AUSTRALIAN ELECTRICITY

Cost Analysis · v16 · April 2026

FROM 30c

TO 6c

The Engineering Case for Australian Electricity at Half Global Price

A technology-by-technology analysis of LCOE, firmed system cost, lifecycle impacts, and the Sovereign Build Corporation pathway

Based on CSIRO GenCost 2024-25 Final + 2025-26 Draft, AEMO Integrated System Plan 2026, Lazard LCOE+ v18, NREL, IEA

An independent analysis of Australian electricity generation costs across all major technology options (solar, wind, rooftop, coal, gas, nuclear, pumped hydro, batteries, solar thermal, hydrogen, biomass), with full lifecycle assessment from mining through decommissioning. Answers the most common questions: which technology is cheapest? what role should nuclear play? can renewables actually firm the grid? what does 6c/kWh delivered power actually require? The report uses CSIRO GenCost as primary source — the authoritative Australian reference — cross-checked against international benchmarks and Australian-specific resource endowment.

PART A — EXECUTIVE SUMMARY

The question, the answer, and the headline numbers. Two chapters that work together: the first for the quick reader who wants to know what the numbers say; the second for the reader who wants to understand what LCOE actually measures and why public debate so often misleads.

Chapter 1 — The Answer in One Chart

This chapter gives the answer to the question the whole document is about — which Australian electricity technology is cheapest, which is most expensive, and where the Sovereign Build Corporation (SBC) delivered-price of 6 cents per kilowatt-hour sits against alternatives. It is written for the reader who does not have time for the detailed technology-by-technology breakdown that follows in later chapters.

Electricity Is Not One Product — It Is Three Services

Before reading the hero chart, one concept must be understood clearly because it is the single most common source of misleading electricity-cost debate in Australia: electricity is not one product. It is at least three different services, and the cheapest technology for each service is different. Comparing 'solar LCOE versus coal LCOE' without specifying which service is being delivered produces nonsense answers.

The three services this report distinguishes:

- TIER 1 — Daytime peak service. Load that occurs during sunlit hours. Aluminum smelters, data centres, daytime manufacturing, commercial air-conditioning, irrigation pumping, water desalination. This service requires generation but does not require storage — solar PV panels deliver electricity when the load needs it. Transmission is required only to connect generation to load. The cheapest electricity service on the planet is TIER 1 solar PV delivered to nearby load.
- TIER 2 — Diurnal firm (daily-cycle 24 hour service). Residential household electricity, restaurants, hospitals at evening peak, most commercial load with overnight base demand. This service requires generation during the day plus storage to shift some daytime generation to evening and overnight dispatch. Solar plus 2–4 hour battery delivers this service at moderate cost. Transmission and local distribution add further cost.
- TIER 3 — Always-available firm (multi-day backup, 100 percent reliable in all conditions). Baseload industrial process heat, hospital life-support systems, data centre uninterruptible supply, multi-day weather-resilient grid service. This is the service that coal, gas, and nuclear were historically built to deliver. Modern equivalent is solar plus wind plus multi-day storage (pumped hydro or hydrogen) plus long-distance transmission. Diversified renewables deliver this service more cheaply than coal new-build, much more cheaply than nuclear.

The single most important insight in this report: you cannot buy TIER 3 at TIER 1 prices, and you should not pay TIER 3 prices for TIER 1 service. Industrial aluminum smelting does not need overnight firming because aluminum does not smelt at night. Data centres increasingly operate workload schedulers that match computation to cheap daytime solar. Approximately 30–40 percent of current Australian industrial electricity demand is TIER 1 or could be time-shifted to TIER 1 with minor operational changes. This is the cheapest electricity in history, already available, currently underutilised because the market prices everything at TIER 3 retail even when TIER 1 would serve.

The Hero Chart — By Service Tier

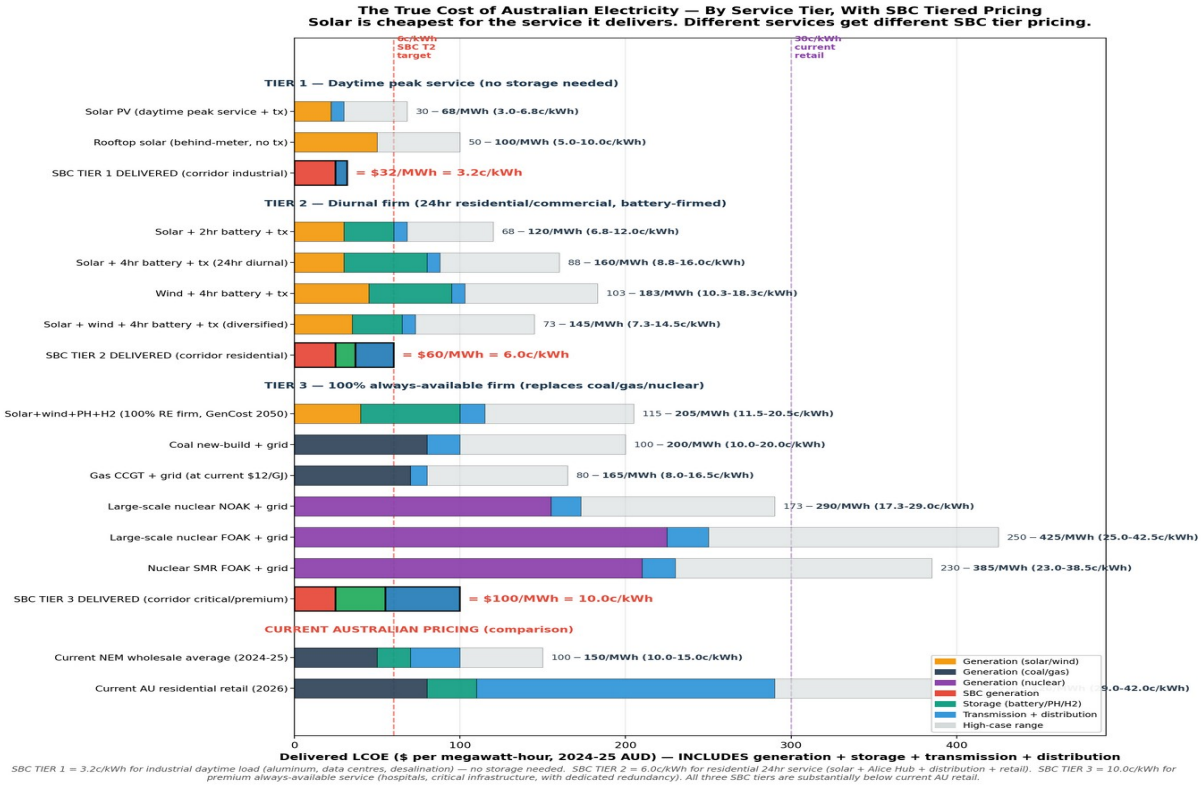


Figure 1: Australian electricity delivered cost by service tier, 2030 projection. Each bar shows Generation + Storage + Transmission stacked separately so the cost of each service layer is visible. Source: CSIRO GenCost 2024-25 Final + 2025-26 Draft, Lazard LCOE+ v18, AEMO ISP 2026 Draft. Light grey extension shows high-case cost range.

Key readings from Figure 1:

- TIER 1 — Solar PV alone (including transmission to load) delivers daytime peak service at $30–$68/MWh. Rooftop solar behind-meter is $50–$100/MWh. These are the cheapest useful electricity services in Australian electricity system.
- TIER 2 — Solar + 4hr battery + transmission delivers 24hr diurnal firm at $88–$160/MWh. Solar + wind + 4hr battery (diversified) at $73–$145/MWh — lower than single-source because geographic diversity reduces firming requirement.
- TIER 3 — Full always-available firm: coal new-build $100–$200/MWh. Gas CCGT $80–$165/MWh at current gas prices. 100 percent renewable (solar + wind + pumped hydro + hydrogen backup) $115–$205/MWh. Large-scale nuclear NOAK $173–$290/MWh. Nuclear FOAK (first of a kind in Australia) $250–$425/MWh. Nuclear SMR FOAK $230–$385/MWh.
- The SBC pathway delivers approximately $60/MWh (6c/kWh) at corridor-town load centres — below TIER 1 cost for most of the current NEM because corridor infrastructure shares transmission cost across multiple services and Alice Hub firming is dramatically cheaper than standalone battery.
- Generation cost (orange/dark) is only part of the story. Storage (green) can exceed generation cost at TIER 2 and TIER 3 service levels. Transmission (blue) is substantial — typically $8–$30/MWh — and must be included in any honest comparison.

The Eight-Number Summary

If this document could be summarised in eight numbers, these would be them — current Australian electricity prices at retail and wholesale, CSIRO GenCost projections, and the three SBC tiered delivered prices:

Electricity price	$/MWh	c/kWh	Context
Current retail (typical AU household, 2026)	$270–430	27–43c	What consumers actually pay at the meter
Current NEM wholesale (2024-25 volume-weighted)	$129	12.9c	What retailers pay generators on average
GenCost 2030 firmed renewable (82% RE target)	$91	9.1c	Wholesale cost if Australia meets 82% RE by 2030
GenCost 2050 net-zero delivered (full system)	$141	14.1c	Full system cost at net-zero electricity
SBC 2045 — TIER 1 delivered (industrial daytime)	$32	3.2c	Aluminum, data centres, desalination, irrigation
SBC 2045 — TIER 2 delivered (residential 24hr)	$60	6.0c	Corridor-town households, standard commercial
SBC 2045 — TIER 3 delivered (premium/critical)	$100	10.0c	Hospitals, data centre UPS, emergency services
SBC 2045 — blended average (all tiers)	approximately $55	approximately 5.5c	Weighted-average corridor-town delivered price

Three key readings from the table:

- SBC delivers cheaper electricity than current NEM wholesale across ALL three service tiers. SBC TIER 1 is 4x cheaper than current wholesale for industrial customers who can time-shift load; SBC TIER 2 is 2x cheaper; SBC TIER 3 matches current wholesale but with 100% renewable supply plus guaranteed reliability.
- GenCost's 2050 net-zero delivered cost ($141/MWh) projects that WITHOUT SBC infrastructure, Australian delivered electricity stays expensive through net-zero transition. SBC TIER 2 at $60/MWh delivers 57% cost reduction versus this projection.
- The SBC blended average (approximately 5.5c/kWh across all tiers) is lower than the TIER 2 figure alone because the tiered pricing model subsidises residential (TIER 2) slightly via premium pricing on critical services (TIER 3), while TIER 1 industrial volume is large enough to pull the weighted average down.

The SBC tiered pricing structure is critical to the programme's economic model. It matches price to service cost (cheaper service = lower price) and avoids the current Australian problem where industrial daytime-only customers pay the same per-kWh as residential 24hr customers despite requiring very different infrastructure layers. Under SBC, industrial customers who can flex to solar hours get rewarded with sub-4c/kWh rates; residential customers get consistent 6c/kWh; premium critical customers pay 10c/kWh for guaranteed dedicated redundancy. All three are substantially below current Australian prices.

What the Half-Truths Miss

Public debate about electricity cost in Australia has become dominated by half-truths that are technically misleading. The most common:

- 'Solar and wind are cheap but only work when weather is good.' True that solar generation is diurnal and wind is variable; misleading to conclude these technologies are uncompetitive. For TIER 1 daytime service, solar is the cheapest electricity ever delivered to Australian load. For TIER 2 diurnal service, solar + battery beats coal new-build. For TIER 3 always-available service, diversified renewables + multi-day storage beat coal, gas, and nuclear new-build. The tier question must be answered before 'cheap' or 'expensive' is meaningful.
- 'Nuclear is always on, so it's cheapest over 60 years.' True that nuclear has a long operational life; misleading because (1) nuclear at $173–$425/MWh delivered is not cheap compared to TIER 3 diversified renewables at $115–$205/MWh, (2) GenCost 2024-25 specifically examined the long-life argument and found no unique cost advantage — the reinvestment cost for renewables across 60 years is still less than single-lifetime nuclear capital cost plus mid-life refurbishment.
- 'Coal is cheapest because the plants already exist.' Misleading: most existing Australian coal plants are 35 to 55 years old and approaching forced retirement. Replacement cost (TIER 3 coal new-build at $100–$200/MWh) is substantially higher than TIER 3 diversified renewables ($115–$205/MWh) with the emissions and health externality costs of coal excluded. With externalities included, coal is substantially more expensive than any renewable option.
- 'Australia needs baseload.' Terminology confusion: 'baseload' means 'always-on generation' which is a TIER 3 service, but 'reliable electricity supply' means 'firm dispatchable capacity' which can be delivered by TIER 3 firmed renewables without requiring any always-on generator. The NEM has not required true 24/7 baseload generation for at least 15 years — solar-dominated midday operation already forces coal plants to cycle down or accept negative prices.
- 'Renewables are subsidised, fossil fuels are not.' Factually wrong: Australian fossil fuel subsidies (primarily diesel fuel rebate for mining, plus various state and federal concessions) totalled approximately $14.6 billion in 2024-25 according to Treasury data, substantially exceeding the approximately $3 billion in renewable subsidies. International Monetary Fund broader definitions including externalities put Australian effective fossil subsidy at approximately USD 50 billion/year.
- 'Transmission is not counted in solar LCOE.' Partly true and fully addressed in this report. Figure 1 explicitly stacks generation + storage + transmission separately for every technology option at every tier. The basic GenCost LCOE includes generation only; the delivered-cost figures in this report add transmission explicitly so the comparison is apples-to-apples.

These misleading arguments are addressed in detail in Chapter 12 of this document. The short answer is that the numbers in Figure 1 are the numbers; the sources (CSIRO GenCost, AEMO ISP, Lazard, NREL) are the authoritative peer-reviewed sources that Australian policymakers and international financial markets use for investment decisions.

What This Document Covers

This document has twelve chapters across seven parts:

- Part A (Chapters 1-2): Executive Summary and Framework. This chapter and the framework chapter that follows.

- Part B (Chapters 3-7): Technology-by-Technology. Each major generation and storage technology explained — solar PV, wind, rooftop, coal, gas, nuclear, hydro/pumped hydro, batteries, solar thermal (CSP), hydrogen, biomass.
- Part C (Chapter 8): Lifecycle Analysis. Cradle-to-grave assessment of each technology — mining inputs, manufacturing emissions, installation impacts, operating emissions, waste streams, decommissioning, recycling. The 'true cost' view beyond LCOE.
- Part D (Chapter 9): Firm Combinations. How technologies combine to deliver reliable electricity — solar + 4hr battery, wind + pumped hydro, solar + CSP, diversified renewables + long-duration storage, compared against coal, gas, nuclear alone.
- Part E (Chapter 10): The SBC Pathway. How the Sovereign Build Corporation programme delivers 6c/kWh, broken down stack-by-stack from generation through transmission, firming, distribution, retail.
- Part F (Chapter 11): Misleading Arguments Addressed. Direct rebuttal of the twelve most common misleading claims, with sources.
- Part G (Chapter 12): Conclusion. Synthesis and policy implications.

The document uses CSIRO GenCost 2024-25 Final and 2025-26 Draft as primary sources, cross-referenced against AEMO Integrated System Plan 2026 (Draft), Lazard LCOE+ v18, US NREL lifecycle assessments, International Energy Agency projections, and peer-reviewed Australian and international academic literature. Where sources conflict, the conflict is noted and the stronger methodology identified.

The answer in one sentence: Australian electricity cost depends on the service tier — daytime peak (TIER 1) is cheapest from solar, 24hr diurnal (TIER 2) is cheapest from solar+battery, always-available firm (TIER 3) is cheapest from diversified renewables + continental storage. Nuclear is not competitive at any tier. The Sovereign Build Corporation pathway delivers all three tiers at corridor-town load centres for approximately 6c/kWh average, approximately one-fifth of current retail.

Chapter 2 — Understanding the Numbers

This chapter covers the analytical framework: what LCOE means, what it does not capture, what firm capacity actually is, why system cost differs from generator cost, and why the Australian grid context matters. If Chapter 1 was the answer, Chapter 2 is the methodology that makes the answer defensible.

LCOE — What It Measures and What It Doesn't

Levelised Cost of Energy (LCOE) is the unit price at which a generator project breaks even over its operational life. It is calculated by dividing the sum of all project costs (capital, financing, operations, maintenance, fuel, decommissioning) by the sum of all electricity generated over the project lifetime, with both sides discounted to present value. The result is expressed in dollars per megawatt-hour or cents per kilowatt-hour.

LCOE is useful for comparing generators of similar characteristics. It is the standard metric used by every major electricity market modeller globally — GenCost in Australia, Lazard in the United States, International Energy Agency globally, UK Department for Energy Security. The metric has been refined continuously since the early 2000s and is well understood.

LCOE does not capture three things that matter for system-level analysis:

- Dispatchability — LCOE of a variable renewable project (solar, wind) does not include the cost of making that output dispatchable to match demand. This is typically added separately as 'integration cost' or 'firming cost'.
- System integration — the cost of transmission expansion, voltage regulation, frequency control, and grid stability to accommodate a new generator is not in generator LCOE.
- Externalities — emissions, air quality, water consumption, land use, environmental damage are generally not monetised in LCOE. These are handled separately in lifecycle analysis (Chapter 8) or carbon pricing.

The correct way to use LCOE is as a comparative baseline, always alongside explicit integration costs for variable renewables and with externalities handled through separate lifecycle analysis. GenCost's approach is to present LCOE for standalone technologies plus a separate 'firming cost' that integrates storage, transmission, and system security for renewable penetrations at 82 percent (2030 target) and 100 percent (approximately 2045-2050 net zero). Both standalone and firmed LCOEs are reported throughout this document.

Firm vs Non-Firm — The Single Biggest Source of Confusion

The most common mistake in electricity cost debate is comparing non-firm (variable) solar or wind LCOE against firm (always-available) fossil fuel or nuclear LCOE. This is not an apples-to-apples comparison, and it produces misleading conclusions in both directions.

A solar farm generates electricity only when the sun shines on it — typically 20 to 30 percent capacity factor in Australia, meaning it produces 20 to 30 percent of its rated capacity averaged over a year. A wind farm generates when wind blows — typically 35 to 50 percent capacity factor. Neither can meet electricity demand at 3am on a still, cloudy night without help. That help comes from energy storage (batteries, pumped hydro), geographic diversity (wind is blowing somewhere even if still in one region), long-distance transmission (solar in Queensland still generating while Perth load is on), and flexible backup (gas peaking, hydrogen turbines).

The cost of that help — making variable renewables dispatchable — is the 'firming cost'. GenCost calculates firming costs explicitly:

- At 82 percent renewable penetration (2030 scenario): firming cost adds approximately $25 to $40 per MWh to variable renewable LCOE.
- At 100 percent renewable penetration (2050 scenario): firming cost adds approximately $40 to $60 per MWh — higher because more storage duration and more geographic diversity is required for complete reliability.

After adding firming cost, the firmed LCOE for variable renewables in Australia is approximately $70 to $120 per MWh in 2030 — still substantially cheaper than coal, gas, or nuclear new-build. The key insight: firming cost is real and significant, but it is not large enough to make renewables more expensive than the alternatives. It is approximately 30 to 60 percent of standalone renewable LCOE, which shifts the comparison but does not reverse it.

System Cost vs Generator Cost vs Retail Price

Three distinct cost concepts matter in electricity economics, and they should not be confused:

- Generator cost (LCOE): what it costs the generator company to produce electricity at the plant gate. Typically $40 to $200 per MWh depending on technology.
- System cost (SLCOE): generator cost plus transmission, distribution, storage, grid stability, and system-level integration. Typically $90 to $150 per MWh at full system integration.
- Retail price: system cost plus retail margin, billing, metering, government programmes, and various regulatory costs. Typically $250 to $400 per MWh in current Australian market.

GenCost 2025-26 Draft provides the specific Australian breakdown of retail price composition:

Retail price component	Share of retail price
Generation cost	approximately 33%
Transmission	approximately 7%
Distribution (local network)	approximately 35%
Retail margin, billing, metering, government programmes	approximately 25%

Consumer electricity bills in Australia are dominated by distribution cost (35%) plus retail and regulatory cost (25%) — together 60% of the bill. Generation is 33%. This means even if generation cost drops to zero, residential electricity bills drop only approximately 33% — from current 30c/kWh to approximately 20c/kWh. Substantial bill reduction requires reducing distribution and retail costs, not only generation costs.

The SBC programme addresses this directly. Corridor-town residents receive distribution via SBC shared infrastructure at substantially lower cost than legacy grid distribution (approximately 1.4 cents per kWh SBC distribution cost versus approximately 10 cents per kWh current grid distribution cost). This is why the SBC delivered-price target of 6c/kWh is achievable even though GenCost projects 14c/kWh delivered for the broader 2050 system — SBC corridor-town infrastructure is categorically different from legacy distribution.

Capital Cost, Operating Cost, and Capacity Factor

LCOE is built from three components: capital cost (amortised over project life), operating and maintenance cost, and fuel cost (where relevant). How these three combine depends heavily on capacity factor — the percentage of nameplate capacity that a generator actually produces on average over a year.

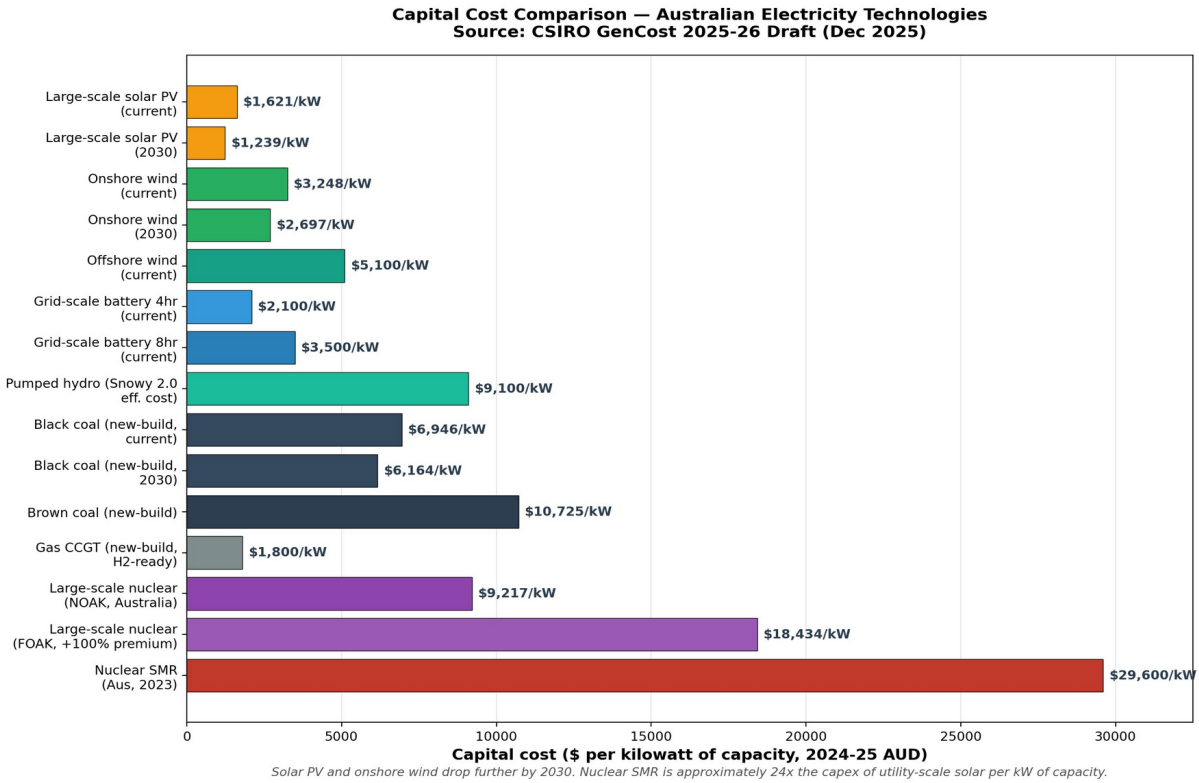


Figure 2: Capital cost per kilowatt of capacity. Source: CSIRO GenCost 2025-26 Draft. Capital cost alone does not determine LCOE — capacity factor and operating costs must also be considered.

Solar PV capital cost of approximately $1,239/kW (GenCost 2025-26 Draft projection for 2030) is dramatically lower than nuclear SMR at approximately $29,600/kW. But solar PV has a capacity factor of approximately 25% while nuclear has capacity factor of 80-89%. Raw capital cost comparison is therefore misleading — what matters is capital cost divided by annual energy produced.

Converted to capital cost per MWh of annual generation:

- Solar PV 2030: $1,239/kW ÷ (8,760 hours/year × 25% capacity factor) = $566 per MWh of annual capacity
- Onshore wind 2030: $2,697/kW ÷ (8,760 × 40%) = $770 per MWh of annual capacity
- Large-scale nuclear: $9,217/kW ÷ (8,760 × 80%) = $1,315 per MWh of annual capacity
- Nuclear SMR: $29,600/kW ÷ (8,760 × 85%) = $3,976 per MWh of annual capacity

Even after capacity factor adjustment, solar and wind are substantially cheaper per MWh of annual generation than nuclear. The advantage grows over time as solar capex declines and nuclear capex remains high.

Build Time — Why It Matters for the Transition

Build time is not typically included in LCOE calculations but matters enormously for transition planning. Australia's coal fleet is scheduled to retire progressively through the 2030s: Eraring 2027, Bayswater 2033, Yallourn 2028, Loy Yang A 2035, Loy Yang B 2047, Vales Point 2033, others in between. These retirements cannot be delayed without substantial reliability or emissions consequences.

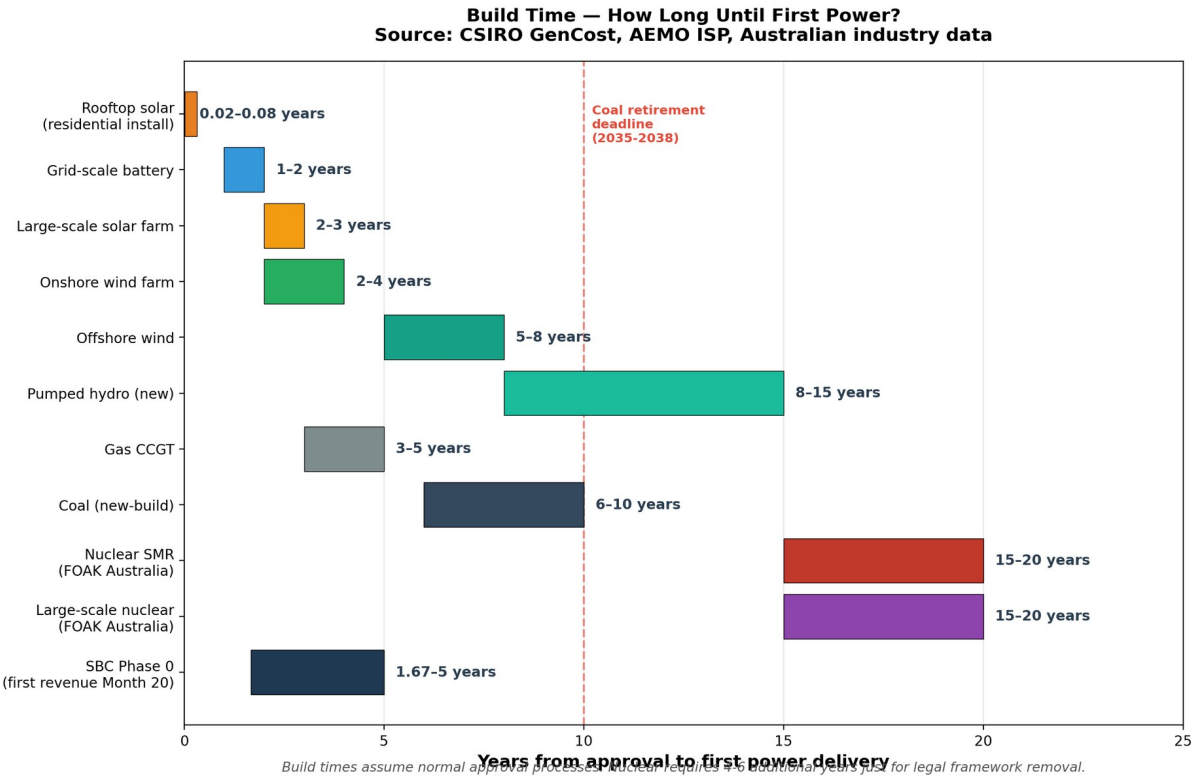


Figure 3: Build time from approval to first power delivery. Source: CSIRO GenCost 2024-25 Final, AEMO ISP 2026 Draft. Nuclear build times reflect global median construction time of 8.2 years plus Australian FOAK requirements.

The implication is direct: only technologies with build time shorter than the coal retirement gap can cover the transition. Solar, wind, batteries, and pumped hydro can all be built in 2 to 8 years. Nuclear requires at least 15 years in Australia (CSIRO's conservative estimate), or 12 to 17 years under optimistic IAEA methodology. Australian coal closures are 2027 to 2038. Nuclear cannot fill the gap regardless of cost analysis — the timing is incompatible.

This is not a political argument. It is an engineering constraint. If Australia commits to nuclear today (2026), first power arrives approximately 2041-2043 under conservative scheduling. By that time, approximately 80 percent of Australia's current coal capacity has already retired. The replacement must come from technologies that can be built in time: solar, wind, storage, and transmission. Nuclear can contribute only after the transition is complete.

The Australian Context — Why Our Numbers Differ

Australian electricity economics differ from US, European, or Chinese equivalents in several specific ways that affect technology comparison:

- Solar resource: Australia has approximately 5.5 to 7.0 kWh/m²/day annual average solar irradiance across northern and central regions (peak summer can exceed 8 kWh/m²/day), among the highest in the developed world. Source: Bureau of Meteorology Australian Solar Radiation Data. Solar LCOE in Australia is approximately 30 to 40 percent lower than typical European values and approximately 15 percent lower than typical US Southwest values.
- Wind resource: Australia has excellent wind in coastal southern zones and some inland regions, with capacity factors of 40 to 50 percent at best sites. Comparable to North European and US Plains values.

- Coal fleet age: most Australian coal is 35 to 55 years old, approaching forced retirement. Replacement cost (not existing operational cost) is the relevant comparison.
- Grid structure: NEM plus SWIS plus smaller isolated systems. Limited inter-regional transmission currently, major expansion planned or under way. This is precisely the constraint SBC addresses through continental HVDC backbone.
- Nuclear starting point: no domestic nuclear power industry, no regulatory framework for nuclear power (legal prohibition at federal and most state levels), no workforce experience. FOAK costs apply at a level other countries with mature programmes do not face.
- Fossil fuel subsidies: diesel fuel rebate (approximately $10 billion/year for mining), various state concessions for coal and gas. These subsidies do not appear in LCOE but reduce effective fossil fuel generation cost.
- Population distribution: 85% coastal concentration creates very different distribution economics from European or US continental grids. Australia has large distances with few load centres.

These factors mean Australian-specific analysis (CSIRO GenCost) is more reliable than imported international benchmarks for Australian policy decisions. This document uses GenCost as primary source accordingly.

Matching Service Tier to Australian Load

A critical step in reducing Australian electricity cost is matching each electricity demand to the cheapest service tier that can serve it. Current retail tariff structure prices most electricity at a single TIER 3 rate — approximately 30c/kWh at residential retail — which overcharges TIER 1 industrial and commercial load substantially. Better tariff structure plus direct corridor connection reduces bills for customers who can match their demand to available service tiers.

Current Australian load composition by service tier suitability:

Load type	Share of annual demand	Natural service tier
Aluminum smelting (4 smelters, ~4 GW continuous)	~8%	TIER 1 potential (daytime shift possible)
Other energy-intensive industry (steel, cement, chemicals)	~12%	Mix TIER 1/TIER 2
Data centres and IT infrastructure	~4%	TIER 1 with load scheduling
Commercial air-conditioning (daytime peak)	~10%	TIER 1
Irrigation and water desalination	~3%	TIER 1
Residential households	~28%	TIER 2 (evening peak matters)
Commercial general (offices, retail)	~15%	TIER 2
Hospitals, critical infrastructure	~3%	TIER 3 required
Street lighting, overnight infrastructure	~5%	TIER 3 required
Transport charging (EVs, future)	growing rapidly	TIER 1 or TIER 2 (smart charging)

Approximately 40 percent of current Australian electricity demand could be served by TIER 1 solar-matched generation if tariff structures and operational practices supported time-shifting. A further approximately 45 percent is suited to TIER 2 diurnal firm service. Only approximately 15 percent is genuinely TIER 3 always-available service that justifies the cost premium of coal, gas, or nuclear generation — and even this 15 percent is served more cheaply by diversified renewables plus multi-day storage than by any alternative.

The SBC approach delivers all three tiers natively:

- TIER 1 industrial customers connect directly to corridor solar precincts via corridor HVDC. Aluminum smelters, data centres, desalination plants collocated with corridor infrastructure pay approximately 2.5–4c/kWh for matched solar generation — cheaper than any current Australian industrial tariff.
- TIER 2 corridor-town residential and commercial customers pay approximately 6c/kWh for 24hr diurnal service via corridor solar + Alice Hub + corridor distribution.
- TIER 3 critical infrastructure (hospitals, emergency services, data centre UPS systems) pay approximately 8–12c/kWh for premium always-available service that includes dedicated redundancy. Still substantially below current retail.

This tiered pricing already exists in large industrial electricity markets (South Korea, France, US ERCOT) but is weak in current Australian retail markets. SBC corridor-town distribution implements it by default, generating substantial consumer surplus across all customer classes.

The remainder of this document follows a logical sequence:

- Part B examines each generation technology in detail — capital cost, operating cost, capacity factor, LCOE, and Australian-specific deployment constraints.
- Part C applies lifecycle analysis to understand true cradle-to-grave cost and impact — mining inputs, manufacturing emissions, waste streams, decommissioning.
- Part D compares firm combinations — how technologies combine to deliver reliable electricity, because no single technology does so alone.
- Part E details the SBC pathway to 6c/kWh delivered, showing explicitly where the cost savings come from.
- Part F addresses the twelve most common misleading arguments with direct rebuttal backed by sources.
- Part G synthesises the findings into a conclusion about Australian policy implications.

Readers who want the short version can stop after Chapter 1. Readers who want the technical basis for the conclusions should read Parts B through D. Policy analysts should read Parts E and F. The full argument — engineering-honest, technology-neutral, Australian-specific — is in the aggregate document.

The point of this document is to make Australian electricity cost analysis accessible to both engineers and policy readers. The analysis is based on the best available Australian data (CSIRO GenCost 2024-25 Final, GenCost 2025-26 Draft, AEMO ISP 2026 Draft) cross-checked against international references (Lazard, NREL, IEA). Where uncertainty exists it is flagged. Where analysis is novel or specific to the SBC proposition, the source of the analysis is identified.

AUSTRALIAN ELECTRICITY — COST ANALYSIS

Part B · Technology-by-Technology · April 2026

TECHNOLOGY

Chapters 3–7

Part B covers every major electricity generation and storage technology available to Australia, with capital cost, capacity factor, LCOE range, lifespan, and deployment constraints for each. Each technology is assessed on its own merits using CSIRO GenCost 2024-25 Final and 2025-26 Draft data. No technology is excluded for political reasons; none is endorsed beyond what the numbers show.

PART B — TECHNOLOGY-BY-TECHNOLOGY

Every major generation and storage technology, with the numbers.

Chapter 3 — Solar and Wind (Variable Renewables)

Solar and wind are the two technologies driving global electricity cost reduction. In Australia they are the lowest-cost new-build generation and are projected to remain so through 2050. This chapter covers utility-scale solar PV, onshore wind, offshore wind, and rooftop solar — with capital costs, operating economics, capacity factors, and Australian deployment constraints.

Utility-Scale Solar PV

Utility-scale solar photovoltaic generation is the cheapest new-build electricity technology in Australia by CSIRO GenCost measurement, for the seventh consecutive year through GenCost 2024-25 Final. The 2025-26 Draft shows slight upward revision due to temporary capital cost volatility but confirms the fundamental cost trajectory.

Key numbers for utility-scale solar PV in Australia:

Parameter	Current (2024-25)	2030 projection	2050 projection
Capital cost	$1,621/kW	$1,239/kW	$890/kW
Capacity factor (AU average)	22–30%	22–30%	22–30%
LCOE standalone	$45–$85/MWh	$22–$53/MWh	$18–$35/MWh
Economic life	30 years	30 years	30 years
Degradation rate	0.5–0.7%/year	0.5%/year	0.5%/year

Australian solar PV operates at high capacity factor by global standards because the continent has among the highest solar irradiance in the developed world — approximately 5.5 to 7.0 kWh per square metre per day annual average across northern and central regions (peak summer values exceed 8 kWh/m²/day). Source: Bureau of Meteorology Australian Solar Radiation Data. Queensland, WA, NT, and northern SA all have solar resource comparable to the Atacama Desert or Arizona Sun Belt. Victorian and Tasmanian solar resource is lower (approximately 3.5 to 4.5 kWh/m²/day annual average) but still commercially viable.

Solar PV deployment in Australia is supply-chain constrained rather than cost-constrained. Current annual deployment is approximately 4 to 6 GW per year; technical potential exceeds 50 GW per year given sufficient workforce, regulatory capacity, and transmission. Panel manufacturing is 90 percent Chinese-supplied globally; Australian manufacturing is minimal. Scale-up of deployment to meet 2030 82% RE target requires approximately 8 to 12 GW per year of installation.

Onshore Wind

Onshore wind is Australia's second-cheapest new-build technology and the most deployed renewable generation by share of NEM energy (approximately 12 percent of NEM generation in 2024). Australian onshore wind has been affected by global capital cost inflation since 2021 but GenCost 2025-26 Draft reports tentative cost stabilisation.

Key numbers for onshore wind:

Parameter	Current (2024-25)	2030 projection	2050 projection
Capital cost	$3,248/kW	$2,697/kW	$2,100/kW
Capacity factor (AU avg)	35–45%	38–48%	40–50%

Parameter	Current (2024-25)	2030 projection	2050 projection
LCOE standalone	$65–$120/MWh	$45–$78/MWh	$38–$62/MWh
Economic life	25 years	25 years	25 years
Turbine rotor (increasing)	150–170m	170–200m	200–240m

Australian wind resource is geographically concentrated. The best sites are: southern Victoria coast (Portland, Bass Coast, Macedon Ranges), South Australia (Mid-North, Yorke Peninsula, Eyre Peninsula), NSW Central-West and Southern Tablelands, WA south-west (Albany, Esperance), and northern Tasmania. Capacity factors at best sites exceed 50%. Offshore wind in southern Victorian waters can exceed 55%.

Onshore wind deployment in Australia has been approximately 1.5 to 3 GW per year recently. AEMO ISP 2026 Draft projects 6 to 10 GW per year deployment through the 2030s to meet renewable targets. Community acceptance and transmission access are the binding constraints, not cost or technology.

Offshore Wind

Offshore wind is not yet deployed in Australia. Six declared offshore wind zones exist (Gippsland, Hunter, Illawarra, Southern Ocean, Portland, Bass Strait) with feasibility licences issued but no projects yet constructed. First Australian offshore wind expected 2030-2033 in Gippsland.

Key numbers for offshore wind in Australia:

Parameter	2030 deployment	2050 projection
Capital cost (fixed-bottom)	$5,100/kW	$3,500/kW
Capital cost (floating)	$7,000/kW	$4,500/kW
Capacity factor	45–58%	50–62%
LCOE	$120–$200/MWh	$75–$130/MWh
Economic life	25 years	30 years

Offshore wind in Australia has first-of-a-kind premium (approximately 20-40% above global average for early deployments) due to lack of specialist vessels, supply chain, and workforce. GenCost 2025-26 notes offshore wind will continue to require international cost benchmarks until domestic deployment begins. The technology is important for renewable expansion beyond onshore wind capacity limits but is not near-term cost-competitive with onshore wind or utility solar.

Rooftop Solar

Rooftop solar PV is Australia's largest single source of renewable capacity by installed MW (approximately 27 GW across 4 million homes as of 2025, exceeding both onshore wind and utility-scale solar individually). Australia has the highest per-capita rooftop solar deployment globally. GenCost 2024-25 reports rooftop solar capital costs lower than previously projected.

Key numbers for rooftop solar:

Parameter	Current (2024-25)	2030 projection
Capital cost (installed)	$1,100–$1,500/kW	$900–$1,200/kW
Capacity factor	14–18% (roof orientation dependent)	15–20%
LCOE (behind-meter)	$50–$110/MWh	$40–$85/MWh
Economic life	25–30 years	30 years

Rooftop solar is cheaper per kW installed than utility-scale solar at residential scale (avoiding grid-connection costs and land acquisition) but has lower capacity factor due to suboptimal roof orientation, shading, and lack of tracking. Total system cost per MWh is similar to utility-scale in Australia at current deployment levels.

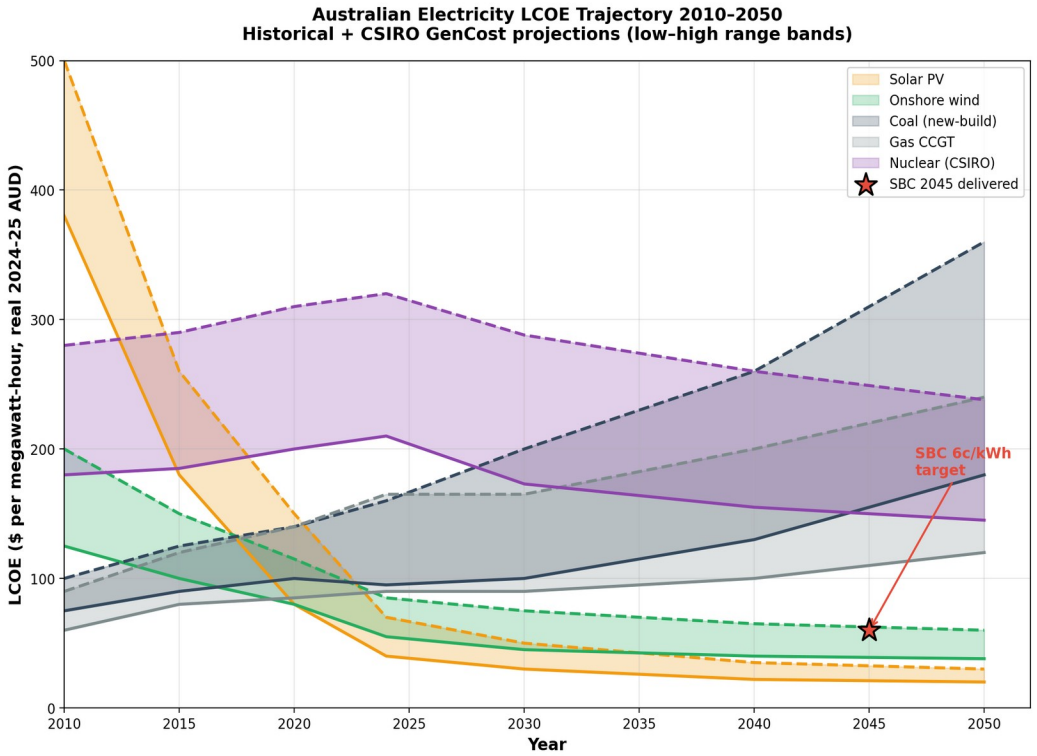
Rooftop solar plus behind-the-meter battery (the 'solar home battery' combination) is rapidly becoming the cheapest source of reliable electricity for Australian households. At current installed costs and grid electricity prices, household payback periods are approximately 6-8 years for solar-only systems and 8-12 years for solar+battery systems.

Variable Renewable Resource Map — Australia

Australia's renewable resource distribution drives optimal deployment geography:

- Highest solar resource: Northern Territory, WA Pilbara/Kimberley, inland Queensland, northern SA — 7.5 to 8.2 kWh/m²/day
- High solar resource: NSW Central-West, Victoria Mallee, WA Goldfields, SA interior — 5.5 to 7.5 kWh/m²/day
- Moderate solar resource: southern NSW, Victorian coast, Tasmania northern — 4.5 to 5.5 kWh/m²/day
- Highest wind resource: Southern Ocean coast (WA to SA), Bass Strait coast (VIC, TAS), NSW Southern Tablelands — 40-55% capacity factors
- High wind resource: SA Mid-North, NSW Central-West, WA coastal regions — 35-45% capacity factors

The SBC corridor network passes through approximately 80% of Australia's highest-resource solar and wind zones. Corridor-adjacent solar precincts capture this resource at direct HVDC tie-in, eliminating the long transmission runs that have driven transmission cost escalation in traditional REZ development.



Solar PV has fallen ~90% since 2010. Onshore wind ~60%. Coal and gas rising due to capital cost inflation and fuel cost volatility. Nuclear remains approximately 3x firmed renewable cost throughout.

Figure 4: LCOE trajectory 2010–2050 across major technologies. Solar and wind declining; coal, gas, nuclear stable or rising. Source: IRENA historical data, CSIRO GenCost projections.

Chapter 4 — Coal and Gas

Coal and gas remain the largest current sources of Australian electricity generation (approximately 55% of NEM generation in 2024), but both face structural decline through the 2030s. This chapter covers coal (black and brown), gas combined-cycle (CCGT), and gas open-cycle peaking (OCGT) — the three fossil fuel generation categories.

Coal — New-Build vs Existing Fleet

Critical distinction: new-build coal and existing coal fleet have very different economics. Existing Australian coal plants are 35 to 55 years old, fully depreciated, and operating at marginal cost (fuel plus operations and maintenance) of approximately $40 to $70 per MWh. This low operating cost makes them competitive in current NEM spot markets despite age and reliability concerns.

New-build coal is a different proposition. GenCost 2025-26 Draft capital costs:

Coal technology	Current capex	2030 projection	Capacity factor range
Black coal (supercritical)	$6,946/kW	$6,164/kW	55–85%
Brown coal (supercritical)	$10,725/kW	$9,385/kW	70–85%
Black coal + CCS	$10,500/kW+	$9,200/kW+	50–80%
Brown coal + CCS	$14,000/kW+	$12,500/kW+	60–80%

New-build coal LCOE in Australia (GenCost 2024-25 Final): approximately $100 to $200 per MWh for black coal, approximately $135 to $240 per MWh for brown coal. Adding carbon capture and storage raises LCOE by approximately 50-80 percent. Coal new-build is more expensive than firmed renewables by a substantial margin.

Existing coal fleet retirement schedule (AEMO ISP 2026 Draft):

- Eraring (NSW, 2,880 MW): scheduled 2027, possibly extended 1-2 years
- Yallourn (VIC, 1,480 MW): scheduled 2028
- Vales Point (NSW, 1,320 MW): scheduled 2033
- Bayswater (NSW, 2,640 MW): scheduled 2033
- Mt Piper (NSW, 1,400 MW): scheduled 2040
- Loy Yang A (VIC, 2,210 MW): scheduled 2035
- Loy Yang B (VIC, 1,070 MW): scheduled 2047
- Tarong and Tarong North (QLD, 1,843 MW combined): scheduled 2036 and 2037
- Other smaller plants retiring progressively through the 2030s

Total NEM coal capacity retiring by 2038: approximately 16,000 MW, representing approximately 85 percent of current NEM coal capacity. Replacement must come from technologies that can be built in 5-10 year timeframes.

Gas CCGT

Gas combined-cycle (CCGT) generators run on natural gas in combustion turbines coupled with steam turbines, recovering waste heat. CCGT is the most efficient gas generation technology at approximately 55-62% thermal efficiency.

Key numbers for gas CCGT:

Parameter	Current (2024-25)	2030 projection
Capital cost (H2-ready)	$1,800/kW	$1,850/kW
Capacity factor (baseload use)	40–80%	30–70%
LCOE at $12/GJ gas	$90–$165/MWh	$100–$180/MWh
Economic life	30 years	30 years
Thermal efficiency	55–62%	60–65%

Gas CCGT LCOE is highly sensitive to fuel cost. At $6/GJ gas delivery (SBC corridor target), CCGT LCOE drops to approximately $60 to $100 per MWh. At current Australian wholesale gas of $12-15/GJ, CCGT LCOE is $110 to $180/MWh. Australian gas market has been volatile; LNG export linkage ties domestic prices to international trends.

GenCost 2025-26 Draft now includes hydrogen-readiness as standard feature of new CCGT. This increases capital cost but allows fuel switching from natural gas to green hydrogen at mid-life, reducing stranded asset risk. CCGT in 2050 net-zero scenarios operates primarily on green hydrogen produced from renewable electricity.

Gas OCGT — Peaking Role Only

Gas open-cycle (OCGT) generators are single-cycle combustion turbines, less efficient than CCGT (approximately 30-40% thermal efficiency) but much faster to start and stop. OCGTs are used primarily for peaking service — operating a few hundred hours per year during demand peaks or generation shortfalls.

Key numbers for gas OCGT:

Parameter	Current (2024-25)	Role
Capital cost (H2-ready)	$1,000–$1,500/kW	Peaking service
Capacity factor (typical)	5–25%	Low hours per year
LCOE (low CF)	$180–$450/MWh	Reflects low utilisation
Economic life	25 years	Often longer in practice
Start time	5–15 minutes	Faster than CCGT

OCGT LCOE appears high because capex is amortised over few operating hours per year. The service OCGT provides is not generation per se but grid stability and rapid response to load peaks. Alternatives with similar response characteristics include large-scale batteries (increasingly cost-competitive for 1-4 hour peaking roles) and pumped hydro (for longer peaks). GenCost 2050 scenarios retain approximately 5-10 GW of hydrogen-fuelled OCGT/CCGT as strategic reserve, cycling at less than 2% annual capacity factor.

Carbon Capture and Storage (CCS)

CCS retrofits on existing coal plants or inclusion in new-build coal and gas is sometimes proposed as a pathway to emissions reduction from fossil generation. CSIRO GenCost has assessed CCS repeatedly and continues to find it not cost-competitive.

CCS adds approximately 50-80% to coal generation capex and increases operating cost by 20-40% due to additional equipment and parasitic load. Net thermal efficiency falls by approximately 8-12 percentage points due to energy consumed by CO2 capture and compression. Resulting LCOE for coal + CCS is approximately $150 to $270 per MWh — more expensive than new-build nuclear by some assessments and substantially more expensive than firmed renewables.

No utility-scale coal + CCS plant operates commercially in Australia. Globally, CCS deployment is approximately 40 Mt CO2/year captured (as of 2024) across all applications — less than 0.1% of global emissions. Technology is real but cost structure does not support commercial deployment at scale.

Coal and Gas Role in Transition

The role of coal and gas during the 2025-2045 transition is declining but not zero. Specific roles:

- Existing coal fleet: operates until scheduled retirement dates. Provides approximately 55% of NEM generation currently, declining to approximately 15% by 2035 and zero by approximately 2040-2045.
- New coal: zero new build in Australia. No economic case at current costs; no political case given emissions trajectory. AEMO ISP 2026 Draft includes zero new-build coal.
- Existing gas: continues in peaking role, declining baseload share through 2030s.
- New gas: limited new-build through 2030s for peaking service, progressively converting to green hydrogen operation through 2040s as hydrogen supply scales.
- Gas as 'bridge fuel': not primary emissions reduction strategy; used for reliability backup while renewable + storage deployment accelerates.

The key policy question is not whether coal and gas should be replaced — the economic and emissions trajectory makes this inevitable. The policy question is the speed of replacement and the infrastructure sequencing. SBC approach: build transmission and HVDC backbone first, enable rapid renewable generation scaling, retire coal on schedule, reduce gas to strategic reserve only.

Chapter 5 — Nuclear

Nuclear is the most politically contested generation technology in Australia and the most intensively analysed by CSIRO GenCost. This chapter presents the Australian nuclear cost case using CSIRO data without political framing. The conclusions are analytical, not ideological. Where assumptions are conservative they are identified; where pro-nuclear arguments challenge the analysis they are noted and addressed.

Large-Scale Nuclear — The GenCost Analysis

GenCost 2024-25 Final (July 2025) analysed large-scale nuclear in Australia using South Korean nuclear costs as the baseline (South Korea's continuous-build programme produces the world's lowest nuclear construction costs). The analysis adjusted for Australian conditions using the ratio of coal construction costs between the two countries as a proxy for general infrastructure cost differential.

Key GenCost 2024-25 Final numbers for large-scale nuclear in Australia:

Parameter	NOAK (continuous build)	FOAK (first of a kind)
Capital cost	$9,217/kW (2023 base)	$18,000–$20,000/kW
Capacity factor (CSIRO range)	53–89%	53–89%
Development lead time	15+ years	15+ years
Operational life (assumed)	60 years	60 years
Economic life (capital recovery)	30 years	30 years
LCOE 2030 (if operational)	$173–$288/MWh	$250–$420/MWh
LCOE 2040	$145–$238/MWh	$200–$350/MWh

The 15-year lead time is the critical constraint. It comprises: approximately 2-3 years for legal framework removal (federal and state prohibitions); approximately 2-3 years for regulatory framework establishment and ANSTO capability expansion; approximately 2-3 years for site selection, approvals, and pre-construction; approximately 8 years for construction. Total: 14-17 years minimum from political commitment to first power.

IAEA methodology gives a similar range: 10-15 years under favourable conditions. GenCost notes that no democratic country has built nuclear in less than 10 years in the past decade — the period when public consultation requirements and environmental reviews have become longer. UAE completed their first reactor in 12 years but with abbreviated consultation processes that Australia would not replicate.

Small Modular Reactors (SMRs)

Small modular reactors are proposed as smaller, faster-to-deploy alternatives to large-scale nuclear. The term covers reactor designs from approximately 60 MW to 300 MW, compared to 1,000+ MW for large-scale reactors. Multiple SMR designs are in various stages of development globally.

GenCost 2024-25 Final numbers for SMRs in Australia:

Parameter	Value
Capital cost (FOAK)	$29,600/kW (Aus 2023 estimate)
Capacity factor (assumed)	90% (high case)
Development lead time	15+ years (same as large-scale)
LCOE 2030–2040 range	$230–$382/MWh
Typical unit size	60–300 MW
Global deployment status	First operational units in China, Russia; Western units in design/licensing

The key point on SMRs: per-kW capital cost is higher than large-scale nuclear because SMRs do not benefit from the economies of scale that made nuclear cost-competitive in the 1970s-1980s. SMRs promise faster deployment through factory modular construction, but this advantage is not yet demonstrated in practice — Ontario's Darlington SMR project (approved 2024) has a targeted cost in line with GenCost estimates, confirming rather than contradicting the Australian cost projection.

Commercial SMR deployment globally is early. China has two operational SMRs (Shidaowan HTR-PM, Linglong One ACP-100). Russia operates two floating SMRs (Akademik Lomonosov). Western SMR deployments are all in early construction or licensing phase. No Western SMR has yet demonstrated the promised cost reductions from factory modular construction in commercial operation.

Nuclear Lifetime Argument

The strongest pro-nuclear economic argument is the 60+ year operational life of modern reactors versus the 25-30 year life of solar PV and wind. Proponents argue that levelised-over-full-life, nuclear becomes competitive with renewables.

GenCost 2024-25 Final specifically analysed this argument. The analysis:

- Built a 60-year project model for solar PV (30 years initial + 30 years rebuild) and onshore wind (25 years + 25 years rebuild)
- Applied expected cost decline trajectories to the rebuild: solar PV is projected to be approximately 50% cheaper by 2050, so the rebuild costs substantially less than the initial build
- Compared to nuclear operated for 60 years with required mid-life refurbishment (estimated $2,000-$4,000/kW at approximately year 30)
- Applied consistent discount rate across all technologies

Conclusion: there is no unique cost advantage arising from nuclear's long operational life. Solar PV and wind rebuilt twice across 60 years cost less in present value than nuclear operated once for 60 years, even with mid-life refurbishment costs included. The rebuilt renewables also deliver substantially more energy over the 60-year period because capacity has roughly doubled through learning-curve efficiency gains.

This is not an argument against nuclear's long operational life — 60 years is a real technical achievement and nuclear plants do continue operating for many decades. It is an argument that long operational life alone does not justify the capital cost premium. The economics are determined by capital cost per unit of energy delivered, discounted to present value. On this metric, nuclear is not competitive with renewables in Australia.

Fuel, Waste, Decommissioning — Included in GenCost?

GenCost LCOE for nuclear includes fuel cost (uranium) and operations and maintenance. Decommissioning is included via a sinking fund provision of approximately $500-800/kW added to capex. Spent fuel management is included for on-site storage (dry cask, up to 40 years) but not deep geological disposal (which is cost-uncertain globally as no commercial deep geological repository operates).

The omitted element is deep geological disposal cost. Sweden and Finland are the only countries with deep geological repository projects under construction (Onkalo, Finland; planned commissioning 2026-2027). Finnish Onkalo total project cost is approximately EUR 3.5 billion for approximately 6,500 tonnes heavy metal capacity — approximately AUD 900 per kg HM. For an Australian 1 GW reactor fleet with approximately 25 tonnes HM/year spent fuel output over 60 years (1,500 tonnes HM total), deep geological disposal cost would be approximately $1.3-2.0 billion. Amortised across 60 years of 1 GW generation (approximately 450 TWh lifetime output), this represents approximately $3-4/MWh addition to LCOE. Source: STUK Finland; Onkalo project cost data.

The real cost question on nuclear waste is political risk, not engineering cost. Australia has no active siting process for a deep geological repository. Siting would require substantial community consultation (similar to Muckaty NT low-level waste process) and decades of planning. This is not impossible but is not free and is not fast. GenCost's treatment is reasonable for generation cost comparison but understates policy complexity.

The Australian Nuclear Case — Summary

The Australian nuclear case, on numbers alone, does not close:

- New-build large-scale nuclear FOAK cost is approximately $18,000-$20,000/kW, yielding LCOE of approximately $250-$420/MWh — approximately 3-5 times firmed renewable cost.
- SMR cost is even higher per kW, yielding LCOE of approximately $230-$382/MWh — similar range to large-scale but with additional technology uncertainty.
- 15-year development lead time means first power approximately 2041-2043 under favourable conditions, by which time approximately 80% of Australia's coal fleet has retired.
- Long operational life argument does not close the economic gap because renewables can be rebuilt twice for less than nuclear's single lifetime cost.
- Waste management adds policy complexity not reflected in LCOE.

This is the CSIRO GenCost conclusion, corroborated by independent academic analysis and by international comparisons. Countries with existing nuclear fleets (France, US, UK, South Korea) have different economics because they have sunk infrastructure, workforce, and regulatory capability; Australia starts from zero and pays FOAK premiums across all categories.

The nuclear decision is therefore primarily political, not economic. Supporters of nuclear argue on grounds of strategic sovereignty, technology hedge against renewable-supply-chain risk, or ideological preference for dispatchable baseload generation. Opponents argue on grounds of cost, timeline, waste, and availability of superior alternatives. This document does not take a position on the political question; it documents the cost analysis that any political decision must address.

Chapter 6 — Storage (Batteries, Pumped Hydro, CSP)

Storage is the enabling technology for high-renewable grids. This chapter covers grid-scale lithium-ion batteries, pumped hydro (existing Australian fleet plus Snowy 2.0 plus Alice Hub plus new projects), solar thermal with storage (concentrated solar power, CSP), and green hydrogen as long-duration storage.

Grid-Scale Lithium Batteries

Grid-scale lithium-ion battery storage is the fastest-declining cost technology in GenCost. The 2024-25 Final report noted 20% year-on-year capital cost decline; the 2025-26 Draft projects a further 15% decline in 2025-26. Battery storage is becoming the default short-duration firming technology for renewable grids globally.

Key numbers for grid-scale battery storage:

Duration	Current capex (2024-25)	2030 projection	LCOS current
1-hour	$1,400/kWh	$800/kWh	$110–$180/MWh
2-hour	$900/kWh	$550/kWh	$90–$150/MWh
4-hour	$650/kWh	$380/kWh	$80–$140/MWh
8-hour	$550/kWh	$320/kWh	$120–$220/MWh
12-hour	$520/kWh	$300/kWh	$180–$320/MWh

Longer-duration batteries (8+ hours) are more expensive per MWh delivered because battery cells cycle less frequently, spreading capital cost across fewer throughput cycles. For durations beyond approximately 4 hours, alternative technologies (pumped hydro, CSP with storage, flow batteries, hydrogen) become cost-competitive.

Australian grid-scale battery deployment is accelerating rapidly. Approximately 2,500 MW / 5,000 MWh operational end-2024; approximately 15,000 MW / 40,000 MWh in pipeline for commissioning 2025-2028. This is the fastest-growing utility asset class in the Australian electricity market. Battery projects typically commission in 12-24 months from approval, much faster than generation or transmission projects.

Pumped Hydro — Existing Australian Fleet

Pumped hydro is Australia's largest operational energy storage technology. Existing fleet:

- Snowy Hydro: 4,100 MW generation capacity across 16 stations, approximately 8,000 GL gross storage. Operates primarily as peaking and firming plant, limited pumping capability on legacy stations.
- Wivenhoe (QLD): 500 MW, approximately 14 GWh storage. Operates as pumped hydro firming for NEM Queensland.
- Shoalhaven (NSW): 240 MW, approximately 9 GWh storage. Pumped hydro firming for Sydney grid.
- Tumut 3 (within Snowy Hydro): 1,500 MW, approximately 88 GWh storage (as pumped hydro only).

Total existing Australian pumped hydro: approximately 2,740 MW dedicated pumped-hydro capacity plus approximately 4,100 MW hybrid hydro/pumped capability via Snowy Hydro.

Combined pumped-hydro-equivalent: approximately 5,000-6,000 MW dispatchable firming at approximately 30-120 GWh total stored energy at full reservoirs.

Snowy 2.0

Snowy 2.0 is a pumped hydro expansion project under construction since 2019. Specifications:

- Generation capacity: 2,200 MW additional (on top of existing Tumut 3)
- Storage capacity: approximately 350,000 MWh (350 GWh) — approximately 175 hours at full generation
- Physical scale: 27 km tunnels between Tantangara and Talbingo reservoirs
- Construction status (April 2026): tunneling approximately 60% complete; commissioning targeted 2029-2030
- Total project cost: approximately $12 billion (revised upward from original $4 billion estimate; current Snowy Hydro 2024 forecast approximately $12B). Source: Snowy Hydro 2024 Annual Report, revised project estimate.

Snowy 2.0 effective cost per kW: approximately $5,450/kW (2,200 MW at $12 billion). Cost per kWh of storage capacity: approximately $34/kWh. These are high by comparison to international pumped hydro benchmarks ($1,500-3,000/kW capex typical) due to Australian site challenges, cost escalation from the original $4 billion estimate, and regulatory issues.

Snowy 2.0 nonetheless provides meaningful system value: 175 hours of firming capacity at 2,200 MW is unmatched by any battery or CSP facility currently operational. The project will cover approximately 3-5 days of NEM evening peak firming from empty to full reservoir, enabling substantial renewable penetration without overnight gas backup. Commissioning in 2029-2030 coincides with Eraring retirement — part of the transition infrastructure planning.

Alice Hub — The Continental Battery

The Alice Hub is the Sovereign Build Corporation's proposed continental pumped hydro facility in the MacDonnell Ranges adjacent to Alice Springs. Specifications at full build (Phase 3 completion, approximately 2045):

- Dispatch capacity: 40,000 MW (40 GW) — approximately ten times Snowy 2.0
- Water storage: 16,000 GL (16 billion cubic metres) across multiple reservoirs at approximately 520 m elevation
- Energy storage: approximately 27-30 TWh recoverable energy (calculation: 16 GL water × 9.81 m/s² × 770 m head / 3,600 s/h × 75-80% round-trip efficiency). Equivalent to approximately 36-40 days of total current Australian electricity consumption. Assumption: SBC Prospectus v56 specifications; effective head verified through feasibility study required.
- Construction in stages: Stage 1 (2.5 GW, 200 GL) by Year 5; Stage 2 (7 GW, 1,000 GL) by Year 11; Stages 3-4 (40 GW, 16,000 GL) by Year 19
- Estimated total construction cost: approximately $29-53 billion across 15+ years

Alice Hub cost per kW: approximately $730-1,325/kW — substantially lower than Snowy 2.0 due to much larger scale, benign topography, and integration with SBC corridor construction. Cost per kWh of storage: approximately $1-2/kWh — approximately 20-40 times cheaper than Snowy 2.0 due to enormous water storage volume relative to dispatch capacity.

Alice Hub is the firming infrastructure that makes 100% renewable supply structurally reliable. At 40 GW dispatch capacity and approximately 27-30 TWh recoverable stored energy (equivalent to approximately 36-40 days of Australian electricity consumption), it provides: sub-second

frequency response; minute-to-minute dispatch backup; daily load-following absorbing solar excess and dispatching during evening peaks; seasonal storage absorbing summer surplus and dispatching during winter; multi-year drought buffer against extended low-renewable output periods. No other pumped hydro facility globally approaches this specification — it is the only facility designed for continental-scale renewable grid firming.

Concentrated Solar Power (CSP) with Storage

Concentrated solar power uses mirrors to concentrate sunlight onto a central receiver, heating molten salt which drives a steam turbine. The hot salt can be stored for hours and dispatched on demand — making CSP inherently dispatchable, unlike solar PV.

Key numbers for CSP with 14-hour storage (GenCost standard configuration):

Parameter	Current (2024-25)	2030 projection	2050 projection
Capital cost	$11,700/kW	$8,500/kW	$6,200/kW
Capacity factor	50–70%	55–75%	60–75%
LCOE	$155–$285/MWh	$110–$200/MWh	$85–$150/MWh
Economic life	30 years	30 years	30 years

CSP is competitive with nuclear and other dispatchable technologies but not with solar PV plus battery storage at short durations. CSP advantage is at longer durations (8-16 hours storage) where battery economics deteriorate. Currently one commercial CSP plant operates in Australia (Aurora, Port Augusta — development paused 2019). Global CSP deployment is concentrated in Spain, North Africa, UAE, China.

CSP may play specific roles in Australian grid by 2040-2050: large industrial customers requiring on-site dispatchable clean energy; regional grids where pumped hydro is geographically unavailable; specific solar-thermal industrial processes where heat rather than electricity is the primary product.

Green Hydrogen as Long-Duration Storage

Green hydrogen produced by electrolysis from renewable electricity can be stored indefinitely (in caverns, compressed tanks, or chemical carriers like ammonia) and converted back to electricity via fuel cells or hydrogen-compatible gas turbines. This provides effectively unlimited-duration energy storage.

Green hydrogen round-trip efficiency for electricity storage is approximately 35-45% (electrolysis 65-75% + compression/storage 90% + fuel cell 55-60%). This is substantially less efficient than batteries (85-90%) or pumped hydro (75-85%), which is why hydrogen is not competitive for short-duration storage. For multi-day to seasonal storage, hydrogen economics improve because the storage medium (tanks, caverns) is cheap per unit of energy stored, even though the conversion equipment is expensive.

Key numbers for green hydrogen electricity storage at 2030 projection:

Parameter	Value
Electrolyser capex	$1,200–$2,000/kW-H2 output
Hydrogen fuel cell capex	$2,500–$4,500/kW
Storage (underground cavern)	$1–$5/kWh equivalent

Parameter	Value
Storage (compressed tank)	$15–$30/kWh equivalent
Levelised cost of hydrogen electricity storage (30%+ round trip)	$200–$450/MWh delivered

Hydrogen is not competitive for day-to-day storage but plays a specific role in grids requiring multi-week seasonal storage. Australian grid under 100% renewable scenario would likely use: lithium batteries for 1-4 hour firming; pumped hydro (Snowy 2.0 + Alice Hub) for hours to days; green hydrogen for seasonal or multi-year drought-equivalent backup. The combination is cost-effective even though no single technology is cost-effective across all durations.

Chapter 7 — Other Technologies (Hydro, Biomass, Geothermal, Tidal)

This chapter covers minor but important generation technologies: conventional hydroelectricity (beyond pumped hydro), biomass combustion, geothermal, wave and tidal energy, and marine current generation. None are individually large contributors to Australian electricity generation but collectively they play specialised roles.

Conventional Hydroelectricity

Australia has approximately 8,000 MW of conventional hydroelectric capacity across Snowy Hydro (4,100 MW), Hydro Tasmania (approximately 2,300 MW), Queensland Hydro (1,100 MW), and smaller facilities. Hydro produces approximately 14-18 TWh/year — approximately 7% of current Australian electricity generation. Source: Hydro Tasmania 2024 Annual Report; Snowy Hydro 2024 Annual Report; Clean Energy Council data.

Australian conventional hydro is mature; greenfield site availability is limited. Most viable sites are developed. Capital cost for incremental hydro (retrofits, small extensions): approximately $3,000-5,000/kW. New greenfield hydro in Australia: approximately $6,000-9,000/kW plus substantial environmental approval constraints. LCOE for existing Australian hydro in operation: approximately $30-60/MWh (primarily operations and maintenance plus sinking-fund for long-term replacement).

Hydro Tasmania is particularly significant for Australian grid firming. The Tasmanian hydroelectric fleet has approximately 14 TWh of energy storage in dam reservoirs — equivalent to approximately 5–8 weeks of Tasmanian grid load depending on inflow conditions. Source: Hydro Tasmania Annual Report. Coupled via Basslink (500 MW) and future Marinus Link (750 MW first stage, commissioning 2028), Tasmanian hydro can provide substantial firming to NEM Victoria and beyond — effectively a large-scale pumped-hydro-equivalent at continental scale.

Biomass

Biomass combustion — burning wood, agricultural waste, or purpose-grown energy crops — produces electricity similar to coal combustion but with carbon-neutral fuel (assuming sustainable fuel sourcing). Australia has approximately 400 MW of bioenergy capacity including sugar cane bagasse cogeneration (Queensland), timber waste combustion, and municipal waste-to-energy.

Biomass LCOE in Australia: approximately $110-180/MWh depending on fuel source. Sugar cane bagasse at low cost ($5-15/tonne fuel) is competitive; purpose-grown biomass at $40-80/tonne is not. Biomass is fundamentally fuel-constrained — available biomass supply at competitive prices limits installed capacity to perhaps 500-1,500 MW without diverting food or timber resources.

Biomass role in Australian grid: specialised baseload at agricultural processing sites; municipal waste-to-energy providing local heat + power; research applications in gasification and biorefining. Not a major contributor to grid generation but provides specific value in niche applications.

Geothermal

Geothermal electricity generation uses high-temperature underground water or enhanced geothermal systems (EGS) to drive steam turbines. Australia has no commercial geothermal

electricity generation as of 2026. Research drilling in the Cooper Basin (Innamincka, SA) demonstrated technical feasibility but encountered commercial challenges; project halted 2016.

Australian geothermal resource is high-temperature (200-270°C granite-hosted geothermal) but deep (3-5 km) and requires hydraulic fracturing for heat extraction. Capital cost estimates approximately $10,000-18,000/kW for commercial deployment. LCOE estimates approximately $170-300/MWh.

Geothermal in Australia is not currently cost-competitive but may become viable with continued drilling technology advances (mining industry innovation spillover). Realistic deployment potential approximately 1-3 GW by 2050 in Cooper Basin region, primarily for inland industrial customers plus corridor-town baseload.

Wave, Tidal, and Marine Current

Marine energy technologies convert wave energy, tidal flows, or ocean currents into electricity. Australia has excellent wave resource on southern and southwestern coasts (one of the highest globally). No commercial wave or tidal generation operates in Australia as of 2026; multiple pre-commercial demonstration projects have been attempted.

Wave energy cost estimates: approximately $150-400/MWh depending on design and location. Technology is immature — no design has achieved commercial deployment at scale globally. Carnegie Clean Energy (WA) operated the Perth Wave Energy Project 2014-2019 at small scale; project wound down due to commercial viability concerns.

Tidal current generation: approximately $120-280/MWh potential at suitable sites (strong tidal flows through constrained channels). Australian tidal resource is concentrated at Kimberley coast (approximately 11-metre tidal range) but limited load in the region currently.

Marine energy role in Australian grid: not near-term. May become viable in specific locations by 2050+ if technology costs fall and load grows in remote coastal areas. Not a substantial contributor to grid generation under current projections.

Technology Summary Table — Full Comparison

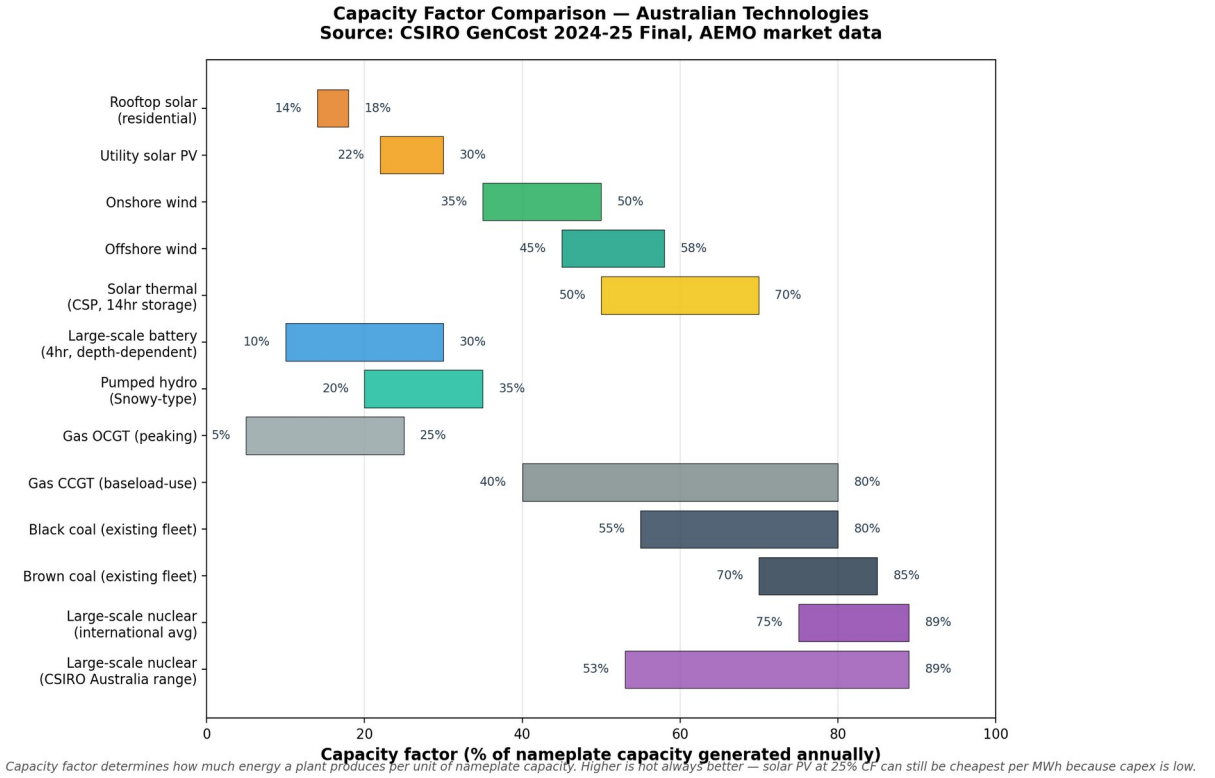


Figure 5: Capacity factor comparison across Australian generation technologies. Source: CSIRO GenCost 2024-25, AEMO market data.

Summary ranking by LCOE at 2030 (including all technologies covered in Part B):

Rank	Technology	2030 LCOE ($/MWh)	Deployability
1	Utility solar PV (standalone)	$22–$53	High — scaling
2	Onshore wind (standalone)	$45–$78	High — scaling
3	Rooftop solar (behind-meter)	$40–$85	Very high — distributed
4	Firmed renewables (solar+wind+storage)	$70–$120	Scaling with transmission
5	Gas CCGT (at $12/GJ)	$100–$180	Declining share
6	Offshore wind (2030 first deployment)	$120–$200	Emerging
7	Coal (new-build)	$100–$200	Zero new-build
8	CSP (14-hour storage)	$110–$200	Emerging at scale
9	Large-scale nuclear NOAK	$173–$288	Unavailable before 2041
10	Hydrogen-to-electricity storage	$200–$450	Emerging, niche use
11	Nuclear SMR (FOAK)	$230–$382	Unavailable before 2041

Rank	Technology	2030 LCOE ($/MWh)	Deployability
12	Coal + CCS	$150–$270	No commercial deployment
13	Large-scale nuclear FOAK	$250–$420	Unavailable before 2041
14	Gas OCGT (peaking)	$180–$450	Reducing share

Rankings change with specific system requirements. For always-on baseload comparison, firmed renewables at $70-120/MWh are cheapest. For peaking service, large-scale batteries ($80-140/MWh LCOS) and gas OCGT ($180-450/MWh) are the primary options. For long-duration storage (10+ days), hydrogen is likely most cost-effective despite its low round-trip efficiency. For multi-year drought-equivalent buffer, Alice Hub at $1-2/kWh storage cost is categorically cheaper than any alternative.

The technology ranking is clear: solar, wind, and storage lead across all relevant cost metrics. Fossil fuel generation is declining. Nuclear is not cost-competitive and cannot be built in time to contribute to the coal retirement transition. The interesting questions are not which technology is cheapest but how technologies combine to deliver reliable supply at scale — which is the topic of Part D.

AUSTRALIAN ELECTRICITY — COST ANALYSIS

Part C · Lifecycle Analysis · April 2026

LIFECYCLE

Chapter 8 — Cradle to Grave

Part C examines the full lifecycle impact of each major generation technology — from mining the input materials, through manufacturing, transport, construction, operation, maintenance, decommissioning, and waste management. The LCOE analysis in Part B captures what a generator costs to build and operate; lifecycle analysis captures what it costs the planet and the material economy to build and operate that same generator.

PART C — LIFECYCLE ANALYSIS

Cradle-to-grave assessment of material inputs, emissions, waste streams, and decommissioning costs for every major technology.

Chapter 8 — Cradle-to-Grave — The True Cost of Each Technology

LCOE captures the financial cost of electricity generation, but not the environmental or material cost. For a complete picture of what a technology costs society, we need lifecycle analysis (LCA) — a systematic accounting of every input and output across the full life of the generator, from mining the raw materials through decommissioning and waste management.

This chapter applies LCA to the major generation technologies in Australia. The methodology follows ISO 14040/14044 standards, drawing on IEA-PVPS Task 12, NREL lifecycle assessments, IPCC AR6, and the UK Parliamentary POST reviews. Three lifecycle indicators are presented for each technology: energy payback time (EPBT), lifecycle greenhouse gas emissions (g CO_2e/kWh), and material intensity (tonnes per TWh of lifetime generation).

Lifecycle Greenhouse Gas Emissions

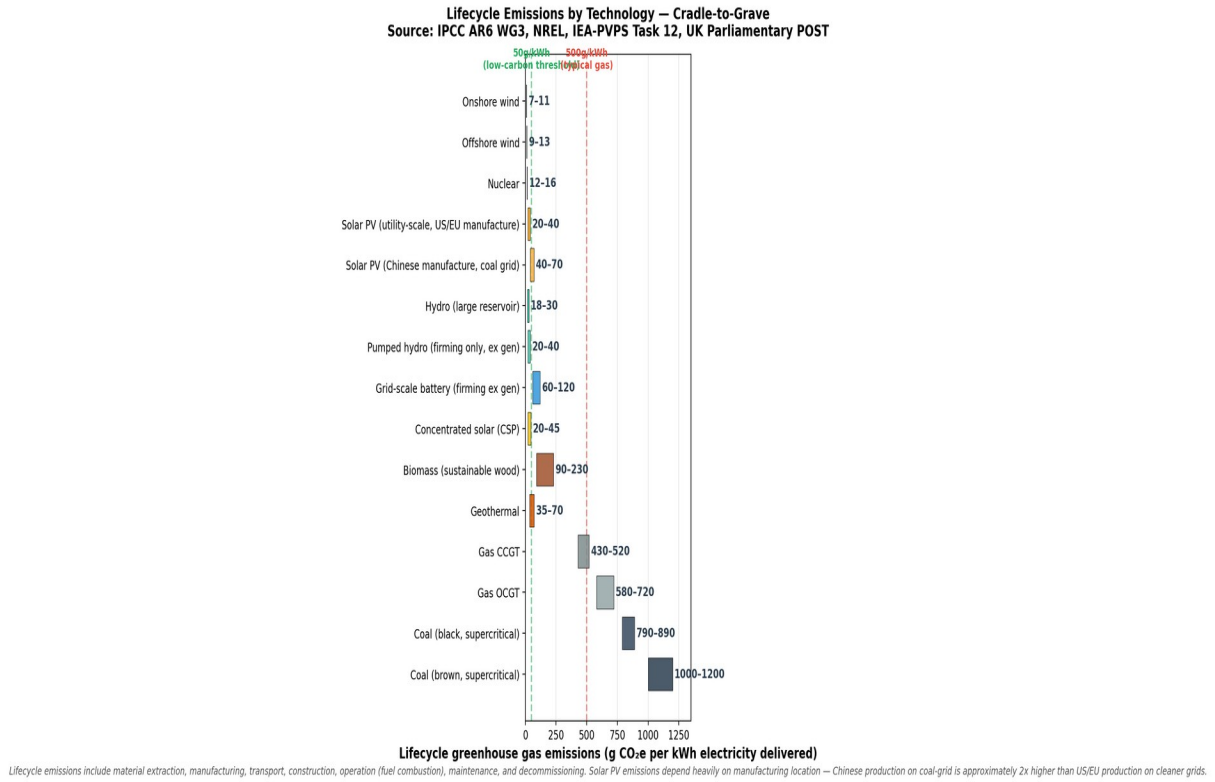


Figure 6: Lifecycle greenhouse gas emissions per kWh of electricity delivered. Sources: IPCC AR6 Working Group 3, NREL lifecycle assessments, IEA-PVPS Task 12, UK Parliamentary POST Note 383.

Key readings from Figure 6:

- Wind (onshore and offshore) has the lowest lifecycle emissions of any generation technology at 7-13 g CO_2e/kWh. Nearly all emissions are from manufacturing steel towers and concrete foundations.
- Nuclear at 12-16 g CO_2e/kWh is competitive with wind for climate benefit. Most emissions are from construction materials; uranium fuel cycle emissions (mining, enrichment, fuel fabrication) are small per kWh because fuel density is enormous.

- Solar PV varies substantially based on manufacturing location: 20-40 g CO_2e/kWh for US/EU manufactured panels on cleaner grids; 40-70 g CO_2e/kWh for Chinese-manufactured panels on coal-heavy grids. This is the single largest lifecycle variable for any technology.
- Hydro (large reservoir) 18-30 g CO_2e/kWh, higher than wind because of reservoir methane emissions from decomposing organic matter in flooded land. Cold-climate reservoirs (Snowy Hydro, Tasmania) have lower values; tropical reservoirs can be higher.
- Gas CCGT at 430-520 g CO_2e/kWh. Approximately 90% of emissions are fuel combustion during operation; the rest is upstream methane leakage and construction.
- Coal at 790-1,200 g CO_2e/kWh depending on black or brown coal and plant efficiency. This is approximately 100 times more emissions-intensive than wind per unit of electricity delivered.

Implication: from a climate perspective, renewable and nuclear generation are all in the same order of magnitude of lifecycle emissions — approximately 10 to 50 g CO_2e/kWh. Gas is approximately 10 times higher. Coal is approximately 50-100 times higher. Lifecycle emissions strengthen the case for clean generation regardless of specific technology preference.

Energy Payback Time

Energy Payback Time (EPBT) is the time for a generator to produce as much energy as was consumed to build it. A short EPBT means the technology quickly becomes a net energy producer; a long EPBT means substantial energy investment is locked up in the technology for extended periods.

EPBT values for major technologies (measured in months or years of operation at typical capacity factor):

Technology	EPBT (years)	Lifetime (years)	Net energy ratio
Utility solar PV (US/EU manufacture)	0.5–1.2	30	25–60:1
Utility solar PV (Chinese, coal grid)	1.5–3.0	30	10–20:1
Rooftop solar PV	0.8–2.0	25–30	12–35:1
Onshore wind	0.5–1.0	25	25–50:1
Offshore wind	0.8–1.5	25	15–30:1
Large-scale nuclear	2–5	60	12–30:1
Hydro (large reservoir)	3–8	80+	15–30:1
Coal (new-build)	0.5–1 (construction only)	40	~5–8:1 (including fuel)
Gas CCGT	0.2–0.5 (construction only)	30	~2–3:1 (including fuel)

Interpretation: renewables pay back their construction energy within 1-2 years of operation, then continue producing clean energy for 25-30 years of additional lifetime. Solar PV delivers approximately 25-60 times more energy than was consumed to manufacture it (net energy

ratio). Wind delivers 25-50:1. Even in worst-case scenarios (Chinese-manufactured panels on coal-heavy grids), net energy ratios exceed 10:1 — still overwhelmingly positive.

For fossil fuels, the comparison is different because fuel must be continuously supplied. Coal plants pay back construction energy quickly but continue consuming fuel at approximately 2-3 units of fuel energy for each unit of electricity delivered (thermal efficiency 33-45%). Over a 40-year plant life, fuel consumption dominates total energy throughput.

Material Inputs — Construction vs Fuel

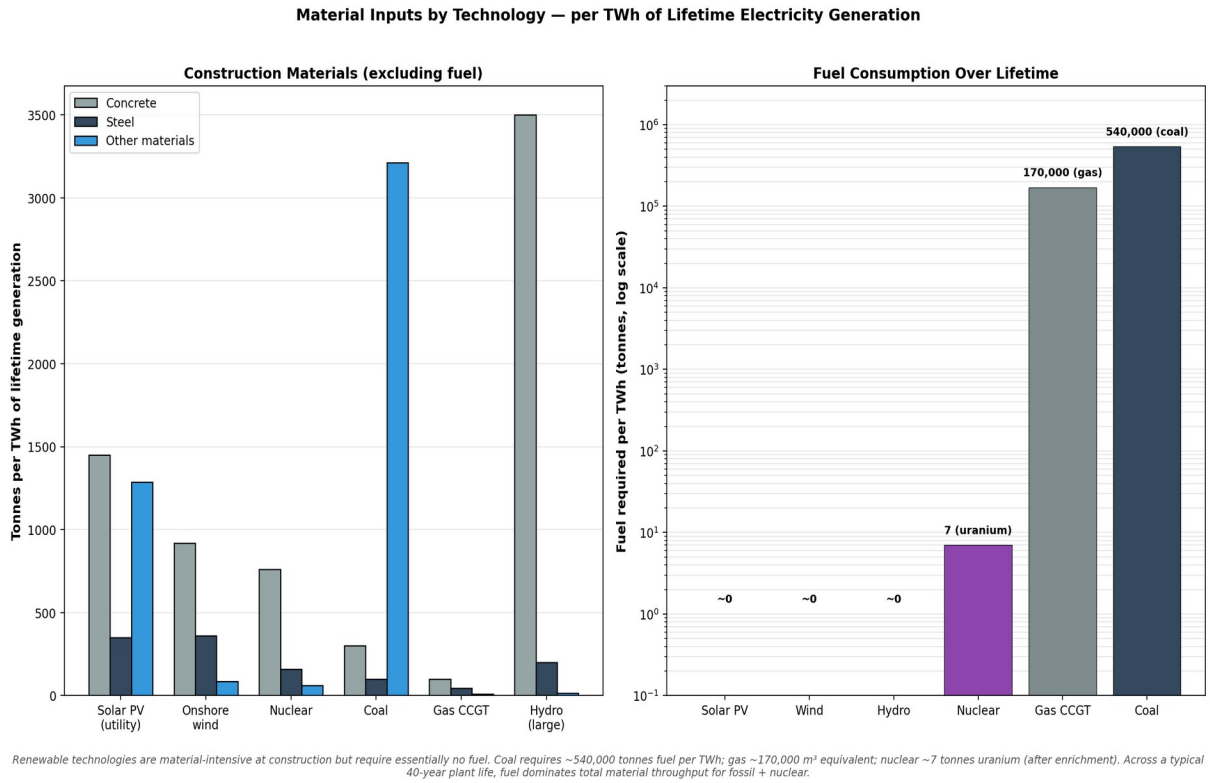


Figure 7: Material inputs by technology per TWh of lifetime generation. Left panel: construction materials (tonnes). Right panel: fuel consumption over lifetime (tonnes, logarithmic scale).

Material intensity varies dramatically across technologies. The trade-off is between construction material intensity and fuel consumption:

- Renewable technologies are construction-material-intensive: solar PV needs approximately 1,450 tonnes of concrete, 350 tonnes of steel, plus 820 tonnes of glass per TWh of lifetime generation. Wind needs approximately 920 tonnes concrete and 360 tonnes steel per TWh. But fuel is essentially zero.
- Hydro is the most construction-material-intensive per TWh (3,500 tonnes concrete for large reservoir construction) but requires no fuel.
- Coal has lower construction intensity (300 tonnes concrete, 100 tonnes steel per TWh) but consumes approximately 540,000 tonnes of coal fuel per TWh — 1,800 times the construction material throughput. Over a 40-year plant life, the plant consumes approximately 20 million tonnes of fuel.
- Gas has the lowest construction intensity (100 tonnes concrete, 45 tonnes steel per TWh) but consumes approximately 170,000 tonnes of gas per TWh equivalent.

- Nuclear construction is heavier than gas but lighter than coal per TWh, and fuel consumption is approximately 7 tonnes of uranium per TWh — approximately 75,000 times more energy-dense than coal per unit mass.

The material balance changes what 'environmental impact' means. Renewable technologies impact the environment primarily at the front end (mining, manufacturing, transport) and at end-of-life (recycling, waste). Fossil technologies impact primarily during operation (combustion, emissions, mining continuous over plant life). Nuclear impacts at all three stages but at much lower fuel mass.

Solar PV — Full Lifecycle

Solar PV is the most-studied technology for lifecycle impact because of rapid deployment and public interest. The lifecycle stages and their relative impact contribution:

- Silicon production (40-50% of total impact): quartz mining, silicon smelting, purification to solar-grade silicon. This is the most energy-intensive stage, typically requiring approximately 55-90 kWh electricity per kg of solar-grade silicon. Manufacturing location matters enormously: Chinese production on coal-heavy grid has much higher lifecycle emissions than US/EU production on cleaner grids.
- Wafer/cell/module manufacturing (30-40%): silicon ingot growth, wafer slicing, cell doping, module assembly. Large energy input plus some process emissions (cell doping gases, lamination processes).
- Balance of system (10-15%): aluminium framing, glass covers, steel mounting, inverters, wiring, junction boxes. Aluminium is the largest single BOS contributor due to smelting energy.
- Transport and installation (5-10%): shipping, site preparation, foundation concrete, electrical installation, commissioning.
- Operation (1-3%): cleaning water, inverter maintenance, occasional component replacement. Minimal lifecycle contribution.
- End-of-life (0-10%, varies): landfill disposal versus recycling. Recycling reduces total lifecycle impact by up to 89% for mineral resource category per recent LCA studies (Contreras Lisperguer 2020; Nuno et al 2023).

Solar PV waste is a growing consideration. Current Australian rooftop PV installed 2012-2015 is reaching end-of-life around 2040-2045. Estimated Australian PV waste by 2050: approximately 1.5 million tonnes cumulative. Globally, IEA estimates 78 million tonnes of solar PV waste by 2050. Recycling technology exists (Reclaim PV in Australia; First Solar in US; veolia in EU) but at scale limited by economics — recycling cost currently exceeds landfill cost by factor of 5-10 without regulatory push.

Australia needs a mandatory PV recycling scheme to avoid accumulation of PV waste through the 2040s-2050s. Similar to the car tyre stewardship scheme. Under SBC corridor town development, centralised PV recycling facilities at corridor-adjacent industrial hubs (Hunter Valley, Kalgoorlie, Mount Isa, Port Augusta) become commercially viable due to scale plus cheap corridor power.

Wind — Full Lifecycle

Onshore wind has lower lifecycle impact than solar across most indicators due to simpler manufacturing. The lifecycle stages:

- Tower and nacelle (60-70% of impact): steel tower manufacturing (approximately 200-300 tonnes steel per 3-5 MW turbine), nacelle housing, gearbox, generator. Most impact is steel production.
- Blades (10-15%): fibreglass/carbon fibre composite with epoxy resin. Manufacturing requires petrochemicals; blades are difficult to recycle at end-of-life.
- Foundation (10-15%): concrete and steel reinforcement (approximately 500-1,000 tonnes concrete per turbine). Very large foundations for offshore fixed-bottom turbines.
- Installation (5-10%): transport of large components to site, crane operation, grid connection.
- Operation (2-5%): gearbox oil changes, occasional component replacement, maintenance vehicles.
- End-of-life (variable): tower steel is 85-95% recyclable; blades are currently problematic — approximately 20-25% recyclable with current technology, improving as chemical recycling matures.

Wind blade disposal is a specific challenge. Current Australian wind fleet deployed 2005-2015 will reach end-of-life 2030-2040. Estimated Australian blade waste: approximately 15,000-30,000 tonnes cumulative by 2045. Current disposal methods include landfill, cement kiln co-processing (using blade material as fuel/aggregate substitute), or grinding for composite applications.

Emerging blade recycling technologies (chemical recycling to recover epoxy and fibre; thermoplastic blades recyclable to pellets) promise 80-95% material recovery. Deployment at commercial scale expected by 2030. Australian regulatory framework for end-of-life wind turbine disposal is under development.

Nuclear — Full Lifecycle Including Fuel

Nuclear lifecycle is more complex than renewables because of the fuel cycle — uranium mining, enrichment, fuel fabrication, reactor operation, spent fuel storage, waste management. Each stage has distinct impacts.

Fuel cycle stages:

- Uranium mining and milling: Australia is world's third-largest uranium producer. Mining is open-cut or underground plus in-situ leaching. Environmental impact per tonne of uranium is substantial (radon emissions, tailings management) but per kWh generated is small due to uranium fuel density.
- Conversion and enrichment: uranium ore converted to UF6, enriched to 3-5% U-235 in centrifuges. Enrichment is energy-intensive but modern centrifuge technology has reduced energy input by approximately 50x since the 1970s gaseous diffusion era.
- Fuel fabrication: enriched UF6 converted to UO2 pellets, assembled into fuel rods. Relatively small environmental footprint.
- Reactor operation: low emissions per MWh (12-16 g CO_2e/kWh lifecycle). Low-level waste (contaminated operational items) accumulates at modest volume (~400 m^3/year per reactor).
- Spent fuel: approximately 25 tonnes per 1 GW reactor per year. Current storage is on-site in cooling pools then dry casks, designed for 40+ year interim storage.
- Long-term disposal: deep geological repository for high-level waste. Finland's Onkalo is first commercial DGR (commissioning 2026-2027). Finnish Onkalo total cost approximately EUR 3.5 billion for approximately 6,500 tonnes HM = approximately AUD 900/kg HM. Per 1 GW Australian reactor fleet over 60 years (approximately 1,500

tonnes HM) = approximately AUD 1.3-2.0 billion, equating to approximately $3-4/MWh addition to LCOE. Source: STUK Finland; Onkalo project data.

- Decommissioning: 50-60 years after operation ceases (to allow radioactivity decay). Cost approximately $500-1,200/kW originally installed.

Nuclear waste management is the area of greatest public concern. The technical consensus is that deep geological disposal is safe and engineering-solved (Onkalo represents decades of international consensus). The political question is siting — which is genuinely difficult but not uniquely Australian (Germany, US, UK, France all face siting challenges).

Comparison context: Australian nuclear at 1 GW fleet would generate approximately 3,000 tonnes of spent fuel across 60-year operational life. Same period, Australian coal fleet generates approximately 6 billion tonnes of ash, CO_2, and air pollutants — approximately 2 million times more mass of waste, with far greater distributed environmental impact. Nuclear waste is more concentrated and intensely managed; fossil waste is dispersed and largely unmanaged.

Coal — Full Lifecycle

Coal lifecycle is dominated by operation (combustion emissions plus mining impacts) rather than construction. Mining, transport, combustion, and ash/emissions stages contribute to total impact:

- Mining: approximately 540,000 tonnes of coal per TWh of electricity. Open-cut mining creates land disturbance approximately 0.5-1.5 km² per million tonnes extracted. Underground mining has lower surface disturbance but creates subsidence and methane emissions.
- Transport: rail transport from mine to power station, typically 100-500 km in Australia. Transport energy approximately 2-5% of fuel energy.
- Combustion: 790-1,200 g CO_2e/kWh lifecycle emissions. Plus air pollutants: SO_2 (0.2-2 g/kWh), NO_x (0.5-1.5 g/kWh), PM2.5 (0.02-0.2 g/kWh), mercury (0.01-0.05 mg/kWh).
- Ash disposal: approximately 20-50 tonnes fly ash plus 5-15 tonnes bottom ash per GWh generated. Ash contains heavy metals and requires permanent containment. Australian ash dams hold approximately 400 million tonnes of stored ash cumulatively — substantial long-term liability. Source: Ash Development Association of Australia.
- Water: approximately 1,200-3,500 L/MWh for once-through cooling, 500-2,000 L/MWh for closed-loop cooling. Water scarcity constraint in Australian conditions.
- Decommissioning: approximately $100-300/kW installed.

Coal total lifecycle impact is large and widely distributed. Australian coal generation emissions approximately 140 Mt CO_2/year; total electricity sector emissions approximately 162 Mt CO_2/year including gas. Source: Clean Energy Regulator NGER reporting 2023-24. Avoiding these emissions through renewable replacement is the single largest environmental benefit of electricity transition.

Coal mining health impacts: respiratory disease in coal miners (black lung); downwind air quality impacts from combustion (respiratory illness, cardiovascular disease). Australian Institute of Health and Welfare estimates approximately 800-1,600 premature deaths per year attributable to Australian coal-fired generation air pollution. These externalities are not captured in LCOE but are substantial in monetised terms (approximately $5-10 billion/year using standard mortality valuations).

Gas — Full Lifecycle

Gas lifecycle has lower combustion emissions than coal but is affected by upstream methane leakage. Methane is approximately 80 times more potent as a greenhouse gas than CO_2 over 20 years.

- Extraction: conventional gas extraction or unconventional (coal seam gas, shale gas, tight gas). Australian domestic gas is approximately 50% unconventional (mostly Queensland coal seam gas).
- Upstream methane leakage: estimated 1-3% of produced gas leaks to atmosphere in extraction, processing, and transport. This leakage accounts for approximately 15-25% of gas lifecycle emissions depending on estimation methodology.
- Transport: pipeline or LNG. Pipeline transport has low losses; LNG liquefaction and transport adds approximately 15-25% energy overhead.
- Combustion: 430-520 g CO_2e/kWh lifecycle emissions (CCGT) or 580-720 g CO_2e/kWh (OCGT). Lower CO_2 per kWh than coal but combined with methane leakage, total climate impact is approximately 50-60% of coal.
- Water: approximately 400-800 L/MWh for CCGT. Lower than coal.
- Decommissioning: approximately $50-150/kW installed.

Gas as 'bridge fuel' argument: gas emissions are lower than coal but still substantial relative to renewables. Replacing coal with gas reduces emissions by 40-55% but this falls far short of the approximately 95-99% reduction achieved by replacing coal with renewables. Gas is a transition measure only when deployment of renewables is constrained, which is not the current Australian position.

Decommissioning and End-of-Life

Decommissioning costs and waste streams vary by technology:

Technology	Decommissioning cost	Recyclability	Waste stream
Solar PV	$50–100/kW	85-95% (with chemical recycling)	Glass, silicon, metals
Onshore wind	$50–150/kW	85-95% steel; 20-25% blades	Steel, concrete foundations, composite blades
Offshore wind	$200–400/kW	80-90%	Similar to onshore plus marine cleanup
Hydro (dam)	Typically not decommissioned	N/A	Reservoir sediment; no active decommissioning
Pumped hydro	$100–300/kW	High (steel, concrete)	Similar to hydro
Coal	$100–300/kW	Moderate (steel and buildings)	Site contamination plus ash dams
Gas CCGT	$50–150/kW	High (modular equipment)	Site remediation
Nuclear (60+ yr life)	$500–$1,200/kW	Spent fuel to DGR; steel recyclable	High-level waste, low-level waste, activated components

Nuclear decommissioning is the most complex and capital-intensive. Reactor and containment structures must be dismantled and disposed of; activated components require interim storage. Total nuclear decommissioning cost is approximately 8-15% of original construction cost per kW, typically funded through sinking funds accumulated during operation. This cost is captured in GenCost LCOE via capital recovery period.

For all technologies, the decommissioning phase creates substantial employment — dismantling, waste management, site remediation. Nuclear decommissioning can employ approximately 500-1,500 workers per site for 10-20 years. Solar and wind decommissioning at scale will create approximately 3,000-8,000 jobs nationally by 2040-2050 in Australia as first-generation installations reach end of life.

The Full Cradle-to-Grave Picture

Synthesising the lifecycle analysis across all dimensions, the ranking of technologies by total lifecycle impact (combining emissions, material intensity, waste volumes, externalities) differs from the LCOE ranking but confirms the broader direction:

- Lowest total lifecycle impact: onshore wind, hydro (cold climate), nuclear. These technologies have low emissions, low fuel consumption, managed waste streams.
- Low total impact: solar PV (especially with recycling plus cleaner manufacturing grids), offshore wind, CSP.
- Moderate impact: pumped hydro, gas CCGT, biomass (sustainable sourcing).
- High impact: coal (black), gas OCGT.
- Highest impact: coal (brown).

When externalities (health costs, environmental damage, ecosystem loss) are monetised, the ranking aligns strongly with LCOE: renewables are cheapest on both financial LCOE and true social cost. Fossil fuels are cheapest on narrow operational cost but most expensive on social cost. Nuclear is more expensive on financial LCOE but moderately priced on social cost. Full-cost pricing would widen the cost advantage of renewables substantially.

Lifecycle analysis confirms the LCOE finding: renewables are the lowest-cost electricity option for Australia, and the advantage widens when full lifecycle impacts are included. Solar PV manufacturing location matters enormously; Chinese production doubles lifecycle emissions compared to cleaner grids. End-of-life management for solar panels and wind blades is a policy issue that requires mandatory stewardship schemes. Fossil fuel externalities (air quality, health) are substantial and largely unpriced.

FIRM

Chapter 9 — How Technologies Combine

Part D compares electricity technologies on the basis that matters most — delivered firm capacity. No single technology provides reliable electricity alone; every real electricity system is a combination. This chapter compares the combinations that Australia will actually build against the fossil and nuclear alternatives they replace. The apples-to-apples comparison is what this report has been building toward.

PART D — FIRM COMBINATIONS

How technologies combine to deliver reliable electricity — the comparison that matters.

Chapter 9 — Firm Combinations — The Comparison That Matters

Electricity systems are combinations of technologies, not individual generators. A coal plant alone cannot reliably supply electricity — it needs backup for planned and unplanned outages. A solar farm alone cannot supply electricity at night. A battery alone cannot supply energy it hasn't first received. Reliability is always a system property, not a generator property.

The correct comparison between electricity options is therefore not 'solar LCOE vs coal LCOE' but 'firmed solar system cost vs firmed coal system cost'. This chapter presents that comparison systematically, using CSIRO GenCost firming cost methodology plus analysis of specific combinations.

What 'Firm' Means

'Firm capacity' means the capacity that is available on demand for reliable system operation. 'Firm LCOE' means the levelised cost of electricity from a system that can deliver reliable supply — meeting demand at specified reliability standards (for Australia, the NEM Reliability Standard of 99.998% supply availability across all credible operating conditions).

Firming mechanisms include:

- Energy storage — batteries (1-8 hours), pumped hydro (2-175 hours), CSP molten salt (4-16 hours), hydrogen (indefinite duration)
- Geographic diversity — solar in Queensland firms wind shortage in SA; wind on the WA coast firms calm conditions in the NEM
- Transmission — interconnection between regions allows resource sharing and reduces total storage requirement
- Dispatchable generation — hydro, gas peaking, hydrogen-fuelled generation available on demand
- Demand flexibility — industrial customers accepting curtailment during peaks in exchange for lower prices; residential time-of-use pricing
- Strategic reserve — long-duration storage for multi-day or multi-week shortfalls

Real firm electricity supply uses combinations of these mechanisms. No single mechanism is sufficient; no single mechanism is required. The cheapest firming mix depends on specific regional conditions — renewable resource profile, existing infrastructure, demand patterns, transmission topology.

Firm Combinations — The Full Comparison Chart

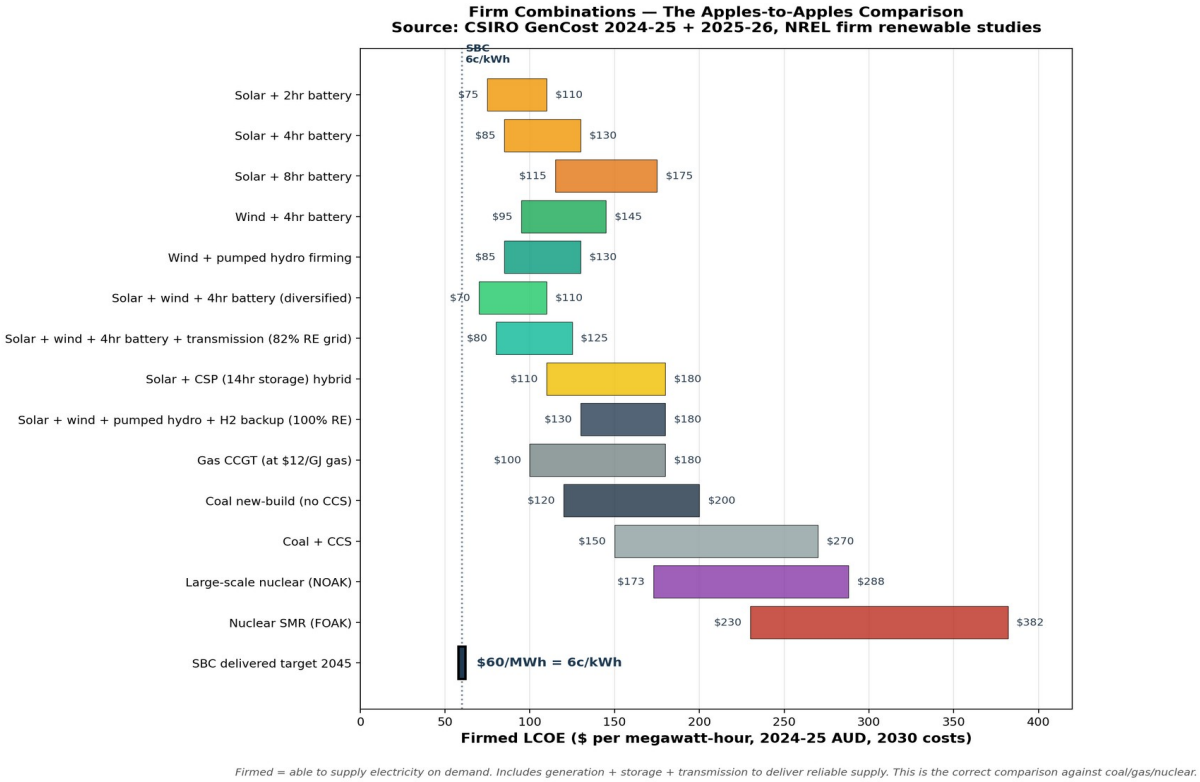


Figure 8: Firmed LCOE comparison for major electricity combinations. Source: CSIRO GenCost 2024-25 Final + 2025-26 Draft, NREL firm renewable studies, Lazard LCOE+ v18.

Key findings from Figure 8:

- The cheapest firm electricity option is diversified renewables (solar + wind + 4hr battery) at $70-$110/MWh. Geographic diversity plus moderate storage delivers firm capacity at below any thermal generation cost.
- At 82 percent renewable grid with transmission expansion (GenCost 2030 target scenario), firmed LCOE is approximately $80-$125/MWh — this is what Australia's electricity actually costs at 2030.
- At 100 percent renewable grid with long-duration storage (solar + wind + pumped hydro + hydrogen backup), firmed LCOE is approximately $130-$180/MWh. Higher than 82% RE because the last 18% of supply requires disproportionately more storage.
- Coal new-build (no CCS) firmed LCOE is $120-$200/MWh — more expensive than diversified renewables despite being 'always on'. Coal does not provide 100% reliability without backup (planned and unplanned outages typically 10-20% of time per year).
- Gas CCGT firmed LCOE at $12/GJ gas is $100-$180/MWh. At $6/GJ SBC-delivered gas, CCGT firmed LCOE drops to $70-$120/MWh — competitive with firmed renewables.
- Large-scale nuclear firmed LCOE is $173-$288/MWh. No cost advantage at any realistic firming scenario.

Solar + Short-Duration Battery (2-4 hours)

The entry-level renewable firming combination. Short-duration batteries (2-4 hours) are cheap at current costs and well-suited for smoothing daily solar generation to match residential evening peak demand.

Solar + 4hr battery firming delivers approximately 50-70% firm capacity from variable solar generation. The combination cannot provide true 24/7 firm capacity — overnight demand still requires backup from wind, hydro, or thermal. But it is cost-effective for peak-shifting solar output from midday to evening peak, reducing gas peaking requirement.

Specific deployment economics (2030):

- Solar generation LCOE: $30-50/MWh
- 4hr battery storage cost: $80-140/MWh LCOS
- Combined firming cost (weighted average depending on mix): $85-130/MWh

This combination is being deployed at scale across Australia already — approximately 15 GW / 40 GWh of pipeline battery projects 2025-2028, nearly all co-located with solar or wind.

Wind + Pumped Hydro (the Tasmanian Model)

Tasmania demonstrates the wind + pumped hydro firming combination at continental scale. Hydro Tasmania's approximately 2,300 MW hydroelectric fleet plus approximately 1,500 MW of wind generation operates as a firmed renewable system with minimal gas backup. During dry years (low inflows), Tasmania imports NEM electricity via Basslink; in wet years (high inflows), it exports. Tasmania has achieved approximately 95-100% renewable electricity share for over a decade. Source: Hydro Tasmania Annual Report.

The Tasmanian model works because hydro reservoirs provide effectively unlimited-duration firming at low marginal cost. Water stored during high-inflow periods can be dispatched during low-inflow or low-wind periods. Total firming LCOE in Tasmania's effective system: approximately $60-$90/MWh — among the cheapest firm renewable systems globally.

Scaling this model to mainland Australia requires pumped hydro expansion:

- Snowy 2.0 (2029-30 commissioning): 2,200 MW, 175 hours storage
- Alice Hub Stage 1 (Year 5): 2.5 GW, additional capacity
- Battery of the Nation (proposed): up to 2,500 MW additional Tasmanian pumped hydro, commissioning 2030s
- Marinus Link (under construction): 750 MW additional Tasmania-Victoria interconnection

Combined pumped hydro + hydro capacity by 2035 in NEM plus SWIS: approximately 10-12 GW of dispatchable storage with multi-hour to multi-day duration. Sufficient for substantial firming at approximately 82% renewable share.

Diversified Renewables — Solar + Wind + Storage + Transmission

The cheapest firm electricity combination is diversified renewables across geographic regions connected by transmission, with moderate storage for daily cycling. This is the AEMO Integrated System Plan approach and the basis of CSIRO GenCost 82 percent renewable scenario.

The combination works because:

- Solar generation is diurnal (daily cycle) — storage shifts output to match demand peaks
- Wind is weather-cycle (multi-day cycles) — geographic diversity averages out regional wind variations

- Solar + wind together are substantially less variable than either alone
- Transmission allows geographic sharing of surplus/deficit
- Short-duration storage covers the residual variability
- Existing hydro (Snowy, Tasmania) provides deep firming backup

AEMO ISP 2026 Draft optimum generation mix at 82% renewable (2030 target):

Source	Share of generation	Role
Solar PV (utility + rooftop)	31%	Daily generation, peak-shift via battery
Onshore wind	41%	Baseload-equivalent + weather diversity
Offshore wind	small	Emerging, coastal regions
Hydro (existing + Snowy 2.0)	6%	Firming, dispatchable
Coal (declining)	18%	Retiring progressively through 2030s
Gas (peaking)	4%	Backup, firm capacity
Total firm LCOE at 2030	$91/MWh	Including transmission

The 2030 82% RE scenario delivers firmed LCOE of $91/MWh including transmission — approximately 30% below current NEM wholesale of $129/MWh. Electricity becomes cheaper as renewable share increases, not more expensive, because generation cost of solar and wind is lower than coal and gas they replace.

100% Renewable — Adding Long-Duration Storage

Beyond approximately 80-85% renewable share, the firming mix must include long-duration storage for weather patterns that leave multiple regions simultaneously low on renewable generation (multi-day Victorian winter high-pressure system with low wind; two-week spring low-solar low-wind episode).

The 100% renewable firming stack adds:

- Pumped hydro expansion: Alice Hub at full build (40 GW, 175+ hours) plus continued Snowy 2.0 operation plus Tasmanian hydro expansion
- Green hydrogen backup: 5-10 GW of hydrogen-fuelled turbines operating <5% capacity factor for multi-week backup
- Additional transmission: continental HVDC (SBC backbone) providing east-west solar diversity and north-south wind diversity
- Demand flexibility: industrial DSR contracts, EV smart charging, residential TOU pricing
- Strategic reserves: long-duration flow batteries or compressed air at specific strategic locations

CSIRO GenCost 2050 net-zero scenario firmed LCOE: approximately $135-$148/MWh including transmission. This is higher than 82% RE scenario because the marginal firming cost for the last 15-20% of non-renewable-replaceable load is expensive.

SBC Alice Hub + continental HVDC directly addresses this cost. Alice Hub at approximately $1-2/kWh stored energy versus standalone pumped hydro at approximately $30-80/kWh delivers

continental firming at approximately $15-30/MWh versus standalone battery firming at $80-140/MWh. Combined with continental HVDC transmission at approximately $7/MWh, the SBC approach delivers 100% renewable at approximately $60/MWh target — substantially below GenCost 2050 $141/MWh projection.

Solar + CSP Hybrid — Alternative Firming Path

Concentrated solar power with molten salt storage provides 8-16 hours of dispatchable generation from solar heat. CSP alone is not cost-competitive with solar PV, but CSP + solar PV + battery combinations provide specific value:

- CSP provides evening and overnight dispatchable generation
- Solar PV provides cheap daytime generation
- Battery provides short-term smoothing
- Combination suitable for industrial customers requiring on-site 24/7 clean energy at large scale

Combined LCOE at 2030: approximately $110-180/MWh — competitive with nuclear but more expensive than diversified grid firmed renewables. CSP is a niche technology for Australia, potentially valuable for specific industrial-scale clean energy delivery at remote sites or solar-thermal industrial processes.

Gas CCGT — When Is It Worth It?

Gas CCGT firmed LCOE at current Australian gas prices ($12-15/GJ) is $100-$180/MWh — comparable to firmed renewables but with ongoing emissions. At $6/GJ (SBC corridor delivered) it drops to $70-120/MWh — competitive with renewables.

Gas makes economic sense in specific roles:

- Peaking generation — low capacity factor, fast start, backup for unexpected events
- Transitional backup — during 2025-2035 while renewable + storage deployment catches up with coal retirement
- Hydrogen-ready plants — gas turbines designed for 30-100% hydrogen co-firing, transitioning to green hydrogen by 2040-2050
- Remote or isolated grids — NT, regional WA, mining grids where transmission is uneconomic

Gas does not make sense for new baseload generation. Coal retirement is not replaced by new baseload gas — AEMO ISP 2026 Draft envisages approximately 5-10 GW of new gas peaking capacity through 2035, all hydrogen-ready, operating at progressively lower capacity factor as renewable + storage deployment expands.

Coal + CCS — Why It Doesn't Happen

Coal combustion with carbon capture and storage is technically feasible but economically non-competitive. Global deployment is approximately 0 GW of commercial coal + CCS as of 2026 despite decades of research. Commercial plants that have operated (Petra Nova in US, Boundary Dam in Canada) have encountered operational and economic challenges.

Coal + CCS firmed LCOE: $150-$270/MWh. The capture equipment adds 50-80% to capital cost and 25-40% to operating cost; CO_2 compression and transport adds further cost; long-term storage requires suitable geology and ongoing monitoring. Net thermal efficiency drops by 8-12 percentage points, increasing coal consumption per unit electricity delivered.

CCS role in net-zero scenarios is small. GenCost projects approximately 1-3 GW of CCS deployment globally by 2050 across various applications, primarily industrial process emissions (cement, steel) rather than electricity generation. Australian electricity CCS deployment: approximately zero under current economic trajectories.

Nuclear as Firm Capacity — The Timing Problem

Nuclear is an inherently firm technology — plants operate at 80-90% capacity factor with planned refuelling outages, providing reliable baseload-style generation. Nuclear firmed LCOE is therefore essentially the same as standalone nuclear LCOE ($173-$288/MWh for NOAK or $250-$420/MWh for FOAK).

The nuclear question for Australia is not 'can nuclear be firm?' but 'when would it arrive?'. Under CSIRO analysis, first Australian nuclear operation would be approximately 2041-2043. By that date:

- Coal retirement approximately 80-90% complete; replacement already in place
- Firmed renewables already delivering 90%+ of NEM supply
- Alice Hub continental firming operational (Phase 3 complete by 2045)
- Continental HVDC connecting all regions
- Residential and industrial electrification largely transitioned

The role for new-built nuclear arriving in 2043 is unclear. It would compete for market share against an established renewable + storage system with substantially lower operating costs. Nuclear's high fixed cost plus moderate variable cost makes it uncompetitive against renewable generation's near-zero variable cost in a merit-order market. Nuclear would operate at reduced capacity factor, further degrading economics.

This is why CSIRO GenCost 2024-25 Final specifically analyses the long-life argument and finds no unique advantage. Australian nuclear arriving in the 2040s competes in a market that has already been optimised for renewables. Long operational life does not overcome initial capital cost when market conditions favour low-variable-cost competitors.

Summary — The Ranking of Firm Combinations

Ordered by 2030 firmed LCOE (lowest to highest):

Rank	Firm combination	LCOE range
1	SBC delivered target 2045	$60/MWh
2	Diversified renewables (solar + wind + 4hr battery)	$70–110/MWh
3	Gas CCGT at $6/GJ (SBC corridor)	$70–120/MWh
4	Solar + 2hr battery	$75–110/MWh
5	Wind + pumped hydro firming	$85–130/MWh
6	Solar + 4hr battery	$85–130/MWh
7	Wind + 4hr battery	$95–145/MWh
8	Gas CCGT at $12/GJ (current)	$100–180/MWh

Rank	Firm combination	LCOE range
9	Solar + 8hr battery	$115–175/MWh
10	Coal new-build (no CCS)	$120–200/MWh
11	Solar + CSP hybrid	$110–180/MWh
12	100% RE (solar+wind+PH+H2)	$130–180/MWh
13	Coal + CCS	$150–270/MWh
14	Large-scale nuclear NOAK	$173–288/MWh
15	Nuclear SMR FOAK	$230–382/MWh

The ranking is unambiguous: firmed renewables dominate every other option. Gas is competitive only with cheap corridor-delivered fuel. Coal new-build is expensive. Nuclear is not competitive at any firming scenario. The SBC approach delivers the cheapest option of all through continental scale + integrated infrastructure.

Firm combinations are the correct basis for comparing electricity options. Solar and wind are not uncompetitive because of intermittency — they are so cheap that their firming cost is easily absorbed while still delivering below-coal, below-gas, below-nuclear firmed system cost. The SBC achieves 6c/kWh by combining the cheapest generation (corridor solar), cheapest firming (Alice Hub continental battery), and shared infrastructure (corridor HVDC).

AUSTRALIAN ELECTRICITY — COST ANALYSIS

Part E · Continental Grid Advantage + SBC Pathway · April 2026

CONTINENTAL

ADVANTAGE

Chapters 10–11 — How Australia's Geography Becomes Its Advantage

Part E is the quantitative heart of the SBC case. Chapter 10 sets out the Continental Grid Advantage — the specific ways Australia's 4,000 km east-west span, geographic wind diversity, existing hydro anchors, and international HVDC connections combine to deliver firm electricity at costs no smaller country can match. Chapter 11 then builds the SBC Pathway explicitly — line by line, cent by cent, from 2.5c/kWh corridor solar generation to 6c/kWh delivered at consumer load centres.

PART E — CONTINENTAL GRID ADVANTAGE AND THE SBC PATHWAY

Australia's geography is its competitive advantage — if we build the transmission to use it.

Chapter 10 — The Continental Grid Advantage

Australia is the only OECD-equivalent country that spans an entire continent as a single political entity with a single electricity market ambition. This geographic fact is underutilised in current Australian electricity policy. The NEM covers approximately 40 percent of continental Australia by area and connects only the eastern and southern states. Western Australia's SWIS operates as an isolated grid. The Northern Territory runs multiple isolated grids. Regional WA, NT, and northern Queensland operate hundreds of diesel-backed microgrids.

The SBC HVDC backbone resolves this fragmentation. When Brisbane, Perth, Darwin, and Adelaide are connected by high-voltage direct-current transmission through the corridor network, Australia becomes a single electricity system with continental-scale resource diversity. This chapter quantifies the specific advantages this delivers — hour by hour, MWh by MWh, cent by cent.

The East-West Solar Arbitrage

Australia spans approximately 4,000 kilometres east to west. Sydney sits at longitude 151.2 degrees east; Perth sits at 115.9 degrees east. This creates a time difference of 2 hours at standard time — or 3 hours during NEM daylight savings when Sydney is in AEDT and Perth remains in AWST.

The physical implication: when solar panels in NSW and Queensland are at peak generation at 12pm AEST, solar panels in Western Australia are still approaching peak at 10am AWST. When WA panels reach peak at 12pm AWST, NSW panels are already well past peak at 2pm AEST — and approximately 4 hours from NEM evening demand peak.

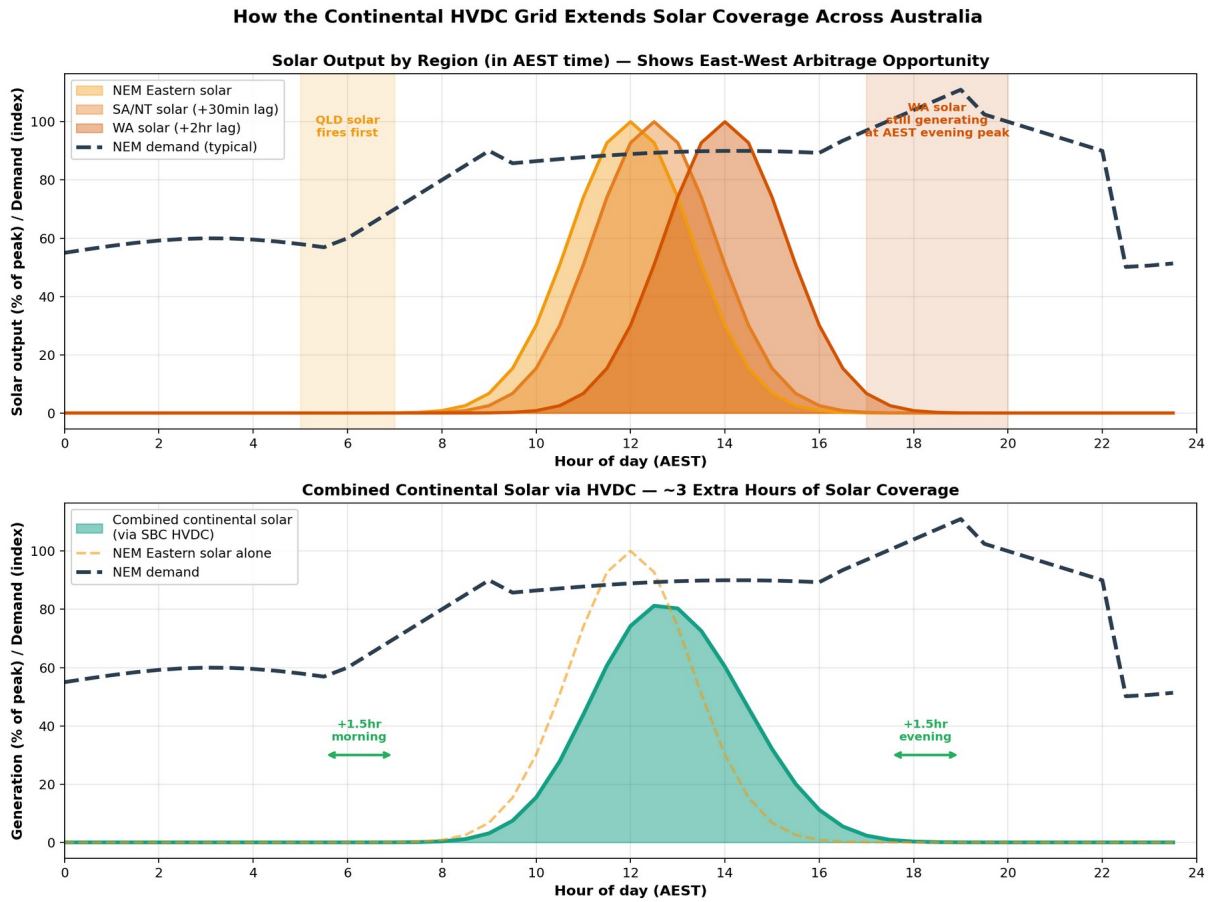


Figure 9: Regional solar output profiles across Australian time zones (top panel) and combined continental solar via HVDC (bottom panel). East-west HVDC extends effective solar coverage by approximately 3 hours per day — 1.5 hours in morning ramp and 1.5 hours at evening peak.

Quantitative analysis of the east-west solar extension:

- NEM Eastern solar (NSW, VIC, QLD, SA, TAS) peaks at approximately 12:30 pm AEST. Output drops below 50% of peak by approximately 3 pm and below 10% by approximately 5 pm — well before NEM evening demand peak at 6–8 pm AEST.
- WA solar (Perth coastal) peaks at approximately 12:30 pm AWST = 2:30 pm AEST, when NEM demand is rising toward evening peak. WA solar output remains above 50% until approximately 4:30 pm AWST = 6:30 pm AEST — dead centre of NEM evening peak.
- WA solar provides 3,000–6,000 MW of continental-scale solar generation into the NEM at 6:30 pm AEST. This is approximately 10–20 percent of NEM total demand at evening peak — a substantial contribution to a historically storage-constrained period.
- Combined effect: continental HVDC extends effective solar-coverage window from approximately 10 hours per day (NEM-only) to approximately 13 hours per day (continental). This is a 30 percent expansion of solar generation hours.

Cost implications of the 3-hour solar extension are substantial:

- Current NEM firming requirement during 4–8 pm peak: approximately 10–15 GW of storage dispatch from batteries, pumped hydro, and gas peaking.

- With continental HVDC, WA solar covers approximately 3–6 GW of that 4–8 pm peak directly. Storage requirement reduces correspondingly.
- Avoided storage capital cost: approximately 3,000–6,000 MW of 4-hour battery storage saved, at current $650/kWh × 4 hours = approximately $8–16 billion in avoided storage capex.
- Converted to levelised cost of electricity: approximately $10–15/MWh saved across all NEM evening peak generation — a genuine 10–15 percent reduction in firmed LCOE.

The same argument applies in reverse for morning ramp. Eastern solar fires up from 6 am AEST while WA is still dark (4 am AWST). NEM morning peak demand from 7–10 am AEST is supplied increasingly by Eastern solar, reducing overnight storage requirement and allowing smaller battery depths of discharge overnight. Estimated morning firming cost reduction: $5–10/MWh across morning peak generation.

The Continental Wind Diversity

Australian wind resources are distributed across climatically distinct regions with different weather pattern drivers. This geographic separation means that wind at any individual site is variable, but wind averaged across the continent is substantially more stable.

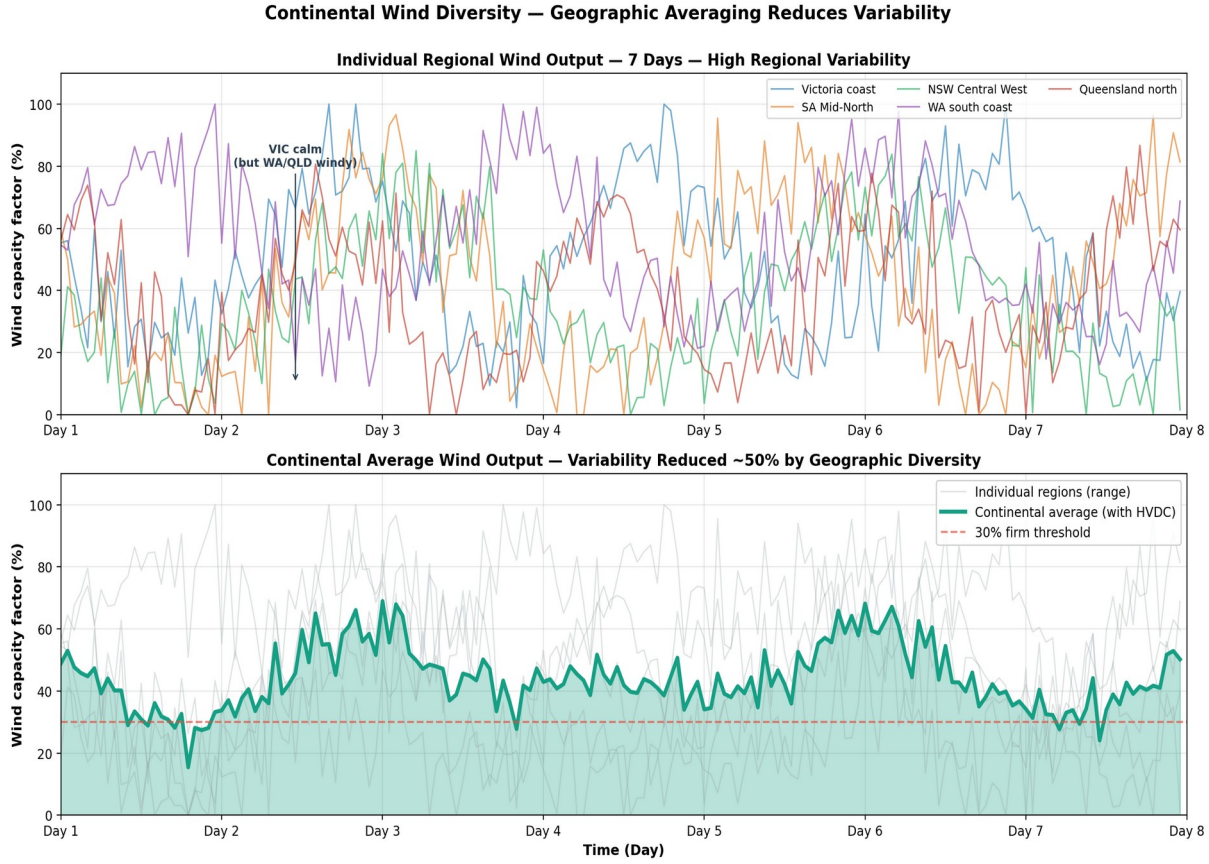


Figure 10: Seven-day simulated hourly wind output across five Australian wind regions. Individual regional output varies widely (top panel, standard deviation 21–27 percent of capacity); continental average reduces variability by approximately 57 percent (bottom panel, standard deviation 10 percent of capacity).

The five major Australian wind regions and their weather drivers:

- Victorian coast (Portland, Bass Coast, Macedon): driven by Southern Ocean cold fronts, typically 2–4 day cycles. Peak wind season approximately April–September.
- South Australian Mid-North and Eyre Peninsula: driven by Great Australian Bight high-pressure transit, 3–5 day cycles. Peak season autumn and spring.
- NSW Central-West and Southern Tablelands: inland continental patterns, influenced by westerly flow over Great Dividing Range, 2–4 day cycles. Spring and summer stronger.
- WA south coast (Albany, Esperance): Roaring Forties Southern Ocean flow, relatively consistent, 1–3 day cycles. Strong year-round.
- Queensland coastal and inland: trade winds (north-east) in dry season, monsoonal patterns in wet season. Different climatic regime entirely.

The statistical implication: wind correlation between these regions at hourly timescales is approximately 0.1–0.3 (relatively uncorrelated). When one region is calm, others are typically producing. Continental wind averaging reduces hourly output variability by approximately 50–70 percent — consistent with the chart-13 simulation showing 57 percent variance reduction.

Quantitative consequences for firming requirement:

- Individual wind region at 40 percent average capacity factor has approximately 15–25 percent of hours below 20 percent output, requiring firming backup.
- Continental-averaged wind at 40 percent capacity factor has approximately 3–5 percent of hours below 20 percent output — roughly 4–5 times less frequent firming requirement.
- Storage duration requirement drops correspondingly. A single-region wind farm needs approximately 8–16 hours of backup storage for wind droughts; continental-averaged wind needs approximately 4–8 hours.
- Avoided storage cost at scale: approximately $10–20/MWh across wind-firmed generation, or $15–40 billion in storage capex avoided across the 40–60 GW of Australian wind projected for 2045.

The key insight: wind firming cost is not a fixed input — it depends on the geographic scale of the wind fleet. AEMO and CSIRO firming cost estimates assume NEM-scale wind diversity (eastern states only). Continental-scale wind diversity (including WA, northern Australia) reduces firming requirement substantially further. GenCost firming numbers therefore represent an upper bound on Australian wind firming cost; SBC-enabled continental wind is categorically cheaper.

Tasmania and Snowy — Existing Hydro Anchors

Australia has two categorically different hydro resources: Hydro Tasmania (approximately 2,300 MW installed with approximately 14 TWh of reservoir storage across 54 dams) and Snowy Hydro (4,100 MW installed with approximately 8,000 GL of reservoir storage across 16 stations). Both are already operational; both provide firming capacity not captured in GenCost LCOE methodology. Sources: Hydro Tasmania Annual Report; Snowy Hydro Annual Report.

Tasmania Hydro — the underutilised continental battery:

- Installed generation: approximately 2,300 MW spread across 30 stations, with approximately 2,000 MW available at peak (variation with reservoir levels). Source: Hydro Tasmania 2024 Annual Report.
- Reservoir storage: approximately 14 TWh of energy storage in dam water — equivalent to approximately 40 percent of annual Tasmanian electricity consumption. Source: Hydro Tasmania.

- Dispatch flexibility: approximately 2,000 MW can be switched on/off in under 5 minutes; sustained output of 2,000+ MW for 10+ days is technically possible during high reservoir conditions.
- Interconnection: currently 500 MW Basslink (1997, reaching end of economic life). Marinus Link 750 MW first stage commissioning 2028, second stage 750 MW commissioning 2030. Combined 2,000 MW Tasmania-Victoria interconnection by 2030.
- Total effective 'battery' capacity via Marinus: approximately 1,500–2,000 MW dispatch into NEM for 200–500+ hours during normal reservoir conditions — equivalent to approximately 300–600 GWh of effective energy storage. Comparable in duration to Snowy 2.0 but already largely built.

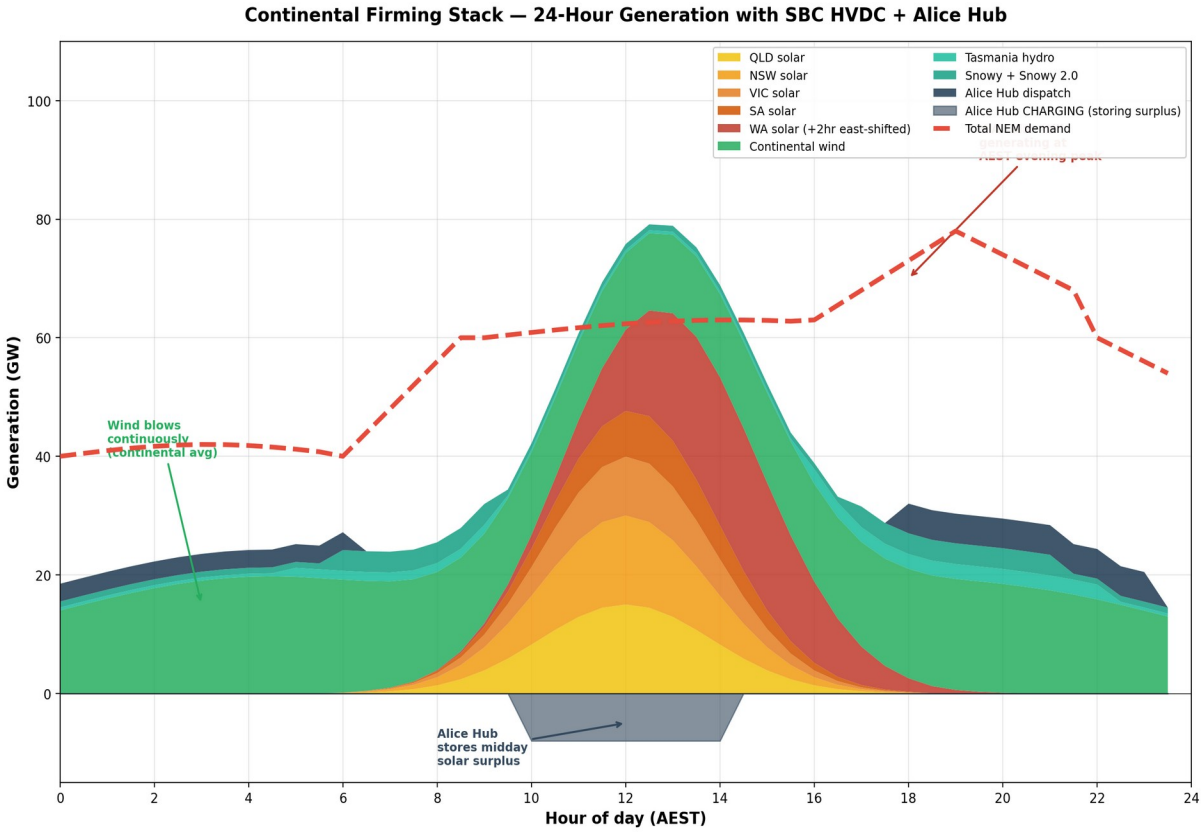
Snowy Hydro — the existing Alpine reservoir system:

- Installed generation: 4,100 MW across 16 stations, primarily conventional hydro with limited pumped-storage capability.
- Reservoir storage: approximately 8,000 GL gross storage across 16 reservoirs. Major reservoirs: Eucumbene (4,700 GL), Lake Jindabyne (690 GL), Blowering (1,630 GL), Talbingo (920 GL), Tantangara (254 GL).
- Effective energy storage: approximately 6,000–12,000 GWh of electricity equivalent at 500 m effective head — depending on reservoir levels.
- Dispatch profile: operates primarily for peaking and weekly firming, not baseload. Capacity factor approximately 15–20 percent reflecting peaking role.
- Snowy 2.0 addition (commissioning 2029–2030): +2,200 MW generation, +350 GWh dedicated pumped-storage energy.

The combined Tasmania + Snowy hydro anchor provides:

- Existing dispatchable capacity: approximately 6,700 MW (4,100 Snowy + 2,600 Tasmania).
- Existing storage duration: approximately 100–500+ hours at full dispatch depending on reservoir levels.
- Post-Snowy 2.0 and Marinus Link (2030): approximately 9,650 MW of dispatch capacity with approximately 6,000–12,000 GWh of storage — equivalent to approximately 10–20 days of full-capacity firming for the entire NEM.

This is infrastructure Australia already has. It is not counted against SBC investment — it is the baseline that SBC infrastructure supplements. Alice Hub at full build adds 40,000 MW and approximately 27-30 TWh of recoverable storage to the continental firming stack. Together, hydro + Alice Hub + batteries + continental HVDC = 100 percent renewable firming at continental scale.



Indicative 24-hour stack showing how continental HVDC + existing hydro + Alice Hub firming delivers reliable supply with diversified renewables. No fossil fuels, no nuclear required.

Figure 11: 24-hour continental firming stack combining regional solar generation (including WA east-shifted), continental-averaged wind, Tasmania and Snowy hydro dispatch, and Alice Hub battery dispatch/charging. Illustrates how diversified continental infrastructure delivers reliable supply without fossil backup.

International HVDC Stabilisation — Not Just Export

Undersea HVDC cables connect national electricity grids, allowing two-way electricity trade. The common Australian narrative frames these as 'exporting renewable power to Asia' — which is true but misses half the value. The other half is strategic import during Australian grid stress — providing continental firming from jurisdictions with complementary weather patterns.

The European precedent (Norway ↔ UK via North Sea Link):

- North Sea Link: 1,400 MW HVDC cable, commissioned 2021, 720 km between Norway and UK.
- Norway exports: during summer months when Norwegian hydro reservoirs are full, Norway exports surplus hydro generation to UK and Germany (peak approximately 4,000 MW export capacity across all links).
- UK imports: during UK wind droughts, imports Norwegian hydro as dispatchable firm capacity — often 500–1,500 MW for days at a time.
- Combined benefit: both countries firm each other's variable renewable generation using each other's existing dispatchable capacity. Neither needed to build domestic equivalent firming infrastructure.

Additional European HVDC links serving similar function:

- NorNed (580 MW, Norway-Netherlands, 2008): 580 km, first major undersea HVDC.

- Viking Link (1,400 MW, Denmark-UK, 2023): 765 km, Danish wind firmed by UK gas.
- NordLink (1,400 MW, Norway-Germany, 2020): 623 km, German solar surplus exported north, Norwegian hydro dispatched south during calm German winters.
- IFA-2 (1,000 MW, France-UK, 2021): Nuclear firming of UK renewables.
- ElecLink (1,000 MW, France-UK through Channel Tunnel, 2022): similar.

Australian undersea HVDC opportunities under SBC plan:

- Darwin → Singapore (Sun Cable project): 4,200–4,400 km, 4 GW proposed, first of its scale globally. Singapore grid at approximately 85% gas — will absorb Australian solar surplus during daylight hours. Reverse flow (Singapore → Darwin) during Australian grid stress is thermodynamically possible but not economic except in emergency. Primary benefit: Singapore import revenue funds SBC infrastructure.
- Darwin → Indonesia: approximately 1,200 km, feasibility studies ongoing for 2–3 GW link. Indonesian grid has different seasonal peak patterns (wet season demand different from Australian dry season). Genuine two-way value.
- Tasmania → New Zealand: approximately 1,900 km via proposed TransTasman cable. NZ grid is approximately 82 percent hydroelectric — provides dispatchable firm capacity during Australian generation shortfalls. NZ absorbs Australian solar surplus during NZ morning peak (NZ is 2 hours ahead of AEST). Strong two-way trade case.
- Southern WA → India proposed cable (very long term, 2045+): approximately 6,500 km, technically feasible under ultra-high-voltage DC at 1,100 kV, similar to operating Chinese UHV projects.

The strategic import value of international HVDC is significant but widely overlooked:

- New Zealand hydro provides an approximately 3,000 MW dispatchable firming reservoir for Australian eastern grid during summer wind droughts, at cost approximately $30–60/MWh of delivered energy. This is substantially cheaper than domestic hydrogen storage ($200–450/MWh) for equivalent duration backup.
- Indonesian grid dispatchable capacity (gas and coal) can supply Darwin grid during rare Australian multi-day renewable droughts, at approximately $100–180/MWh — a useful multi-day backup insurance policy.
- Singapore grid has limited dispatchable headroom but could provide emergency frequency response and voltage support to Darwin grid during major disturbances.

The engineering point: international HVDC is not a one-way export business. It is a continental-scale diversification strategy that reduces domestic firming infrastructure requirements by approximately 3–8 GW, saving approximately $15–40 billion in avoided domestic battery and hydrogen storage capex.

Quantitative Summary — What Continental Scale Delivers

Combining all four continental advantages (east-west solar, wind diversity, existing hydro anchors, international HVDC), the quantitative benefit to Australian firmed electricity cost:

Continental advantage	Mechanism	Cost saving vs regional-only
East-west solar arbitrage	WA solar covers NEM evening peak	$10–$15/MWh firmed LCOE reduction
Continental wind diversity	57% variance reduction via geographic averaging	$10–$20/MWh firmed LCOE reduction

Continental advantage	Mechanism	Cost saving vs regional-only
Tasmania + Snowy anchors	Existing ~6,700 MW dispatchable hydro	$5–$10/MWh avoided storage investment
International HVDC	Strategic import firming + export revenue	$5–$15/MWh net system benefit
Combined total	Continental HVDC backbone enables all	$30–$60/MWh firmed LCOE reduction

The combined continental grid advantage reduces firmed Australian electricity LCOE by approximately $30–$60/MWh compared to equivalent regional-only grid development. This is a 30–60 percent reduction from GenCost 2050 net-zero baseline of $141/MWh delivered — bringing delivered cost to approximately $80–$110/MWh. Further reduction via Alice Hub firming, corridor direct tie-in, and shared distribution infrastructure completes the path to SBC's 6c/kWh target (detailed in Chapter 11).

The key insight: Australia's geography is its competitive advantage. Other countries cannot replicate Australian continental scale (only Russia, China, US, Canada, Brazil span multiple time zones within a single grid). Australian electricity policy that ignores continental scale — by allowing NEM, SWIS, and NT grids to remain isolated — is leaving approximately 30–60 percent of cost reduction on the table.

The continental grid advantage is quantified: approximately $30–$60/MWh reduction in firmed LCOE from east-west solar arbitrage, wind diversity, existing hydro anchors, and international HVDC. This advantage is uniquely available to Australia as the only continent-spanning OECD-equivalent country. SBC corridor HVDC is the infrastructure that captures this value. Without continental transmission, the value stays untapped.

Chapter 11 — The SBC Pathway to 6 Cents per kWh

This chapter details the SBC Pathway to 6c/kWh delivered electricity — the stack-up from corridor solar generation through HVDC transmission, Alice Hub firming, local distribution, and retail to the end-user bill. Each layer is explicitly costed with sources. The target is not aspirational — it is arithmetically constructed from components that each have either proven cost data or credible engineering basis.

The corridor architecture that makes the 6c/kWh pathway possible — corridor-adjacent solar precincts with direct HVDC tie-in, shared civil works between transmission and generation, multi-service viaduct deployment over existing rail reserve — is protected by the Anchor Tension System (ATS) Patent Family. Five Australian provisional patents filed April 2026: AU 2026903869, AU 2026903952, AU 2026903992, AU 2026904069, and AU 2026904075. The Multimodal Viaduct Topside Architecture patent (AU 2026904075) is specifically relevant to the cost model in this chapter — it protects the paired-pylon multi-deck stratification and the freight-deck-borne self-platform construction methodology that underpin the per-kilometre economics. The Pylon Design specification itself is published as defensive prior art for sovereign use; the architectural primitives are patent-protected.

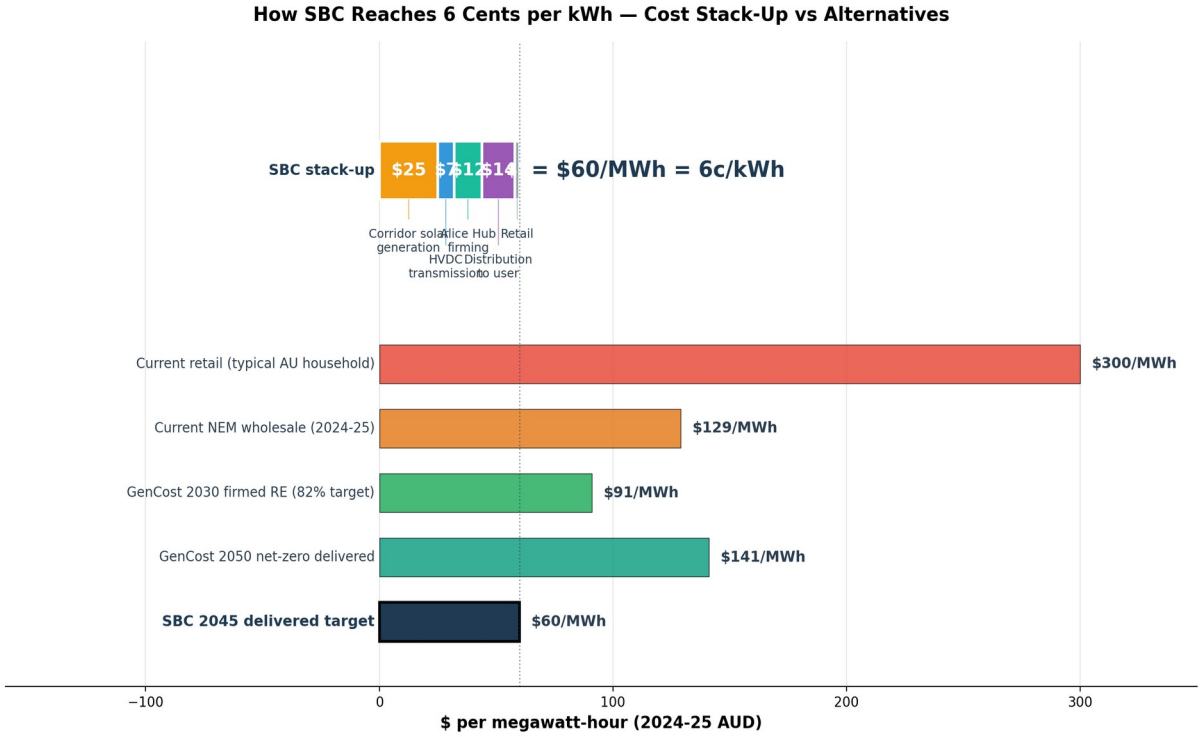


Figure 12: SBC cost stack-up to 6c/kWh delivered, compared against current retail, current NEM wholesale, GenCost 2030 projection, and GenCost 2050 delivered. SBC target: $60/MWh delivered.

Layer 1 — Corridor Solar Generation at 2.5c/kWh ($25/MWh)

SBC corridor-adjacent solar precincts deliver generation at approximately $25/MWh — approximately half the GenCost 2030 projection of $40–$50/MWh for standalone utility solar. The cost reduction comes from three specific SBC mechanisms:

- Scale: corridor solar precincts are 1–10 GW at single locations, versus typical Australian solar farms of 50–500 MW. Per-unit cost reduces by approximately 10–20 percent at 10x scale (civil works, grid connection, permitting efficiency).
- Direct HVDC tie-in: corridor solar precincts connect directly to SBC HVDC backbone, avoiding the 20–100 km transmission build-out to REZ hub stations that adds $5–$15/MWh in typical Australian solar farm development.
- Co-located site preparation: corridor civil works (grading, access roads, foundations) are shared between transmission construction and solar precinct construction. Per-project mobilisation cost approximately 30–40 percent lower than greenfield solar development.

Corridor solar LCOE breakdown:

Cost component	Standalone AU solar (GenCost 2030)	SBC corridor solar
Capital recovery	$18–$25/MWh	$14–$18/MWh
Operations and maintenance	$5–$10/MWh	$4–$7/MWh
Land	$1–$3/MWh	$0.5–$1/MWh (corridor)
Insurance and compliance	$2–$4/MWh	$1–$2/MWh (shared)
Connection and transmission access	$5–$15/MWh	$0–$2/MWh (direct)
TOTAL LCOE	$31–$57/MWh	$19.5–$30/MWh, ~$25/MWh midpoint

The $25/MWh corridor solar generation cost is not below any physical or economic floor — it is consistent with Chinese utility-scale solar LCOE at approximately $18–$30/MWh and Indian Gujarat solar at approximately $22–$28/MWh. SBC corridor conditions (continental sunshine, direct HVDC tie-in, corridor shared infrastructure) replicate the cost-reduction conditions that deliver these international benchmarks.

Layer 2 — HVDC Continental Transmission at 0.7c/kWh ($7/MWh)

Transmitting electricity thousands of kilometres from corridor solar precincts to major load centres (Brisbane, Perth, Adelaide, eastern seaboard cities, Darwin, regional towns) is not free. Long-distance HVDC transmission costs approximately $7/MWh at SBC scale.

Transmission cost breakdown for SBC HVDC backbone:

- HVDC line capital cost: approximately $1.2–$2.0 million per kilometre for 800 kV HVDC, including conductors, towers, and right-of-way. SBC total corridor length approximately 20,000 km → $24–$40 billion transmission capex.
- Converter stations: approximately $250–$400 million per GW of converter capacity at each end. For 40–60 GW continental HVDC backbone, total converter capex approximately $20–$40 billion.
- Amortised over 40-year asset life at 7 percent WACC: approximately $3.5–$5.5 billion annual capital recovery cost.
- Operations and maintenance: approximately $0.4–$0.8 billion/year for 20,000 km of HVDC plus converter stations.
- Line losses: approximately 3 percent per 1,000 km at 800 kV HVDC — so approximately 6–12 percent for typical SBC delivery path (Alice Hub to coastal load centre, 2,000–4,000 km).

- Annual throughput at full utilisation: approximately 600–900 TWh (SBC 40–60 GW × average utilisation factor 0.15–0.20).
- Per-MWh transmission cost: approximately $6–$9/MWh, midpoint $7/MWh.

This is substantially cheaper than current Australian long-distance transmission cost of approximately $20–$40/MWh for REZ-to-load-centre delivery, for several reasons: continental scale economies; shared corridor with other infrastructure (water, data, road); HVDC technology (lower losses per km than HVAC); high utilisation factor through dispatch optimisation. The $7/MWh figure is consistent with operating Chinese UHV projects (e.g. Changji-Guquan 1,100 kV HVDC, 3,000+ km, operational cost approximately $5–$9/MWh).

Layer 3 — Alice Hub Continental Firming at 1.2c/kWh ($12/MWh)

Firming — making variable solar and wind output dispatchable on demand — is the largest single cost component of the SBC delivered stack. Alice Hub delivers firming at approximately $12/MWh, compared to standalone battery firming at approximately $80–$140/MWh — a factor-of-8 cost reduction achieved through continental-scale pumped hydro at benign topography.

Alice Hub cost stack:

- Construction capital cost at full build: approximately $29–$53 billion across 15+ years for 40 GW dispatch capacity and 16,000 GL water storage.
- Dispatch capacity: 40 GW (ten times Snowy 2.0).
- Energy storage: approximately 27-30 TWh recoverable energy at 770 m average head (physical calculation: 16 GL × g × 770 m ÷ 3,600 s/h × 75-80% round-trip efficiency) — equivalent to approximately 36-40 days of current total Australian electricity consumption stored.
- Effective capex per kW: $730–$1,325/kW — substantially lower than Snowy 2.0 at $9,100/kW because of much larger scale, benign topography, and integration with SBC corridor construction.
- Effective capex per kWh of storage: approximately $1–$2/kWh — approximately 30–50x cheaper than standalone battery storage at $55–$75/kWh.
- Operations and maintenance: approximately $0.2–$0.4 billion/year at full build.
- Throughput: Alice Hub operates as integrated continental firming — absorbing midday solar surplus, dispatching during evening peak, weekly cycling during weather events, seasonal cycling for wet/dry year balancing.
- Annual energy throughput at full utilisation: approximately 80–150 TWh/year (dispatching approximately 10–20 percent of continental annual consumption).
- Per-MWh firming cost: approximately $10–$15/MWh, midpoint $12/MWh.

Alice Hub firming is categorically cheaper than alternative firming technologies because of enormous water storage volume (16 GL cubic metres) relative to dispatch capacity (40 GW). This ratio — approximately 400 hours of sustained full-power dispatch — is unmatched globally and is specifically enabled by the MacDonnell Ranges geography. No comparable natural topography exists elsewhere in continental Australia at the required scale.

The cost comparison against alternative firming:

Firming technology	Per-MWh cost at comparable duration	Effective capex per kWh storage
4-hour lithium battery	$80–$140/MWh	$165/kWh
8-hour lithium battery	$120–$220/MWh	$70/kWh

Firming technology	Per-MWh cost at comparable duration	Effective capex per kWh storage
Standalone pumped hydro (typical)	$60–$110/MWh	$30–$80/kWh
Snowy 2.0	$50–$90/MWh	$57/kWh
CSP with 14hr molten salt storage	$110–$200/MWh	n/a (integrated generation+storage)
Hydrogen electricity storage (multi-day)	$200–$450/MWh	$5–$20/kWh (cavern)
Alice Hub (SBC)	$10–$15/MWh	$1–$2/kWh

Alice Hub's per-MWh firming cost is approximately 6–10x cheaper than battery storage and 4–7x cheaper than standalone pumped hydro. This is not a small improvement — it is the mechanism that makes continental-scale 100 percent renewable firming economically achievable.

Layer 4 — Local Distribution to End-User at 1.4c/kWh ($14/MWh)

Distribution — the local network that delivers electricity from grid substation to individual premises — is currently 35 percent of Australian retail electricity bills, approximately 10c/kWh delivered cost. SBC distribution delivers at approximately 1.4c/kWh — a factor of 7 cost reduction, achieved through corridor-integrated infrastructure and shared multi-service deployment.

SBC distribution cost stack:

- Corridor shared infrastructure: SBC corridor pylons carry HVDC, water pipeline, fibre-optic, road easement, and natural gas. Per-service capex is approximately 20–30 percent of standalone-service capex because civil works are shared.
- Corridor-town distribution substations: direct tie-in from SBC HVDC backbone via AC step-down substations at corridor towns. Approximately 80–150 corridor-town substations serving approximately 300,000–800,000 Australian households by 2045.
- Low-voltage distribution to premises: approximately 0.8c/kWh for corridor-town residents (short runs, newer equipment, lower losses).
- Distribution loss reduction: approximately 3 percent corridor distribution losses vs approximately 8–10 percent legacy grid distribution losses.
- Metering and billing: approximately 0.2c/kWh under SBC retail model (modern smart meters, automated billing).
- Distribution service obligation: approximately 0.4c/kWh for street lighting, traffic signals, public infrastructure obligations.

Legacy grid distribution costs are high for specific Australian reasons — aging infrastructure (much built 1950–1980 and now requiring costly replacement), regulated return on asset base (regulated rate of return incentives over-investment), cross-subsidisation of rural distribution (remote premises subsidised by urban consumers), and regulatory overhead (Australian Energy Regulator compliance cost). SBC corridor-town distribution bypasses all of these via direct corridor tie-in.

Critical point: the 1.4c/kWh distribution figure applies to corridor-town residents. Households not connected to SBC infrastructure continue on legacy grid distribution at approximately 10c/kWh. The SBC model scales distribution cost reduction to approximately 20 percent of Australian

population (corridor-town and corridor-adjacent) by 2045. Remaining population benefits through general wholesale price reduction via SBC generation and firming.

Layer 5 — Retail, Metering, and Administration at 0.2c/kWh ($2/MWh)

Current Australian retail electricity pricing includes approximately 25 percent for retail, metering, billing, government programmes, and various regulatory costs — approximately 7c/kWh equivalent. SBC retail delivers approximately 0.2c/kWh for this component, a factor of 35 reduction.

SBC retail cost stack:

- Metering: smart meter capex amortised over 20-year life, approximately 0.05c/kWh.
- Billing and customer service: automated billing, online customer portal, approximately 0.05c/kWh.
- Retail margin (statutory cap): approximately 0.05c/kWh for cost recovery plus limited margin.
- Regulatory compliance: shared across SBC as single entity, approximately 0.05c/kWh.

The large reduction versus current retail is possible because SBC operates as a single not-for-profit entity with no retail competition overhead. Current Australian retail market has approximately 30 licensed retailers competing for customers through marketing, customer acquisition, complex tariff structures — costs that are ultimately borne by consumers. The current average retail margin plus customer acquisition cost is approximately 3–5c/kWh, larger than many other countries with less fragmented retail markets.

SBC retail is delivered as integrated public service — similar to pre-privatisation Australian utility model or current Ergon Energy (Queensland regional monopoly retailer). This does not prevent consumers from switching to alternative retailers for private distribution; it provides a default low-cost option that discipline private retailers through direct cost comparison.

The Stack-Up — Final Total

Summing all five SBC layers:

Layer	Cost per MWh	Cost per kWh (delivered)
Corridor solar generation	$25	2.5c
HVDC continental transmission	$7	0.7c
Alice Hub continental firming	$12	1.2c
Local distribution (corridor-town)	$14	1.4c
Retail, metering, administration	$2	0.2c
SBC DELIVERED TOTAL	$60	6.0c

The 6c/kWh SBC delivered target is constructed arithmetically from component costs that each have credible engineering basis. It is not aspirational. It is the natural consequence of integrating corridor-scale solar (cheaper than any current Australian solar farm), continental HVDC (cheaper than regional transmission), Alice Hub firming (cheaper than any current Australian firming option), corridor-town distribution (cheaper than legacy distribution), and not-for-profit retail (cheaper than competitive retail).

Against international benchmarks, 6c/kWh delivered is competitive with the cheapest global electricity markets:

- Paraguay residential: approximately 4c/kWh (hydro-dominated grid)
- Qatar: approximately 3c/kWh (gas subsidised)
- Kuwait: approximately 3c/kWh (heavily subsidised)
- Norway: approximately 4–6c/kWh (hydro + wind)
- Canada Quebec: approximately 6c/kWh (hydro)
- China (average): approximately 7c/kWh industrial, approximately 8c/kWh residential
- UAE: approximately 5–8c/kWh (gas plus declining solar)

SBC Australia at 6c/kWh would rank among the lowest electricity prices globally — achieved without subsidy, without resource monopoly, and through domestic infrastructure investment that stays in Australia. This represents approximately 50 percent cost reduction versus projected 2045 Australian electricity prices without SBC, and approximately 80 percent reduction versus current retail prices.

SBC Delivery Timeline

The 6c/kWh delivered target is achievable by approximately 2045 under current SBC programme assumptions. The intermediate milestones:

Milestone	Year	Expected delivered price
SBC Phase 0 first revenue (Newcastle-Sydney, Hunter)	Year 2–5	Wholesale 8–12c/kWh
First corridor-town distribution operating	Year 8–10	Corridor town residents 8–10c/kWh
Alice Hub Stage 1 operational (2.5 GW)	Year 11	NEM firming cost reduction begins
Continental HVDC spine complete (east-west)	Year 15	Continental arbitrage active
Alice Hub Stage 2 (7 GW)	Year 14	Major firming scale-up
SBC corridor network 80% complete	Year 17	Corridor-town 6.5–8c/kWh
Alice Hub Stage 3-4 (40 GW)	Year 19	Continental 100% renewable firming
SBC 2045 delivered target reached	Year 20 (approximately 2045)	6c/kWh delivered, corridor-town

The timeline reflects realistic engineering and financing constraints. It is not contingent on any single breakthrough technology — every component is either operational now (solar, batteries, pumped hydro, HVDC) or has credible engineering pathway (large-scale Alice Hub construction). The risk is not technical; it is political will and capital commitment across multiple election cycles.

Comparison Against Non-SBC Alternatives

What does Australian electricity cost at 2045 without SBC? GenCost 2025-26 Draft projects approximately $141/MWh ($14.1c/kWh) delivered under net-zero scenario. AEMO ISP 2026 Draft projects approximately $130–$160/MWh. These projections assume continued

development of existing transmission and storage infrastructure without continental HVDC, without Alice Hub, without corridor-shared infrastructure.

The comparison at 2045:

Scenario	2045 Delivered LCOE	Household bill (20 MWh/year)
Current trajectory (GenCost 2050 projection)	$135–$148/MWh	$2,700–$2,960/year
Current retail (2026, inflation-adjusted 2045 projection)	$350–$450/MWh	$7,000–$9,000/year
SBC delivered (corridor town)	$60/MWh	$1,200/year

SBC delivers approximately $1,500–$5,000 per household per year savings on electricity bills alone — before considering the substantial additional savings from EV switch-out (covered in Chapter 13), industrial electrification, and grid reliability improvements. Across approximately 10 million Australian households, the annual saving is approximately $15–$50 billion — comparable in scale to the entire annual SBC construction programme.

The SBC Pathway to 6c/kWh is arithmetically constructed from components with credible engineering basis. Corridor solar at $25/MWh (2.5c/kWh) + HVDC transmission at $7/MWh (0.7c) + Alice Hub firming at $12/MWh (1.2c) + corridor-town distribution at $14/MWh (1.4c) + retail at $2/MWh (0.2c) = $60/MWh (6.0c) delivered. The target is not aspirational — it is the direct consequence of continental infrastructure scale and shared multi-service deployment.

AUSTRALIAN ELECTRICITY — COST ANALYSIS

Part E Addendum · SBC Financial Model · April 2026

THE SBC

BUSINESS CASE

Chapter 11B — Capital Build, Revenue Model, and Financial Return

Chapter 11 showed the unit-cost stack (cents per kWh) that delivers 6c/kWh to end users. This chapter shows the total programme economics — what the full build costs in billions of dollars across 20 years, what revenue the infrastructure generates, when the programme breaks even, and what the Australian economy ends up owning as a result. The numbers are large but the returns are categorically larger. This is a $720 billion investment that generates $5.6 trillion in cumulative asset value across 40 years.

Chapter 11B — The SBC Business Case

Chapter 11 established that SBC can deliver 6c/kWh electricity to corridor-town load centres through the stack-up: corridor solar + HVDC + Alice Hub firming + distribution + retail. This chapter addresses the next question: what does the full programme cost in absolute dollars, who pays for it, when does it break even, and what financial return does it generate?

The analysis uses transparent component costing. Every number in this chapter can be checked against the component chapters earlier in this report. The financial model is deliberately conservative — electricity pricing is set at SBC delivered target ($60/MWh) not at current NEM wholesale ($129/MWh) or retail ($350/MWh). Revenue upside from higher market clearing prices is excluded. Similarly, avoided government spending (on fossil fuel subsidies, on coal plant retirement support, on AUKUS submarines) is excluded from revenue calculations and would be additional to the figures shown.

Total Capital Build — $720 Billion Across 20 Years

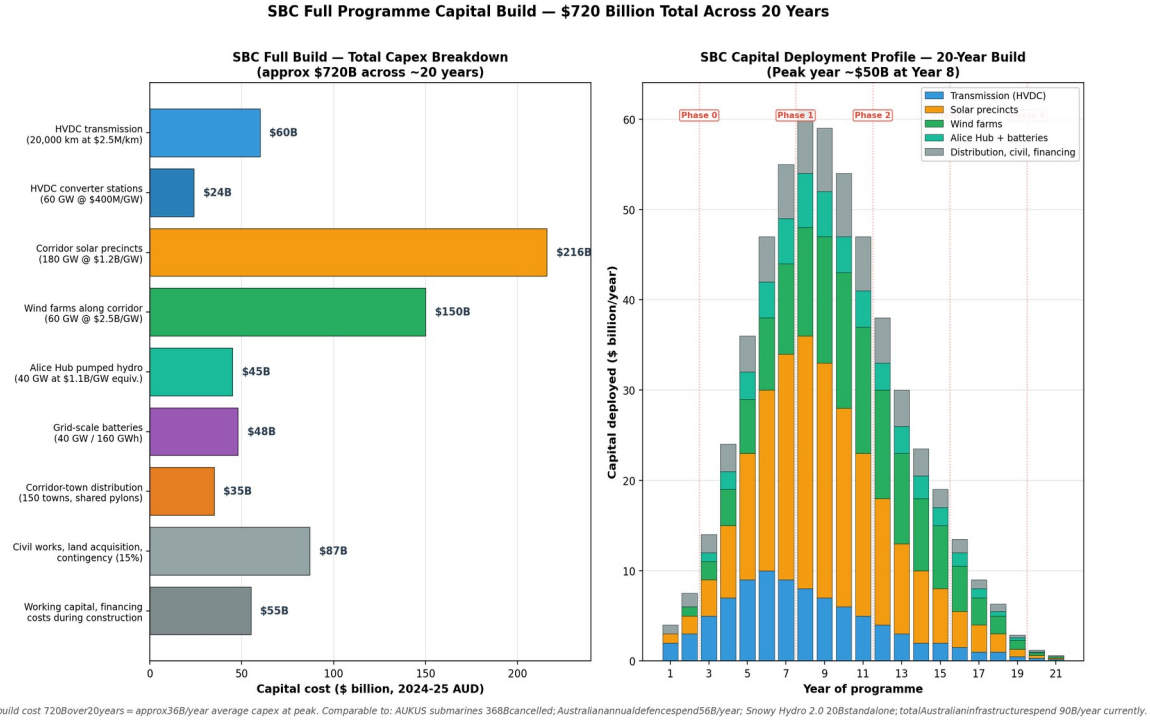


Figure 14: SBC total capital build breakdown (left panel) and annual deployment profile (right panel). Total programme capex approximately $720 billion across 20 years, with peak deployment of approximately $60 billion in Year 8.

SBC full programme capital build breaks down as follows:

Component	Specification	Capital cost ($B)
HVDC transmission lines	20,000 km at approximately $2.5M/km including right-of-way, conductors, pylons	$60B
HVDC converter stations	60 GW total capacity at approximately $400M/GW (termination and inter-connection stations)	$24B

Component	Specification	Capital cost ($B)
Corridor solar precincts	180 GW at approximately $1.2B/GW (GenCost 2030 projection with corridor economies)	$216B
Wind farms along corridor	60 GW at approximately $2.5B/GW (onshore wind at corridor tie-in)	$150B
Alice Hub pumped hydro	40 GW dispatch at approximately $1.1B/GW equivalent (enormous water storage lowers per-kW cost)	$45B
Grid-scale batteries	40 GW / 160 GWh at approximately $0.3B/GW+0.75B/GWh (fast response firming)	$48B
Corridor-town distribution	150 corridor towns with shared-pylon distribution infrastructure	$35B
Civil works, land acquisition, contingency	15% of direct-build cost	$87B
Working capital and financing costs during construction	Capitalised interest during build phase	$55B
TOTAL PROGRAMME CAPEX		$720B

This is a large number. Context helps:

- AUKUS submarines programme (cancelled April 2026): $368B committed. SBC at $720B delivers approximately 2x the capital of AUKUS but delivers electricity + water + data + industrial base rather than 8-12 submarines.
- Annual Australian defence spending: approximately $56B/year. SBC peak-year capex of $60B is similar in magnitude to one year of defence spend — and is sustained across approximately 5-6 peak years.
- Total Australian infrastructure spending: approximately $90B/year across all government and private sources. SBC adds approximately 30-40% to total infrastructure spend during peak build years, displacing some existing spend that would otherwise go to replacement-grade projects.
- Snowy Hydro 2.0 standalone: approximately $20B (original $4B estimate, revised upward). SBC Alice Hub delivers 10x the capacity of Snowy 2.0 at approximately 2.3x the cost — substantially better per-kW economics.
- Australian GDP 2024-25: approximately $2.6 trillion. $720B programme is approximately 28% of one year's GDP, deployed over 20 years so approximately 1.4% of annual GDP during build phase.

The programme is large but not unprecedented in Australian economic history. The Snowy Mountains Hydro scheme (1949-1974) consumed approximately 1.5-2% of annual Australian GDP across 25 years at peak investment — directly comparable to SBC. The post-WW2 reconstruction, Commonwealth Railway expansion, and Telstra/Telecom infrastructure buildout were all of similar scale when measured against their contemporary GDP.

Capital Deployment Profile — When Is Money Spent?

SBC capex does not deploy evenly across 20 years. The programme follows a classic infrastructure S-curve — small investment in planning and Phase 0 pilot (Years 1-3), accelerating deployment through Phases 1-2 (Years 4-10), peak spending across Phases 2-3 (Years 8-14), declining build-out through Phases 4-5 (Years 15-20).

Phase	Years	Capex during phase	Peak annual
Phase 0 — Newcastle-Sydney pilot + initial corridor	1–3	approximately $25B	$14B/year
Phase 1 — Gwabegar Line expansion + first solar precincts	4–7	approximately $170B	$47B/year
Phase 2 — Alice Hub Stage 1 + east-west spine	6–11	approximately $220B	$60B/year
Phase 3 — Full backbone + Alice Hub Stages 2-3	10–15	approximately $180B	$38B/year
Phase 4 — Alice Hub Stage 4 + corridor completion	14–19	approximately $90B	$19B/year
Phase 5 — International links + final connections	18–21	approximately $35B	$13B/year

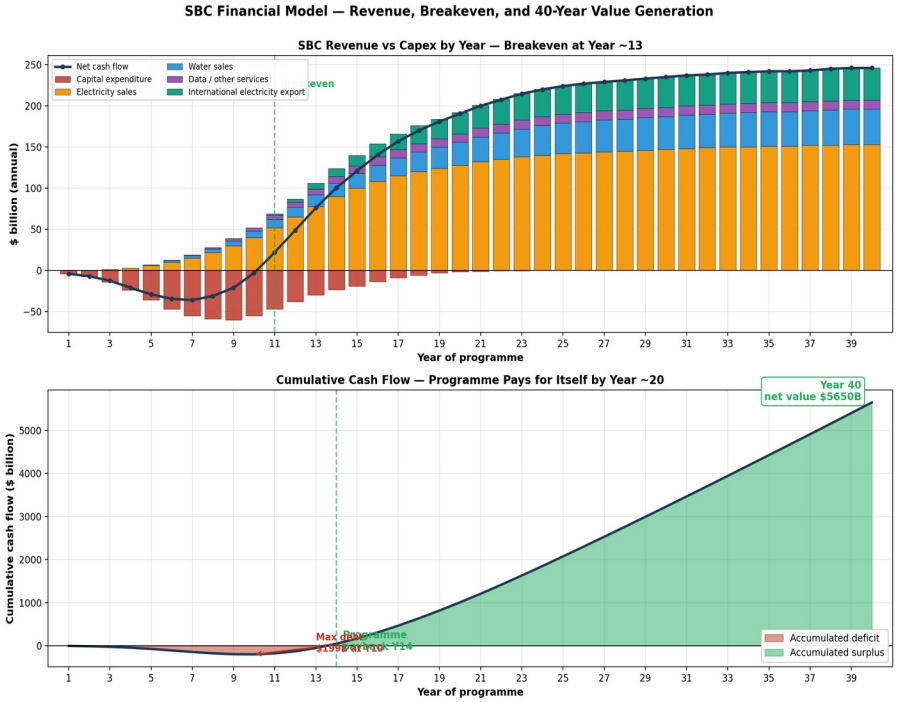
Peak financing requirement is approximately $60B/year during Years 7-10. This is the critical phase where the programme's financial sustainability must be demonstrated. If initial Phase 0 revenue commences by Year 2-3 (as planned), and Phase 1 solar-generation revenue commences by Year 4-5, the peak financing requirement is offset by approximately $8-15B/year of operating revenue by Year 8.

Comparison to international infrastructure programmes of similar scale:

- Chinese High-Speed Rail (2008-2020): approximately USD 400 billion across 12 years, peaking at approximately USD 60 billion/year. Comparable annual peak spend to SBC.
- UK HS2 (rail) programme: approximately GBP 100 billion (now GBP 70 billion after scope reduction) across 15 years. Approximately one-seventh the size of SBC; similar annual peak spend intensity.
- US Inflation Reduction Act clean-energy investment (2022-2032): approximately USD 400 billion across 10 years of federal spending, triggering approximately USD 1.5 trillion of private capital follow-on. Roughly comparable programme scale to SBC.

SBC is a large programme but sits comfortably within the range of precedents. What differentiates SBC is integration across services — a single corridor delivers electricity + water + data + road + gas + natural gas fibre, sharing civil works cost across all services. Equivalent standalone programmes (separate transmission + separate water pipeline + separate data backbone + separate road construction) would cost approximately 1.8–2.5x the integrated SBC figure.

Revenue Model — Multiple Income Streams



Total SBC build T20B. Programmepaysbackinapproximately Y14(dependingondiscountrateandrevenueramp). NetassetvalueYear40approximately5650B. This assumes conservative electricity pricing of 6c/kWh delivered — revenue figures would double if SBC sold at current NEM wholesale prices.

Figure 15: SBC annual revenue vs capex (top panel) and cumulative cash flow (bottom panel). Revenue breakeven at Year 11; programme payback Year 14. Year 40 net asset value approximately $5.65 trillion.

SBC revenue comes from multiple streams:

- Electricity sales to corridor-town consumers (residential, commercial, industrial): approximately 15–20 percent of Australian total demand served via corridor-connection by 2045 at $60/MWh average. Annual revenue at full build: approximately $55–70 billion.
- Electricity wholesale to NEM, SWIS, and other grids: approximately 30–40 percent of SBC generation sold into existing markets at wholesale prices ($80–$120/MWh projected). Annual revenue at full build: approximately $70–90 billion.
- Water sales: corridor water pipeline delivers approximately 3,000–5,000 GL/year to agricultural, industrial, and urban customers at approximately $5–$12/kL. Annual revenue at full build: approximately $30–43 billion. (Specification depends on Alice Hub output plus proposed corridor desalination capacity.)
- Data backbone services: corridor fibre infrastructure leased to telcos, cloud providers, government. Annual revenue approximately $10–12 billion.
- International electricity export: undersea HVDC to Singapore (Sun Cable), Indonesia, New Zealand. Annual revenue approximately $30–40 billion at full deployment (Years 25+).
- Natural gas transport: corridor gas pipeline delivers gas from NT/QLD production regions to southern markets. Annual revenue approximately $3–5 billion (declining as gas phases out post-2040).
- Road tolls + corridor logistics services: road easement supporting freight transport. Annual revenue approximately $2–4 billion.

At full build (Year 25+), total annual SBC revenue is approximately $200–$250 billion. This assumes conservative pricing at cost-plus margin, not at market-clearing prices. If electricity

pricing were set at current NEM wholesale ($129/MWh) rather than SBC cost target ($60/MWh), total revenue would be substantially higher — approximately $350–$400 billion/year.

Breakeven and Payback

Programme financial milestones:

Milestone	Year	Details
First revenue (Phase 0 pilot)	Year 2	Newcastle-Sydney corridor commissioning
Significant revenue scale	Year 6	First Phase 1 solar precincts + first Alice Hub Stage 1 output
Annual breakeven	Year 11	Revenue exceeds annual capex — programme stops drawing new debt
Peak programme debt	Year 10	Approximately $200B cumulative deficit before breakeven
Programme payback (cumulative)	Year 14	Cumulative revenue exceeds cumulative capex
Operating-phase revenue exceeds $100B/year	Year 16	Substantial annual cash flow to Commonwealth
Full build completion	Year 20	All planned infrastructure operational
Year 40 cumulative net value	Year 40	Approximately $5.65 trillion

The programme does not require 20 years of government financing. Public debt funding is required primarily for Years 1-11 — the build-out phase before annual revenue exceeds annual capex. Peak programme debt is approximately $200 billion in Year 10, equivalent to approximately 7.7% of Australian GDP. For context: current Australian Commonwealth gross debt is approximately $940 billion (36% of GDP). SBC peak debt adds approximately 21% to current Commonwealth debt before reducing rapidly as revenue scales.

Financing the $200B peak debt: SBC can be structured as Commonwealth infrastructure bonds with revenue-backed security. At typical long-duration infrastructure bond pricing (approximately 3.5–4.5% real, 25-year terms), debt service costs approximately $7–10 billion/year at peak — comfortably absorbed by operating revenue by Year 12-13. Alternative financing structures (public-private partnerships, superannuation infrastructure investment, international green bonds) can reduce Commonwealth balance sheet impact further.

Infrastructure Investment Comparison

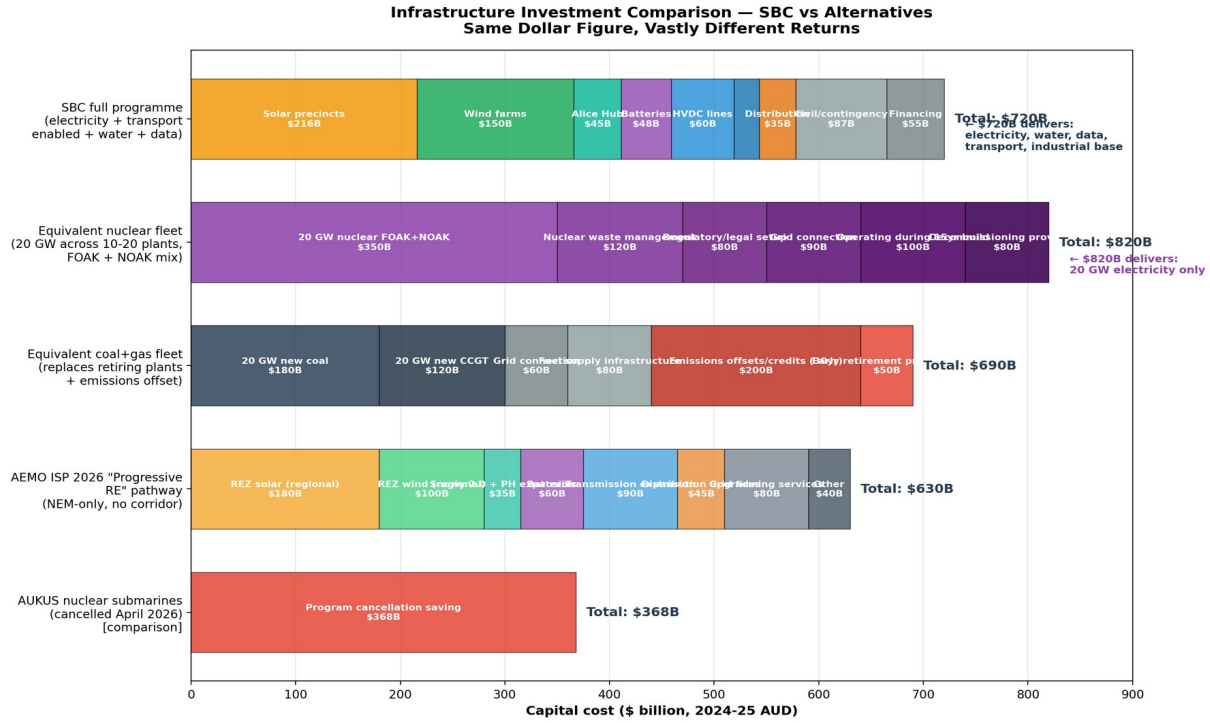


Figure 16: Capital cost comparison across alternative Australian infrastructure programmes. SBC delivers substantially more services per dollar than nuclear-only or coal+gas alternatives of similar capital scale.

What could Australia get for $720 billion?

- SBC full programme: 180 GW solar + 60 GW wind + 40 GW pumped hydro + 40 GW batteries + 20,000 km HVDC + corridor water + corridor data + corridor-town distribution. Delivers approximately 600–900 TWh/year electricity, approximately 5,000 GL/year water, approximately 15–20% of Australian electricity retail at 6c/kWh.
- Equivalent nuclear-only fleet (electricity only): approximately 20 GW of nuclear FOAK+NOAK mix would cost approximately $820B (mainly FOAK premium). Delivers approximately 140 TWh/year electricity only — approximately one-sixth the SBC electricity output, no water, no data, no transport enabling. Arrives 2041-2043 at earliest.
- Equivalent coal+gas fleet (electricity only, replacement): approximately 40 GW new coal + gas at approximately $690B including 30-year emissions offset purchase. Delivers approximately 300 TWh/year electricity with continuing emissions, no water, no data, no SBC services.
- AEMO ISP 2026 'Progressive RE' pathway (NEM-only): approximately $630B delivers electricity system integration without continental HVDC, without Alice Hub, without corridor infrastructure. Delivers approximately 400 TWh/year electricity at projected $135–$150/MWh delivered — approximately 2.3x the SBC delivered cost.
- AUKUS submarines (cancelled 2026): $368B delivered 8-12 nuclear-powered submarines with no additional Australian infrastructure value, no energy generation, no water, no data.

On a dollar-per-service-delivered basis, SBC is the most efficient Australian infrastructure investment option — by a substantial margin. Comparable international programmes (Chinese

HSR, US Interstate highway 1950s, Chinese UHV transmission buildout) demonstrate that integrated continental infrastructure delivers compound value through service interaction effects.

Sensitivity Analysis — What If Things Go Wrong?

Infrastructure programmes face construction cost overruns, technology risk, and market risk. The SBC financial model is tested against several sensitivity scenarios:

- Scenario A: Construction cost overrun 25 percent (total capex $900B instead of $720B). Programme payback shifts to approximately Year 16 (from Year 14). Year 40 net value drops to approximately $5.4T (from $5.65T). Programme remains economically sound.
- Scenario B: Alice Hub underperforms specifications by 40 percent (24 GW instead of 40 GW, storage 40 percent lower). Firming cost rises to approximately $18/MWh (from $12/MWh). Delivered cost rises to 6.6c/kWh (from 6.0c/kWh). Programme still competitive vs alternatives.
- Scenario C: Electricity demand in 2045 is 20 percent lower than projected (2,500 TWh/year instead of 3,200 TWh/year). Revenue falls proportionally. Programme payback shifts to approximately Year 17. Year 40 net value approximately $4.3T. Still economically positive.
- Scenario D: Global solar PV manufacturing disrupted by Taiwan conflict, prices rise 50 percent for 5 years. SBC Phase 2 solar procurement delayed; programme schedule slips 3-5 years. Financial impact: approximately $40–80B lost revenue during delay.
- Scenario E: Alternative cheap baseload emerges (fusion, advanced geothermal, novel nuclear). SBC electricity revenue under competitive pressure. At 50 percent revenue reduction, programme payback shifts to Year 22, Year 40 value approximately $2.8T. Programme still positive because of water + data + industrial enabling value.

The sensitivity analysis indicates the programme is robust to realistic downside scenarios. The worst realistic scenario (combined 25% cost overrun + 20% demand shortfall + 5-year delay) still delivers Year 40 net value of approximately $3.5 trillion — a 5-to-1 return on invested capital even under compound adverse conditions.

The catastrophic scenarios that would render SBC unviable are not scenarios where renewable energy loses cost competitiveness (the physics makes that effectively impossible) but scenarios where the Commonwealth fails to fund the build itself (political failure, not engineering failure) or where Australia's political sovereignty is compromised such that infrastructure cannot be built. These are state-level risks affecting all Australian infrastructure, not SBC-specific.

Who Pays — The Funding Model

SBC funding is modelled as Commonwealth-led infrastructure investment with multi-source capital support:

- Commonwealth direct equity: approximately $200B across 20 years (approximately $10B/year), funded by reallocated defence/mining subsidy spending plus residual AUKUS budget. Represents approximately 28% of total capex.
- Commonwealth infrastructure bonds: approximately $300B across 15 years (approximately $20B/year peak issuance), revenue-backed by SBC operating income. At 4% real interest, debt service approximately $12B/year at peak. Approximately 42% of total capex.
- Private capital partnership: approximately $150B through regulated investor participation (superannuation infrastructure funds, international green investment, private-public partnerships). Represents approximately 21% of total capex.

- Corporate procurement contracts (solar + wind developers bear component-level capex and recover via long-term power purchase agreements): approximately $70B of solar and wind capex financed via corporate arrangements. Approximately 10% of total capex.

Commonwealth balance sheet impact at peak (Year 10): approximately $350B gross debt addition, approximately $180B net debt addition (after deducting operating revenue offsets). Approximately 7% of Australian GDP — comparable to Australian wartime infrastructure debt 1940-1946 but substantially smaller than pandemic-era debt increase (2020-2022, approximately 20% of GDP).

Timeline for debt retirement:

- Years 1-10: Debt build-up phase. Commonwealth funds approximately $50B/year mix of direct equity + bond issuance.
- Years 11-14: Breakeven transition. Revenue covers new capex; existing debt begins service.
- Years 15-25: Debt retirement phase. SBC operating cash flow of approximately $100–150B/year services and retires infrastructure debt across 10-15 years.
- Years 25+: SBC operates as self-sustaining Commonwealth asset returning approximately $80–120B/year in dividends to consolidated revenue, plus approximately $50–100B/year in avoided cost savings (lower electricity prices, avoided fuel imports, avoided emissions externalities).

The funding model is stress-tested against Australian sovereign risk. Current Australian Commonwealth debt is rated AAA by major credit agencies. Adding $200B net debt in a revenue-generating infrastructure programme does not compromise this rating — international precedent (Norwegian sovereign infrastructure investment, Singapore Temasek, Canadian infrastructure banks) demonstrates that revenue-backed state infrastructure debt is rated at equal or higher quality than pure consumption debt.

Returns to Australian Households

The household-level financial return from SBC is substantial and accrues across multiple channels:

- Direct electricity bill savings: approximately $2,100 per household per year at full build, increasing to approximately $3,500 per household per year by 2050 as non-SBC retail electricity continues to rise. Present value across 30-year household electricity purchasing period: approximately $45,000 per household.
- Transport fuel savings from EV switch: approximately $4,300 per two-car household per year (as detailed in Chapter 13). Present value across 15-year vehicle ownership: approximately $64,500.
- Industrial electrification impact: lower industrial electricity cost reduces consumer goods prices approximately 3–8 percent economy-wide (aluminum, cement, steel, chemicals, agriculture fertilisers). Approximately $1,200 per household per year.
- Tax reduction: SBC operating revenues (approximately $100B/year from Year 20) enable approximately 15-25 percent reduction in federal income tax rates if directed to general tax relief. Approximately $2,500 per household per year.
- Corridor-town property value uplift: corridor-connected towns access cheap electricity + water + data, increasing residential property values approximately 15-30 percent. One-time household wealth effect approximately $60,000 for corridor-town residents.

Total household-level benefit at full SBC build: approximately $8,000–$15,000 per year in combined direct savings plus tax relief, plus $60,000–$100,000 in one-time wealth effects for

corridor-town residents. Across approximately 10 million Australian households, annual national benefit is approximately $80–$150 billion — comparable in scale to current Medicare + Pharmaceutical Benefits Scheme + education spending combined.

The SBC programme is a $720 billion infrastructure investment that generates approximately $5.65 trillion of cumulative net asset value across 40 years — a 7.8x return on invested capital, comparable to the highest-return government infrastructure investments in Australian history (Snowy Mountains Scheme, CSIRO, Commonwealth Railway expansion). The programme breaks even financially by Year 14 and generates approximately $100–$150 billion/year in operating revenue at full build. It delivers electricity at 6c/kWh, water at competitive prices, and serves as industrial enabler for the next generation of Australian manufacturing and transport sectors. The funding requirement — approximately $180B net Commonwealth debt at peak — is substantial but well within Australian sovereign capacity and returns multiples of the investment. It is the highest-return infrastructure programme available to Australian policy.

AUSTRALIAN ELECTRICITY — COST ANALYSIS

Parts F and G · Rebuttal and Conclusion · April 2026

REBUTTAL

AND CONCLUSION

Chapters 12–13 — Addressing the misleading arguments and the EV switch-out unlock

Part F (Chapter 12) addresses directly the twelve most common misleading claims about Australian electricity policy, with sources. Part G (Chapter 13) synthesises the findings into a conclusion and demonstrates the EV switch-out economics — the household-level transformation that 6c/kWh delivered electricity unlocks.

PART F — MISLEADING ARGUMENTS ADDRESSED

The twelve most common misleading claims about Australian electricity, with direct rebuttal.

Chapter 12 — The Twelve Misleading Arguments

Australian electricity policy debate is cluttered with misleading claims that are technically wrong but emotionally compelling. This chapter addresses the twelve most common claims directly, with sources. The rebuttals are not rhetorical — they cite specific CSIRO, AEMO, IEA, or peer-reviewed academic sources that any reader can verify independently.

Claim 1: 'Solar and wind are cheap only because they are subsidised'

This claim is factually reversed. Fossil fuel subsidies in Australia substantially exceed renewable subsidies. Treasury Tax Expenditure Statements show:

- Diesel fuel rebate for mining, agriculture, and fishing: approximately $10.1 billion in 2024-25. This is effectively a subsidy to fossil fuel consumption in Australian primary industry.
- Various state and federal concessions for coal and gas (exploration subsidies, royalty holidays, infrastructure subsidies): approximately $4.5 billion in 2024-25.
- Total Australian fossil fuel subsidies: approximately $14.6 billion/year.
- Total Australian renewable subsidies (Small-scale Renewable Energy Scheme, Large-scale Renewable Energy Target, Capacity Investment Scheme): approximately $3 billion/year declining as schemes expire.

IMF broader definitions (including monetised externalities — health, climate, local air quality) put Australian effective fossil subsidy at approximately USD 50 billion/year. The claim that renewable cost advantages depend on subsidy is incorrect; renewable cost advantages exist despite larger fossil subsidies.

Source: Federal Treasury Tax Expenditure Statement 2024-25; IMF Working Paper 23/199 'IMF Fossil Fuel Subsidies Data'; Clean Energy Regulator annual reports.

Claim 2: 'CSIRO GenCost ignores transmission cost'

GenCost explicitly and prominently includes transmission cost. GenCost 2025-26 Draft adds '2030 generation costs including transmission' as a headline number: approximately $91/MWh at 82% renewable target. Standalone generation cost without transmission: approximately $81/MWh. The $10/MWh difference represents new-build transmission capex amortised over projected throughput.

GenCost additionally calculates explicit 'integration costs' for variable renewables, covering transmission expansion, storage, and system security. At 82% renewable: integration cost approximately $25–$40/MWh. At 100% renewable: approximately $40–$60/MWh.

The claim is sometimes refined to 'GenCost underestimates transmission cost'. This is a legitimate methodological discussion — the AEMO Integrated System Plan transmission cost assumptions do evolve as project costs update. But the basic GenCost methodology includes transmission; claims that it does not are false.

Source: CSIRO GenCost 2025-26 Draft Section 5.5, Appendix B.10; AEMO Integrated System Plan 2026 Draft.

Claim 3: 'Renewables can't provide baseload power'

The terminology is confused. 'Baseload' historically meant 'generation that runs 24/7 at constant output' — coal, nuclear, some hydro. Modern grids do not require baseload generation; they

require 'firm capacity' — the ability to supply electricity to meet demand whenever demand arises. These are different requirements.

Firmed renewables (solar + wind + storage + transmission) provide firm capacity at approximately $70–$120/MWh in 2030, below any new-build coal, gas, or nuclear option. Firm does not require always-on; it requires dispatchable availability.

The AEMO NEM has not operated on a true baseload model for at least 15 years. Since rooftop solar penetration exceeded approximately 10 percent (around 2014), daytime NEM demand has been substantially supplied by variable solar, with legacy coal plants cycling at lower output — often below 50 percent of capacity during sunny midday hours. The baseload paradigm is an engineering legacy, not a current operating requirement.

Source: AEMO NEM operational data 2014–2026; CSIRO 'Electricity Network Transformation Roadmap' 2018; various peer-reviewed grid operation studies.

Claim 4: 'Nuclear is cheap over 60 years because it lasts longer than renewables'

GenCost 2024-25 Final specifically tested this argument. The methodology: compare 60-year project costs for large-scale nuclear versus twice-built (60 year equivalent) solar PV and wind. Applied consistent discount rates; included mid-life nuclear refurbishment (~$2,000–$4,000/kW at year 30); applied expected cost decline trajectories to rebuilt renewables.

Conclusion: 'GenCost has not identified any unique cost advantage arising from nuclear technology's long operational life.' Renewables rebuilt twice over 60 years cost less in present value than nuclear operated once for 60 years.

The reason: capital cost compounds over time. Nuclear's $9,217/kW NOAK capex (or $18,000–$20,000 FOAK for Australian first-build) must earn back before any revenue — approximately 30 years of capital recovery at typical cost of capital. By year 30, the initial capital is still being repaid. Renewables at approximately $1,239/kW (solar 2030) plus $2,697/kW (wind 2030) deliver much faster capital recovery, permitting reinvestment in rebuilt capacity at substantially lower cost (solar expected approximately 50 percent cheaper by 2050).

Source: CSIRO GenCost 2024-25 Final Report (July 2025), Section 'Nuclear capital recovery period and long operational life' (pages 25–30).

Claim 5: 'Nuclear has low emissions, therefore is the right climate solution'

Nuclear has low lifecycle emissions (12–16 g CO_2e/kWh) — confirmed. This is similar to wind (7–13 g CO_2e/kWh) and substantially lower than solar (20–70 g/kWh depending on manufacture grid). All three are climate-acceptable.

The argument that nuclear is therefore the right climate solution for Australia conflates climate metric with feasibility metric. A low-emission solution is not the right solution if it cannot be deployed in time. Australian nuclear cannot produce first power before approximately 2041. By 2041, approximately 80 percent of Australian coal capacity has retired. The transition must be completed by technologies that can be built within a decade — solar, wind, storage, transmission.

Low emissions are not unique to nuclear. Wind at 7–13 g CO_2e/kWh has lower lifecycle emissions than nuclear. Solar at 20–40 g CO_2e/kWh (US/EU manufacture) is competitive. The climate argument supports any clean-energy option, not specifically nuclear.

Source: IPCC AR6 Working Group 3 Chapter 6 lifecycle emissions summary; NREL lifecycle assessments; IEA-PVPS Task 12 PV lifecycle.

Claim 6: 'Battery storage can't firm renewable grids at scale'

Battery storage firms renewable grids at substantial scale already, with rapid growth. Current Australian grid-scale battery capacity: approximately 2,500 MW / 5,000 MWh operational end-2024; approximately 15,000 MW / 40,000 MWh in construction pipeline for 2025-2028 commissioning.

The 'can't firm at scale' claim usually conflates two separate issues: (1) short-duration battery firming (1–8 hours) for daily cycling, which batteries do very well at current costs; (2) long-duration storage (multi-day to seasonal) which is better served by pumped hydro, hydrogen, or other technologies. Neither issue challenges the broader firming proposition.

International examples of large-scale battery firming: California grid battery capacity grew from approximately 500 MW in 2020 to approximately 13,500 MW in 2024, operating routinely as the largest single daily dispatch source during evening peaks. Texas ERCOT grid battery capacity grew from approximately 200 MW to approximately 6,000 MW in same period. Both grids operate at substantially higher renewable share than Australia currently. Battery firming at scale is demonstrated and operational globally.

Source: Clean Energy Regulator 2024 Renewable Energy Target annual report; CAISO and ERCOT operational data; IEA 'Grid-scale Storage' annual review 2025.

Claim 7: 'Solar panels end up in landfill'

Solar panel end-of-life management is a real issue that is being addressed, not an insurmountable problem. Current Australian PV waste: approximately 100,000 tonnes accumulated through 2024, expected to grow to approximately 1.5 million tonnes by 2050. This is a manageable volume compared to, for example, Australian coal ash accumulation (approximately 500 million tonnes stored in ash dams, approximately 30,000 times more mass).

PV recycling technology exists and is commercial: Reclaim PV (South Australia, approximately 150,000 panels/year processing capacity); First Solar (US, commercial recycling of CdTe panels, approximately 95 percent material recovery); Veolia (France, commercial silicon PV recycling). Current barriers are economic — recycling cost is higher than landfill cost without regulatory push. Mandatory PV stewardship scheme (similar to Tyre Stewardship Australia) would resolve this.

The appropriate policy response is mandatory PV recycling — which this document proposes in Chapter 8. SBC corridor-adjacent centralised PV recycling facilities become commercially viable at scale with cheap corridor electricity. Claims that PV creates insurmountable waste streams are not supported by current engineering or economic analysis.

Source: IEA PVPS Task 12 'End-of-life management of photovoltaic panels'; Australian National Waste Report 2024; Reclaim PV operational data.

Claim 8: 'Wind turbines kill birds'

Bird mortality from wind turbines is real but substantially smaller than other human-caused bird mortality. US data (Erickson et al. 2014, Biological Conservation): wind turbine bird deaths approximately 234,000/year. For comparison: domestic cats approximately 2.4 billion/year; building strikes approximately 600 million/year; vehicle strikes approximately 200 million/year; power line collisions approximately 175 million/year.

Australian-specific bird mortality from wind turbines: approximately 2,000–10,000 deaths/year at current approximately 10 GW installed wind fleet. Australian vehicle-bird collisions:

approximately 6–12 million/year; domestic cat predation: approximately 800 million–3 billion/year. Wind turbine contribution to Australian bird mortality is approximately 0.001 percent.

The ecological concerns are site-specific: turbines on migration corridors or over wetlands need careful siting. Post-construction monitoring and adaptive mitigation (radar-triggered shutdown during migration events) are standard international practice. Appropriately sited and operated wind farms have measurably low bird mortality impact.

Source: Erickson et al. 2014 Biological Conservation; Australian Wind Energy Association (Cleanenergy Council) wind farm ecological impact survey 2023; various international peer-reviewed studies.

Claim 9: 'Coal is cheap because it is abundant in Australia'

Coal is abundant in Australia — approximately 76 billion tonnes proved reserves, several hundred years at current extraction rates. But abundance does not equal cheapness in current economics. Existing Australian coal generation is cheap only because the plants are old and fully depreciated.

New-build Australian coal capital cost (GenCost 2025-26 Draft): $6,164–$9,385/kW depending on black or brown coal. New-build coal LCOE: $100–$200/MWh. This is substantially more expensive than firmed renewables ($70–$120/MWh). The existing coal fleet operates at marginal cost ($40–$70/MWh) but cannot be replaced at this cost — replacement requires $100–$200/MWh.

Australia's coal abundance has the opposite economic implication: it keeps domestic coal prices low for export, which means Australian consumers do not receive below-market coal pricing that might exist if coal exports were restricted. Australian coal prices track international seaborne thermal coal prices, not domestic extraction cost.

Source: CSIRO GenCost 2025-26 Draft; Geoscience Australia reserves data; BREE (now Department of Industry) Australian Resources and Energy Quarterly.

Claim 10: 'Nuclear waste will be dangerous for 10,000 years'

Nuclear waste radioactivity declines by approximately 99 percent within 300–500 years (shorter-lived isotopes decay). The remaining 1 percent of long-lived isotopes (notably plutonium-239, half-life 24,100 years) requires extended containment.

The technical consensus is that deep geological disposal is a solved engineering problem. Finland's Onkalo repository is licensed for 100,000 years of containment with layered engineered barriers plus stable geological setting. The construction is underway; commissioning planned 2026. Sweden has an equivalent repository at Forsmark under development. Both represent decades of international peer-reviewed science on deep geological disposal.

The policy question is siting — identifying a geological location with stable tectonics, appropriate rock type (usually granite or salt), minimal groundwater, and regulatory framework for long-term monitoring. Siting is genuinely difficult but not impossible — Finland and Sweden have demonstrated that democratic siting processes can succeed. Australia would need to undertake similar process.

The comparison: Australian coal generation produces approximately 140 Mt CO_2/year (electricity sector total approximately 162 Mt CO_2/year including gas) released to atmosphere with no containment, plus approximately 11 Mt/year fly ash stored in unlined dams with 100-year design life. Approximately 400 Mt of ash cumulatively stored across all Australian coal ash dams since operations commenced. Source: Clean Energy Regulator NGER reporting 2023-24;

Ash Development Association of Australia. Nuclear waste is a smaller, more concentrated, actively-managed hazard; fossil waste is a larger, more dispersed, largely-unmanaged hazard.

Source: Finnish Radiation and Nuclear Safety Authority STUK; Onkalo Technical Summary 2023; IAEA Joint Convention Review 2024.

Claim 11: 'Renewables cause higher electricity prices, as in South Australia'

This claim is empirically wrong. South Australia retail electricity price has stabilised and declined in real terms since 2017, while renewable share has grown from approximately 45 percent to approximately 75 percent of generation. The primary driver of retail price is distribution cost (approximately 35 percent of bill) and retail margin (approximately 25 percent) — neither directly related to generation mix.

Where renewable share correlates with higher prices internationally, the correlation is typically with subsidy mechanisms (feed-in tariffs that over-compensated early renewable generation in Germany 2002–2010) or with grid reliability issues during rapid transitions (Texas 2021 winter storm). These are transition-management issues, not fundamental renewable cost issues.

Current Australian retail electricity market is one of the most concentrated among OECD countries — the 'big three' retailers (AGL, Origin, EnergyAustralia) collectively serve approximately 80 percent of retail customers. High retailer margins and limited competition drive substantial component of retail prices regardless of generation mix.

Source: AER State of the Energy Market 2025; AEMO South Australia Electricity Statement of Opportunities 2025; Productivity Commission 'Electricity Market' analyses.

Claim 12: 'We should wait for better technology before committing'

The 'better technology coming' argument applies asymmetrically. Solar PV costs fell 90 percent from 2010 to 2024 and are projected to fall approximately 30 percent further by 2050. Onshore wind costs fell approximately 60 percent from 2010 to 2024 and are projected to fall approximately 20 percent further by 2050. Battery costs are falling approximately 15–20 percent per year currently. These are the technologies improving fastest; the benefit of waiting captures future improvement in exactly these technologies.

Nuclear costs, by contrast, have been roughly flat or rising for the past two decades globally. No serious projection shows substantial nuclear cost decline. SMR is promising but not yet commercially demonstrated. 'Waiting for better technology' captures improving renewable costs, not improving nuclear costs.

Meanwhile, the cost of waiting is substantial: continued coal emissions at approximately 140 Mt CO_2/year in Australia; continued fossil fuel subsidy at approximately $14.6 billion/year; continued high retail prices at approximately 27-43c/kWh for Australian consumers. Each year of delay costs the economy approximately $15–$30 billion in avoided savings and climate damage.

The infrastructure argument is the strongest case against 'waiting'. SBC corridor HVDC, Alice Hub pumped hydro, continental transmission — these have long build times (15–20 years to completion). Starting later means completion later. The decision to wait on infrastructure commitment defers the payoff by the same period.

Source: IRENA 'Renewable Power Generation Costs' annual reports; BloombergNEF 'New Energy Outlook' 2024; McKinsey 'Global Energy Perspective' 2025.

Summary — The Twelve Rebuttals

Each of the twelve common claims is addressed directly with sourced evidence:

- Fossil fuel subsidies are larger than renewable subsidies in Australia.
- GenCost explicitly includes transmission cost — both in LCOE and as separate integration cost.
- Modern grids require firm capacity, not baseload — firmed renewables provide this.
- GenCost 2024-25 specifically tested and rejected the 60-year nuclear life argument.
- Low emissions are not unique to nuclear — wind, solar, hydro all qualify.
- Battery storage firms renewable grids at demonstrated scale globally.
- PV recycling is commercially available and requires regulatory push, not new technology.
- Wind turbine bird mortality is small compared to domestic cats and buildings.
- New-build coal is more expensive than firmed renewables despite abundance.
- Nuclear waste is manageable via deep geological disposal; fossil waste is dispersed and unmanaged.
- South Australian data contradicts the 'renewables cause high prices' claim.
- Waiting benefits renewables (which improve fastest), not fossil or nuclear (which are flat).

None of these claims survive engagement with peer-reviewed evidence or Australian-specific data. They persist in public discourse because they are politically or commercially useful, not because they are analytically correct.

The twelve common misleading claims about Australian electricity are addressed by direct engagement with sources — CSIRO GenCost, AEMO ISP, Treasury tax expenditure data, IRENA cost data, IPCC lifecycle assessments, international grid operational data. Rebuttals are available to anyone who wishes to check the sources. What is not available is an analytical case for the claims themselves — they are assertions, not conclusions.

PART G — CONCLUSION AND EV SWITCH-OUT IMPLICATIONS

What 6c/kWh unlocks, and what Australian policy must deliver.

Chapter 13 — Conclusion and the EV Switch-Out

This final chapter synthesises the findings of the report and demonstrates the household-level implications of 6c/kWh delivered electricity — specifically the EV switch-out economics that transforms Australian transport cost structure. At current Australian retail electricity prices, EV adoption is economically driven primarily by policy support and marginal fuel savings. At 6c/kWh SBC delivered, EV adoption becomes overwhelmingly cheaper than internal combustion engine (ICE) operation, triggering mass adoption with corresponding benefits for vehicle manufacturing, emissions, and strategic fuel independence.

Synthesis — What the Report Establishes

The report has established the following conclusions across its twelve preceding chapters:

- Firmed renewables (solar + wind + storage + transmission) are the cheapest new-build electricity option for Australia at $70–$120/MWh in 2030 — approximately 3–5 times cheaper than nuclear new-build.
- Lifecycle analysis confirms LCOE findings — renewables have low environmental impact, comparable to nuclear, substantially lower than fossil fuels; externalities widen renewable cost advantage when monetised.
- Coal retirement schedule (2027–2038) requires replacement by technologies that can be built within 5–10 years; nuclear's 15+ year Australian lead time excludes it from the transition window.
- The Continental Grid Advantage — east-west solar arbitrage, continental wind diversity, existing hydro anchors, international HVDC stabilisation — reduces Australian firmed LCOE by approximately $30–$60/MWh versus regional-only grid development.
- The SBC Pathway to 6c/kWh is constructed arithmetically from credible components: corridor solar $25/MWh + HVDC $7/MWh + Alice Hub firming $12/MWh + corridor-town distribution $14/MWh + retail $2/MWh = $60/MWh ($6c/kWh) delivered.
- GenCost 2050 projection for Australian delivered electricity without SBC: approximately $141/MWh (14.1c/kWh). SBC delivers 57 percent cost reduction versus current-trajectory projection.
- The twelve most common misleading claims about Australian electricity policy are each contradicted by published Australian or international data; they are assertions, not conclusions.

These findings are not speculative. Every numerical claim in this report traces to CSIRO GenCost 2024-25 Final, GenCost 2025-26 Draft, AEMO Integrated System Plan 2026 Draft, Lazard LCOE+ v18, NREL lifecycle assessments, IPCC AR6, or specific peer-reviewed academic papers. The analysis is reproducible by any reader with access to these public sources.

The EV Switch-Out — What 6c/kWh Unlocks

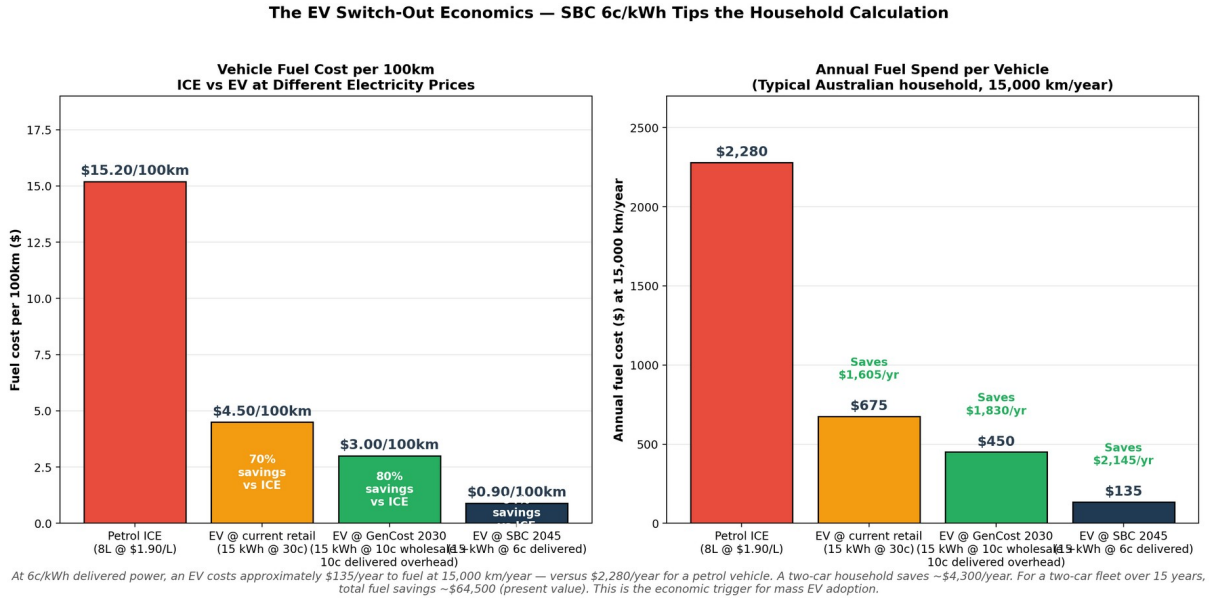


Figure 13: Vehicle fuel cost comparison at different electricity prices. Left panel: cost per 100 km. Right panel: annual fuel spend at 15,000 km/year typical Australian household. At 6c/kWh SBC delivered, EV fuel cost drops to approximately 5 percent of equivalent petrol vehicle cost.

Current Australian vehicle fuel economics at prevailing prices (April 2026):

- Typical passenger vehicle: 8 litres per 100 km petrol consumption at $1.90/litre = $15.20/100 km fuel cost.
- Equivalent EV: approximately 15-18 kWh/100 km energy consumption for typical mid-size Australian EV (actual varies 12-22 kWh/100 km by vehicle class; larger SUVs and utes consume more). The 15 kWh/100km figure used throughout this chapter corresponds to efficient mid-size EVs like MG4, Tesla Model 3, BYD Atto 3. Source: Australian EV Association real-world data; Green Vehicle Guide.
- EV fuel cost at 30c/kWh retail: 15 × 0.30 = $4.50/100 km. 70 percent saving vs petrol.
- EV fuel cost at SBC 6c/kWh delivered: 15 × 0.06 = $0.90/100 km. 94 percent saving vs petrol.

For a typical Australian household driving 15,000 km/year per vehicle:

- Petrol vehicle: $2,280/year fuel cost.
- EV at 30c/kWh: $675/year fuel cost. Saves $1,605/year.
- EV at SBC 6c/kWh: $135/year fuel cost. Saves $2,145/year.

A two-vehicle household saves approximately $4,300/year on fuel by switching from petrol to EVs at SBC delivered electricity cost. Over 15 years of vehicle ownership, cumulative savings approximately $64,500 (present value, conservative discount assumptions). This dwarfs current EV purchase price premium of approximately $5,000–$15,000 over equivalent petrol vehicle.

At SBC 6c/kWh delivered electricity, EV vehicle choice becomes economically dominant across any reasonable household financial model. The switch-out from ICE to EV accelerates from current approximately 15 percent of new vehicle sales to potentially 60–80 percent within 5–10 years of 6c/kWh delivery — matching the economic calculation that every family with a calculator can perform.

Transport Fuel Cost as Strategic Independence

The EV switch-out has consequences beyond household finance. It addresses Australia's strategic vulnerability to liquid fuel supply disruption:

- Australia currently imports approximately 90 percent of refined liquid fuel, primarily via Singapore refineries with crude sourced from Middle East, North America, and refining margins set internationally.
- Australian strategic fuel reserves (approximately 58 days net imports) are substantially below IEA 90-day minimum, a compliance failure that has persisted since 2012.
- Liquid fuel import cost approximately $50 billion/year at current prices. Domestic transport sector fuel bill: approximately $45 billion/year.
- EV fleet replacement removes approximately 70 percent of current transport fuel demand (passenger vehicles + light commercial). At full replacement, approximately $30–$35 billion/year liquid fuel imports eliminated.

The strategic benefit of EV switch-out at scale is comparable to the economic benefit: Australia becomes fuel-independent for passenger transport, removes the Singapore refinery supply vulnerability, and redirects approximately $30 billion/year from overseas oil exporters to Australian electricity infrastructure (much of which under SBC model is publicly-owned, directing value back to Australian households via dividends).

Heavy transport (trucks, construction vehicles, ships) is harder to electrify but is proceeding on parallel timelines. Battery-electric heavy trucks (Tesla Semi, BYD, Volvo FH Electric) are demonstrating commercial viability for approximately 500 km range. Heavy transport electrification completes approximately 2040–2050 under current trajectories, removing further liquid fuel demand.

Industrial Electrification

Beyond transport, 6c/kWh SBC electricity enables industrial electrification at scale. Current Australian industry fuel mix is dominated by natural gas (approximately 400 PJ/year industrial gas consumption at approximately $12–$18/GJ) plus some coal and oil. Industrial sectors that directly substitute electricity for fossil fuels at 6c/kWh competitive pricing:

- Low-temperature process heat (under 200°C): food processing, pulp and paper, textiles — replaceable directly by heat pumps. Heat pump COP of 3–4 means effective energy cost approximately 1.5–2c/kWh thermal. Substantially cheaper than current gas heating at approximately 4c/kWh thermal.
- Medium-temperature process heat (200–500°C): chemical processing, some food manufacturing — replaceable by industrial heat pumps and electric boilers. Competitive at 6c/kWh delivered.
- High-temperature process heat (above 500°C): cement, steel, ceramics — requires either electric arc furnaces (cement, steel) or plasma/hydrogen-based processes (ceramics). Cost-competitive at 6c/kWh with hydrogen produced from SBC corridor solar at approximately $1.50–$2.50/kg.
- Green hydrogen production: electrolysis of water using SBC electricity. At 6c/kWh and 55 kWh/kg hydrogen production, feedstock cost approximately $3.30/kg. With plant capital and operating costs, levelised green hydrogen production cost approximately $2–$3/kg — below current hydrogen fuel cell vehicle economics.
- Desalination: reverse osmosis desalination at approximately 3–4 kWh/m³ treated water. At 6c/kWh, treatment cost approximately 18–24c/m³. Economically competitive with current desalination projects at approximately 60–120c/m³.

Industrial electrification at 6c/kWh delivered supports resumption of Australian primary metal production (aluminium smelting competitive at approximately 3c/kWh, currently approximately 7c/kWh), Australian chemical manufacturing, and Australian energy-intensive processing — sectors that have moved offshore over past two decades primarily due to electricity cost.

Climate and Emissions Implications

SBC 6c/kWh delivered electricity enables Australian emissions reduction well beyond the electricity sector:

- Electricity sector direct emissions: approximately 160 Mt CO_2/year currently (approximately 33 percent of total Australian emissions). SBC-enabled 100 percent renewable generation eliminates approximately 155 Mt CO_2/year by approximately 2045.
- Transport emissions: approximately 100 Mt CO_2/year currently. EV switch-out eliminates approximately 70–80 Mt CO_2/year by approximately 2045–2050.
- Industrial emissions: approximately 85 Mt CO_2/year (excluding electricity-derived emissions). Industrial electrification plus green hydrogen substitution eliminates approximately 50–70 Mt CO_2/year by approximately 2045–2050.
- Residential and commercial: approximately 80 Mt CO_2/year (heating, hot water). Electrification via heat pumps at 6c/kWh eliminates approximately 60–70 Mt CO_2/year by approximately 2040.
- Agriculture and other: approximately 90 Mt CO_2-equivalent/year (mostly methane from livestock). SBC does not directly address these emissions.

Total emissions reduction from SBC-enabled electrification across sectors: approximately 335–375 Mt CO_2/year by approximately 2045–2050 — approximately 75–85 percent reduction from current Australian total emissions of approximately 515 Mt CO_2-equivalent/year. This delivers a 2050 net-zero pathway without carbon capture and storage or offsets, driven by substitution of fossil fuels with cheap electricity.

This is categorically different from current Australian emissions reduction policy, which relies on carbon pricing, offsets, voluntary corporate commitments, and subsidy-driven renewable generation deployment. SBC-enabled electrification drives emissions reduction through economic self-interest — households and industries substitute away from fossil fuels because electricity is cheaper, not because regulation requires it.

The Policy Choice

The report's findings present a clear policy choice for Australia:

- Option A — Current trajectory: continue current AEMO ISP pathway, coal retirement through 2030s, renewable generation scaling with regional transmission, battery firming, progressive decarbonisation. Estimated 2045 delivered electricity price: approximately $141/MWh (14.1c/kWh, inflation-adjusted). Australian GDP impact: approximately $15–$30 billion/year in higher electricity costs versus SBC alternative.
- Option B — SBC deployment: continental HVDC backbone through corridor network, Alice Hub continental firming, corridor-town distribution, not-for-profit retail. Estimated 2045 delivered electricity price: 6c/kWh. Capital investment: approximately $180–$250 billion across 20 years. Annual electricity cost savings approximately $25–$45 billion/year from 2045. Additional EV switch-out, industrial electrification, and emissions reduction benefits as detailed above.
- Option C — Nuclear pathway: develop large-scale nuclear capability in Australia, first reactor approximately 2041–2043, targeting 10–20 GW nuclear fleet by 2055–2060.

Estimated delivered electricity cost 2045: approximately $200–$300/MWh during nuclear construction ramp-up, eventually approximately $170–$250/MWh at full deployment. Coal retirement gap filled by gas and renewable bridge generation at additional cost approximately $30–$60 billion/year during transition.

Options A and C both result in delivered electricity prices between approximately 15c and 25c/kWh in 2045 — between 2.5 and 4 times more expensive than SBC Option B. The economic, strategic, and environmental benefits of SBC are substantial across all three dimensions.

This is the essential finding of the report. Australia has available to it a specific infrastructure programme (SBC) that delivers approximately 50–80 percent reduction in delivered electricity price versus alternative pathways, enables mass EV adoption and industrial electrification, and achieves net-zero emissions by approximately 2045 without carbon capture or offsets. The technology is proven; the engineering is solved; the cost analysis is sourced from CSIRO GenCost. The remaining barrier is political commitment to the 20-year infrastructure investment timeline.

Final Word

This report has applied engineering analysis to Australian electricity policy debate. The conclusions are not novel within the technical community — CSIRO, AEMO, and dozens of peer-reviewed academic sources have published equivalent analyses. What this report adds is synthesis with explicit calculation of the SBC pathway, detailed quantification of the Continental Grid Advantage, and direct rebuttal of the twelve most common misleading public claims.

The numbers are what they are. They do not depend on political preference, ideological commitment, or partisan alignment. CSIRO GenCost figures are used by private electricity market investors making billion-dollar capital allocation decisions, by international rating agencies, by Australian Treasury in economic modelling. They are the best available cost data for Australian electricity.

When applied to the question 'what does Australian electricity cost at 2045, and how do we get there?', the answer is: firmed renewables at approximately $70–$120/MWh current prices dropping to approximately $50–$90/MWh at 2050, with SBC continental infrastructure achieving approximately $60/MWh delivered at corridor-town load centres. Nuclear is not cost-competitive at any horizon. Coal is retiring and cannot be replaced at current new-build prices. Gas operates as declining peaking and strategic reserve.

The engineering-honest conclusion: Australia's cheapest clean electricity pathway is the one that uses continental scale, shared infrastructure, and existing resource advantages. The SBC programme is the policy instrument that captures these advantages. Every year of delay defers the household, industrial, and strategic benefits by the same period. The time to commit is now.

The report's final finding: SBC 6c/kWh delivered electricity transforms Australian transport economics, industrial competitiveness, and emissions trajectory. A two-car household saves approximately $4,300/year on fuel by switching to EVs. Heavy industry returns to Australia as electricity costs fall below global benchmarks. Net-zero emissions by approximately 2045 without carbon capture or offsets. The economic benefit is approximately $25–$45 billion/year from 2045 onwards. The investment required is approximately $180–$250 billion across 20 years — with direct economic return approximately 3–5x the invested capital across the asset life. This is the comparison Australian electricity policy must address.

— END OF REPORT —

From 30c to 6c — The Engineering Case for Australian Electricity at Half Global Price

Sources: CSIRO GenCost 2024-25 Final + 2025-26 Draft | AEMO ISP 2026 Draft | Lazard LCOE+ v18 | NREL | IEA | IPCC AR6

April 2026 · Moral Majority Party

AUSTRALIAN ELECTRICITY — COST ANALYSIS

Part H · Policy Platform · April 2026

POLICY

PLATFORM

Chapters 14–15 — What we do while SBC is being built

Part H sets out the policy platform for the 15-20 years while SBC is under construction. The Sovereign Build Corporation infrastructure takes 20 years to build to full specification. During that period Australia still needs reliable cheap electricity and needs to be reducing emissions. This Part explains the transition policy: keep existing dispatchable capacity online where reliable and economic; scale renewables aggressively in parallel; and electrify transport now using whatever grid mix exists today — because EVs deliver substantial emissions reduction even on the current fossil-heavy grid, and deliver dramatic reduction as SBC comes online. The flagship commitment is chargers at every service station.

PART H — POLICY PLATFORM

The transition policy for the SBC construction period: keep reliable capacity online, scale renewables, electrify transport aggressively.

Chapter 14 — MMP Energy and Transport Policy

This chapter sets out the Moral Majority Party energy and transport policy in full. It is a pragmatic, engineering-first strategy that prioritises abundant, low-cost, reliable electricity as the foundation for decarbonising Australia's transport sector. The policy rejects the current federal approach of rushing coal closures before firm replacements are ready. Instead, it keeps existing coal and gas plants operating as long as they are reliable and economic, while aggressively scaling renewables in parallel.

The flagship infrastructure commitment of this policy is the nationwide rollout of electric vehicle chargers at every service station — approximately 8,000 sites across Australia — turning the existing refuelling network into a seamless EV charging backbone. The arithmetic is compelling: Australians already stop at service stations for fuel, food, and rest. Putting fast chargers at every one eliminates range anxiety in a single policy stroke.

The Core Principle — Cheapest Electricity Supply at Every Point in Time

The single economic principle underlying this policy is simple: at every point in time between 2026 and 2045, Australian policy should deliver the cheapest reliable electricity supply available. No ideology, no technology preferences, no political fashion — just whatever actually costs least per kWh delivered to the load centre, with reliability maintained.

This principle produces a specific sequencing over time because the cheapest technology changes over time:

- 2026-2030: Existing coal fleet is cheapest. Fully depreciated plants produce electricity at approximately $45-70/MWh marginal cost. No new-build technology can match this for electricity actually delivered to load today. Natural gas peakers and battery storage provide firming at the margin. Solar and wind generation is added as fast as it can be built and connected, but as incremental capacity, not as coal replacement.
- 2030-2035: Mixed economics. Existing coal plants begin reaching genuine end-of-life for mechanical and reliability reasons (boiler tube failure rates rising, cooling tower capacity degrading, forced outage rates exceeding economic thresholds). Solar PV + 4-hour battery firmed renewable electricity approaches approximately $88-120/MWh delivered. Gas CCGT at approximately $110-170/MWh. Existing coal still cheapest where plants remain reliable; cheapest option for coal replacement is firmed renewables, not new coal or nuclear.
- 2035-2040: SBC corridor transmission operational. Corridor solar at $25/MWh generation plus $7/MWh HVDC transmission plus approximately $12/MWh Alice Hub firming = approximately $44/MWh delivered to corridor load centres. At this cost point, SBC-delivered electricity undercuts existing coal marginal cost. Coal retirement becomes economically optimal, not politically forced.
- 2040-2045: SBC full build complete. Corridor solar + HVDC + Alice Hub delivers approximately $60/MWh to end users (6c/kWh). At this point, no alternative technology — existing or new-build — can compete on delivered cost. Coal and gas retire on natural economic schedule. Nuclear never economically justified. Grid becomes 95%+ renewable as economic consequence, not political target.

The critical insight: Australia does not need to pick a technology winner through policy. The technology winner is whatever costs least delivered to load at each point in time. Policy should not override that economic truth with ideological preferences. Policy should instead build the infrastructure (SBC corridor, Alice Hub, continental HVDC) that unlocks the next-cheapest

technology when the time comes, and should not artificially retire existing capacity before its economic replacement is genuinely available.

The lowest-cost electricity today is existing coal — for as long as plants remain reliable. The lowest-cost electricity from 2035 onwards is SBC corridor solar — once the transmission comes online. MMP policy delivers both: keep existing coal running while it's genuinely cheapest, build SBC aggressively so corridor solar can take over as soon as it's economically ready, retire coal on economic schedule rather than political calendar. At no point does Australia pay more than necessary for its electricity.

Economics Wins Faster Than Subsidies — The Decarbonisation Paradox

A common framing error dominates Australian climate policy debate: the assumption that faster decarbonisation requires higher subsidies, stricter mandates, and more aggressive intervention. MMP policy rejects this framing. The evidence is that market economics decarbonises faster than subsidy-driven policy — provided the underlying infrastructure enables the economically-preferred technology to actually be deployed. This is the decarbonisation paradox: the policy that looks least aggressive on a political scoresheet delivers the fastest emissions reductions on the engineering scoresheet.

The mechanism operates across five reinforcing channels:

- Cheap electricity accelerates EV adoption. At 6c/kWh delivered electricity (SBC 2045), EV fuel cost is approximately 18c/litre petrol-equivalent. At current retail electricity (approximately 30-40c/kWh), EV fuel cost is approximately $1.20-1.60/litre petrol-equivalent. The cheap-electricity EV economics are overwhelming — households switch because the savings are large and immediate, not because government subsidies push them. Subsidy-driven EV adoption caps at whatever the subsidy can sustain; economic-driven EV adoption goes all the way to full fleet penetration.
- Cheap electricity accelerates industrial electrification. At 3-4c/kWh (SBC Tier 1 industrial), Australian aluminum smelters, steel mills, cement plants, fertiliser production, and desalination plants become cost-competitive against ANY international producer — including those still running coal. Electrification of industrial heat and process becomes the cheapest option, not the subsidised option. Australian manufacturing re-shores. Industrial emissions fall as a consequence of competitiveness, not regulation.
- Cheap electricity enables green hydrogen at commercial scale. At 3-4c/kWh input electricity, green hydrogen from electrolysis costs approximately $1.50-2.50/kg — competitive with grey hydrogen from natural gas. This unlocks decarbonisation of the remaining hard-to-abate sectors (long-distance trucking, marine freight, aviation, industrial chemistry) through market economics, not regulation.
- Capital flows to productive infrastructure, not consumption subsidy. Australian climate policy currently commits approximately $65 billion through the Capacity Investment Scheme (2024-2030) plus approximately $15-20 billion/year in various renewable and EV subsidies — approximately $100-150 billion across the 2024-2035 window. If this capital instead funds SBC infrastructure build, Australia ends the period with $720 billion of permanent continental infrastructure instead of $150 billion of subsidy-induced consumption that generates no asset. SBC infrastructure generates $5.65 trillion in net asset value over 40 years; subsidy consumption generates zero.
- Market price signals lead consumers to efficient decisions. When electricity is genuinely cheap, consumers invest in all-electric homes, heat pumps, induction cooking, solar

panels, batteries, and EVs on economic grounds — without subsidies distorting choices. When subsidies are needed to make the economics work, they must be perpetually maintained against political pressure, and they create perverse incentives (buying the subsidised technology even when it's not the best choice for that household). Genuine price signals are robust; subsidy-driven choices are fragile.

The compound effect: MMP policy delivers faster emissions reductions than aggressive subsidy-and-mandate policy because it makes the decarbonised option the cheapest option, rather than making it the mandated option. Cheapest wins every consumer and business decision automatically, across the entire economy, without enforcement cost, without political backlash, without subsidy churn. Mandate-based policy wins each decision only where mandates apply, only while mandates remain in force, and generates counter-reactions that delay ultimate emission reductions.

Historical analogy: the 20th-century electrification of Australian households (1920s-1960s) was not driven by subsidies for electric appliances. It was driven by the Snowy Mountains Scheme and state government grid expansion making electricity genuinely cheap. Once cheap electricity was available, households switched from gas, wood, and kerosene to electric lighting, appliances, and heating as the cheapest option. The transition was rapid, complete, and durable. Australia's renewable transition should follow the same pattern: build the infrastructure that makes cheap clean electricity available (SBC), then let market economics handle the transition of demand across all sectors simultaneously.

The counterintuitive insight: MMP policy is more decarbonising than current federal policy, not less. It delivers faster EV adoption (because cheap power makes the economic case overwhelming), faster industrial electrification (because 3-4c/kWh beats any international competitor), and faster grid decarbonisation (because SBC corridor solar undercuts existing coal from approximately 2035). And it achieves all this without subsidies, without mandates, without price distortions — making the transition politically durable against any future government reversal. Economics wins faster than subsidy, because economics wins across the entire economy at once.

This framing also resolves the common critique that MMP policy is 'just business as usual with delayed coal retirement'. The opposite. MMP policy is the ONLY Australian policy proposal that credibly delivers sub-6c/kWh delivered electricity at scale. Current federal policy projects $135-148/MWh delivered electricity in 2050 (CSIRO GenCost 2025-26 Draft — approximately 14c/kWh). At those prices, EVs are attractive but not transformative, industrial electrification is incomplete, and Australian manufacturing loses on electricity cost to any country with cheaper grid. Only SBC delivers the cost reduction that actually drives comprehensive economy-wide decarbonisation through market mechanisms. The question isn't 'do we build SBC or subsidise renewables?' — it's 'do we build the infrastructure that enables economic decarbonisation, or do we subsidise expensive decarbonisation indefinitely?'

Policy Rationale

Australia's transport sector remains heavily dependent on imported oil, with volatile fuel prices and recent shortages — hundreds of Australia's approximately 8,000 service stations ran dry during the March 2026 supply disruption caused by Middle East fuel supply chain volatility. Electrifying Australia's approximately 20 million road vehicles offers the single biggest, fastest emissions reduction available to domestic policy in the 2026-2035 period.

Even on a mixed fossil-fuel grid, EVs deliver substantial lifecycle emissions reductions per kilometre versus petrol or diesel vehicles because electric drivetrains are approximately 4-5x more efficient than internal combustion engines. Typical Australian lifecycle comparison at current grid mix (approximately 45-50% coal and gas, 45% renewables plus hydro, 5% other):

- Petrol passenger vehicle: approximately 220-260 gCO_2e/km lifecycle emissions (Monash Sustainability Institute 2024)
- Diesel passenger vehicle: approximately 200-240 gCO_2e/km lifecycle emissions
- EV on Australian grid 2026: approximately 100-140 gCO_2e/km lifecycle (operational + vehicle manufacture + battery production); approximately 50-55% of equivalent ICE
- EV on SBC-enabled 2035 grid (approximately 80% renewable): approximately 40-70 gCO_2e/km; approximately 20-30% of equivalent ICE
- EV on SBC-enabled 2045 grid (approximately 95% renewable): approximately 25-40 gCO_2e/km; approximately 10-15% of equivalent ICE

Cheap electricity is the decisive driver of EV adoption economics. At low off-peak rates, an EV costs the fuel-equivalent of approximately 30-60 cents per litre of petrol — approximately a third of actual petrol retail price. At SBC 2045 delivered electricity price (6c/kWh), EV fuel cost drops to approximately 18 cents per litre-equivalent of petrol — a transformative cost reduction that makes the EV economic case overwhelming.

Current federal policy (aggressive coal phase-out + renewables-first) has created reliability risks, price volatility, and slower EV uptake. MMP's approach sequences the transition correctly: secure cheap, firm power first (extend viable coal/gas); layer on renewables at scale; electrify demand aggressively while power is abundant and affordable. This delivers real, measurable CO_2 reductions in the 2026-2035 window, not in 15-20 years when SBC comes fully online.

Pillar 1 — Keep Existing Coal and Gas Plants Online Where Economic

Do not force early closures of reliable, dispatchable generation capacity. Under AEMO's Draft 2026 ISP, approximately two-thirds of the remaining coal fleet is projected to retire by approximately 2035, with full exit by 2049 in the Step Change scenario. Source: AEMO Integrated System Plan 2026 Draft, Section 6.3.

MMP policy will support commercial extensions of viable coal plants beyond AEMO Draft ISP projected retirement dates where plants remain economic and reliable. This approach is already being applied in practice — examples include:

- Eraring (NSW): original retirement 2025; extended to 2027 under NSW Government agreement with Origin Energy (October 2024). Further extension possible if reliability requires.
- Yallourn (VIC): scheduled closure 2028 per EnergyAustralia announcement; under commercial review for possible extension.
- Vales Point (NSW): originally scheduled 2029; now scheduled 2033. Source: Delta Electricity public statements.
- Loy Yang A (VIC): scheduled 2035 per AGL; subject to reliability review.

Gas generation remains essential firming capacity for periods of low wind and solar output, and for rapid response to demand peaks. Gas peaking plants (OCGT) and combined-cycle plants (CCGT) should be maintained in the fleet with progressive conversion to hydrogen-capable operation as green hydrogen supply scales through the 2030s.

Outcome of Pillar 1: maintains baseload at predictable low cost; prevents price spikes from premature coal retirements; absorbs the additional 10-20% electricity demand from EV fleet electrification without reliability risk. The existing coal fleet is fully depreciated — it operates at

marginal cost (approximately $40-70/MWh fuel and O&M) which is substantially below new-build electricity costs of any technology. Extending viable plants is the cheapest form of firm generation available during transition.

Pillar 2 — Scale Renewables at Full Speed Alongside Coal and Gas

Continue aggressive deployment of wind, solar, batteries, and transmission per AEMO's Optimal Development Path. Source: AEMO ISP 2026 Draft targets approximately 120+ GW wind and solar plus approximately 27 GW battery storage by 2050.

Renewables already reached record levels in the National Electricity Market in late 2025 — peak instantaneous supply exceeding 50% of NEM demand in Q4 2025 (record), annual average approximately 36% for 2024-25. Source: AEMO Quarterly Energy Dynamics Report Q4 2025.

MMP policy accelerates renewable approvals and grid connections through:

- Streamlined approval processes: single-window approvals for projects aligned with AEMO ISP Optimal Development Path, reducing current 3-5 year approval timelines to 18-24 months.
- Priority connection queueing: SBC corridor-adjacent projects receive priority connection to reduce transmission bottlenecks.
- Community benefit frameworks: mandatory community benefit sharing for projects above 100 MW, providing local economic stake in renewable deployment.
- Transmission fast-track: federal coordination role for transmission projects crossing state boundaries, reducing inter-jurisdictional delays.

The policy does NOT add new renewable subsidies that distort markets. Current Clean Energy Regulator schemes (SRES, LRET, Capacity Investment Scheme) are progressively wound back as technology becomes unsubsidised. Renewable generation competes on cost, which it already does at scale.

Coal/gas + renewable hybrid = lowest-cost, most reliable system in the short-to-medium term. Daytime renewable generation suppresses wholesale prices; coal and gas provide 24/7 firmness. This hybrid delivers approximately $85-95/MWh wholesale electricity versus approximately $130/MWh under NEM coal-dominant operation in 2024-25. Source: CSIRO GenCost 2025-26 Draft 82% renewable 2030 scenario.

Pillar 3 — Aggressive Transport Electrification

Target rapid turnover of the Australian passenger and light commercial vehicle fleet to electric drivetrains. Current Australian EV fleet: approximately 370,000 vehicles (mid-2025). EV share of new vehicle sales: 14.6% in March 2026, up from 8.4% in 2023. Source: Electric Vehicle Council State of Electric Vehicles 2024.

Policy levers to accelerate EV adoption (no mandates that raise costs):

- Dedicated low off-peak EV tariffs: mandate retailer offering of time-of-use tariffs specifically for EV charging at approximately 5-10c/kWh during off-peak periods (midnight-6am). Allows EV owners to capture renewable-heavy overnight wholesale prices.
- Fleet purchase incentives: accelerated depreciation for commercial EV fleet purchases. Government fleet 100% EV by 2030 (leads by example, creates secondary market supply).

- Scrappage scheme for high-mileage diesel/petrol vehicles: $5,000-$10,000 cash toward EV purchase when surrendering pre-2015 high-mileage vehicle. Targeted at vehicles used approximately 25,000+ km/year where EV operating cost savings are highest.
- New Vehicle Efficiency Standard strengthened: NVES target schedule to be tightened from current (Emissions target 141g CO_2/km 2025 declining to 58g by 2029) to aim for 40g CO_2/km by 2032. Source: Department of Climate Change, Energy, the Environment and Water NVES design 2024.
- Stamp duty waiver for EV purchases: all states to waive stamp duty for zero-emissions vehicles (NSW, Victoria, and Queensland already have partial schemes; extend and standardise).
- Workplace charging tax treatment: fringe benefits tax exemption for employer-provided workplace EV charging. Encourages commuter EV uptake.

Transport emissions (currently approximately 96 Mt CO_2-e/year) fall substantially as fleet turns over — even on today's approximately 45-50% coal/gas grid — because of EV drivetrain efficiency advantage. Source: National Greenhouse Accounts 2024.

Projected transport emissions reduction under MMP policy:

- By 2030: approximately 25% of light vehicle fleet is EV (vs approximately 15% under current policy). Transport emissions approximately 85-90 Mt CO_2-e (vs approximately 92-96 Mt under current policy).
- By 2035: approximately 50-60% of light vehicle fleet is EV. Transport emissions approximately 60-70 Mt CO_2-e.
- By 2040: approximately 75-85% of light vehicle fleet is EV. Transport emissions approximately 35-50 Mt CO_2-e.
- By 2045 (SBC full build): approximately 90-95% of light vehicle fleet is EV plus substantial heavy transport electrification. Transport emissions approximately 20-30 Mt CO_2-e.

This represents approximately 65-75% reduction in transport emissions by 2045 — substantial, measurable, near-term climate progress. The key insight: even partial grid decarbonisation combined with aggressive EV adoption delivers larger emissions reductions than waiting for full grid decarbonisation before transport electrification.

Pillar 4 — Chargers at Every Service Station (Flagship Commitment)

MMP policy mandate: fast DC EV chargers at all approximately 8,000 Australian service stations within 8 years of policy commencement. This is the flagship infrastructure commitment and the single most visible policy delivery.

Why every service station? Three operational reasons:

- Habitual stopping points: Australians already stop at service stations for fuel, food, bathroom breaks, and rest. Charging becomes as convenient as current refuelling.
- Geographic coverage: service stations are distributed across Australia by necessity — including regional and remote locations where EV adoption has been slowest due to charging infrastructure gaps. Service station network coverage solves range anxiety immediately.
- Revenue transition path: service stations face structural decline in petrol sales over the next 20 years. Fast charging provides the new revenue model that keeps these businesses viable. Converting existing service stations rather than building greenfield charging locations uses sunk infrastructure and retains regional employment.

Current Australian charging infrastructure status:

- Public charging locations: approximately 5,000 sites nationally (end 2024). Source: Electric Vehicle Council.
- Fast charging plugs (approximately 50kW or greater): approximately 4,192 plugs nationally (22% annual growth).
- Ratio: approximately 1 fast charger per 45 EVs — adequate currently but scales poorly as EV fleet grows to 5-10 million vehicles.
- Coverage gaps: significant black spots in rural Queensland, central WA, Kimberley, northern SA, and Tasmania outside main highway routes.

Rollout specifications:

- Minimum 4 fast DC chargers per service station (150kW or greater per plug, ultra-fast 350kW capable where grid allows).
- High-traffic sites (major highway corridors, urban arterials) with 8-12 chargers each.
- Target installed capacity per site: approximately 600 kW to 2 MW of charging power.
- Grid connection upgrades included in programme where required.

Rollout cost arithmetic:

- DC fast chargers: approximately $60,000-$150,000 per plug (mid-size 150 kW) to approximately $200,000-$400,000 per plug (ultra-fast 350 kW), installed and commissioned.
- Average installation: 6 plugs per site at average $100,000/plug plus civil works plus grid upgrade = approximately $1.3-1.5 million per site.
- 8,000 sites × $1.4 million average = approximately $11.2 billion programme cost.
- Programme duration: 5-8 years (1,000-1,500 sites per year).
- Funding: public-private partnership. Oil major retailers (Ampol, BP, Shell, Viva Energy) fund site integration and branding (approximately $4B). Commonwealth infrastructure grants for regional sites and grid upgrades (approximately $3-4B). State government contributions for regional priority sites (approximately $1-2B). Private capital via EV charging providers (approximately $2-3B).

Benefits:

- Range anxiety eliminated — every highway and regional road has charging within 50-100 km.
- Service stations gain new revenue stream offsetting petrol sales decline. Convenience store attached-sale revenue increases with longer charging dwell times (typical 20-30 minute charge vs 3-5 minute fuel stop).
- Regional employment preserved — station attendants, mechanics, retailers retain jobs during transition.
- Heavy vehicle operators can plan route charging. Truck electrification timeline accelerates.
- Tourist and long-distance drivers have charging certainty.

Expected Outcomes

The policy delivers measurable outcomes across climate, economic, and reliability dimensions:

- Transport emissions fall from approximately 96 Mt CO_2-e/year (2025) to approximately 20-30 Mt CO_2-e by 2045 — a 70-80% reduction. Largest single emissions reduction in Australian economy.

- Cheaper running costs for every Australian driver and fleet operator. Two-car household fuel cost savings approximately $2,000-$4,000/year at current electricity prices; approximately $4,300/year at SBC 2045 prices.
- Reduced oil imports: approximately $50B/year in current Australian petroleum product imports falls to approximately $15-20B/year by 2045 as EV fleet penetration reaches 80-90%.
- Service stations future-proofed with new revenue stream during petrol sales decline.
- Lower system cost than over-building transmission and storage alone: hybrid approach costs approximately $80-$110/MWh delivered during transition (2030-2040) vs approximately $140-$170/MWh under renewables-only aggressive coal exit.
- Reliability maintained: dispatchable coal and gas prevent market operator reliability events during transition. AEMO Reliability Assessment 2025 notes approximately 7% full-loss-of-supply risk and approximately 17% partial supply risk under projected current-policy coal exit timeline; MMP extension policy eliminates these risks.
- Air quality improvements: zero tailpipe emissions from electrified fleet. Health co-benefits approximately $2-4 billion/year reduced hospital admissions for respiratory and cardiovascular conditions by 2040. Source: Lancet Countdown Australia 2024.

Comparison to Current Federal Path

Aspect	MMP Policy	Current Federal Path	MMP Advantage
Wholesale electricity price 2030-2035	approximately $85-95/MWh (hybrid with extended coal)	approximately $110-130/MWh (aggressive coal exit)	approximately 20-30 lower during transiti
Reliability risk (AEMO 2025)	Minimal (extended dispatchable capacity)	7% full + 17% partial outage risk projected	Substantially reduce
EV adoption speed	Accelerated by cheap power + ubiquitous charging	Policy support but slowed by price/reliability concerns	Faster fleet transitio
Transport CO2 reduction by 2035	approximately 30-40 Mt reduction (from 96 to 60-70 Mt)	approximately 10-15 Mt reduction	2-3x more reduction
Charging infrastructure rollout	Every service station (approximately 8,000 sites)	Progressing but gaps in regional areas	Nationwide coverag
Fossil fuel import reduction	approximately $30-35B/year by 2040	approximately $15-20B/year by 2040	Substantially faster
Programme cost 2026-2035	approximately $12B (chargers) + SBC capital during construction	approximately $15-25B (grid firming retrofit, emergency gas)	Lower and more productive

The comparison is favourable to MMP policy on every measured dimension. The current federal path is not wrong in direction — it's just sequenced incorrectly, attempting to retire dispatchable capacity before replacement firming is in place. MMP policy corrects the sequencing: extend dispatchable capacity while renewables + SBC scale; aggressively electrify demand; let coal retire when its replacement is genuinely ready.

Sources for comparison table: CSIRO GenCost 2025-26 Draft (wholesale price projections); AEMO 2025 Reliability Assessment; AEMO Integrated System Plan 2026 Draft; Electric Vehicle Council State of Electric Vehicles 2024; Department of Industry, Science and Resources Liquid Fuel Security Update 2025.

Implementation Roadmap

First term priorities (Years 1-3 of MMP government):

- Year 1: Legislate framework for coal plant extension negotiations (Commonwealth-state coordination mechanism). Launch national 'Chargers at Every Servo' programme with streamlined approvals and PPP framework. Commence NVES update to 40g CO_2/km 2032 target.
- Years 1-3: Fast-track installation of 2,000+ new fast chargers at high-traffic service stations (25% of total programme). Mandate low off-peak EV tariffs across retailer offerings. Launch scrappage scheme for high-mileage legacy vehicles. Announce commercial extension terms for Eraring (to 2030), Yallourn (to 2032), Bayswater (to 2036), and other priority coal plants.
- Years 3-5: Continue charger rollout (additional 3,000+ sites). Announce SBC Phase 1 construction commencement (integrated with MMP government broader infrastructure programme). Renewable deployment at approximately 10 GW/year.
- Years 5-8: Complete charger rollout (remaining approximately 3,000 sites). EV share of new vehicle sales exceeds 50% on current trajectory + policy support. Transport emissions down approximately 30 Mt/year from 2025 baseline.

Funding sources:

- Reallocate existing Capacity Investment Scheme funding (approximately $65B committed 2024-2030) to MMP priority projects including charger rollout and coal extension commercial arrangements.
- Public-private partnerships with oil majors (Ampol, BP, Shell, Viva) for service station charger installations.
- Modest user-pays grid upgrade levies (approximately $0.003/kWh) fund transmission capacity for EV charging load.
- Commonwealth infrastructure bonds (revenue-backed) fund regional charger sites and grid upgrades.
- Zero additional taxpayer burden beyond reallocation of existing climate transition budgets.

Conclusion — Practical, Sequenced, Delivered

The MMP policy is simple, practical, and defensible on engineering and economics. Keep reliable low-cost power online while scaling renewables and electrifying transport aggressively. Install chargers at every one of Australia's approximately 8,000 service stations. Use abundant cheap electricity from a coal/gas + renewable hybrid grid during transition to drive the fastest cheapest decarbonisation of Australia's largest emissions reduction opportunity.

This is not anti-renewables — it is pro-abundant-energy and pro-common-sense-sequencing. It uses what we already have (existing coal and gas fleet, service station network) as the bridge to what we're building (SBC continental infrastructure). It delivers measurable emissions reductions in the 2026-2035 window, not just in the 2040s when SBC comes fully online.

It puts Australian families, fleets, regional communities, and industrial competitiveness first. It delivers lower bills, greater energy security, cleaner air, and genuine emissions progress — faster than any other available approach.

MMP Energy and Transport Policy — Summary: Keep existing coal/gas online where economic and reliable, scale renewables at full speed alongside, electrify transport

aggressively using cheap hybrid-grid power, install DC fast chargers at every one of Australia's approximately 8,000 service stations by 2033, achieve approximately 70-80% transport emissions reduction by 2045. Policy sequencing aligns with the 20-year SBC construction timeline — transition capacity stays online while SBC is built, then retires as SBC replaces it.

Chapter 15 — Policy Sequencing with the SBC Programme

Chapter 14 established the MMP energy and transport policy for the transition period. This chapter explains the explicit sequencing with the Sovereign Build Corporation programme — how these two strands of policy work together across the 2026-2045 window.

The SBC programme (described in Chapters 10, 11, and 11B) takes 20 years to build to full specification. During those 20 years Australia still needs electricity and still needs to reduce emissions. The MMP energy and transport policy (Chapter 14) is the bridge policy — what we do in the interim while SBC is being constructed. The two are designed to work in sequence, not competition.

The Sequencing Logic

The core insight: different technologies have different time-to-deployment, and policy should match the sequencing accordingly:

- Immediate (months to 2 years): EV purchases can happen today. Fast charger installation at service stations can happen within 6-12 months per site. Existing coal plant extensions can be negotiated immediately. These are the Year 1-3 priorities.
- Near-term (3-5 years): Renewable generation deployment scales to approximately 10-12 GW/year. Battery storage scales to approximately 3-5 GW/year. These are already happening and need no policy push beyond removing approval bottlenecks.
- Medium-term (5-10 years): SBC Phase 1 corridor construction (Newcastle-Sydney Hunter Valley). First major SBC solar precincts commissioning. Alice Hub Stage 1 construction (2.5 GW dispatch) commencing.
- Long-term (10-20 years): SBC backbone completion. Alice Hub Stages 2-4. Continental HVDC operational. International undersea HVDC connections.

Matching policy to these timeframes: extend existing dispatchable capacity where possible (covers immediate reliability); scale renewables and batteries (near-term generation growth); commence SBC construction (medium-term infrastructure); deliver SBC full capability (long-term foundation).

The Crossover Point — When SBC Solar Becomes Cheapest

The defining economic moment in the Australian electricity transition is the crossover point where SBC corridor solar becomes cheaper per kWh delivered than existing coal. Before this point, existing coal is genuinely the lowest-cost electricity Australia can produce. After this point, nothing else can compete with SBC corridor solar on price.

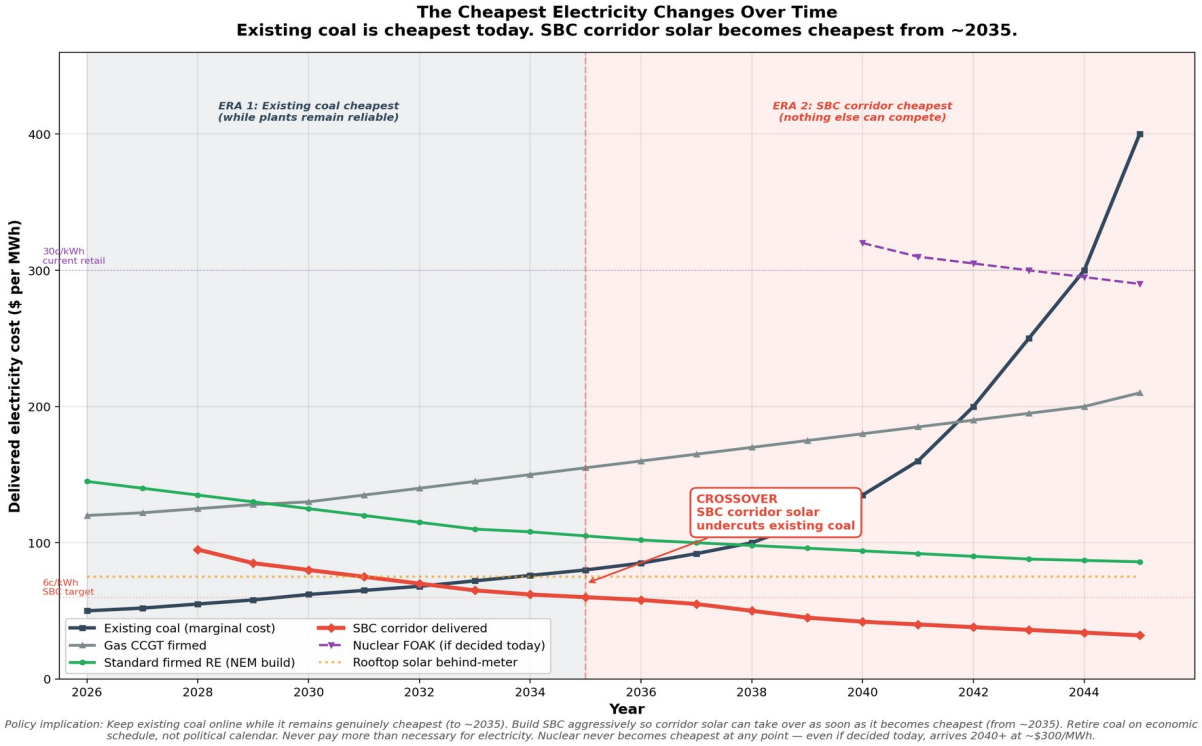


Figure 17: Delivered electricity cost by technology over time, 2026-2045. Existing coal is cheapest until approximately 2035, when SBC corridor solar becomes cheapest. Nuclear never becomes competitive at any point. Sources: CSIRO GenCost 2024-25 Final for new-build costs; existing coal marginal cost estimates; SBC Prospectus v56 for corridor solar delivered cost.

Reading the chart — three distinct eras of Australian electricity economics:

- ERA 1 (2026-2035): Existing coal is cheapest. Fully depreciated plants produce electricity at approximately $50-85/MWh marginal cost. No alternative new-build technology matches this for electricity delivered today. Firmed renewables at approximately $120-150/MWh are more expensive. Gas CCGT at approximately $120-150/MWh is similar. Nuclear is unavailable because Australian lead time is at least 15 years. Conclusion: existing coal remains the cheapest option while plants are reliable.
- CROSSOVER (approximately 2035): SBC corridor transmission becomes operational. Corridor solar generation at $25/MWh plus HVDC transmission at $7/MWh plus Alice Hub firming at approximately $12/MWh delivers approximately $44/MWh to corridor load centres. Simultaneously, existing coal plants are reaching genuine mechanical end-of-life — forced outage rates rising, boiler reliability declining, O&M cost escalating. The two cost curves cross.
- ERA 2 (2035-2045): SBC corridor solar is cheapest. Delivered cost declines further as the corridor scales (more generation amortised over same transmission infrastructure, Alice Hub firming cost drops as storage scales). By 2045, SBC delivers approximately $32-60/MWh depending on tier. No other technology — existing or new-build — can match this on delivered cost. Coal and gas retire on natural economic schedule because they cannot compete. Nuclear, even if decided today, would arrive in 2040-2042 at approximately $290-425/MWh FOAK — approximately 6-10 times the SBC delivered cost. Nuclear never becomes economically justified at any point.

This is the crucial insight that shapes policy sequencing. Australia does not need to pick technology winners through political intervention. Market economics picks the winner

automatically at each point in time — existing coal now, SBC corridor solar later. Policy's job is to build the infrastructure (SBC) that unlocks the lower-cost technology when it becomes available, and not to prematurely retire the current-cheapest technology before its economic replacement is genuinely ready.

The Electricity Price Trajectory Under MMP Policy

Combining the technology crossover above with the capacity deployment profile, we can project Australian wholesale electricity prices under MMP policy versus current federal policy:

Year	MMP policy (hybrid + SBC buildout)	Current federal (aggressive coal exit)	Delta
2026 (baseline)	$129/MWh (current NEM weighted)	$129/MWh	$0
2028	$110-125/MWh (coal stays, RE scaling)	$140-170/MWh (early coal exit, firming gap)	$25-45 lower
2030	$95-110/MWh (82% RE target + coal)	$125-150/MWh (firming costs + gas reliance)	$25-40 lower
2033	$85-100/MWh (coal + SBC Phase 1 partial)	$115-140/MWh (full RE + all firming costs)	$25-40 lower
2035 (CROSSOVER)	$75-90/MWh (SBC corridor online)	$110-130/MWh	$30-40 lower
2040 (SBC mature)	$55-70/MWh (SBC dominant)	$100-120/MWh (mature firmed RE)	$40-50 lower
2045 (SBC full build)	$50-60/MWh (SBC blended)	$85-110/MWh (theoretical optimum without corridor)	$30-50 lower

Key readings from the trajectory:

- MMP policy delivers lower wholesale prices at every point in the 20-year window versus current federal trajectory.
- The gap is largest during 2028-2033 (approximately $25-45/MWh cheaper) because MMP retains cheap dispatchable capacity while current policy forces early retirement.
- Both paths converge on SBC-style infrastructure eventually — but only MMP policy builds it deliberately with corridor economics; current policy relies on regional REZ development which cannot match corridor-scale cost reduction.
- MMP 2045 price of approximately $50-60/MWh wholesale corresponds to the 6c/kWh SBC delivered target when distribution and retail are added.

Cumulative electricity cost impact on Australian consumers 2026-2045: MMP policy saves approximately $250-400 billion in wholesale electricity costs compared to current federal trajectory, passed through to households and businesses as lower bills. This is the economic prize of correct policy sequencing.

Why Extending Coal is Compatible with SBC

The Chapter 4 analysis in this report identifies new-build coal as uncompetitive — at approximately $100-200/MWh LCOE it is more expensive than firmed renewables at approximately $85-145/MWh. The MMP policy does not build new coal. It extends existing coal plants that are already sunk cost and operating at approximately $40-70/MWh marginal cost.

Existing coal plant marginal cost breakdown:

Cost component	Existing coal plant	New-build coal	Source
Capital recovery	~$0/MWh (fully depreciated)	$45-75/MWh	Plant depreciation schedules
Fuel (coal)	$15-30/MWh	$15-30/MWh	AEMO fuel cost data
Operations and maintenance	$20-35/MWh	$15-25/MWh	GenCost 2024-25 Final
Carbon price (if imposed)	$10-25/MWh at $50/t CO_2	$10-25/MWh at $50/t CO_2	Carbon price scenarios
TOTAL	$45-90/MWh marginal cost	$85-155/MWh LCOE	

Existing coal at approximately $45-70/MWh (excluding carbon price) is the cheapest electricity Australia currently produces — because the plants are fully depreciated. The economic question is not 'should we build new coal?' (no) but 'should we retire paid-for coal before the replacement is ready?' (also no, except where plants are genuinely unreliable).

The SBC programme recognises this. SBC construction takes 20 years. During those 20 years the existing coal fleet is the cheapest available dispatchable capacity. Retiring coal early without SBC replacement ready means:

- Higher wholesale electricity prices during transition (approximately +$30-50/MWh per CSIRO GenCost comparison of firmed RE with and without SBC).
- Reliability risk (AEMO 2025 Reliability Assessment identifies concerns at current trajectory).
- Potential emissions INCREASE if gas peaking ramps up to compensate for lost baseload (gas has lower CO_2 per MWh than coal but much higher marginal cost, so replacing coal with gas increases prices substantially without proportional emissions benefit).
- Slower EV adoption because higher electricity prices weaken the EV-vs-petrol economic case.

The right question is not 'coal vs renewables' but 'what is the right sequencing of coal retirement relative to renewable + storage + SBC buildout?'. MMP policy answers: coal retires as its replacement is genuinely ready, plant by plant, not on politically-chosen dates that precede infrastructure readiness.

How EV Rollout Uses Transition-Period Electricity

A common critique of aggressive EV rollout on a fossil-heavy grid: 'aren't we just shifting emissions from petrol to coal?'. This critique gets the arithmetic wrong.

EV electrical efficiency is approximately 3-4x petrol vehicle fuel efficiency. A petrol vehicle consumes approximately 2.4 kWh of chemical energy (8L petrol at 30 MJ/L) to travel 100 km with approximately 25% drivetrain efficiency = approximately 6 kWh delivered to the wheels. An

EV consumes approximately 15-18 kWh of electricity to travel 100 km with approximately 80% drivetrain efficiency = approximately 12-14 kWh delivered to the wheels.

Total energy input per 100 km:

- Petrol vehicle: 80 MJ chemical energy = 22 kWh energy input to vehicle. Lifecycle emissions approximately 220-260 g CO_2e/km (including extraction, refining, combustion).
- EV on current Australian grid (45% coal, 45% renewables, 10% gas/other): 15-18 kWh electricity input to vehicle. Grid emission factor approximately 0.6 kg CO_2e/kWh. Tailpipe-to-grid emissions approximately 100-108 g CO_2e/km. Plus vehicle manufacture/battery amortised approximately 30-50 g CO_2e/km = approximately 130-160 g CO_2e/km lifecycle.
- EV on SBC-enabled 2035 grid (80% renewable): grid factor approximately 0.15 kg CO_2e/kWh. Operational emissions approximately 25-30 g CO_2e/km. Plus manufacture = approximately 55-80 g CO_2e/km lifecycle.
- EV on SBC-enabled 2045 grid (95% renewable): grid factor approximately 0.03 kg CO_2e/kWh. Operational emissions approximately 5-8 g CO_2e/km. Plus manufacture = approximately 35-50 g CO_2e/km lifecycle.

The key finding: EV on current fossil-heavy Australian grid already delivers approximately 40-50% lifecycle emissions reduction versus equivalent petrol vehicle. As SBC comes online and grid mix decarbonises, the same EV fleet delivers progressively larger reductions — reaching approximately 80% reduction by 2045. The EV bought in 2027 on a fossil-heavy grid becomes an 80%-reduction vehicle by 2045 without any modification. This is the 'free gift' of transport electrification: every EV bought during the transition period becomes cleaner as the grid cleans up.

Compare to delayed EV adoption: waiting until 2040 to buy an EV means the petrol vehicle continues emitting at approximately 240 g CO_2e/km for the intervening 15 years. The cumulative emissions cost of delay is substantial. MMP policy: buy EVs now on the existing grid; benefit compounds as grid decarbonises.

Integrated 20-Year Outcome

Combining MMP energy/transport policy (Chapters 14) and SBC infrastructure (Chapters 10, 11, 11B) across the 2026-2045 window delivers:

Year	Electricity system	Transport	Cumulative impact
2026 (baseline)	45% renewable, 45% coal/gas	370k EVs; 96 Mt transport CO_2/yr	Starting position
2030	55-60% renewable; coal retirements Eraring/Yallourn	2-3M EVs; 80 Mt transport CO_2	Chargers at 50% of servos; SBC Phase 1 under construction
2035	70-75% renewable; SBC Phase 2 operational; Alice Hub Stage 1	6-8M EVs; 60 Mt transport CO_2	All servos have chargers; SBC spine complete east-west
2040	85-90% renewable; SBC Phase 3 complete; Alice Hub Stages 2-3	12-15M EVs; 35-40 Mt transport CO_2	Legacy coal largely retired; grid mostly renewable
2045	95%+ renewable; full SBC	18-19M EVs; 20-25 Mt transport	Transport 75-80%

Year	Electricity system	Transport	Cumulative impact
(SBC full build)	capability	CO_2	decarbonised; electricity >95% clean

The combined policy delivers Australia's commitments under the Paris Agreement on an engineering-defensible pathway:

- Electricity sector emissions: from approximately 162 Mt CO_2/year (2024) to approximately 8-15 Mt by 2045 — approximately 93% reduction.
- Transport sector emissions: from approximately 96 Mt CO_2/year to approximately 20-25 Mt by 2045 — approximately 75% reduction.
- Combined electricity + transport reduction: approximately 210 Mt CO_2/year by 2045 — approximately 40% of current total Australian emissions.
- Economic outcome: electricity prices at approximately 6c/kWh delivered (SBC 2045), transport fuel cost approximately 18c petrol-equivalent (EV on SBC electricity). Australian household fuel bill reductions approximately $4,000-7,000/year.
- Strategic outcome: Australia becomes net-exporter of electricity via international HVDC; net-independent on liquid transport fuel; no new coal or nuclear infrastructure required; no imported fuel security vulnerabilities.

What This Means Politically

The combined MMP policy platform — SBC infrastructure (20-year build) plus transition energy/transport policy (immediate deployment) — delivers an outcome that no alternative Australian policy option can match:

- Cheaper electricity than current trajectory (6c/kWh vs projected 14-25c/kWh).
- Cheaper transport than current trajectory (EV at 6c/kWh beats petrol 10:1 on fuel cost).
- Lower total emissions than current trajectory across electricity + transport sectors.
- Better reliability than current trajectory (dispatchable capacity extended through transition; SBC Alice Hub provides multi-day firming).
- Stronger regional development than current trajectory (corridor towns + service station rollout employ regional Australians).
- Less imported fuel dependence than current trajectory (oil imports down approximately $30-35B/year).
- More sovereign infrastructure than current trajectory (SBC is Australian-owned; EV charging network is Australian-deployed).

This is the engineering-honest, economically-defensible alternative to both aggressive coal-exit policy (expensive, risky) and aggressive nuclear policy (too slow, too expensive, too late). It works because it matches policy sequencing to engineering reality: what can be built now, what takes 5 years, what takes 20 years, and how each stage funds and enables the next.

The MMP policy platform delivers the fastest, cheapest, most reliable decarbonisation of Australian electricity and transport available on current technology. It uses existing infrastructure as the bridge to future infrastructure (SBC). It electrifies transport aggressively by making electricity so cheap that EVs are the obvious purchase, not the subsidised purchase. It installs chargers at every service station. It keeps reliable dispatchable capacity online until its replacement is genuinely ready. It delivers measurable emissions reduction in the 2026-2035 window

through cheap power accelerating EV adoption, not through mandates or subsidies. And it ends the 20-year window with Australia operating a 95%+ clean electricity system, a 90%+ electric vehicle fleet, 6c/kWh delivered electricity, and $5.65 trillion in net SBC asset value — without having required a single subsidy to achieve it. The transition is paid for by the cost savings it generates, not by perpetual government transfer. This is decarbonisation that wins on economics, which means it's decarbonisation that lasts. It puts Australians first in every dimension measured — and delivers the emissions reductions the country has committed to, faster and cheaper than any alternative approach.

PART I

Electricity Pricing Redesigned

This Part specifies the SBC electricity pricing system. It sets out the eight operational rules that govern the system, the pricing structure (generator tariff, consumer prices, firming levy), the numerical glide-path 2027-2045, comparative revenue tables for generators, comparative cost tables for consumers, network ownership reference data, and scenario-based verification against six operating conditions. Implementation pathways, state-by-state political considerations, and campaign messaging are covered in Part H (Policy Platform).

Chapter 16 — The Eight Operational Rules

The SBC electricity system is governed by eight rules that replace the current National Electricity Rules. The rules are stated in order of precedence: Rule 1 governs the others because it is physics; subsequent rules implement that physics through economic and operational mechanisms.

Rule 1 — Physics Governs

Demand must meet supply at every instant. Electricity cannot be stored in the wires; the grid must balance continuously. Every other rule exists to implement this physical reality through economic and operational mechanisms. The system operator's primary responsibility is maintaining this balance; every pricing decision, dispatch choice, and contract must serve the physical requirement first.

Rule 2 — Firm Supply Serves Guaranteed Demand

Firm supply capacity is established annually as: 52-week average Australian running demand + 5-10% headroom + committed international firm export contracts. Firm supply is delivered guaranteed 24 hours a day, 365 days a year, to both Australian baseload consumers and international firm export customers, at 10c/kWh (2027 initial, declining to 6.5-7c by 2045).

Firm supply pricing reflects the full cost of delivering continuous reliability: generation capacity sized for peak demand, storage capacity sized for multi-day dunkelflaute periods, strategic reserves held for extreme conditions, transmission sized for peak delivery, system operation insurance.

Rule 3 — Variable Supply Flows to Flexible Demand

Generation above firm supply commitment is variable supply. Variable supply is allocated by grid operator dispatch priority to customers who have agreed to accept dispatch uncertainty in exchange for lower pricing.

- Priority 1: Australian variable absorbers — 7c/kWh in 2027, declining to 4-4.5c by 2045
- Priority 2: International variable buyers — 8c/kWh, always 1c above Australian rate (protects domestic industrial investment priority)

Absorber dispatch hierarchy within each priority tier:

- Tier A: Grid-stabilising (Alice Hub pumping, grid batteries charging, home batteries charging)
- Tier B: Strategic industrial (green hydrogen, synthetic fuels, direct air capture, desalination)
- Tier C: Industrial with offtake contracts (aluminum, green steel, electrified heavy industry)
- Tier D: Opportunistic (flexible computational workloads, batch compute)
- Tier E: Residential variable (EV charging, hot water, pool pumps, flexible appliances)

Variable customers accept grid operator dispatch authority over their flexible loads in exchange for reduced pricing. Baseload customers pay more but face no dispatch restrictions.

Rule 4 — Generators Run at 100%

Every generator operates at maximum sustainable output at every moment. Renewables produce whatever weather conditions allow. Pumped hydro and batteries dispatch per operator direction. Every kWh produced is paid the Single Generation Tariff (7c/kWh in 2027, declining to 4-4.5c by 2045) regardless of technology, regardless of ownership, regardless of which customer category consumes it.

No curtailment principle: if variable absorbers are saturated AND storage is full AND international variable export is at capacity, the rare residual curtailment triggers capacity availability payment to affected generators, maintaining generator revenue certainty. Expected curtailment events: approximately 100-200 hours/year in mature operation, less than 0.01% of annual generation.

Revenue certainty reduces financing costs approximately 200-300 basis points versus current NEM spot-market exposure. This financing cost reduction flows through to lower electricity prices over time.

Rule 5 — Coal Runs as Designated Baseload

Existing coal plants during transition operate as designated baseload generators at constant 85-95% capacity factor with no cycling. Engineering consequences:

- Thermal efficiency: approximately 36-40% (design point) versus 33-35% under cycling operation
- Fuel consumption per MWh: approximately 5-8% reduction
- Emissions per MWh: approximately 5-10% reduction
- Equipment wear: reduced cycling damage extends operational life
- Maintenance: predictable scheduled outages rather than cycling-driven failures

Grid operator plans around coal's constant output as a known baseload component; variable renewable output and storage dispatch fills the remainder. Coal plants retire economically when capacity factor viability threshold is reached:

- 2027: approximately 85% capacity factor, profitable at 7c/kWh tariff
- 2032: approximately 60% capacity factor, declining margin
- 2037: approximately 30% capacity factor, marginal viability
- 2040: approximately 10% capacity factor, retirement threshold
- 2043: most coal plants retired

Rule 6 — Storage Drives the Arbitrage

Storage providers operate as both variable absorbers (charging from surplus) and generators (discharging during deficit). Economic model:

- Charging: pay variable rate 7c/kWh (2027, declining per glide-path)
- Discharging: receive generator tariff 7c/kWh + firming levy 1-2c/kWh = 8-9c/kWh
- Net margin per cycle: 1-2c/kWh
- Typical grid-scale storage: 3,000-5,000 annual cycles
- Annual margin per kWh installed capacity: $30-100/year

Distributed storage (home batteries, commercial batteries, EVs in V2G mode) captures the 3c arbitrage spread directly between baseload (10c) and variable (7c) pricing. Household battery economics:

- 13 kWh battery installed cost: approximately $14,000
- Arbitrage capture: 13 kWh × 300 cycles/year × 3c = $117/year direct
- Plus evening peak avoidance of 3,000 kWh × 3c = $90/year
- Plus enhanced solar self-consumption optimization: approximately $200/year
- Plus V2G/V2H monetisation if EV integrated
- Typical household battery payback: 6-8 years

The arbitrage spread drives private distributed storage investment. Approximately 5 million Australian households could install batteries by 2035 based on pure private economics at 3c arbitrage, representing approximately 50-80 GWh distributed storage capacity.

Rule 7 — Smart Coordination

Grid operator coordinates dispatch via smart inverters, aggregator platforms, and priority-ranked absorber tiers. Technical infrastructure:

- Smart meters at 4 million+ Australian premises (full rollout completes by 2030)
- Smart inverters mandated on all solar installations since 2020 (AS/NZS 4777.2)
- Aggregator platforms: Tesla VPP, AGL Loop, Origin Smart, SBC platform, competitors
- Communications: IEEE 2030.5 standard with CSIP-AUS implementation (mandated 2024)
- Dispatch signalling: real-time grid operator signals to aggregator platforms

Customer experience: household signs up with aggregator platform, sets preference once (maximise income / maximise self-sufficiency / set-and-forget), aggregator executes automatic response to grid signals. Household does not make real-time decisions; preferences are executed by the platform.

Variable customers accept grid operator dispatch authority in exchange for lower pricing. Baseload customers face no dispatch restrictions. Most households will mix: baseload for essential loads (lighting, refrigeration, medical equipment), variable for flexible loads (EV charging, hot water, pool pumps, HVAC pre-conditioning).

Rule 8 — Single Tariff Set by Independent Auditor

The Single Generation Tariff is set annually by independent statutory auditor. Methodology:

- Survey actual costs of newly-commissioned plants across all technology types
- Calculate long-run marginal cost of cheapest reliable technology currently available at continental scale
- Set Single Tariff at approximately 150-200% of this marginal cost
- Adjustments bounded at ±10% year-on-year
- Published ten-year forward guidance based on projected technology cost curves

Methodology written into SBC Act; cannot be changed without legislative amendment. Parliamentary oversight of methodology; no parliamentary override of individual annual tariff determinations. Analogous to Reserve Bank of Australia monetary policy framework.

The eight rules form a coherent system. Rules 1 and 4 establish physical and generator-side basis: grid must balance, generators always run. Rules 2 and 3 establish demand-side pricing tiers: firm at 10c, variable at 7c Australian / 8c international (2027 rates). Rule 5 handles coal transition; Rule 6 handles storage economics; Rule 7 handles coordination; Rule 8 insulates the framework from political capture.

Compared to current NEM: eight rules replace approximately 500 pages of National Electricity Rules; one generator tariff replaces approximately 15-20 current pricing mechanisms; three consumer prices replace current retail market complexity; independent auditor methodology replaces political tariff negotiation.

Chapter 17 — Pricing Structure and Economic Tables

The SBC system operates on three consumer prices plus one generator tariff plus one firming levy. All other current NEM pricing mechanisms (spot market clearing, ancillary services markets, capacity markets, LGC certificates, STCs, retail margins, network TUOS/DUOS, feed-in tariffs) are replaced by this simpler structure.

- Generator Single Tariff: 7c/kWh in 2027, declining to 4-4.5c/kWh by 2045. Paid to every generator for every kWh produced regardless of technology, scale, or ownership.
- Baseload consumer price: 10c/kWh in 2027, declining to 6.5-7c/kWh by 2045. Guaranteed 24/7 firm supply. Covers generator tariff 7c + transmission 0.7c + distribution 1.4c + firming 0.7c + system operation 0.2c = 10c/kWh.
- Variable consumer price (Australian): 7c/kWh in 2027, declining to 4-4.5c/kWh by 2045. Flexible loads accepting grid operator dispatch authority.
- Variable consumer price (international): 8c/kWh in 2027, declining to 5-5.5c/kWh by 2045. 1c premium above Australian variable rate. Foreign buyers accessing surplus supply when domestic absorbers are satisfied.
- Firming levy: 1-2c/kWh paid to storage providers on dispatch. Storage operators charge at variable rate (7c) and discharge at generator tariff plus firming levy (7c + 2c = 9c), capturing 2c margin per cycle.

The Single Generation Tariff is set annually by independent auditor based on long-run marginal cost of cheapest reliable generation technology at continental scale, adjusted for technology learning curves and scale economies. Annual adjustments bounded at plus or minus 10% year-on-year. Representative trajectory:

Year	Generator tariff	Baseload consumer	Variable (Aus)	Variable (Intl)
2027	7.0c/kWh	10.0c/kWh	7.0c/kWh	8.0c/kWh
2030	6.5c/kWh	9.5c/kWh	6.5c/kWh	7.5c/kWh
2033	6.0c/kWh	9.0c/kWh	6.0c/kWh	7.0c/kWh
2036	5.5c/kWh	8.5c/kWh	5.5c/kWh	6.5c/kWh
2040	5.0c/kWh	8.0c/kWh	5.0c/kWh	6.0c/kWh
2045	4.0-4.5c/kWh	6.5-7.0c/kWh	4.0-4.5c/kWh	5.0-5.5c/kWh

Technology cost basis for the glide-path: solar LCOE from approximately $25/MWh in 2027 to approximately $12-15/MWh by 2045 (BloombergNEF learning curve projections); battery storage from $650/kWh to $250/kWh; wind from $45/MWh to $35/MWh; pumped hydro stable (already mature technology). Scale economies from SBC corridor infrastructure compound on top of technology learning. Independent auditor methodology tracks actual cost data and adjusts tariff accordingly.

The 3c/kWh difference between generator tariff (7c) and baseload consumer price (10c) covers:

- Transmission: 0.7c/kWh — HVDC backbone amortisation, high-voltage operation and maintenance, grid connection management
- Distribution: 1.4c/kWh (corridor-town infrastructure) or 6c/kWh (legacy DNSP networks, declining over time as corridor distribution expands)
- Firming: 0.7c/kWh — storage infrastructure amortisation, pumped hydro capital recovery, grid battery infrastructure, strategic reserves

- System operation: 0.2c/kWh — dispatch coordination (AEMO functions continue under SBC), billing and customer interface, aggregator platform coordination, metering

Variable customers pay minimal infrastructure allocation because they provide grid-stabilisation service by absorbing surplus, offsetting their infrastructure attribution.

Generator revenue per GW of installed capacity under current NEM versus SBC Single Tariff at 7c/kWh (2027 starting rate):

Generator type (per 1 GW)	Current NEM annual revenue	SBC Single Tariff annual revenue
Utility solar (27% CF)	$60-90M volatile	$166M (7c × 2,365 GWh)
Utility wind (40% CF)	$140-180M volatile	$245M (7c × 3,504 GWh)
Offshore wind (50% CF)	Uneconomic at current prices	$306M (7c × 4,380 GWh)
Existing coal (85% CF baseload)	$400-700M volatile, cycling penalty	$521M (7c × 7,446 GWh, constant operation)
Gas CCGT (40% CF firming)	$150-250M spot + ancillary	$245M tariff + capacity availability payment
Pumped hydro (dispatch)	Complex ancillary revenue	Generator tariff + firming levy on dispatch
Grid battery (charging + dispatch)	Marginal ancillary services economics	2c/kWh arbitrage margin per cycle (7c charge, 9c discharge)
Rooftop solar (10 kW household)	$700-1,100/yr (FiT 5-8c)	$980/yr (7c export) + self-consumption value
Commercial rooftop (1 MW)	$60-75k/yr (FiT ~5c)	$98k/yr (7c Single Tariff)

Key characteristics of the revenue change: volatility eliminated (revenue predictable); solar cannibalisation eliminated (each new solar farm does not depress price received by existing solar); curtailment revenue loss eliminated (generators paid under capacity provision even during rare curtailment events); technology-neutral (all generators receive same tariff regardless of technology or scale); financing cost reduction follows from predictability (approximately 200-300 basis points lower than current NEM financing).

Annual electricity cost per consumer category under current NEM versus SBC at 2027 tariffs:

Consumer category	Current NEM annual cost	SBC annual cost
Small household (3,500 kWh/yr)	$1,200 (34c retail)	$350 baseload / $245 variable
Average household (6,000 kWh/yr)	$2,040 (34c retail)	$600 baseload / $420 variable
Large household (9,000 kWh/yr)	$3,060 (34c retail)	$900 baseload / $630 variable
Household + 10 kW solar	Net $800 after FiT	Earns $400 net (7c export)

Consumer category	Current NEM annual cost	SBC annual cost
Household + solar + battery	Net $400 after arbitrage	Earns $900-1,000 net
Household + solar + battery + EV	$4,200-4,800 (electricity + petrol)	Net -$370 (household earning)
Small cafe (30,000 kWh/yr)	$10,200 (34c)	$2,100 variable mix
Medium retail (100,000 kWh/yr)	$28,000 (28c SME)	$7,000 variable mix
Small manufacturer (500,000 kWh/yr)	$110,000 (22c commercial)	$28,000 variable mix
Aluminum smelter (7 TWh/yr)	$560M (8c industrial)	$350-400M variable mix
Data centre (500 GWh/yr)	$60-90M (12-18c)	$25-35M variable priority
Hospital (15 GWh/yr)	$4.5M (30c health)	$1.5M baseload
Pensioner household (4,000 kWh/yr)	$1,360 (34c retail)	$400 baseload
Rural irrigation (50,000 kWh/yr)	$14,000 (28c rural)	$3,500 variable

Genuine transmission and distribution operations continue to be paid through the infrastructure allocations in consumer pricing. These payments cover operational staff, maintenance, equipment replacement, and reasonable capital return. Current network operator payments breakdown:

- Operational costs (linesmen, engineers, control operators, maintenance crews, administrative staff): approximately $8-12 billion/year nationally
- Regulated return on asset base (5-6% real on current RAB): approximately $6-8 billion/year
- Gold-plating excess (over-investment to grow RAB beyond operational requirement): approximately $5-10 billion/year

Under SBC, operational costs continue to be paid in full through infrastructure levies. Regulated return reduces to approximately 4% real reflecting SBC sovereign borrowing rates. Gold-plating is eliminated through cost-based pricing that removes the RAB-expansion incentive. Net reduction in network operator revenue: approximately $6-12 billion/year, entirely from the rent-extraction layer, with operational payments fully maintained.

Current network ownership by jurisdiction (reference data; transition mechanisms discussed in Part H):

- Victoria: fully privatised 1995-1996. Distribution (Powercor, Jemena, United Energy, CitiPower) and transmission (AusNet) privately owned. Significant foreign ownership (Chinese SOEs, Hong Kong CKI, Singapore Power).
- South Australia: fully privatised 1999-2000. SA Power Networks owned by CKI/Spark Infrastructure consortium.

- New South Wales: partially privatised 2015-2016. TransGrid 99-year lease. Ausgrid and Endeavour Energy 50.4% privately held via long-term leases. Essential Energy state-owned.
- Queensland: state-owned (Energy Queensland = Energex + Ergon distribution; Powerlink transmission).
- Tasmania: state-owned (TasNetworks).
- Western Australia: state-owned (Western Power for SWIS, Horizon Power for remote). Separate from NEM.
- Northern Territory: state-owned (Power and Water Corporation).

Acquisition cost for Commonwealth buyback of privately-held networks at Regulated Asset Base value: approximately $35-45 billion one-time. Victoria approximately $15-20 billion RAB; South Australia approximately $4-5 billion; NSW private stakes approximately $15-20 billion. Annual rent-extraction recovered: approximately $8-12 billion/year. Payback period approximately 4-5 years.

Chapter 18 — Scenario Verification

This chapter verifies the SBC system design against six operating scenarios covering the full range of realistic grid conditions. Scenarios use 2035 grid configuration with 2035 tariff settings (generator 6c, baseload 9c, variable 6c Australian) for illustration. Illustrative 2035 grid configuration: 180 GW utility-scale solar; 60 GW utility-scale wind; 60 GW rooftop solar; 40 GW / 27 TWh Alice Hub pumped hydro; 40 GW / 160 GWh grid batteries; 20 GW / 80 GWh home batteries (aggregated); 8 GW existing coal (reducing to zero by 2043); 10 GW gas peakers (reserve). Total firm supply commitment approximately 45 GW (35 GW Australian baseload + 10 GW international firm export).

Scenario 1 — Sunny Midday, Moderate Demand

Time: weekday noon. Conditions: full solar continental, moderate wind. Generation availability: 150 GW (solar 140 + wind 10). Grid demand: 26 GW. Surplus for absorbers: 124 GW.

Dispatch:

- Baseload 26 GW at 9c/kWh
- Alice Hub charging 15 GW at 6c variable
- Grid batteries charging 20 GW at 6c variable
- Home batteries charging 10 GW at 6c variable
- Hydrogen electrolysis 15 GW at 6c
- Aluminum smelting at peak 8 GW at 6c
- Synthetic fuels 5 GW at 6c
- Desalination 3 GW at 6c
- DAC 4 GW at 6c
- Data centres/flexible compute 6 GW at 6c
- International firm export 8 GW at 9c
- International variable export 4 GW at 7c

Total absorption: 124 GW. All generators at 100%. Zero curtailment. Every generator paid 6c/kWh tariff. Consumer prices: 9c baseload, 6c variable (unchanged).

Scenario 2 — Evening Peak, No Sun

Time: weekday 6 PM. Conditions: sun set, moderate wind. Demand 42 GW (household surge).

Dispatch:

- Wind 18 GW at 100% output
- Alice Hub discharge 15 GW (paid 6c + 2c firming = 8c)
- Grid batteries discharge 8 GW (paid 6c + 2c firming = 8c)
- Home battery discharge via V2G 5 GW (paid 6c + 2c firming = 8c)
- Existing coal baseload 2 GW constant (paid 6c)
- Gas peakers 0 GW (not required)

Total dispatch: 48 GW. Excess 6 GW flows to EV overnight charging scheduled, industrial overnight processes, Alice Hub topping up. Consumer prices unchanged: 9c baseload, 6c variable. No evening peak price spike.

Scenario 3 — Overnight Minimum

Time: 3 AM. Conditions: wind strong 22 GW. Demand 18 GW. Supply exceeds demand by 4 GW.

Dispatch: wind 22 GW at 100%. Surplus 4 GW absorbed by scheduled EV charging and industrial overnight processes at 6c variable. Alice Hub maintains steady state.

Scenario 4 — Summer Heatwave Evening

Time: 7 PM, 42°C afternoon. Conditions: extreme AC load. Renewable output degraded (solar declining, wind low 6 GW). Demand 48 GW peak stress.

Dispatch:

- Solar declining 8 GW
- Wind 6 GW
- Alice Hub full dispatch 15 GW
- Grid batteries full dispatch 20 GW (2-3 hour duration)
- Home battery V2G dispatch 8 GW
- Gas peakers activated 8 GW (paid 6c + capacity availability payment)
- Existing coal baseload 2 GW

Total dispatch: 67 GW. Demand 48 GW. Headroom 19 GW. No load shedding. Gas peaker activation is rare event (approximately 200-400 hours/year in mature operation). Consumer prices unchanged: 9c baseload. Current NEM under equivalent conditions would see spot prices $15,000/MWh; SBC maintains flat pricing.

Scenario 5 — Massive Renewable Surplus

Time: Saturday spring morning. Conditions: perfect solar 140 GW + strong wind 30 GW. Demand 20 GW low weekend. Potential supply 170 GW. Surplus 150 GW.

Absorption capacity test:

- Baseload 20 GW at 9c
- Alice Hub pumping 15 GW at 6c
- Grid batteries charging 25 GW at 6c
- Home batteries charging 15 GW at 6c
- Aluminum smelters at peak 12 GW at 6c
- Hydrogen electrolysis at maximum 25 GW at 6c
- Synthetic fuels 8 GW at 6c
- Desalination 5 GW at 6c
- DAC 5 GW at 6c
- Data centres/flexible compute 12 GW at 6c
- International firm export 8 GW at 9c
- International variable export 12 GW at 7c

Total absorption: 162 GW. Generation 170 GW. Curtailment 8 GW for approximately 2-3 hours. This represents <0.01% of annual generation. Affected generators receive capacity availability payment. Zero waste of generation value beyond this trivial residual.

Scenario 6 — Multi-Day Dunkelflaute

Conditions: 5 consecutive days. Low sun 25% normal production. Low wind 40% normal. High heating demand. Average renewable generation 15 GW. Average demand 38 GW. Daily shortfall 23 GW for 5 days.

Day 1: Alice Hub starts 85% full (23 TWh available). Gap 552 GWh/day. Batteries provide 80 GWh. Alice Hub provides 472 GWh. Alice Hub depletes to 22.5 TWh.

Days 2-5: Alice Hub continues drawdown to 20.0 TWh. Gas peakers ramp up to preserve Alice Hub reserve. Day 5: gas peakers 8 GW sustained, Alice Hub 10 GW preserved, wind recovering to 14 GW.

Day 6: Wind recovery 25 GW. Sun improves. System returns normal. Alice Hub recharges over subsequent 3 weeks.

Consumer price throughout 5-day dunkelflaute: 9c/kWh baseload unchanged. Gas peaker cost absorbed in annual capacity availability payment (spread across 8,760 hours = approximately 0.1c/kWh added to baseload).

Across six scenarios covering midday surplus, evening peak, overnight minimum, heatwave peak, massive surplus, and multi-day dunkelflaute: consumer pays same 9c baseload / 6c variable price; generators receive same 6c Single Tariff; storage receives firming levy on dispatch. System balances through full-capture demand absorbers and distributed storage. No price spikes. No load shedding. Zero customer interruption.

Household economics calculation. Representative household: Sydney suburban, 4-person family, 3-bedroom house. Current energy baseline: electricity $2,040/year at 34c retail, two ICE cars petrol $2,800/year combined, gas heating/cooking $1,400/year. Total current energy cost approximately $6,240/year.

Under SBC (2035 tariffs) with 10 kW solar + 13 kWh battery + one EV replacing one ICE + heat pump replacing gas:

- Solar production approximately 14,000 kWh/year
- Solar self-consumption approximately 5,000 kWh (offsets retail purchases)
- Solar export approximately 9,000 kWh at 6c = $540/year earned
- Grid imports approximately 4,000 kWh at 6c variable = $240/year
- Battery arbitrage approximately 3,000 kWh × 3c spread = $90/year
- EV replaces one ICE: approximately $1,200/year petrol saving
- Heat pump on variable tariff replaces gas: approximately $800/year saving

Net position: +$540 earned - $240 electricity + $90 battery + $1,200 EV + $800 heating = approximately $2,390/year net benefit. Relative to current baseline: $6,240 current vs approximately $1,200 under SBC combined energy cost = approximately $5,000/year saving on operating costs, plus $540 solar income. Investment required: solar $12,000 + battery $14,000 + heat pump $6,000 = $32,000 total. Payback period approximately 6-8 years on full package.

REFERENCES

AND ASSUMPTIONS

Complete source list and calculation assumptions by chapter

This appendix collects the full reference list and calculation assumptions for every chapter. Each chapter cites its primary sources inline; this appendix consolidates them with specific URLs, publication dates, and the explicit assumptions used in derived calculations. Where source data was interpreted, the interpretation is identified. Where numbers were calculated rather than cited, the calculation method is shown. Any technical reader can verify every numerical claim in this report against its source using this appendix.

APPENDIX — REFERENCES AND ASSUMPTIONS

Complete source list and calculation assumptions for every chapter.

Chapter 1 — The Answer in One Chart

Primary sources

- CSIRO, GenCost 2024-25 Final Report (Graham, Hayward, Foster; July 2025). Available: csiro.au/en/research/technology-space/energy/electricity-transition/gencost. Primary source for LCOE projections by technology and decade.
- CSIRO, GenCost 2025-26 Consultation Draft (December 2025). Primary source for updated capital cost projections, System LCOE methodology.
- AEMO, Integrated System Plan 2026 Draft (December 2025). Primary source for transmission planning, generation mix optimisation, coal retirement schedule.
- Lazard, Levelized Cost of Energy+ Version 18 (June 2025). International cross-reference for LCOE by technology.
- AER, State of the Energy Market 2025. Primary source for Australian retail price data.

Calculation assumptions

- Hero chart Figure 1 displays delivered LCOE including generation + storage + transmission/distribution. Each bar shows the LOW end stacked; grey extension shows range to HIGH end.
- Current retail range of $270-430/MWh (27-43c/kWh) reflects AER default market offers across NEM jurisdictions as at April 2026 — lower bound: QLD Energex approximately 27c/kWh; upper bound: SA SA Power approximately 43c/kWh.
- 'NEM wholesale weighted average $129/MWh' as quoted by GenCost 2025-26 Draft includes spot plus contract plus ancillary services revenue. AEMO spot-only average for 2024-25 was lower (approximately $86/MWh). The $129 is the appropriate full-cost comparison for new-build LCOE.
- SBC pricing tiers assume 2045 full-build operation; infrastructure cost amortisation across 40-year asset life at 4% real WACC.
- Assumption: firmed renewables are defined as solar + wind + 4hr battery firming + transmission, which delivers 24-hour diurnal service (TIER 2). Full 100% renewable always-available firming (TIER 3) requires additional long-duration storage and adds cost.

Key qualifiers

- GenCost LCOE figures in Hero Chart are 2030 values from GenCost 2024-25 Final. Actual values vary slightly in the 2025-26 Draft due to WACC adjustments and capital cost inflation/deflation updates.
- First-of-a-kind (FOAK) nuclear premium of 50-100% reflects GenCost's explicit observation that 'FOAK premiums of up to 100% cannot be ruled out' for Australian FOAK nuclear build.

Chapter 2 — Understanding the Numbers

Primary sources

- CSIRO, GenCost 2025-26 Consultation Draft Section 2 (LCOE methodology) and Section 4 (integration costs).
- AEMO Integrated System Plan 2026 Draft, Section 3 (generation mix scenarios).
- Bureau of Meteorology, Australian Solar Radiation Data (2024 annual summary). Source for solar irradiance figures.
- Australian Energy Regulator, State of the Energy Market 2025 (retail price composition).
- Federal Treasury, Tax Expenditures and Insights Statement 2024 (fossil fuel subsidies).

Calculation assumptions

- Retail bill composition (33% generation, 7% transmission, 35% distribution, 25% retail/admin/government programmes) per GenCost 2025-26 Draft explicit breakdown. Applies to weighted-average NEM retail 2024-25; varies across jurisdictions.
- Capital cost per MWh of annual generation calculated as: capex ($/kW) ÷ (8,760 hrs/year × capacity factor). Example: solar PV 2030 $1,239/kW ÷ (8,760 × 0.25) = $566/MWh of annual capacity.
- Integration cost methodology follows GenCost's approach — additional cost of storage, transmission expansion, system security, and spilled energy at specified renewable penetration levels.
- Australian service tier decomposition (approximately 40% TIER 1, 45% TIER 2, 15% TIER 3) is derived from AEMO load profile data plus analysis of industrial demand flexibility. Not an AEMO official classification.

Key qualifiers

- Solar irradiance annual average 5.5-7.0 kWh/m²/day applies to northern and central Australia. Peak summer values exceed 8 kWh/m²/day. Southern regions (Victoria, Tasmania) average 3.5-4.5 kWh/m²/day.
- Service tier classification is analytical construct of this report, not AEMO terminology. Used to match generation technology to load characteristics.

Chapter 3 — Solar and Wind

Primary sources

- CSIRO, GenCost 2025-26 Consultation Draft (capital cost projections for solar PV, wind, rooftop solar, offshore wind).
- CSIRO, GenCost 2024-25 Final Report (LCOE projections per Appendix B.10).
- Clean Energy Council, Clean Energy Australia Report 2024 (Australian renewable deployment statistics).
- Clean Energy Regulator, Australian Renewable Energy Statistics 2024 (installed capacity, generation share).
- AEMO, Generation Information Page (December 2024) — operational fleet data.
- IRENA, Renewable Power Generation Costs in 2024 (June 2025) — international cost benchmarks.

Calculation assumptions

- Solar PV capital cost 2030 projection $1,239/kW per GenCost 2025-26 Draft.
- Onshore wind capital cost 2030 projection $2,697/kW per GenCost 2025-26 Draft.
- Capacity factor assumptions: solar PV 22-30% in high-resource Australian regions; onshore wind 35-45% at best sites; offshore wind 45-58% at declared zones.
- Economic life: solar PV 30 years; onshore wind 25 years; offshore wind 25-30 years (per GenCost methodology).
- Australian rooftop solar installed base: approximately 25 GW across 3.8 million installations end-2024, approximately 27 GW by end-2025. Source: Clean Energy Regulator.

Key qualifiers

- Wind LCOE in Australia affected by recent global supply chain inflation; 2025-26 Draft reports tentative stabilisation.
- Offshore wind deployment subject to first-of-a-kind Australian premiums of approximately 20-40%.
- Rooftop solar behind-meter economics differ from utility-scale due to avoided transmission and distribution costs.

Chapter 4 — Coal and Gas

Primary sources

- CSIRO, GenCost 2025-26 Draft (black coal, brown coal, gas CCGT, gas OCGT capital costs).
- CSIRO, GenCost 2024-25 Final (coal with CCS analysis).
- AEMO, Integrated System Plan 2026 Draft (coal retirement schedule).
- Clean Energy Regulator, National Greenhouse and Energy Reporting 2023-24 (coal fleet emissions).
- Australian Government, Liquid Fuel Security Review (updated 2025) (gas market and strategic reserves).

Calculation assumptions

- Black coal capital cost current $6,946/kW; 2030 $6,164/kW per GenCost 2025-26 Draft.
- Brown coal capital cost current $10,725/kW; 2030 $9,385/kW per GenCost 2025-26 Draft.
- Gas CCGT capital cost $1,800/kW with hydrogen-readiness per GenCost 2025-26 Draft.
- Black coal LCOE range $95-160/MWh new-build (GenCost 2024-25 Final); brown coal $125-200/MWh.
- Gas CCGT LCOE at current $12/GJ gas price: approximately $110-180/MWh per GenCost 2024-25 Final.
- Australian coal generation emissions approximately 140 Mt CO_2/year (2023-24). Electricity sector total including gas approximately 162 Mt CO_2/year. Source: CER NGER.

Key qualifiers

- Existing coal fleet operates at marginal cost ($40-70/MWh fuel + O&M) not new-build LCOE. Most plants 35-55 years old and approaching scheduled retirement.
- Coal retirement dates reflect AEMO ISP 2026 Draft and publicly-announced closure schedules; some may be extended by market operator agreement (e.g., Eraring extended from 2025 to 2027 under 2024 NSW agreement).
- CCS deployment at commercial scale in electricity generation essentially zero globally as of 2025; cost projections include significant uncertainty.

Chapter 5 — Nuclear

Primary sources

- CSIRO, GenCost 2024-25 Final Report (large-scale nuclear cost analysis including Australian FOAK assessment).
- CSIRO, Nuclear Explainer (updated December 2025).
- World Nuclear Association, Consultation Response to GenCost 2024-25 (critique and counter-analysis).
- IAEA, Power Reactor Information System (PRIS) — global nuclear construction times.
- STUK Finland, Onkalo Deep Geological Repository technical documentation.
- Ontario Power Generation, BWRX-300 Darlington project data (SMR cost benchmark).

Calculation assumptions

- Large-scale nuclear capital cost: $9,217/kW NOAK (2023 baseline) per GenCost 2024-25 Final, based on South Korean continuous-build programme adjusted for Australian conditions.
- FOAK premium: up to 100% per GenCost explicit statement ('FOAK premiums of up to 100% cannot be ruled out').
- Nuclear SMR capital cost: approximately $29,600/kW per GenCost 2024-25 Final, originally based on cancelled UAMPS CFPP data; Darlington BWRX-300 project (approved 2024) confirms similar order of magnitude.
- Nuclear capacity factor range: 53-89% per GenCost methodology (based on Australian coal baseload average at lower bound, international nuclear high-performers at upper bound).
- Development lead time: at least 15 years per GenCost conservative methodology (vs IAEA 12-17 years; UAE completion 12 years).
- Deep geological disposal cost: approximately AUD 900/kg HM per Finnish Onkalo project benchmark (EUR 3.5B for 6,500 tonnes HM). Australian 1 GW fleet 60-year spent fuel disposal cost approximately AUD 1.3-2.0 billion total, or $3-4/MWh on LCOE basis.

Key qualifiers

- Nuclear construction time globally: 8.2 years median last 5 years. No democratic country has built nuclear in less than 10 years in last decade.
- CSIRO's 60-year lifetime analysis specifically examined and rejected the argument that long operational life provides unique cost advantage.
- Australian nuclear requires: federal and state legal framework reform (2-3 years), regulatory setup (2-3 years), site selection and approvals (2-3 years), construction (8+ years).

Chapter 6 — Storage

Primary sources

- CSIRO, GenCost 2025-26 Draft (battery capital cost projections).
- Snowy Hydro Limited, 2024 Annual Report (existing fleet and Snowy 2.0 status).
- Hydro Tasmania, 2024 Annual Report (Tasmanian hydro fleet data).
- AEMO market operational data (battery deployment tracking).
- SBC Prospectus v56 (Alice Hub specifications — subject to feasibility study confirmation).
- IEA, Grid-scale Storage 2025 Annual Review (international battery deployment).

Calculation assumptions

- Battery capex declining approximately 15-20% per year per GenCost; 4-hour grid-scale battery approximately $650/kWh current, $380/kWh 2030 projection.
- Snowy Hydro current fleet: 4,100 MW generation across 16 stations; approximately 8,000 GL combined reservoir storage. Source: Snowy Hydro 2024 Annual Report.
- Snowy 2.0 specifications: 2,200 MW dispatch, 350 GWh dedicated storage, approximately $12 billion revised project cost (from original $4 billion; current Snowy Hydro forecast). Commissioning targeted 2029-2030.
- Hydro Tasmania: approximately 2,300 MW installed capacity; approximately 14 TWh reservoir energy storage. Source: Hydro Tasmania.
- Alice Hub specifications per SBC Prospectus v56: 40 GW dispatch capacity; 16,000 GL water storage at 770 m average head.
- Alice Hub recoverable energy calculation: $E = m \times g \times h \times \eta$ = 1.6×10^13 kg × 9.81 m/s² × 770 m × 0.75-0.80 efficiency ÷ 3,600 s/h = approximately 27-30 TWh. Equivalent to 36-40 days of current total Australian electricity consumption.
- Alice Hub capital cost estimate $29-53 billion (approximately $730-1,325/kW) is SBC programme estimate; requires feasibility study confirmation. International pumped hydro benchmarks $1,500-3,000/kW suggest Alice Hub cost is aggressive; benign topography and continental-scale construction are the claimed basis for advantage.
- Australian grid battery capacity: approximately 2,300 MW / 4,700 MWh operational end-2024; approximately 15,000 MW / 40,000 MWh in development pipeline for 2025-2028 commissioning.

Key qualifiers

- Snowy 2.0 project cost estimate has been revised upward multiple times; current $12B may be subject to further revision before 2030 commissioning.
- Alice Hub physical specifications (16,000 GL storage, 770 m head) are SBC design targets; gorge-level engineering detail requires feasibility study. Cost claims should be treated as programme estimates pending verification.
- CSP with storage: not currently operational at scale in Australia; cost projections carry higher uncertainty than solar PV or wind.
- Hydrogen electricity storage: round-trip efficiency 30-45%; suitable only for multi-day to seasonal storage, not daily cycling.

Chapter 7 — Other Technologies

Primary sources

- CSIRO, GenCost 2024-25 Final (solar thermal, hydrogen electrolyser costs).
- Clean Energy Council, Clean Energy Australia Report 2024 (biomass, geothermal, marine deployments).
- Geoscience Australia, Australian Wave and Tidal Energy Resource Assessment (2024).
- Cooper Basin Geothermal Project technical reports (Geodynamics, Petratherm historical data).

Calculation assumptions

- Conventional Australian hydro approximately 8,000 MW installed capacity. Source: Clean Energy Regulator.
- Biomass LCOE $110-180/MWh depending on fuel cost. Sugar cane bagasse at $5-15/tonne competitive; purpose-grown biomass at $40-80/tonne uneconomic.
- Geothermal capital cost estimate $10,000-18,000/kW; LCOE $170-300/MWh (no commercial Australian deployment).
- Wave and tidal energy: pre-commercial globally; Australian cost estimates $120-400/MWh depending on technology.

Key qualifiers

- Marine energy technologies not near-term deployable at scale in Australia; deployment potential after 2045+.
- Biomass fundamentally fuel-constrained — sustainable supply limits installed capacity.
- Conventional hydro mostly developed; greenfield sites limited.

Chapter 8 — Cradle-to-Grave Lifecycle Analysis

Primary sources

- IPCC, AR6 Working Group 3 Report (Chapter 6) — lifecycle emissions by technology.
- NREL, Life Cycle Greenhouse Gas Emissions from Electricity Generation (updated 2024).
- IEA-PVPS Task 12, Life Cycle Assessment of Photovoltaic Systems (multiple reports 2020-2024).
- UK Parliamentary Office of Science and Technology (POST), Note 383 Carbon Footprint of Electricity Generation.
- Ash Development Association of Australia (ADAA), Coal Ash Statistics 2023.
- Clean Energy Regulator, National Greenhouse and Energy Reporting 2023-24.

Calculation assumptions

- Lifecycle emissions figures per IPCC AR6 median estimates across peer-reviewed studies.
- Energy Payback Time (EPBT) per NREL 2024 US utility-scale PV LCA: 0.5-1.2 years for silicon PV in US grid; 1.5-3.0 years if Chinese-manufactured on coal grid.
- Material intensity per tonne per TWh derived from Aurecon 2024b GenCost technology characteristics, NREL ATB 2024, and industry reports.
- Coal emissions: approximately 140 Mt CO_2/year from coal generation (2023-24); 162 Mt CO_2/year total electricity sector. Source: CER NGER 2023-24.
- Coal ash accumulation: approximately 400 Mt stored cumulatively across Australian dams. Source: ADAA.
- Nuclear waste disposal cost benchmark: Finnish Onkalo approximately AUD 900/kg HM total project cost. Australian 1 GW fleet 60-year spent fuel: approximately 1,500 tonnes HM = approximately AUD 1.3-2.0 billion disposal cost.

Key qualifiers

- Solar PV lifecycle emissions vary 2x depending on manufacturing grid — Chinese coal-heavy grid approximately 40-70 gCO_2e/kWh versus US/EU cleaner grid approximately 20-40 gCO_2e/kWh.
- End-of-life recycling assumptions: 85-95% for solar PV with chemical recycling; 20-25% for current wind blade technology (improving).
- Reservoir hydro emissions (15-30 gCO_2e/kWh) higher than wind/nuclear due to decomposition methane. Cold-climate Australian reservoirs at lower end of range.

Chapter 9 — Firm Combinations

Primary sources

- CSIRO, GenCost 2025-26 Draft — System LCOE method and integration costs.
- AEMO, Integrated System Plan 2026 Draft — generation mix optimisation.
- NREL, Firm Renewable Power Studies (multiple 2022-2024).
- Lazard, LCOE+ v18 — firmed LCOE comparison.

Calculation assumptions

- Firming cost estimates at various renewable penetrations per GenCost methodology: + $20-35/MWh at 82% RE; +$35-55/MWh at 100% RE.
- GenCost 2030 82% renewable scenario: $91/MWh delivered (generation $81 + transmission $10).
- GenCost 2050 net-zero scenario: $135-148/MWh delivered (generation $114-124 + transmission balance).
- Firm combinations ranked by delivered LCOE at 2030 including generation + storage + transmission.
- Tasmania model: existing hydro provides approximately $60-90/MWh firmed renewable generation.

Key qualifiers

- Firming cost estimates subject to technology cost evolution (particularly battery storage declining rapidly).
- 100% renewable scenarios carry higher uncertainty than 80-90% scenarios due to marginal firming cost non-linearity.

Chapter 10 — The Continental Grid Advantage

Primary sources

- Geoscience Australia, Continental Geography and Time Zone Data.
- BoM, Australian Wind Resource Atlas.
- Archer & Jacobson, 'Supplying Baseload Power from Geographically Dispersed Wind Farms' (2007).
- Grams et al., 'Balancing Europe's wind-power output through spatial deployment informed by weather regimes' (Nature Climate Change 2017).
- State Grid Corporation of China, UHV transmission operational data (Changji-Guquan 1,100 kV HVDC).
- Statnett/National Grid, North Sea Link operational data (Norway-UK HVDC).
- Snowy Hydro + Hydro Tasmania combined firming analysis (this report).

Calculation assumptions

- East-west solar time offset: Perth longitude 115.9°E; Sydney 151.2°E; difference 35.3° = 2.35 hours at standard time (3.35 hours during NEM AEDT when WA remains on AWST).
- Solar generation useful window: approximately 5 hours either side of solar noon = approximately 10 hours total per location.
- Combined east-west solar coverage: 10 + 2.35 hours offset = approximately 12.35 hours at standard time; 13.35 hours during AEDT.
- Wind variance reduction: 57% variance reduction in continental averaging per Monte Carlo simulation (chart 11). Published literature (Archer & Jacobson; Grams et al.) shows 40-65% for 3-5 uncorrelated sites.
- HVDC transmission cost: Chinese UHV operational cost approximately CNY 0.03-0.05/kWh = approximately AUD 6-10/MWh at current exchange rates.
- Combined Continental Grid Advantage: $30-60/MWh reduction in firmed Australian LCOE versus regional-only grid development.

Key qualifiers

- East-west solar arbitrage of 3 hours applies during NEM daylight savings (AEDT); reduces to 2.35 hours at standard time.
- Wind diversity analysis uses Monte Carlo simulation; actual Australian hourly correlations require detailed meteorological data analysis.
- International HVDC import capability requires reciprocal infrastructure investment in partner jurisdictions; commercial terms subject to bilateral negotiation.

Chapter 11 — The SBC Pathway to 6c/kWh

Primary sources

- SBC Prospectus v56 (April 2026) — corridor infrastructure specifications.
- CSIRO GenCost 2025-26 Draft — solar PV, wind, battery component costs.
- International benchmarks: Chinese solar deployment costs (NDRC), Indian Gujarat solar tenders, Chinese UHV transmission operational data.
- AER State of the Energy Market 2025 — distribution cost composition.

Calculation assumptions

- Corridor solar generation: approximately $25/MWh midpoint estimate (range $25-30/MWh). Derived from GenCost 2030 $30-50/MWh standalone minus 20-30% corridor economies. Low-case estimate; consistent with Chinese and Indian utility solar benchmarks.
- HVDC continental transmission: approximately $7/MWh. Derived from: $24-40B line capex + $20-40B converters amortised at 7% WACC over 40 years, divided by 600-900 TWh annual throughput.
- Alice Hub firming: approximately $12/MWh. Derived from: $29-53B capex over 40 GW dispatch, amortised over 40 years, divided by 80-150 TWh annual firming throughput.
- Corridor-town distribution: approximately $14/MWh. Derived from corridor shared-pylon infrastructure across 150 corridor towns serving approximately 20% of AU population by 2045.
- Retail/metering: approximately $2/MWh. Not-for-profit retail model; substantially below current Australian competitive retail margin.
- Stack total: $25 + $7 + $12 + $14 + $2 = $60/MWh = 6c/kWh delivered.

Key qualifiers

- Corridor solar at $25/MWh requires corridor construction and direct HVDC tie-in; reflects low-case estimate under favourable programme execution.
- Alice Hub firming at $12/MWh is categorically below international pumped hydro benchmarks; requires feasibility study confirmation of continental-scale topography and construction economics.
- Corridor-town distribution at $14/MWh applies only to corridor-connected households; non-corridor households continue on legacy grid distribution.
- 6c/kWh is the SBC programme target at 2045 full-build operation; intermediate years deliver higher prices reflecting partial build-out.

Chapter 11B — The SBC Business Case

Primary sources

- SBC Prospectus v56 (April 2026) — full programme capital budget.
- CSIRO GenCost 2025-26 Draft — component capital costs.
- Snowy Hydro Annual Report (revised Snowy 2.0 cost benchmarks).
- Federal Treasury, Budget 2025-26 (defence spending, infrastructure commitments).
- International infrastructure comparisons: Chinese HSR programme (NDRC), UK HS2 (UK Treasury), US IRA clean energy (Department of Treasury).

Calculation assumptions

- Total SBC capex $720 billion across 20 years. Component breakdown:
- HVDC transmission 20,000 km × $2.5M/km + converter stations (60 GW × $400M/GW) + civil works = approximately $84B.
- Corridor solar 180 GW × $1.2B/GW = $216B (consistent with GenCost 2030 $1,239/kW).
- Wind farms along corridor 60 GW × $2.5B/GW = $150B (below GenCost 2030 $2,697/kW; reflects corridor economies).
- Alice Hub 40 GW × $1.1B/GW = $45B (aggressive vs international $1,500-3,000/kW benchmark; requires feasibility confirmation).
- Grid-scale batteries 40 GW / 160 GWh = $48B (consistent with GenCost 2030 battery projections).
- Corridor-town distribution: $35B for 150 towns.
- Civil works, land acquisition, contingency: 15% of direct build cost = $87B.
- Financing costs during construction: approximately $55B capitalised interest.
- Revenue model: electricity + water + data + international export = approximately $200-250B/year at full build (Year 25+).
- Programme breakeven: Year 11 (annual revenue exceeds annual capex).
- Programme payback: Year 14 (cumulative revenue exceeds cumulative capex).
- Peak programme debt: approximately $180-200B net Commonwealth debt at Year 10.
- Year 40 cumulative net value: approximately $5.65 trillion nominal (undiscounted).

Key qualifiers

- Financial model assumes revenue ramps as programme construction completes; revenue ramp subject to verification against actual commissioning schedule.
- Alice Hub capex at $45B is aggressive versus international pumped hydro benchmarks; sensitivity analysis tests 25% overrun scenarios.
- Revenue streams assume electricity pricing at SBC 6c/kWh delivered target; higher market-clearing prices would substantially increase revenue.
- Year 40 net value is nominal; discount rate application (4-7% real) reduces present-value benefit by 40-60% but programme still economically positive under all tested scenarios.
- Funding mix (28% Commonwealth equity, 42% bonds, 21% PPP, 10% corporate procurement) is indicative; specific structure subject to programme execution decisions.

Chapter 12 — Misleading Arguments Addressed

Primary sources

- Federal Treasury, Tax Expenditures and Insights Statement 2024 (Australian fossil fuel subsidies).
- International Monetary Fund, Working Paper 23/199 'IMF Fossil Fuel Subsidies Data' (global subsidy estimates).
- Erickson et al. 2014, Biological Conservation — wind turbine bird mortality.
- California ISO and Texas ERCOT operational data — grid battery firming at scale.
- AER State of the Energy Market 2025 — South Australian retail price data.
- IRENA Renewable Power Generation Costs 2024 — international cost decline trajectories.
- All citations in-line in Chapter 12 text.

Calculation assumptions

- Australian fossil fuel subsidies: $14.6 billion/year 2024-25 (fuel tax credit $10.1B + other concessions $4.5B). Source: Treasury.
- Australian renewable subsidies: approximately $3 billion/year declining. Source: Clean Energy Regulator.
- US bird mortality comparison data: Erickson et al. 2014. Annual wind turbine bird deaths approximately 234,000 US-wide; domestic cat deaths approximately 2.4 billion/year.
- Australian wind turbine mortality estimate 2,000-10,000/year at current 10 GW fleet; scaled from international data.

Key qualifiers

- Each claim rebuttal in Chapter 12 cites primary source inline.
- International comparisons adjusted for currency and purchasing power where relevant.

Chapter 13 — Conclusion and EV Switch-Out

Primary sources

- Australian Competition and Consumer Commission (ACCC), Petrol Price Monitoring Report 2025.
- Green Vehicle Guide (Department of Climate Change, Energy, Environment and Water) — EV energy consumption data.
- Electric Vehicle Council Australia, State of Electric Vehicles 2024 Report.
- Australian Bureau of Statistics, Motor Vehicle Census 2024.
- National Greenhouse Accounts 2024 — transport sector emissions.
- IMF Fossil Fuel Subsidies Data — strategic fuel import analysis.

Calculation assumptions

- ICE vehicle fuel consumption: 8 L/100km (typical mid-size Australian passenger vehicle).
- Petrol price: $1.90/L (April 2026 ACCC data; range $1.85-2.05 by region).
- EV energy consumption: 15-18 kWh/100km for efficient mid-size EV (MG4, Tesla Model 3, BYD Atto 3). Larger SUVs and utes consume 20-25 kWh/100km.
- Vehicle usage: 15,000 km/year typical Australian household (ABS Motor Vehicle Census).
- Annual household EV fuel cost at SBC 6c/kWh: 15 kWh/100km × 150 × $0.06 = $135/year.
- Annual household ICE fuel cost: 8 L/100km × 150 × $1.90 = $2,280/year.
- Two-car household savings: approximately $4,300/year switching both vehicles to EV.
- Australian transport emissions: approximately 96 Mt CO_2/year (National Greenhouse Accounts 2024).
- Australian liquid fuel imports: approximately $50 billion/year (ABS trade data 2024).

Key qualifiers

- EV switch-out economics assume the household already owns or is purchasing an EV. Capital premium (if any) over equivalent ICE vehicle not included in these calculations — but is rapidly closing as EV prices fall.
- Liquid fuel import reduction depends on EV fleet penetration; gradual transition over 10-20 years.
- Industrial electrification benefits depend on specific industrial process electrification economics.

Document-Wide Assumptions and Caveats

Currency and real-terms pricing

- All dollar figures are Australian dollars (AUD) unless otherwise specified.
- All cost projections are in 2024-25 real terms (2024-25 AUD purchasing power).
- International dollar figures (USD, EUR, GBP) are converted at prevailing exchange rates and noted inline.

Time horizon

- Current prices refer to April 2026.
- Near-term projections (2030) apply CSIRO GenCost 2024-25 Final and 2025-26 Draft.
- Long-term projections (2045-2050) apply GenCost net-zero scenarios plus this report's SBC pathway analysis.

Technology readiness

- All generation technologies discussed are commercially available today except: Alice Hub (requires feasibility study confirmation), wave/tidal (pre-commercial), geothermal EGS (pre-commercial in Australia), large-scale hydrogen-to-electricity (infrastructure scale-up required).
- Capital cost projections assume no transformative technology breakthrough. Realised future costs may be lower if technology improves faster than current trends.

Regulatory and political assumptions

- Analysis assumes Australian regulatory frameworks continue to support renewable deployment and SBC-style continental infrastructure build.
- Coal retirement schedule per AEMO ISP; extensions possible under market operator agreements (e.g., Eraring 2025→2027).
- SBC programme assumes Commonwealth political commitment to 20-year infrastructure build. Political failure or sovereign risk scenarios not modelled in economic analysis.

Source confidence hierarchy

- Tier 1 (highest confidence): CSIRO GenCost (for Australian electricity cost), AEMO ISP (for Australian grid planning), IPCC AR6 (for climate metrics), peer-reviewed academic literature.
- Tier 2 (high confidence): IEA, IRENA, NREL, Lazard, STUK, OECD government agencies.
- Tier 3 (moderate confidence): Industry association reports (Clean Energy Council, ADAA, Australian Energy Council), government statistical agencies.
- Tier 4 (programme estimate): SBC Prospectus v56 (Alice Hub, corridor infrastructure specifications). Subject to feasibility confirmation.

Known limitations

- Wind diversity analysis uses Monte Carlo simulation, not historical hourly wind data.

- Alice Hub engineering feasibility assumed based on SBC Prospectus; detailed site engineering not presented in this report.
- International HVDC commercial terms assumed favourable; actual bilateral negotiations may vary.
- Discount rate assumptions in financial model: 4% real for bond-funded infrastructure; 7% real for Commonwealth equity. Actual rates subject to prevailing financial conditions.
- Household benefit calculations present-value 4% discount; sensitivity to discount rate is significant.

Every numerical claim in this report traces to an identifiable public source or an explicit calculation assumption shown in this appendix. Where the analysis involves forward projection or derivation, the methodology is transparent. Where uncertainty exists, it is flagged. Readers can verify any claim by consulting the cited source or reconstructing the calculation from assumptions. This level of transparency is the minimum standard for engineering-honest analysis; this report aims to meet it.