Analysis of proposed LNG export windfall levy: potential impact on energy project economics and fiscal competitiveness

Executive summary

With the Federal Government's Future Gas Strategy making clear the critical, long-term role for gas to support the decarbonisation of power generation and the continuation of local industry in this country, the need to encourage investment in the development of Australia's gas resources is obvious and pressing.

Upstream oil and gas companies invest in projects to generate a return commensurate with the risk level of the investment. Upstream oil and gas exploration and production is inherently higher risk than other capital-intensive investments such as infrastructure projects, as upstream projects are subject to highly uncertain production outcomes and the volatility common in global oil and gas markets. For companies to invest, they must be able to balance upside value generated by higher prices with the downside risk of lower prices or higher operating costs.

The Australian government is being urged to impose a 25% windfall levy on Australian energy production or exports, nominally to combat rising domestic energy costs as a result of the conflict in the Middle East, and to increase Government take from "windfall gas profits". The Commonwealth Treasury is understood to be modelling options for a new levy on gas exports as part of the upcoming federal budget. How this proposed tax may be levied is not yet clear, though some media reports indicate it could be applied to LNG export profits, LNG export revenue or corporate profit.

Australia's existing fiscal terms already allow government to capture substantial share of profits from Australian oil and gas projects, with a current effective tax rate of approximately 53.5% to 57.5%. The current corporate income tax (CIT) and Petroleum Resource Rent Tax (PRRT) framework is also inherently a progressive, profit-based tax that captures additional tax revenue for government when prices increase.

The addition of a 25% windfall levy on LNG exports could increase Total Government Share (the effective tax rate of a project) to as high as 83% (at US$120/bbl), and erode nearly all positive value of a representative offshore gas field development (94% reduction)[1].

All potential windfall tax mechanisms modelled in this analysis result in an increased effective tax rate, and reduction in investment returns, on a scale that could make Australia's oil and gas projects uninvestable at the long-term Brent oil price that underpins investment decisions (~US$70/bbl).

The full lifecycle investment returns of the upstream gas projects in Australia forecast to take FID in the next few years could be materially reduced, potentially making them uninvestable and putting up to A$70.4bn (US$51bn) of Government income under the existing tax regime at risk. Together these projects represent total 2P Reserves of 18 trillion cubic feet (tcf) of natural gas (~19,000 PJ) – the equivalent of more than 300 million tonnes of Liquified Natural Gas (LNG) – and 1 billion barrels of liquids (including oil, condensates and natural gas liquids). If these projects do not proceed, the impact on Australia's energy security, the energy security of our trading partners – who are significant investors in Australia's energy industry – and foregone Government taxation revenue would be material. It would also impact the availability of domestic gas supplies, impact the longevity and valuations of Australia's existing LNG facilities and increase perceived sovereign risk for LNG trading partners.

At a broader level, the addition of a windfall tax to Australia's fiscal terms would reduce competitiveness with peer regimes, reducing Australia's fiscal attractiveness for potential investors. The export levy structure in particular would make Australia the least fiscally attractive regime of all peer countries, significantly impacting its ability to attract and retain investment in upstream oil and gas production.

Examples of other windfall taxes in comparable countries have demonstrated the negative effects on investment in oil and gas production. The cumulative effect of the UK Energy Profits Levy and its subsequent modifications has been a measurable contraction in UK Continental Shelf investment activity. This includes a significant reduction in expected capital expenditure on the UKCS relative to pre-EPL trajectories, with billions of pounds of investment at risk of being redirected to more competitive jurisdictions. While Norway's fiscal regime is frequently referenced to advocate for an increase in headline tax rates, the structure of Norway's fiscal regime differs substantially from the UK and Australia. Norway directly and indirectly owns and participates in Norway's oil and gas industry and projects, taking on project and development risk through its direct equity holdings in projects and development companies. This means the Norwegian Government shares both the upside of higher prices with the downside of lower prices, higher costs and material shares of technical and non-technical risks.

[1] Reduction in Net Present Value (NPV) on an NPV10 basis.

Introduction

The Australian government is being urged to impose a 25% windfall levy on Australian energy production or exports, nominally to combat rising domestic energy costs as a result of the conflict in the Middle East, and to increase Government take from "windfall gas profits". The Commonwealth Treasury is understood to be modelling options for a new levy on gas exports as part of the upcoming federal budget. How this proposed tax may be levied is not yet clear, though some media reports indicate it could be applied to LNG export profits, LNG export revenue or corporate profit.

Wood Mackenzie has modelled the impact of the potential windfall levy on post-tax project economics in Australia and has used the results to assess the corresponding implications for Australia's fiscal attractiveness and competitiveness relative to peer regimes.

Potential windfall levy mechanisms

In Australia, upstream oil and gas exploration and production licences are awarded under concession terms through licensing rounds and direct negotiation. All oil and gas projects are subject to a corporate income tax on profits at a rate of 30%.

For onshore projects (under State jurisdiction) royalty rates vary from 10% to 12.5% depending on which State the block is located in. Excise duties can range from 0% to 55% for oil and condensate, with an exemption for the first 30 million barrels produced.

Offshore projects located more than three nautical miles from the baseline (under Federal jurisdiction) are exempt from royalties and excise duties, with the exception of North West Shelf which is subject to Federal royalties. These projects are subject to and pay Petroleum Resource Rent Tax (PRRT) at a rate of 40%. Additionally, offshore projects pay an offshore petroleum levy to recover the costs of decommissioning and remediating the Laminaria and Corallina oilfields and associated infrastructure, charged at A$0.48/bbl for all offshore production. Based on a representative offshore gas project, current fiscal terms in Australia result in a Total Government Share of profit generated (the effective tax rate of a project) of 53.8% at a US$70/bbl Brent oil price.

In addition to these taxes, the federal government is reportedly considering an additional windfall levy on Australian energy producers, with initial discussions focused on levying the tax on LNG exports. While the exact mechanism of the potential windfall tax remains unclear, Wood Mackenzie has considered the mechanisms proposed publicly as well as considering comparable regimes that have adopted similar mechanisms. A range of scenarios for the potential levy have been developed and modelled:

1. An **export levy** – 25% tax on LNG export revenue;
2. A **windfall profit tax** – 25% tax on surplus taxable profits (Earnings Before Interest and Tax – EBIT);
3. A **windfall revenue tax** – 25% tax on surplus gross revenue; and
4. An **increase in the Corporate Income Tax** (CIT) rate – 25% tax increase in CIT rate (current 30% plus an additional 25%).

'Surplus' taxable profit and 'surplus' gross revenue are calculated as any EBIT or revenue (respectively) earned above that generated at a base reference price for Brent oil of US$70/bbl.

Modelling assumptions & methodology

Our analysis relies on several generalised model inputs and assumptions, including the mechanism applied to calculate the windfall levy; the representative analogue project (i.e., production & cost profile used as a proxy for a potential investment opportunity); macroeconomic factors; and fiscal regimes. Detailed assumptions are provided as Appendix 1 of this analysis.

To avoid introducing project-specific factors and to ensure comparability with other fiscal structures, a standardised hydrocarbon development analogue is used as the basis of our calculations of project economics. To ensure relevance to Australia, we have selected a proxy for a large-scale offshore gas asset as our analogue. The asset characteristics include a reserve size of 4 tcf, peak gas production of 450 million standard cubic feet per day (mmscfd) and an operational life of 27 years.

Other broad assumptions that underpin our analysis include that the windfall levy is permanent (i.e., there is no expiry of the windfall levy throughout the project life). To estimate export revenue, we assume that a given project exports 85% of total volumes, with 15% sold into the domestic gas market. Only the export revenue will serve as the basis of the export levy.

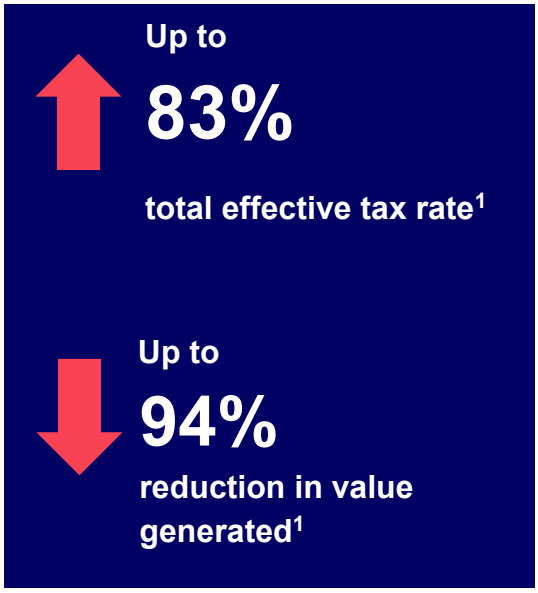
For both the windfall revenue and windfall profit taxes, we estimate surplus profits and surplus gross revenue as the difference between EBIT and revenue, respectively, under a base case US$70/bbl (2026 real terms) scenario

against those under a US$120/bbl scenario. Further, we assume no offsetting incentives (investment allowances) under the windfall levy mechanism and no fiscal synergies with existing assets – the economics of each development are calculated on a stand-alone basis (i.e. ring-fenced at the project level). For modelling purposes, we assume that the export levy, windfall revenue and windfall profit taxes are not tax deductible for PRRT and CIT calculation purposes.

Impact of the proposed windfall tax on Australian energy projects

At US$120/bbl Brent oil, imposing a 25% export levy on LNG would result in an effective project tax rate of 83%, and a reduction in the value generated by 94%, effectively eroding nearly all positive value[2]. This could make existing projects and future backfill gas supply projects uninvestable.

Impact of a 25% export levy at US$120/bbl Brent oil



Export levy

An export levy applied as a 25% tax on export revenue results in the largest windfall levy generated in absolute dollar terms and is modelled to be the most disruptive to energy project economics. Such a levy would erode nearly all positive value of the analogue offshore gas development in NPV10 terms – value generated is reduced by 94% at a US$120/bbl Brent oil price as a result of the levy.

Windfall profit tax

Tax on surplus profit also has a considerable impact on the expected value of the modelled asset. At a US$120/bbl Brent oil price, value generated is reduced by 32% as a result of the levy in NPV10 terms, and IRR is reduced by 2.4%. Total Government Share of profit (the effective tax rate of the investment) rises by 8%, taking it to almost two-thirds of total profit generated.

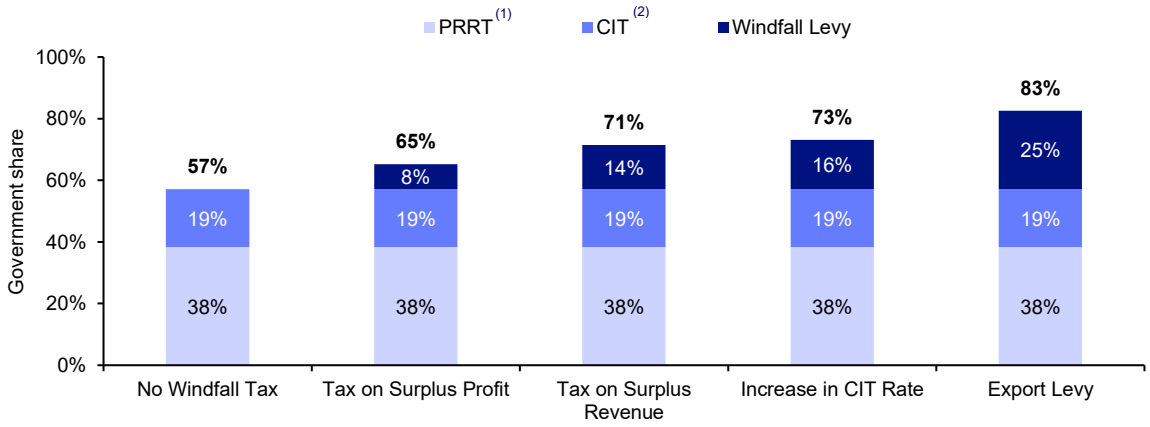
Windfall revenue tax

Similarly, at a US$120/bbl Brent oil price, a tax on surplus revenue erodes over half of the projects value, with a 54% decrease in NPV10 terms. As a result, IRR is reduced by 3.9%. Total Government Share of profit (the effective tax rate of the investment) rises by 14% to reach 71% of total profit.

Increase in CIT

Applying a 25% increase in the rate of CIT yields results that are comparable to those of a tax on surplus revenue. The slight differences (lower IRR impact but higher impact on Total Government Share) arise from the timing of CIT – while the increase in CIT rate generates more tax revenues in nominal (undiscounted) terms, a greater portion of CIT is incurred later in the project life.

Figure – Breakdown of government share under different windfall levy mechanisms at US$120/bbl Brent oil price



(1) While the nominal PRRT rate is 40%, the allowable/deductible uplift of E&A and CAPEX by 9.25% (annual interest) lowers the effective PRRT
(2) While Australia's nominal CIT rate is 30%, effective PRRT is deductible for CIT calculation purposes; 30% x (1-38%) = 19% (effective CIT rate)

[2] Due to a 25% levy on export revenue at a constant US$120/bbl Brent oil price, when compared to current Australian fiscal terms.

The mechanics of Petroleum Resource Rent Tax (PRRT)

Petroleum Resource Rent Tax (PRRT) is a tax on petroleum production. It is levied at a rate of 40% of gross revenue of hydrocarbons at their point of extraction after consideration of a range of deductions. These deductions include exploration costs, project development and operating costs, and decommissioning costs. These deductions are in place in order to account for the expenditures required to find, extract and transport oil and gas for processing into marketable products (e.g. LNG).

The deductions against PRRT generally mean lower amounts of PRRT are paid early in a project's life, as the capital costs associated with exploration for hydrocarbons, and the construction phase of an upstream development project, are higher than the revenue generated in the early years of production.

For the analysis in this Briefing Note, the effective PRRT rate has been calculated on a full lifecycle basis (i.e., total PRRT payable over the entire operational life of the project divided by total pre-tax cash flow, on an undiscounted basis). This full lifecycle effective rate is sensitive to several underlying assumptions, most notably ring-fencing and the quantum of assessable receipts.

Most important, though, is the assumed price for the purposes of calculating project revenue. Under the US$120/bbl Brent oil price scenario the project is profitable from the first year of production, causing the accumulated net operating loss (NOL) carried forward (i.e. the deductions of exploration and capital development costs) to largely expire within 3 to 4 years. This reduces the impact of cost augmentation – currently 9.25% per annum on the unutilised balance – reducing the total uplift realised and in turn increasing the effective full lifecycle PRRT rate. Conversely, in a lower price environment, NOLs persist for longer, the uplift mechanism generates greater cumulative deductions, and the effective PRRT rate is correspondingly lower.

For assessable receipts, rather than applying the Residual Pricing Method (RPM) – which averages the netback and cost-plus prices – we have used the downstream netback price as a simplified proxy. Additionally, the economics of the analogue have been calculated on a stand-alone basis, with no fiscal synergies assumed from existing assets.

Table – Change in metrics under different tax mechanisms relative to Australia's current fiscal terms (US$120/bbl Brent oil price)

	Tax on Surplus Profit (EBIT)	Tax on Surplus Revenue	Increase in CIT	Export Levy
IRR	-2.4%	-3.9%	-3.7%	-7.5%
NPV10	-32%	-54%	-54%	-94%
Change in Government Share	+8%	+14%	+16%	+25%
Total Government Share	65%	71%	73%	83%

Impact on Total Government Share

In all scenarios, Total Government Share increases from the current 57% at US$120/bbl to as high as 83% for the export levy structure. However, the way in which Total Government Share changes as prices change is different across the different structures. The intention of a windfall tax in general is to capture a greater tax share of profits generated from high prices. However, some of the structures modelled in this analysis actually result in a regressive tax structure. This decreases Total Government Share as prices increase and increases Total Government Share as prices decrease, introducing significant downside risk for project proponents given the volatile nature of oil and gas markets.

Flat taxes on revenue (such as the export levy) are regressive

A flat 25% export levy has been specifically proposed as a potential mechanism. However, this is a regressive tax which would lead to lower effective tax rates when product prices increase, and higher rates when prices decrease. This is due to the nature of revenue-based taxation, where increases in revenue do not scale directly with profit.

The impact of a regressive tax on an industry such as oil and gas production is significant. The exploration for, and production of, oil and gas is inherently high risk. Projects are capital-intensive with long lead times, and the volatile nature of oil and gas markets mean a high range of uncertainty associated with future cashflows. This risk is balanced with the potential for upside value capture during periods of elevated commodity prices. A regressive tax significantly impacts this balance – Total Government Share would increase at lower commodity prices, which erodes project returns, increases downside risk and reduces overall investability of a given project.

Windfall or 'surplus' taxes may be progressive or regressive, depending on project economics

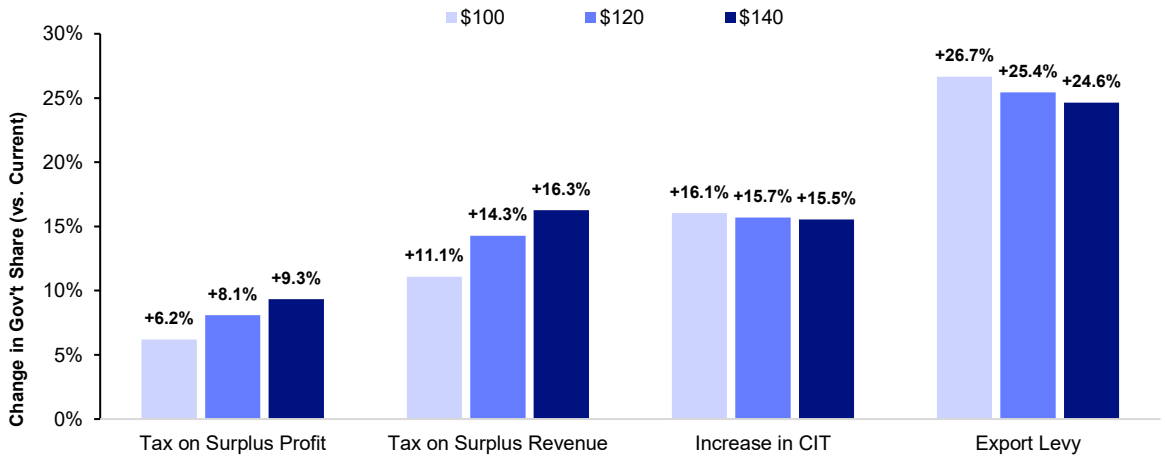
While a tax on surplus revenue appears to be progressive under our modelled scenarios, the same mechanism can exhibit regressivity under a higher-cost or lower-margin environment. Taxes on surplus revenue can also make an otherwise profitable project uneconomic – when revenue is the sole taxable basis, tax can be substantial in a high price environment regardless of operating margins, potentially resulting in negative post-tax cashflow because of the windfall tax.

While a tax on surplus profit is more likely to retain progressivity, this tax can also be regressive in some cases. A project that generates negative profit under baseline prices and modestly positive profit under 'windfall prices' would exhibit regressive properties. In these marginal scenarios, a windfall profit tax may be disproportionately high relative to pre-tax cashflow, leading to a high Total Government Share which then decreases as prices increase.

An increase in CIT dilutes the progressivity of PRRT

CIT is not a regressive tax, but when CIT increases as a proportion of Total Government Share, the progressive impact of PRRT becomes less pronounced, making the tax structure less sensitive to an incremental increase in price. Under Australia's current fiscal terms, Total Government Share increases from 53.8% to 57.4% (+3.6%) when Brent oil price increases from US$70 to US$140/bbl. However, the increased CIT scenario results in Total Government Share only increasing from 71.6% to 73.0% (+1.4%) under the same conditions. This suggests that an increase in the CIT rate will cause Australia's oil and gas fiscal structure to become less progressive.

Figure – Change in Total Government Share at US$100, $120 & $140 per barrel (relative to current terms with no windfall tax)



Impact on investability

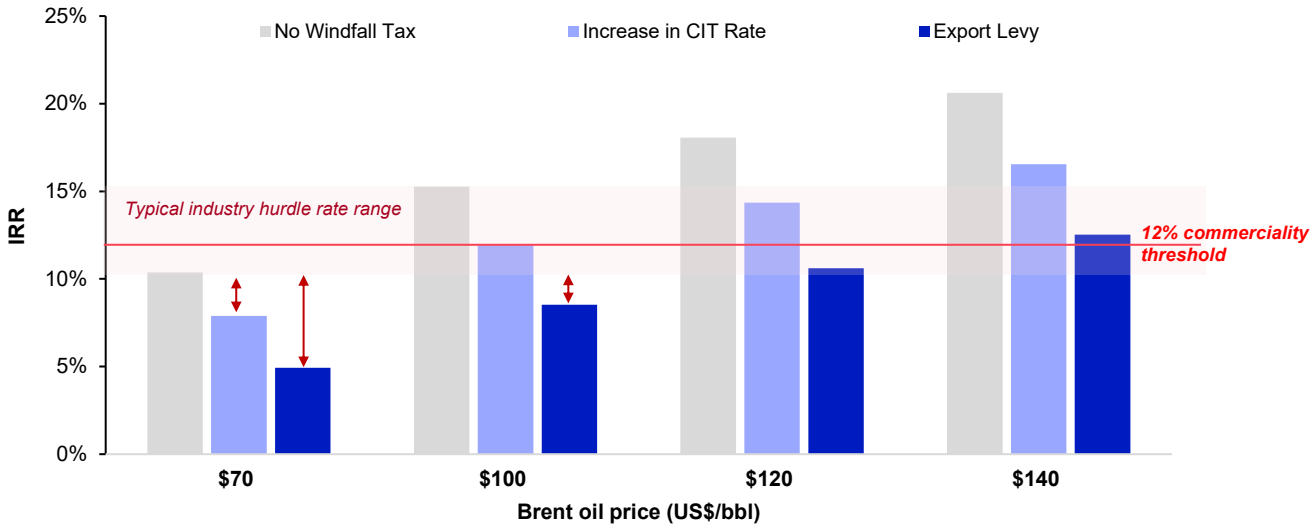
Upstream oil and gas companies invest in projects to generate a return commensurate with the risk level of the investment. Upstream oil and gas exploration and production is inherently higher risk than other investments such as infrastructure projects, as upstream projects are subject to the volatility inherent in global oil and gas markets and must balance upside value generated by higher prices with the downside risk of lower prices or higher operating costs. They are also typically highly capital-intensive, have long lead times, and operate over decades.

Typical hurdle rates for investment in greenfield upstream oil and gas projects can be as much as 15% or more, while brownfield expansion or backfill projects may have slightly lower rates (reflecting their lower risk profiles). Australia's Federal regulator, the National Offshore Petroleum Titles Administrator (NOPTA), states in the Guideline for Retention Leases that "*mid-case nominal after tax IRR of 12% or greater will be considered commercially viable*".

Investments are also predicated on assumptions of long-run oil and LNG prices, which do not incorporate short term volatility – both upside and downside. Whilst projects may appear economic at high oil prices, investors evaluate projects at more conservative long-run prices that reflect long-term market fundamentals. Typically, these valuations are performed at oil prices between US$65 and US$75/bbl. This is further reinforced by the fact that current debates on windfall levels of revenue or profit are centred around any revenue or profit generated by oil prices being above US$70/bbl, implying that US$70/bbl is a reasonable long-run assumption for Brent oil prices. Indeed, UK's 'windfall tax' Energy Profits Levy has introduced a price floor of US$71.4/bbl – at or below this price, the Energy Profits Levy is not levied on projects.

At a Brent oil price of US$70/bbl, the imposition of a 25% export levy would make currently economic projects uninvestable, with full lifecycle IRR's falling by up to 5.5% under this tax structure. Further, full lifecycle IRRs would fall below NOPTA's definition of a commercial or investable return (12%) at any Brent oil price up to US$140/bbl, meaning that investable returns could not be achieved unless long-term oil prices were to remain at or above US$140/bbl over the project's lifecycle.

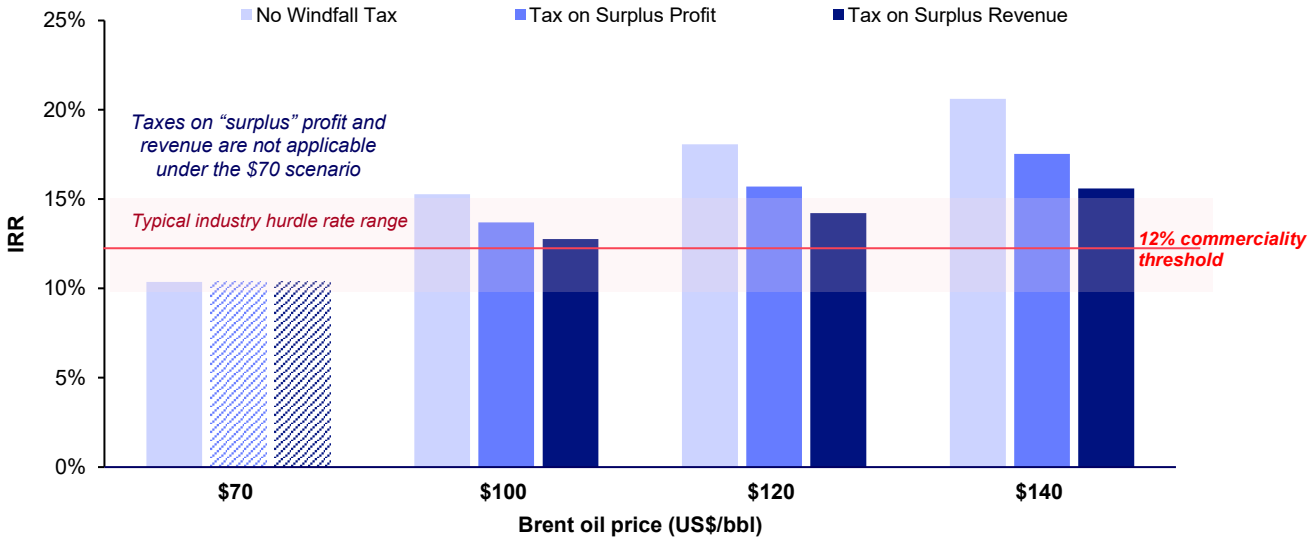
Figure – Comparison of IRR under export levy & CIT-based mechanisms compared with the typical industry hurdle rate range



Windfall taxes aimed at capturing a greater share of 'surplus' revenue or profits also reduce investor returns, by limiting potential upside when prices are elevated. Without additional measures being incorporated into the design of fiscal terms to protect against downside risk – for example, allowing immediate expensing of capital expenditure or direct reimbursement of tax deficits – the balance of upside value and downside risk is fundamentally shifted. The exposure to downside risk remains, however the potential for upside value capture is blunted, increasing overall investment risk for project proponents.

As a result, it is likely that project proponents would impose higher hurdle rates on projects to account for the increase in risk presented by fiscal terms that include windfall taxes without additional downside protection. At a Brent oil price of US$120/bbl, a 25% windfall tax on revenue would reduce IRR by 3.9%, and a 25% windfall tax on EBIT would reduce IRR by 2.4%.

Figure – Comparison of IRR under windfall 'surplus' tax mechanisms compared with the typical industry hurdle rate range



Case Study – the United Kingdom Energy Profits Levy (EPL)

The most recent wave of windfall taxes, introduced in 2021–2023 in response to elevated oil, gas, and energy prices following COVID-19 disruptions and Russia's invasion of Ukraine, provide a useful case study to assess the impact that windfall-related modifications may have on overall fiscal attractiveness. Despite their intended purpose of capturing increased profits for the state, many of these mechanisms have produced disappointing and, in some cases, counterproductive outcomes – deterring investment, accelerating asset disposals, and undermining long-term production capacity in exchange for temporary tax revenue gains. The UK's Energy Profits Levy (EPL) and its impact on upstream investments provides a useful reference.

The UK EPL

The Energy Profits Levy was introduced by the UK government in May 2022 as a 25% surcharge on the profits of oil and gas companies operating on the UK Continental Shelf (UKCS), due to apply until 2025. Combined with the existing 30% Ring Fence Corporation Tax and 10% Supplementary Charge, the EPL brought the headline marginal tax rate on UKCS profits to 65%. The mechanism also included an 80% investment allowance to incentivise capital spend. This introduction was followed by a series of changes and additions:

- **Increase in EPL rate** to 35% and subsequently to 38%, ultimately raising the combined tax rate to 78%.
- **Reduction of investment allowance** to 29% for oil & gas spend not related to decarbonisation.
- **Extension of the sunset clause to 2030**, to be replaced by a permanent mechanism to tax "excess" profits.

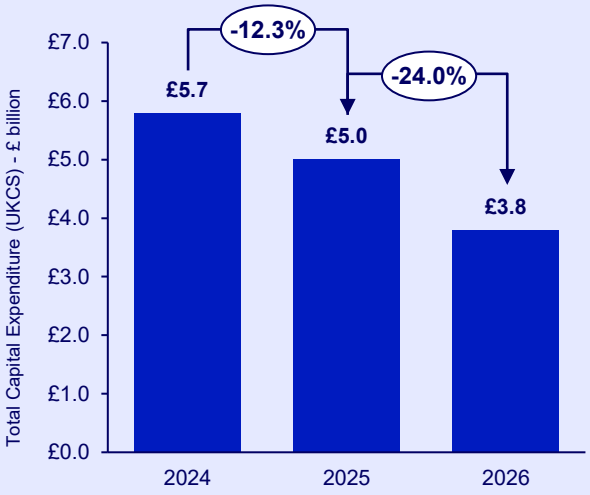
Impact on investment and activity

Each successive modification has added to investor uncertainty, reinforcing a perception that the UKCS fiscal regime is structurally unpredictable and politically exposed. The cumulative effect of the EPL and its subsequent modifications has been a measurable contraction in UKCS investment activity.

This includes a significant reduction in expected capital expenditure on the UKCS relative to pre-EPL trajectories, with billions of pounds of investment at risk of being redirected to more competitive jurisdictions.

The North Sea Transition Authority (NSTA)'s historical data and projections (as of February 2026) indicate a declining trend in total capital expenditure spend since the implementation of EPL (£5.7bn in 2024, £5.0bn in 2025, and £3.8bn in 2026). Additionally, Wood Mackenzie estimates that more than £15bn of potential CAPEX (spend on Pre-FID projects) is at high risk of being cancelled.

Total capital expenditure – UKCS (£ billion)



The UK has also seen cancellations or delays of drilling and development programmes, with major operators citing the deteriorating fiscal environment as a primary driver of reduced exposure to UKCS. For example, Equinor and Harbour Energy, among other international companies, have publicly announced a pivot away from the country to Norway and/or the US and South America.

The result of this fall in investment is a decline in exploration activity on the UKCS to historically low levels, with E&A spend expected to remain constrained going forward. This suggests a reduction in the long-term pipeline of developable resources.

Long-term impacts

By compressing post-tax returns and introducing fiscal uncertainty while offering limited downside protection for investors, windfall tax mechanisms like EPL may deter the long-cycle capital investment that sustains future production, in turn reducing the tax revenue generated from future operational projects. Furthermore, declining domestic production increases dependence on imports, exposing the economy to price volatility and geopolitical risks.

Impact on Australia's fiscal competitiveness

Fiscal terms in the oil and gas sector represent the specific set of laws, regulations, and contractual agreements that determine how the economic value generated from hydrocarbon production is shared between a host government and a private oil company. These terms define the total percentage of project cash flow retained by the state through various mechanisms such as royalties, corporate income taxes, bonuses, and, in some cases, state participation or production sharing.

Because exploration and production are highly capital-intensive and investments require consideration of long-term returns, fiscal frameworks are designed to balance a country's need for revenue with the investor's requirement for a competitive rate of return. Among other project metrics such as geological prospectivity, investors evaluate fiscal terms across jurisdictions as a key input into deciding whether to invest in a given location.

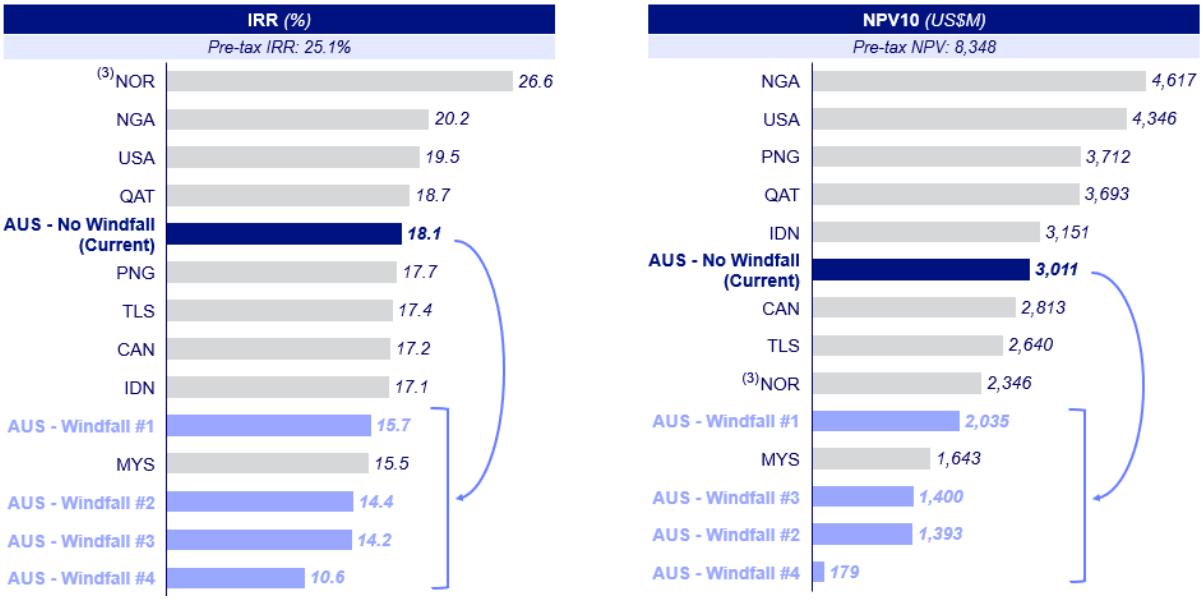
When compared to peer countries that compete with Australia for upstream oil and gas investment, Australia's current fiscal regime ranks moderately. Among the nine peer countries analysed (Canada, Indonesia, Malaysia, Nigeria, Norway, PNG, Timor-Leste, Qatar[3] and the United States) Australia ranks fifth for investment return (IRR), sixth for total value (NPV10) and seventh for Total Government Share. Among the top three LNG exporters globally (USA, Qatar, Australia), Australia ranks the poorest across all three metrics.

The addition of a new windfall levy will further adversely impact Australia's relative position, placing it in the bottom quartile of its peers across all three metrics of fiscal attractiveness. While the magnitude of the impact varies by mechanism, the windfall tax would cause Australia's fiscal competitiveness to fall behind those of its regional peers.

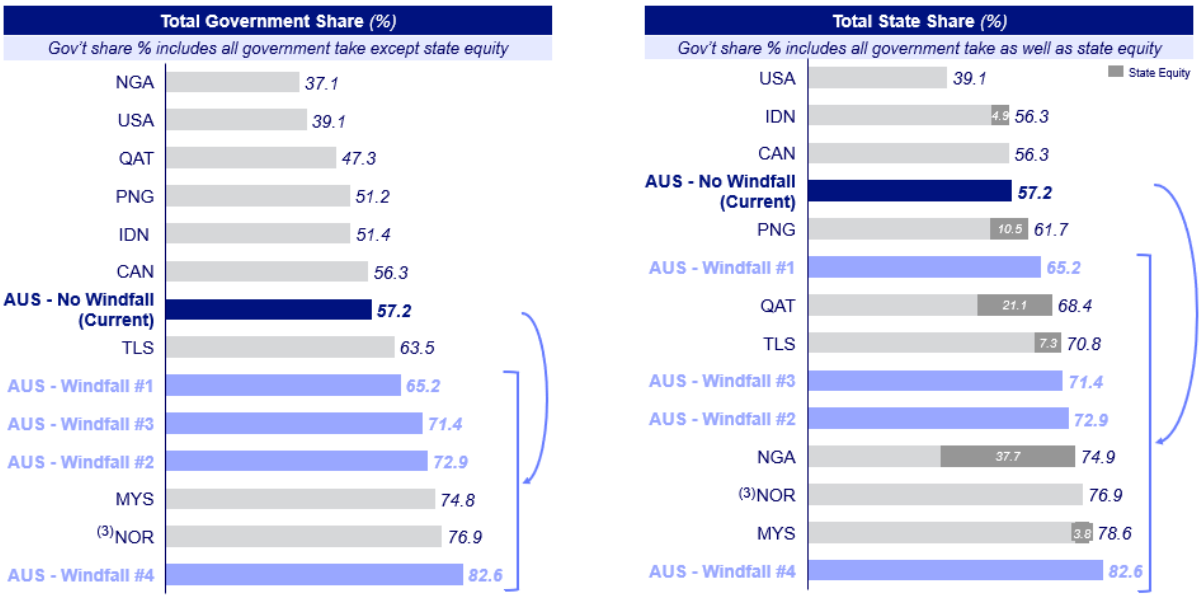
The charts below highlight Australia's current position relative to peers for each of the key evaluation metrics when considering the standardised analogue offshore gas field development at a US$120/bbl Brent oil price, along with the potential impact various windfall levy mechanisms may have on competitiveness. For readability, the chart uses short-hand names for the different windfall mechanisms discussed in the preceding sections:

- **Windfall #1:** windfall profit tax – 25% tax on surplus taxable profits (EBIT)
- **Windfall #2:** increase in CIT – 25% tax increase in CIT rate (current 30% + additional 25%)
- **Windfall #3:** windfall revenue tax – 25% tax on surplus gross revenue
- **Windfall #4:** export levy – 25% tax on export revenue

Figure – Australia's fiscal competitiveness at US$120/bbl relative to benchmarked peers[(1)] (with & without windfall tax)[(2)]



[3] As of 1 January 2026. The impact of the current conflict in the Middle East may affect investment returns and value generated by Qatari energy projects, though this remains to be quantified.



(1) AUS = Australia / USA = United States of America (Gulf of Mexico) / CAN = Canada (British Columbia) / NOR = Norway / QAT = Qatar / PNG = Papua New Guinea / TLS = Timor Leste / NGA = Nigeria / MYS = Malaysia (Deepwater) / IDN = Indonesia (Profit Sharing Contract)

(2) Assessment based on Wood Mackenzie's existing database of benchmark countries' fiscal terms; results based on the assumed analogue and macroeconomic inputs (high-price environment (Brent price of $120/bbl)); for details on how surplus profit/revenue are calculated, refer Appendix 1

(3) Norway's State Equity can vary between 0% and 30% via State Direct Financial Interest (SDFI). For simplification of the analysis, Total State Share comparisons exclude the impact of SDFI and other forms of ownership (i.e., via Equinor). Details of the mechanism are provided in the "Norway Special Tax" analysis in this Briefing Note. Norway has a cash-based tax system ("Special Tax") which contributes to a wide divergence in ranking (i.e., high ranking for IRR coupled with low ranking for NPV10 and total government share). The

As can be seen, the addition of a windfall tax to Australia's fiscal terms would reduce competitiveness with peer regimes, reducing Australia's fiscal attractiveness for potential investors. The export levy structure in particular would make Australia the least fiscally attractive regime of all peer countries, significantly impacting its ability to attract and retain investment in upstream oil and gas production.

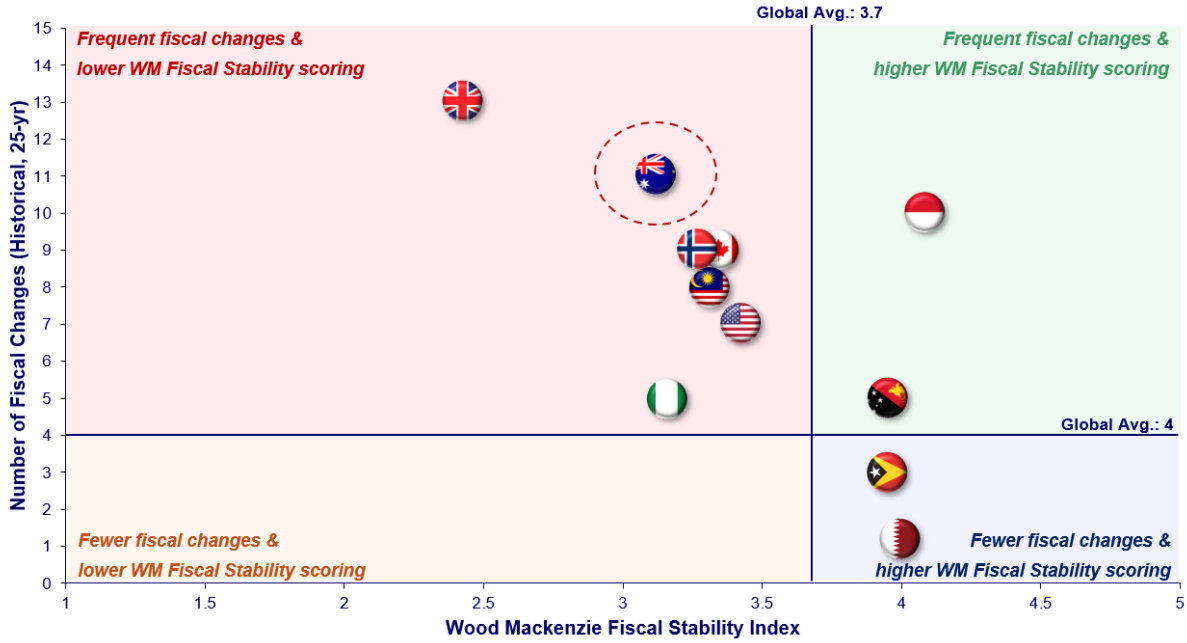
Additionally, when considering the attractiveness of a fiscal regime, investors also place importance on the relative stability of those fiscal terms. The long-term nature of oil and gas investment means that developers place a high value on the predictability of long-term cashflows. In many cases, stability of terms can be more important than the overall attractiveness of those terms. Frequent or negative changes to fiscal terms can lead investors to place a higher risk premium on investments within a regime, as there is lower certainty in their long-term stability.

Wood Mackenzie's Fiscal Stability Index is a tool used to assess and compare the stability of fiscal regimes in different countries or regions for the oil and gas industry. The index aims to measure how stable and predictable a country's fiscal regime is for oil and gas investments over time. The index considers various factors that contribute to fiscal stability, which include the frequency of changes to fiscal terms, the magnitude of changes when they occur, the predictability of changes, transparency in the process of changing fiscal terms, adherence to contracts and agreements, political stability and its impact on fiscal policies and the historical track record of fiscal changes.

Since 2002, Australia has made several significant changes to its fiscal terms for upstream oil and gas projects, which have had various impacts on investment returns. This included the changes to the PRRT in 2012, the PRRT Review and Reforms between 2016 and 2019, the introduction of a PRRT deductions cap for LNG producers in 2023, and the introduction of a Decommissioning Cost Recovery levy in 2021.

As a result, Australia's current fiscal stability is considered to be lower than all peer countries with the exception of the United Kingdom, who's fiscal stability has been eroded by the introduction of, and subsequent changes to, the UK EPL. The introduction of a windfall tax in Australia would further reduce Australia's fiscal stability.

Figure – Number of Historical Fiscal Changes x WM Fiscal Stability Index Matrix (Australia, Peer Countries, UK)



Australia's increased tax take during high-price periods, compared with other jurisdictions

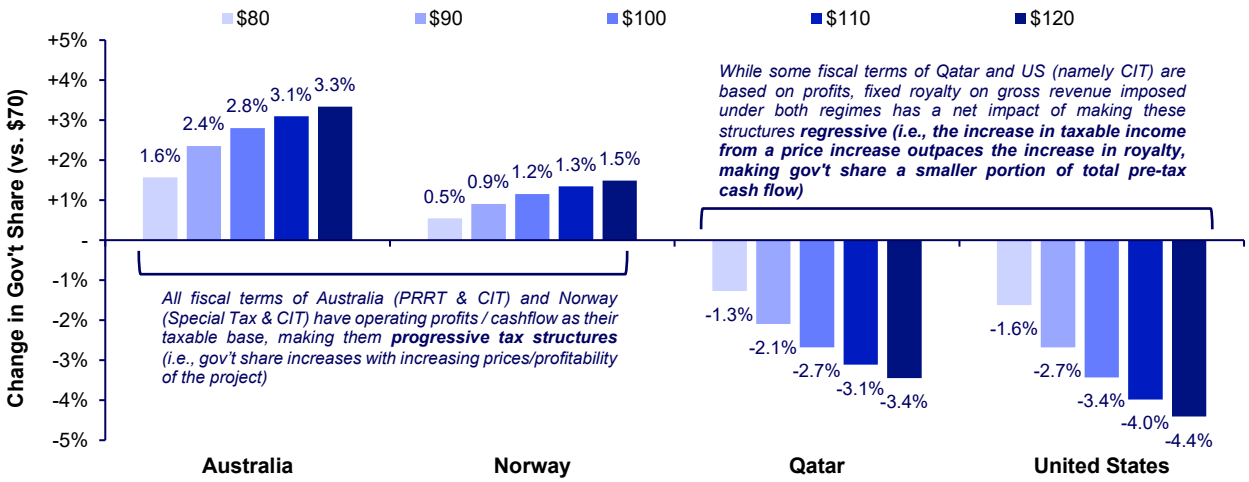
Preserving the government's fair share of resource revenues and maintaining a competitive investment environment are not mutually exclusive. Several jurisdictions have fiscal mechanisms that capture resource rent effectively across the commodity cycle without the structural drawbacks of retrospective windfall levies.

In fact, Australia's existing fiscal terms already allow government to capture substantial upside during high-price environments – even without a windfall tax mechanism. The existing CIT and PRRT-based terms constitute a progressive, profit-based tax structure that captures additional tax revenue when prices increase. This is demonstrated by the change in Total Government Share of Australia's existing fiscal regime when increasing average realised oil price.

Other jurisdictions such as Norway also use progressive taxation to capture additional value upside when prices rise, but the structure of this tax also includes downside protections and lower upfront costs that improve investor returns when compared with a windfall tax.

Conversely, regimes with direct state participation on an equity basis utilise regressive fixed royalties on a revenue basis. However, this is combined with significant state participation, meaning that the government shares the risk and capital costs of development as well as sharing in any additional value capture from higher prices. This both reduces risk and improves returns for private oil and gas companies in these regimes, as the government relies less on taxation and royalties, and more on their equity participation to drive state revenue.

Figure – Change in Total Government Share as oil prices increase (relative to share at US$70/bbl)



Norway: high levels of State participation, with a cashflow-based tax and structural downside protection supporting upside capture

Norway's fiscal regime is frequently referenced to advocate for an increase in headline tax rates – its combined corporate income tax and Special Tax rate of 78% has been used to justify, for example, the UK's latest increase in EPL (the revised EPL rate of 38%, when combined with the Ring Fence Corporation Tax of 30% and Supplementary Charge of 10%, results in a combined headline rate of 78%).

However, the structure of Norway's fiscal regime differs substantially from the UK and Australia. **Norway directly and indirectly owns and participates in Norway's oil and gas industry and projects**. Equinor ASA is an international energy company that accounts for 70% of all oil and gas production on the Norwegian shelf. The Norwegian state owns 67% of the shares in Equinor ASA, and this share is managed by government ministries. Additionally, Norway directly participates in petroleum activities through its State Direct Financial Interest (SDFI) mechanism and its licensee Petoro AS. Petoro's main objective in managing the SDFI shares in production licenses and fields is to create the highest possible value and maximize state revenues from the portfolio.

In addition, while the headline rate of Norway's Special Tax is 78%, the mechanics of the tax differ fundamentally from a windfall levy such as the UK EPL or those proposed in Australia. In 2022, Norway's Special Tax was converted to a cash flow tax, allowing the immediate expensing of all capital expenditure (i.e., full depreciation of CAPEX incurred each year). Furthermore, companies that do not have any taxable income receive direct reimbursement of the special tax value of their deficit rather than being required to carry losses forward against uncertain future income.

Under this structure, the **Norwegian state effectively participates in project economics symmetrically, sharing downside risk in direct proportion to its tax take on the upside**, with its tax revenues adjusting automatically in line with project profitability and commodity market conditions. In practice, this mechanism achieves the following:

- **Higher investor IRR & downside protection:** Immediate expensing of CAPEX and direct reimbursement of Special Tax losses allow investors to effectively incur lower upfront costs (and in turn reduced risk), materially benefiting companies with high hurdle rates. The pre-production cost refund shortens the payback period and enhances returns on a risk-adjusted basis.
- **Upside capture for the government:** Once a project achieves profitability and CAPEX requirements decrease, the 78% marginal rate helps allocate a substantial majority of positive cash flow to the state. From the investor's perspective, Norway's structure reduces the overall "scale" of the investment.
- **Fiscal deterrence:** By dynamically calibrating the state's take to actual project economics, the regime structurally reduces the incentive for reactive fiscal intervention during periods of commodity price surges and downturns. This renders intervention like fiscal incentives (i.e., investment allowances) or windfall taxes less necessary.

The Norwegian fiscal regime is fundamentally different from that in Australia. The ability to transition from Australia's current fiscal structure to one similar to that in Norway is difficult. Norway operates with a high level of state participation, leverages Equinor's position as a major global oil and gas company and also operates a non-profit gas transportation network in the country. Additionally, Norway's gas is mostly exported via pipeline to European neighbours, which is significantly lower cost and lower risk than exporting to market via LNG.

Transitioning from a capped deduction structure under PRRT to the immediate deduction of capital expenditure in the Norwegian structure, for example, could result in large amounts of un-deducted historic capital expenditure being immediately fully depreciated.

Qatar: risk-sharing via state equity participation with no or limited carry obligations

With an automatic right to take equity in any commercial discovery, QatarEnergy typically participates directly as the dominant equity partner in domestic assets (a few exceptions include Pearl GTL and Bunduq). While Wood Mackenzie has conservatively modelled Qatar's state equity share as 40% (in line with our understanding of the provisions related to QatarEnergy's right to take equity), QatarEnergy's negotiated stake in projects often exceeds 60%. While some investors prefer greater ownership and operatorship, this partnership structure allows Qatar to maintain a relatively simple and attractive set of fiscal terms, with the government capturing a substantial portion of project cashflows via QatarEnergy's working interest in the asset, as opposed to relying solely on royalty and tax (in our model, Qatar's state equity constitutes 31% of its total undiscounted state share). Furthermore, Wood Mackenzie understands that there are no pre-production carry obligations under the regime, meaning that QatarEnergy assumes its equity portion of cash outflows in the development stage of the project.

High state equity with no development CAPEX carry obligations translates to lower upfront capital requirements and risks for the private investor. While the fiscal system does not provide direct reimbursement for tax losses like Norway, and has regressive taxes (royalties), QatarEnergy's equity co-participation ensures that the government shares both downside risk and upside potential in proportion to its ownership stake. Qatar is also the lowest cost producer of gas and LNG in the world, providing opportunity for higher profitability and increased fiscal attractiveness for investors.

The NOC is exposed to the same cost overruns and commodity price cycles as the private investor, creating an alignment required for efficient project delivery and long-run commercial success. Additionally, Qatar's attractive fiscal terms (i.e., relatively low combined tax rate) lead to a high overall fiscal competitiveness. Wood Mackenzie's comparative fiscal analysis reflects this, with Qatar ranked in the top three or four among peers across the IRR, NPV10, and Total Government Share (excluding state equity) metrics.

A high degree of state ownership and direct government involvement also yield other benefits, including operational stability, access to regulatory and physical/infrastructure networks, technical capacity and institutional knowledge, among others. Each of these factors contribute to enhanced risk management from the private investor's perspective (i.e., downside protection), while the government's direct participation ensures a "fair share" of upside value capture under high-price and/or low-cost environments.

Similar to the Norwegian fiscal regime, **Qatar operates with a high level of direct State participation in oil and gas projects through its large state-owned oil and gas companies. This is in contrast to Australia, which does not participate in projects and does not have a National Oil Company or state-owned developer that would allow this kind of fiscal structure to operate effectively.**

The potential impacts of a windfall levy on Australia's oil and gas industry

With the Federal Government's Future Gas Strategy making clear the critical, long-term role for gas to support the decarbonisation of power generation and the continuation of local industry in this country, the need to encourage investment in the development of Australia's gas resources is obvious and pressing.

We model that the most recently sanctioned offshore gas to LNG backfill projects in Australia took FID with full lifecycle IRRs of between 9% and 13% under existing Australian fiscal terms. As outlined in the analysis, the impact of an export levy could potentially reduce project IRR (at US$70/bbl) by 5.5%. This reduction would likely make these projects uninvestable, with full lifecycle IRR falling to as low as 3.5%. The impact of this on Australia's energy security, the energy security of our trading partners, and foregone Government taxation revenue would be material.

Wood Mackenzie estimates that upstream gas projects in Australia forecast to take FID in the next few years could generate A$151.8bn (US$110bn) in cumulative pre-tax nominal cashflow. Of this, Total Government Share is estimated to total approximately A$70.4bn (US$51bn) (cumulative post-tax nominal cashflow net to Government) under current fiscal terms. These projects are also estimated to have full lifecycle IRRs of between 9% and 18% - the addition of an export levy could reduce these returns to as low as 4.5% to 12.5%[4], potentially making them uninvestable and putting up to A$70.4bn of Government income at risk.

Together these projects represent total 2P Reserves of 18 tcf (~19,000 PJ) of natural gas – the equivalent of more than 300 million tonnes of LNG – and 1 billion barrels of liquids (including oil, condensates and natural gas liquids). If these projects do not proceed, the impact on Australia's energy security, the energy security of our trading partners – who are significant investors in Australia's energy industry – and foregone Government taxation revenue would be material.

[4] Estimated, based on the reduction in IRR observed for the analogue development analysed in this Briefing Note, which may not exactly match the profiles of these individual pre-FID projects.

Given the backfill nature of these projects, it would also impact the longevity and valuations of Australia's existing LNG liquefaction facilities as a result of constrained upstream gas supplies and shortened economic lives. Additional impacts could also include an increase in perceived sovereign risk for LNG trading partners and lower economic activity as a result of projects not proceeding.

It would also impact the availability of domestic gas supplies, particularly in the West Australia domestic gas market given its reliance on LNG exporter domestic gas commitments and the need for new supply to enter the market from the end of this decade in order to keep the market sufficiently supplied.

Appendix 1 – detailed assumptions and methodology

Development analogue

To avoid introducing project-specific factors and to ensure ready comparability with other fiscal structures, Wood Mackenzie uses a standard field (production & cost profile) as the basis of our calculations of project economics. To ensure relevance to Australia, we have selected a proxy for a large-scale offshore gas development as our assumed profile. The asset characteristics include:

- **Reserve size**: 4 tcf
- **Peak gas production**: 450 mmcf/d
- **E&A and development spend**: A$1,035M (US$750M) and A$8,832M (US$6,400M), respectively, in 2026 real terms
- **Unit OPEX**: A$0.77/mcf (US$0.56/mcf) in 2026 real terms
- **Operational lifespan**: 27 years

To capture the economics of an integrated asset (upstream + LNG), we apply netback pricing (LNG DES price *minus* tolling fee *minus* shipping) to calculate the expected net revenue. Details of price & formula assumed are outlined in the following section. For simplicity, no boil-off gas is assumed.

Macroeconomics

Our model's assumed netback pricing consists of the following:

$$Netback\ pricing = LNG\ (DES)\ price - tolling\ fee - shipping\ fee$$

- **LNG (DES) price**: 12.5% x Brent + 0.5 (assumes all volumes are contracted; no spot sales)
    - Brent prices assumed in our models are US$70/bbl ("base line" price scenario) and US$120 /bbl ("windfall" price scenario), both in 2026 real terms
- **Tolling fee**: A$3.45/mcf (US$2.5/mcf) (2026 real terms)
- **Shipping fee**: A$1.10/mcf (US$0.8/mcf) (2026 real terms) (assumed to be the same across peer regimes for simplicity)
- **Exchange rate**: Wood Mackenzie Q1 2026 Exchange Rate Forecast long-term real exchange rate: US$1 = A$1.38.

This translates to the following realised netback prices:

- **"Base line" price scenario**: A$8.21/mmBtu (US$5.95/mmBtu) (2026 real terms)
- **"Windfall" price scenario**: A$16.84/mmBtu (US$12.20/mmBtu) (2026 real terms)

For both prices and costs, we apply an annual 2% escalation; for NPV/discounted cashflow calculation purposes, we apply a 10% discount rate.

Comparable regimes & fiscal terms

For the purposes of evaluating Australia's fiscal competitiveness against comparable regimes, we have included the following regimes into the peer group: **United States, Canada, Norway, Qatar, Papua New Guinea, Timor-Leste, Nigeria, Malaysia, Indonesia.** Our assessments are performed based on our proprietary database of concession/PSC documents. The following outlines the key assumptions we've adopted for each fiscal regime:

Table – Peer regimes' assumed fiscal terms

Regime	Contract type	Royalty	Cost Recovery Ceiling	Gov't Profit / Revenue Share	Federal CIT / PIT	State Equity	Other
Australia (Federal)	Concession	-	-	-	30.0%	-	PRRT (40%)
United States (GoM)(1)	Concession	18.75%	-	-	21.0%	-	-
Canada (BC)(2)	Concession	5-36% (price dependent)	-	-	15.0%	-	Provincial income tax (12%)
Norway	Concession	-	-	-	22.0%	0-30%(3)	Special tax (71.8%)
Qatar	Concession(4)	15.0%	-	-	35.0%	40.0%	-
Papua New Guinea	Concession	2.0%	-	-	30.0%	22.5%	Development levy (2%), APT (30%)
Timor-Leste	PSC	5.0%	100.0%	40.0%	30.0%	20.0%	Supp. petroleum tax (22.5%)
Nigeria(5)	Concession	5.0%	-	-	30.0%	-	Education tax (3%)
Malaysia(6)	PSC	10.0%	60-80%	20-50%	38.0%	15.0%	Supp. payment (50-70%)
Indonesia(7)	PSC	10.0% (FTP)	100.0%	19.9%	37.6%	10.0%	Land & building tax (0.5%)
United Kingdom(8)	Concession	-	-	-	30.0% (RFCT)	-	Supp. charge (10%), EPL (38%)

(1) Assumes water depth of >200m (shallow water w/ water depth of <200m are subject to a lower 12.5% royalty under the US GoM fiscal terms)
(2) While there are no offshore upstream opportunities in British Columbia, the province's fiscal terms are most relevant among Canada's provinces given the concentration of (potential) LNG developments in the region
(3) Variable range; direct state participation (state equity) is typically between 0% and 20% to 30% via Petoro (State's Direct Financial Interest). Indirect participation via majority ownership of Equinor does not contribute to State Equity figures but does increase the Norwegian Government's participation indirectly. Petoro pays share of exploration and development costs (no carried costs).
(4) Historically, production in Qatar was taxed under Production Sharing Contracts (PSCs), but since 2014 the renewal of licenses has been under a Concession (tax and royalty) framework. The exact Concession terms have not been made publicly available. As a result, our assumptions are based on operator feedback of existing contracts. We expect Concessions to be used for future license awards
(5) "Hydrocarbon Tax" payable only on onshore & shallow water oil production
(6) Cost recovery PSC for deepwater assets; fiscal structures like EPT, SFA, and LLA are not considered in this study
(7) Cost recovery PSC for deepwater assets; Gross Split terms are not considered in this study
(8) Provided for reference (EPL case study); not considered a "peer" in WM's fiscal competitiveness analysis for Australia's offshore/LNG assets

Calculation approach

When conducting the analysis, we adopt the following in our calculations:

- **Process**: Based on the selected analogue, we calculate the "pre-tax"/operational cash flow net to all shareholders (i.e., before government take). We subsequently apply each regime's fiscal terms to assess the impact of each jurisdiction's fiscal structures on investor IRR, NPV, and state share.
- **Cash flow calculation method**: This approach assumes that the hypothetical investor had recently acquired a licence and is conducting operations under the latest terms available for exploration in each jurisdiction. The economics of each development are calculated on a full cycle (incl. exploration cost) & standalone basis, and only direct taxes and fiscal terms associated with production / revenue / profit of the project are evaluated (i.e., excludes VAT, withholding taxes, among others).
- **Evaluation metrics**: To ensure a more holistic evaluation and comparison of the impact of the windfall levy, we calculate three metrics that are widely accepted and used within the oil & gas industry:
    - **Internal Rate of Return (IRR)**: Discount rate at which NPV of cashflows equals zero.
    - **Net Present Value (NPV)**: The sum of project costs (cash outflows) and cashflow generated from a project (cash inflows), discounted at 10%.
    - **Government share %**: Government take as a share of operational/"pre-tax" field profits. This includes royalties, corporate income taxes, government profit share and any other fees or levies. **State share** also includes state equity % where applicable (required in certain regimes).

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