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AUSTRALIA-MONGOLIA EXTRACTIVES PROGRAM (AMEP)

# MONGOLIA COAL BED METHANE – COMPARATIVE ASSESSMENT OF FISCAL REGIMES

The University Of Queensland
AUSTRALIA

THRE360 ENERGY

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Adam Smith International

**MARCH 4, 2021**

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4 March 2021

# Foreword - Professor A. Garnett, University of Queensland Centre for Natural Gas (UQ-CNG)

The following report "*Australia Mongolia Extractives Program (AMEP) Mongolia Coal Bed Methane - Comparative Assessment of Fiscal Regimes"* has been compiled by consultancy company Three60 Energy Australia (Three60 Energy), on behalf of the Australia-Mongolian Extractives Program (AMEP).

I am the Director of The University of Queensland's Centre for Natural Gas (UQ-CNG), a multi-disciplinary applied research centre focussed on technical, environmental, social, and economic and policy issues for the onshore natural gas sector (https://natural-gas.centre.uq.edu.au/). The Centre is a University-Industry collaboration with CBM gas companies Santos, Arrow Energy (a Shell-PetroChina joint venture) and Australia Pacific LNG (a joint venture between ConocoPhillips, Origin and Sinopec). I have been in this role for nine years following over 25 years' international experience in the upstream oil and gas sector. Until end Oct 2020, I was also non-Executive Director (NED) of the industry growth centre, National Energy Resources Australia (NERA) and am currently NED of the Australian Gas Industry Trust (AGIT). I have also been reviewer for natural gas aspects of the International Energy Agency's, World Energy Outlook since around 2015. In addition to research, I teach *Petroleum Economics and Decision Making* in UQ's Master of Petroleum Engineering, as well as, *Energy Scenario Analysis* in our Master of Sustainable Energy.

Part of my role as Director of UQ-CNG is to provide advice to State and Federal policy makers and regulators. This has included advice to various formal inquiries and reviews including, The Australian Productivity Commission (Issues Paper for Resource Sector Regulation); the Australian Competition and Consumer Commission (Gas Inquiry, 2017-2025); the Queensland Department of Natural Resources and Mines (Gas Supply Demand Action Plan, and the Petroleum Royalties Review); the Australian Department of Industry, Science, Energy and Resources (Technology Investment Roadmap, and Gas Reservation Issues Paper); the Northern Territory Government (Independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs).

Three60 Energy is an expert consultancy specialising in the combination of technical, commercial and economic analyses for the oil and gas sector. They have assembled a suitably qualified, professional team with significant senior technical and management experience in the international sector and, in particular, in the world's largest and most successful coal bed methane (CBM) industry in Australia. In conducting the studies for this report, Three60 Energy has been highly collaborative and open, sharing any and all levels of detail requested and iterating on draft versions addressing questions and comments in a well-considered, highly professional manner.

Three60 Energy has undertaken a series of quantitative and qualitative assessments to inform stakeholders about the relative attractiveness of Mongolian CBM opportunities to external investors. The methods and analyses employed by Three60 Energy are in my view sound, highly appropriate for AMEP's objectives and are in line with those used by small and large, private oil and gas companies. The illustrative quantitative case studies are appropriate and representative enough to inform policy makers. The conclusions drawn are also considered sound (see *additional commentary* below) and indicate well the potential for improvements. This includes discussion on both fiscal and non-fiscal measures, which could significantly increase investment attractiveness. That said, it was not intended as a full review of *all* commercial and regulatory settings that relate to the CBM sector. Other regulatory improvements may further improve the chances for investment.

Additional commentary: There is significant potential for the commercial production of natural gas from coal seams in Mongolia. The country likely has rich CBM resources though they are technically complex. Mongolia has, however, a unique and relatively high investment-risk profile for overseas investors (compared to other areas with CBM or other unconventional gas potential). Investors must consider not only technical and engineering risks in monetising this type of resource, but also those risks relating to availability of data, stability, attractiveness and transparency of the fiscal regime, the availability and ease of access to domestic or export markets, whether these markets are competitive or price-regulated, competition from other sources of gas (e.g. Russian gas imports) and so on.

To create a large-scale gas sector for local consumption and/or for export, it is self-evident (from low activity levels) that the current regulatory settings that govern how government and industry benefit from gas developments, do not incentivise investment sufficiently to compensate for technical and non-technical risk. This view is supported by the comparative analysis of simple cases in this Three60 Energy study.

In common with analyses in other jurisdictions, this study concludes that a well-designed royalty-tax regime is likely to attract more external investment than a Production Sharing Contract (PSC) regime. Paradoxically, while the government-take *per development project* may seem lower in a royalty-tax regime, the overall government-take over time can be higher because more projects are generated. It is essential to take a long-view to develop these resources focussing on building investment over time, rather than seeing initial, small projects as an opportunity to maximise government rent in the short term. It is also essential to recognise, that in order to develop CBM resources, significant funds must be put at risk, and that, in essence, the government wishes companies to take this risk (i.e. not tax payer funds). They therefore must give confidence that there will be commensurate rewards which are competitive compared to other jurisdictions.

Not only does a stable, well designed royalty-tax regime provide a more attractive investment environment, compared generally to PSCs, it can also increase the size of economically producible national resources and reduce the minimum size required to bring gas to market. The Three60 Energy modelling supports this - and it has been recognised previously in other areas (e.g. Smith, 2013; Bindeman, 2016 and Busby et. al, 2011).

In this report, Three60 Energy analysed the current Queensland specific royalty-tax regime. This was an appropriate choice because Queensland is a real example of perhaps the most successful and certainly largest CBM development. It is important to note however that, while Queensland's tax-royalty settings are more attractive than the current Mongolian PSCs, the *details* of Queensland's model are not suggested as being the most suitable for Mongolia. Both technical and non-technical risks for CBM development in Queensland are less than those in the Mongolian situation. Queensland's CBM resources are amongst the best in the world; the geology is relatively simple and flow-rates and total recovery per well, are also high. There are both domestic and export markets with infrastructure already in place. In addition, the current Queensland tax-royalty regime is not as attractive as the regime which attracted the earliest investments from the early 1990s, leading to the major decisions for three CBM to LNG projects around 2009 and an industry that now produces >1500 PJ pa (~43 bcm). And, also in those early years, the State government increased the demand for gas in the local market through new power generation policies. And finally, in contrast to World Bank findings, the latest Queensland royalty regime is an over-riding royalty model and is based on produced volumes rather than on revenue. Mongolia would need to design a regime which is congruent with its risk profile and more competitive than countries with which it competes for investment.

Literature from academia and international institutions such as the World Bank largely supports Three60 Energy's conclusions. While beyond the scope of Three60 Energy's work, literature also provides guidance for consideration for other improvements that could be made (in conjunction with future modelling). The World Bank's 2006 global review of mining royalties sought to advise resource-rich jurisdictions on best practice (World Bank, 2006: p3). Some considerations for fiscal system design were suggested in that document, including the following [my emphasis]: -

> "*… designing a tax system, policy makers should be aware of the cumulative effects taxes can have on mine economics and on potential* ***levels of future investment*** *... The overall tax system should be equitable to both the nation and the investor and* ***be globally competitive***"
>
> "*… Nations should carefully* ***weigh the immediate fiscal rewards*** *to be gained from high levels of tax, including royalty,* ***against the long-term*** *benefits to be gained from a sustainable mining industry that will contribute to long-term development, infrastructure, and economic diversification*"

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In 2013, Smith published a peer reviewed article "*Issues in extractive resource taxation: A review of research methods and models*". In it he noted (p320) that: -

> "… *the fiscal regime touches many aspects of an investor's plan of exploitation, including the scope of exploration and discovery, the timing and scale of initial development, the rate of production and decline, the timing and scale of* ***enhanced recovery operations****, the overall resource* ***recovery factor****, and the timing of* ***final abandonment****.* ***The pervasive impacts of the fiscal system, on the investor as well as the government, magnify the importance of designing and implementing a sound fiscal regime***."

Overall, the literature on natural resource economics is fairly clear that a tax-royalty regime, with royalties based on economic rent (revenue minus costs) is best practice and most likely to attract the external investment required to develop the country's resources. In line with Three60 Energy's broader discussions, it is also clear that overall risk, competition and other factors need to be considered when designing any *specific* details or royalty rates.

In summary, the work done by Three60 Energy for AMEP can provide an important input for local policy and decision making. It forms a sound basis by which strategies can be designed to increase the attractiveness of Mongolia's natural gas resources and the amount of inward investment. While it was not intended to be a full review of Mongolia's resource policies and regulations the report also points to other areas where improvements might be considered. Further work is needed, with local Mongolian expertise and insights, to progress this.

## Selected References


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A. Garnett

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Director
**UQ Centre for Natural Gas**
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# Revision and Amendment Register

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# Cover Letter by THREE60 Energy

Our Ref : AMEP 2021-1

Date : March 4, 2021

To : Adam Smith International (ASI) and Australia-Mongolia Extractives Program (AMEP)

**SUBJECT: MONGOLIA COAL BED METHANE – COMPARATIVE ASSESSMENT OF FISCAL REGIMES**

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Dear Sir/Madam,

In response to the Proposal ("**Proposal**") dated August 14, 2020, with Adam Smith International ("**ASI**") as the manager of the Australia-Mongolia Extractives Program Phase 2 ("**AMEP 2**"), THREE60 Energy Australia ("**THREE60 Energy**") has completed a report to assist Mongolian authorities in understanding their options and decision-making in support of the development of the Coal Based Methane (**CBM**) industry in Mongolia.

This report is issued by THREE60 Energy under the appointment by ASI as the manager of AMEP 2 and is produced as part of the services ("**Services**") detailed therein and subject to the terms and conditions of the Proposal.

This report is addressed to ASI. The report is only capable of being relied on by ASI and any third parties under, pursuant and subject to the terms of the Proposal.

This report is based primarily on data and information available up to November 30, 2020. The Services have been performed by a THREE60 Energy team of professional petroleum engineers, geoscientists and economists and is based on the data supplied through AMEP 2.

## Qualifications

THREE60 Energy, formerly known as LEAP Energy, is an independent consultancy specialising in petroleum industry evaluations and assessments. THREE60 Energy is independent of ASI and its programs and is remunerated by way of a fee that is not linked to any asset in Mongolia. Neither THREE60 Energy nor any of its directors, staff or sub-consultants who contributed to the report has any interest in AMEP 2.

The report has been compiled by: Dr. Mike Reeder, Director Commercial Advisory; Mr Chris Connell, Director Australia; Ms. Vicky Yawapongsiri, Senior Advisor Economics; and Mr Terry O'Neill, Senior Advisor Economics. Dr. Reeder has 20 years of experience in upstream oil and gas and Mr. Connell has over 35 years' experience in upstream oil and gas. Both are long standing members of the Society of Petroleum Engineers. Vicky Yawapongsiri and Terry O'Neill are highly experienced economists in the oil and gas sector. The team are highly experienced in CBM and have been heavily involved with the exploration, appraisal, development and production in Australia's CBM industry over the last 15 years. Mr Connell and Mr O'Neill have both held senior technical and executive positions in the CBM industry in Australia.

## Basis of Opinion

The results presented herein reflect our informed judgement based on accepted standards of professional investigation but is subject to generally recognised uncertainties associated with the interpretation of petrophysical, geological, geophysical and engineering data. The Services have been conducted within our understanding of petroleum legislation, Taxation and other regulations that currently apply to these interests.

The report represents THREE60 Energy's professional judgement and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving exploration and future petroleum development projects, may be subject to significant variations over short periods of time as new information becomes available or as circumstances change. THREE60 Energy cannot and does not guarantee the accuracy or correctness of any interpretation made by it of any of the data, documentation and information provided by AMEP 2 or others in accordance with the Proposal. THREE60 Energy does not warrant or guarantee, through the Services, this report or otherwise, any geological or commercial outcome.

In preparing the report, THREE60 Energy has used reasonable skill and reasonable care to be expected of a consultant carrying out services of the type set out in the Proposal. THREE60 Energy is responsible for this report and declares that it has taken all reasonable care to ensure that the information contained in the report is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

## Consent for Use and Distribution

THREE60 Energy hereby consents to the publication and use of: (i) the report; and (ii) its name, by ASI, in both electronic and paper form, including AMEP' websites, in the form and context in which it appears. As at the date of this letter, THREE60 Energy has not withdrawn this consent.

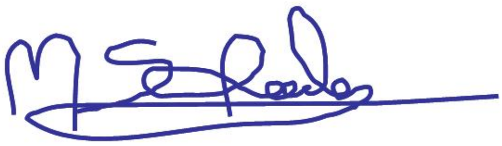
This report relates specifically and solely to the assisting Mongolian authorities in understanding their options and decision making in support of the development of the CBM industry in Mongolia. The report, of which this letter forms part, must therefore be read in its entirety. This report may only be used in accordance with purpose stated in the Proposal, except with permission from THREE60 Energy. THREE60 Energy respectfully requests that any reproduction or publication of any excerpts of this report acknowledges reference to THREE60 Energy and that THREE60 Energy is able to review such reproductions/publication for context and correctness prior to issuance.

## Date and Signature

I, Dr. Mike Reeder, holder of a B.Sc. (Honours) in Geology from Royal Holloway, University of London and a Ph.D. in Geology from the University of Southampton), of 1 Leonie Hill Road, #28-02 Singapore 239191 hereby certify that:

1. I am an employee of THREE60 Energy and supervised the preparation of the Report. The effective date of this report is **November 30, 2020**.
2. THREE60 Energy and I are independent of ASI, their subsidiaries, their respective directors, senior management, and advisers.
3. I attended Royal Holloway, University of London with a Bachelor's of Science (First Class Honours) degree (1994) and Southampton University with a Doctorate of Philosophy in Geology (2000).
4. I am a holder of the title Certified Petroleum Geologist (CPG #6310) awarded by the Department of Professional Affairs (DPA) of the American Association of Petroleum Geologists (AAPG). I am an upstanding member of the AAPG (since 1999) and also a member of the SPE (since 2003, chairman of SPE Singapore Section 2012-2018). I have 23 years' experience in the Petroleum Industry.

SIGNED:



Date: March 4, 2021

Dr. Mike Reeder
THREE60 Energy
Director of Commercial Advisory
Certified Petroleum Geologist (DPA AAPG #6310)

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# 1 Executive Summary

## 1.1 Summary

The Australia Mongolia Extractives Program ("**AMEP**") is funded by the Australian Government's Department of Foreign Affairs and Trade and managed by Adam Smith International ("**ASI**"). Working with Mongolian partners, AMEP provides technical expertise and policy advice that contribute to the equitable and sustainable development of Mongolia's extractive sector.

The objective of the activity is to provide Mongolian Ministry of Mining and Heavy Industry ("**MMHI**"), and the Mineral Resources and Petroleum Authority ("**MRPAM**") with advice on fiscal systems applicable to CBM in Queensland, Australia and other relevant jurisdictions to assist Mongolian authorities in understanding their options and making decisions supportive of the development of the CBM industry in Mongolia. The report has been produced in cooperation with Centre for Natural Gas at University of Queensland.

This activity contributes to:

a) improvement of the regulatory environment for CBM investment and development; and

b) positive Investor perception of the Mongolian extractives sector contributing to increased investment potential in the future.

Since CBM is a relatively new industry in Mongolia, the study is intended to be helpful to provide policy makers with an introduction to the industry based on another country's experience. Policy makers can also consider the reforms most appropriate to manage the industry's development in Mongolia once informed of CBM experience elsewhere and comparing this experience to the Mongolian context. The proposed approach is set out below.

1) Producing a report illustrating the impacts of different fiscal and associated policy settings on sample CBM projects. The report will be based on high-level CBM asset evaluations using economic models that encompass exploration, appraisal, field development and operational project phases. It also provides a comparative analysis of petroleum fiscal regimes in Mongolia, Australia (Queensland) and other jurisdictions to be agreed for further comparison and consideration.

2) The results of the asset evaluations and comparative analysis will be presented and discussed at workshops and roundtables with key stakeholders from Government and industry to consider and assess the findings. A communique will be produced from these discussions outlining policy recommendations and a proposed way forward.

Specifically, the report will address:

- Compilation and Review of PSC and Royalty-Tax Base Case Models for Mongolian and Australian (Queensland) regimes, respectively. This will take into consideration the variables that may exist with the current Mongolian CBM licenses held by the PSC Operators;
- Economic Modelling of gas projects of different scales (e.g. small, mid-size and major developments) under alternative Royalty regimes to derive an understanding of state financial "take" and company "take" as these will vary depending upon the type of Royalty regime being modelled, the profitability of the project as well as Taxation treatment. It is understood that the CBM Operators have adapted scenarios for development at such scales. THREE60 Energy will review and confirm selected models to be applied in all economic regimes;
- Economic Modelling Sensitivities – to run variables within a composite model that best offers guidance as to what may be considered a fair financial return to the state for its resource;
- Benchmarking of other selected and relevant international and competing Royalty regimes to gain insights into competition for international investment funds and an appreciation of what other jurisdictions consider to be a fair financial return for the developers and Government;
- Assessment of general prospectivity/ state of resource knowledge – noting that the poorer the general prospectivity the greater the "take" that an international Investor will desire to invest in Mongolia *vs*. another international location; and
- Assessment of barriers to entry – benchmarking the Mongolian context across a range of considerations, e.g. prospectivity, permit access, land access, environmental and other approvals, supplier and service company availability and support, markets, costs. Potential implementation of discount rate factors to indirectly address any apparent political risks.

## 1.2 Conclusions

THREE60 Energy concludes that a number of measures would be required to attract significant and sustained investment in CBM in Mongolia. These measures traverse the fiscal system, legislation, prospectivity, data access and administrative procedures of the licensing system. An integrated and holistic approach is considered to be necessary. Many countries have addressed these issues and a range of systems have been evolved. There are significant learnings available from these other jurisdictions to formulate a system for Mongolia that is highly functional and attractive.

CBM development is different to conventional gas and petroleum in significant ways. Unlike conventional gas reservoirs, CBM reservoirs are highly variable over short distances. Conventional gas reservoirs generally require a limited number of wells to estimate the resource and production performance which de-risks a project much earlier than CBM. CBM typically requires many more wells and larger upfront investment to assess the sub-surface characteristics and obtain certainty about the resource. This exposes CBM Investors to higher levels of risk all the way through to the execution phase of a project.

A fiscal regime for CBM should take this difference in cost and risk between CBM and conventional gas/petroleum into account. Both the quantitative and qualitative assessments in this study indicate that the Royalty-Tax regime would help attract investment for potential CBM business opportunities more than an equivalent PSC regime.

There may be companies that are prepared to invest in CBM in Mongolia regardless of the perceived barriers to entry. However, the barriers to entry identified are expected to have the effect of limiting the number of companies prepared to invest or subsequently impact their ability to raise funds to develop CBM. Smaller and highly entrepreneurial companies may be prepared to take on significant risk in relation to early and limited investments. However, the global norm is for junior companies to establish the value of a resource and then rely on attracting a larger company to invest or acquire the development opportunity to enable the project to achieve its full scale. These high levels of investment risk may result in only attracting a few Investors. The pool of Investors will also shrink over time as investment shifts away from fossil fuels and into renewables. The window for attracting investment and developing CBM projects is expected to progressively diminish in line with this trend.

### 1.2.1 Economic Modelling

Economic modelling was performed in relation to the Mongolian PSC regime and Queensland, Australia Royalty-Tax Regime as of December 2020. A comparative analysis was performed utilising three example cases (Low, Mid and High) representing CBM developments of different scale. Each case was modelled separately under each regime prior to performing the comparative analysis.

The observations for the Low, Mid and High Cases evaluated by economic modelling of the Mongolian PSC regime and the Queensland, Australia Royalty-Tax Regime are outlined below.

- In all cases, the Royalty-Tax regime yields significantly higher undiscounted cashflows and rates of return to Investors, compared to the PSC regime.
- Conversely, in all cases Government cashflow and discounted cashflow are higher for all cases under the PSC regime. However, when Government take is too high it does not encourage new investments, few or no projects will be developed resulting in sub-optimal Government take. The fiscal regime should be designed to encourage new investments which will result in multiple project developments and optimised Government cashflow at an aggregate level.
- From an Investor / Operator / Contractor perspective, projects exemplified by the **Low Case** could not be supported under the PSC and yielded only marginally economic results under the Royalty-Tax terms. The impact of this is that under the PSC regime there will be less gas supply that can be developed compared to a Royalty-Tax regime. Natural resource opportunities tend to follow distributions where there are far more "low case" opportunities than "high case" ones. The fiscal model chosen influences how many opportunities are economic. Ultimately, lower supply will tend to cause higher gas prices and, thus, fewer opportunities for economic development.
- Similarly, marginal projects under a PSC framework, as demonstrated by the **Mid Case** would struggle to pass through the internal decision-making process for most companies unless returns could be supported

by further technical improvement and/or commercial improvement and/or some type of fiscal incentive. The Mid Case project yielded economic results under the Royalty-Tax regime terms and could proceed under this fiscal regime.

- Projects like the **High Case** could proceed on the economic merits, but the reality is that investment decisions are not made on economic merits alone. For most successful businesses, a range of decision criteria are used for their investment decisions. Decisions of this scale, or requiring entry into a new country, would normally be supported by a comprehensive risk and opportunity assessment that is both quantitative and qualitative in nature i.e. would include a range of non-technical risks. These risk and opportunity assessments would include thorough evaluations of the technical, commercial, political, legislative, financial and fiscal, environmental, security and geographical risks for conducting a new business venture in a developing, non-Organisation for Economic Co-operation and Development (OECD) country.
- Compared to the PSC regime, the Royalty-Tax regime treats smaller scale, lower value projects less harshly than larger scale, more profitable projects. At the same time, the Royalty-Tax regime still provides a "good" level of return to the Investor / Operator / Contractor for those large-scale, more profitable cases.
- For the larger scale projects exemplified by the High Case, the returns are high under both regimes, with better after-Tax returns for the Operator under the Royalty-Tax regime at all discount rates considered. The high returns for such a large-scale venture would be considered commensurate with the higher capital exposures (i.e. larger amounts of capital placed at-risk) involved, the longer lead timings to first production, the commercial complexity of the project and higher risks in a new resource play in a new business environment.
- Other criteria such as fiscal certainty, transparency and consistency of the terms and potential future fiscal liabilities for an Investor/ Operator / Contractor would also be considered. In most instances, these more qualitative criteria would have a significant weighting in the decision-making process for non-OECD countries where the regimes are still maturing. If the fiscal regimes themselves were deemed to pose significant uncertainty and risks to the Investor, then these factors alone would deter many potential international Investors, even if the economic returns and quantitative outcomes looked highly attractive at face value.

### 1.2.2 Benchmarking

A new and simplified approach for the relative ranking of the PSC and Royalty-Tax regimes was applied, based on a range of quantitative criteria and a number of qualitative factors relating to any fiscal regime. Other criteria such as data access and prospectivity, whilst highly relevant to any opportunity, could be considered to sit alongside, but not be an integral part of the fiscal regime comparison *per se*.

The quantitative assessment was based on four parameters:

- Undiscounted and Discounted Cashflow

- Profit Investment Ratio
- Payback Year
- Internal Rate of Return

The economic results derived from the Royalty-Tax regime attained the best quantitative relative ranking of 3.0 compared to the 1.4 ranking attained by the Mongolian PSC based results.

The qualitative assessment was based on five parameters:

- Transparency of Fiscal Framework
- Consistency of Application of Terms
- Certainty of Terms
- Stability/Maturity of Fiscal Terms
- Capacity for Risk Mitigation

The results of both the quantitative and qualitative assessments indicate that the Royalty-Tax regime provides a very clear advantage to an Investor contemplating new business in a new country, like Mongolia, and would support investment for potential CBM business opportunities more readily than an equivalent PSC regime.

A high-level overview of CBM in Indonesia and the PSC terms there concluded that despite generally favourable geological conditions (prospectivity) in Indonesia for CBM it is insufficient to facilitate development of the industry. The fiscal regime currently applied to CBM in Indonesia is not supportive for the development of the industry and as a result CBM development has not advanced significantly.

The fiscal terms for CBM in China from 2006 - 2010 were favourable to Contractors but the production targets set by the Government were not achieved. At the time it was noted that large investments were needed to accelerate CBM exploration and prove up reserves. During this time, approximately 70% of exploration expenditures were from foreign companies but most were companies with a low market capitalisation and limited capacity to fund large capital programmes.

Of particular note is that China CBM production targets in 2010 were not achieved despite good fiscal terms and a more mature industry than exists in Mongolia today.

### 1.2.3 CBM Prospectivity

The data and quality of information available to an oil or gas company is instrumental in the assessment of prospectivity. Where limited data have been acquired or the availability of data historically acquired is limited to some extent then this will lead to a downgrade in the prospectivity of an area as the risks are deemed much higher, or there are significant costs and time delays to de-risk.

CBM prospectivity in Mongolia is difficult to assess due to the limited information available, notwithstanding that there is an abundance of coal basins and deposits in Mongolia and an extensive history of coal mining. There is a lack of information available on key reservoir parameters necessary for viable and economic development of CBM including: gas content, gas saturations, permeability, permeability distribution and water content. In the absence of comprehensive and published information on the important reservoir parameters and productivity it is not possible to form any detailed view on the CBM prospectivity of the various coal basins. Consequently, we would perceive CBM prospectivity in Mongolia to be low and would expect any potential Investor to form a similar conclusion.

### 1.2.4 Barriers to Entry

It is apparent that there are a few issues that would influence any decision by an Investor evaluating an opportunity to invest in CBM in Mongolia. These issues, collectively referred to in this document as "barriers to entry", may be real or perceived but nevertheless influence investment decisions. These barriers to entry may impact a decision to consider Mongolia as an investment location or may affect any subsequent decision as a result of detailed evaluation of opportunities.

**CBM Prospectivity.** The perception of low CBM prospectivity in Mongolia is considered a barrier to entry as discussed elsewhere in this report.

**Data Access.** Data access for potential CBM Investors is considered to be a significant barrier to entry. There are very large areas of Mongolia that have little or no available or published subsurface data and that there are no readily available base maps or Geographic Information Systems (GIS) data available. The petroleum information that may exist in the records of the Government are not readily available for public inspection or use.

**Technical Risk.** The technical risk (geological and reservoir) of CBM projects is inherently high, regardless of country. CBM developments typically carry more risk in the development phase than do conventional gas developments by virtue of the inherent geological variability of coals over short distances. This presents a possible barrier, particularly if the regime framework does not address the risks the Investor undertakes for CBM development.

**Legislation.** Similar to Australia, Mongolia's mineral resources are owned by the state. The Ministry of Mining is responsible for the drafting of Government policy for developing the petroleum sector and the Petroleum Authority is responsible for implementing the petroleum legislation and decisions of Government and the Ministry of Mining.

The Law of Mongolia on Petroleum (the new addition), referred to herein as "**the Petroleum Law**', raises a number of issues that would act as potential barriers to entry:

- PSC terms are to be negotiated at the time an exploration licence is awarded. There are no clear guidelines as to how these terms and conditions are evaluated and agreed by authorities and there is no provision to amend PSC terms subsequent to the award of an exploration licence. Additionally, the PSC Profit Sharing provisions are based on a production rate threshold but are not graduated. This would potentially lead to Investors considering the terms to be distortionary in that decisions and alignment on the sizing of a plant may be influenced by the profit sharing terms.
- A Contractor is required to submit the reserve estimate to the Petroleum Authority 90 days before the expiry of the exploration period for review. Based on international standards such as Society of Petroleum Engineers - Petroleum Reserves Management System (SPE-PRMS) it is unlikely that Reserves could be estimated (booked) in the absence of a plan of development and appropriate approvals to exploit. It is unlikely this requirement could be met.
- The Petroleum Authority and the Contractor shall set a price of the extracted petroleum on the basis of the price of petroleum of the same character as sold on the world market. This is problematic as there is no world market benchmark for CBM and as such one of the key factors in determining the economics of a project is not subject to commercial market negotiations alone.
- There do not appear to be any petroleum regulations that have been formulated to complement the petroleum legislation. Petroleum regulations in many countries provide specific detail on many matters including data acquisition, reporting, consent procedures, timeframes for applying for and consideration by authorities of various matters. The absence of well-articulated regulations introduces significant uncertainty relating to treatment of any licence holder on a range of matters which may ultimately affect the perceived value of a CBM investment.
- It has been reported that there is a lack of clarity in respect of overlapping licences under the Minerals Law and the Petroleum Law. Given CBM and coal mining activities are frequently undertaken in the same sedimentary basins there would be a perceived risk that a CBM PSC may not enable full access to the CBM resource.

**Infrastructure.** Gas infrastructure is limited in Mongolia. There is no pipeline network in Mongolia and accordingly transportation of gas to markets will necessarily be linked to specific gas developments as they evolve unless pre-investment in infrastructure is undertaken by the Government. Any pre-investment in infrastructure would be high risk due to poor knowledge of the resources that could potentially be developed. It is noted that an initiative to develop a Methane Gas Supply Chain Development Master Plan has commenced. Whilst this report will address infrastructure amongst other issues it is anticipated that the absence of a good understanding of the CBM resource will pose a challenge.

# 2 Introduction

## 2.1 Work Conducted in Support of this Report

THREE60 Energy has undertaken a review of PSC and Royalty-Tax Regimes by evaluating representative Mongolian CBM assets using economic models. The Australian (Queensland) Royalty-Tax regime has been used as an example of a Royalty-Tax system for purposes of this evaluation. All this work was performed in relation to the Coal Bed Methane ("CBM") industry in Mongolia. The PSC and Royalty Tax economic models evaluated the representative assets, provided modelling sensitivities to compare these two regimes.

THREE60 Energy has also benchmarked the PSC and Royalty-Tax Regimes benchmarked other selected/ relevant international and competing fiscal systems; assessed the general prospectivity/ level of resource knowledge; and assessed barriers to entry for potential international Investors.

Information was sourced from several companies already involved in Mongolian CBM exploration and appraisal to assist THREE60 Energy in developing a representative and relevant set of economic inputs for the modelling work. Publicly available information and experienced based knowledge from the THREE60 Energy team of experts was also applied in the preparation and conditioning of the economic inputs.

Publicly available data were sourced and interviews undertaken with the several companies involved in Mongolian CBM to enable benchmarking of other selected and relevant international and competing Royalty regimes; assessment of the general prospectivity/ state of resource knowledge; and assessment of barriers to entry.

## 2.2 Coal Bed Methane Development

Coal bed methane is defined as an "unconventional petroleum" under the Law of Mongolia on Petroleum (the new edition).

CBM is generally considered to be an unconventional resource in that the gas does not typically reside in pore spaces where it does in conventional sandstone and carbonate gas reservoirs. Methane (chemical composition $CH_4$) is typically contained within the coal and is attached to the coal surface. It can also exist in cleats and fractures within the coals as "free gas". Coals comprise a large number of faces or surfaces and the methane molecules are packed on the many surfaces which means that coal has the ability to hold significant volumes of gas. Carbon dioxide ($CO_2$) and nitrogen ($N_2$) are typically present, with nitrogen levels often up to 2% and carbon dioxide varying significantly.

Water is frequently found in the cleats or fractures and to produce the coal bed methane it is necessary to first reduce the pressure in the cleats and fractures by producing the water or gas occupying that space. With the decrease in pressure the methane, nitrogen and carbon dioxide molecules desorb from the coal and are progressively produced.

Commercial production of CBM usually occurs from coals at depths varying from 250 – 1,200 metres where sufficient pressure is present such that the gas has not desorbed. Gas content typically increases with depth, but permeability typically reduces with depth. Successful CBM developments require suitable gas content and permeability, enabling commercial gas production rates to be achieved.

CBM development differs from conventional gas field development in several key aspects. Firstly, a CBM well will typically produce water initially with gas production progressively increasing and water production reducing, representing the "dewatering" phase. This differs from conventional gas wells where water production will occur later in field life and potentially not at all. Secondly, CBM well performance uncertainty is reduced primarily during the execution phase of a development and that uncertainty can be significant in some fields at the time of project sanction, unlike conventional assets where the uncertainty tends to be largely de-risked prior to project sanction or development. The rather unique uncertainty profile for CBM development results from the highly variable nature of CBM reservoir characteristics over relatively short lateral distances. It is not unusual for well performance to vary significantly over short lateral distances (e.g. 500 – 1,000 m). Experience in the Surat and Bowen Basins in Queensland, Australia, is that production from many wells (10's to 100's) is necessary to establish reliable production trends and reduce reservoir uncertainty from a larger pool of variable producers.

In contrast, conventional gas reservoirs generally require a limited number of wells to estimate the resource ranges and likely production performance rates that underpin project sanction. CBM development typically requires large numbers of wells to estimate the resource ranges.

CBM is, therefore, unique in terms of the subsurface risks it presents, how these uncertainties drive the scale and the approach to its development and, crucially, how Investors view the business opportunity because of these increased levels of subsurface and production performance uncertainties. From an Investor viewpoint CBM carries higher technical risk as the uncertainties increase the possibility of either under-capitalising or over-capitalising the development cost relative to the production. From an Operator point of view, it demands additional costs associated with the water treatment and disposal that are required to unlock the gas producible from the coals. These costs are not typically significant for conventional developments but can be significant for CBM and these costs need to be recoverable in any fiscal regime being contemplated. In addition, the larger number of wells required for CBM, with periodic workovers, place an additional operational cost burden which also needs to be recoverable for the Operator / the Investor.

CBM has been produced in North America for several decades but diminished in the early part of this century as the economic viability could not be sustained with low gas prices and preferential investment in shale gas. Since late 2014, Australia emerged as the largest CBM producer in the world with capital investment of in excess of United States Dollars ($USD) 50 Billion in field development and the commissioning of three LNG plants with CBM as a feedstock. CBM development in Australia has slowed significantly since 2015 despite significant ullage in the associated LNG trains and this is primarily driven by the challenging economics of developing lower quality CBM areas not previously developed in a highly challenging price environment. It is widely recognised that the economic viability of the major CBM to LNG projects in Australia has been significantly lower than initial projections due to these reasons along with project delays and cost overruns in some cases.

Due to the learnings in both North America and Australia on the higher risk and marginal economic returns from CBM developments, there would be some uncertainty as to whether companies experienced with large scale CBM developments would choose to leverage that experience or further expose themselves in further CBM developments internationally, unless incentivised by attractive fiscal terms to do so.

## 2.3 Fiscal Systems

There are a vast number of petroleum fiscal systems in the world that have continually evolved since the inception of the oil and gas industry; and it is not uncommon to have different fiscal systems in the one country or for Governments to negotiate the terms of each. Regardless of the fiscal system applied, the key issue is a financial one: how are costs recovered and profits divided between Operator and the State. The intent of devising a fiscal system and associated Taxation is to capture the economic rent whilst allocating the industry a reasonable proportion of the profit such that the industry continues to invest and operate.

Economist Daniel Johnston (REF: 1) stated:

> *"Taxation theory and economic rent are central to the derivation of any fiscal system. Economic theory focusses on the produce of the earth derived from labour and capital. Rent theory deals with how this produce is divided among the labourers, owners of the capital and landowners through wages profit and rent.*
>
> *Economic rent in the petroleum industry is the difference between the value of production and the costs to extract it. These costs consist of normal exploration, development and operating costs as well as an appropriate share of profit for the petroleum industry. Rent is the surplus and Economic rent is synonymous with excess profits."*

Figure 1 provides a diagram illustrating the allocation of gross revenues from a petroleum project in relation to costs and revenues.

It can be seen that the Contractor Take, essentially, the Operator profit is considered as a cost by Governments and that Government Take is what remains after the various exploration, development and operating costs as well as Contractor take have been deducted. In a Royalty-Tax regime the Government Take comprises Royalties and Taxes paid and Contractor take is profit after Royalty and Taxes paid.

The design of a fiscal system needs to account for risk. Typically, oil and gas companies are risk takers and will design their opportunity portfolio to diversify risk. Governments, on the other hand, are generally risk averse as they do not have the ability or appetite to manage a diverse portfolio or to undertake speculative business ventures. A fiscal system where bonuses and royalties are paid represents the lowest risk to Government but the highest risk to oil and gas companies as payments are made to the Government in advance of all costs being recovered whereas production sharing schemes and Taxation represent risk sharing between Government and oil companies.

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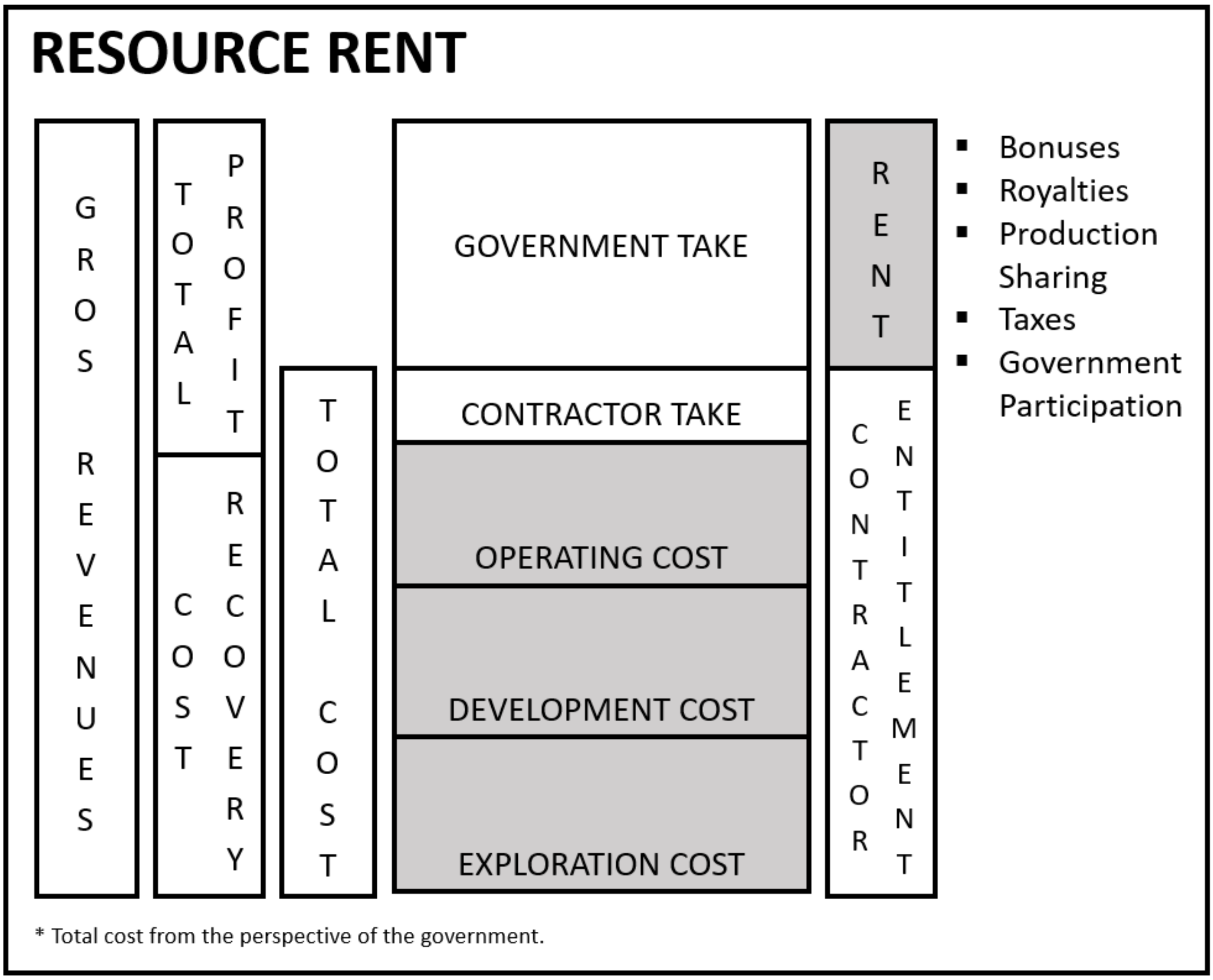
[1] Source: Johnston, Daniel; International Petroleum Fiscal Systems and Production Sharing Contracts




*Note:* from Johnston, Daniel; International Petroleum Fiscal Systems and Production Sharing Contracts.

***Figure 1: Allocations of Revenue from Production***

Government and Contractor objectives are not always aligned. Government objectives will include a fair financial return to the Government; promote competition and market efficiency and limit administrative burden. Contractors, however, wish to build equity and maximise wealth.

An issue may arise as to how exploration costs are captured. Frequently exploration wells are unsuccessful and typically only 10-20 % of exploration wells are successful. The Operator / Contractor carries all the cost and risk of this uncertainty and consequently, the fiscal terms applied need to be sufficiently attractive for the Contractor to be willing to take the risk of exploration failures and recover, not just the costs of successful exploration wells, but also the unsuccessful ones. The design of a fiscal system also needs to account for the political and geological risks to the profits.

### 2.3.1 Contractor Take

The allocation of profits between Contractor / Operator is typically described by Contractor and government "take" respectively. Contractor take is the percentage of profits due to the Contractor and the government take is the balance of the profits available. When comparing different fiscal systems, it is relevant to compare the different takes which may vary depending upon fiscal terms and the dimensions of the project e.g. sales price, sales volume, project size and various financial metrics.

The government and Contractor take can be modelled using a detailed cash flow analysis or approximated using a quick look approach, the latter enabling a larger number of fiscal systems to be compared.

### 2.3.2 Classification of Petroleum Fiscal Systems

Broadly speaking there are two types of fiscal systems; concessionary; and contractual. The key difference is related to resource ownership.

**Concessionary Systems** allow private ownership of resources and the USA is a good example of this where individuals may own the resource rights. A common form of concessionary systems is one when the government or state owns the resources but transfers the title of the resources once produced in return for payment of royalties and Taxes. Queensland in Australia is a good example of such a system. In both systems the Contractor / Operator also owns the physical assets it has invested in to extract the resource, including wells, surface infrastructure, plant and equipment. This compares with a PSC situation, where typically the State assumes ownership of the physical assets and the Contractor simply recovers the costs it spent installing and operating them, on behalf of the State.

**Contractual Systems** allow the government to retain ownership of the resources. Under this system oil and gas companies have the rights to a share of production or revenues. There are two broad forms of Contractual Systems:

I. Production Sharing Contract (PSC) or a

II. Service Contract,

with the key difference being that PSCs allow sharing of production volumes whereas Service Contracts allow sharing of revenues.

Many petroleum fiscal systems are variations or hybrids of Concessionary and Contractual Systems but the distinction between these is important in terms of understanding that each deal with Contractor and government risk in different ways.

### 2.3.3 Attracting International Investment

International oil and gas companies generally have a broad range of investment opportunities available to them and traditionally their decisions on where to invest have been largely influenced by prospectivity, government take, development costs and political risk. Companies will typically invest in resource developments that align with their experience and capability to ensure that risks and uncertainties can be adequately managed, and value realised.

Countries with attractive prospectivity, low development costs and a stable investment environment are able to demand higher levels of government take. Conversely, if any of these key factors are not favourable or have higher risk then the level of government-take needs to accommodate this disadvantage to attract sufficient investment for the development to proceed, with a reasonable level of return for the investment risks. In other words, countries are not able to demand a high government take where one or more of these factors is unfavourable. In the event that the government take does not reasonably balance the prospectivity, cost exposures and the investment environment then it is expected that investment interest will be limited.

Historical comparative analysis of fiscal systems has focussed on prospectivity, government take, development costs and political risk and this study adopts a similar approach. However, globally a "sea change" is underway with a major shift in public sentiment, government policies and Investor appetite towards renewable and alternative energy sources which is affecting investment decisions and sourcing of funds in traditional fossil fuel industries. It remains uncertain as to the nature and rate of impact this global shift is having on international investment in hydrocarbon development, but this change presents new and unforeseen risks to future hydrocarbon investments. These risks include penalty costs for industries that generate high levels of greenhouse gases, Investors and banks refusing to support or underwrite the finance needed to fund petroleum investments, and more crucially, increased market uncertainties from downward pressure on future prices and demand for petroleum products. There are already examples of banks and Investors refusing to support / underwrite coal industry investments [REF: 2]. It is almost certain this shift away from coal investment will also occur in the petroleum industry and the only uncertainty about this is when this is likely to happen. Ongoing monitoring of the extent and the rate of this global change will be important to understand how this may impact future appetite to invest in petroleum opportunities internationally. Fiscal regimes that are punitive towards the international Investor are more likely to be overlooked in favour of those that provide a good balance of returns commensurate with the risks to the Investor is expected to undertake including technical, political, environmental and commercial risks.

Although the market conditions are shifting towards a preference for investment in renewable energy sources rather than hydrocarbons, there is still a need for hydrocarbons, particularly gas. Given this situation, it is likely that there will be plentiful ongoing hydrocarbon resource investment options worldwide but a reducing level of traditionally sourced investment funds available for hydrocarbon developments. Some commentators have suggested that the window of opportunity for hydrocarbon development and exploitation will progressively diminish as investment in renewables and storage solutions increases. These observations would suggest that there may be an increase in the competition for international investment funds, reducing funding available for hydrocarbon developments and some countries may well consider modifying previously established fiscal terms to remain

[2] Data source reference: https://www.abc.net.au/news/2020-01-28/why-finance-is-fleeing-fossil-fuels/11903928

attractive for a diminishing pool of Investors. Accordingly, any comparative analysis of fiscal systems must consider that other well-established fiscal systems do not, at the time of analysis, take into account this new global situation of sustained lower oil prices in combination with a general shift away from fossil fuels, not just in terms of project opportunities, but also in terms of Investor appetites. However, it is likely that fiscal regimes in other countries may be amended to address the new global situation.

The historical context of record- breaking high oil prices in June 2008 (WTI @$USD 139 per stock tank barrel, $USD/stb) and sustained oil prices above $USD 70/stb) between August 2009 and June 2014 needs further consideration here [REF: 3]. Quite understandably, the historical higher oil price environment led to increased levels of resource nationalism and the contemplation or imposition by some government jurisdictions of windfall Taxes or petroleum fiscal regime changes to increase the government take whilst the higher returns available to Operators and Investors could sustain this. The subsequent oil price crash by 60-70 % between June 2014 and February 2016 [REF:3] and the inability of Investors and Operators to continue producing in some cases led to a complete reversal of the higher government takes being contemplated or imposed previously.

An example of this was the Petroleum Resources Rent Tax (PRRT) [REF: 4] that was applied by the Australian Federal Government to most onshore projects in 2012 at reasonably considers the current and expected business environment would, but was subsequently removed from the scope of the PRRT from July 1, 2019. A petroleum fiscal regime need to differ from those established during a more benign business environment when higher government takes were sustainable by higher oil prices. Therefore, comparisons of petroleum fiscal systems need to be treated with caution and consider the historical market context when those comparable petroleum fiscal systems were put in place.

It is also recognised that some jurisdictions may elect to modify their fiscal systems and accessibility to opportunities to discourage investment in hydrocarbon development and encourage investment in alternative energy sources. An example of this would be the current policy of the New Zealand Government not to release new offshore exploration areas for licensing although the fiscal system remains unchanged. Similar approaches in other jurisdictions could lead to a tightening on the opportunities available to international oil and gas companies.

Globally, there are a limited number of companies that have current experience in CBM development and many of those companies participate in CBM in Queensland, with others involved in countries such as China, India, and North America.

A smaller subset of these companies is likely to be looking for CBM opportunities beyond their existing portfolios.

To attract international investment in oil and gas it is important to understand some of the key elements that influence oil and gas company decisions on where to invest and how much. Several key aspects are noteworthy:

- Economic viability

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[3] Data source reference: https://tradingeconomics.com/commodity/crude-oil

[4] Date source reference: https://www.ato.gov.au/Business/Petroleum-resource-rent-tax/

- Prospectivity
- Political Risk

Analysis of potential **Economic Viability** is important to enable an oil and gas company to make an investment in a country, whether it be exploration or development. Economic analysis is typically performed to assess potential projects that would meet or exceed internal company economic hurdles. Exploration cost and risk as well as development (capital and operating) cost and risk are factored into any such analysis, as are the fiscal terms. Project dimensions (e.g. size, volumes, scalability, timing) and market scenarios for oil, gas or both and pricing into the market are important economic inputs. Many of the inputs to the economic analysis will be uncertain and a range of key inputs are typically applied to assess scenarios and the robustness of any investment relative to internal investment criteria and competing opportunities in competing jurisdictions.

The term **Prospectivity** in the oil and gas sector generally refers to the potential for the discovery of oil or gas in sufficient quantities to justify development. Geological conditions and the knowledge of those geological conditions are important factors for any oil and gas company in assessing their perception of the prospectivity. The data and quality of information available to an oil or gas company is instrumental in the assessment of prospectivity. Where limited data have been acquired or the availability of data historically acquired is limited to some extent then this will lead to a downgrade in the prospectivity of an area as the risks are deemed much higher, or there are significant costs and time delays to de-risk. Where a significant amount of historical exploration and or development data is available the oil and gas company is better placed to assess prospectivity. However, that assessment of prospectivity may range from being positive to negative. For example, significant amounts of high-quality data that allows a comprehensive understanding of the geology may result in an assessment that the prospectivity of an area is poor. It is generally considered that the more information and data that is made available the greater the likelihood that prospectivity can be assessed to be good.

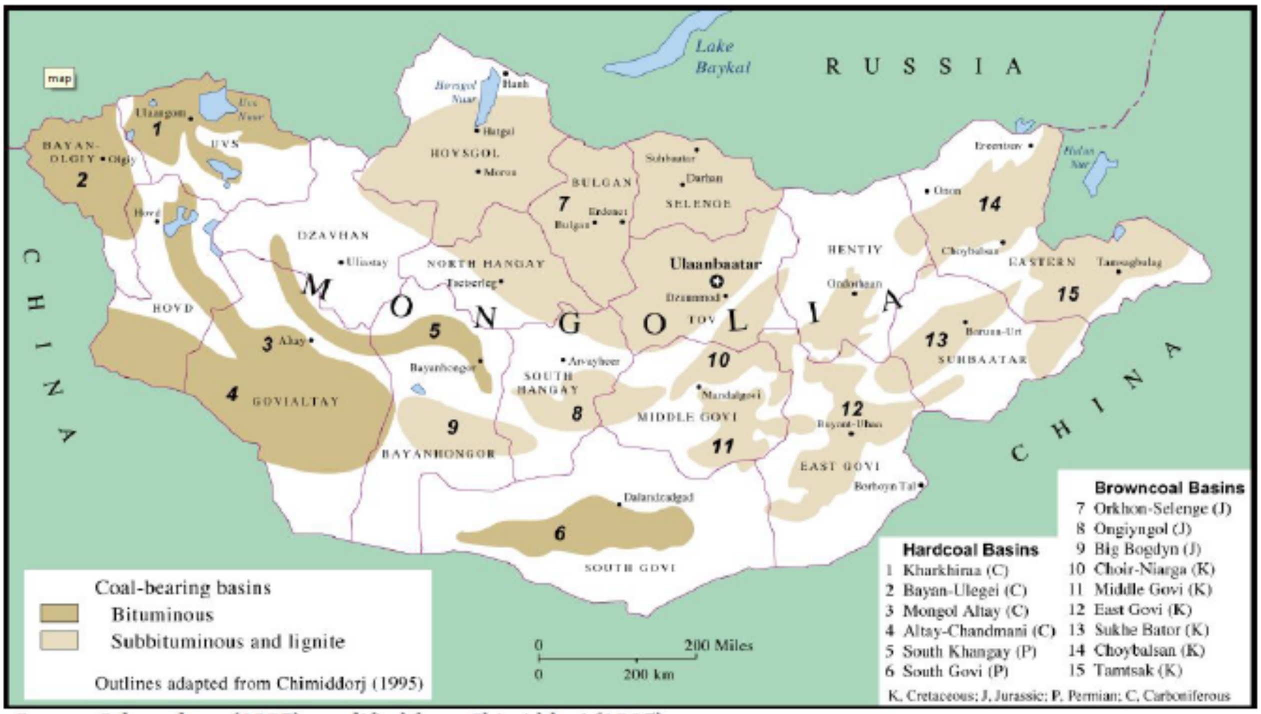
**Political Risk** is a major consideration for any oil or gas company. This risk includes: resource nationalisation or expropriation of assets; expanding Taxes; progressive labour legislation; and future access that is subject to national or state government approvals (e.g. development and environment); and land access. Oil and gas companies prefer stable, predictable government regulation, approval processes and outcomes so that they can sustain the technical and market/price risks on an existing or future investment. Other factors that could be grouped under political risk include unnecessary delays in granting approvals and changes in the fiscal terms. As the world progresses with the transition to renewables and other forms of energy, some companies will perceive a higher political risk associated with future approvals of hydrocarbon based projects or the imposition of conditions leading to higher costs or restrictions on production.

# 3 Mongolian Situation Overview

## 3.1 Assessment of Prospectivity

The term Prospectivity in the oil and gas sector generally refers to the potential for the discovery of oil or gas in sufficient quantities to justify development. Geological conditions and the knowledge of those geological conditions are important factors for any oil and gas company in assessing their perception of the prospectivity. The data and quality of information available to an oil or gas company is instrumental in the assessment of prospectivity. Where limited data have been acquired or the availability of data historically acquired is limited to some extent then this will lead to a downgrade in the prospectivity of an area as the risks are deemed much higher, or there are significant costs and time delays to de-risk. Where a significant amount of historical exploration and or development data is available the oil and gas company is better placed to assess prospectivity.

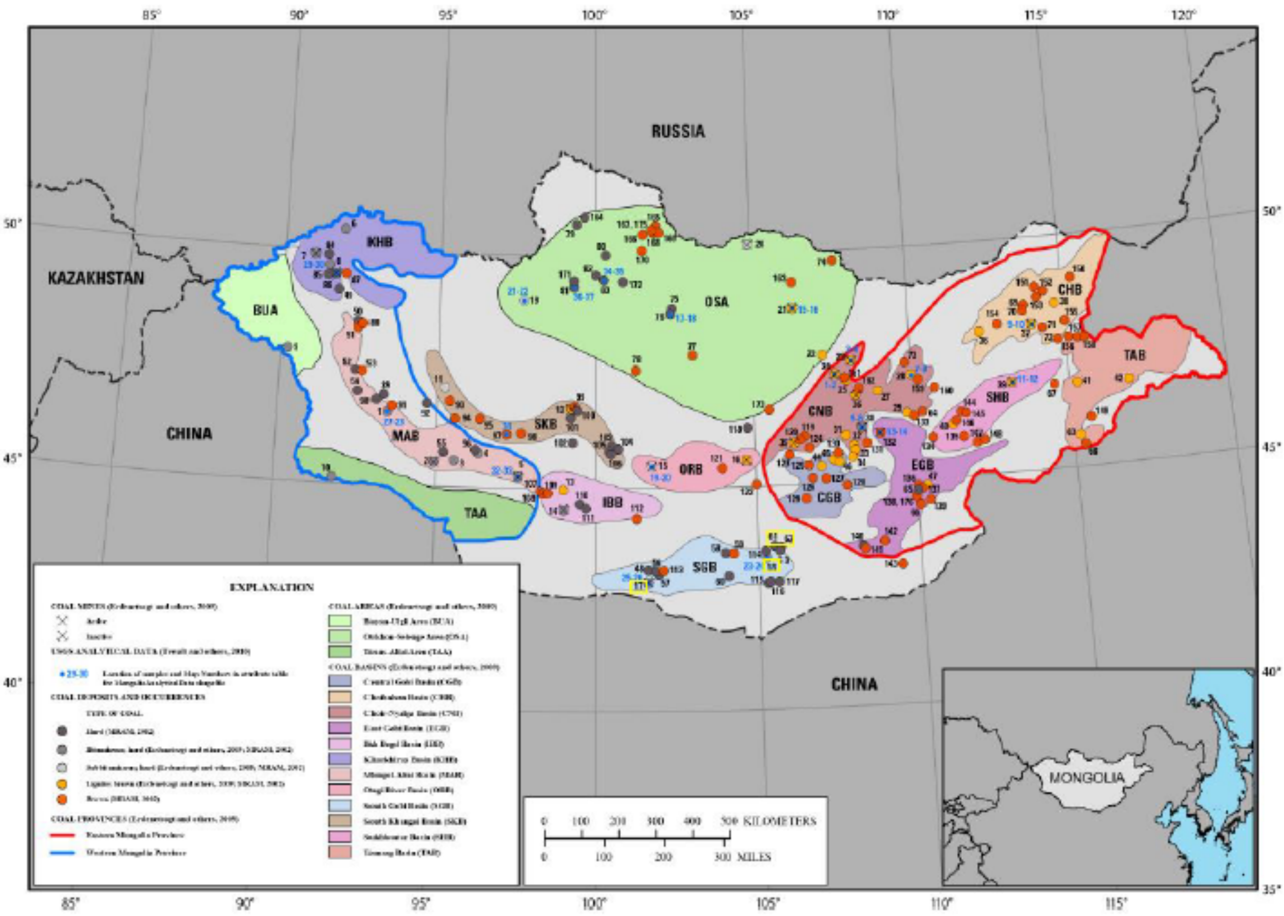
Mongolia has large coal resources and it provides the large majority of energy requirements in the country. There are 15 large scale coal bearing basins in Mongolia (Figure 2).




Source: Schwochow (1997), modified from Chimiddorj (1995)

***Figure 2: Map of Coal Basins in Mongolia***

There are presently 62 open-pit coal mines operating in Mongolia. Coal production has been steadily growing and in in 2019 some 57.2 Million tons were produced (Figure 3, and REF: [5]).



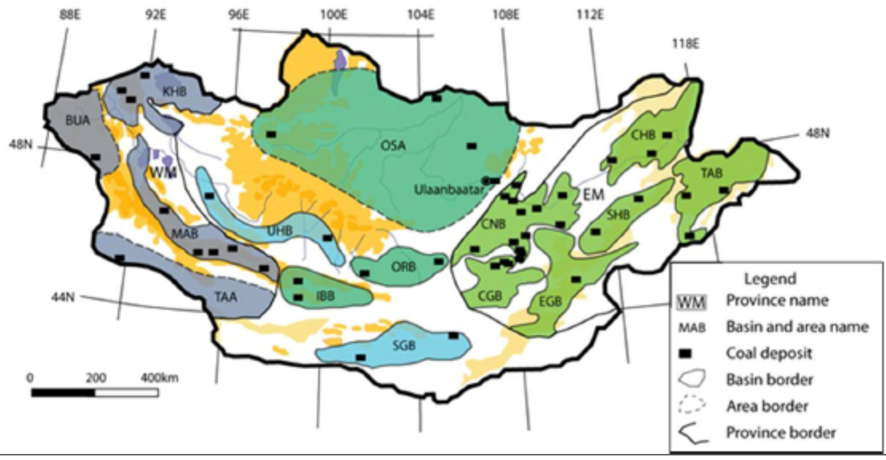

Ref: USGS Compilation of Geographic Information System (GIS) Data Representing Coal Mines & Coal-Bearing Areas, Mongolia (pp4)

***Figure 3: Coal Mines, Deposits, Occurrences, Areas, Basins in Mongolia***

Figure 4 summarises the 15 coal basins in Mongolia including area, estimated coal resources, Proved coal reserves and percent of total coal resource.

[5] Zagarin Tumurbaater, 2020. Climate Change and Utilizing the CBM in Mongolia

| Region | Age | Coal rank | Coal basin | Name | Area ($10^3$ km$^2$) | Estimated resources ($10^9$ ton) | Proved reserves ($10^6$ ton) | Percent of total resource (%) |
|---|---|---|---|---|---|---|---|---|
| Western Mongolia | Carboniferous | Anthracite and Low-rank bituminous | Mongol-Altai | MAB | 60 | 10 | 49 | 15 |
| | | | Kharkhiraa | KHB | 45 | 4.8 | 172.5 | |
| | | | Bayan-Ulgii | BUA | 35 | Unknown | Unknown | |
| | | | Trans-Altai | TAA | 72 | 3.8 | 2.1 | |
| Southern Mongolia | Permian | High-rank bituminous | South Gobi | SGB | 40 | 13 | 2,900 | 13 |
| | | | South Khangai | UHB | 4.8–35 | 1.2 | 4.2 | |
| Northern and central Mongolia | Jurassic | Sub bituminous | Orkhon–Selenge | OSA | 240 | 7.7 | 428.8 | 7 |
| | | | Ikh Bogd | IBB | 4.8–35 | 2.0 | 5.2 | |
| | | | Ong River | ORB | 4.8–35 | 1.5 | 42.4 | |
| Eastern Mongolia | Cretaceous | Lignite | Choir Nyalga | CNB | 50 | 20.3 | 5,900 | 65 |
| | | | Choibalsan | CHB | 45 | 14.9 | 213.2 | |
| | | | Sukhbaatar | SHB | 32 | 4.3 | 68 | |
| | | | Tamsag | TAB | 40 | 32.0 | 190 | |
| | | | Central Gobi | CGB | 25 | 13.2 | 104.1 | |
| | | | East Gobi | EGB | 60 | 23.5 | Unknown | |
| Total | | | 15 | | 758–849 | 152.2 | 10,079 | 100 |




Ref: Erdenetsogt *et al.*, 2009

***Figure 4: Mongolian Coal Resources and Reserves and Coal Distribution in Mongolia***

It is reported that several key papers on Mongolian coal geology have been published and that several Mongolian/Western scientists have focussed on the basement geology in terms of the collage of techno-stratigraphic terranes, the history of the intracontinental deformation and the sedimentary basins of Mongolia but it is also reported that the overall research level is relatively shallow (REF: 6). Major reference works on Mongolian Coal geology are written in Mongolian and Russian. THREE60 Energy has sourced and reviewed various papers

6 TA 9938-MON Methane Gas Supply Chain Development Master Plan.

in English and is of the view that the literature does not allow a comprehensive understanding of the coal geology of Mongolia and that this correspondingly extends to CBM.

In an unpublished report from the Mongolian Nature and Environment Consortium (MNEC) reports possible total CBM resources in Mongolian coal basins of 3.11 Trillion cubic metres ([REF: 7], reported in the Press Release by the Ministry of Mining). Based on the results of many years of geological exploration and detailed analysis by coal laboratories, the most promising coal basins and deposits with high CBM gas content are the South Gobi Coal Basin, Ulaan-Ov00 (Selenge), Nalaikh, Sharin Gol, Ikh Bogd, Southern Khangai, Mongol Altai and Kharkhiraa basins in the Western Region. The South Gobi coal basin is expected to be the largest CBM deposit in the country ([REF: 8]).

There has been some CBM exploration activity since at least 2004 when Storm Cat Energy (SCE) entered into a PSC for CBM in parts of the Nemegt-VI and Boron-VII exploration blocks. The target of the exploration was a 144 km long and 10-120 km wide band of relatively steeply dipping, folded and faulted coals. In 2005 SCE acquired an exploration licence known as Block Tsaidam-XXVI but drilling and sampling indicated very low gas content.

In 2010 KOGAS commenced exploratory in proximity to the Nalaikh coal mine but it was not economically viable due to low gas content (below 5 cubic metres/tonne, $m^3/t$, [REF: 9]). Various other studies have been performed and in 2011, Dr Sc B, Bayarsaikhan from MRA's Coal Research Department calculated the methane gas resources of 22 coal mines. The gas contents reported were generally low compared to CBM resources presently being developed in Australia but it is uncertain whether the gas content is on a Raw or Dry Ash Free (DAF) basis ([REF:10]). Details are summarised in Table 1.

Since that time, several other companies have been awarded PSCs but limited information is available. Elixir Energy has publicly announced a Prospective Resource of 14.6 Trillion standard cubic feet (Tscf) of gas in relation to the Nomgon IX CBM PSC, but information from Telmen resources, Jade Gas and Petrovis on prospective gas resources was not available.

The CBM prospectivity in Mongolia is not well understood at this time. The geological presence and abundance of coal in Mongolia is evident from literature on the geology of Mongolia and the extensive coal mining operations in the country. The coal quality and rank of some of the coals are expected to be suitable for CBM development.

Prospectivity is closely linked to geological risk which can be quantified albeit relying on geological inputs and application of probabilities of particular parameters being successful or unsuccessful. Such a quantitative analysis relies on detailed information being available to make such assessments.

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7 http://www.mm.gov.mn/news/viwe/257

8 TA 9938-MON Methane Gas Supply Chaon Development Master Plan

9 Exploration and Drilling and Gas Analysis of CBM in Mongolia Final Report, 5 April 2011, KIGAM

10 The Potential for Methane Gas Development in Mongolia, CH. Otgochuluu and R. Bold-Erdrne (Erdenes Mongol

| Coal basins | Resource, Million tonnes | $CH_4$ content, $m^3$/tonnes | $CH_4$ resource, million $m^3$ |
|---|---|---|---|
| Nuurst Khotgor | 143.3 | 4.53 | 715.7 |
| Khar Tarvagatai | 19.73 | 2.41 | 52.3 |
| Khushuut | 88 | 4.81 | 467 |
| Zeegt | 4.58 | 3.26 | 16.4 |
| Mogoingol | 4.1 | 2.55 | 11.5 |
| Saikhan Ovoo | 28.3 | 6.51 | 203.2 |
| Uvurchuluut | 3.8 | 1.42 | 5.9 |
| Bayanteeg | 29.7 | 2.83 | 92.7 |
| Tevshiingovi | 588 | 2.83 | 1835.4 |
| Tavantolgoi | 6,400 | 7.65 | 53,938.1 |
| Shariingol | 61.3 | 2.97 | 200.9 |
| Nalaikh | 58.85 | 2.97 | 192.9 |
| Baganuur | 511 | 2.92 | 1,642.9 |
| Shivee Ovoo | 563 | 2.97 | 1,845.2 |
| Chandganatal | 123 | 1.84 | 249.6 |
| Talbulag | 81.5 | 2.69 | 241.7 |
| Aduunchuluun | 241.26 | 1.42 | 376.5 |
| Nariin Sukhait | 21.84 | 3.4 | 81.8 |
| Ulaan Ovoo | 53.98 | 3.68 | 219 |
| Khuut | 87.5 | 1.84 | 177.5 |
| Uvdughudag | 159.2 | 1.84 | 323 |
| Amangol | 1,500 | 3.11 | 5,150.3 |
| **Total** | **10,771.94** | | **68,039.5** |

***Table 1: CBM Resources of the Main Coal Deposits of Mongolia***

However, CBM prospectivity in Mongolia is difficult to assess due to the limited information available, notwithstanding that there is an abundance of coal basins and deposits in Mongolia and an extensive history of coal mining. There is a lack of information on key reservoir parameters necessary for viable and economic development of CBM including: gas content, gas saturations, permeability, permeability distribution and water content. This information would be expected to be available from dedicated exploration and appraisal programmes supported by rigorous laboratory analysis. In addition, there are no producing CBM assets in Mongolia. In the absence of comprehensive and published information on the important reservoir parameters and productivity it is not possible to form any detailed view on the CBM prospectivity of the various coal basins. Whilst it may be possible to challenge this perspective, THREE60 Energy has taken the view that if it was a potential Investor in Mongolia and using public domain data and information it would likely assess that prospectivity is low, primarily due to the limited information available. It could be argued that a deeper analysis of data potentially available in-country would reveal an improved assessment of prospectivity but it would be necessary to invest significant time and effort to source and analyse data.

Consequently, THREE60 Energy would qualitatively form the view that CBM prospectivity in Mongolia would be considered low until such time as further definitive reservoir performance and associated reservoir parameter data are available. In addition, given the large number of coal basins and geographic spread, we would anticipate that any improvement in prospectivity as a result of data acquisition would potentially be specific to the particular basis or sub-basin only.

## 3.2 Data Access

THREE60 Energy has made general enquiry with the oil and gas sector as to data access to assist in assessing potential investment in Mongolia. Access to relevant data can be problematic in relation to CBM for several reasons:

- There is limited data in existence that is relevant to CBM (e.g. well data and seismic);
- Data needs to be sourced physically in Mongolia, at least to some extent;
- Historical data that would be of benefit may not be held by MRPAM e.g. data from coal holes drilled; and
- The data and information that is available is not always in a suitable form that allows potential Investors to assess the data i.e., not all data is available in a digital form and may not be in English.

Many countries have implemented databases and online access that allows Investors to remotely access a vast array of data at little or no cost. This is supported by the access to physical data at a repository in country. The availability and quality of data is a function of regulations describing data to be acquired and submitted as wells as the enforcement of data lodgement requirements. Data availability is subject to any confidential periods described in regulations. In addition, many countries will invest in further processing, conditioning or organising data to assist Investors in their assessment of opportunities within the country. Such data may be released to the industry at a cost but progressive countries have often chosen to provide the data and information at little or no cost in order to facilitate greater competition and enhance the likelihood of investment.

It is noted that Article 35 of the Law of Mongolia on Petroleum (the new addition) contains a very general requirement to lodge data. Those countries with very prescriptive data lodgement regulations can ensure a full set of data and information is available to the industry once regulated confidentiality periods have expired which improves their rating in terms of data supporting prospectivity assessments by potential Operators / Contractors. Article 35 is set out below.

> Article 35. Information materials and reports of results. A Contractor shall hand over to Petroleum Authority reports and primary information and data materials on the results of its exploration or exploitation work within 90 days after the end of the respective calendar year. Section 35.2: Upon permission from Petroleum Authority, a Contractor may send rock samples, petroleum, gas, and primary information materials abroad for studying, refining, reporting, laboratory tests, and analysis. Section 35.3: A Contractor shall hand over

reports and results of the analysis of petroleum, gas, liquids and rock samples and primary data of the study to Petroleum Authority within 90 days after the end of a respective calendar year's work.

The development of high-quality databases is a progressive process in that data availability is a function of the regulatory requirements for data lodgement over history.

A good example of a high-quality data system is the system in place in New Zealand (REF:11). The New Zealand Government provides the following:

*Exploration Database* – a collection of free geoscience exploration data and reports, collected by permit holders and the government comprising:

- 2D and 3D seismic data
- well data
- geochemistry
- airborne and ground-based geophysics
- a catalogue of core photos and samples from the Core Store

*Petroleum Exploration Data Pack* – provided on an external hard drive with the latest technical data and an easy to navigate interface. This is provided at a cost of New Zealand Dollars ($NZD) 400.

*Block Offer Data Pack* – data set comprising all relevant open-file well and seismic data. Such data sets are made available online and can be downloaded for free.

The New Zealand Government also has an online permitting system.

In order to facilitate investment in CBM in Mongolia it would be beneficial to implement regulations and database systems that provide similar benefits available to Investors in other jurisdictions. Ease of access and cost are important considerations in a market where Investors have a range of opportunities globally and limited time and availability to assess. Any requirement to travel to source data represents a partial barrier, particularly given current travel restrictions associated with COVID-19 currently, or future travel risks. In addition, any significant fees for access to data represent an impediment to Investors, and in particular, to smaller entrepreneurial companies with limited resources. It should be recognised that such companies have played a critical role globally in identifying investment opportunities and often play a leading edge role in advance of larger companies investing in and entering a new country.

MRPAM currently has two blocks open for petroleum exploration. A data package is available in hard copy at a price of $USD 25,000. In addition, seismic and drilling/basic well data is available upon request for an extra but undisclosed charge.

[11] https://www.nzpam.govt.nz/maps-geoscience/

## 3.3 Barriers to Entry

It is apparent that there are a number of issues that would influence any decision by an Investor evaluating an opportunity to invest in CBM in Mongolia. These issues, collectively referred to in this document as "**barriers to entry**", may be real or perceived but nevertheless influence investment decisions. These barriers to entry may impact a decision to consider Mongolia as an investment location or may affect any subsequent decision as a result of detailed evaluation of opportunities. Some of these issues have been discussed elsewhere in this report.

THREE60 Energy considers that a number of measures would be required to attract significant and sustained investment in CBM in Mongolia. These measures traverse the fiscal system, legislation, prospectivity, data access and administrative procedures of the licensing system. An integrated and holistic approach is considered to be necessary. Many countries have addressed these issues and a range of systems have been evolved. There are significant learnings available from these other jurisdictions to formulate a system for Mongolia that is highly functional and attractive.

There may be companies that are prepared to invest in CBM in Mongolia regardless of the perceived barriers to entry. However, the barriers to entry identified below are expected to have the effect of limiting the number of companies prepared to invest or subsequently impact their ability to raise funds to develop CBM. Smaller and highly entrepreneurial companies may be prepared to take on significant risk in relation to early and limited investments. However, their ability to fund larger developments will most likely be reliant on attracting larger companies to invest or acquire the development opportunity.

**CBM Prospectivity.** The technical prospectivity of CBM in Mongolia in terms of geology and reservoir engineering is perceived by THREE60 Energy to be low. In order to formulate a view that CBM prospectivity is good it is necessary for significant literature to be available from a reputable body that demonstrates this to be so or a significant amount of quality data being available to the Investor in order to independently formulate such a view. The research performed by THREE60 Energy indicates that literature on CBM prospectivity is limited and primarily focussed on coal as a resource rather than CBM. In addition, access to data is perceived to be difficult and this is further discussed below.

**Data Access.** Data access for potential CBM Investors considered to be a significant barrier to entry. It has been reported that there are very large areas of Mongolia that have little or no available or published subsurface data and that there are no readily available base maps or Geographic Information Systems (GIS) data available. The petroleum information that may exist in the records of the Government are not readily available for public inspection or use ([REF: 12]).

It would appear that access to relevant data is an impediment in relation to CBM development in Mongolia for several reasons:

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[12] TA 9938-MON Methane Gas Supply Chain Development Master Plan

- PSCs usually provide for ownership and confidentiality of the data acquired for the term of the PSC whereas Royalty regimes typically provide for data to be submitted to the Government and identified for public release after a period of confidentiality, the latter enabling new Investors to make informed decisions;
- There is limited data in existence that is relevant to CBM (e.g. well data, coal reservoir properties and seismic);
- Data needs to be sourced physically in Mongolia, at least to some extent;
- Historical data that would be of benefit may not be held by MRPAM but by different Government departments e.g. data from coal holes drilled. A single repository of data generally allows better data access for potential Investors; and
- The data and information that is available is not always in a suitable form that allows potential Investors to assess the data i.e. not all data is available in a digital form and may not be in English.

Technical Risk. The technical risk (geological and reservoir) of CBM projects is inherently high. CBM developments typically carry more risk in the development phase than do conventional gas developments by virtue of the inherent geological variability of coals over short distances. The higher levels of risk and lower than expected rates of investment return from large scale CBM developments in Australia are widely known among the international investment community. This presents a possible barrier to enter into new large-scale projects elsewhere in the world, particularly if the regime framework does not address the risks the Investor undertakes for CBM development.

Legislation. Mongolia's mineral resources are owned by the state. The Ministry of Mining is responsible for the drafting of Government policy for developing the petroleum sector and the Petroleum Authority is responsible for implementing the petroleum legislation and decisions of Government and the Ministry of Mining.

The Law of Mongolia on Petroleum (the new addition) referred to herein as "the Petroleum Law' regulates matters pertaining to petroleum and unconventional petroleum prospecting, exploration, and exploitation within the territory of Mongolia. There are a number of issues with the petroleum legislation that would act as potential barriers to entry:

- PSC terms are to be negotiated at the time an exploration licence is awarded. There are no clear guidelines as to how these terms and conditions are evaluated and agreed by authorities, nor is there a demonstrable track record. Accordingly, an Investor would be concerned that it is negotiating terms in the absence of having performed exploration activities as well as development feasibility studies. In essence it is negotiating terms with no knowledge as whether the terms will ultimately lead to an economic development. Given this risk, a prudent Investor would endeavour to negotiate very favourable terms, increasing the likelihood that a PSC will not be agreed. In addition, there is no provision to amend PSC terms subsequent to the award of an exploration licence.

- The PSC Profit Sharing provisions are based on a production rate threshold but are not graduated. This would potentially lead to Investors considering the terms to be distortionary in that decisions and alignment on the sizing of a plant may be influenced by the profit sharing terms.
- A Contractor shall submit the reserve estimate to the Petroleum Authority 90 days before the expiry of the exploration period for review, hold discussion of it by the Mineral Resources Council of the Ministry of Mining, and seek issuance of a decision by the Ministry of Mining as to whether or not to accept the reserves. Based on international standards such as Society of Petroleum Engineers - Petroleum Reserves Management System (SPE-PRMS) it is unlikely that reserves could be estimated (booked) in the absence of a plan of development and appropriate approvals to exploit.
- The Petroleum Authority and the Contractor shall set a price of the extracted petroleum on the basis of the price of petroleum of the same character as sold on the world market. This is problematic in that for CBM there is no world market benchmark and as such one of the key factors in determining the economics of a project is not subject to commercial market negotiations alone.
- There do not appear to be any petroleum regulations that have been formulated to complement the petroleum legislation. Petroleum regulations in many countries provide specific detail on many matters including data acquisition, reporting, consent procedures, durations for applying for and consideration by authorities of various matters. The absence of well-articulated regulations introduces significant uncertainty relating to treatment of any licence holder on a range of matters which may ultimately affect the value of a CBM investment.
- It has been reported that there is a lack of clarity in respect of overlapping licences under the Minerals Law and the Petroleum Law. Given CBM and coal mining activities are frequently undertaken in the same sedimentary basins there would be a perceived risk that a CBM PSC may not enable full access to the CBM resource.

**Infrastructure.** Gas infrastructure is limited in Mongolia. There is no pipeline network in Mongolia and accordingly transportation of gas to markets, whether by pipeline, road or rail will necessarily be linked to specific gas developments as they evolve unless pre-investment in infrastructure is undertaken by the Government. Any pre-investment in infrastructure would be high risk due to poor knowledge of the resources that could potentially be developed. It is noted that an initiative to develop a Methane Gas Supply Chain Development Master Plan has commenced. Whilst this report will address infrastructure amongst other issues it is anticipated that the absence of a good understanding of the CBM resource will pose a challenge.

# 4 Economic Modelling

THREE60 Energy have developed two distinct economic models to evaluate three representative Mongolian CBM asset datasets, or scenarios.

One model has been set up to evaluate Operator / Contractor cashflow with the capability to consider a range of potential PSC fiscal terms based on an amalgamation of existing precedents and ranges for Operators in Mongolia. These terms have been amalgamated and normalised to preserve anonymity and maintain the commercial confidentiality for the Operators who provided this information for the purposes of this study.

The other model has been developed for post-Tax cashflow analysis based on the Australian Federal Government Income Tax applicable to both large and small corporations operating in Australia. This model also includes the Royalty rates chargeable to CBM that are governed and applied by the Queensland Office of State Revenue. These Royalty fiscal terms were updated by the Queensland Office of State Revenue as recently as October 2020.

Both models have been normalised and harmonised to the extent possible by adopting the exact same boundary conditions, also known as model settings. This approach focuses the evaluation on the different fiscal terms that a Government may choose to apply to the development of a CBM asset. It should be noted here that all input costs, pricing and results are in $USD terms. The main model settings are summarised in Table 2.

The following sections describe how the input data was compiled into representative cases for analysis using the two distinct models.

## 4.1 Economic Model Scenarios and Inputs

It was essential to ensure that both models use the exact same input datasets for each CBM asset scenario, or case, being evaluated, apart having common settings for both models. This ensured that the only differences in the model outputs could be attributable to the fiscal terms alone and would ensure the integrity of the conclusions and recommendations arising from the analyses and the comparison of the two regimes.

With this in mind, a template was set up to capture all relevant input data for both models. The benefits of using a common template for each asset scenario being modelling are manifold:

- Ensured consistent model input datasets as described above
- Preserved anonymity of data sources and confidentiality of their information
- Enabled THREE60 Energy experts to apply their own oversight / review of the data and to adjust the source data based on wider industry norms, where deemed necessary. Any adjustments would only be made to bring costs and production in line with reasonable benchmarked norms for the CBM industry, whilst also considering the local operating environment for CBM development in Mongolia.

- Templates serve as a good reference source for the input data used for the analysis and therefore provides a helpful audit trail.

| Model Boundary Conditions / Settings | Agreed Model Settings (Final) |
|---|---|
| **Project Start Date** (development decision going forward excluding sunk costs) | 2021 |
| **Project End Date** | 2060 |
| **Asset Life Duration** – concept to abandonment | 40 |
| | |
| **Discount Date** | 1/1/2021 |
| **Discounting Methodology** – recommend mid-year discounting for annual models | Mid year. |
| **Discount Rates** for results, e.g. 0%, 10%, 15%, 20% | 0%, 7%, 10%, 15% |
| | |
| **Macro Economics Assumptions** | |
| **Currency** – confirm currency for costs and prices and results reporting – typically USD for Non-OECD countries.<br>Noting that Australian Royalty Tax evaluations are conducted in AUD$ with currency conversions from $USD inputs and to $USD outputs as needs be. | $USD |
| **Foreign Exchange Rate for $USD to AUD$** | 0.75 |
| To what extent might we model and capture local currency costs and / or pricing? | All in $USD |
| **Foreign Exchange for $USD to Mongolian Tughrik** | Not needed. |
| **Inflation Rates for CAPEX in $USD** | 2.00% |
| Inflation rates for OPEX in $USD | 2.00% |
| Inflation rates for local currency costs or prices, if applicable | Not applicable for this exercise. |
| **Pricing**: based on current local and international market pricing considerations | $USD 5.5 for domestic market consumption.<br>$USD 7.5 for export market. |
| **Price Escalation** | Default inflation rate of 2% to be used for product pricing. This is consistent with cost inflation assumptions to avoid a real price reduction over time whilst costs still inflate. |

***Table 2: Common Model Settings used for the Royalty-Tax and PSC Models***

### 4.1.1 Economic Model Scenarios / Cases

The THREE60 Energy team of experts considered the data that had been received from Operators, and based on this, scoped out three representative asset scenarios for a CBM business operating in Mongolia. The main purpose of defining three distinct asset scenarios / cases was to provide a sufficiently broad range of projects, in terms of development scale, scope and cost, to represent the potential range of CBM business opportunity in Mongolia. This is relevant from an Investor perspective contemplating new business entry into Mongolia and also highly relevant to Mongolian authorities who wish to design their fiscal regime so that it meets a range of needs, some of which are essential and some desirable, depending on the strategic goals of the State, including;

- Attracting sufficient investment and skillsets into the country, if not locally available, not just for the short-term but also for longer-term mutual benefit;
- Promoting economic growth and local employment from construction, infrastructure development and operations;
- Increasing energy independence and energy reliability within Mongolia; and
- Unlocking stranded resources that can be used domestically, and if sufficient surplus exists, exporting and selling internationally to generate revenue for the State, support the Federal budget and the balance of trade.

Three CBM development scenarios, comprising a Low, Mid and a High Case, were considered to be sufficiently broad to assess and compare fiscal regimes, without being too onerous in terms of the volume of input and output data to be analysed.

After consideration of data received from Operators the three scenarios or cases were broadly defined as follows:

- Low Case: Small scale CBM to LNG production for transportation fuel to the local market, e.g. as fuel for cars, trains and trucks. This scenario assumed 30-32 Billion standard cubic feet (Bscf) of gas sales s from an initial undeveloped resource of about 40 Bscf. Development costs (CAPEX) were assumed to be about $USD 51 Million and Exploration and Appraisal (E&A) capital of about $USD 5 Million.
- Mid Case: CBM for gas fired power generation for local market base load power at 80 Mega Watts (MW). This scenario assumed about 146 Bscf of sales gas from an initial undeveloped resource of about 188 Bscf. Development costs were assumed to be about $USD 236 Million and E&A capital of about $USD 11 Million.
- High Case: CBM for pipeline export to an international buyer. This scenario assumed about 1.015 Tscf of sales gas from an initial undeveloped resource of about 1.48 Tscf. Development costs were assumed to be about $USD 1,856 Million and E&A capital of about $USD 44 Million.

The discount date is set to 1 January 2021 after the completion of exploration and appraisal program and at the time when project participants decide whether the investment in project is attractive to progress into development phase. Therefore, negative cash flows from exploration and appraisal costs paid by contractors are sunk and excluded from the net cash flows and net present value calculation. The impact from sunk cost income tax deductible for tax royalty regime and cost recoverable for PSC regime is included in the cash flows and net present value calculation.

With all three cases the development takes place after the E&A phase sufficiently defines and de-risks the resources, leading to first gas and operations around 2024 for the Low and Mid Cases. However, for the High Case, where gas will be exported to international buyers through a pipeline, the first production is estimated to be around 2028 as the project will need finalisation of gas sales and gas transportation agreements to end users via an onshore pipeline constructed and owned by a third party. As with all CBM developments, unlike conventional, the field appraisal and development continues throughout the operational phase until late field life to maintain plateau production by compensating for the more rapid decline rates and wider geographical footprints typically observed with CBM.

All three cases assumed about 22% volume reduction from the initial resource as a result of field fuel usage, $CO_2$ removal, gas shrinkage and other operational related losses. The upstream development scope in all three cases excluded gas processing plant and capital as it was assumed, based on the local market setting, that the gas processing would be handled under a tolling arrangement with a third party. This cost is, therefore, included as part of the field operating expenses (OPEX) assumption. Likewise, the water treatment costs, that are also a typical CBM feature, are handled as an OPEX via a tolling arrangement through third party plant.

In all cases the CBM development scope and costs were limited to the upstream project only. In other words, the fiscal point of sale for the gas would be the field export pipeline flange to one of three potential market entry points.

From a fiscal modelling viewpoint it is very important to be clear about the point of sale, where the gas produced is valued, as that location defines the upstream development scope and costs that are recoverable (for PSCs) or depreciable (for Royalty-Tax Regimes) and the scope and costs that fall outside the petroleum fiscal framework. For the purposes of this exercise and for simplicity the modelling scope encompasses upstream assets to the point of sale as defined below.

1. **Low Case:** Point of sale would be from the field exit flange / at the inlet flange of the feed line into the small-scale LNG plant.
2. **Mid Case:** Point of sale would be from the field exit flange / at the inlet flange of the feed line into the power station.
3. **High Case:** Point of sale would be from the field gas compression and treatment plant exit flange / at the inlet flange to the pipeline connection point.

### 4.1.2 Economic Model Inputs

Estimated capital and operating expenditures for Low Case, Mid Case and High Case were provided by current Operators in Mongolia CBM projects. The THREE60 Energy team reviewed these cost estimates and made necessary adjustments to normalise the data based on benchmarked information and in some cases to anonymise the data from their sources. All the cost estimates were provided in 2020 real values and then inflated using a 2% inflation per annum assumption to the time they were incurred.

The basis and the unit cost assumptions for capital and operating expenditures are described in Table 3.

| CAPEX and OPEX Assumptions | Basis and Unit Costs |
|---|---|
| Well and Facility CAPEX | $USD 0.450 MM/well |
| Gas Production Related OPEX (variable) | $USD 0.050 /Mscf raw gas |
| Water Treatment OPEX (variable) | $USD 0.100 /barrel of water |
| Workover, Maintenance & Field Operation OPEX | $USD 0.5 MM fixed per year and $USD 150,000 per online well |
| Gas Processing Tariffs (OPEX) | $USD 0.750 /Mscf raw gas |
| Abandonment Cost (ABEX) | 6.5 % of well and facility CAPEX to be spent equally 5 years after the drilling campaign |
| Exploration and Appraisal | 10 % of CAPEX for Low Case<br>5 % of CAPEX for Mid Case<br>2.5 % of CAPEX for High Case |

***Table 3: Basis and Unit Cost Assumptions for Capital and Operating Expenditures***

Estimated gas price assumptions were provided by CBM Operators in Mongolia, and like the cost information this was adjusted to normalise prices based on a range of market price ranges provided for each case and anonymise the Operator information. All price estimates were assumed to be 2020 real values and then inflated using a 2% inflation per annum assumption. The assumed domestic gas prices and export gas price assumptions are described in Table 4 and are reported as prices per Million British thermal units (MMBtu) that converts gas volumes to units of heat.

| Market | Netback Gas Price |
|---|---|
| Domestic Gas Sales for Low Case and Mid Case | $USD 5.50 /MMBtu |
| Export Gas Sales for High Case | $USD 7.50 /MMBtu |

***Table 4: Gas Price Assumptions for Domestic and Export Markets***

No analysis has been performed on the gas market or gas market risks as part of this study. The following gas market sectors have been identified (REF: 13):

- Urban Gas Demand. This market comprises supply for residential use for winter heating and gas vehicles. The winter heating demand occurs from October to May, whereas gas demand for gas vehicles would be classified as regular use.
- Industrial Gas Demand. This market comprises industrial and chemical enterprises. The number of users will increase as the economy develops.
- Heat and Power Cogeneration. Currently, all heat and power cogeneration plants in Mongolia are coal fired. The substitution of coal for gas is possible subject to available and reliable gas supply in sufficient quantities.

In addition to the above, there is the potential to supply gas to international markets such as China. Significant gas resources would be required to supply such a market and justify capital investment in facilities and pipelines.

For the **Low Case**, an ex-field delivery price of $USD 5.50 /MMBtu was assumed. With estimated LNG processing and liquefaction fees of $USD 3.0 - 3.5 /MMBtu for LNG and an assumed distribution fee of $USD 0.75-1.00 /MMBtu, LNG would be sold to end users at a market price slightly below $USD 10 /MMBtu. At this price level, LNG was considered to be competitive to liquid fuel alternatives, i.e. sufficiently cheaper to petrol for cars or diesel for trucks / trains to incentivise the switch to LNG.

For the **Mid Case**, an ex-field delivery of $USD 5.50 /MMBtu was assumed for gas sold to a power generation plant. At this price level, gas would be competitive to diesel, fuel oil, or even coal if environmental impacts are taken into consideration.

For the **High Case**, an ex-field delivery price of $USD 7.50 /MMBtu was assumed based on an estimated landed gas price in international markets of about $USD 8.50 /MMBtu with $USD 1.00 /Mscf for pipeline transportation fee.

Additional price and cost sensitivities were not conducted for the scope and purposes of this exercise.

The input summaries for each of these cases in **Table 5** to **Table 7** and illustrated in charts in **Appendix C** for further reference.

[13] TA 9938-MON Methane Gas Supply Chain Development Master Plan: Inception Report

1. Low Case: Small Scale CBM to LNG Production for Transportation Fuel to the Local Market.

| Development Metrics | Value | Unit |
|---|---|---|
| Raw Gas Production | 40.6 | Bscf |
| Total Sales Gas Produced | 31.5 | Bscf |
| Total Water Produced | 19.2 | MMstb |
| Development Wells Drilled | 106 | # Wells |
| Average Recovery Per Well (post fuel+flare use) | 0.30 | Bscf/Well |

***Table 5: Development Input Summary for Low Case***

2. Mid Case: CBM for Gas Fired Power Generation for Local Market Base Load Power at 80 MW.

| Development Metrics | Value | Unit |
|---|---|---|
| Raw Gas Production | 188.2 | Bscf |
| Total Sales Gas Produced | 146.1 | Bscf |
| Total Water Produced | 89.1 | MMstb |
| Development Wells Drilled | 492 | # Wells |
| Average Recovery Per Well (post fuel+flare use) | 0.30 | Bscf/Well |

***Table 6: Development Input Summary for Mid Case***

3. High Case: CBM for Pipeline Export to an International Buyer.

| Development Metrics | Value | Unit |
|---|---|---|
| Raw Gas Production | 1,477.6 | Bscf |
| Total Sales Gas Produced | 1,147.0 | Bscf |
| Total Water Produced | 700.2 | MMstb |
| Development Wells Drilled | 3,872 | # Wells |
| Average Recovery Per Well (post fuel+flare use) | 0.30 | Bscf/Well |

***Table 7: Development Input Summary for High Case***

## 4.2 Production Sharing Contract Modelling - Mongolia

Mongolia CBM projects currently operate under Production Sharing Contracts (PSC) with cost recovery and profit split between Government and Contractors. The revision of Mongolia Petroleum Law in 2014 simplifies certain fiscal terms including the elimination of income Tax, dividend withholding Tax, and value added Tax and customs tariff. Key Government take fiscal terms for CBM projects are negotiable with the authorities for each individual Operator and potentially for each individual licence. In accordance with the 2014 Petroleum Law, Royalty ranges from 5 % to 10 % of gross revenues. The cost recovery limit and profit sharing for the Government are negotiable on project-by-project basis. The profit sharing for Government is not graduated but applied on a production rate threshold.

For the analysis, Royalty rate is assumed to be 7.5 % as the midpoint of the 5-10 % range. The THREE60 Energy team has reviewed the cost recovery limit and profit sharing for Government assumptions made by Operators and made necessary adjustments to normalise and anonymise the fiscal terms. Signature bonus and production bonuses are not included in the analysis. Table 8 summarises the fiscal terms assumptions.

| Fiscal Terms | Petroleum Law | Assumptions in the Analysis |
|---|---|---|
| Royalty | 5 % - 10 % | 7.5 % |
| Cost Recovery Limit | For CBM - to be determined | 70 % |
| Profit Sharing for Government | | |
| 0- 1 Million $m^3$/day | For CBM - to be determined | 30.0 % |
| 1-2 Million $m^3$/day | | 32.5 % |
| 2-3 Million $m^3$/day | | 35.0 % |
| 3-4 Million $m^3$/day | | 37.5 % |
| >4 Million $m^3$/day | | 40.0 % |
| Tax Rate | Exempted | 0.0 % |
| Dividend Withholding Tax | Exempted | 0.0 % |
| VAT and Customs Tariff | Exempted | 0.0 % |
| Contractor Participating Interest | 100 % | 100 % |
| Signature Bonus | As proposed by Contractor | Not included |
| Production Bonus | As proposed by Contractor | Not included |

Note: 1 Million $m^3$ per day is 35.315 Million standard cubic feet per day (MMscf/d)

***Table 8: Summary of Mongolian PSC Terms***

## 4.3 Royalty-Tax Model – Queensland Australia

The Federal and Queensland Governments have been under intense political pressure in recent years from industrial, commercial, and general consumers in the domestic market to apply increasing levels of price regulation on gas exporters to keep local gas prices down. Domestic gas retail prices in Queensland were typically in the $AUD 3.5–6.0 /GigaJoules (GJ) range prior to 2009, until the three LNG plants linked the South Eastern Australia Gas Market to international market pricing from around 2010. This resulted in much higher gas prices than was historically the case, almost doubling within a 5-year period from 2010.

LNG export prices are typically linked to international oil and gas-hub benchmark price indices and these were historically much higher than recent lows that have resulted from the impact of COVID-19 on the demand side, over-production on the international supply side, and all of this against a backdrop of disruptive technologies (renewables and storage) supported by the global shift previously described in this report.

In managing its fiscal responsibilities, the Federal and State Governments have been cognisant of this market context and have been treading a very fine line between supporting local market consumers who demand gas prices stay low in order to grow and sustain their businesses and not discouraging Operators and producers from further investment in the short-medium term as this would pose a risk to security of gas supply for the domestic market in the medium-long term future, not just the short term.

**Federal Government Corporation Tax**: Considering the above context, the Federal Government has been quite progressive in recent years by lowering the corporate Tax rates from 30 % to 26-25 % for smaller sized businesses in order to stimulate business growth and more crucially, employment. A smaller sized business is defined as those whose revenues are below an $AUD 50 Million threshold per financial year. Larger businesses with annual revenues above this threshold are liable to a Tax rate of 30 % on profits as they are deemed large enough and robust enough to sustain this level of Federal Government take.

A summary of the Federal Government Tax Terms and links to Australian Tax Office (ATO) website are included in **Table 9**.

**Queensland State Government Royalty:** The Queensland Office of State Revenue changed the Royalty calculation methodology as recently as October 2020.

The historical context to this recent change, which is relevant to any State Government contemplating the fiscal framework for CBM developments, is that the three major CBM-to-LNG proponents in Queensland had previously been subject to separate and distinct approaches to determining the net wellhead value for calculating their Royalty liability, largely as a result of the different corporate structure and related party arrangements across the value chain from subsurface to ship. Historically the Royalty calculation methodologies across the three major LNG export proponents were not considered to be consistent or transparent or publicly available as these were agreed / negotiated in commercial confidence. Another factor in this situation was that CBM to large scale LNG had never been done in the world before. There was in fact, a legislative lag as the State Government, and industry also, needed time to understand the features and challenges that are unique to large scale CBM development for

LNG export and how it could be equitably assessed for Royalty purposes, also considering smaller producers and domestic market requirements.

| |
|---|
| **Corporate Tax Rate Reduction:** For a business with an aggregate turnover of less than $50 million per financial year a lower company tax rate can be applied. For smaller businesses this means the standard 30% tax rate could be reduced to 25%. |
| These company tax rates are based on the ATO site information below |
| https://www.ato.gov.au/Rates/Changes-to-company-tax-rates/#Futureyearcompanytaxrates |

| Base rate entity company tax rate |
|---|
| From the 2017–18 to 2019–20 income years, companies that are base rate entities must apply the lower 27.5% company tax rate. The rate will then reduce to 26% in the 2020–21 income year and 25% in the 2021–22 income year. |
| A base rate entity is a company that both: |
| has an aggregated turnover less than the aggregated turnover threshold – which is $25 million for the 2017–18 income year and $50 million from the 2018–19 income year |
| 80% or less of their assessable income is base rate entity passive income – this replaces the requirement to be carrying on a business. |
| |
| Base rate entity passive income is: |
| |
| corporate distributions and franking credits on these distributions |
| royalties and rent |
| interest income (some exceptions apply) |
| gains on qualifying securities |
| a net capital gain |
| an amount included in the assessable income of a partner in a partnership or a beneficiary of a trust, to the extent it is traceable (either directly or indirectly) to an amount that is otherwise base rate entity passive income. |

| Progressive changes to the company tax rate | | | |
|---|---|---|---|
| Income year | Aggregated turnover threshold | Tax rate for base rate entities under the threshold | Tax rate for all other companies |
| 2017–18 | $25m | 27.50% | 30.00% |
| 2018–19 to 2019–20 | $50m | 27.50% | 30.00% |
| 2020–21 | $50m | 26.00% | 30.00% |
| 2021–22 and future years | $50m | 25.00% | 30.00% |

***Table 9: Australian Federal Tax for Corporate Income Tax***

It took some time for the State Government to recognise the need for a consistent and clear system for applying Royalty to all producers, not just the three major LNG export proponents. There was a need to recognise the unique challenges of CBM development where Operators incur more time and investment to reduce the subsurface uncertainties. There was also a need to promote domestic market producers to meet the demands of local industrial and commercial consumers, while at the same time the fiscal terms needed to accommodate Operator's high exposure to the volatile international pricing environment that has placed many Operators in a challenging and precarious business situation.

One of these proponents conducted a legal challenge to the State interpretation and assessment of net wellhead value in the Royalty calculation methodology that was specifically applied to them. A court judgement on May 19, 2019 (REF:14) in favour of the proponent's legal challenge was soon followed by the Queensland State Government announcing a 25 % increase of Royalty rates from 10 % to 12.5 % on June 11, 2019. his sudden increase led to an outcry from most Operators in Queensland and placed future project investment at risk which was not in the best interests of the State or of the Nation in promoting investment into the long term security of gas supply (REF:15).

Cognisant of this, the Queensland Office of State Revenue introduced a revised Royalty calculation methodology from October 1, 2020 that reflects a more stable and mature Royalty regime. The new methodology appears to be fair to all stakeholders and is reflective of a much more progressive Royalty regime that actually promotes and sustains ongoing investment in the industry. The terms are transparent for all Operators, they take account of price exposures and price risks to the Investor and Operators, and they also promote gas development for the domestic market. At the same time the terms are not overtly punitive towards the large-scale LNG export proponents, effectively recognising their significant historical investments, their need to recoup a fair return on this investment, and their ongoing contribution to the state economy and to the employment of its citizens.

In summary, the fiscal terms that were originally designed for conventional petroleum extraction projects have been adapted and changed to terms more suitable for the specific features of this relatively new unconventional large-scale resource play. The Royalty methodology as it was applied in the early days of the CBM-LNG export industry were challenged in the courts with a ruling in favour of one of the LNG proponents in mid-2019. A subsequent reactionary hike of 25 % to the Royalty rate from 10 % to 12.5 % later in 2019 was replaced in October 2020 with a more transparent and consistent methodology across production licences and Operators that should stand the test of time. The new methodology allows for price volatility by applying lower Royalty rates at lower prices and conversely higher rates when Operators benefit from higher gas prices. At face value the Royalty regime changes over recent years could be perceived as presenting sovereign risk and appear as fiscal uncertainty. In early 2020 this would certainly be the case. Since the Royalty methodology changes came into force in October 2020, a more accurate conclusion would be that this is a regime that has evolved and matured over time, in response to a new industry emerging since 2009 that has had major impacts to the domestic market,

[14] Data source reference: https://www.afr.com/companies/energy/gas-consortium-wins-royalty-decision-against-queensland-government-20190524-p51qru

[15] Data source reference: https://www.hopgoodganim.com.au/page/knowledge-centre/court-decision/petroleum-royalties-in-queensland---challenges-and-changes

namely large scale CBM to LNG. This evolution has resulted in a new Royalty regime that is clear, transparent, adaptive to market pricing and therefore more likely to remain stable in the years to come. The state Royalty terms are summarised in Table 10, and further details can be viewed in the link to the State Government website.

| |
|---|
| Explanation of the new Queensland Government Royalty regime, effective from 1st october 2020 is found in the following link: |
| https://www.business.qld.gov.au/industries/mining-energy-water/resources/minerals-coal/authorities-permits/payments/royalties/petroleum-royalty |
| This new royalty calculation methodology applies from 1 October 2020, and is far simpler than the previous mehtodology. It is described as a "Volume Model" as the royalty charges are driven by volume and royalty rates that depend on the market category and the sales price. |
| The first step in the process is to determine who the gas is sold to (as this sets the royalty rates), with the categories set out as follows: |
| 1. Domestic gas: Producer sells its gas or uses the gas in service of the domestic market |
| 2. Supply gas: Producer sells its gas to an LNG Project (Noting that all Australian LNG projects are larger scale for export, not small scale domestic usage) |
| 3. Project gas: Producer is a member of LNG Project. The gas may not be for LNG export but is developed by a producer who is a JV partner in an LNG export project |
| 4. Liquid petroleum: Liquid petroleum products - typically, condensate or oil |
| Once the category is determined, the next stage is to determine the price that is received. This can be determined using two methods: |
| 1. The actual price received for the product; or |
| 2. A benchmark price (Wallumbilla for domestic and Brent linked for Supply and Project gas). |
| From this point you are able to calculate the royalty payment. This is simply the royalty rate multiplied by the price. The royalty rate is dependent on both the category and the price. With Domestic gas having the lowest royalty rate which is summarised here ====> |
| So for domestic gas the top tax rate is 10%, but for supply and project gas it tops out at 12.5% (although for project gas this top rate does not kick in until \$14/GJ). |
| Calculating petroleum royalty |
| Petroleum is produced when it is released or recovered to ground level from a natural underground reservoir. Your petroleum royalty liability is based on the volume of liable petroleum produced in a return period. |
| The volume model is used for calculating royalty for petroleum produced from 1 October 2020. Under this model, you need to determine: |
| the total liable volume of petroleum produced during the period |
| the classification (e.g. domestic gas, supply gas, project gas or liquid petroleum) |
| the royalty rate that applies to each class of petroleum. |
| Other relevant links to QLD Royalty Regime-see below |
| Measurement of Petroleum: https://www.treasury.qld.gov.au/resource/measurement-petroleum/ |
| Classification of Petroleum: https://s3.treasury.qld.gov.au/files/Petroleum-classification.pdf |

***Table 10: Australian Federal Tax for Corporate Income Tax***

The Royalty charges per GigaJoule (GJ) and barrel of oil or condensate are calculated for each price and category as presented in Table 11:

| Domestic gas | ALL PRICES HERE ARE $AUSTRALIAN |
|---|---|
| **Average sales price** | **Royalty payable per GJ** |
| Up to and including $3/GJ | 0.02 cents/GJ for each 1 cent/GJ more than $0/GJ |
| Over $3/GJ and up to and including $8/GJ | 6 cents/GJ plus 0.08 cents/GJ for each 1 cent/GJ more than $3/GJ |
| More than $8/GJ | 46 cents/GJ plus 0.10 cents/GJ for each 1 cent/GJ more than $8/GJ |
| | |
| **Supply gas** | |
| **Average sales price** | **Royalty payable per GJ** |
| Up to and including $3/GJ | 0.05 cents/GJ for each 1 cent/GJ more than $0/GJ |
| Over $3/GJ and up to and including $8/GJ | 15 cents/GJ plus 0.10 cents/GJ for each 1 cent/GJ more than $3/GJ |
| More than $8/GJ | 65 cents/GJ plus 0.125 cents/GJ for each 1 cent/GJ more than $8/GJ |
| | |
| **Project gas** | |
| **Average sales price** | **Royalty payable per GJ** |
| Up to and including $9/GJ | 0.03 cents/GJ for each 1 cent/GJ more than $0/GJ |
| Over $9/GJ and up to and including $14/GJ | 27 cents/GJ plus 0.09 cents/GJ for each 1 cent/GJ more than $9/GJ |
| More than $14/GJ | 72 cents/GJ plus 0.125 cents/GJ for each 1 cent/GJ more than $14/GJ |
| | |
| **Liquid petroleum (oil and condensate)** | |
| **Average sales price** | **Royalty payable per bbl** |
| Up to and including $50/bbl | 0.03 cents/bbl for each 1 cent/bbl more than $0/bbl |
| Over $50/bbl and up to and including $100/bbl | $1.50/bbl plus 0.115 cents/bbl for each 1 cent/bbl more than $50/bbl |
| More than $100/bbl | $7.25/bbl plus 0.125 cents/bbl for each 1 cent/bbl more than $100/bbl |
| **Benchmark price** | |
| **Petroleum type** | **Benchmark price for a royalty return period** |
| Domestic gas | The firm End of Day Wallumbilla Benchmark Price averaged over the royalty return period |
| Supply gas | 0.09 bbl/GJ multiplied by the daily Europe Brent Spot Price FOB ($/bbl) averaged over the relevant period |
| Project gas | 0.135 bbl/GJ multiplied by the daily Europe Brent Spot Price FOB ($/bbl) averaged over the relevant period |
| Liquid petroleum | The daily Europe Brent Spot Price FOB ($/bbl) averaged over the royalty return period |

***Table 11: Queensland State Royalty Charging Mechanism Based on Price and Project Category***

## 4.4 Fiscal Regime Analyses and Comparisons

The three cases were assessed using the models as described previously. The results of this are summarised for each case below.

1. **Low Case: Small Scale CBM to LNG Production for Transportation Fuel to the Local Market** (**Table 12** and **Table 13**).

| Development Metrics | Value | Unit |
|---|---|---|
| Raw Gas Production | 40.6 | Bscf |
| Total Sales Gas Produced | 31.5 | Bscf |
| Total Water Produced | 19.2 | MMstb |
| Development Wells Drilled | 106 | # Wells |
| Average Recovery Per Well (post fuel+flare use) | 0.30 | Bscf/Well |
| **Revenues and Key Costs, $USD Millions** | **Value** | **Comment** |
| Gross Revenue Total, nominal | 244.4 | |
| E&A CAPEX, real 2020 Values | 5 | |
| Development CAPEX, real 2020 Values | 51 | |
| OPEX, real 2020 Values | 84 | |
| If applicable, Government **Royalty**, nominal | 16 | Royalty-Tax |
| If applicable, Government **Royalty**, nominal | 18 | PSC |
| If applicable, **Bonuses** (Signing & Production), nominal | N/A | PSC |
| If applicable, **Cost Oil**, nominal | 166 | PSC |
| If applicable, **Profit Oil**, nominal | 21 | PSC |
| If applicable, Federal Government **Tax**, nominal | 8 | Royalty-Tax |

***Table 12: Low Case Key Value Drivers and Financial Metrics***

**HEADLINE VALUE METRICS**

| Discount Rate, % | NPVS & IRR | Royalty-Tax Regime | | PSC Regime | | Units |
|---|---|---|---|---|---|---|
| | | Gross Project | Post-Tax | Pre-Govt Take | Post-Govt Take | |
| 0% | NPV0 | 52 | 28 | 52 | 13 | $USD Millions, Nominal |
| 7% | NPV7 | 11 | 4 | 11 | -2 | $USD Millions, Nominal |
| 10% | NPV10 | 5 | 1 | 5 | -4 | $USD Millions, Nominal |
| 15% | NPV15 | 1 | -2 | 1 | -5 | $USD Millions, Nominal |
| | **$USD IRR** | **15.9%** | **10.8%** | **15.9%** | **5.3%** | **%** |

| | Royalty-Tax Regime | PSC Regime | |
|---|---|---|---|
| **Profit/Investment Ratio, $USD NPV10** | **1.03** | **0.84** | |
| **Max Exposure** | **$USD-12.75 in year 2025** | **$USD-14.87 in year 2025** | |
| **Payback Year** | **2033** | **2039** | |

***Table 13: Low Case Headline Economic Value Metrics***

The case input value drivers, such as gross revenue, CAPEX and OPEX, are identical for both models as previously mentioned. The results for the Low Case are broadly comparable for the PSC and Royalty-Tax Regimes indicating a sub-economic to marginally economic project depending on the fiscal terms.

The post-Tax/take undiscounted cashflows are significantly better under the Royalty-Tax system at $USD 28 Million *versus* about $USD 13 Million under the PSC system. The rate of return is significantly better in relative terms under a Royalty-Tax regime, with a 10.8 % rate of return, yielding marginally economic results, *versus* the sub-economic 5.3 % rates of return under the PSC terms. This is consistent with the qualitative observations made earlier about the Royalty-Tax regime being supportive of smaller scale businesses with lower levels of profitability, in the best interests of promoting domestic economic growth and employment.

For the purposes of this exercise, a rate of return above 15 % is treated as the minimum threshold required to support a new country entry into a new resource play, in a relatively new / evolving market and business environment. With this in mind, a rate of return of about 10 % is considered to be marginal for this exercise, whereas in well-established business environments in other countries this would be considered to be economic.

Another observation is that the project reaches payback 6 years earlier, in 2033, under the Royalty-Tax regime, illustrating the increased risk and exposure a small, less profitable business would face under the PSC terms, and the maximum capital exposure under the Royalty-Tax regime is lower in the first year of operations ($USD 12.8 Million in 2025 *vs.* $USD 14.9 Million).

One feature of this analysis that appears counter-intuitive in all cases (Low, Mid and High) is the variance between the pre-Tax Earnings Before Income Tax (EBIT) figures and the Pre-Government take figures. This is attributable to the depreciation treatment of capital costs under the Royalty-Tax system.

From an Investor / Operator / Contractor perspective, this project would not proceed as the returns do not justify the risks and exposures involved. With such low investment returns, adjustment of fiscal terms is unlikely to change this outcome. The poor economic results in this case raise questions about the fundamental value drivers of the project itself and what would be required to bring it up to the minimum economic threshold required, for example, is the ex-field gas price too low and/or are the costs to develop and operate too high? Based on the benchmarked data used for the modelling it is less likely that there would be significant movement in these key value drivers. More fundamentally, in this case it raises a question about the CBM itself; are the reserves and expected recoveries per well high enough to drive an economic outcome and what would it take to improve on these outcomes?

The charts and diagrams below provide visual comparisons of the Low Case outputs for both models (Figure 5 to Figure 10).

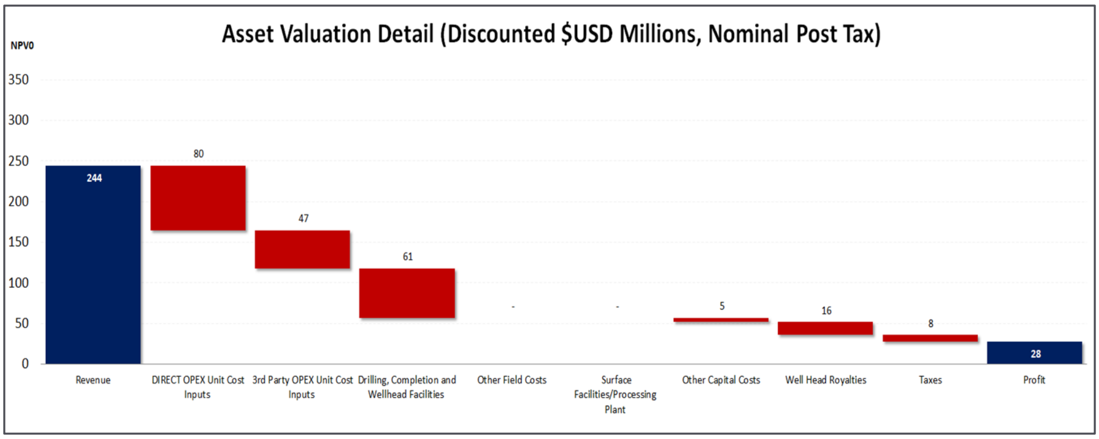
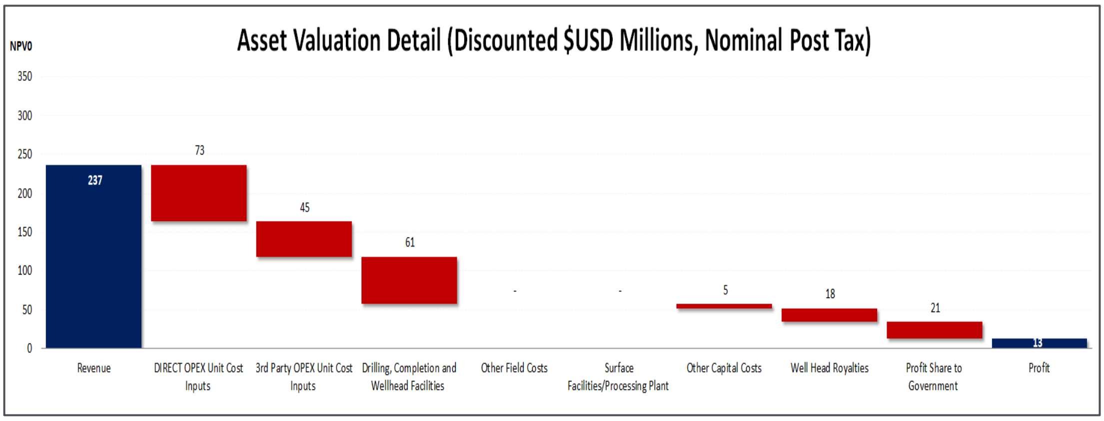



***Figure 5: Low Case Royalty-Tax Waterfall Chart, Discount Rate 0 %***




Note: Gross revenues derived from PSC model is lower than from Royalty-Tax regime due to earlier economic cut off for PSC model in 2056.

***Figure 6: Low Case PSC Waterfall Chart, Discount Rate 0 %***

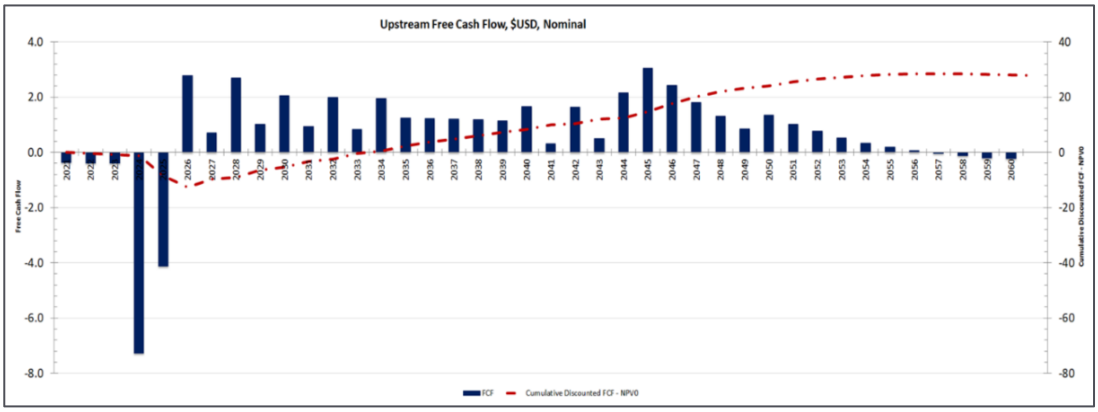



***Figure 7: Low Case Upstream Free Cashflow, Royalty-Tax Regime***

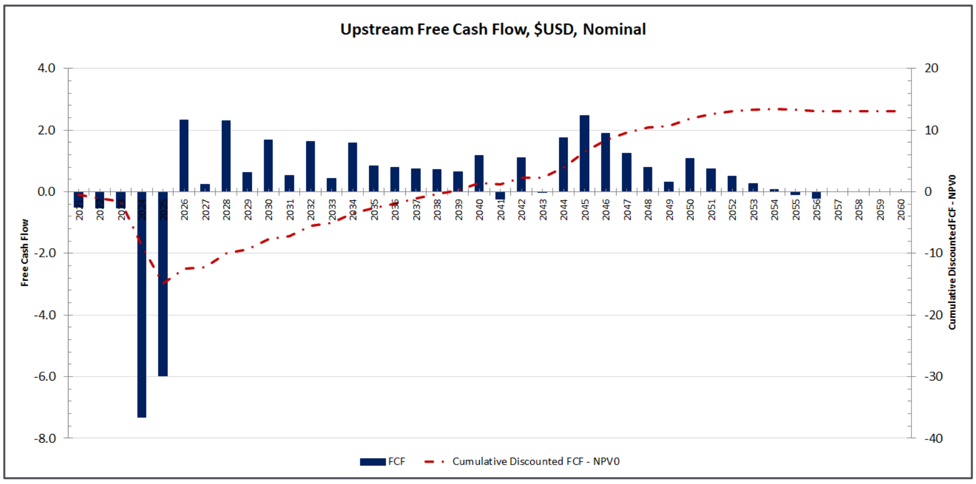



***Figure 8: Low Case Upstream Free Cashflow, PSC Regime***

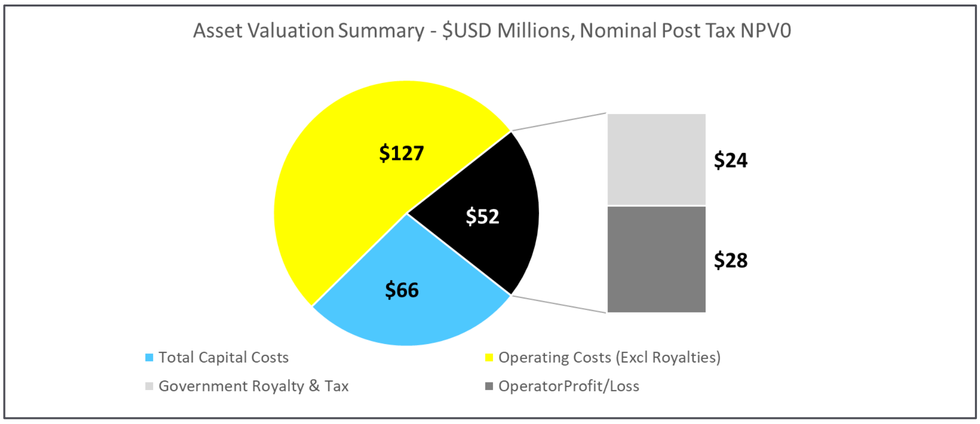



***Figure 9: Low Case Asset Valuation, Royalty-Tax Pie Chart***

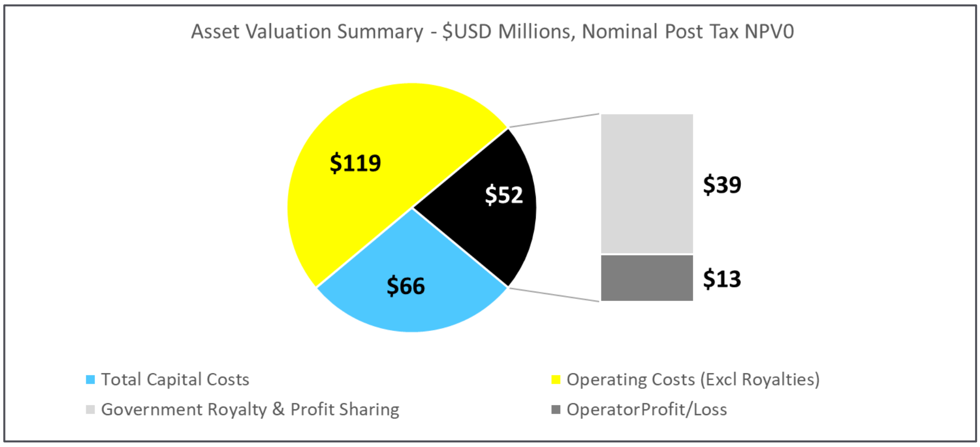


***Figure 10: Low Case Asset Valuation, PSC Pie Chart***

The charts above illustrate the main points covered in the discussion above regarding prohibitively low economic returns and unacceptably high risks to the Investor under the PSC regime terms and only marginal returns under the Royalty-Tax regime. They also highlight the need to focus on improving the fundamental project value drivers, particularly, recovery per well if the project were to operate under a PSC framework. Further, they also demonstrate one clear difference between the two regimes; where smaller, less profitable businesses are better supported under the Royalty Tax regime, thereby promoting small business growth and employment. It is generally accepted that smaller businesses form the backbone of any national economy, employing a larger proportion of the labour force and generating a larger share of Gross Domestic Product (GDP) than the few larger corporations and it is usually in a sovereign nation's best interests to promote growth in this sector of the economy.

2. Mid Case: CBM for gas fired power generation for local market base load power at 80 MW (Table 14 and Table 15).

| Development Metrics | Value | Unit |
|---|---|---|
| Raw Gas Production | 188.2 | Bscf |
| Total Sales Gas Produced | 146.1 | Bscf |
| Total Water Produced | 89.1 | MMstb |
| Development Wells Drilled | 492 | # Wells |
| Average Recovery Per Well (post fuel+flare use) | 0.30 | Bscf/Well |
| Revenues and Key Costs, $USD Millions | Value | Comment |
| Gross Revenue Total, nominal | 1,135.1 | |
| E&A CAPEX, real 2020 Values | 11 | |
| Development CAPEX, real 2020 Values | 236 | |
| OPEX, real 2020 Values | 319 | |
| If applicable, Government **Royalty**, nominal | 75 | Royalty-Tax |
| If applicable, Government **Royalty**, nominal | 85 | PSC |
| If applicable, **Bonuses** (Signing & Production), nominal | N/A | PSC |
| If applicable, **Cost Oil**, nominal | 793 | PSC |
| If applicable, **Profit Oil**, nominal | 103 | PSC |
| If applicable, Federal Government **Tax**, nominal | 74 | Royalty-Tax |

***Table 14: Mid Case Key Value Drivers and Financial Metrics***

The results for the Mid Case are comparable for the PSC and Royalty-Tax Regimes and they both indicate a marginal-to-economic project depending on the fiscal terms. The post-Tax/take undiscounted cashflows are significantly better under the Royalty-Tax system at $USD 203 Million *versus* about $USD 165 Million. The rates of return are significantly better under a Royalty-Tax regime terms, yielding an economic rate of return above 15 % *versus* 11.8 % under the PSC regime.

| HEADLINE VALUE METRICS | | | | | | |
|---|---|---|---|---|---|---|
| Discount Rate, % | NPVS & IRR | Royalty-Tax Regime | | PSC Regime | | Units |
| | | Gross Project | Post-Tax | Pre-Govt Take | Post-Govt Take | |
| 0% | NPV0 | 353 | 203 | 353 | 165 | $USD Millions, Nominal |
| 7% | NPV7 | 84 | 38 | 84 | 24 | $USD Millions, Nominal |
| 10% | NPV10 | 48 | 17 | 48 | 6 | $USD Millions, Nominal |
| 15% | NPV15 | 17 | 0 | 17 | -7 | $USD Millions, Nominal |
| | **$USD IRR** | **22.9%** | **15.1%** | **22.9%** | **11.8%** | **%** |

| | | | |
|---|---|---|---|
| **Profit/Investment Ratio, $USD NPV10** | **1.16** | **1.06** | |
| **Max Exposure** | **$USD-52.5 in year 2025** | **$USD-57.88 in year 2025** | |
| **Payback Year** | **2031** | **2033** | |

***Table 15: Mid Case Headline Economic Value Metrics***

From an Investor / Operator / Contractor perspective this project would struggle to proceed under the PSC terms, as the returns do not sufficiently balance the risks and exposures involved. Only a very limited number of Investors, i.e. those who are supported by a low cost of capital or those who could sustain a low rates of return would choose to proceed with the development in the Mid Case under PSC terms, especially considering the risks. For example, this could work for the development of a marginal CBM project in an OECD country with a mature gas market and proximity to existing infrastructure, as Investors could add incremental developments to pre-existing adjacent oil and gas assets.

The investment for the same project in less developed gas market or in a location with higher risks would demand a higher cost of capital or required rate of return. If the Investors require an additional 5 % return in a new non-OECD country with a less mature gas market or a less attractive fiscal regime, Net Present Values (NPV) above a 15 % discount rate might be considered as a minimum threshold in the decision making process. In the Mid Case, the project yields an IRR of 12.8 % and - $USD 7 Million at NPV15 under PSC terms and would be very unlikely to proceed.

With these marginal investment returns, adjustment of PSC fiscal terms such as higher cost recovery limit or lower profit share to Government could bring some improvement to the results to swing an Investor decision to proceed. Similar to the Low Case, the marginal economic results from the Mid Case would raise questions about what would else could be done to improve the results, including increasing the ex-field gas price slightly and/or reducing the costs to develop and operate too high. As with the Low Case, under a PSC regime there is more likely to be an issue about the viability of the CBM resource itself; are the reserves and expected recoveries per well high enough and what would it take to improve on the outcomes? Under a Royalty-Tax regime the pursuit of value would also be paramount but the project could sustain lower productivity wells and therefore able to sustain higher levels if subsurface risk.

Figure 11 to Figure 16 provide visual comparisons of the Mid Case outputs for both models.

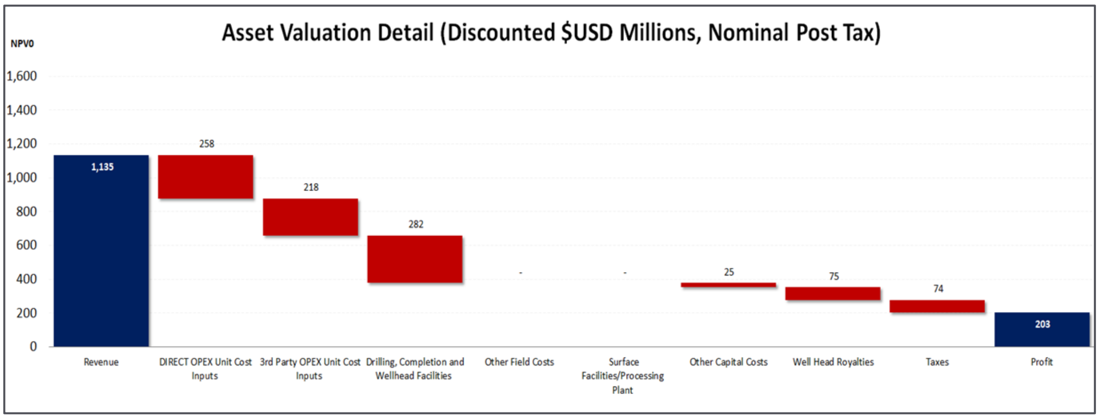



*Figure 11: Mid Case Royalty-Tax Waterfall Chart, Discount Rate 0 %*

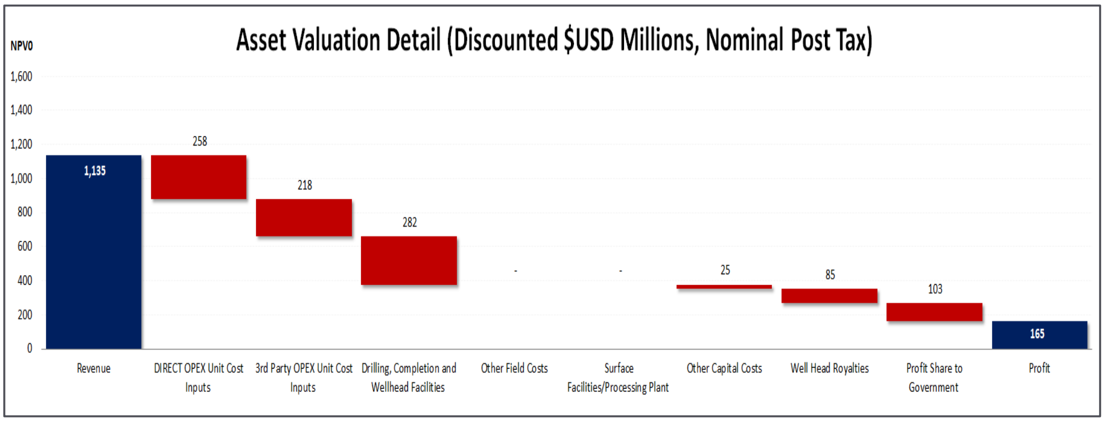



*Figure 12: Mid Case PSC Waterfall Chart, Discount Rate 0 %*

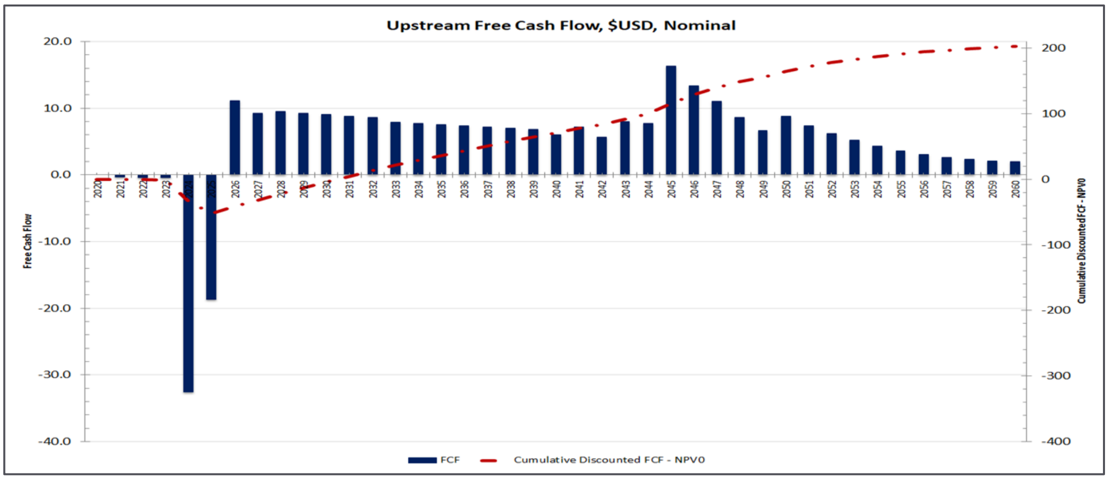


*Figure 13: Mid Case Upstream Free Cashflow, Royalty-Tax Regime*

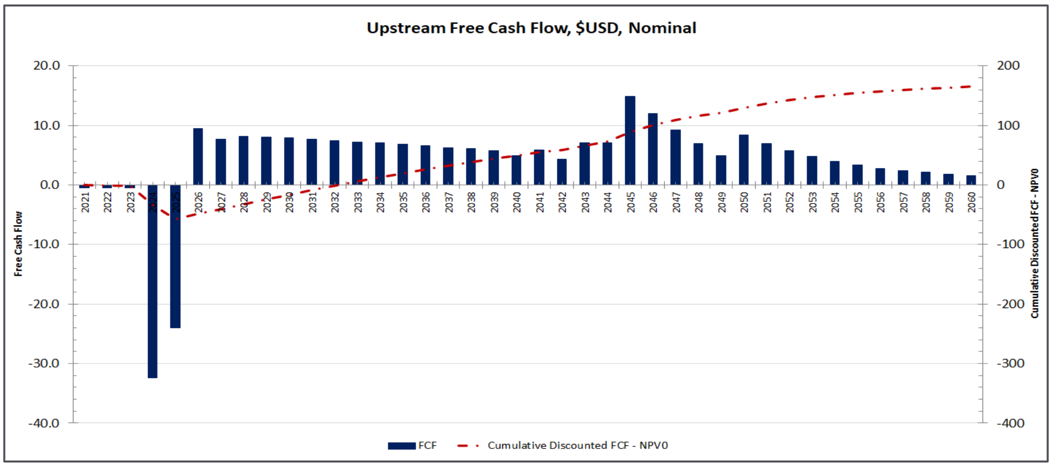



*Figure 14: Mid Case Upstream Free Cashflow, PSC Regime*

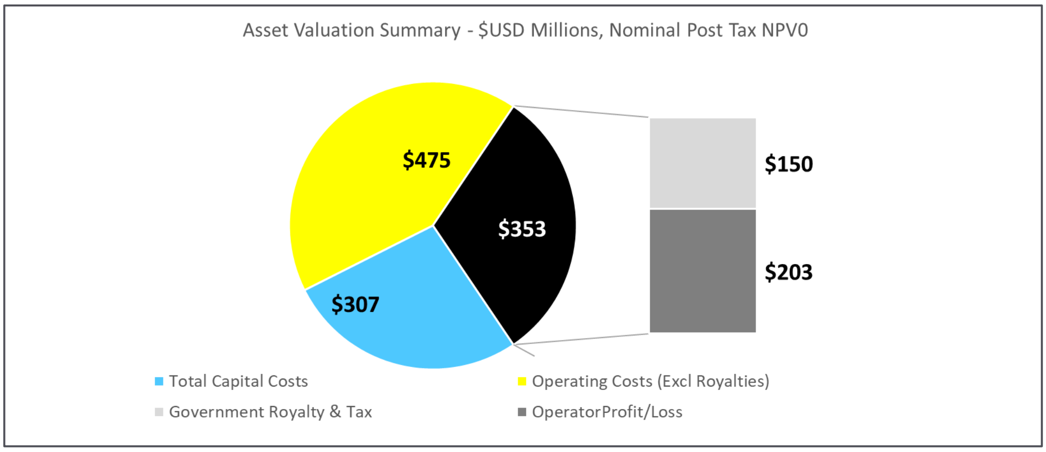



*Figure 15: Mid Case Asset Valuation, Royalty-Tax Pie Chart*

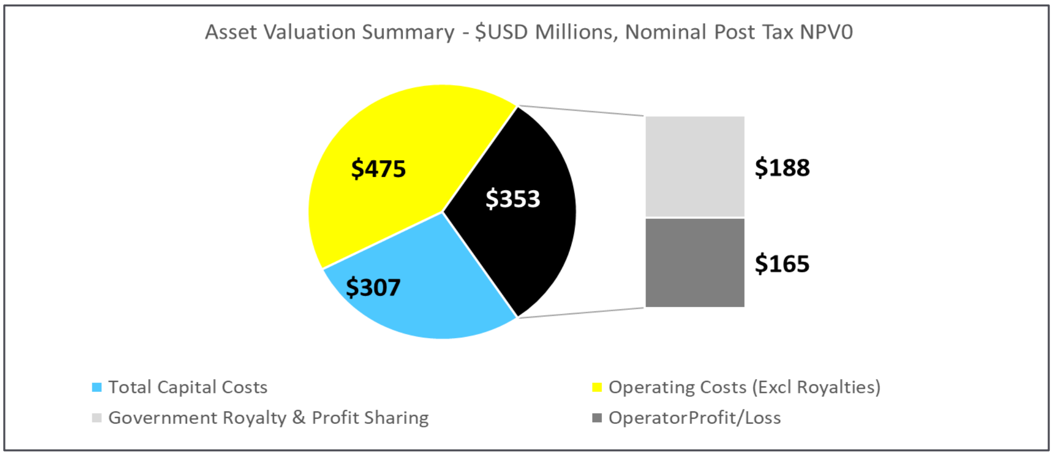


***Figure 16: Mid Case Asset Valuation, PSC Pie Chart***

The charts above illustrate the main points covered in the discussion above regarding the marginal to economic returns depending on the fiscal terms, which may not be sufficient to balance the risks to the Investor under the PSC regime. They also highlight the need to focus on improving the fundamental project value drivers, particularly, recovery per well for projects yielding only marginal results under the PSC system. The project is economic under a Royalty-Tax regime and would likely be able to proceed to development.

3. High Case: CBM for Pipeline Export to an International Buyer (Table 16 and Table 17).

| Development Metrics | Value | Unit |
|---|---|---|
| Raw Gas Production | 1,477.6 | Bscf |
| Total Sales Gas Produced | 1,147.0 | Bscf |
| Total Water Produced | 700.2 | MMstb |
| Development Wells Drilled | 3,872 | # Wells |
| Average Recovery Per Well (post fuel+flare use) | 0.30 | Bscf/Well |
| Revenues and Key Costs, $USD Millions | Value | Comment |
| Gross Revenue Total, nominal | 12,207 | |
| E&A Capital, real 2020 Values | 44 | |
| Development Capital, real 2020 Values | 1,856 | |
| OPEX, real 2020 Values | 2,373 | |
| If applicable, Government **Royalty**, nominal | 1,161 | Royalty-Tax |
| If applicable, Government **Royalty**, nominal | 916 | PSC |
| If applicable, **Bonuses** (Signing & Production), nominal | N/A | PSC |
| If applicable, **Cost Oil**, nominal | 6,193 | PSC |
| If applicable, **Profit Oil**, nominal | 2,298 | PSC |
| If applicable, Federal Government **Tax**, nominal | 1,461 | Royalty-Tax |

***Table 16: High Case Key Value Drivers and Financial Metrics***

The results for the high case are broadly comparable for the PSC and Royalty-Tax Regimes, with both regimes indicating an attractive economic project. Post Tax undiscounted returns are significantly better under the Royalty-Tax regime and are consistently higher at all discount rates. This higher risk, larger scale project yields much better rates of return than for the Mid and Low Cases, namely, about 30 % under Royalty-Tax and about 27 % under the PSC regime.

| HEADLINE VALUE METRICS | | | | | | |
|---|---|---|---|---|---|---|
| Discount Rate, % | NPVS & IRR | Royalty-Tax Regime | | PSC Regime | | Units |
| | | Gross Project | Post-Tax | Pre-Govt Take | Post-Govt Take | |
| 0% | NPV0 | 6,057 | 3,435 | 6,057 | 2,844 | $USD Millions, Nominal |
| 7% | NPV7 | 1,496 | 769 | 1,496 | 636 | $USD Millions, Nominal |
| 10% | NPV10 | 877 | 425 | 877 | 348 | $USD Millions, Nominal |
| 15% | NPV15 | 382 | 161 | 382 | 127 | $USD Millions, Nominal |
| | **$USD IRR** | **45.0%** | **29.8%** | **45.0%** | **26.6%** | **%** |
| | **Profit/Investment Ratio, $USD NPV10** | **1.60** | | **1.51** | | |
| | **Max Exposure** | **$USD-411 in year 2030** | | **$USD-450.64 in year 2030** | | |
| | **Payback Year** | **2033** | | **2033** | | |

***Table 17: High Case Headline Economic Value Metrics***

Whilst the results for the High Case are significantly better than those of the Low and Mid cases it should be noted that typically in developing economies, it is the larger number of small-medium scale businesses that in aggregate generate higher levels of revenue, local engagement and employment than a few larger scale ventures that usually rely on higher levels of expat rotational staff and have an obligation to return profits to an international parent company.

We noted earlier that the project reaches payback at the same time under both regimes (2033), indicating similar capital risk and exposure profiles for the Investor / Operator / Contractor under each fiscal regime.

From an Investor / Operator / Contractor perspective this High Case project could proceed on the economic merits, but the reality is that board level investment decisions are not made on economic merits alone and a range of criteria are used for these type of investment decisions. Decisions like this would normally be supported by a comprehensive risk and opportunity assessment that is both quantitative and qualitative in nature. These risk and opportunity assessments would include a thorough evaluation of the technical, commercial, political, legislative, environmental, security and geographical risks for conducting a new business venture in a developing, non-OECD country and may apply country risk premium to their cost of capital or increase the required rate of return accordingly.

The charts and diagrams provide a visual comparison of the High Case outputs for both models (Figure 17 to Figure 22).

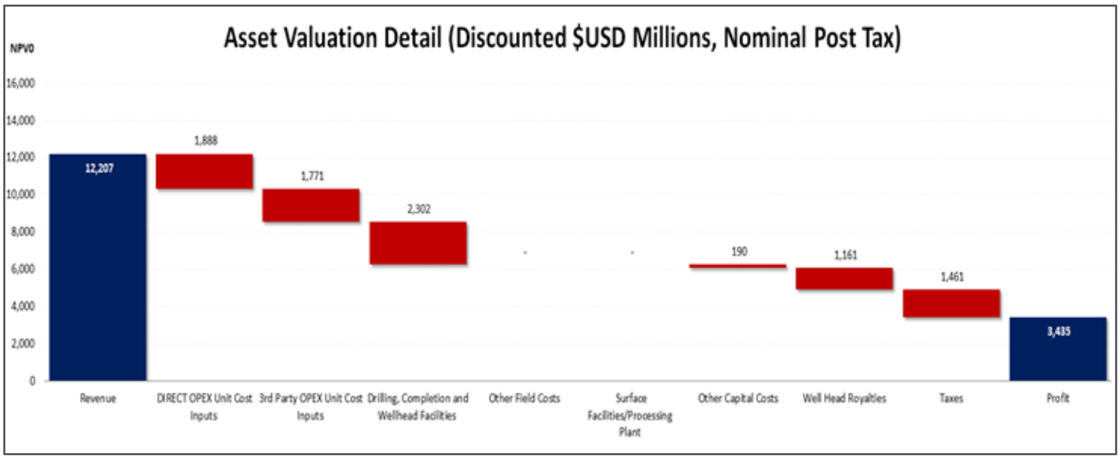



*Figure 17: High Case Royalty-Tax Waterfall Chart, Discount Rate 0 %*

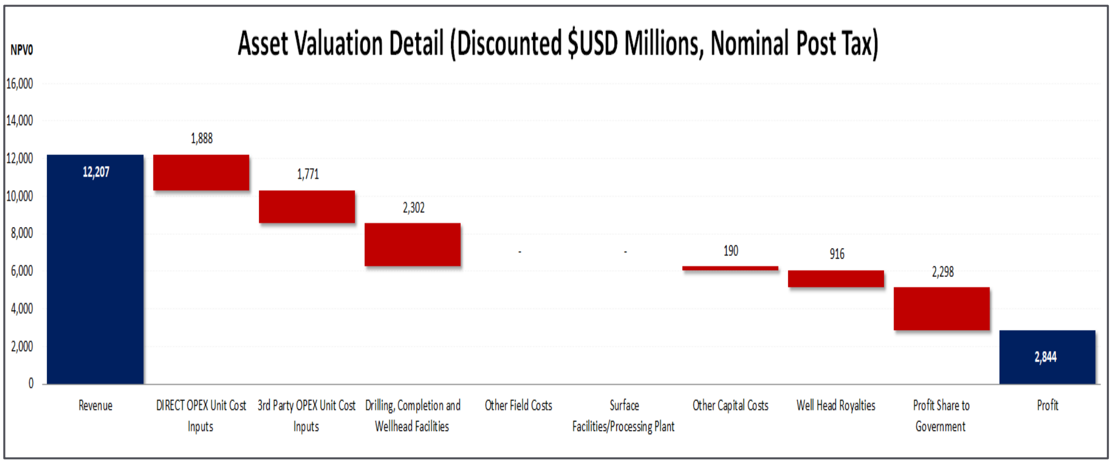



*Figure 18: High Case PSC Waterfall Chart, Discount Rate 0 %*

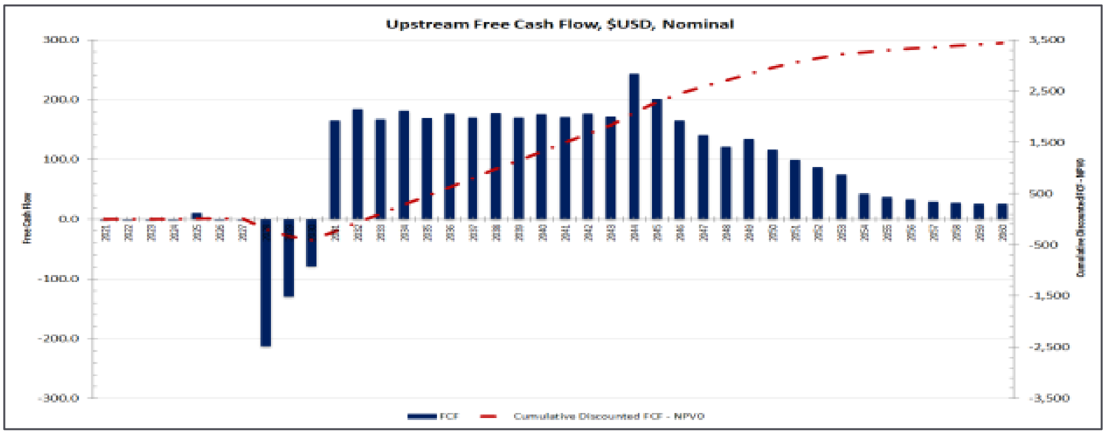



*Figure 19: High Case Upstream Free Cashflow, Royalty-Tax Regime*

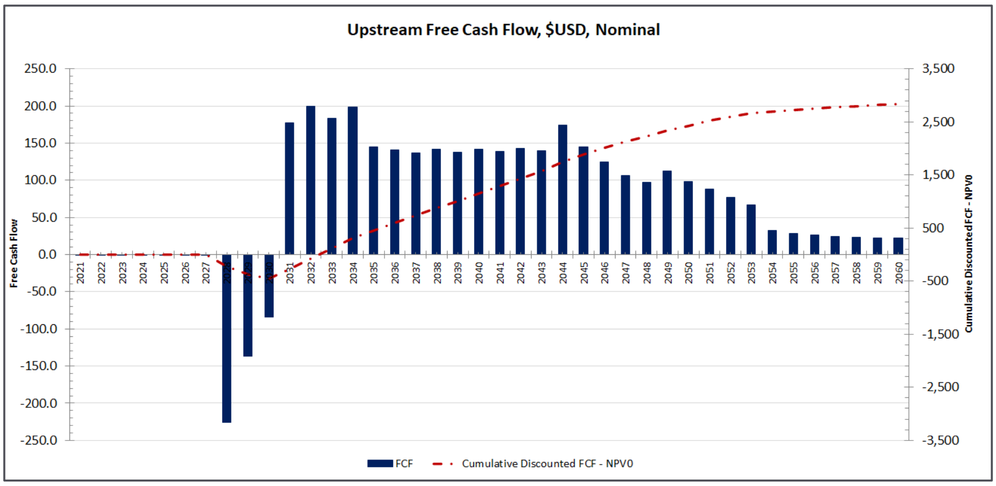



*Figure 20: High Case Upstream Free Cashflow, PSC Regime*

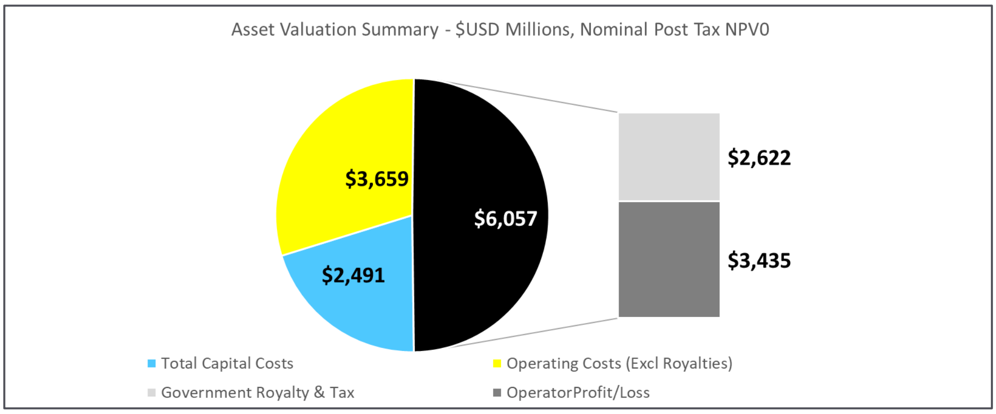



*Figure 21: High Case Asset Valuation, Royalty-Tax Pie Chart*

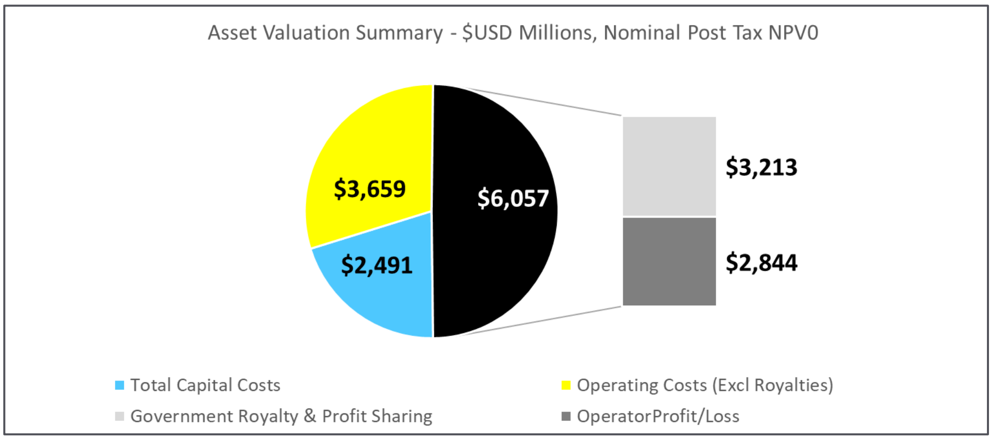



*Figure 22: High Case Asset Valuation, PSC Pie Chart*

The charts above illustrate the main points covered in the discussion above.

## 4.5 Economic Modelling Conclusions

The detailed observations for the Low, Mid and High Cases evaluated by economic modelling of the two regimes were included in the previous section and are not repeated here. High-level conclusions are outlined below for further consideration.

- In all cases, the Royalty-Tax regime yields significantly higher undiscounted cashflows and rates of return to Investors, compared to the PSC regime.
- Conversely, Government cashflow and discounted cashflow are higher for all cases under the PSC regime. However, when Government take is too high it does not encourage new investments, few or no projects will be developed resulting in sub-optimal Government take. The fiscal regime should be designed to encourage new investments which will result in multiple project developments and optimised Government cashflow at an aggregate level.
- From an Investor / Operator / Contractor perspective, projects exemplified by the Low Case could not be supported under the PSC and yielded only marginally economic results under the Royalty-Tax terms
- More fundamentally for all stakeholders involved here, the results for the smaller scale less profitable project indicate the need to identify better resource plays with better recoveries per well to achieve the minimum economic threshold values required to attract investment and compensate for risks involved over the project life.
- A project like the Low Case would likely require additional support from the Government under the PSC regime with some type of fiscal incentive. This intervention could take the form of domestic price subsidies for consumers or low-cost finance to local power producers or vehicle owners so that the prices charged by the upstream Investor can support the investment required.
- Another possibility where this could work is if it was managed as an incremental project that could leverage off a larger, more robust project to capture economies of scale and make use of spare infrastructure capacity later on. This could enable it to meet the required economic return thresholds, but this would significantly delay the start date and the delay the benefits to the local and regional economy from import fuel substitution and energy independence of the state.
- Similarly, marginal projects under a PSC framework, as demonstrated by the Mid Case would struggle to pass through the internal decision-making process for most companies unless returns could be supported by further technical improvement and/or commercial improvement and/or some type of fiscal incentive. The Mid Case project yielded economic results under the Royalty-Tax regime terms and could proceed under this fiscal regime.

- Projects like the High Case could proceed on the economic merits, but the reality is that investment decisions are not made on economic merits alone. For most successful businesses, a range of decision criteria are used for their investment decisions. Decisions of this scale, or requiring entry into a new country, would normally be supported by a comprehensive risk and opportunity assessment that is both quantitative and qualitative in nature. These risk and opportunity assessments would include thorough evaluations of the technical, commercial, political, legislative, financial and fiscal, environmental, security and geographical risks for conducting a new business venture in a developing, non-OECD country.
- The Royalty-Tax regime, as currently modelled does appear to moderate the post-Tax economic outcomes by treating smaller scale, lower value projects less harshly and by applying comparable levels of Government take as the PSC regime to the larger scale, more profitable projects, whilst still providing a good level of return to the Investor / Operator / Contractor for these large-scale, more profitable cases.
- For the larger scale projects exemplified by the High Case, the returns are high under both regimes, with better after-Tax returns for the Operator under the Royalty-Tax regime at all discount rates considered. The high returns for such a large-scale venture would be considered commensurate with the higher capital exposures involved, the longer lead timings to first production, the commercial complexity of the project and higher risks in a new resource play in a new business environment.
- As previously mentioned, the scope of this exercise did not include sensitivity analyses of cost and price variances, or considerations of schedule or a host of other risks. These components would typically feed into an overall assessment of the multi-faceted risk-opportunity continuum for any new business venture. Effectively, projects would be stress tested across a range of boundary conditions, including market price, recovery per well, development cost, development schedule etc., to establish how robust the opportunity is and how much downside exposure the business could sustain and how this may be balanced by the potential upsides it could attain, under a range of potential future outcomes.
- Other criteria such as fiscal certainty, transparency and consistency of the terms and potential future fiscal liabilities for an Investor/ Operator / Contractor would also be considered. In most instances these more qualitative criteria would have a significant weighting in the decision-making process for non-OECD countries where the regimes are still maturing. If the fiscal regimes themselves were deemed to pose significant uncertainty and risks to the Investor, then these factors alone would deter many potential international Investors, even if the economic returns and quantitative outcomes looked highly attractive at face value. A simple example of how a comparative assessment of fiscal systems could be developed or applied is included in the next section.

# 5 Benchmarking of Alternative Regimes

## 5.1 Introduction

The purpose of benchmarking relevant CBM fiscal systems is not to make recommendations but to provide comparative information that allows informed decision making on the fiscal terms to be applied in Mongolia. Such decisions require consideration of many elements including the need to attract investment and generating a fair financial return to the state. The prospectivity of the coal bed methane resource, its accessibility and potential size and markets are important considerations, as are the costs and associated returns to the developer but these criteria apply to opportunities regardless of the applicable fiscal system. For the purposes of this exercise, these predominantly technical criteria are considered only where they directly impact, or are impacted by the fiscal terms applied to their evaluation.

A new and simplified approach for the relative ranking the PSC and Royalty-Tax regimes is outlined here, based on a range of quantitative criteria and a number of qualitative factors relating to any fiscal regime. Other criteria such as data access and prospectivity, whilst highly relevant to any opportunity, could be considered to sit alongside, but not be an integral part of the fiscal regime comparison *per se*. These technical criteria are essential for decision making in their own right and as far as fiscal regimes are concerned, they become highly relevant if the fiscal terms need to be adjusted to sufficiently compensate for poor prospectivity or data challenges that would require additional E&A expenditures to address. These technical criteria are, therefore, considered as separate decision-making factors, separate to fiscal system ranking regarding the attractiveness of creating a CBM business in a country like Mongolia.

## 5.2 Quantitative Assessment

The quantitative criteria below are impacted by fiscal terms and are contemplated for the results of the three cases analysed to represent the range of CBM opportunities in Mongolia as follows:

Undiscounted and Discounted Cashflow: This metric represents Net Cashflow to the company after royalties, Taxes and other forms of Government Take: A business first and foremost needs certainty about positive cashflow that can be generated over the life of the project. This simple metric also allows a direct assessment of scale and how returns compare with the amount of capital invested to generate the cashflow.

Profit Investment Ratio (PIR), discounted at 10% Nominal (NPV10): This metric enables a business to rank an opportunity against alternative opportunities in its portfolio and is a measure of capital efficiency – i.e. what return a certain amount of capital can generate and then discounting this to establish how quickly it can provide this return on capital placeholder to include the definition used in the model. Definitions for the PIR, or PI ratio, as it is commonly known, vary from company to company. For the purposes of this exercise the PI Ratio definition used in the analyses was as follows:

$$\text{PI Ratio} = 1 + (\text{NPV10 Cashflow} / \text{NPV10 CAPEX})$$

Payback Year: An Investor needs to know how long it takes to recoup their risk capital. The longer it takes to do this, the higher the risk to an Investor and the less attractive a prospect or opportunity becomes.

Internal Rate of Return % (IRR): This metric is a key measure used to rank and compare the economic merits of opportunities in the portfolio of most companies. Mature, progressive fiscal systems in countries where it is easy to do business in may have a lower minimum IRR threshold applied, sometimes not significantly above the company's weighted cost of capital. Other countries where the fiscal terms are deemed to be unstable, unclear or high risk would have a much higher minimum IRR threshold applied, for example 15-20 %.

For the purposes of this exercise the fiscal regimes are compared based on each of the four economic criteria outlined above, applied to each of the Low, Mid and High Cases. A high-level comparative score of 1, 2 or 3 based on the relative rankings of the results for each case against each fiscal regime was applied to arrive at an aggregate average score for each of the economic criteria assessed. For simplicity, each of the four economic criteria were assigned an equal weighting of 25 % to arrive at an overall quantitative, relative ranking of fiscal regime. For this exercise, a score of 1 represented the lowest value or less economic result, with a score of three representing the best relative value, and a score of 2 was applied where the relative values under each regime were too close to call, or effectively neutral to make a meaningful judgement of the relative fiscal regime ranking, or where the relative value was neither highest nor lowest. This quantitative assessment of fiscal regimes based on the case results to date are summarised in Table 18.

**FISCAL COMPARISON**

*Relative rankings:* *1 = worst result* *2 = mid, inconclusive, neutral* *3 =best result*

| Quantitative Ranking | Royalty-Tax Low Case | PSC Low Case | Royalty-Tax Mid Case | PSC Mid Case | Royalty-Tax High Case | PSC High Case | Weightings | Royalty-Tax | PSC |
|---|---|---|---|---|---|---|---|---|---|
| Cashflow | 3 | 1 | 3 | 1 | 3 | 1 | 25% | 0.8 | 0.3 |
| P/I Ratio | 3 | 2 | 3 | 2 | 3 | 2 | 25% | 0.8 | 0.5 |
| Payback | 3 | 1 | 3 | 2 | 3 | 2 | 25% | 0.8 | 0.4 |
| IRR | 3 | 1 | 3 | 1 | 3 | 1 | 25% | 0.8 | 0.3 |
| | | | | | Quantitative Relative Ranking | | | **3.0** | **1.4** |

***Table 18: Quantitative Assessment and Rankings***

As this is a comparative ranking assessment only, the absolute ranking value is less important than the relative ranking.

The economic results derived from the Royalty-Tax regime attained the best quantitative relative ranking of 3.0 compared to the 1.4 ranking attained by the PSC based results. The results indicated that the Royalty-Tax regime provides a distinct advantage to an Investor contemplating new business in a new country, like Mongolia, and would help attract investment for potential CBM business opportunities more readily than an equivalent PSC regime. The rankings can be tested by changing the relative weightings of the economic criteria or the weightings applied to each case to arrive at the overall comparative quantitative ranking but the margin between to two regimes is not close and would suggest that the Royalty-Tax regime as the one most likely to succeed in attracting an Investor / Operator / Contractor.

It is noted that Government cashflow and discounted cashflow are higher for all cases under the PSC regime. However, when Government take is too high it does not encourage new investments, few or no projects will be developed resulting in sub-optimal Government take. The fiscal regime should be designed to encourage new investments which will result in multiple project developments and optimised Government cashflow at an aggregate level.

## 5.3 Qualitative Assessment

In similar fashion to the quantitative assessment, the following qualitative measures were considered to compare fiscal regimes and each of these criteria were applied in aggregate to all three cases. For this exercise an equal weighting of 20 % was applied to each of the five criteria considered to arrive at an overall qualitative ranking of each fiscal regime (see Table 19).

| Qualitative Ranking | Royalty-Tax | PSC | Royalty-Tax | PSC | Royalty-Tax | PSC | Weightings | Royalty-Tax | PSC |
|---|---|---|---|---|---|---|---|---|---|
| | Low Case | | Mid Case | | High Case | | | | |
| Transparency | 3 | 1 | 3 | 1 | 3 | 1 | 20% | 0.6 | 0.2 |
| Consistency | 3 | 1 | 3 | 1 | 3 | 1 | 20% | 0.6 | 0.2 |
| Certainty of terms | 3 | 1 | 3 | 1 | 3 | 1 | 20% | 0.6 | 0.2 |
| Stability / Maturity | 3 | 1 | 3 | 1 | 3 | 1 | 20% | 0.6 | 0.2 |
| Capacity for Risk Mitigation | 3 | 1 | 3 | 1 | 3 | 1 | 20% | 0.6 | 0.2 |
| | | | | | Qualitative Relative Ranking | | | **3.0** | **1.0** |

***Table 19: Qualitative Assessment and Rankings***

- Transparency of fiscal framework – are the terms fixed and transparent to all key stakeholders?
- Consistency of application of terms across a range of opportunities / Operators – are the terms consistently applied to a range of opportunities and for all potential Investors / Operators / Contractors? This would also extend to overlapping tenures and priority.
- Certainty of Terms: Are the terms certain, i.e. are the terms well defined and are potential future liabilities for an Operator, based on these terms from exploration to abandonment phases, clearly set out?
- Stability / Maturity: Are the fiscal terms mature and unlikely to change unpredictably?
- Capacity for Risk Mitigation: Do the terms mitigate some risks to the business – e.g. price change, revenue change? In other words, are the terms supportive of business investment?

As this is a comparative ranking assessment only, the absolute ranking value is less important than the relative ranking.

As these rankings apply to the fiscal regime per se, rather than a particular licence area of specific project, they apply regardless of Low, Mid or High cases.

The Australian federal legislation for corporate Tax is transparent and is consistent in its application regardless of business or location. It is stable and supportive of small businesses or larger business that are subject to high revenue risk. For clarity, this is not to say that the detailed Tax *settings* are optimal in terms of the economics for investment, rather that the regime is, at least, clear and predictable.

The background narrative provided in Section 4.3 on the evolution of the Queensland State Royalty legislation likewise demonstrates a system that has undergone some instability in the recent past but has matured into a system that is transparent and is consistent in its application, regardless of business or location. It is stable and supportive of CBM businesses that are always subject to price risk and promotes domestic market growth.

The results of our analysis indicate that a Royalty-Tax regime provides a very clear advantage to an Investor contemplating new business in a new country, like Mongolia, and would support investment for potential CBM business opportunities more readily than an equivalent PSC regime. The rankings can be tested by changing the relative weightings of the qualitative criteria or to the weightings applied to each case to arrive at the overall comparative quantitative ranking. However, the relative ranking between the two regimes is not close and the Royalty-Tax regime, as it exists in Queensland Australia, is more likely to attract an Investor / Operator / Contractor. It is important to note that this does not necessarily imply that the same precise settings as applied in Queensland are the best for Mongolia. Further Royalty-Tax optimisation (e.g. rates and other key terms) within such a system may be beneficial, as Mongolia has many risk factors not present in Queensland.

When applying an equal decision weighting of 50 % to the quantitative and the qualitative ranking, as could occur with senior level corporate investment decisions, then the overall rankings from the fiscal terms comparison plays out as presented in Table 20:

| Overall Ranking | Overall Weighting | Royalty-Tax | PSC |
|---|---|---|---|
| **Quantitative Component** | **50%** | 1.5 | 0.7 |
| **Qualitative Component** | **50%** | 1.5 | 0.5 |
| | **Overall Fiscal Ranking** | **3.0** | **1.2** |

***Table 20: Overall Fiscal Regime Relative Ranking***

As this is a comparative ranking assessment only, the absolute ranking value is less important than the relative ranking. The results indicate that the Royalty-Tax regime provides a distinct advantage to an Investor contemplating new business in a new country, like Mongolia, and would help attract investment for potential CBM business opportunities more readily than an equivalent PSC regime.

As mentioned previously, other criteria that do not rely directly on fiscal terms or impact the fiscal terms directly are not considered further here for the purposes of comparing the fiscal terms. They are, however, highly relevant to the decision-making process, as far as ranking how attractive a country may be for a potential investment opportunity. The fiscal comparisons would be a significant part of this wider, and more holistic, business decision. These other decision criteria include critical factors like ease of data access, data quality, data relevance, and essentially for CBM development, the prospectivity and opportunity presented by the resource itself.

In addition, the administration of a PSC regime where all procurements need to be approved by the relevant authority is a major hurdle for CBM business. Unlike conventional oil and gas projects where major projects can be awarded and executed, CBM operations require small and ongoing projects which need to be executed on-time and over a long period.

Other less defined but important considerations would include regional stability in terms of security of personnel and assets and the stability of the political, legal and environmental setting.

With the current fiscal regime in Mongolia and how it is applied under different terms across licences and Operators, where data that could support E&A activity for potential new country entrants is hard to obtain it is unlikely to attract Investors who are becoming increasingly risk averse. This risk aversion is likely to increase in the wake of COVID-19 and its consequent political, social, and economic challenges around the globe.

Under these challenging circumstances very few Investor groups would contemplate entry into CBM development in Mongolia unless there are changes to the fiscal regime and how it is administered and unless there are more prospective resources available to develop. Further work should be performed to identify a fiscal regime and conditions, combined with clear regulations that provide an attractive investment setting. Such work would necessarily address the regime type, fiscal terms and the detailed terms and conditions. Fiscal regimes in themselves do not attract investment and, therefore, supporting work on the resource opportunity and prospectivity would be highly beneficial.

Usually in these situations, the only Investor groups likely to consider a presence in Mongolia are small scale speculative Investor groups with a strong interest in exploration geology but who are not able to fund the development phases, nor have the scale of business or experience in house to execute these phases. Their business model is typically based on a shorter-term strategy to exit and farm out or sell their interests to a larger scale Investor once the E&A phase has been matured and packaged sufficiently. The large Investor groups likely to consider CBM development in Mongolia are those who can sustain exceptionally low cost of capital and these entities may be backed by sovereign debt as part of a larger strategy play to enter a new country. In a post-COVID-19 world that is transitioning away from fossil fuels even these large-scale Investors may have reservations about CBM in Mongolia unless it is part of a broader strategic goal.

## 5.4 Discussion on Other CBM Fiscal Regimes

THREE60 Energy had some difficulty in sourcing reliable information on other CBM fiscal regimes. As a consequence the discussion on other CBM fiscal regimes is limited to Indonesia and China.

### 5.4.1 Indonesia

With CBM resources of 453 Tscf, Indonesia ranks 6th in the world. The CBM resources are estimated to be larger than the natural gas resources. The first CBM contract was signed in 2008, and by the end of 2015 there were 46 CBM cooperation contracts in place. Indonesia's shale gas resources are estimated to be 574 Tscf. However, the development of CBM and Shale Gas in Indonesia has not been significant to date. By the end of 2019, there were 27 CBM blocks remaining.

There are two fiscal system for CBM projects in Indonesia:

1. ***Production Sharing Contract (PSC)***. There are two PSC generations in respect of CBM.

    a. Net PSC (similar to conventional PSC). The fiscal terms include 90 % cost recovery limit on OPEX and depreciated CAPEX based on 25 % declining balance. Post Tax profit share has been modified to 55:45 (Government of Indonesia:Contractors) to attract prospective CBM Investors compared with 70:30 (GOI:Contractors) for conventional gas. The CBM 45 % profit split after Tax to Contractor is equivalent to 80 % pre-Tax split with 44 % Tax rate (combined income Tax and dividend withholding Tax).

    b. Net PSC Sliding Scale. There is no cost recovery ceiling, but it has sliding scale for First Tranche Petroleum (FTP). FTP is a percentage taken from the gross revenue; therefore, the cost recovery is actually capped as the amount of FTP percentage. The first CBM PSC has non-shareable 10 % FTP, but the latest CBM PSC has shareable 20 % FTP. Domestic Market Obligation (DMO) price is priced at full price.

    The PSC regime creates complications for Investors due to manifold regulations attached to a PSC. For example, there is a specific CBM procurement process for rig service. Indonesia has not developed a national rig service for CBM, meaning that the Investor needs to comply with local content regulation as set by SKKMigas. The process for approval is lengthy and serves to delay CBM exploration. This has brought about a delay for subsequent activities and production. This ultimately impacts the economics of CBM projects. The fiscal term with no cost recovery was introduced to solve this issue. CBM Contractors are free from all the regulations related to the cost recovery items and this is expected to provide more space for the Contractors to manage their budget and expenditures. The Contractor bears all the risks of the projects.

2. ***Non-cost recovery gross PSC sliding scale as proposed by CBM Investors***. All of the expenditures spent for the activities are not recoverable. The sliding scale is based on the gross production. Table 21 presents the sliding scale for the shares based on the gross production.

| Annual Production | Government's Share | Contractor's Share |
|---|---|---|
| < 5 bcf | 5% | 95.00% |
| 5 - 20 bcf | 15% | 85.00% |
| 20 - 50 bcf | 17.5% | 82.50% |
| 50 - 100 bcf | 20% | 80.00% |
| > 100 bcf | 25% | 75.00% |

(National Exploration Committee (NEC), 2013)

***Table 21: Sliding Scale of Government vs. Contractor Share***

It is concluded that despite generally favourable geological conditions (prospectivity) in Indonesia for CBM it is insufficient to facilitate development of the industry. The fiscal regime currently applied to CBM in Indonesia is not supportive for the development of the industry and as a result CBM development has not advanced significantly.

### 5.4.2 China

THREE60 Energy has sourced information dating back to 2010 on CBM PSCs in China. It is recognised that the fiscal regime may have been amended since then and caution is advised in the use of the information set out below.

In 2010 CBM exploration was progressing in the Ordos, Junggar and Guangxi-Guizhou basins where vast coal resources are present. The Quinshui basin was the only basin with CBM production with production at a fairly modest 100 MMscf/d. Production levels were approximately 20 % of the target under the 11$^{th}$ Five-Year Plan (2006-2010).

CBM licences in China are signed under PSCs which are negotiated between the licensee and the local partner. Licences typically have a 30 year term and comprise an exploration period, development period and production period.

1. Exploration CAPEX costs are fully funded by the foreign Investor;
2. CAPEX and OPEX costs are shared on the basis of equity interest in the PSC;
3. The fiscal terms include 70 % cost recovery from approximately 70% of revenue; and
4. Profit splits vary from 85 % – 100 % for the Contractor.

In addition to the above, the Chinese Government had provided various fiscal incentives, including:

- CBM gas prices are not regulated;
- A direct subsidy of 0.2 RMB/m$^3$ production. The Shanxi Government was offering a further 0.05 RMB/m$^3$;

- CBM companies are provided an initial two year Tax holiday and a 50 % reduction for the next 3 years;
- CBM was exempt from Value Added Tax (VAT); and
- Imported equipment and materials are exempt from customs duty

The fiscal terms for CBM in China from 2006 - 2010 were favourable to Contractors but the production targets set by the Government were not achieved. At the time it was noted that large investments were needed to accelerate CBM exploration and prove up reserves. During this time approximately 70 % of exploration expenditures were from foreign companies but most were companies with a low market capitalisation and limited capacity to fund large capital programmes.

Of particular note is that China CBM production targets in 2010 were not achieved despite good fiscal terms and a more mature industry than exists in Mongolia today.

# Appendix A: Glossary of Terms and Abbreviations

| | |
|---|---|
| 1C | denotes a Low estimate scenario of Contingent Resources |
| 1P | denotes a Low estimate / Proved Reserves (see ***Proved Reserves***) |
| 1U | denotes a Low estimate scenario of Prospective Resources |
| 2C | denotes a Best estimate scenario of Contingent Resources |
| 2P | denotes a Best estimate / Proved plus Probable Reserves |
| 2U | denotes a Best estimate scenario of Prospective Resources |
| 3C | denotes a High estimate scenario of Contingent Resources |
| 3P | denotes a High estimate / Proved plus Probable plus Reserves |
| 3U | denotes a High estimate scenario of Prospective Resources |
| 2D seismic | seismic data acquired in a single traverse or series of traverses. 2D seismic data provides single cross sections |
| 3D seismic | seismic data acquired as multiple, closely spared traverses. 3D seismic data typically provides a more detailed and accurate image of the subsurface than 2D seismic |
| ABEX | Decommissioning costs |
| Aggregation | the process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country or company totals. Arithmetic summation may yield different results from probabilistic aggregations of distributions |
| ALS | Abnormal Limit State – structural design |
| API | American Petroleum Institute |
| appraisal | the phase of petroleum operations immediately following a successful discovery. Appraisal is carried out to determine size, production rate and the most efficient development of a field |
| appraisal well | a well drilled as part of an appraisal of a field |
| asl | above sea level |
| B | billion |
| bbl | barrels |
| bbl/d | barrels per day |
| Bcm | billion cubic metres |
| block | term commonly used to describe areas over which there is a petroleum or production licence |
| Bg | gas formation volume factor |
| Bgi | gas formation volume factor (initial) |
| Bo | oil formation volume factor |
| Boi | oil formation volume factor (initial) |
| Bw | water volume factor |

| | |
|---|---|
| BOE | barrels of oil equivalent. Converting gas volumes to oil equivalent is customarily done on the basis of the nominal heating content or calorific value of the fuel. Before aggregating, the gas volumes must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1 barrel of oil equivalent = 5,600 scf of gas to 6,000 scf of gas |
| BOP | Blowout Preventer |
| bopd | barrels of oil per day |
| BTU | British Thermal Unit |
| Bscf | billions of standard cubic feet |
| bwpd | barrels of water per day |
| CAPEX | Capital expenditure |
| CBM | Coal Bed Methane (also known as Coal Seam Gas, CBM) |
| CCTV | Closed Circuit Television |
| charge or migration | the movement of hydrocarbons from source rocks into reservoir rocks. Migration can be local or can occur along distances of hundreds of kilometres in large sedimentary basins, and is critical to a viable petroleum system |
| closure | the height from the apex of a reservoir structure to the lowest contour that contains the reservoir structure (spill). Measurements of both the areal closure and the distance from the apex to the lowest closing contour are typically used for the calculations of the estimates hydrocarbon content of a trap |
| $CO_2$ | Carbon dioxide |
| commercial discovery | discovery of oil and gas which the Company determines to be commercially viable for appraisal and development |
| condensate | liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas |
| CGR | Condensate Gas Ratio |
| Contingent Resources | those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies |
| Conventional | Conventional resources are defined as hydrocarbons above a mapped structural closure. |
| cP | centipoise |
| Cretaceous | the final period of the Mesozoic era ranging from approximately 65 to 144 million years ago |
| CROCK | rock compressibility |
| CT | Corporation Tax |
| Cw | water compressibility |
| DBA | decibels |
| DCA | Decline Curve Analysis |
| Decommission or decommissioning | the process or the procedure by which the facilities and the infrastructure related to the production of hydrocarbon from an oil field are demobilised and abandoned |
| deepwater | any area of water over 250 m in depth |
| dip | the angle at which a rock stratum or structure is inclined from the horizontal |

| | |
|---|---|
| discovery | an exploration well which has encountered oil and gas for the first time in a structure |
| drilling campaign | a period of time in which drilling activities are performed |
| dry well | a well which does not encounter hydrocarbons in economically producible quantities |
| DST | drill stem test |
| Decommissioning charge | cost of charge associated with decommission procedures |
| E&P | exploration and production |
| Ea | areal sweep efficiency |
| ELE | Extreme Level Earthquake |
| ELT | Economic Limit Test |
| EMV | Expected Monetary Value |
| ESD | emergency shut down |
| EUR | Estimated Ultimate Recovery (Technically Recoverable pre-ELT) |
| exploration | the phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling |
| exploration drilling | drilling carried out to determine whether oil and gas are present in a particular area or structure |
| exploration well | a well in an unproven area or prospect, may also be known as a "wildcat well" |
| facies | sedimentological description of rock |
| farmout | a term used to describe when a company sells a portion of the acreage in a block to another company, usually in return for consideration and for the buying company taking on a portion of the selling company's work commitments |
| FBHP | flowing bottom hole pressure |
| FDP | Field Development Plan (also POD, Plan of Development) |
| field | a geographical area under which either a single oil or gas reservoir or multiple oil or gas reservoirs lie, all grouped on or related to the same individual geological structure feature and/or stratigraphic condition |
| formation | a body of rock identified by lithic characteristics and stratigraphic position which is mappable at the earth's surface or traceable in the subsurface |
| FPSO | Floating production storage and offloading |
| FTHP | flowing tubing head pressure |
| ft | feet |
| GDT | Gas Down To |
| geophysical | geophysical exploration is concerned with measuring the earth's physical properties to delineate structure, rock type and fluid content — these measurements include electrical, seismic, gravity and magnetics |
| GIIP | Gas Initially-In-Place |
| GOM | Government of Mongolia |
| GOR | gas/oil ratio |
| GRV | gross rock volume |
| GSA | Gas Sales Agreement |
| GWC | Gas Water Contact |
| $H_2S$ | Hydrogen sulphide |

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| HIC | hydrogen induced cracking |
| hydrocarbon | a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term describes any combination of oil, gas and/or condensate |
| infrastructure | oil and gas processing, transportation and off-take facilities |
| IRR | internal rate of return |
| KB | Kelly Bushing |
| ka | absolute permeability |
| kh | horizontal permeability |
| km | kilometres |
| $km^2$ | square kilometres |
| kPa | kilopascals |
| kr | relative permeability |
| krg | relative permeability of gas |
| krgcl | relative permeability of gas @ connate liquid saturation |
| krog | relative permeability of oil-gas |
| kroso | relative permeability at residual oil saturation |
| kroswt | relative permeability to oil @ connate water saturation |
| kv | vertical permeability |
| licence | an exclusive right to explore for petroleum, usually granted by a national governing body |
| licence area | the area covered by a licence |
| m | metre |
| M | thousand |
| Miocene | the epoch after the Oligocene and before the Pliocene in the Tertiary period approximately from 23 million to 5.3 million years ago |
| MM | million |
| MMBOE | million barrels of oil equivalent |
| MMstb | million stock tank barrels |
| M$ | thousand US dollars |
| MM$ | million US dollars |
| MD | measured depth |
| mD | permeability in millidarcies |
| $m^3$ | cubic metres |
| $m^3/d$ | cubic metres per day |
| MMscfd | millions of standard cubic feet per day |
| m/s | metres per second |
| msec | milliseconds |
| mV | millivolts |
| Mt | thousands of tonnes |
| MMt | millions of tonnes |
| MOD | Money of the Day |

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|---|---|
| MPa | mega pascals |
| MPD | managed pressure drilling |
| natural gas | gas, predominantly methane, occurring naturally, and often found in association with crude petroleum |
| $N_2$ | Nitrogen |
| NTG | net to gross ratio |
| NGL | Natural Gas Liquids |
| NUI | Normally Unmanned Installation |
| offshore | that geographical area that lies seaward of the coastline |
| oil | a mature of liquid hydrocarbons of different molecular weight |
| oil field | the mapped distribution of a proven oil-bearing reservoir or reservoirs |
| Oligocene | the epoch after the Eocene and before the Miocene in the Tertiary period approximately from 34 million to 23 million years ago |
| onshore | that geographic area that lies landward of the coastline |
| Operator | the company that has legal authority to drill wells and undertake production of oil and gas. The Operator is often part of a consortium and acts on behalf of the consortium |
| OPEX | Operating expenses |
| OSR | Offshore Support Rig |
| OWC | oil water contact |
| P90 | denotes a scenario which has at least a 90% probability of occurring |
| P50 | denotes a scenario which has at least a 50% probability of occurring |
| P10 | denotes a scenario which has at least a 10% probability of occurring |
| participating interests | the proportion of exploration and production costs each party will bear and the proportion of production each party will receive, as set out in an operating agreement |
| Pb | bubble point pressure |
| Pc | capillary pressure |
| Pd | Probability of development (of a discovery) |
| petroleum | A generic name for oil and gas, including crude oil, natural gas liquids, natural gas and their products |
| petroleum system | Geologic components and processes necessary to generate and store hydrocarbons, including a mature source rock, migration pathway, reservoir rock, trap and seal |
| Pg | Probability of geologic discovery of an undrilled exploration lead or prospect |
| phase | a distinct state of matter in a system, e.q. liquid phase or gas phase |
| PHI | porosity fraction |
| PHIT | Total porosity (including clay-bound water) |
| PHIE | Effective porosity |
| pi | initial reservoir pressure |
| PI | productivity index |
| PIIP | Petroleum Initially-In-Place |
| Play | a conceptual model for a style of hydrocarbon accumulation |
| PLEM | Pipeline end manifold |

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| Pliocene | the epoch after the Miocene up to the end of the Tertiary period approximately from 5.3 million to 1.8 million years ago |
| PLT | Production Logging Tool |
| POD | Plan Of Development (also FDP, Field Development Plan) |
| POR | porosity |
| Possible Reserves | Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted. |
| ppm | parts per million |
| Probable Reserves | Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. |
| prospect | an identified trap that may contain hydrocarbons. A potential hydrocarbon accumulation may be described as a lead or prospect depending on the degree of certainty in that accumulation. A prospect is generally mature enough to be considered for drilling |
| Prospective Resources | those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations |
| prospectivity | the likelihood of an area to contain potential hydrocarbon accumulations, i.e. prospects |
| Proved Reserves | Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. |
| psi | pounds per square inch |
| psia | pounds per square inch absolute |
| psiq | pounds per square inch gauge |
| Pwt | flowing bottom hole pressure |
| PVT | pressure volume temperature |
| rb | barrel(s) of oil at reservoir conditions |
| RCAL | Routine Core Analysis |
| rcf | reservoir cubic feet |

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| Reserves | those quantities of petroleum which are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions, reference should be made to the full SPE PRMS definitions for the complete definitions and guidelines |
| reservoir | an underground porous and permeable formation where oil and gas has accumulated |
| Resources | Contingent and Prospective Resources, unless otherwise specified |
| RFT | repeat formation tester |
| RKB | relative to Kelly bushing |
| rm3 | reservoir cubic metres |
| SCAL | Special Core Analysis |
| scf | standard cubic feet measured at 14.7 pounds per square inch and 60° F |
| SCSSV | Surface Controlled Subsurface Safety Valve |
| scfd | standard cubic feet per day |
| scf/stb | standard cubic feet per stock tank barrel |
| seal | a relatively impermeable rock, commonly shale, anhydrite or salt that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system |
| seismic survey | a method by which an image of the earth's subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata |
| SGS | Sequential Gaussian Simulation |
| SIS | Sequential Indicator Simulation |
| So | oil saturation |
| Sor | residual oil saturation |
| Sorw | residual oil saturation (waterflood) |
| Soi | irreducible oil saturation |
| source | characteristic of organic-rich rocks to contain the precursors to oil and gas, such that the type and quality of expelled hydrocarbon can be assessed |
| source potential | characteristic of a rock formation to constitute a source of oil and gas |
| source rock | a rock rich in organic matter which, if given the right conditions, will generate oil or gas. Typical source rocks, usually shales or limestones, contain at least 0.5 per cent total organic carbon (TOC), although a rich source rock might have as much as 10 per cent organic matter. Access to a working source rock is necessary for a complete petroleum system |
| SPE PRMS | Society of Petroleum Engineers – Petroleum Resources Management System (of 2018) |
| SRC | Seismic Risk Category |
| stb | stock tank barrels measured at 14.7 pounds per square inch and 60° F |
| stb/d | stock tank barrels per day |
| STOIIP | Stock Tank Oil Initially-In-Place |
| Sw | water saturation |
| Swc | connate water saturation |
| $Sw_{irr}$ | Irreducible water saturation |
| t | tonnes |
| THP | tubing head pressure |

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| trap | A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch outs and reefs). A trap is an essential component of a petroleum system |
| Tscf | trillion standard cubic feet |
| TVDSS | true vertical depth (sub-sea) |
| TVT | true vertical thickness |
| TWT | two-way time |
| Unconventional | Unconventional intervals are those below structural closure in which hydrocarbons have been demonstrated to be present or considered to be present |
| ULS | Ultimate Limit State – structural design |
| US$ | United States Dollar |
| Vsh | shale volume |
| W2W | Walk to Work Vessel |
| W/m/K | watts/metre/°K |
| WAP | weighted average gas price |
| WC | water cut |
| WUT | Water Up To |
| μ | viscosity |
| μgb | viscosity of gas |
| μob | viscosity of oil |
| μw | viscosity at water |

# Appendix B: Key Elements of the Petroleum Law

The following summarises key parts of the Petroleum Law that are relevant to investment decisions in CBM exploration and exploitation in Mongolia CBM is defined as "Unconventional petroleum"

- Prospecting, Exploration and Exploitation are defined terms that include such activities in relation to CBM
- A "Contractor" means a company that entered into a contract to conduct petroleum exploration or exploitation within the territory of Mongolia
- "exploration and exploitation contract" means a contract to conduct petroleum exploration or exploitation that has been made between the Petroleum Authority of Mongolia and a Contractor
- "royalties" means the fees imposed on extracted petroleum;
- "exploration work costs" means costs incurred in connection with operations specified in this law
- "development costs" means costs incurred in connection with operations specified in this law;
- "operating cost" means costs incurred in connection with petroleum extraction except for the costs incurred in connection with the development and dismantling on an exploitation area;
- "dismantling cost" means costs incurred in connection with completely restoring the environment, closing the extraction wells, and dismantling and moving buildings and structures upon expiry of an exploration and exploitation contract;
- "cost recoverable expense" means the sum of exploration work costs, development costs, operating costs and dismantling costs;
- "cost oil" means petroleum calculated by the percentage specified in this law intended to recover the costs specified in this law from crude oil;
- "profit oil" means petroleum divided between the Government and a Contractor after deduction of the petroleum specified in this law from the total petroleum measured at a delivery point;
- Petroleum and unconventional petroleum in its natural state shall be the property of the state and it shall exercise its ownership by means of issuing petroleum and unconventional petroleum exploration and exploitation licences;
- The State may receive the Royalty and petroleum allotted to the Government in cash and petroleum oil or unconventional petroleum products as mutually agreed with a Contractor;
- The State may receive the Royalty and petroleum allotted to the Government in cash and petroleum oil or unconventional petroleum products as mutually agreed with a Contractor;
- Ministry of Mining will perform the following functions:
    - announcing an open tender for exploration areas;
    - issuing, extending, suspending, and terminating exploration and exploitation licenses.
- The Petroleum Authority of Mongolia shall be responsible for performing the following:
    - receive application for an exploration area, select a Contractor, enter into a production sharing agreement;

- issuing a proposal and assessment as to whether or not to grant a petroleum or unconventional petroleum exploitation license;
- accepting and reviewing primary data, reports, and materials concerning petroleum and unconventional petroleum geology, geophysics, hydrogeology, geochemistry, drilling, exploration, and exploitation performed in an exploration or exploitation area;
- developing and having approved the standards, rules, regulations, and instructions for carrying out petroleum operations, monitoring the implementation thereof.

- The Contractor shall have the following rights:
  - Dispose of the petroleum allotted to it;
  - The administrative costs of the Contractor shall be up to five percent of the cost recoverable expenses for a respective year.
- The Contractor shall have the following obligations:
  - If the Government exercises its pre-emptive right to purchase refined products at international process and conditions then supply same;
  - set up equal salaries, wages and bonuses for domestic and foreign employees performing same duties and work, and protect their rights and interests;
  - deposit a cash amount equal to 3% of investment to the exploration work of the relevant year, or to 1% of its profit-bearing oil during an exploitation phase for that year respectively into an escrow account annually in a bank operating in Mongolia within 60 days from the approval of its plan and budget as a guarantee of Contractor's full performance of its obligation for environmental rehabilitation;
  - demobilization of exploration or exploitation buildings and facilitates;
  - produce an estimate of petroleum resource flows each year for review by the Petroleum Authority;
  - produce and hand over any information associated with its investment, ownership, and operations at request of the Cabinet; and
  - prepare accurately its financial statements, a report on expenditures which are cost-recoverable and calculation of petroleum oil for splitting according to the procedures and submit them to Petroleum Authority.
- A Contractor shall have no right to transfer whole or one third or more percentage of its rights and obligations under a production sharing agreement to others without permission from the Cabinet;
- A legal entity shall carry out petroleum or unconventional petroleum oil prospecting upon making a contract with the Petroleum Authority;
- A contract to prospect for petroleum or unconventional petroleum oil shall be concluded for a period of up to three years;
- A party performing petroleum or unconventional petroleum prospecting shall give the primary materials and reports and information on the results of its prospecting work to the Petroleum Authority for assessment;

- A body which concluded prospecting shall present its request to enter into production sharing agreement pertaining to the petroleum or unconventional petroleum area prospected within 60 days from the date the Petroleum Authority issued its assessment of Contractor's report on prospecting work results;
- The body party that performed prospecting shall prepare a draft production sharing agreement containing the conditions and submit it to the Petroleum Authority:
  - the percentage of profit oil allotted to the Government;
  - the percentage of royalties;
  - the limit of the percentage of cost oil;
  - the amount of exploration investment;
  - the amount of funds spent on environmental restoration;
  - the amount of the premium for instruction/training;
  - the amount of a bonus for signing the contract;
  - the amount of a bonus for beginning extraction;
  - the amount of a bonus for increasing the extraction;
  - the amount of a bonus for local development;
  - operational support of the representative office;
  - other profitable conditions proposed to the Government.
- The Petroleum Authority shall hold negotiations with the party regarding the draft contract in 60 days of receipt of the draft. The Cabinet shall issue a decision as to whether or not to conclude a contract;
- A Contractor shall submit its application for an exploration license to the Ministry of Mining appending the following:
  - a copy of the production sharing agreement;
  - an environmental impact assessment;
  - a draft of the work project and plan to be performed during the respective year; and
  - proof of deposit of the requisite funds.
- A term for unconventional petroleum exploration shall be up to 10 years, and Petroleum Agency may extend this period once by up to 5 years;
- The Petroleum Authority shall announce an open tender on exploration areas and notification that an exploration area has been declared for open tender on its webpage and through the daily press and mass media no fewer than three times;
- Bids for exploration licences shall include:
  - documents evidencing the bidder's technical, equipment, and professional capabilities;
  - a guarantee of the funds to be spent on exploration work; and
  - a work plan and budget to be performed during the exploration term.
- Petroleum Authority shall evaluate bids in accordance with the regulation on ―selecting a Contractor under the tender process and define the bidder that submitted the most profitable proposal;

- Petroleum Authority shall agree with a tender winner a draft of a production sharing agreement , and enter into this agreement;
- A Contractor shall submit the reserve estimate to the Petroleum Authority 90 days before the expiry of the exploration period for review, hold discussion of it by the Mineral Resources Council of the Ministry of Mining, and seek issuance of a decision by the Ministry of Mining as to whether or not to accept the reserves;
- Within 30 days of the Ministry of Mining issuing a decision accepting the reserves, a Contractor shall apply for an exploitation license;
- A Contractor shall submit the following documents, inter alia, to Ministry of Mining when applying for an exploration license:
    - a decision of Ministry of Mining registering the petroleum reserve;
    - a draft of the work plan and budget for the respective year;
    - a deposit mining operations plan; and
    - the detailed environmental impact assessment current for the exploitation period.
- If within 90 days after end of exploration period the Contractor did not submit application for engaging in exploitation, the production sharing contract shall be terminated and the area shall be announced as an open area;
- The term of unconventional petroleum exploitation shall be up to 30 years, and in the event a Contractor applied for an extension of the exploitation term, the Petroleum Agency may extend it once by up to 5 years;
- Delivery points for extracted petroleum shall be established by mutual agreement of the Petroleum Authority and the Contractor;
- The Petroleum Authority and the Contractor shall set a price of the extracted petroleum on the basis of the price of petroleum of the same character as sold on the world market;
- The annual license fee during the term of petroleum exploration shall be an amount in tugrugs equal to three American dollars per square kilometre of the contracted area. In the event the term of an exploration license is extended, the annual license fee shall be an amount in tugrugs equal to eight American dollars per square kilometre. The annual license fee during the term of petroleum exploitation shall be an amount in tugrugs equal to 100 American dollars per square kilometre. In the event the term of an exploitation license is extended, the annual license fee shall be an amount in tugrugs equal to 200 American dollars per square kilometre;
- The amount of unconventional petroleum royalties shall be 5–10 percent;
- Contractor shall bear responsibility itself for all costs necessary for carrying out petroleum operations;
- Cost recovery expenses shall be recovered by the cost oil in the amount specified in a production sharing contract;
- For the unconventional petroleum the amount of cost oil shall be determined by the relevant regulation specified in this law;
- Once the term of exploitation ends, the Contractor shall not be granted the portion of cost recoverable expenses that remains unrecovered;

- Costs of test extraction during the exploration shall be part of exploration costs;
- The fees shall not be regarded the [in] cost recovery expenses;
- Government shall not pay any interest on the Contractor's accumulated expense for cost recovery;
- The Government shall share the profit oil with the Contractor as agreed in the production sharing contract.
- The amount of profit oil allocated to the Government shall [be] determined and specified in the contract in relation to daily extraction volume;
- Bonuses for signing the contract, beginning the extraction, increasing extraction, and training shall be included in the contract at the rate proposed by the bidder;
- The service fee for an exploration area bid shall be an amount in tugrugs equal to 20,000 American dollars;
- A Contractor shall pay an amount in tugrugs equal to 100,000 American dollars to the state budget when increasing the size of an exploration area, and 250,000 American dollars when increasing the size of an exploitation area, respectively;
- A Contractor shall pay an amount in tugrugs equal to 20,000 American dollars to the state budget when transferring its contractual rights and obligations before a discovery has been established on the exploration area, and 50,000 American dollars after a discovery has been established;.
- If the rights and obligations have been transferred during the exploitation period, an amount in tugrugs equal to 100,000 American dollars shall be paid to the state budget;
- A Contractor shall hand over to Petroleum Authority reports and primary information and data materials on the results of its exploration or exploitation work within 90 days after the end of the respective calendar year; and
- A Contractor shall hand over reports and results of the analysis of petroleum, gas, liquids and rock samples and primary data of the study to Petroleum Authority within 90 days after the end of a respective calendar year's work.

# Appendix C: Model Inputs for Low, Mid and High Cases - Charts

The inputs each of the scenarios is illustrated in the charts (Figure C-1 to Figure C-15).

## 1. Low Case Inputs: Small-scale CBM to LNG Production for Transportation Fuel to Local Market

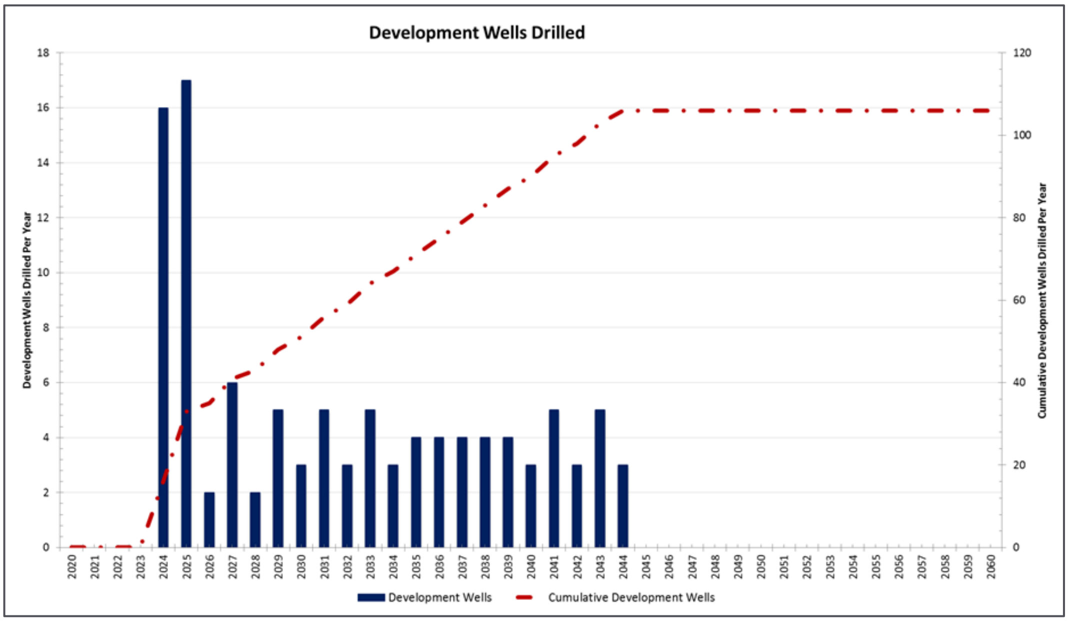



*Figure C-1: Development Wells – Low Case*

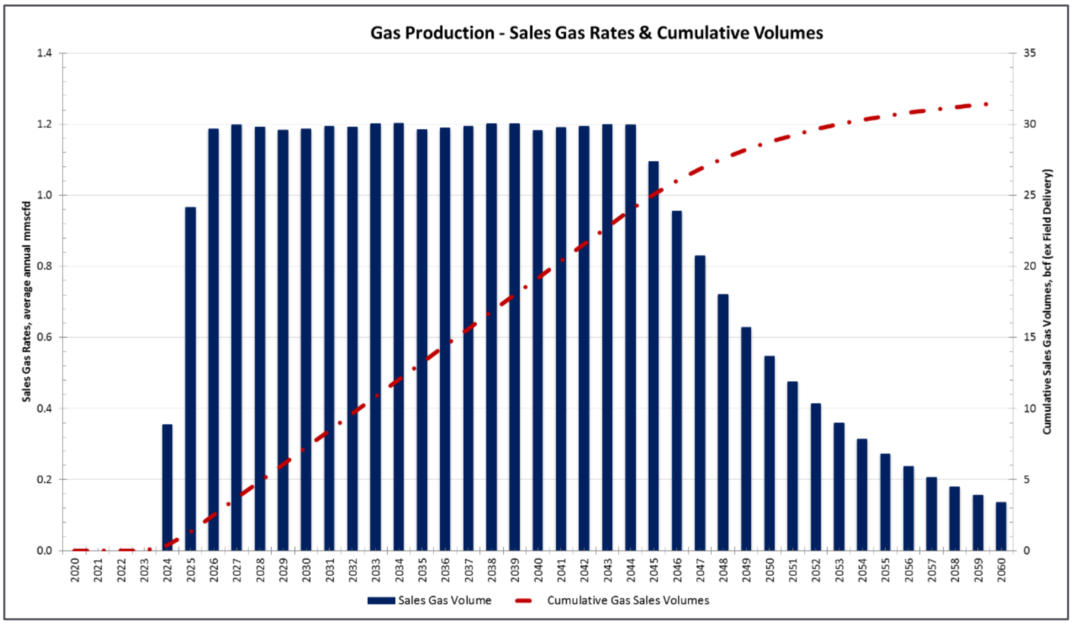


*Figure C-2: Gas Production – Low Case*

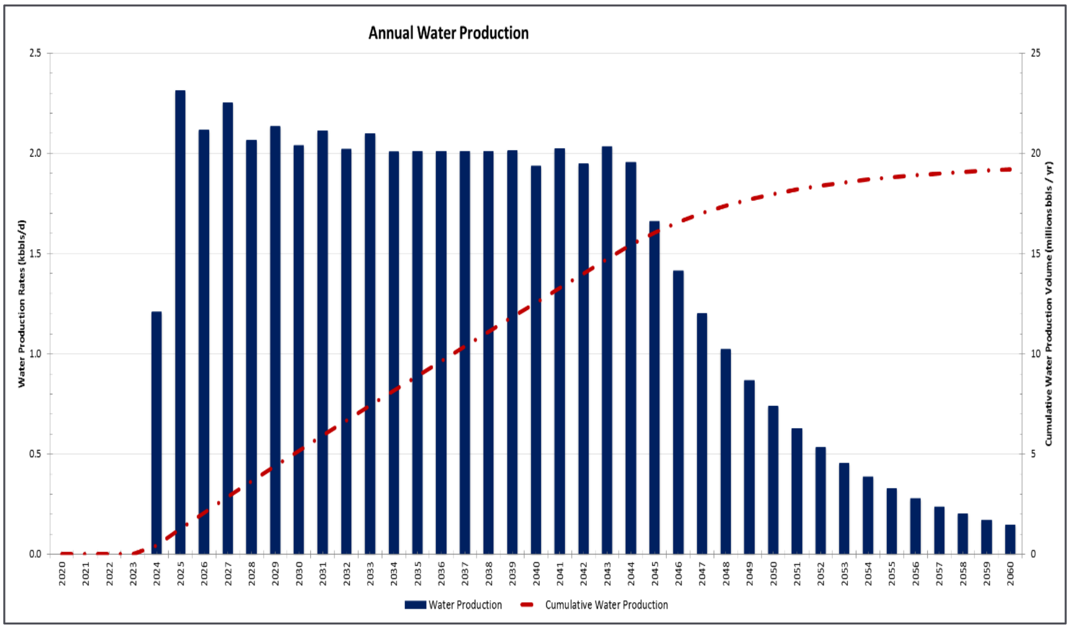



*Figure C-3: Water Production – Low Case*

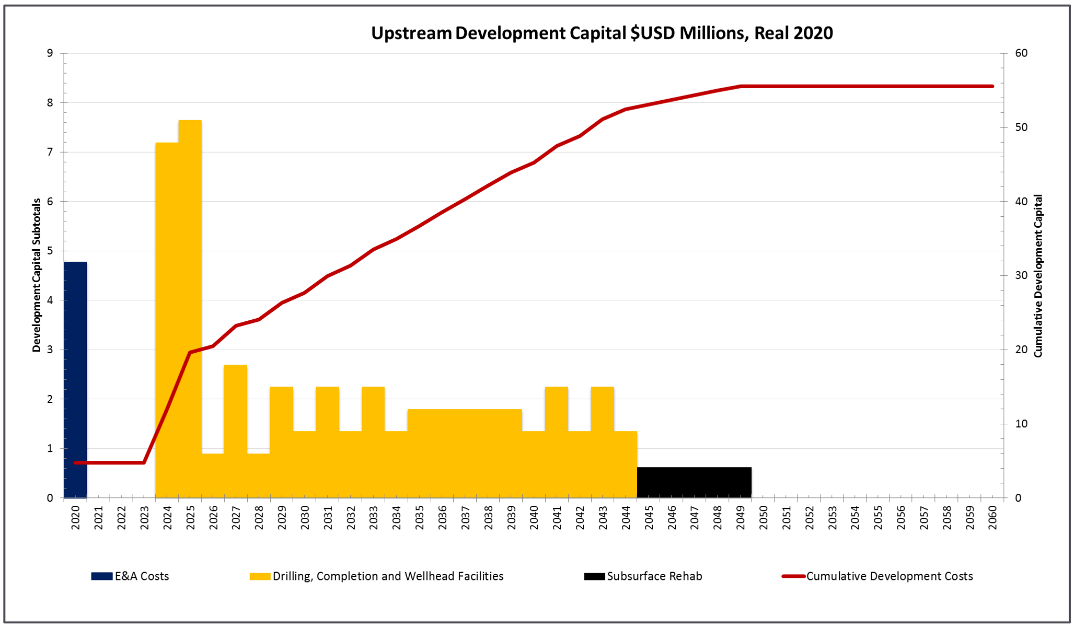
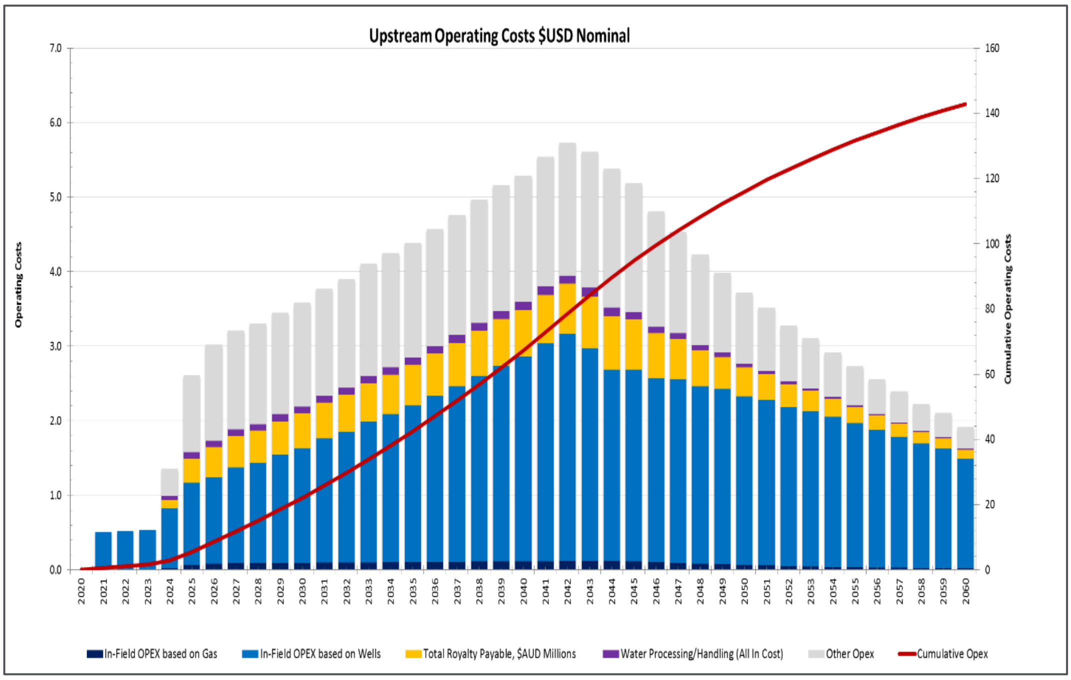



*Figure C-4: Upstream Development Capital – Low Case*




"Other OPEX" = Gas Processing Cost

***Figure C-5: Upstream Operating Costs – Low Case.***

2. Mid Case Inputs: CBM for Gas Fired Power Generation for Local Market, Base Load Power at 80 MW.

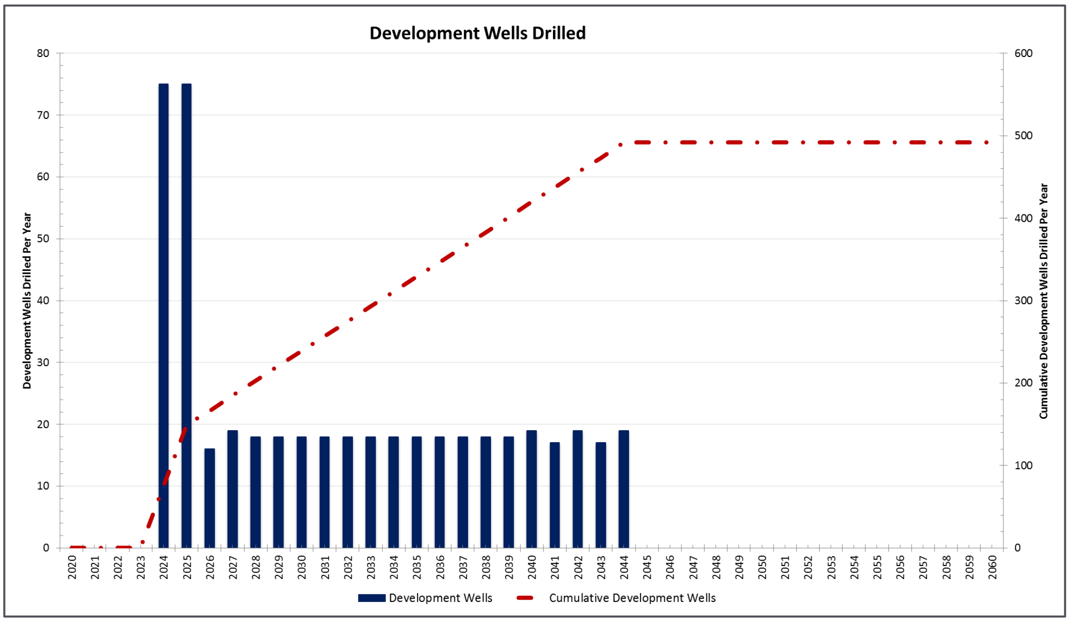



***Figure C-6: Development Wells – Mid Case***

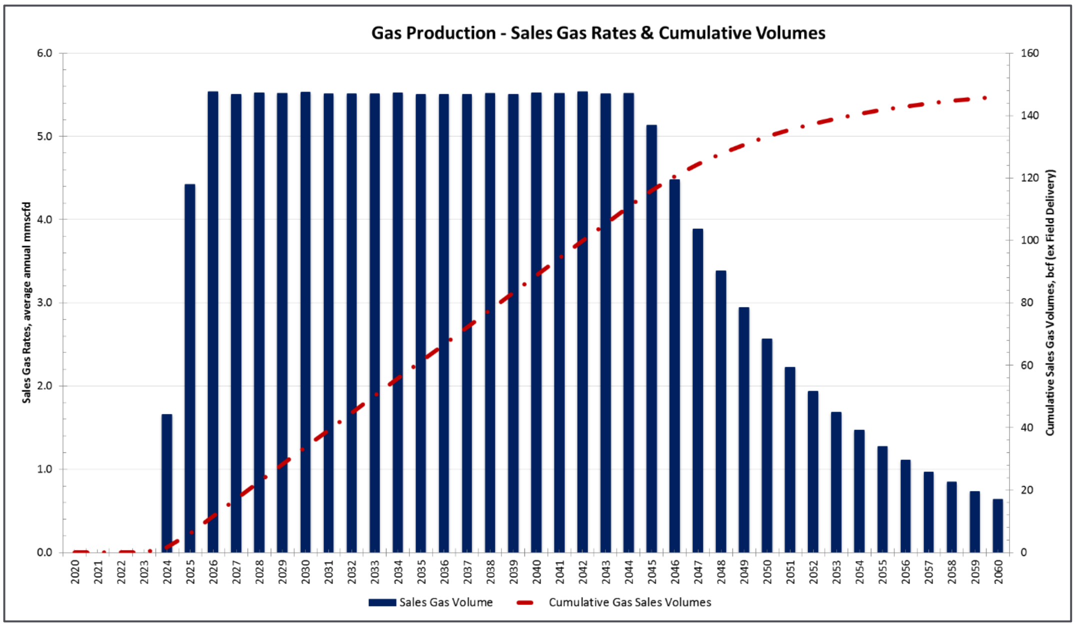



***Figure C-7: Gas Production – Mid Case***

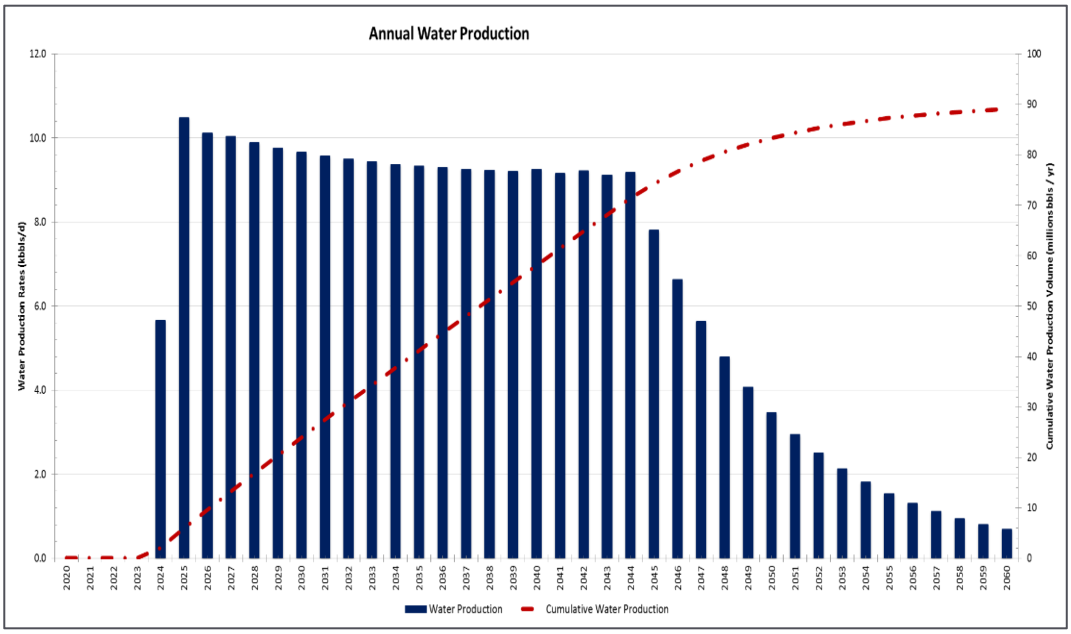



***Figure C-8: Water Production – Mid Case***

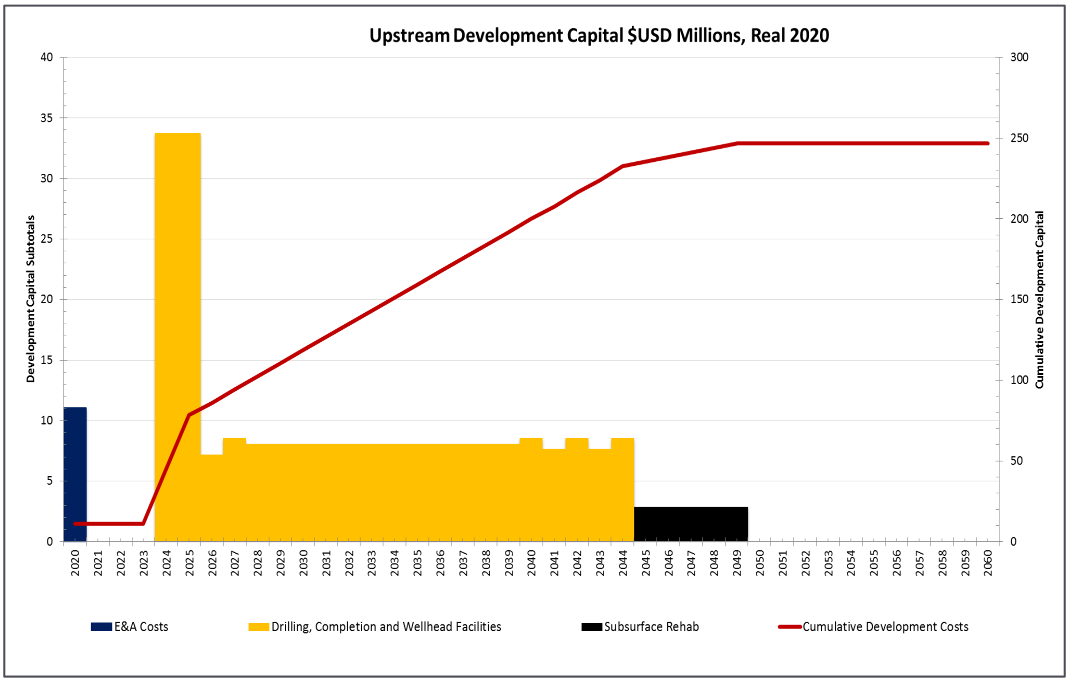
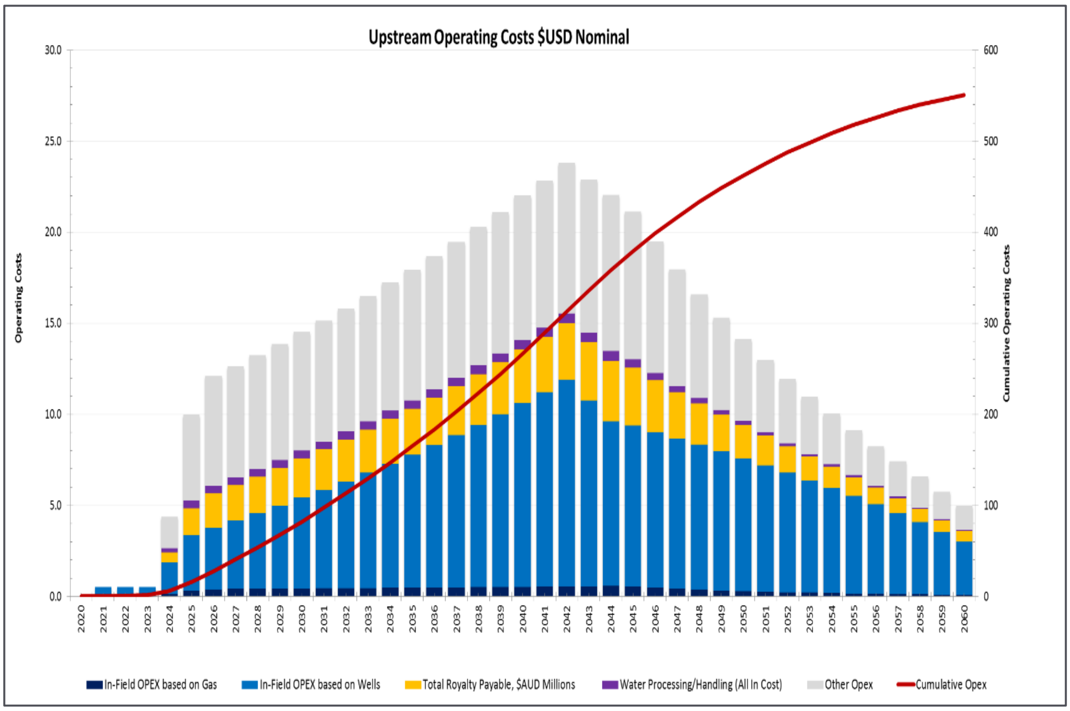



*Figure C-9: Upstream Development Capital – Mid Case*




"Other OPEX" = Gas Processing Cost

*Figure C-10: Upstream Operating Costs – Mid Case.*

3. High Case Inputs: CBM for Pipeline Export to International Market

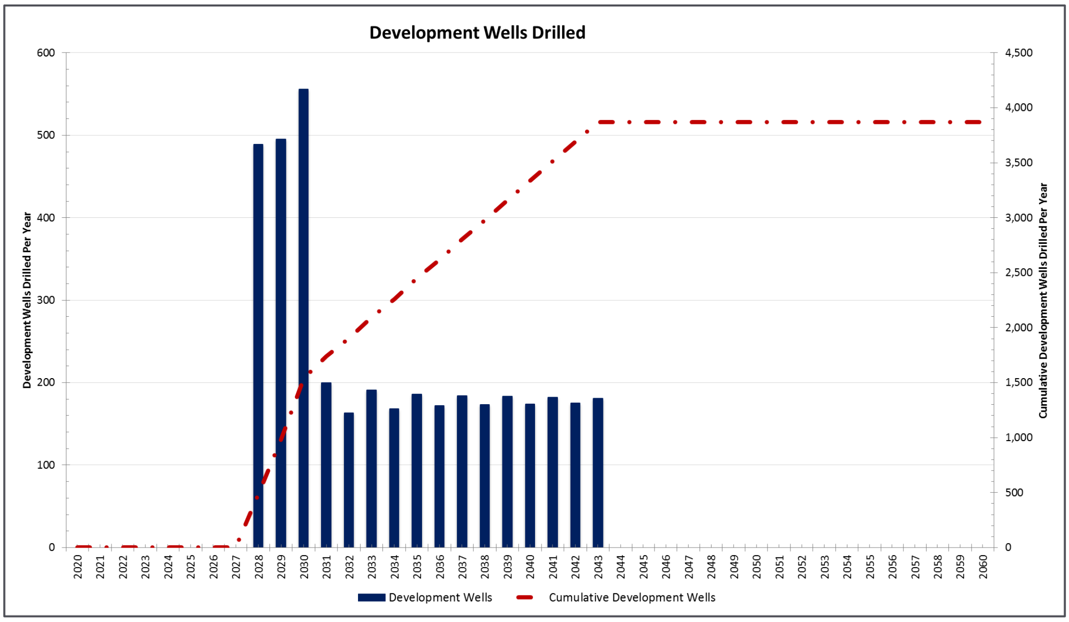



*Figure C-11: Development Wells – High Case*

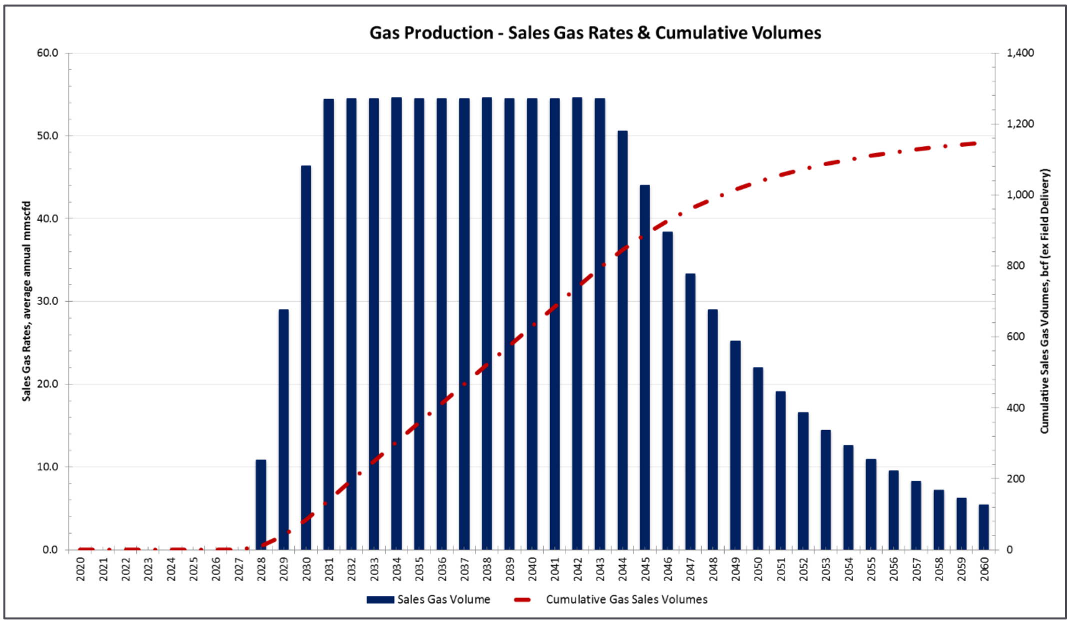



*Figure C-12: Gas Production – High Case*

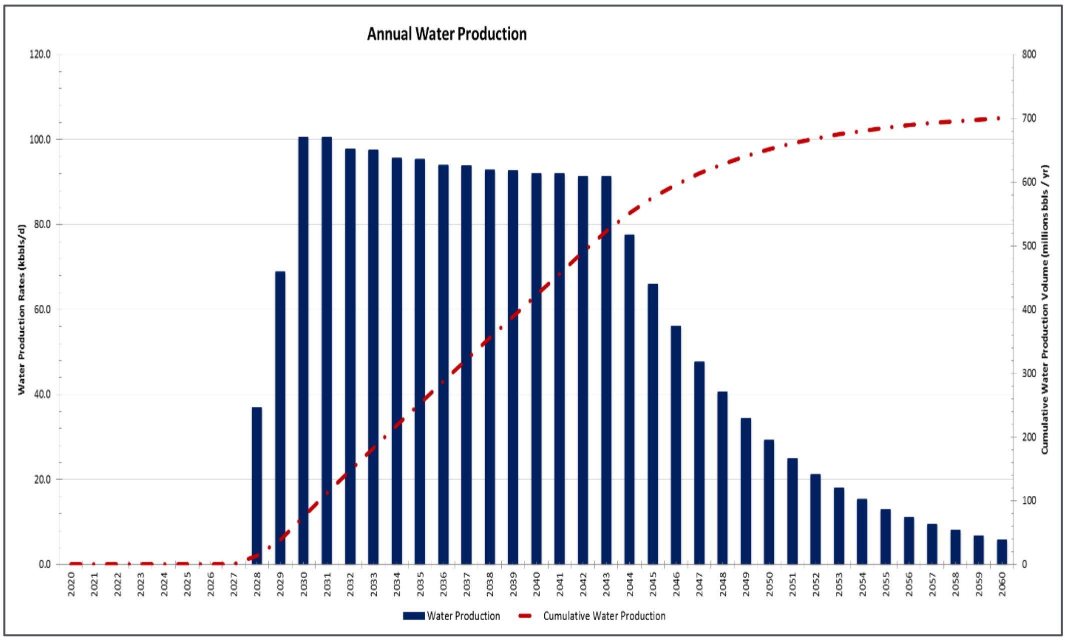



*Figure C-13: Water Production – High Case*

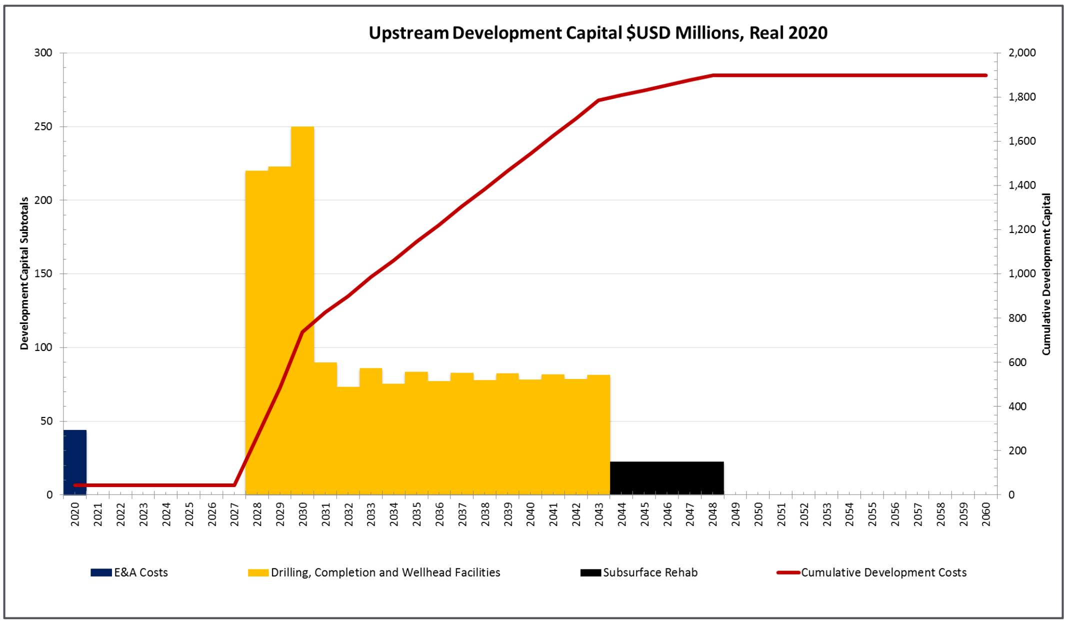
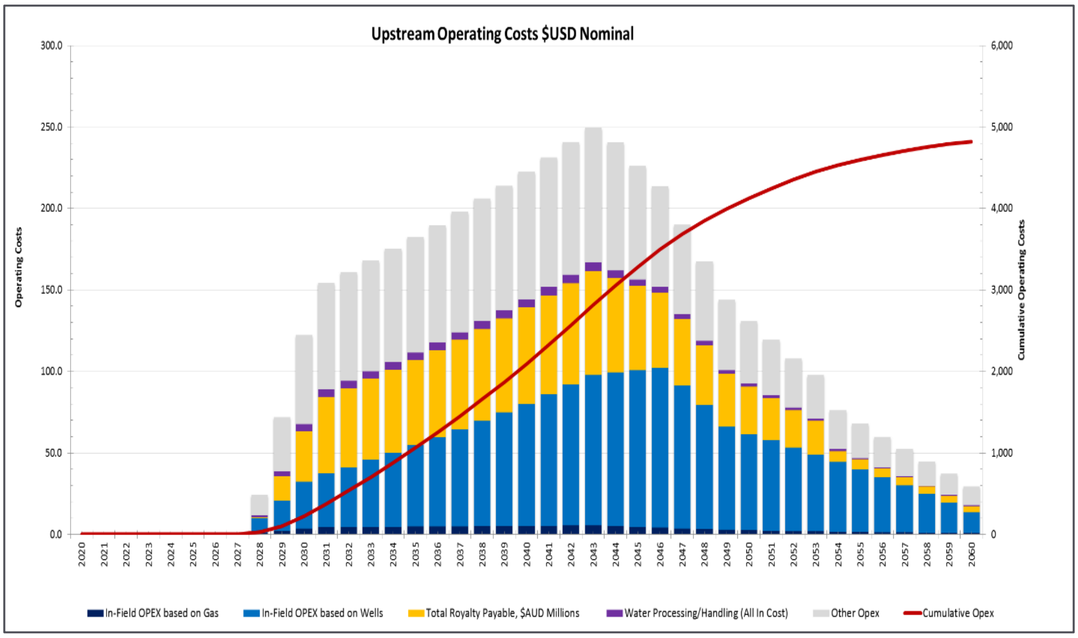



*Figure C-14: Upstream Development Capital – High Case*




"Other OPEX" = Gas Processing Cost

***Figure C-15: Upstream Operating Costs – High Case.***

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