Castles Built on Sand

Increasing Supply, Declining Demand & the Stranded Asset Risk:

Global LNG Market Outlook

GLOBAL LNG MARKET OUTLOOK 2026-2035

Renewables are increasing the gap between expected demand and committed supply: the LNG Stranded Asset Risk

February 2026

Methodology, data gathering, calculation, & report compilation by SolAbility.

Data Sources

IEA Gas Market Report Q4 2024, GIIGNL Annual Report 2024, Shell LNG Outlook 2025, Wood Mackenzie Q4 2024, LUT University Jan 2025, IEEFA, various Company Filings 2024/25

About SolAbility

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1 Executive Summary

The global LNG landscape is characterised by two opposite developments:

- Approximately $394 billion in committed LNG capital is currently under construction or in advanced development globally across 25 major projects, representing roughly 390 MTPA of new and expanded liquefaction capacity.
- At the same time, planned LNG receiver terminal and re-gas stations are being cancelled (Pakistan, Vietnam, the Philippines)
- On cost-based comparison, LNG-fired electricity generation at $80-120/MWh is not even remotely competitive against solar/battery generation at $30-40/MWh – the leapfrogging (bypassing fossil energy infrastructure development in favour of cheaper renewable electricity) in lesser developed economies has already taken off and is only going to accelerate

Increasing LNG supply meets declining demand

This report presents five demand scenarios for global LNG through 2035 to evaluate the economic viability and expected returns of planed and/or projects under construction expanding LNG export capacity around the World. The most economically defensible segmentation of global demand assigns OECD economies a linear trajectory (infrastructure lock-in and political constraints slow renewable displacement) and a "leapfrog" trajectory to non-OECD economies (building new electricity infrastructure from scratch, where solar at $30-40/MWh defeats LNG-fired power at $80-120/MWh on pure economics with no existing gas infrastructure to protect).

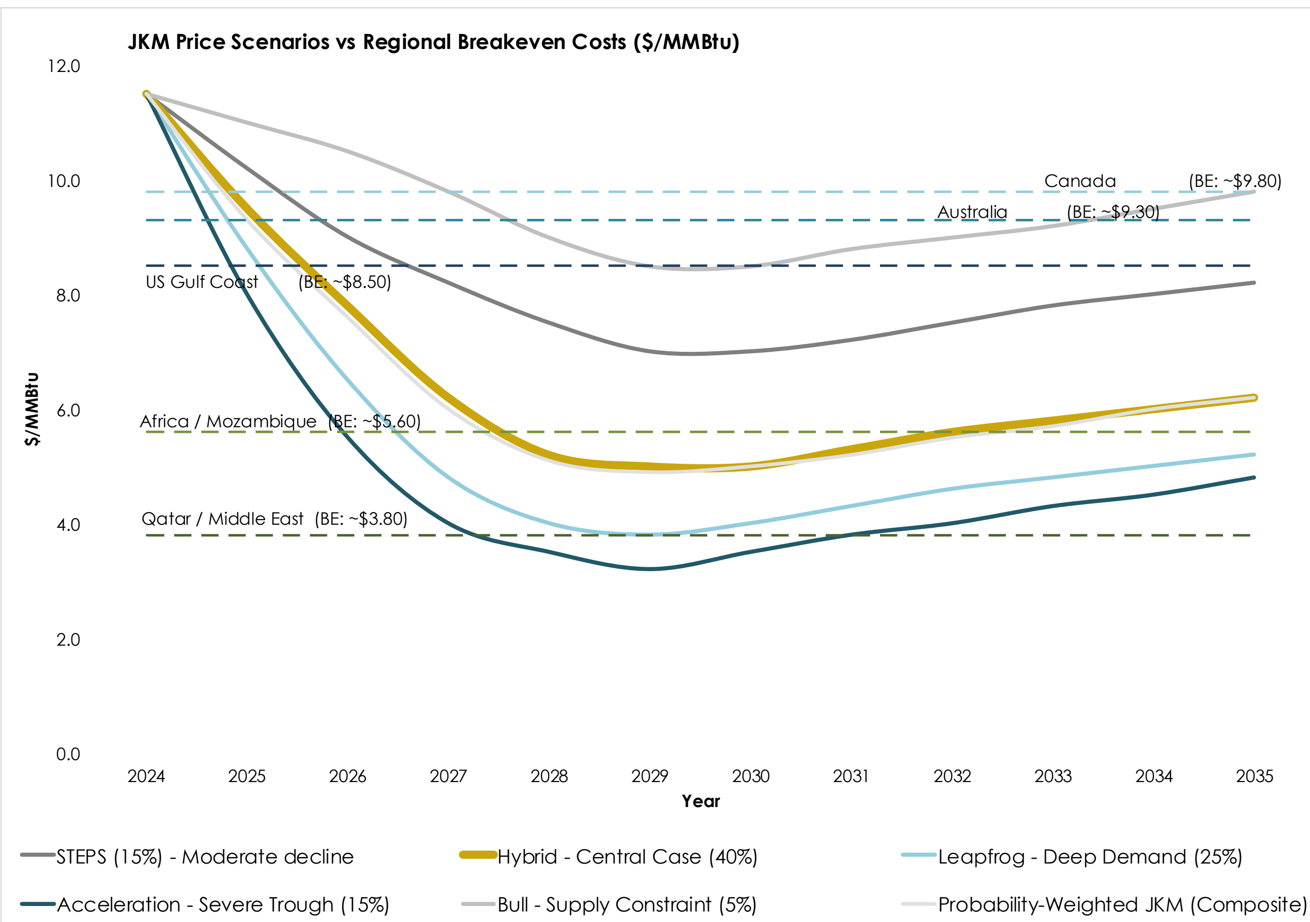
Global LNG Market outlook, key takeaways:

- The most likely scenario produces global LNG demand of approximately 297 MTPA by 2030, against supply capacity of ~575 MTPA - a structural surplus of ~278 MTPA, representing 48% of capacity under construction sitting idle.
- At that utilisation rate, LNG does not clear at project break-even points. It clears at the cash operating cost of the marginal curtailed supplier: approximately $4.50-5.50/MMBtu for US Gulf Coast projects, well below every all-in breakeven in the pipeline.
- Every US, Canadian and Australian project is loss-making on a cash-cost basis, not just on IRR.
- Qatar (breakeven ~USD 3.80-3.90/MMBtu) and UAE Ruwais (~USD 5.10) remain (marginally) profitable in all scenarios, including the leapfrog case.

1.1 Summary of scenarios

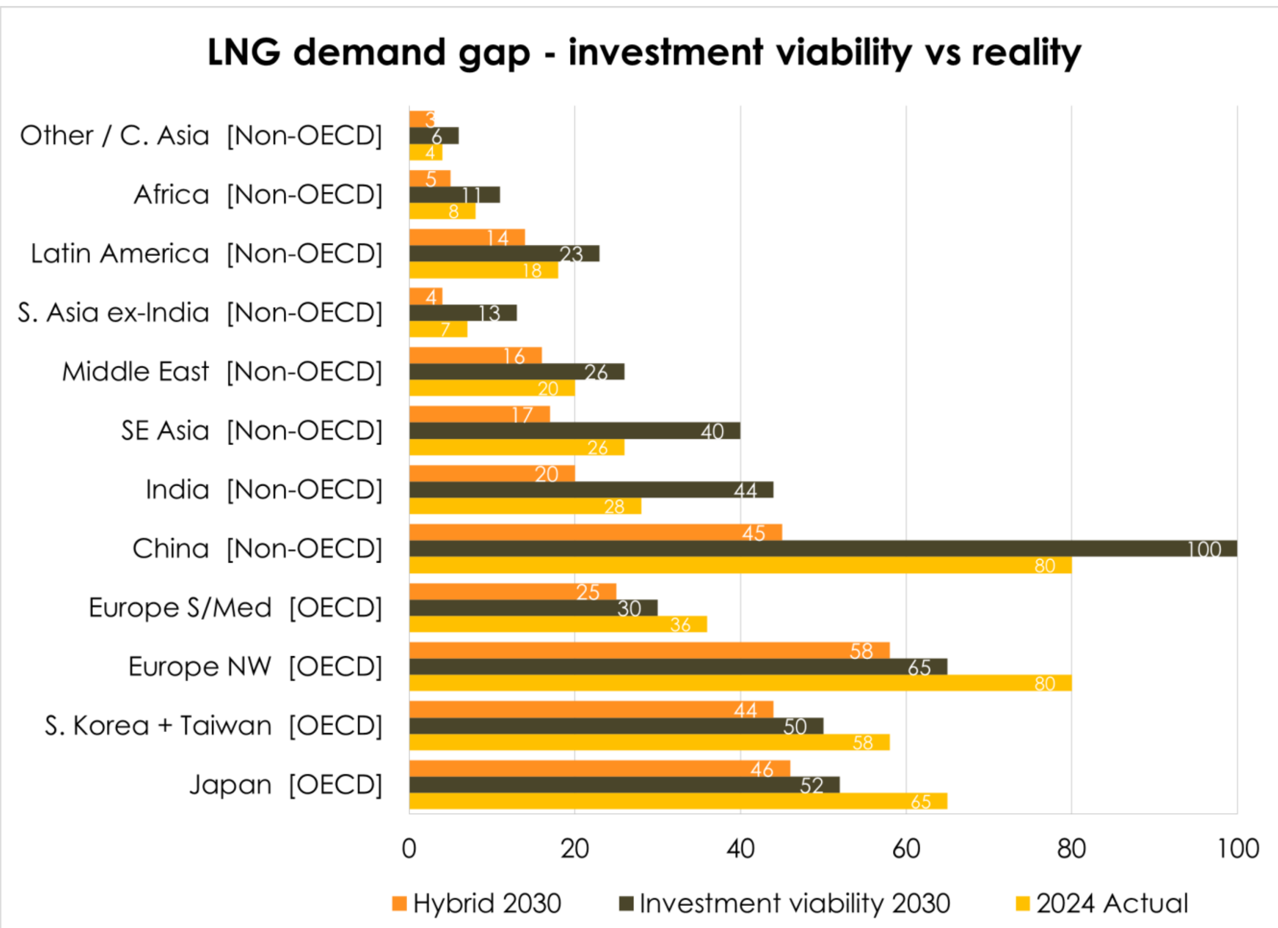
Scenario	Weight	2030 Demand	Supply surplus	Utilisation	JKM Trough 2028	Rationale
Bull Case	5%	~510 MTPA	~65 MTPA	89%	~$9.50	Demand resilience / supply disruption
IEA STEPS	15%	~460 MTPA	~115 MTPA	80%	~$7.50	IEA forecasts finally prove accurate
Lock-in cost transition]	25%	~367 MTPA	~208 MTPA	64%	~$6.00	Solar 1 TW/yr; demand peaks 2026-27
Leapfrog	15%	~265 MTPA	~310 MTPA	46%	~$4.50	Solar 1.5-2 TW/yr; all markets bypass
HYBRID	40%	~297 MTPA	~278 MTPA	52%	~$5.00	OECD=Lock-in + Non-OECD=Leapfrog — most defensible
Probability-Weighted	**100%**	**~343 MTPA**	**~232 MTPA**	**~60%**	**~$5.78**	Hybrid 40% ($5.00) + Lock-in cost transition 25% ($6.00) + STEPS 15% ($7.50) + Leapfrog 15% ($4.50) + Bull 5% ($9.50) = $5.78/MMBtu

Expected LNG Spot-Prices and Project Break-Even Points



Capital at Stake
Approximately $394 billion in committed LNG capital is currently under construction or in advanced development globally across 25 major projects, representing roughly 390 MTPA of new and expanded liquefaction capacity. Of this, an estimated $235 billion is already irreversible. The largest single concentrations are in the US Gulf Coast ($113bn, 9 projects), Canada ($68bn, 4 projects), Qatar ($70bn, 3 expansion projects), and Africa/LatAm ($62bn). Russia's $33bn Arctic LNG 2 and Ust-Luga projects are effectively total losses under current sanctions.

Expected Supply Surplus
On a probability-weighted basis across five demand scenarios, global LNG demand in 2030 is estimated at 343 MTPA against supply capacity of approximately 575 MTPA, implying a structural surplus of 232 MTPA and global utilisation of around 60%. The probability-weighted JKM trough is $5.78/MMBtu. Under the Hybrid central case alone, the trough reaches $5.00/MMBtu — a level at which all US Gulf Coast and Canadian projects are cash-negative. Only Qatar (all-in breakeven ~$3.80–3.90/MMBtu) and UAE remain structurally viable at any realistic trough.



Regional Implications

- Qatar / Middle East – most protected: Qatar's cash operating cost of ~$2.20/MMBtu creates a permanent competitive moat; it remains cash-positive even at a $4 JKM floor, pricing all competitors out of the spot market.
- US Gulf Coast – most exposed: All nine projects under construction face cash losses at the $5 probability-weighted central case. Cash operating costs of ~$5.10–6.50/MMBtu mean these terminals are better left idle than run at spot during troughs. Annual cash destruction across US projects is estimated at $12–15bn/yr at $5 JKM.
- Canada - worse than US Gulf Coast: higher feed-gas costs ($4–6/MMBtu for feed-gas vs ~$3.50 in the US) push Canadian break-even above $9/MMBtu all-in. LNG Canada Phase 1 (already operating, $29.6bn sunk) faces existential off-taker renegotiation risk below $7 JKM. Phase 2 ($18bn, Shell 40%) is difficult to justify at current pricing.
- Africa / Mozambique – mixed; Coral North FLNG (operating) and contracted Mozambique volumes are partially protected. TotalEnergies Mozambique LNG (resumed construction January 2026) and Rovuma LNG remain viable above $5.60 all-in breakeven — but uncontracted volumes are exposed, and the security situation adds non-commercial risk.
- Australia – vulnerable: Scarborough/Pluto T2 (Woodside, $12.5bn) carries an all-in breakeven of ~$9.30/MMBtu — loss-making in all scenarios except STEPS and Bull. Woodside has committed a total of $46.5bn in LNG capex representing 152% of its current market cap of $19.8bn.

1.2 Investment Implications

At the probability-weighted central JKM of $5.78, an estimated 211 MTPA of global LNG capacity (54% of total) cannot recover its all-in investment. ***$255bn of committed capital is at risk of impairment. The sunk cost fallacy will keep most terminals running at cash losses for years before write-downs are booked — likely beginning 2027–28.***

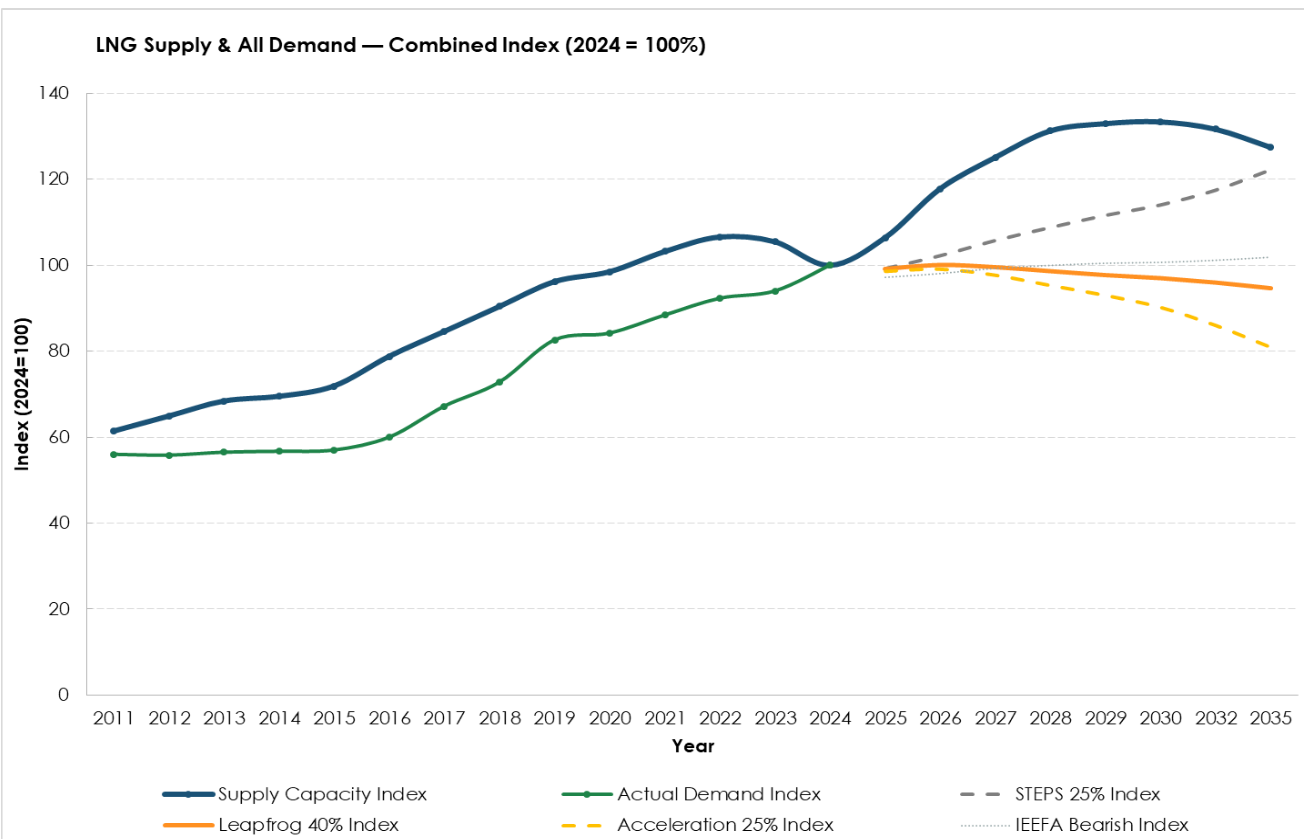
A key market signal to watch: if Venture Global's arbitration exposure ($26bn+) triggers forced contract renegotiations, it will serve as the canary for broader off-taker FM risk across the US Gulf Coast project fleet.

2 The LNG Supply Pipeline

Total global liquefaction capacity reaches approximately 574 MTPA by 2029 and 576 MTPA by 2030, with the largest wave of additions arriving 2027-2030 from US Gulf Coast projects. The critical observation is that the supply wave arrives precisely as the demand scenarios diverge most sharply, creating maximum price pressure during the early operating years of the most expensive projects.

- Qatar North Field (NFE/NFS/NFW): 77 → 142 MTPA by 2030, breakeven $3.80-3.90/MMBtu. Profitable in all five scenarios.
- UAE Ruwais: 9.6 MTPA, breakeven $5.10, 83% contracted. Profitable in all except Hybrid trough.
- Oman Train 4: 3.8 MTPA brownfield, breakeven $5.50. FID expected 2026, onstream 2029.
- US Gulf Coast (Port Arthur Ph.2, Louisiana LNG, CP2 Ph.1, Corpus Christi T8-9, Rio Grande T4-5): >60 MTPA, breakeven $8.50-10.80. Loss-making in Lock-in cost transition, Leapfrog and Hybrid.
- LNG Canada Phase 2, NT LNG Australia, Woodfibre: $9.60-10.80 breakeven, <15% contracted. Loss-making in all scenarios except Bull.

Mexico Pacific / Saguaro (14.1 MTPA contracted) is excluded from the supply model. The Sierra Madre Gas Pipeline (800 km through active cartel territory in Chihuahua state) has no construction start date; the DOE non-FTA export licence expired December 2025. Physical delivery is not credible before 2031.



3 The Five Demand Scenarios

3.1 IEA STEPS (15%)

IEA's Stated Policies Scenario projects demand growing to ~460-490 MTPA by 2030. It is weighted at 15% — the optimistic upside case — because it requires the IEA's renewable energy deployment forecasts to finally prove accurate after 15 consecutive years of gross underestimation by large margins.

3.2 Lock-in cost transition (25%)

Solar additions reach 1 TW/yr from 2026. Demand peaks globally at ~430 MTPA in 2026-27 then declines as RE displacement accelerates.

3.3 Leapfrog (15%)

Solar reaches 1.5-2 TW/yr by 2028. All economies — OECD and Non-OECD — adopt renewable energy at maximum feasible pace. Demand falls to ~265 MTPA by 2030. The Monte Carlo model assigns this a very low probability based on historical IEA error distribution alone, but structural mechanisms (Non-OECD bypass, development finance shift) justify a higher weight than the pure statistical extrapolation implies.

3.4 Hybrid (40% weight — Most Economically Defensible)

OECD economies follow Lock-in cost transition (infrastructure lock-in, regulated utilities, sunk-cost politics slow displacement). Non-OECD economies follow Leapfrog (building from scratch, solar wins on pure economics). This is not a probability-weighted average of other scenarios — it is a structurally grounded segmentation based on the actual mechanism of displacement in each group of economies. Demand reaches ~297 MTPA by 2030.

3.5 Bull Case (5%)

Sustained demand resilience from cold winters, LNG supply disruptions, or demand growth materially above STEPS. JKM sustains above $9.50/MMBtu through the supply wave. Assigned 5% probability; the Monte Carlo model assigns this scenario 0% as it would require a significant slow-down of the renewable energy deployment globally.

4 The Hybrid Scenario — OECD Lock-in cost transition / Non-OECD Leapfrog

The Hybrid scenario rests on a simple but analytically powerful observation: the mechanism and speed of LNG demand displacement differ fundamentally between OECD and Non-OECD economies, and the segmentation follows directly from the energy economics of each group.

4.1 Non-OECD economies: Leapfrog

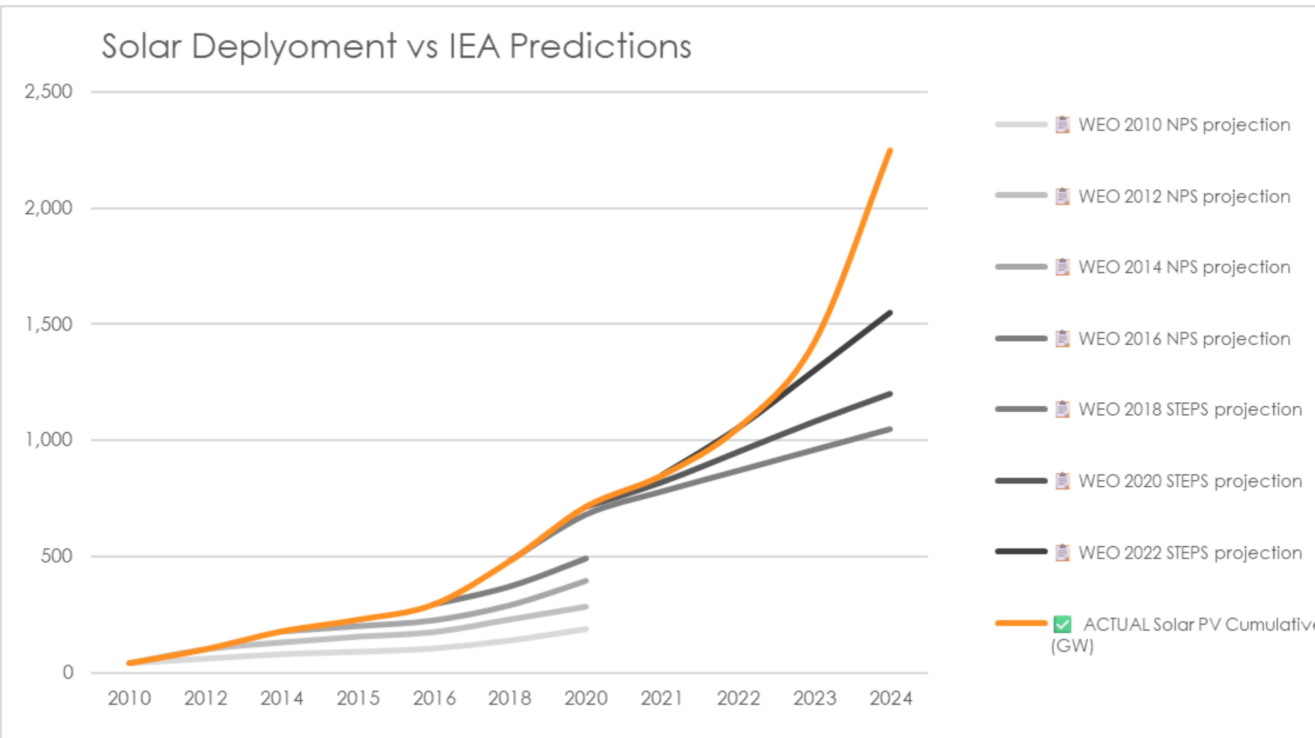
Non-OECD economies that are growing their electricity systems — China, India, Southeast Asia, South Asia, Africa, Latin America — face a binary capital allocation decision for new power infrastructure. The choice is not theoretical:

Technology	LCOE ($/MWh)	Fuel Risk	Infrastructure Needed	Import Dependency
Solar PV + Storage (utility)	$30-45	None	Local grid only	None — domestic
Solar PV (grid-connected)	$20-35	None	Grid balancing	None
Wind Onshore + Grid	$25-50	None	Grid balancing	None
LNG-fired CCGT (new build)	$80-120	High — JKM	Terminal + regas + pipeline + CCGT	Full — foreign FX
Coal-fired (new build)	$65-90	Moderate	Port + rail + plant	Partial

For a finance ministry managing a current account deficit in USD, or an energy planner choosing between infrastructure programmes, the economics are not close. Solar+storage at $30-45/MWh versus LNG-fired power at $80-120/MWh is a factor of two cost difference, before accounting for foreign currency exposure, take-or-pay import contract obligations, and the stranded asset risk of LNG import infrastructure in a world of falling solar costs.

The Leapfrog scenario is not a forecast about future technology costs. It describes the economics today, at current prices, with current technology, in 2025. The question is how quickly decision-makers, development banks and energy planners update their infrastructure programmes to reflect it. The evidence — Vietnam, Bangladesh, Pakistan, Philippines, sub-Saharan Africa — suggests the update is already underway.

Every IEA World Energy Outlook from 2010 through 2022 systematically underestimated solar deployment — not by a small margin, but by a factor of two to four within just a few years of publication. Actual cumulative solar PV capacity reached 2,250 GW by 2024, more than double the IEA's most optimistic 2022 STEPS projection for that year. This is not a forecasting curiosity: it is the single most important context for evaluating LNG demand projections. The same institution whose solar forecasts have been structurally wrong for 15 consecutive years is the source of the STEPS demand growth that underpins the investment case for $394 billion in committed LNG capacity. The IEA STEPS scenario is weighted at just 15% in this analysis precisely because its track record on the technology that is now displacing LNG demand — solar — gives no basis for confidence. When the IEA's own projections are overtaken by reality within two to three years of publication, building 25-year LNG infrastructure on those projections is not conservative planning. It is a structural mispricing of risk.



4.2 OECD economies: Lock-in cost transition

OECD economies are not immune to LNG demand displacement — they are already experiencing it. But the pace is constrained by factors that do not apply in Non-OECD markets:

- Infrastructure lock-in: Japan has over 200 MTPA of installed LNG regasification capacity, long-term contracted positions, and a gas distribution network serving industrial and residential customers.
- Regulated utility structures: European and Japanese utilities operate under regulatory frameworks that socialise stranded asset risk across ratepayers, slowing the pace of fuel switching relative to what pure economics would imply.
- Incumbent politics: Nuclear restarts in Japan and Korea are contested; offshore wind permitting in Germany and the UK takes 8-12 years from planning to operation. The displacement is real but policy-constrained.
- Take-or-pay contract obligations: OECD importers are locked into long-term SPAs that create structural demand floors even as economics shift. These contracts expire on multi-decade timescales, not years.

The result is that OECD LNG demand falls — materially — but more slowly than Non-OECD demand, and along the Lock-in cost transition trajectory rather than Leapfrog.

4.3 The OECD/Non-OECD Split in Numbers

Region	OECD?	2024 MTPA	Hybrid 2030	Change	Scenario Applied	Key Constraint / Driver
Japan	OECD	65	46	-19	Lock-in cost transition	Nuclear restarts + offshore wind; 200+ MTPA re-gas lock-in
S. Korea + Taiwan	OECD	58	44	-14	Lock-in cost transition	Contract non-renewal; utility lock-in; nuclear policy
China	Non-OECD	80	45	-35	Leapfrog	600 GW solar 2024; gas-fired share already declining
India	Non-OECD	28	20	-8	Leapfrog	Solar $30-40/MWh vs LNG-fired $80+; 500 GW RE target
SE Asia	Non-OECD	26	17	-9	Leapfrog	LNG terminals deferred; solar wins new-build economics
S. Asia ex-India	Non-OECD	7	4	-3	Leapfrog	Pakistan/Bangladesh cancel LNG plants; FX constraints
Middle East (imp.)	Non-OECD	20	16	-4	Leapfrog	Gulf solar deployment; LNG increasingly backup not baseload
Europe NW	OECD	80	58	-22	Lock-in cost transition	Offshore wind & solar; industrial demand decline
Europe S/Med	OECD	36	25	-11	Lock-in cost transition	Solar penetration; gas-fired peak displacement

Region	OECD?	2024 MTPA	Hybrid 2030	Change	Scenario Applied	Key Constraint / Driver
Latin America	Non-OECD	18	14	-4	Leapfrog	Brazil hydro+RE; Argentina Vaca Muerta reduces imports
Africa	Non-OECD	8	5	-3	Leapfrog	Purest bypass: solar $25-35/MWh; dev-finance won't fund LNG
Other/Central Asia	Non-OECD	4	3	-1	Leapfrog	Small; pipeline gas dominant; solar competitive
TOTAL	OECD: 239 | Non-OECD: 191	430	297	-133	Hybrid	Structural floor: ~238 MTPA | Buffer: +59 MTPA

> *The Hybrid scenario (297 MTPA) is 70 MTPA lower than full Lock-in cost transition (367 MTPA) because Non-OECD demand is switched from Lock-in cost transition to Leapfrog. China alone accounts for -27 MTPA of that gap (72 → 45 MTPA). SE Asia (-13 MTPA) and India (-12 MTPA) account for most of the rest. These are not tail-risk assumptions — they reflect the economics already observable in real-time energy infrastructure decisions in each region.*

5 Supply-Demand Balance — All Five Scenarios

Year	Supply (MTPA)	STEPS Demand	Surplus vs STEPS	Lock-in cost transition Demand	Surplus vs Lock-in	Hybrid Demand	Surplus vs Hybrid	Hybrid Utilisation
2024	431	415	+16	415	+16	430	+1	100%
2025	459	427	+32	426	+33	427	+32	93%
2026	508	440	+68	430	+78	411	+97	81%
2027	540	455	+85	428	112	386	154	71%
2028	567	468	+99	424	143	356	211	63%
2029	574	480	+94	420	154	327	248	57%
2030	576	460	116	367	209	297	279	52%
2035	550	480	+70	407	143	269	281	49%

The Hybrid scenario produces the most structurally consequential numbers in this analysis. By 2028, surplus against the Hybrid demand trajectory reaches 211 MTPA — 37% higher than the Lock-in cost transition surplus at the same point. Utilisation falls to 63% by 2028 and 52% by 2030, levels at which the marginal price-setter is not the project breakeven but the cash operating cost.

> *At 52% utilisation (2030, Hybrid), the spot LNG price gravitates toward the cash operating cost of the highest-cost curtailed supplier. US Gulf Coast: Henry Hub + liquefaction opex + shipping = ~$4.50-5.50/MMBtu, with zero capex recovery. Qatar cash cost: ~$2.50/MMBtu. Sustained JKM at $4.50-5.50 triggers: US capacity curtailments, take-or-pay contract defaults by underwater offtakers, LNG Canada and Australian project write-downs, and permanent regas mothballing in markets that built excess import capacity.*

6 Regional Demand Breakdown

The five scenarios used for the purpose of this analysis are built bottom-up from 12 demand regions. The Hybrid scenario's 297 MTPA outcome is driven by three regions that collectively account for 95 MTPA of the STEPS vs Hybrid gap:

6.1 China — The Single Largest Variable (−55 MTPA vs STEPS)

China is the most consequential single market in the global LNG balance. The spread between STEPS (100 MTPA) and Leapfrog (45 MTPA) — which is what the Hybrid scenario applies — is 55 MTPA. This exceeds the entire output of Qatar's North Field expansion.

The Leapfrog trajectory is already observable in current data. China installed 600 GW of solar in 2024 alone — more than the IEA projected for the entire world by 2022. LNG imports have been flat from 2022-2024 despite IEA projecting material growth. Gas-fired power's share of China's electricity generation is declining even as total power demand grows rapidly. China is a Non-OECD economy with no incumbent gas utility lobby comparable to OECD markets, and a government that demonstrably redirects capital rapidly at scale.

6.2 SE Asia + India — The Bypass Battleground (−47 MTPA vs STEPS)

Southeast Asia (−23 MTPA vs STEPS) and India (−24 MTPA) together represent the most important demand battleground because they are the markets that IEA STEPS relies on most heavily for global LNG demand growth. STEPS projects these two regions to add +28 MTPA by 2030. The Hybrid scenario projects them to decline.

The mechanism is identical in both cases: new electricity infrastructure is being built from scratch in economies where solar at $30-40/MWh defeats LNG-fired power at $80-120/MWh on unsubsidised economics. The evidence is already there: Vietnam has deferred LNG terminals twice for RE targets; Philippines is building solar capacity that directly competes with planned LNG utilisation; Pakistan cancelled two LNG power plants in 2024 citing solar competitiveness; Bangladesh cannot sustain USD-denominated LNG import contracts.

6.3 OECD Decline — Structural and Irreversible (−66 MTPA vs STEPS)

OECD demand falls from 239 MTPA in 2024 to 173 MTPA by 2030 under the Lock-in cost transition trajectory applied in the Hybrid scenario. This is structural and irreversible: Japanese utilities are publicly flagging LNG contract non-renewal in the 2030s; European offshore wind is scaling rapidly along the North Sea and Baltic coasts; South European solar penetration is already above 20% of the power mix in Spain. The OECD decline is baked in. The Hybrid scenario simply acknowledges it takes longer than Non-OECD displacement because of infrastructure lock-in.

7 Project Viability Under the Hybrid Scenario

The Hybrid scenario's JKM implication (~$5.00/MMBtu trough in 2028-2030, probability-weighted across all five scenarios: ~$5.78/MMBtu) changes the viability picture from "loss-making" to "loss-making on a cash basis". This is the critical distinction: at JKM below cash opex, projects do not just fail to recover capex — they actively lose money on every cargo shipped.

Project	Breakeven (all-in)	Breakeven (cash only)	% Ctd	Hybrid JKM ~$5.00	Loss vs Cash BE	Loss vs All-in BE	Verdict
Qatar NFE/NFS	$3.80	~$2.50	100%	+$2.50	+$2.50	+$1.20	RESILIENT — all scenarios
UAE Ruwais	$5.10	~$3.20	83%	+$1.80	+$1.80	-$0.10	VIABLE — thin at hybrid trough
Oman Train 4	$5.50	~$3.50	60%	+$1.50	+$1.50	-$0.50	MARGINAL — positive cash, loss all-in
Nigeria NLNG T7	$4.80	~$3.00	100%	+$2.00	+$2.00	+$0.20	RESILIENT — all scenarios
Port Arthur Ph.1	$8.65	~$5.20	90%	-$0.20	-$0.20	-$3.65	CASH LOSS at hybrid trough
Corpus Christi T8-9	$8.50	~$5.10	90%	-$0.10	-$0.10	-$3.50	CASH LOSS at hybrid trough
Louisiana LNG	$9.20	~$5.40	30%	-$0.40	-$0.40	-$4.20	CASH LOSS — plus low contract cover
LNG Canada Phase 2	$9.60	~$5.80	10%	-$0.80	-$0.80	-$4.60	CASH LOSS — minimal protection
NT LNG Australia	$10.80	~$6.20	10%	-$1.20	-$1.20	-$5.80	DEEPEST CASH LOSS — all scenarios

The "cash loss" designation is significant. When JKM falls below cash operating cost, project operators face a choice between curtailing production (accepting lost revenue but avoiding cash burn) and shipping at a loss (preserving customer relationships but destroying value). Take-or-pay contracts with committed offtakers do not fully protect against this — if the offtaker itself is loss-making on the resale, credit deterioration and renegotiation attempts follow, as demonstrated clearly in 2015-2017.

8 Stranded Asset Risk

Under the Hybrid scenario, the stranded asset risk profile is more severe than under full Lock-in cost transition and approaches the Leapfrog profile for high-cost projects.

- ~278 MTPA of surplus at the 2030 trough (Hybrid) vs ~208 MTPA (Lock-in cost transition). The additional 70 MTPA reflects Non-OECD demand that was Lock-in cost transition-paced but is now Leapfrog-paced.
- All US, Canadian and Australian projects are cash-flow negative at the Hybrid JKM trough (~$5.00/MMBtu) — not just IRR-negative. The distinction matters for debt service and operational decisions.
- Russia Arctic LNG 2 (19.8 MTPA) remains geopolitically stranded. EU transshipment ban March 2025. No new Russian capacity credible without Western technology and finance. Not counted in supply model.
- Saguaro/Mexico Pacific remains excluded — Sierra Madre pipeline unbuilt, DOE licence expired December 2025. If included, surplus widens by a further 14.1 MTPA.

The "contracting illusion" is most visible under the Hybrid scenario. Tier 2 contracted US projects (Port Arthur, Corpus Christi) may be protected at the project level by take-or-pay SPAs, but their customers are losing $0.10-$0.20/MMBtu in cash on every cargo at a Hybrid JKM of ~$5.00 — holding contracts priced at oil-indexed equivalents of $10-13/MMBtu. The 2015-2017 experience shows where this is leading to: renegotiation requests, volume deferrals, credit deterioration, and eventual restructuring.

9 Revenues at Risk: Government Income & Fiscal Exposure

Overview
Governments across the Gulf, North America, and Australia have embedded future LNG revenues into national budgets, infrastructure spending plans, and sovereign wealth projections — most of them calibrated to price assumptions that are materially higher than our probability-weighted central case of $5.78/MMBtu JKM. The gap between those planned revenues and what a structurally oversupplied market is likely to deliver represents one of the most underappreciated fiscal risks in the current LNG cycle.

9.1 Qatar —Strongest Position, But High Reliance

Qatar is the most exposed in absolute terms but the most resilient in relative terms. Hydrocarbon revenues totalled $47.5bn in 2024, accounting for 81% of total government revenue, MEES and the government has built its entire North Field expansion programme — targeting 142 MTPA by 2030 — on the assumption that LNG revenues will rise substantially from 2026 onward. Qatar's fiscal breakeven oil price is expected to fall from around $64/bbl in 2024 to $50/bbl in 2027 as NFE/NFS trains come online and support government revenue from 2026. AGBI That trajectory assumes sustained strong LNG pricing. Because Qatar prices its LNG primarily on oil-linked long-term contracts rather than spot JKM, it is partially insulated from short-term spot price collapses — but the risk is not zero. If Asian off-takers invoke destination flexibility clauses or seek renegotiation as spot falls to $5, Qatar's contracted revenue base is more at risk than commonly assumed. The government projects a $3.6bn budget deficit in 2025 based on a $60/bbl oil price assumption U.S. Department of State — meaning it is already in deficit territory before any LNG-specific pricing shock materialises. The deeper risk is 2027–2030: Qatar has publicly committed to expanding sovereign spending, debt reduction, and National Vision 2030 infrastructure on the basis of LNG revenues that may not materialise at planned scale if the global market overshoots the supply surplus. With sovereign net foreign assets of ~$398bn (187% of GDP), Qatar can absorb short-term shocks — but a sustained $5 JKM environment would force a fundamental rethink of the NFW expansion economics and the fiscal model underpinning the 142 MTPA target.
Revenue at risk at JKM $5 vs baseline: estimated ~$8–12bn/yr in foregone revenue upside, with no direct budget collapse but meaningful pressure on planned surpluses.

9.2 United States — Diffuse but Real

The US federal government does not depend on LNG revenues the way Gulf states do, but the fiscal stakes are larger than commonly recognised. The US LNG export sector currently supports an estimated 222,450 jobs, adds $43.8bn to GDP, and contributes more than $26bn in taxes and royalties at the federal, state, and local level — projected to rise to $47.7bn annually by 2044 under the high-growth scenario. National Association of Manufacturers Those projections assume sustained export growth and competitive pricing. At JKM $5, a significant share of new US capacity would be uneconomic to operate, constraining output, employment, and the tax base associated with the sector. The more immediate fiscal exposure sits at the state level along the Gulf Coast — Louisiana, Texas — where LNG-linked jobs, property taxes, and royalty income have been incorporated into regional economic plans. Louisiana alone has structured economic development incentives and infrastructure

commitments around the assumption of full Plaquemines LNG, CP2, and Rio Grande buildout. If those projects curtail operations or delay commissioning, the anticipated economic multiplier does not materialise. Federal royalties on gas production feeding US LNG terminals — approximately $1.9bn in 2023 — would also contract meaningfully if utilisation rates fall.
Revenue at risk: $5–10bn/yr in foregone federal, state, and local fiscal contributions if US LNG utilisation rates fall materially below 80% nameplate capacity.

Canada (British Columbia) — Highest Relative Fiscal Dependency
Canada's exposure is the most acute relative to the scale of government planning. BC has explicitly incorporated LNG royalty revenues into its budget forecasts to manage an $11.2bn provincial deficit and a rising debt-to-GDP ratio. BC's Budget 2025 projects natural gas royalties doubling from $576m in 2024–25 to $920m in 2025–26 and $1.2bn in 2026–27, Resource Works driven almost entirely by the ramp-up of LNG Canada Phase 1 and the associated upstream Montney production. The Conference Board of Canada projected LNG exports could increase BC's GDP by $8bn/year and generate $78bn in cumulative government revenue to 2064, Fnnga with LNG Canada alone estimated to deliver $23bn in direct benefits to the provincial government over the life of the project. Those projections were built on LNG price assumptions well above our central case. Canadian LNG carries the highest all-in breakeven cost of any major exporting region — above $9/MMBtu — because feedgas costs in the Montney ($4–6/GJ) are structurally higher than US Gulf Coast Henry Hub equivalents, and because Coastal GasLink pipeline tolls add further cost. At JKM $5.78, LNG Canada is operating below all-in recovery cost. At $5.00, it is deeply cash-negative and the upstream Montney producers supplying feedgas face severe margin compression. The fiscal multiplier BC is counting on disappears almost entirely below $7 JKM, and reverses — requiring government to support stranded upstream operators rather than receiving royalty income from them.
Revenue at risk: C$1–2bn/yr in direct royalty shortfall vs budget projections, plus indirect loss of the C$2bn/yr GDP uplift LNG Canada was projected to deliver to BC economy.

9.3 Australia — A Structural Fiscal Paradox

Australia presents the most complex and politically contentious picture. It is the world's second-largest LNG exporter but captures a structurally low share of the fiscal value. The Australian oil and gas industry paid a record $21.9bn in taxes and royalties in 2024–25 Energy producers — but over half (56%) of gas exported from Australia attracts zero royalty payments The Australia Institute under the current offshore framework, and in 2023 the Qatari government generated around A$56bn in government revenue from LNG exports, compared to Australia's estimated A$10.6bn The Australia Institute — despite comparable export volumes. The primary tax instrument, the PRRT, was specifically designed to raise more revenue as prices rose — but most offshore LNG projects carried forward capital expenditure deductions large enough to shield profits through the high-price era of 2022–23. Australia's LNG export earnings are expected to fall from $66bn in 2024–25 to $53bn by 2026–27, The energy driven by lower prices even before the structural oversupply scenario modelled here materialises. PRRT revenues are budgeted at $1.98bn in 2025–26, falling to $1.45bn by 2028–29 — already a declining trajectory under consensus pricing. Under our central case ($5.78 JKM), many offshore LNG projects would fall back below profit thresholds, PRRT payments would likely revert to near zero, and the politically contentious debate about whether Australia adequately captures returns from its natural resources would intensify substantially. Western Australia — which receives

approximately two-thirds of NWS royalties — budgeted $522m in gas royalties for 2024–25, already down from $660m the prior year and expected to decline further.
Revenue at risk: A$3–6bn/yr in foregone PRRT and royalty revenues vs government projections at JKM $5-6, on top of an already-low baseline capture rate. The structural fiscal paradox — Australia exports the world's most gas while capturing among the lowest sovereign returns — becomes a live political crisis if prices fall to our central case.

Summary Table — Government Revenue at Risk

Region	Current Annual LNG Fiscal Revenue	Baseline Price Assumption	Revenue at Risk (JKM $5 central)	Fiscal Resilience
Qatar	~$47bn hydrocarbon total (~$35–40bn LNG)	Oil-linked; ~$70–80/bbl equivalent	$8–12bn/yr foregone surplus	High (SWF buffer, low opex)
United States	~$26bn total LNG-linked taxes/royalties	JKM $7–8 implied	$5–10bn/yr loss of sector contribution	Moderate (diversified economy)
Canada (BC)	C$1.2–2bn royalties (rising to C$90bn over project life)	JKM $8–10+ (all-in breakeven)	C$1–2bn/yr direct; C$8bn/yr GDP impact	Low (budget-dependent; deficit context)
Australia	A$10.6bn (LNG share of A$21.9bn total)	JKM $7–9 implied by PRRT projections	A$3–6bn/yr (PRRT collapses)	Low-Moderate (politically exposed)

Note: Revenue-at-risk figures represent the delta between government budget projections and expected outcomes under the Hybrid central scenario (JKM $5.78 probability-weighted trough). They exclude the broader economic multiplier effects of stranded capital write-downs and upstream sector contraction. Sources: IMF Regional Economic Outlook, Fitch Ratings, Australian Energy Producers Financial Survey 2025, BC Budget 2025, Conference Board of Canada, Australia Institute, PwC/NAM LNG Economic Impact Study 2024.

10 Conclusions

10.1 Core Conclusions

- 574 MTPA of supply meets ~297 MTPA of Hybrid demand by 2030 — a 279 MTPA structural surplus, 48% of capacity idle.
- JKM trades near cash opex (~$4.50-5.50/MMBtu) at Hybrid utilisation, not project breakeven. US Gulf Coast projects are cash-flow negative, not just IRR-negative.
- The only projects resilient across all scenarios: Qatar NFE/NFS/NFW, Nigeria NLNG T7, and Coral/GTA FLNG. UAE Ruwais and Oman T4 are viable in all scenarios except the deepest trough.
- The developing economy bypass — solar at $30-40/MWh winning outright in markets building from scratch — is the structural mechanism that drives the Hybrid below full Lock-in cost transition – trends that are already observable today.

10.2 Why the Hybrid Scenario is the most Realistic Scenario

The Hybrid scenario's analytical contribution is to replace a probability-weighted blend with a structurally grounded segmentation. Rather than asking "how likely is global Leapfrog?" — a question the Monte Carlo assigns 1.7% — it asks "what scenario does each economy's energy economics actually imply?" The answer, applied consistently across 12 regions, produces 297 MTPA. This is the number that energy investors, LNG project developers, and importing country policy-makers should stress-test against.

10.3 Final Thoughts

The LNG market's challenge is not that demand will disappear completely. The challenge is that 337 MTPA of supply capacity above demand floor — half of it owned by high-cost producers in the US, Canada and Australia — was sanctioned on the assumption that demand would grow toward STEPS. However - in the Non-OECD world where growth was supposed to come from, this demand is not going to materialise. In those markets, the economics have already been decided. The only remaining question is how fast the infrastructure capital allocation decisions catch up with the economics.

> ***Non-OECD economies are not choosing between LNG and renewables as a matter of climate policy. They are choosing between paying $80-120/MWh for LNG-fired power and paying $30-40/MWh for solar. This is not an energy transition story, it is a cost story - and cost stories in energy have only one ending.***

Abbreviations – Energy

Abbreviation	Full Term	Decription
LNG	Liquefied Natural Gas	Natural gas cooled to −162°C for transport by ship
MTPA	Million Tonnes Per Annum	Standard unit of LNG production or demand capacity
MMBtu	Million British Thermal Units	Standard energy unit for pricing LNG and gas
JKM	Japan-Korea Marker	Benchmark spot price for LNG in Asia-Pacific markets
CCGT	Combined Cycle Gas Turbine	High-efficiency gas-fired power plant technology
FLNG	Floating Liquefied Natural Gas	Offshore liquefaction facility on a floating vessel
FSRU	Floating Storage and Regasification Unit	Vessel used to receive and regasify LNG imports
SPA	Sale and Purchase Agreement	Long-term LNG supply contract between seller and buyer
TW	Terawatt	Unit of power; 1 TW = 1,000 GW = 1 trillion watts
GW	Gigawatt	Unit of power capacity; 1 GW = 1,000 MW
MWh	Megawatt-hour	Unit of electrical energy; used for LCOE comparisons
GJ	Gigajoule	Unit of energy; used in Canadian gas pricing (per GJ)
RE	Renewable Energy	Solar, wind and other non-fossil energy sources
PV	Photovoltaic	Solar panel technology converting sunlight to electricity
BE	Breakeven	Minimum LNG price at which a project recovers costs

Abbreviations - Financial & Project

Abbreviation	Full Term	Context / Definition
IRR	Internal Rate of Return	Project profitability measure; all-in investment return
FID	Final Investment Decision	Formal approval to proceed with project construction
FM	Force Majeure	Contract clause allowing suspension of obligations
FX	Foreign Exchange	Currency risk; relevant for USD-denominated LNG imports
LCOE	Levelised Cost of Electricity	All-in average cost per MWh over a plant's lifetime
PRRT	Petroleum Resource Rent Tax	Australia's profit-based tax on offshore oil & gas
SWF	Sovereign Wealth Fund	State-owned investment fund (e.g. Qatar Investment Authority)
GDP	Gross Domestic Product	Total economic output of a country
USD	United States Dollar	Reference currency for all LNG pricing in this report

Abbreviations - Organisations & Data Sources

Abbreviation	Full Term	Context / Definition
IEA	International Energy Agency	Paris-based intergovernmental energy organisation; source of STEPS scenario
STEPS	Stated Policies Scenario	IEA's baseline demand forecast based on current government policies
WEO	World Energy Outlook	IEA's annual flagship energy forecast publication
GIIGNL	Groupe International des Importateurs de GNL	International Group of LNG Importers; annual LNG data source
IEEFA	Institute for Energy Economics and Financial Analysis	Research institute; source of LNG demand analysis
IMF	International Monetary Fund	Source of fiscal and GDP data used in government revenue section
DOE	Department of Energy (US)	Issues US LNG export licences; FTA and non-FTA authorisations
EU	European Union	Enforces Russia sanctions including transshipment ban (March 2025)
MEES	Middle East Economic Survey	Regional energy industry publication; cited for Qatar fiscal data
LUT	LUT University (Finland)	Source of renewable energy transition modelling (Jan 2025)
AGBI	Arabian Gulf Business Intelligence	Source of Qatar fiscal breakeven oil price projections
NAM	National Association of Manufacturers (US)	Source of US LNG economic impact data

Abbreviations - Organisations & Data Sources

Abbreviation	Full Term	Context / Definition
OECD	Organisation for Economic Co-operation and Development	Group of 38 advanced economies; used to segment demand scenarios
BC	British Columbia	Canadian province; location of LNG Canada project
NWS	North West Shelf (Australia)	Major Australian LNG project; source of WA royalty revenue
NFE	North Field East (Qatar)	Qatar's LNG expansion project; first phase of North Field expansion
NFS	North Field South (Qatar)	Second phase of Qatar North Field expansion
NFW	North Field West (Qatar)	Third phase of Qatar North Field expansion; pre-FID
NLNG	Nigeria LNG	Nigeria's national LNG company; Train 7 under construction
FTA	Free Trade Agreement	DOE export licence category; FTA countries get simpler approval
CP2	Commonwealth LNG Phase 2	US Gulf Coast LNG project by Commonwealth LNG

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