used to test a technology whose economics are known to be supply-chain and fuel-price sensitive [16–18]; and the 0.7-1.0 retained-capacity factors test whether the cross-fuel result survives substantial physical derating. This design deliberately separates price exposure from physical uncertainty so that each robustness claim can be traced to the parameter that drives it.

Gas-price sensitivity is applied to all four scenarios at 0.75×, 1.00×, 1.25× and 1.50× the year-specific baseline. Because the 1.00× cases are the accepted baselines, only the remaining three multipliers are rerun: 3 multipliers × 4 scenarios × 3 years = 36 new runs. The sensitivity quantifies how different fixed gas requirements translate into system-cost exposure.

Carbon-price sensitivity is also applied to all four scenarios. The controlled baseline contains no explicit carbon charge, and additional prices of 25, 50, 75 and 100 USD/tCO_2 are imposed: 4 non-zero prices × 4 scenarios × 3 years = 48 new runs. These cases quantify the economic exposure associated with different direct-combustion emissions rather than forecasting a future Malaysian carbon price.

Co-firing sensitivity is restricted to RET-CF. Three trajectories are tested: low (0%, 5%, 10%), base (5%, 10%, 20%) and high (10%, 20%, 30%) for 2030, 2035 and 2040. For each trajectory, substitute-fuel price is independently set to 0, 10 or 20 USD/GJ, producing 27 runs. The intervention is implemented physically by shifting the corresponding share of the retained thermal block from the coal fuel slot to the substitute-fuel slot while total retained capacity is unchanged.

The independent substitute-fuel-price test is essential because the zero-price baseline is a boundary assumption, not a market-cost estimate.

A final sensitivity test reduced effective availability of the retained thermal block. The retained-capacity factor α is applied deterministically to the 1,600 MW block and associated coal-fuel representation; it is not a probabilistic forced-outage model.

The tested retained-capacity factors are:

$$\alpha \in \{1.0, 0.9, 0.8, 0.7\}$$

The α = 1.0 case is the accepted RET baseline. The three derated values are run for 2030, 2035 and 2040, giving 9 new runs.

For a nominal 1,600 MW retained block, α = 0.9, 0.8 and 0.7 correspond to effective retained capacities of 1,440, 1,280 and 1,120 MW, respectively.

Taken together, the publication sensitivity set contains 36 + 48 + 27 + 9 = 120 new or explicitly evaluated EnergyPLAN cases.

Table 3. Sensitivity design used to test economic and technical robustness of the four transition pathways.

Sensitivity	Range	Scenarios	New reruns	Purpose
Gas price	0.75×, 1.00×, 1.25×, 1.50× year-specific baseline	PD, RET, RET-CF, RE-ST	36	Tests exposure to natural-gas price uncertainty; 1.00× is the controlled baseline
Carbon price	0, 25, 50, 75, 100 USD/tCO_2	PD, RET, RET-CF, RE-ST	48	Tests the economic effect of different direct-combustion emissions; zero is the controlled baseline
Co-firing share	Low: 0/5/10%; Base: 5/10/20%; High: 10/20/30% for 2030/2035/2040	RET-CF	27*	Tests progressively greater substitution of coal within the retained thermal block
Co-firing fuel price	0, 10, 20 USD/GJ	RET-CF	Included in 27*	Tests cost exposure to the substitute fuel and remove dependence on the zero-price baseline assumption
Thermal derating	α = 1.0 (baseline), 0.9, 0.8, 0.7	RET	9	Tests reduced effective availability of the retained 1,600 MW block; α = 1.0 is the baseline.

**Note: The 27 co-firing runs jointly combine three co-firing trajectories, three substitute fuel prices and three study years.*

The design separates economic exposure from physical uncertainty. Gas, carbon and substitute-fuel prices change cost accounting under the adopted dispatch configuration; co-firing share and thermal derating change the physical scenario representation.

The sensitivity ranges are structured stress tests around the controlled baseline rather than probability distributions or forecasts. They are used to test whether the direction and economic interpretation of the principal findings persists under lower and higher fuel/carbon-price exposure, alternative co-firing assumptions and reduced retained thermal availability.

2.8 Interpretation of price sensitivities

The gas-price, carbon-price and substitute-fuel-price cases were rerun through EnergyPLAN. Across all price-only comparisons, coal use, gas use, substitute-fuel use, CO_2 and renewable share remain unchanged within reported output precision; only annual system cost changes. Under the adopted technical-regulation configuration, these price inputs affect cost accounting but do not trigger market-based redispatch. The results are therefore interpreted as fixed-physical-dispatch cost-exposure screens.

For scenario s, fixed-dispatch cost parity against PD is estimated by linear interpolation of the tested cost difference ΔCsys as a function of the gas-price multiplier or carbon price. Because physical dispatch is invariant, the relationship is effectively linear over the tested range. Parity values outside that range are reported only as extrapolative context.

2.9 Pareto comparison

To avoid subjective weighting, the baseline 2030–2040 mean results are also assessed using Pareto dominance. Gas requirement, CO_2 and system cost are minimised, while renewable share is maximised. Scenario a dominates scenario b only when it is no worse in all four objectives and strictly better in at least one. This descriptive classification identifies trade-offs; it does not prescribe a preferred policy pathway. In practical planning, movement along the Pareto set would require policymakers and system planners to state explicitly how they prioritise fuel-security exposure, emissions reduction, renewable integration and system cost; the analysis therefore informs trade-offs rather than selecting a preferred pathway.

2.10 Validation, reproducibility and quality assurance

Validation and quality assurance are applied at multiple levels. First, an external demand-scale check compares the controlled 2025 model peak of 21,065 MW with the Energy Commission's recorded Peninsular Malaysia maximum demand of 21,049 MW, a difference of 16 MW or 0.076% [23]. As a second external plausibility benchmark, the Energy Commission reports that the 2025 transmission-connected energy mix remained dominated by coal (58.5%) and gas (33.5%), with renewable energy contributing 7.2% [26]. The controlled model is not calibrated to reproduce those annual shares exactly, but the official statistics confirm that the starting system context represented in the study is structurally coal- and gas-intensive. These checks are intentionally treated as scale and system-context validation rather than a full historical dispatch calibration.

Second, structural and accounting checks verify the hourly chronology, successful input/output parsing and consistency of the fuel-to-emissions arithmetic. For example, in 2035 RET increases coal fuel by 12.45 TWh and reduces gas fuel by 12.45 TWh relative to PD. Combined with the 40.0 $kgCO_2/GJ$ difference between the controlled coal and gas emission factors, this implies an emissions increment of approximately 1.793 $MtCO_2$, matching the EnergyPLAN result to reported precision. The derived RET fuel-substitution ratio is therefore approximately unity in all three study years.

Third, execution-level quality assurance cross-checks the full scenario matrix in MATLAB. All 120 sensitivity cases are represented in the publication dataset; 116 were fresh executions and four were previously validated executions reused without modification. Price-only cases were checked for invariance of physical outputs within reported precision, while coal fuel, gas fuel, substitute-fuel use, operational CO_2, renewable share, annual system cost and cost intensity were parsed and compared systematically. Table A2 reports the principal validation and reproducibility checks, and Appendix B summarises the sensitivity execution audit. These procedures support internal consistency and reproducibility of the controlled comparison but do not replace probabilistic reliability, unit-commitment or network validation.

3. Results

3.1 Baseline trade-off: lower gas requirement versus higher CO_2 under thermal retention

Table 4 presents the controlled baseline outcomes. Relative to PD, RET reduces natural-gas fuel use in every modelled year: by 9.35 TWh in 2030, 12.45 TWh in 2035 and 12.26 TWh in 2040, equivalent to approximately 5.3%, 4.8% and 3.9% of the corresponding PD gas requirements.

Table 4. Controlled baseline system outcomes for the 2030–2040 intervention window.

Scenario	Year	Gas (TWh)	Coal (TWh)	CO_2 (Mt)	RE (%)	Cost (MUSD)	USD/MWh
PD	2030	176.93	124.86	78.930	24.1	13563	73.628
PD	2035	257.52	66.03	74.852	31.1	19880	84.438
PD	2040	310.50	62.38	84.288	35.2	25063	91.715
RET	2030	167.58	134.22	80.277	24.1	13496	73.264
RET	2035	245.07	78.48	76.645	31.1	19629	83.372
RET	2040	298.24	74.63	86.053	35.2	24818	90.819
RET-CF	2030	167.58	133.42	80.001	24.3	13481	73.183
RET-CF	2035	245.07	76.92	76.104	31.4	19599	83.244

Scenario	Year	Gas (TWh)	Coal (TWh)	CO_2 (Mt)	RE (%)	Cost (MUSD)	USD/MWh
RET-CF	2040	298.24	71.69	85.035	35.7	24751	90.573
RE-ST	2030	170.21	120.11	75.930	27.0	13170	71.494
RE-ST	2035	250.79	64.31	72.897	33.0	19485	82.760
RE-ST	2040	304.41	61.15	82.634	36.8	24658	90.233

Across the three representative years, mean gas requirement falls from 248.32 TWh/yr under PD to 236.96 TWh/yr under RET, a mean reduction of 11.36 TWh/yr. This is a whole-system substitution effect rather than gas avoided directly by the STA. Fuel accounting makes the substitution mechanism explicit. RET increases coal use relative to PD by 9.36, 12.45 and 12.25 TWh in 2030, 2035 and 2040, almost matching the corresponding reductions in gas use. The resulting fuel-substitution ratios, ρ, are 0.999, 1.000 and 1.001, respectively. Renewable shares are unchanged between PD and RET. The dominant physical effect is therefore near one-for-one coal-for-gas substitution on a fuel-input-energy basis rather than a reduction in total fossil-fuel dependence.

The lower gas requirement has an emissions cost. RET raises operational CO_2 by 1.347 Mt in 2030, 1.793 Mt in 2035 and 1.765 Mt in 2040. The result is internally consistent with the controlled emission factors: replacing 1 TWh of gas fuel with 1 TWh of coal fuel increases direct CO_2 by approximately 0.144 Mt, so the 12.45 TWh substitution in 2035 implies about 1.79 Mt of additional CO_2, matching the simulation.

Under the controlled baseline fuel prices, the economic effect moves in the opposite direction to the emissions effect. RET reduces annual system cost relative to PD by USD 67 million in 2030, USD 251 million in 2035 and USD 245 million in 2040. Mean system cost is therefore approximately USD 188 million/yr lower across the three representative years.

The baseline RET result is consequently a cross-fuel trade-off: lower system gas requirement and lower modelled system cost are obtained through higher coal use and higher direct-combustion CO_2. This finding should not be interpreted as a decarbonisation benefit or as evidence of avoided LNG imports. It quantifies how temporary retention changes the fuel balance of the wider Peninsular system under the controlled assumptions.

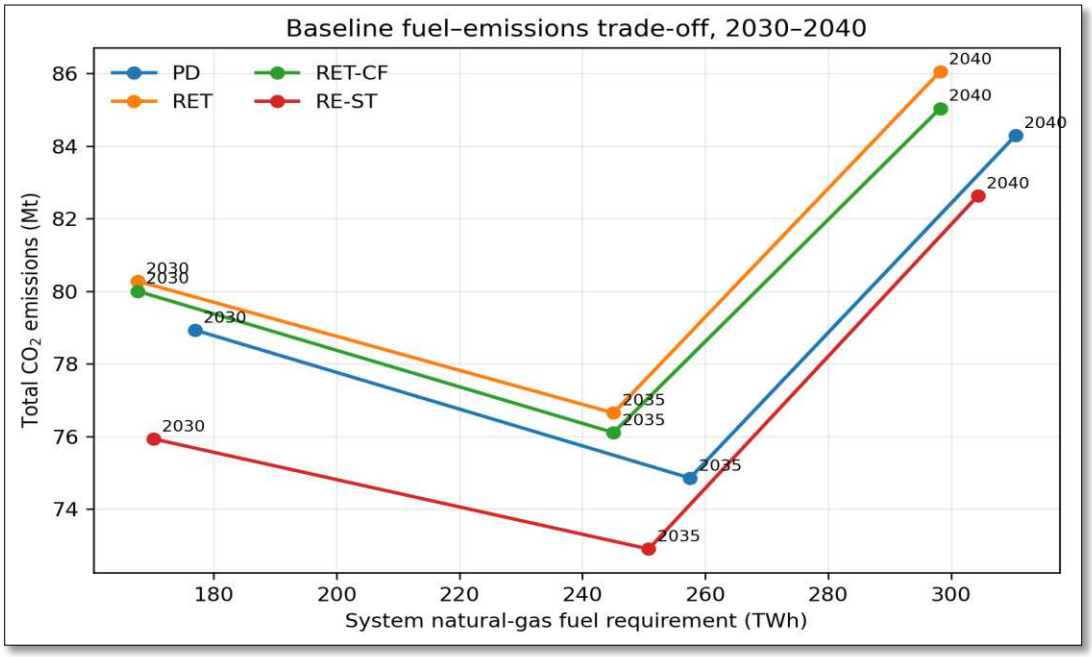


Figure 1. Baseline natural-gas requirement and CO_2 trade-off.
Year labels identify each scenario point

Figure 1 visualises the fuel emissions trade-off across the four pathways and three representative planning years. The horizontal position of each point represents annual natural-gas requirement, while the vertical position shows operational CO_2 emissions. The PD cases lie further to the right because managed coal phase-down requires more natural gas, whereas

RET and RET-CF shift leftward as retained thermal generation displaces gas elsewhere in the system. This lower gas requirement, however, is accompanied by higher CO_2 emissions under RET because the displaced gas is replaced predominantly by coal.

RET-CF occupies essentially the same gas-use position as RET but moves downward because co-firing lowers the emissions intensity of the retained thermal block without changing its 1,600 MW physical contribution. Relative to RET, operational CO_2 falls by 0.276 Mt in 2030, 0.541 Mt in 2035 and 1.018 Mt in 2040 as the configured co-firing share increases from 5% to 10% and 20%, respectively. The unchanged gas requirement reflects the unchanged retained-capacity contribution, while the emissions reduction arises from fuel substitution within the retained block. Renewable share rises modestly because the substitute-fuel slot is treated as renewable in the controlled model. The associated cost result is assessed separately because the baseline substitute-fuel price is zero; Section 3.4 tests the sensitivity of this assumption.

RE-ST produces a structurally different response. Relative to PD, natural-gas use falls by 6.72, 6.73 and 6.09 TWh in 2030, 2035 and 2040, respectively, while coal use also declines by 4.75, 1.72 and 1.23 TWh. Operational CO_2 consequently falls by 3.000, 1.955 and 1.654 Mt, while renewable share increases from 24.1% to 27.0%, from 31.1% to 33.0%, and from 35.2% to 36.8%. In Figure 1, RE-ST therefore shifts both leftward and downward relative to PD, showing that the renewable-plus-storage pathway reduces natural-gas requirements and operational emissions simultaneously rather than primarily shifting the balance between coal and gas. Figure 1 thus distinguishes three transition mechanisms: RET primarily substitutes coal for gas within the wider system; RET-CF preserves this gas-displacement effect while moderating the associated emissions penalty; and RE-ST changes the replacement structure by reducing both coal and gas requirements.

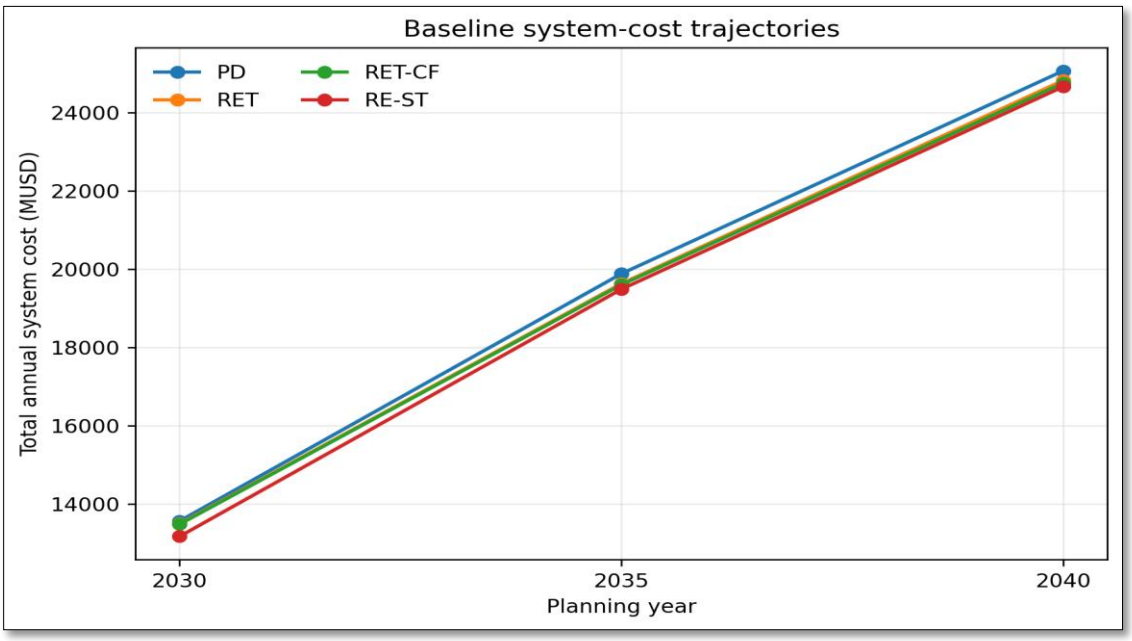


Figure 2. Baseline total annual system cost by scenario and modelled year.
Note: RET-CF costs reflect the controlled zero-price co-firing fuel assumption and are tested separately through substitute-fuel price sensitivity.

Figure 2 shows that these physical differences are accompanied by distinct cost outcomes. RE-ST has a lower modelled annual system cost than PD in each study year, by USD 393 million in 2030, USD 395 million in 2035 and USD 405 million in 2040. RET and RET-CF are also below PD under the controlled baseline assumptions, although the RET-CF cost result remains conditional on the zero-price substitute-fuel assumption and is examined further in the co-firing sensitivity analysis.

Table 5 summarises the arithmetic mean across the three representative years. RET lowers mean natural-gas use by 11.36 TWh/yr but raises mean coal use by 11.36 TWh/yr and mean operational CO_2 by 1.63 Mt/yr relative to PD. RET-CF retains the same mean gas requirement while lowering mean coal use and CO_2 relative to RET. RE-ST lowers mean gas

use by 6.52 TWh/yr and mean coal use by 2.56 TWh/yr relative to PD; mean CO_2 falls by 2.21 Mt/yr, renewable share rises by 2.14 percentage points, and modelled system cost falls by approximately USD 398 million/yr.

Taken together, these results show that the four pathways differ not only in magnitude but also in mechanism. RET primarily reallocates fossil-fuel use from gas toward coal, RET-CF partially mitigates the carbon consequence of that retention, and RE-ST reduces both principal fossil-fuel requirements while increasing renewable penetration.

Table 5. Arithmetic means of baseline system outcomes across 2030, 2035 and 2040.

Scenario	Mean gas	Mean coal	Mean CO_2	Mean RE	Mean cost	Mean USD/MWh
PD	248.32	84.42	79.36	30.13%	19502	83.26
RET	236.96	95.78	80.99	30.13%	19314	82.48
RET-CF	236.96	94.01	80.38	30.47%	19277	82.33
RE-ST	241.80	81.86	77.15	32.27%	19104	81.50

Note: Values are summary statistics across three discrete planning-year states and are not time-weighted averages over the full 2030–2040 period.

3.2 Gas-price sensitivity: cost exposure under fixed dispatch

Changing the gas price from 0.75× to 1.50× the year-specific baseline does not alter physical fuel use, CO_2 emissions or renewable share within any scenario-year. The sensitivity therefore isolates cost exposure associated with each pathway's fixed natural-gas requirement. Because PD uses more gas than RET and RET-CF, its annual system cost increases more rapidly as the gas-price multiplier rises.

In 2030, RET is approximately USD 35 million/yr more costly than PD at 0.75× the baseline gas price, USD 67 million/yr less costly at 1.00×, and USD 270 million/yr less costly at 1.50×. Linear interpolation gives a fixed-dispatch parity multiplier of 0.836. RET-CF exhibits a similar pattern, with a 2030 parity multiplier of 0.799.

Figure 3 illustrates this relationship for 2030 by plotting the system-cost difference of RET, RET-CF and RE-ST relative to PD across the tested gas-price multipliers. Negative values indicate that the alternative pathway has a lower modelled annual system cost than PD, while positive values indicate a higher cost.

The downward trajectories of RET and RET-CF show that their relative cost position improves as the gas price increases because both pathways require less natural gas than PD. RET crosses the zero-cost-difference line between 0.75× and 1.00×, consistent with the estimated parity multiplier of 0.836, while RET-CF crosses at a slightly lower multiplier of 0.799. RE-ST remains well below the zero line throughout the tested range, reflecting the combination of lower natural-gas requirement and lower baseline system cost.

In 2035 and 2040, RET and RET-CF remain below PD throughout the tested 0.75×–1.50× range; their estimated parity multipliers lie below the lower bound and are therefore reported only as extrapolative context. RE-ST remains below PD at every tested multiplier and in every modelled year because it combines lower gas use with a lower baseline system cost.

At 0.75× the baseline gas price, RE-ST is approximately USD 320, 309 and 322 million/yr below PD in 2030, 2035 and 2040, respectively. At 1.50×, the corresponding differences widen to approximately USD 539, 566 and 571 million/yr. Higher gas prices therefore increase the economic value of pathways with lower fixed natural-gas requirements under the adopted cost-accounting framework.

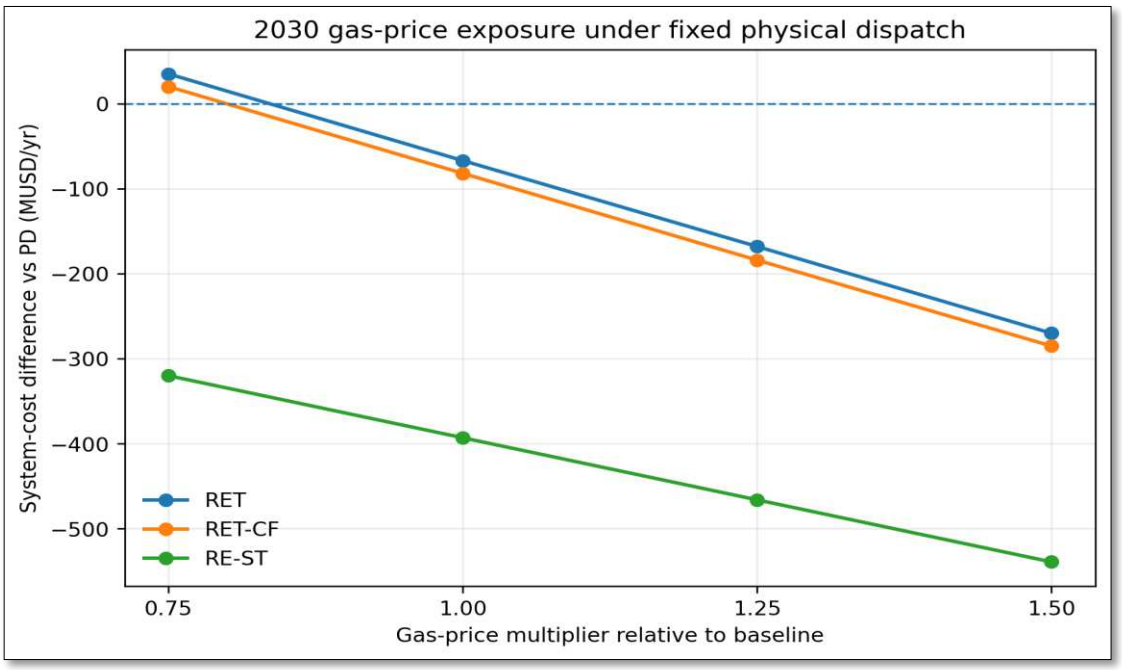


Figure 3. 2030 system-cost difference compared to PD across the gas-price sensitivity.
Note: Physical dispatch is unchanged in these price-only runs.

The gas price results should be seen as exposure analysis rather than market response analysis. They show how the same physical pathways respond economically to alternative gas-price assumptions; they do not imply that EnergyPLAN economically redispatches generation in these cases.

3.3 Carbon-price sensitivity: exposure to the retention emissions penalty

Carbon-price sensitivity also leaves physical dispatch unchanged, so annual cost changes are determined by each scenario's fixed CO_2 output. Increasing the carbon price progressively erodes the system-cost advantage of RET and RET-CF relative to PD because both emit more CO_2, while it strengthens the cost advantage of RE-ST because RE-ST emits less.

In 2030, RET moves from USD 67 million/yr below PD at zero carbon price to approximate parity at USD 49.9/tCO_2 and becomes about USD 68 million/yr more costly than PD at USD 100/tCO_2. RET-CF retains a wider margin because co-firing lowers its emissions penalty; its corresponding 2030 parity is approximately USD 76.9/tCO_2.

In 2035 and 2040, RET remains below PD even at the highest tested carbon price of USD 100/tCO_2. Estimated parity values of USD 139.8/tCO_2 and USD 139.1/tCO_2 lie outside the tested range and are therefore extrapolative. RET-CF has still higher extrapolated parity values because its retained gas displacement is combined with lower emissions than plain RET. RE-ST has no positive parity point within the tested space: its baseline cost and CO_2 are both below PD, so carbon pricing widens rather than narrows its modelled cost advantage. At USD 100/tCO_2, RE-ST is approximately USD 693, 590 and 571 million/yr below PD in 2030, 2035 and 2040.

Figure 4 and Table 6 therefore quantify the cost of fixed emissions differences. They should not be interpreted as wholesale-market switching thresholds because price-responsive unit commitment and redispatch are outside the adopted configuration.

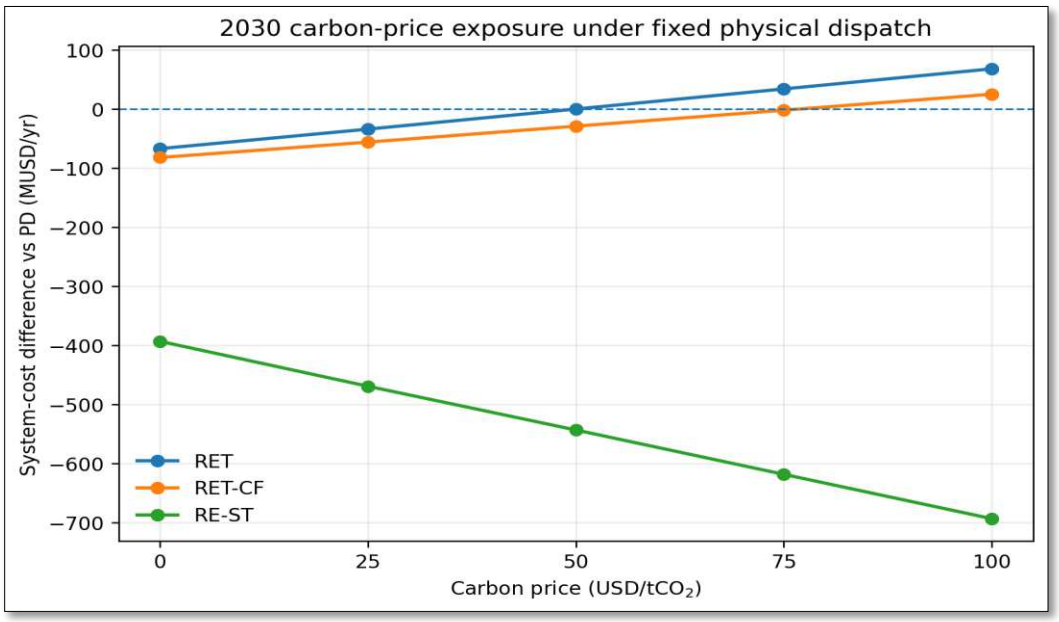


Figure 4. 2030 system-cost difference relative to PD across the carbon-price sensitivity.
Note: Physical dispatch is unchanged in these price-only runs.

Table 6. Fixed-dispatch system-cost parity estimates relative to PD; values outside the tested range are extrapolative.

Scenario	Year	Gas-price parity multiplier	Carbon-price parity (USD/tCO₂)	Interpretation within tested range
RET	2030	0.836	49.9	Parity lies within/near tested range.
RET	2035	0.603	139.8	Parity lies outside tested range.
RET	2040	0.633	139.1	Parity lies outside tested range.
RET-CF	2030	0.799	76.9	Parity lies within/near tested range.
RET-CF	2035	0.556	224.2	Parity lies outside tested range.
RET-CF	2040	0.532	421.1	Parity lies outside tested range.
RE-ST	2030	n/a	n/a	No tested parity; RE-ST remains below PD.
RE-ST	2035	n/a	n/a	No tested parity; RE-ST remains below PD.
RE-ST	2040	n/a	n/a	No tested parity; RE-ST remains below PD.

3.4 Co-firing: emissions benefit with a fuel-price-dependent cost boundary

The co-firing-share sensitivity produces an approximately proportional reduction in coal use and operational CO_2 emissions while leaving system natural-gas use unchanged. As shown in Figure 5, relative to RET, operational CO_2 emissions decline by 0.276 and 0.552 Mt/yr at co-firing shares of 5% and 10% in 2030; by 0.270, 0.541 and 1.082 Mt/yr at shares of 5%, 10% and 20% in 2035; and by 0.509, 1.018 and 1.527 Mt/yr at shares of 10%, 20% and 30% in 2040.

The near-proportional response confirms that, within the adopted model representation, the principal physical effect of co-firing is to displace a portion of coal consumption and its associated direct-combustion emissions without altering the retained thermal capacity or the wider system gas requirement.

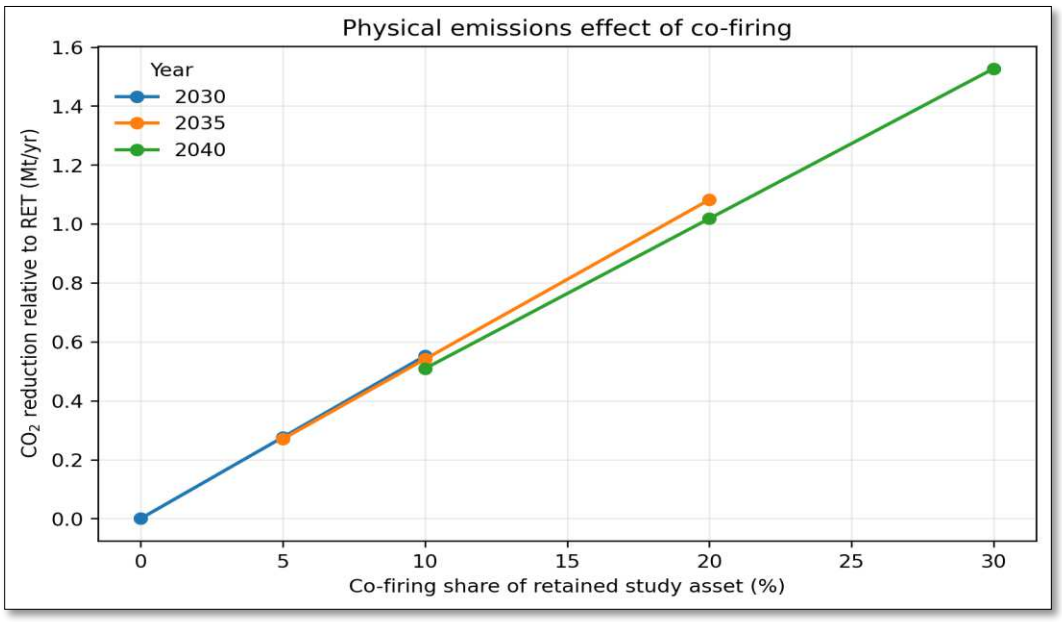


Figure 5. CO_2 reduction from co-firing relative to plain RET.
Note:The result is independent of substitute fuel price in the tested fixed-dispatch cases.

The economic interpretation changes when a non-zero substitute-fuel price is introduced. Table 7 summarises the resulting cost effects at the controlled baseline co-firing shares of 5%, 10% and 20% for 2030, 2035 and 2040, respectively. With a zero substitute-fuel price, RET-CF is less costly than RET by approximately USD 15 million in 2030, USD 30 million in 2035 and USD 67 million in 2040. At a substitute-fuel price of USD 10/GJ, however, this ordering reverses, with RET-CF becoming more costly than RET by approximately USD 14, 26 and 39 million, respectively. At USD 20/GJ, the corresponding cost increments increase to approximately USD 42, 82 and 145 million.

Linear interpolation indicates that cost parity between RET-CF and RET occurs at approximately USD 5.20/GJ in 2030, USD 5.36/GJ in 2035 and USD 6.32/GJ in 2040, as reported in Table 7. These values are close to the corresponding modelled coal-fuel prices. The more robust finding is therefore the reduction in coal use and operational CO_2 associated with increasing co-firing shares, rather than a general system-cost advantage for co-firing. The economic attractiveness of RET-CF depends strongly on the effective price of the substitute fuel.

Table 7. Co-firing sensitivity at the controlled base co-firing shares.

Year	Co-firing share	CO_2 reduction vs RET	Cost parity fuel price	ΔCost at USD 10/GJ	ΔCost at USD 20/GJ
2030	5%	0.276 Mt	5.20 USD/GJ	+14 MUSD	+42 MUSD
2035	10%	0.541 Mt	5.36 USD/GJ	+26 MUSD	+82 MUSD
2040	20%	1.018 Mt	6.32 USD/GJ	+39 MUSD	+145 MUSD

Actual deployment would additionally depend on factors outside the present EnergyPLAN representation, including substitute-fuel availability and transport costs, boiler efficiency and derating, auxiliary consumption, fuel-handling requirements, sustainability criteria and supply-chain reliability [17,18]. Consequently, the results position co-firing as a potentially useful means of moderating the emissions penalty of temporary thermal retention, but not as an inherently lower-cost transition option.

3.5 Thermal derating: the gas-reduction effect weakens but remains present

Deterministic derating reduces only the effective contribution of the retained STA while preserving the common national pathway and all non-intervention assumptions. As the retained-capacity factor α declines from 1.0 to 0.7, coal use falls and natural-gas use rise, indicating that part of the lost retained coal contribution is replaced by gas elsewhere in the modelled system. Figure 6 illustrates this pattern clearly: the gas-saving effect of retention becomes progressively smaller as the effective retained contribution is reduced.

Even at α = 0.7, however, gas use remains below the corresponding PD case by 6.65 TWh in 2030, 8.85 TWh in 2035 and 8.68 TWh in 2040. At the same derating level, annual system cost also remains below PD by USD 49 million, USD 180 million and USD 175 million, respectively, while operational CO_2 emissions remain above PD by 0.958, 1.274 and 1.251 Mt. Table 8 reports the full set of deterministic retained-capacity sensitivity results relative to PD.

Taken together, the results show that the gas-reduction benefit of temporary thermal retention is robust to the tested deterministic derating, although its magnitude declines as effective retained capacity falls. The same pattern is observed for system cost and emissions: lower retained availability reduces the gas-saving and cost-saving effects of RET, while also narrowing, but not eliminating, its emissions penalty relative to PD. The implication is that partial underperformance of the retained thermal block weakens the benefit of retention but does not reverse the underlying direction of the coal-to-gas substitution effect within the tested sensitivity range.

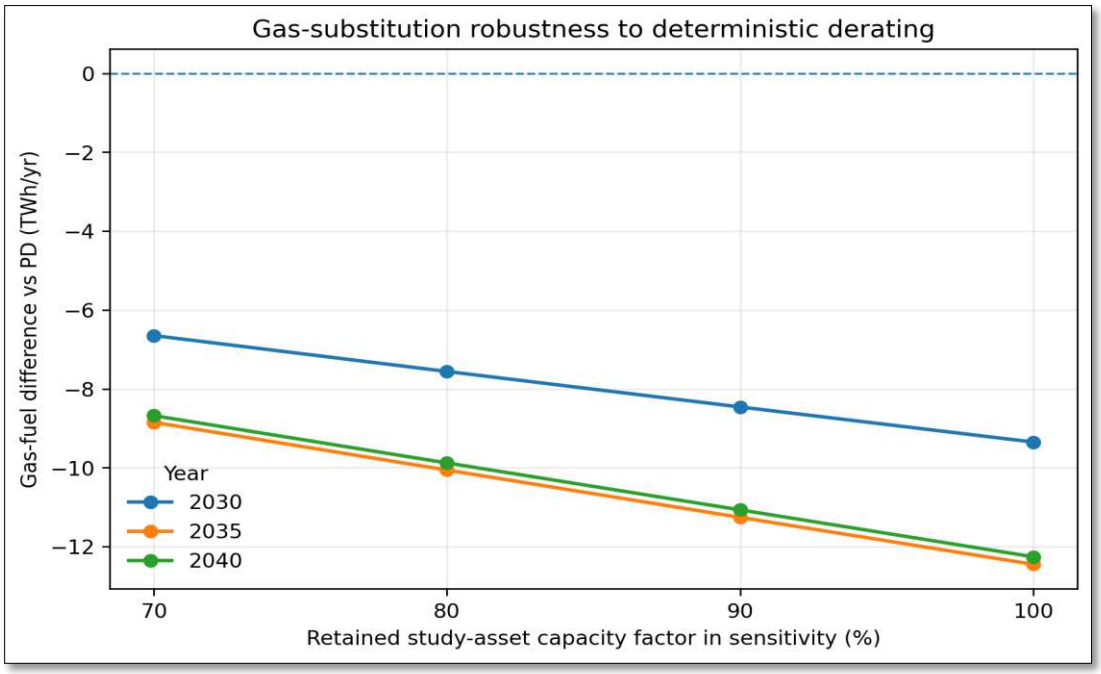


Figure 6. Gas-fuel difference relative to PD as the retained STA contribution is deterministically derated.

Table 8 quantifies this derating effect across all three study years. At every tested retention factor, RET continues to use less natural gas than PD while producing higher operational CO_2 emissions. As the retention factor declines from 0.9 to 0.7, the magnitude of the gas-saving effect decreases systematically: from 8.46 to 6.65 TWh in 2030, from 11.26 to 8.85 TWh in 2035, and from 11.07 to 8.68 TWh in 2040. The corresponding cost advantage also narrows, from USD 61 million to USD 49 million in 2030, from USD 228 million to USD 180 million in 2035, and from USD 222 million to USD 175 million in 2040. At the same time, the emissions penalty relative to PD declines as the retained contribution is reduced.

Even at α = 0.7, however, gas use remains below the corresponding PD case by 6.65 TWh in 2030, 8.85 TWh in 2035 and 8.68 TWh in 2040. At the same derating level, annual system cost also remains below PD by USD 49 million, USD

180 million and USD 175 million, respectively, while operational CO_2 emissions remain above PD by 0.958, 1.274 and 1.251 Mt. Table 8 reports the full set of deterministic retained-capacity sensitivity results relative to PD.

Taken together, Figure 6 and Table 8 show that the gas-reduction benefit of temporary thermal retention is robust to the tested deterministic derating, although its magnitude declines as effective retained capacity falls. Lower retained availability reduces both the gas-saving and cost-saving effects of RET while also narrowing, but not eliminating, its emissions penalty relative to PD. Partial underperformance of the retained thermal block therefore weakens the benefit of retention without reversing the underlying direction of the coal-to-gas substitution effect within the tested sensitivity range.

Table 8. Deterministic retained-capacity sensitivity relative to PD.

Year	Retention factor	Gas vs PD (TWh)	CO_2 vs PD (Mt)	Cost vs PD (MUSD)	Interpretation
2030	0.9	-8.46	+1.219	-61	Lower gas, higher CO_2 than PD
2030	0.8	-7.56	+1.089	-55	Lower gas, higher CO_2 than PD
2030	0.7	-6.65	+0.958	-49	Lower gas, higher CO_2 than PD
2035	0.9	-11.26	+1.622	-228	Lower gas, higher CO_2 than PD
2035	0.8	-10.06	+1.449	-204	Lower gas, higher CO_2 than PD
2035	0.7	-8.85	+1.274	-180	Lower gas, higher CO_2 than PD
2040	0.9	-11.07	+1.595	-222	Lower gas, higher CO_2 than PD
2040	0.8	-9.88	+1.424	-199	Lower gas, higher CO_2 than PD
2040	0.7	-8.68	+1.251	-175	Lower gas, higher CO_2 than PD

3.6 Multi-objective comparison

The baseline pathways were also compared using Pareto dominance to examine whether any scenario performs unambiguously better across the four selected objectives: lower natural-gas requirement, lower operational CO_2 emissions, lower modelled system cost and higher renewable-energy share. The comparison uses the arithmetic mean of the 2030, 2035 and 2040 outcomes and is intended to identify trade-offs rather than to assign subjective weights or select a single preferred pathway.

As summarised in Table 9, the baseline Pareto set contains RET-CF and RE-ST. PD is dominated by RE-ST because RE-ST exhibits lower mean gas use, lower operational CO_2, lower modelled system cost and a higher renewable share across the three representative years. RET is dominated by RET-CF under the controlled baseline assumption because both scenarios have the same mean gas requirement, while RET-CF produces lower mean CO_2, a slightly higher renewable share and a lower modelled system cost.

The baseline classification, however, is sensitive to the economic assumptions applied to co-firing. The lower system cost of RET-CF relative to RET depends on the controlled zero-price substitute-fuel assumption. As demonstrated by the co-firing sensitivity in Section 3.4, once the substitute fuel price rises above the estimated parity level, RET-CF can lose its cost advantage over RET. Under those conditions, neither pathway necessarily dominates the other: RET may retain the lower system cost, while RET-CF maintains lower operational CO_2 emissions and a higher renewable share.

The comparison between RET-CF and RE-ST reveals a more fundamental trade-off. RET-CF achieves the lowest mean natural-gas requirement among the four baseline pathways, whereas RE-ST achieves substantially lower operational CO_2, a higher renewable share and the lowest mean modelled system cost. Consequently, neither pathway dominates the other under the baseline four-objective formulation. This result reinforces the distinction between fuel-security performance and decarbonisation performance: the pathway that minimises gas exposure is not necessarily the pathway that minimises emissions or increases renewable penetration most strongly.

Table 9. Baseline Pareto classification using the arithmetic mean of the 2030, 2035 and 2040 outcomes.

Scenario	Mean gas	Mean CO_2	Mean RE	Mean cost	Pareto status	Dominated by
PD	248.32	79.36	30.13%	19502	Dominated	RE-ST
RET	236.96	80.99	30.13%	19314	Dominated	RET-CF
RET-CF	236.96	80.38	30.47%	19277	Non-dominated	-
RE-ST	241.80	77.15	32.27%	19104	Non-dominated	-

Note: Mean values are arithmetic averages across the three discrete planning years, 2030, 2035 and 2040, and are not time-weighted averages over the full intervention period. Pareto dominance is evaluated using four objectives: minimisation of natural-gas requirement, operational CO_2 emissions and modelled system cost, and maximisation of renewable-energy share. The classification reflects the controlled baseline assumptions and may change under alternative substitute-fuel prices or other sensitivity conditions.

The Pareto analysis should therefore be interpreted as a compact representation of competing system objectives rather than as a ranking of transition pathways. No weighted overall score is calculated because doing so would require explicit value judgements regarding the relative importance of gas exposure, emissions, renewable integration and system cost. Instead, Table 9 identifies which trade-offs remain after clearly inferior baseline combinations are excluded. In application, selecting among non-dominated options requires explicit policy priorities and system-planning judgements; Pareto status alone does not identify a preferred transition pathway.

Taken together with the preceding sensitivity results, the multi-objective comparison shows that the relative attractiveness of the transition pathways depends on both the objective being protected and the assumptions applied to uncertain inputs. RET and RET-CF place greater emphasis on limiting additional gas requirements, whereas RE-ST shifts the system toward lower overall fossil-fuel consumption, lower operational emissions and higher renewable penetration. This distinction provides the basis for the broader transition-strategy interpretation developed in the Discussion.

4. Discussion

4.1 Coal phase-down can reallocate rather than eliminate fuel-security exposure

The central finding is that coal phase-down changes not only the quantity of coal consumed but also the composition of the residual fossil-fuel requirement across the wider power system. Under the controlled Peninsular Malaysia pathway, temporary retention of the Study Thermal Asset (STA) reduces modelled natural-gas use by approximately 9–12 TWh/yr relative to managed phase-down (PD) during 2030–2040. Conversely, withdrawing the retained thermal contribution causes additional gas-fired generation elsewhere in the system. This result is important because it shows that an asset-level coal-retirement decision can create system-wide fuel-substitution effects even when demand, the non-study generation fleet and the broader renewable pathway are held constant.

The mechanism is primarily one of cross-fuel substitution rather than an overall reduction in fossil-fuel dependence. The near one-for-one relationship between the additional coal use under RET and the reduction in gas use indicates that retained thermal generation predominantly displaces natural-gas consumption elsewhere in the modelled system. Coal phase-down therefore improves the carbon profile of the system, but it can simultaneously increase dependence on another fossil fuel. The relevant transition question is consequently not only how much coal is removed, but which resources respond when that coal is withdrawn. This finding extends the coal-to-gas literature by quantifying the substitution at whole-system level under a controlled counterfactual. Lee et al. [15] evaluate the environmental consequences of replacing coal with LNG and show that upstream supply chains can materially change the lifecycle result; the present study addresses a different but complementary question by quantifying how much additional gas demand can emerge when coal is withdrawn before non-fossil replacement is fully available.

This cross-fuel effect has particular relevance in Southeast Asia, where electricity demand continues to grow rapidly [3,4] and natural gas remains an important source of dispatchability and system flexibility. At the same time, growing regional exposure to imported gas and international LNG markets increases sensitivity to supply disruption and price volatility [5]. Greater reliance on new gas infrastructure may also create carbon-lock-in and stranded-asset risks if capacity additions are not accompanied by credible utilisation and retirement pathways [7].

The present analysis does not translate additional gas demand into LNG imports because domestic production, pipeline constraints, contractual supply arrangements and import shares are outside the model boundary. It nevertheless quantifies the incremental gas requirement that future fuel-security, infrastructure and procurement assessments would need to accommodate.

The broader implication is that fuel security should be treated as a portfolio property rather than a characteristic of individual technologies. Coal retirement may reduce exposure to imported coal while simultaneously increasing exposure to gas availability and price. Assessing transition pathways only through coal-capacity reductions or avoided coal generation can therefore obscure an important dimension of system-level energy security.

4.2 Temporary thermal retention provides a time-bounded gas hedge at an explicit carbon cost

Temporary thermal retention creates a clear trade-off between gas exposure and decarbonisation. Relative to PD, RET reduces modelled natural-gas requirements and, under the controlled baseline assumptions, lowers annual system cost. These benefits are obtained at the expense of higher coal consumption and an additional 1.35–1.79 $MtCO_2$/yr of operational emissions. Retention should therefore not be interpreted as a decarbonisation pathway. Its potential value lies instead in temporarily preserving dispatchable thermal output while reducing the amount of gas required elsewhere in the system.

The carbon-price sensitivity makes this trade-off economically explicit. In 2030, the fixed-dispatch system-cost advantage of RET relative to PD disappears at approximately USD 50/tCO_2. Above this level, the monetary consequence of RET's additional emissions outweighs its baseline fuel-cost advantage. In 2035 and 2040, the corresponding parity values lie above the tested USD 0–100/tCO_2 range. These differences should not be interpreted as evidence that later retention is intrinsically more desirable. Rather, they reflect the different fuel balances, gas displacement and wider system configurations inherited by each planning year.

This distinction is important for transition sequencing. If retained coal capacity is used as a temporary adequacy or fuel-security measure, its strategic value depends on how quickly alternative flexibility resources, storage, network capacity and dependable low-carbon supply become available. Retention that is explicitly linked to replacement-resource milestones is fundamentally different from open-ended coal operation. The former can be treated as a transitional risk-management measure; the latter would extend unabated coal dependence and weaken consistency with long-term decarbonisation objectives.

This interpretation is consistent with regional transition analysis recognising that existing thermal assets may retain short-term operational value while their long-term role declines as power systems are modernised and replacement resources are commissioned [6]. The results therefore support treating temporary retention, where considered, as conditional and time-bounded rather than as a default response to concerns over gas dependence. It is also consistent with Lin and Liu [14], who find that flexible coal can retain short-term system value while BESS becomes more attractive over the longer term as renewable penetration increases. The present results add a fuel-security dimension to that comparison: temporary thermal retention reduces gas exposure, but the benefit is accompanied by a measurable carbon penalty.

4.3 Co-firing moderates the emissions penalty of retention but has a narrow economic boundary

The co-firing results separate two effects that are often conflated in transition discussions: the system value of retaining physical capacity and the emissions consequences of changing the fuel composition of that retained capacity. RET-CF preserves the same modelled gas requirement as RET because the physical 1,600 MW retained contribution is unchanged.

The reduction in operational CO_2 therefore arises from fuel substitution within the retained block rather than from an additional system-capacity effect.

At the controlled co-firing trajectory, operational emissions fall progressively relative to RET as the substitute-fuel share increases. This demonstrates that co-firing can moderate the carbon penalty associated with temporary thermal retention without sacrificing the gas-displacement effect observed under RET. Its strategic role is nevertheless bounded: co-firing reduces, rather than eliminates, the emissions associated with continued operation of the retained thermal asset.

The economic interpretation is more conditional than the emissions result. The zero-price substitute-fuel assumption in the controlled baseline makes RET-CF appear less costly than RET, but this relationship reverses when a positive fuel price is introduced. Cost parity occurs close to the modelled coal-fuel price, and at USD 10/GJ RET-CF becomes more costly than RET under the controlled base-share cases. This is consistent with Malaysian biomass co-firing research identifying feedstock processing, transport and supply-chain costs as important determinants of economic viability, and with broader techno-economic evidence showing sensitivity to fuel and carbon prices [17,18].

Accordingly, co-firing is better interpreted as a potentially useful means of moderating the emissions penalty of a time-bounded retained thermal asset than as a stand-alone transition strategy or an inherently lower-cost option. Real-world viability would additionally depend on delivered substitute-fuel cost, sustainable feedstock availability, boiler and auxiliary-load effects, fuel-handling requirements and lifecycle emissions that are outside the present proxy representation. This interpretation is consistent with Malaysian system-level bioenergy modelling, which finds that co-firing can lower transition costs but that the advantage is highly sensitive to biomass supply-chain costs [16], and with the techno-economic sensitivity reported in [17,18]. The present controlled comparison therefore supports the emissions-reduction role of co-firing more strongly than any unconditional cost advantage.

4.4 Renewable-plus-storage changes the substitution mechanism

The renewable-plus-storage pathway produces a fundamentally different response from either RET or RET-CF. Rather than changing the balance between two fossil fuels, RE-ST reduces both coal and natural-gas consumption relative to PD. It simultaneously lowers operational CO_2, increases renewable share and reduces modelled annual system cost in all three study years. Among the four tested pathways, it is therefore the only intervention that reduces both major fossil-fuel requirements relative to managed phase-down under the controlled system states. Accordingly, the physical and emissions direction of the RE-ST comparison is supported directly by the scenario results, whereas its absolute cost advantage should be interpreted as conditional on the adopted solar and storage cost assumptions.

This distinction is strategically important. The thermal-retention pathways mainly manage the consequences of coal withdrawal by preserving dispatchable fossil capacity, whereas RE-ST changes the structure of the replacement portfolio itself. The additional solar capacity reduces fossil-energy requirements, while battery storage improves the ability of the system to utilise that renewable generation within the adopted EnergyPLAN representation. The result demonstrates that the gas increase associated with coal phase-down is not necessarily unavoidable. It can be moderated through additional non-fossil investment.

The direction of this result is consistent with national transition studies that assign increasing importance to renewable expansion, battery storage, transmission and stronger system integration as Malaysia decarbonises [8–13]. It also reinforces a broader planning principle: coal retirement should be evaluated as a portfolio-replacement problem rather than a choice between withdrawing coal and installing additional gas capacity. The result also parallels the hourly comparison by Lin and Liu [14], where BESS gains strategic value relative to flexible coal as renewable penetration increases. However, the present study differs by holding the wider national pathway fixed and tracing the resulting changes in both coal and gas requirements, which makes the cross-fuel mechanism directly observable.

Nevertheless, the RE-ST result should not be interpreted as evidence that installed battery power is directly equivalent to firm thermal capacity. The present manuscript evaluates fuel use, operational emissions, renewable share and annual system cost. It does not estimate effective load-carrying capability, probabilistic capacity credit, state-of-charge adequacy during prolonged stress events, AC network constraints or dynamic-stability performance. These questions become increasingly important as the thermal share declines. The IEA similarly treats storage as one component of a broader

flexibility portfolio that includes dispatchable resources, demand response, operational improvements and grid reinforcement [4].

The policy implication is therefore not simply to replace coal with batteries. It is to accelerate the combination of renewable generation, appropriately sized storage, network capability and other flexibility resources required to reduce both coal and gas exposure without transferring reliability risk elsewhere in the system.

4.5 Price sensitivities quantify economic exposure rather than endogenous redispatch

An important methodological result of the sensitivity programme is that gas, carbon and substitute-fuel prices change the annual cost accounting of the modelled pathways without changing their physical dispatch under the adopted EnergyPLAN technical-regulation configuration. The resulting parity points should therefore be interpreted as measures of economic exposure conditional on fixed physical operation, rather than as predictions of how generation would be redispatched in response to changing market prices.

This distinction is particularly important when interpreting the gas price and carbon-price results. The gas-price sensitivity shows how pathways with different fixed gas requirements become more or less expensive as the assumed fuel price changes. Similarly, carbon-price sensitivity monetises differences in fixed operational CO_2 emissions. The reported parity values consequently identify with the price conditions under which the annual system-cost ordering of two already-defined physical pathways changes.

They do not represent wholesale-market switching prices, generator bidding thresholds or unit-commitment decisions. Such questions require models capable of endogenous economic dispatch, minimum stable generation, start-up and shutdown costs, ramping constraints, contract structures and potentially nodal transmission limits.

This methodological boundary does not invalidate the sensitivity analysis. Rather, it clarifies what the analysis contributes. By holding physical dispatch constant, the sensitivities isolate the exposure of alternative transition configurations to uncertain gas, carbon and substitute-fuel prices. They therefore complement, rather than substitute for, production-cost or market-dispatch modelling.

4.6 Implications for Peninsular Malaysia and wider Southeast Asian coal transitions

Malaysia's emerging coal-retirement timetable gives the controlled experiment direct planning relevance. The results do not determine which individual plant should retire or when. Instead, they demonstrate why retirement sequencing matters at system level. Removing a large thermal block can alter gas requirements, emissions and system costs elsewhere in the power system even when most national assumptions remain unchanged. This system perspective is consistent with evidence from Indonesia and Viet Nam, where concerns over affordability, power shortages and the pace of renewable deployment complicate coal phase-out [27]. The Malaysian case adds a distinct fuel-security issue: even where coal withdrawal lowers direct emissions, the transition can create additional gas requirements unless replacement renewable, storage and network capability arrives in step with retirement.

This finding suggests that retirement assessments should extend beyond plant-level avoided emissions. For each major retirement decision, planners should examine at least three linked effects: the fuel that replaces the withdrawn generation, the infrastructure required to support that replacement, and the resulting change in system-wide emissions and cost. A coal retirement that materially increases gas use may remain consistent with decarbonisation objectives, but the associated gas-supply, LNG, infrastructure and price risks should be made explicit rather than treated as secondary consequences.

The results also strengthen the case for sequencing retirement with replacement investment. Temporary retention may reduce near-term gas exposure but carries a measurable emissions cost. Co-firing can moderate that cost but introduces fuel-supply and economic uncertainties. Additional renewable energy and storage can reduce both coal and gas use, but require sufficient flexibility, network capability and reliability support. These pathways therefore address different dimensions of the transition problem and should not be treated as interchangeable.

The same mechanism has relevance beyond Malaysia. Indonesia, Viet Nam and other fast-growing Southeast Asian systems face combinations of young coal fleets, rising electricity demand, growing renewable penetration and concerns over affordability and supply security [27,28]. Although the numerical results are specific to the controlled Peninsular Malaysia pathway, the analytical lesson is transferable: retiring coal can redistribute rather than eliminate fuel-system risk, and the consequences depend on the portfolio available to replace its energy and operational contribution.

The contribution of the present study is therefore not to prescribe a universal technology sequence, but to demonstrate a transparent method for tracing how an asset-level transition intervention propagates through system-wide fuel use, emissions and cost.

4.7 Limitations and directions for further research

The findings should be interpreted within several methodological boundaries. First, modelled gas requirement is not equivalent to gas-import dependence. The analysis does not distinguish domestic production from imported LNG, nor does it represent pipeline constraints, gas storage inventories, regasification limits, contractual structures or fuel-supply security. Future work could couple the electricity-system results with a dedicated gas-supply and LNG-infrastructure assessment to determine how incremental gas requirements translate into actual import exposure.

Second, the annual system-cost results are comparative EnergyPLAN outputs rather than estimates of project profitability or consumer tariffs. They should not be interpreted as STA net present value, owner revenue, power-purchase-agreement value, retail-price effects or guaranteed avoided costs. Because some technology-specific CAPEX and OPEX inputs are confidential, the absolute cost assumptions cannot be fully reproduced from the manuscript; the economic findings are therefore strongest as within-dataset comparisons using common source-controlled assumptions. More detailed investment analysis would require technology-specific financing assumptions, asset book values, contractual obligations, retirement compensation, market revenues and potentially stranded-asset treatment.

Third, price sensitivities are fixed-dispatch exposure tests. A production-cost or unit-commitment model would be required to evaluate endogenous redispatch under changing fuel and carbon prices. Similarly, thermal availability is represented through deterministic derating rather than probabilistic forced-outage distributions. The study therefore does not estimate statutory reliability metrics such as LOLE or EENS, nor does it derive ELCC or probabilistic storage capacity credit.

Fourth, co-firing is represented as a fuel-share substitution within the retained thermal block. The model does not explicitly capture boiler modifications, changes in thermal efficiency, auxiliary consumption, fuel degradation, supply-chain constraints, lifecycle greenhouse-gas emissions or non-CO_2 pollutants. These factors could materially affect the practical viability of co-firing and require plant-specific engineering and lifecycle assessment.

Fifth, RE-ST is a deliberately capacity-scaled comparator rather than an optimised replacement portfolio. The study does not vary solar/BESS sizing, storage duration or technology CAPEX/OPEX around the RE-ST case. Accordingly, the physical and emissions direction of the RE-ST comparison is supported directly by the scenario results, whereas its absolute system-cost advantage remains conditional on the controlled solar and BESS cost assumptions. Future work should add explicit solar and BESS cost trajectories, alternative storage durations and optimisation of the replacement portfolio before drawing investment-grade cost conclusions.

Sixth, the RE-ST pathway should not be interpreted as proof that the specified storage package can replace all services provided by thermal generation. Detailed state-of-charge chronology, transmission constraints, voltage and frequency performance, system strength and dynamic-stability requirements lie outside the present analysis. These limitations define a clear next stage of research: integrating the controlled system-level fuel and cost experiment with probabilistic reliability, production-cost, network and fuel-supply assessments.

The scenarios should therefore be understood as conditional planning experiments rather than forecasts. Their value lies in isolating mechanisms and trade-offs under a consistent national pathway, not in predicting a single future configuration.

5. Conclusions

This study shows that coal phase-down is not simply a reduction in coal capacity; it is a portfolio-replacement decision that changes which fuels and technologies respond elsewhere in the power system. Under the controlled Peninsular Malaysia pathway, temporary thermal retention reduces system natural-gas requirements but does so by preserving higher coal use and operational CO_2, while co-firing moderates' part of that emissions penalty without removing its dependence on substitute-fuel cost and supply conditions.

The renewable-plus-storage pathway changes the substitution mechanism more fundamentally. Under the tested system states, RE-ST reduces both coal and natural-gas requirements, lowers operational CO_2 and increases renewable penetration relative to managed phase-down. Its physical and emissions direction is therefore distinct from thermal retention; however, the absolute system-cost advantage remains conditional on the adopted solar and BESS cost assumptions because technology-cost sensitivity was not varied in this study.

The sensitivity programme strengthens the main physical interpretation. The gas-reduction effect of thermal retention persists under deterministic derating to 70% of the retained contribution, while the price-only cases alter annual cost without changing physical dispatch under the adopted EnergyPLAN configuration. These tests therefore quantify robustness of the fuel-substitution mechanism and exposure to uncertain fuel and carbon prices rather than endogenous market redispatch.

For transition planning, the central implication is that coal retirement should be sequenced with explicit consideration of the replacement portfolio. Planners need to identify not only how much coal is withdrawn, but also which resources replace its energy and operational contribution, how that replacement changes gas requirements and emissions, and whether sufficient renewable generation, storage, network capability and other flexibility resources are available when retirement occurs.

Methodologically, the study contributes a transferable controlled-counterfactual framework that separates three mechanisms often blended in transition studies: retained dispatchable capacity, lower-carbon fuel substitution within retained thermal capacity, and structural replacement through renewable generation plus storage. This allows the marginal system-wide consequences of an asset-level transition intervention to be traced without conflating them with simultaneous changes in the wider national pathway.

Taken together, the results support a fuel-aware and portfolio-based approach to coal-transition sequencing. Coal phase-down can reduce direct coal dependence while still increasing exposure to natural gas if replacement resources are not developed in parallel; conversely, additional renewable generation and storage can reduce both fossil-fuel requirements under the tested conditions. Incorporating these cross-fuel and portfolio effects into retirement planning can help reduce the risk of shifting transition exposure from one fossil fuel to another.

Declarations

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Competing interests: The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability: Public policy and system information used to construct the model is identified in the manuscript. Some technical, economic and stakeholder-provided inputs are subject to confidentiality restrictions. Appendix A reports the non-confidential controlled assumptions and validation checks needed to interpret the scenario differences, while Appendix B summarises the sensitivity execution and quality-assurance audit. Scenario definitions and aggregated EnergyPLAN results are reported in the manuscript. Non-confidential processed outputs and the scenario/sensitivity matrix may be made available by the corresponding author upon reasonable request, subject to institutional and project approval.

Declaration of generative AI and AI-assisted technologies: During the preparation of this work, the authors used OpenAI ChatGPT and Gemini to improve the clarity, readability, organisation and presentation of selected sections. After using these tools, the authors reviewed and edited the content as needed and took full responsibility for the content of the manuscript.

Appendix A. Core model assumptions and controlled scenario inputs

Appendix A consolidates the non-confidential assumptions that define the controlled counterfactual experiment. Values listed here are either reported directly in the manuscript or inherited from the source-controlled national EnergyPLAN dataset and held constant across paired cases. Confidential plant-, contract- and project-specific CAPEX/OPEX values are not reproduced; where such inputs affect system cost, the manuscript reports only comparative system-level outcomes and explicitly limits their interpretation.

Table A1. Non-confidential controlled assumptions used in the scenario comparison.

Parameter	**Value or rule**	**Provenance / treatment**	**Interpretation**
Core simulation	EnergyPLAN 16.22	Controlled execution environment	Deterministic chronological energy-system simulation.
Automation and post-processing	MATLAB + MaT4EnergyPLAN + custom scripts	Scenario construction, batch execution, validation and analysis	EnergyPLAN dispatch is not altered by MATLAB post-processing.
Chronology	Full-year hourly chronological profiles for each scenario year	Controlled Peninsular Malaysia dataset	Common hourly chronology retained across paired scenarios.
Intervention years	2030, 2035 and 2040	Controlled scenario design	Years in which PD, RET, RET-CF and RE-ST differ.
Retained STA block	+1,600 MW in RET and RET-CF	Controlled intervention	Anonymised screening representation; not a plant-level investment case.
RE-ST package	+3,200 MW solar PV + 1,600 MW / 6.4 GWh BESS (4 h)	Controlled intervention	Incremental to the national pathway; not an optimisation result or firm-capacity equivalence claim.
Base co-firing shares	5% (2030); 10% (2035); 20% (2040)	RET-CF scenario definition	Fuel-share proxy applied to the retained block while physical capacity is unchanged.
Fuel-price basis	Coal: 5.369/5.374/6.308 USD/GJ; gas: 12.070/14.110/15.129 USD/GJ for 2030/2035/2040	Project technical dataset; RM4.28/USD conversion	Controlled assumptions, not market-price forecasts.
Baseline carbon price	0 USD/tCO_2	Controlled EnergyPLAN baseline	No explicit carbon-price term in baseline runs.
Direct-combustion CO_2 factors	Coal 96.1 $kgCO_2/GJ$; natural gas 56.1 $kgCO_2/GJ$	IPCC/MyRER convention	Aggregate system-model factors; not plant-specific inventory factors.

Parameter	**Value or rule**	**Provenance / treatment**	**Interpretation**
Economic calculation	2.7% real calculation interest rate	EnergyPLAN cost input	Used for comparative annual system-cost calculation.
Economic lifetimes	Central thermal 20 y; BESS 10 y; solar PV 21 y; interconnection 60 y	Source-controlled technology-cost inputs	Used for internal annualisation of investment costs.
Technology CAPEX/OPEX	Project/stakeholder inputs; individual values confidential	Held consistently across paired cases	Cost results are comparative system-level indicators, not project NPV, PPA or tariff estimates.
Plant/storage efficiencies and regulation settings	Inherited from the controlled national dataset and held fixed unless explicitly varied	Source-controlled EnergyPLAN inputs	Not independently re-estimated in this manuscript.
Post-2040 treatment	Scenario pathways reconverge after the intervention window	Controlled scenario design	Does not imply physical retirement of RE-ST assets or disappearance of retained infrastructure at 2040.
RE-ST scaling logic	Solar = 2× STA nameplate; BESS power = 1× STA nameplate; BESS energy = 4 h × BESS power	Transparent controlled-comparator design	Not optimisation-derived and not a claim of firm-capacity equivalence.
Annual system-cost components	Annualised investment + fixed/variable O&M + fuel + electricity exchange + CO_2 cost where imposed	EnergyPLAN socio-economic cost framework [20–22]	Common monetary basis; comparative MUSD/yr interpretation.

Table A2. Validation and reproducibility checks for the controlled modelling framework.

Check	Evidence	Result	Interpretation
External demand-scale check	2025 model peak 21,065 MW vs Energy Commission 21,049 MW [23]	+16 MW (+0.076%)	Supports system-demand scale; not a full historical dispatch calibration.
Chronology integrity	Demand, hydro, solar and retrieved hourly outputs	Full-year hourly chronology retained in each controlled scenario year	Common hourly EnergyPLAN chronology retained across paired cases.
Fuel-to-emissions arithmetic	2035 RET vs PD: +12.45 TWh coal, −12.45 TWh gas; ΔEF = 40.0 $kgCO_2/GJ$	Calculated +1.793 $MtCO_2$; EnergyPLAN +1.793 $MtCO_2$	Independent accounting check reproduces the reported emissions increment.
Cross-fuel mechanism	$\rho = -\Delta F_{gas}/\Delta F_{coal}$ for RET	0.999 (2030); 1.000 (2035); 1.001 (2040)	Confirms near one-for-one coal-for-gas substitution on an input-energy basis.
Price-only invariance	Gas-, carbon- and substitute-fuel-price reruns	Physical outputs unchanged within reported precision	Supports interpretation as fixed-dispatch cost-exposure tests.

Check	Evidence	Result	Interpretation
Sensitivity execution audit	120-case publication sensitivity matrix	120/120 represented; no failed parse/execution case	Supports execution completeness; details in Appendix B.
CEEP numeric audit	All sensitivity outputs	0.000000 TWh minimum/mean/maximum	Binary CEEP warning is non-discriminating in this dataset.

Note: These checks establish scale, accounting and execution consistency for the controlled experiment. They do not constitute probabilistic adequacy, security-constrained dispatch, AC network or dynamic-stability validation.

Appendix B. Sensitivity execution and quality-assurance summary

The sensitivity programme comprised 120 required EnergyPLAN cases: 36 gas-price, 48 carbon-price, 27 co-firing and nine deterministic thermal-derating runs. All selected rows had PASS or PASS_RESUME status, with no failed execution or parse case. Of the 120 cases, 116 were fresh executions and four reused previously validated executions without modification.

The 12 gas-price 1.00× rows are the accepted controlled baselines and were not redundantly rerun. MATLAB-based post-processing cross-checked coal fuel, natural-gas fuel, substitute-fuel use, operational CO_2, renewable share, annual system cost and cost intensity. Annual CEEP was 0.000000 TWh in every sensitivity output (minimum/mean/maximum = 0.000000/0.000000/0.000000 TWh).

Because the EnergyPLAN binary CEEP warning string remained present in all outputs despite zero quantitative CEEP, it is treated as a non-discriminating diagnostic flag rather than evidence of curtailment. These checks establish execution and accounting consistency for the published sensitivity matrix; they do not constitute probabilistic reliability or network-security validation.

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