ALBERTA
AT A CROSSROADS

ROYALTY REVIEW ADVISORY PANEL REPORT

CONTENTS

CONTENTS

EXECUTIVE SUMMARY: ALBERTA AT A CROSSROADS

IN SUMMARY

- *The future of Alberta's energy industry is not going to be like the past. Reviewing royalties is not as simple as saying rates should go up or down.*
- *The main focus of our Panel's report and recommendations is on modernizing the framework for crude oil, liquids and natural gas to fulfill the mandate given to our Panel:*
  - *Provide optimal returns to Albertans as owners of the resource,*
  - *Continue to encourage industry investment,*
  - *Encourage diversification opportunities such as value-added processing, innovation or other forms of investment in Alberta, and*
  - *Support responsible development of the resource.*
- *If implemented, our recommendations would create a simpler, more transparent and efficient system that encourages investment, creates jobs and enhances economic activity.*
- *The modernized framework rewards innovation and improved costs, which in turn creates better returns to both Albertans and investors.*
- *Our Panel found that, overall, Alberta's royalties are comparable with other jurisdictions.*
- *While royalties are comparable, our Panel determined there are issues with the royalty structures for crude oil, liquids and natural gas that need to be addressed.*
- *All changes to the framework for crude oil, liquids and natural gas should apply to new wells in 2017. Existing royalties should remain in effect for 10 years on wells drilled before 2017.*
- *The oil sands royalty framework implemented in 2009 provides Albertans an appropriate share of value. This framework, combined with the last decade's substantial investments, is poised to generate increased royalty revenues for Albertans.*
- *More transparency and disclosure on royalty calculations and allowable costs are needed to build trust and improve credibility. Our Panel's recommendations include the publishing annually of a Capital Cost Index for oil and gas, as well as the revenue, expense, and royalty information for each oil sands project.*
- *There are opportunities for Alberta to capitalize on adding value to its vast natural gas reserves. Our Panel's recommendations include the government undertaking further investigation to explore this strategy in depth as well as opportunities to accelerate partial upgrading of bitumen.*
- *Our Panel also heard from Albertans about the principles that are important to them in a royalty framework. To ensure those principles, which align with the mandate objectives above are met on an ongoing basis, the panel recommends that criteria such as returns to the province, industry costs, investment levels, job creation, and environmental performance be measured and reported annually.*

OUR PANEL'S APPROACH

On August 28, 2015, the Government of Alberta announced the establishment of our Royalty Review Advisory Panel. Since then, our Panel has been privileged to meet with and listen to thousands of Albertans – not only people directly connected to Alberta's energy industry, but those who have a wide variety of views on the industry, the important role it plays in Alberta's economy, and its impact on communities across the province. We have learned a lot. And we want to begin by thanking all of the people who, as owners of this resource, took time to get engaged in the process, to offer their views and their expertise, and to help shape the direction and substance of our Panel's report and recommendations.

Overall, our mandate was to identify opportunities to optimize Alberta's royalty framework for crude oil and liquids, natural gas and oil sands, to achieve four inter-related objectives:

- Provide optimal returns to Albertans as owners of the resource,
- Continue to encourage industry investment,
- Encourage diversification opportunities such as value-added processing, innovation or other forms of investment in Alberta, and
- Support responsible development of the resource.

Our process had two sides: public engagement and a technical review.

The public engagement involved a dialogue with Albertans which took place through our website (**www.LetsTalkRoyalties.ca**); community sessions in locations around the province; a telephone town hall; and many meetings with individuals and communities in the private, public and non-profit sectors. All told, we engaged tens of thousands of Albertans.

The technical review involved the use of three Expert Groups, aimed at examining specific mechanics of the royalty framework. To support the technical review, our Panel engaged energy data analytics firms Wood Mackenzie and GLJ Petroleum Consultants, which researched and provided technical, financial and economic data regarding Alberta's resource opportunities and the resource opportunities of other jurisdictions.

Our challenge was to prepare a report that reflects the views and expectations of Albertans and, at the same time, addresses the technical challenges of a very complex royalty framework that may have been effective in the past but needs to be modernized in order to meet the challenges we see today. Most important, our goal was to provide open and transparent information and assessments that shed light on the challenges we face today. This has led us to recommend a modernized framework that will guide Alberta's royalty framework for years to come.

THE ENERGY LANDSCAPE HAS FUNDAMENTALLY CHANGED

Though it has successfully weathered many ups and downs over the past several decades, Alberta's oil and gas industry stands at a critical crossroads today. There are some hard realities we must confront:

- **We cannot continue to operate with a perspective that the world needs to come to Alberta if it wants oil and gas.** Advances in technology have unlocked significant new sources of oil and gas supplies, particularly from unconventional deposits in the United States. The U.S. is now a rejuvenated force in oil and gas production, one that poses huge risks to Alberta's market share. This is problematic, since we have long relied on the U.S. as our primary (and to some extent, only) customer, and we do not have sufficient means to move and sell our oil and gas to other countries.

- **Global forces, competitive pressures from U.S. oil and gas resurgence, and limited market access have placed significant downward pressures on the prices Alberta can receive for crude oil and liquids, natural gas and oil sands resources.** This, in turn, reduces the amount of value Albertans can collect through royalties. Many of these challenges are structural rather than cyclical, and we can expect price pressures to exist for quite some time.

- **Environmental expectations are increasingly influencing our ability to access new markets and our social license to develop our energy resources.** Not all of our competitors are subject to the same expectations, and some of our competitors have much better access to high-value markets despite having much poorer environmental performance. Alberta will need to continue to pursue innovative ways to develop our resources responsibly while remaining cost-effective.

- **Alberta has a skilled workforce, but it is a small one.** Our population is well-educated and skilled, with many professional, technical and other trained workers. However, with a population of only 4.2 million our labour pool is relatively small and, as a result, we have higher labour costs relative to other competing jurisdictions such as Texas, which has a population of almost 30 million.

- **Alberta companies compete for capital investment.** As a relatively small jurisdiction, we depend on outside investment to produce and sell our resources. Today's interconnected world offers investors many different options in many different sectors and countries. With investors potentially requiring both financial returns and sound environmental practices, it is critical that Alberta's resource development opportunities are attractive on both fronts.

To survive and thrive in the face of these new realities, we need to 'up our game', be prepared to think differently, and challenge the status quo. This needs to be recognized equally by industry, by the Province and by all Albertans. Our challenge is to find a common strategy to be a responsible, intentional and determined player. Half-hearted or divided efforts will result in failure.

Industry has become well-practiced in explaining why our province is a 'high cost basin' and arguing that lower royalties and other concessions are the only viable solutions. We need to get past that. Our Panel's advice to Albertans is that the energy company partners we will need in the future are ones who are innovating continuously and striving to reduce their costs and environmental footprints. The game is too tough now to have partners who cannot do that.

At the same time, some Albertans have a belief that industry should simply pay more. Again, our Panel's advice is that while this position may have had substance in the past, the idea that 'they have to come to us anyway' is a dated notion and one that would be a losing proposition.

None of this means, however, that our days in the energy business are numbered. On the contrary, as Albertans, we are known for rising to challenges and overcoming adversity.

We also have many comparative advantages.

- Our province is endowed with a vast array of hydrocarbon products.
- Our population, though relatively small, has energy expertise that is sought after internationally.
- Though it has some capacity challenges, our province's energy infrastructure is extensive, including the makings of a world-scale petrochemical complex.
- Alberta's new Climate Leadership Plan will make Alberta one of the most environmentally responsible energy producers in the world. It also presents the opportunity for our province to reposition itself with investors, other Canadian provinces and other countries, and potentially improve our access to new markets and customers for our energy resources.
- Our vast, low-priced natural gas reserves lend themselves to value-added processing, including the conversion of bitumen to lighter products and the production of petrochemicals, fertilizers and other derivative products.

These and many more strengths can be brought to bear.

Alberta's royalty framework can and should be another strength. Properly optimized, the framework can support Alberta being a responsible, strategic and determined player in the energy business.

OPTIMIZING FOR THE FUTURE

With that challenging context in mind, our Panel reviewed the current royalty framework and considered what changes can and should be made to address immediate issues with the framework and ensure that the framework provides a longer-term foundation for changes the industry will face in the future.

Our focus has been on "optimizing" the outcomes and impact of the royalty framework. And that begins with a need to understand what royalties are and why we collect them.

Royalties are about Albertans, as owners, collecting value from our resources.

We rely on energy companies to develop our resources on our behalf. Both the owners of the resource (Albertans) and the energy companies share in the value of developing our resources. There is only a certain amount of value available to share. **That value is determined by the prices received for our resources, minus the costs to produce and sell them.**

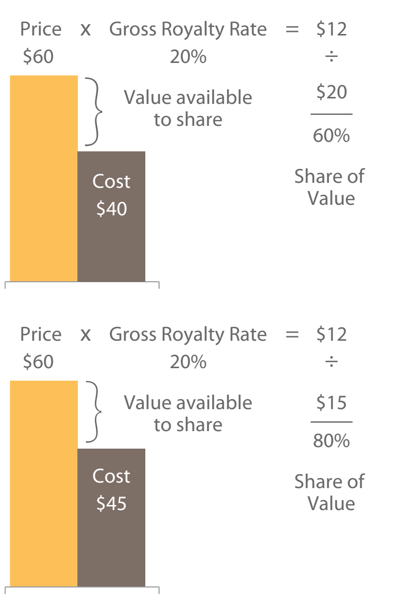
As owners, we have a vested interest in things that affect both the prices received for our resources (such as competition and market access) and the costs to produce and sell our resources (such as geology, geography, technology and risk).

Since we are a relatively small jurisdiction that depends on investment from beyond our borders, we must also take a keen interest in how investors make decisions and how they perceive the attractiveness of investing in our resources.

All of this means that, as owners, we need to think well beyond the question of, "Should royalty rates go up or down?"

In reality, the royalty rates that are applied to oil and gas wells and oil sands projects are not static. They vary from month to month, from well to well, and from project to project. The rates charged each month on each well and project can change depending on resource prices, production levels and even the depth of wells. Looking at royalty rates alone is misleading and unhelpful, because the rates do not generate anything until they are applied to the **value** of our resources.

SHARE OF VALUE DEPENDS ON VALUE AVAILABLE



One area of consistent confusion during the review process was the difference in speaking about **rates** versus **share of value**. In Alberta, for all but the oil sands, the royalty rates apply to gross revenue. How this translates to share of value depends crucially on the amount of value available. As an example, if prices are $60 and costs are $40, the value to be shared is $20. A gross royalty rate of 20% provides a 60% share of value. However, if costs rise to $45, the value to be shared shrinks to $15, and the same 20% gross royalty rate provides an 80% share of value. To maintain a consistent share of value, gross royalty rates must move with price.

The most meaningful question, then, is not about royalty rates, but rather: "Are Albertans receiving an optimum share of that value, and importantly, how can we optimize the value of our resources?"

The comparative analysis work delivered to our Panel demonstrated that Albertans are receiving a share of value in line with their peers in other provinces and countries. However, as the example above illustrates, if this share is coming from a shrinking value it is not optimal to Albertans. For Albertans to receive an optimal share of value from our resources, it is important to focus not just on the percentage take, or share, but also on ensuring the value of the resource itself is optimized. The actual royalty rates used are simply a tool to capture this value.

In speaking with Albertans it was clear that, in addition to royalties collected, jobs and economic activity are also important factors to consider in determining our optimal share.

Our Panel took stock of the fundamental changes that have occurred on the energy landscape and considered the implications for Alberta's energy development outlook. This is what we've learned.

- Conventional oil and gas is quickly being surpassed by unconventional developments. However, Alberta has tens of thousands of conventional wells still in production, all of which sustain employment, surface access fees and municipal taxes. Even with little new drilling expected, the employment and economic activity from these conventional wells is surprisingly large.
- Unconventional oil and gas development (e.g., shale) is the future. The development of Alberta's vast unconventional oil and gas resources can and will need to stand up to significant competitive forces.
- Currently committed oil sands expansions and the maturing of existing projects will provide steadily increasing royalty revenue to Albertans for decades.
- New investments in oil sands projects will tend to be smaller-scale in-situ facilities and expansions of existing facilities. Investments in new large-scale oil sands megaprojects are unlikely.

Our Panel also looked at how Alberta stacks up against other jurisdictions that have similar resource opportunities.

- Albertans are receiving an appropriate share of profits on their resources relative to their comparable peers. The detailed data provided to our Panel showed Alberta to be about the "middle of the pack" in a wide range of well types in comparable jurisdictions. Albertans' share of resource production profits ranks neither as the best of its peers, nor as the worst.
- In terms of investment, our resources and financial regime currently combine to also be about "middle of the pack". Some new U.S. resource plays in Texas and Pennsylvania are more attractive for investment. Texas is particularly attractive for unconventional oil, while Pennsylvania is particularly attractive for natural gas. Within Canada, Saskatchewan's royalty regime is more favourable to investment for similar-type unconventional oil wells. British Columbia's regime, in general, imposes lower rates for natural gas.
- Colombia and Argentina are international comparables for unconventional oil and natural gas. Both are inferior to Alberta from an investment perspective.
- While overall we can compete for investment, we are not the most attractive spot, especially in a North American context. We will need to rely on strong operators and, ultimately, need to bring down our costs.

With these things in mind, our Panel reviewed Alberta's current royalty framework. We found several ways in which the framework is not keeping pace with the changing nature of the energy business and failing to optimize the value of our resources. Notably:

- The framework used to calculate royalty rates for crude oil, liquids and natural gas is rigid and does not adapt to changes in the costs, technology and productivity of oil and gas wells. As a result, even if they were made current today, these royalty structures would become out-of-date in just a few years.
- The distinction between what is an oil well and a gas well is no longer meaningful. An energy company will pay a different royalty depending on whether a well is classified as gas or oil, based on the mix of hydrocarbons encountered. This "black or white" treatment presents unnecessary risks and impedes Albertans from collecting optimum value from these resources.

- The current royalty structures for crude oil, liquids and natural gas can also contribute to practices that are not as efficient or environmentally responsible as they could be. For instance, under the current framework, it can be more economically advantageous for a company to drill two short horizontal wells rather than a single long well, resulting in unnecessary surface disturbances.
- Although the "revenue minus costs" royalty structure used for oil sands is consistent with the global standard, there is a lack of transparency around the costs that energy companies are allowed to claim in calculating royalties. This is undermining Albertans' confidence and trust in the oil sands royalty structure.

Against this backdrop, our Panel considered possible paths forward.

We heard that government should "do nothing" or "leave the current framework alone". Although we understand the nature of these comments, the truth is that the current framework is not only behind the times but also includes temporary programs that are due to expire. Taking no action would result in a flight of investment away from Alberta, a decline in oil and gas production, and lower royalties to Albertans over time, to say nothing of the negative employment and economic impacts that would also result.

Our Panel heard other voices suggest that the current framework might benefit from some minor tinkering and the renewal of temporary programs, but should otherwise be maintained. This approach would maintain distortions that are present in the current framework, including the discriminatory treatment of different hydrocarbons. It would continue to unintentionally encourage sub-optimal practices and would not support responsible resource development or investments in innovation or diversification. In a few short years, the 'minor tweaking' would be out-of-date. Our province would gradually receive less investment and would fail to capitalize on many resource opportunities.

In light of everything we learned and discovered, our Panel determined that the best course forward is to modernize Alberta's royalty framework. Collectively, our recommendations call for Alberta to make changes that will:

- Support ongoing production from Alberta's many conventional oil and gas wells (and the employment and economic benefits they provide).
- Encourage investment in, and development of, Alberta's significant unconventional oil and gas resources, thereby growing the economy and the overall amount of resource value that is available for royalties.
- Improve transparency, predictability and credibility around the calculation of royalties for Alberta's oil sands.
- Position Alberta to strategically create more jobs, value, and economic benefits from our oil, natural gas and oil sands resources.
- Support energy producers in becoming more innovative and efficient in the development of resources, including improved environmental performance.
- Provide Albertans, energy companies and investors with a shared understanding of what Alberta's royalty framework is expected to accomplish and the characteristics that guide its design.

OUR RECOMMENDATIONS

Recommendation #1

Establish guiding principles and design criteria for Alberta's royalty framework.

Our Panel noted that Albertans do not have a shared understanding of what the royalty framework is intended to do. Without this, people have, quite rightly, held very diverse opinions about whether the framework is generating a good deal for Albertans.

The public engagement side of our process sought to address this by creating a conversation with Albertans about their expectations when it comes to the royalty framework.

From this input, along with everything we learned and found about Alberta's energy business, its competitive position and current royalty structures, our Panel distilled a set of guiding principles. The guiding principles reflect what Albertans want the framework to accomplish, and provide a set of criteria to measure our results against. They also provide a longer-term perspective for judging the outcomes of the royalty framework.

Guiding Principles for Alberta's Royalty Framework:

- **Optimize Returns to Albertans.** Innovation and Efficiency are prominent contributors to Albertan's returns. The framework encourages the application of new processes and technologies to improve the efficiency of developing Alberta's energy resources. This, in turn, reduces the costs of producing and selling Alberta's resources and enhances the royalties that Albertans can collect.
- **Attracts investment and promotes job creation.** The framework supports the attraction of investment in the development of Alberta's energy resources, encourages the creation of jobs in the province, and supports a predictable business climate in Alberta.
- **Supports downstream value-added industries.** The framework encourages investment in activities and technological advancements that add value to Alberta's energy resources such as upgrading, refining, petrochemical processing and fertilizer manufacturing.
- **Encourages environmental responsibility.** The framework encourages environmentally responsible development of Alberta's energy resources (e.g., clean air, clean water, reduced greenhouse gas emissions, biodiversity, minimal land footprint, etc.), and the conservation of those resources.

Recommendation #2:

Modernize Alberta's royalty framework for crude oil, liquids and natural gas.

Recommendation in Brief:

- Apply all changes to new wells only. Existing royalties will remain in effect for 10 years on investments already made.
- Design a royalty structure for crude oil, liquids and natural gas that emulates a "revenue minus costs" approach, providing both the Province and investors with a clear line of sight on recouping certain upfront capital costs on average and, ultimately, see them re-invested in Alberta.
- Harmonize the royalty structures across crude oil, liquids and natural gas to remove distortions in the current framework.
- Eliminate the multitude of expiring drilling programs, and replace them with a permanent formula to easily calculate Drilling and Completion Cost Allowances for each well, based on vertical depth and horizontal length.
- Calibrate the Drilling and Completion Cost Allowance each year to a Capital Cost Index, to reflect current average costs.
- Apply a flat royalty rate of 5% until cumulative revenues from a well equal the well's Drilling and Completion Cost Allowance, followed by higher post-payout royalty rates that increase with price.
- In the transition to the modernized framework, calibrate the combination of Drilling and Completion Cost Allowances and new post-payout royalty rates to target the industry returns and Albertans' share of value that are achieved under the current framework, taking into account that current incentive programs are not well designed for very high or very low prices.

The technical details of the recommended changes are in the Recommendations chapter and Appendices of this report. The key point is that the current framework needs to be modernized in fundamental ways – not maintained as-is or merely 'tinkered' with.

The changes we suggest for crude oil, liquids and natural gas are intended to: simplify the current system; better reflect the costs involved in producing oil and gas; and remove the distortions and complexities that arise from a range of expiring programs. With these changes, the royalty framework should serve the purpose of collecting Albertans' share of value, as owners of the resource, while limiting as much as possible any inefficient behaviour or distortion that arises from the imposition of royalties. For example, the current framework distorts the method and timing of oil and gas drilling by imposing arbitrary depth and time limits for certain royalty programs. The modernized framework removes these distortions and the inefficiencies they cause, thereby increasing the realized value of our resources. A new Drilling and Completion Cost Allowance based in dollars, rather than volume or time, achieves the intended goal of recognizing the costs of producing crude oil, liquids and natural gas.

As owners of the resource, it is imperative that Albertans have a framework that is focused on improving the long-run competitiveness of our basin. By instituting a Drilling and Completion Cost Allowance that better reflects well costs, we focus on the value created rather than ad hoc incentive programs that provide insufficient relief at some times and generous relief in other times, leading to inefficient outcomes and cost inflation pressures. By setting the Drilling Cost Allowance at the average cost of similar wells, matched by their depth and lateral length, we maintain industry's incentive to innovate and reduce costs. Over time, industry and Albertans will benefit in the form of a more competitive basin, with more activity, and higher value captured per well.

What does this mean to industry returns and Albertans' share of value?

The modernized framework is to be calibrated such that the returns for industry and the share of value captured by Albertans match the returns generated under the current regime, taking into account that at very high and very low prices the current incentive programs do not achieve their intended goals of accurately reflecting costs or stimulating development. For example, the existing horizontal well program for oil, which would be expected to reflect drilling costs, provides a lower royalty rate for the first 50,000 barrels at certain drilling depths. At prices of $30, $50 and $100 per barrel this would result in lower royalties on the first $1.5, $2.5 or $5 million, respectively, of revenue – all from the same program and presumably to reflect the same average drilling cost for wells of that kind. The same situation exists where a program is time limited rather than based on a dollar amount. The modernized framework removes this uncertainty for both the developer and the Province and focuses on the average actual cost of that well – regardless of oil prices.

Under the modernized framework, Albertans and industry will benefit from the simplicity and predictability of the framework; the harmonization of royalties across hydrocarbons that removes the risk of producing an unintended product and having their royalty classification abruptly switch; and a framework that encourages more efficient operations at all depths and time paths.

Moreover, and most importantly, the new system is designed to increase the value we receive for our resources over time. As the Drilling and Completion Cost Allowance rewards efficiency and lower costs, companies will be more profitable and Albertans will receive an increased share of that value. Removing the highs and lows of royalty rates also makes the Province's revenues more predictable.

Both Albertans and industry stand to benefit from the modernized framework in its improved calculation of the base value of the resources, which enhances the efficiency, transparency and predictability of the system. The establishment of a Drilling and Completion Cost Allowance, based on an average of comparable wells and calibrated annually, also creates a "beat the average" metric that will leverage and reward the competitive entrepreneurial strength of Alberta's energy industry. We expect this will lead to greater levels of investment as companies recognize the modernized framework offers greater alignment with their costs and greater alignment with the production profiles of today's oil and gas wells.

Implementing and properly calibrating the modernized framework requires exhaustive testing and further detailed work. Our Panel recommends that a calibration team be established to deliver the detailed formulas no later than March 31, 2016.

Full details of the modernized framework can be found in the Recommendations chapter of this report.

Recommendation #3

Enhance royalty processes for the oil sands.

> **Recommendation in Brief:**
> - Retain the current structure and royalty rates for oil sands.
> - Increase the transparency of allowable costs.

The royalty structure for oil sands involves two stages. Initially, a royalty rate of between 1% and 9% is applied on gross revenue until a project achieves 'payout' – the point at which cumulative revenue equals costs. After payout, the project pays a royalty rate ranging from 25% to 40% on its net revenue (i.e., revenue minus costs). By using net revenues as the base, this structure is internationally recognized as approximating an optimal system for natural resources. Our Panel recommends the current structure remain in place.

In terms of royalty rates, the current share of value implemented in 2009 continues to strike a balance between sound returns for Albertans and incentives for industry to invest. In fact, the very substantial oil sands investments made during the past decade, combined with the maturing of these projects to payout (which produce the higher 25-40% royalties), means that Albertans are poised to reap significantly increased returns in the next decade.

The main change our Panel recommends for oil sands relates to the transparency of allowable costs. Through our engagement process we heard loud and clear that many Albertans do not have confidence in the validity of allowable costs. This low level of trust is driven in large part by the lack of transparency in respect of these costs to researchers, analysts and the general public. Our Panel believes that the success of the oil sands royalty structure critically depends on the validity of allowable costs. To this end, our Panel proposes a suite of measures aimed at ensuring allowable costs in the oil sands are transparent, reasonable, up-to-date and valid. Full details can be found in the Recommendations chapter of this report.

Recommendation #4

Seize opportunities to enhance value-added processing.

> **Recommendation in Brief:**
> - Develop a value-added natural gas strategy for Alberta.
> - Examine opportunities to accelerate the development and commercialization of partial upgrading and alternative value-creation technologies for bitumen.

Our Panel recognizes that Alberta's vast deposits of natural gas, coupled with significant energy infrastructure, provide the foundation for a broader use of natural gas in the province. As detailed by Alberta's Climate Leadership Plan, with its lower emissions intensity, natural gas offers an effective bridge from our current reliance on coal power generation to a future with increased reliance on renewables. Further, our abundant resources and infrastructure offer a strong case for expansion of value-added industries that use natural gas as a feedstock, including the conversion of bitumen to lighter products, petrochemicals, fertilizers and consumer products.

Our Panel recommends that Alberta develop a strategy to seize the opportunity presented by our shale gas resources and literally "bring the market to Alberta" by strategically setting the stage for the establishment of more downstream industries here in the province. Over time, we can reduce the longstanding competitive disadvantage that Alberta has faced by being located far from markets. This approach involves a long-term strategic plan that would span a number of decades but would ultimately diversify Alberta's industries with downstream uses for our hydrocarbons, offering more employment and economic stability. Our Panel recommends the Government of Alberta enlist the advice of experts to examine many questions that need to be addressed in determining Alberta's potential in this area.

Partial upgrading of bitumen offers another opportunity unique to Alberta's resources. It removes various proportions of the heaviest fraction of the bitumen barrel, allowing the partially upgraded bitumen to flow in a pipeline with little or no diluent. This, in effect, increases the capacity of export pipelines by as much as 30%. Our Panel recommends that the Government of Alberta, as a significant owner of bitumen through in-kind royalties, provide financial support to accelerate the commercialization of partial upgrading technologies.

IN SUMMARY

Our recommendations, including the implementation of a Modernized Royalty Framework for Alberta, address the new realities that we face in getting value for our oil and gas resources in a highly competitive world. It's a world where a return to higher prices is not a given, because global competitors (in particular the United States) are fighting for our markets. From the research and input we received, it became clear to our Panel that our recommendations had to encourage innovation on many fronts – to reduce costs, to enhance efficiency, to improve environmental performance, and to attract investment to the province.

Given how Albertans' share of value is positioned relative to other energy-producing benchmarks, our Panel concluded that the current share of value Albertans receive from our resources is generally appropriate. Given that, the focus for Albertans should be less on the persistent questions of "are the rates right", and more on what changes need to be made to our royalty framework to position Alberta and our energy industry to address the challenges of a very different environment and outlook for the future. By modernizing the royalty framework, we will simplify how it works, remove distortions and better reflect the value of our resources in the calculation of royalties. We will encourage and support investment, reward innovation and improved performance of the industry, and set the stage for future development of our resources. All of this will enable Albertans, as owners of the resource, to see steady increases in the value we receive from our resources.

Most importantly, our recommendations will ensure Albertans benefit from a strong economic partnership. We have an opportunity for the Province and the energy industry to enter a "new era". Not an antiquated one dominated by rhetoric about royalty increases or royalty concessions, but one borne out of strategy, partnership and trust – where the partners are executing on a shared, mutually beneficial strategy with all the muscle they have.

Alberta's future prosperity will require no less.

- Annette, Dave, Leona and Peter

OUR PANEL'S WORK & APPROACH

IN THIS CHAPTER:

- *Introducing our Panel*
- *An outline of our Panel's process*
- *A description of our Panel's approach*

OUR MANDATE

On August 28, 2015, the Government of Alberta announced the establishment of our Royalty Review Advisory Panel (the "Panel").

Our Panel consisted of the following members:

- Dave Mowat (Chair), President and Chief Executive Officer, ATB Financial
- Leona Hanson, Mayor, Town of Beaverlodge, Alberta, and President, CoAction Consulting Inc.
- Peter Tertzakian, Chief Energy Economist & Managing Director, ARC Financial Corp.
- Annette Trimbee, President and Vice-Chancellor, University of Winnipeg

The membership of our Panel was not designed to have all the answers. Instead, it was formed as a group of individuals who collectively brought an understanding of strategy, economics, community issues and decision making. Our Panel had the capacity to ask tough questions and to listen to diverse viewpoints, and we did both in ample measure.

The work of our Panel was guided by a mandate, a copy of which can be found in Appendix A.

Overall, our mandate was to achieve a common base of understanding to assess whether the royalty framework is designed so that it will benefit Albertans, now and in the future. To do that, it needs to achieve four inter-related objectives:

- Provide optimal returns to Albertans as owners of the resource,
- Continue to encourage industry investment,
- Encourage diversification opportunities such as value-added processing, innovation or other forms of investment in Alberta, and
- Support responsible development of the resource.

Stated more clearly—our work was to ensure Alberta optimizes the value of its resources.

OUR PROCESS

To inform our work and analysis, our Panel engaged a wide range of individuals, stakeholders, organizations and communities. Our process had both a public side and a technical side.

PUBLIC ENGAGEMENT

The public side of our process involved many conversations with thousands of Albertans about their expectations of, and aspirations for, Alberta's royalty framework.

At an early stage, our Panel noted that there was no consensus on the 'mission' for Alberta's royalty framework. When asked, "What is the royalty framework designed to accomplish?", different people told our Panel different things.

Even though we are the resource owners, Albertans do not have a shared understanding or expectation of what our royalty framework is intended to do. Without this, people have quite rightly held very diverse opinions about whether the framework is generating a good deal for Albertans. There has simply been no way for them to know. This has led to multiple reviews of the royalty framework, with each successive review generating skepticism and cynicism.

To address this, our process included a dialogue with Albertans, aimed at establishing a set of guiding principles for Alberta's royalty framework.

With a set of guiding principles in place, Albertans can have a shared understanding of the characteristics the royalty framework is based upon, and what we expect the framework to achieve. We will have criteria against which we can measure performance, enabling us to make predictable, periodic adjustments to the framework. Through principles we will also define what's important to us, putting us in a much better position to tell investors, operators and employees in our energy sector, our fellow Canadians, and the rest of the world, what our province stands for.

Our engagement with Albertans took several forms. Most significant was a robust presence coordinated through our website **www.LetsTalkRoyalties.ca**, that enabled a wide range of Albertans to participate in the process.

Through the website, Albertans were able to read information about our province's energy industry and existing royalty framework. They were also invited to answer stages of questions, including:

- Tell us what you think — or want to understand — about the Alberta royalty framework today.
- What would you like this review to accomplish?
- What characteristics do you consider most important for Alberta's royalty review framework?
- What do you think of the principles that we've compiled so far?
- Tell us which of these principles are most important to you.

At each stage, our Panel reported back to Albertans on the responses we had received, and these formed the basis of the next stage. In this way, we held an iterative and interactive conversation with Albertans about what the guiding principles of Alberta's royalty framework should be. As of December 4, 2015, there were 64,927 individual visitors on our website. Through our website, we received 7,217 submissions.

This engagement was supplemented with several community engagement sessions held in Grande Prairie, Fort McMurray, Edmonton and Calgary. People who attended these sessions had the opportunity to learn about our Panel's process and ask questions of Panel members. They were also able to review the same information and answer the same questions that were on our Panel's website at the time, such that the community sessions served as an 'in-person' version of the website. A total of 550 individuals attended these sessions.

In addition, our Panel held a telephone town hall on October 15, 2015. This gave people the opportunity to listen to information about our Panel's work and process, and participate in a question-and-answer session. A total of 22,710 individuals from across the province participated via telephone.

Our Panel also held many meetings with individuals and communities, and organizations in the public, private and nonprofit sectors. These included meetings with individuals who came from a variety of backgrounds including:

- Community groups
- Municipalities
- First Nations
- Métis
- Youth (student engagement)
- Upstream producers of oil, gas and oil sands
- Other businesses and industry associations
- Labour organizations
- Environmental non-governmental organizations
- Post-secondary institutions
- Chambers of Commerce
- Academics, researchers and think tanks
- The Alberta Energy Regulator (AER)
- The Climate Change Advisory Panel
- The Office of the Auditor General
- The Alberta Petroleum and Marketing Commission
- Financial institutions
- Other businesses and industries in sectors peripheral to energy

Attendees at these meetings were briefed about our Panel's mandate and process, and were also invited to share their views and perspectives about the principles that should guide Alberta's royalty framework.

TECHNICAL REVIEW

The other side of our process involved a technical review, aimed at examining specific and detailed mechanics of the royalty framework.

Three Expert Groups were established, one for each major "stream" of Alberta's energy business – crude oil and liquids, natural gas and oil sands. Each Expert Group was comprised of a spectrum of individuals bringing perspectives from upstream oil and gas producers, the financial sector, academics and researchers, First Nations and Métis, and various non-governmental organizations. A list of the members of each Expert Group can be found in Appendix B.

Each Expert Group helped our Panel understand specific strengths and challenges of the existing royalty framework, relative to Alberta's position in the changing global energy landscape. The groups assisted our Panel in determining how the framework could be optimized to achieve the four inter-related objectives identified in our Panel's mandate.

To support the technical analysis, our Panel engaged the services of energy data analytics firms Wood Mackenzie and GLJ Petroleum Consultants. These firms researched and provided technical, financial and economic data regarding Alberta's resource opportunities and the resource opportunities of other jurisdictions. To enable Albertans to have confidence in the information used for the review, the data was certified by Mr. Blake Shaffer with the University of Calgary.

OUR APPROACH

As we learned about the current energy landscape, it became clear that our review needed to be about more than just mathematical royalty rates.

Major changes have occurred in the energy business since Alberta's royalty framework was last reviewed. Some of the recent changes have been highly disruptive to business models and to Alberta's energy markets. For this reason, we approached our work through several lenses.

Previous examinations of the royalty framework have mostly been confined to 'traditional' reviews. In such reviews, a reputable energy analytics firm is hired to examine how Alberta's royalty rates compare with rates in other jurisdictions. This analysis helps the province determine what royalty rates it should establish in the context of global competition.

Our Panel undertook such a review, engaging Wood Mackenzie, a reputable energy analytics firm, to examine how Alberta's royalty rates compared with those in several other jurisdictions. Our Panel also retained GLJ Petroleum Consultants, a well-regarded Alberta-based reservoir engineering and research firm, to complement Wood Mackenzie with local knowledge.

To this traditional review we overlaid three additional lenses.

One was a "competitive" overlay, which examined how well companies in Alberta's energy sector can attract investment, generate returns, and compete for markets. This was important because in order for Alberta to collect royalties, our energy sector must be capable of producing and selling our resources competitively. That requires investment capital, customers, and the prospect of being profitable.

We also looked at royalties from an economic standpoint. The structure of Alberta's royalty framework impacts how much energy activity happens on the ground which, in turn, has impacts on employment, income levels, and the sustainability of rural communities. For example, in fiscal year 2014-2015, the Government of Alberta collected approximately $8.3 billion in royalty revenues;[1] the industry generated those royalties through about $65 billion in economic activity.[2] Our Panel therefore considered how adjustments to the royalty framework might expand the overall amount of economic activity, helping generate broader benefits for families across Alberta.

Finally, our Panel applied a strategic lens, examining Alberta's opportunities and challenges in respect of energy. Through this lens, we considered how the royalty framework could act as a lever to support a number of strategic directions that our province wishes to pursue, such as innovation, competition and generating more jobs, income and value out of our crude oil and liquids, natural gas and oil sands resources. As a starting point, it's helpful to outline some background information about energy development and royalties in Alberta.

[1] Alberta Energy.

[2] Statistics Canada.

SOME STARTING POINTS

IN THIS CHAPTER:

- *Background about Alberta's royalty framework*
- *The importance of partnership in developing our resources*
- *What goes into producing our resources*

ABOUT ALBERTA'S ROYALTY FRAMEWORK

Key Points In This Section:

- Royalties are about Albertans collecting the value from our resources when they are produced and sold. The price we receive for our resources and the costs involved in producing and selling those resources affect the amount of value available for royalties and it varies over time.
- Developing Alberta's resources requires partnership between the Province and energy companies.
- Annual royalty revenues have evolved over time, as have the proportions of royalties coming from each of Alberta's energy products.
- Due to market forces, Alberta's total royalty revenues in fiscal year 2015/16 are projected to fall to approximately $2.8 billion – a decrease of 67% from 2014/15. The price we receive for our resources, and the costs involved in producing and selling those resources, affect the amount of value available for royalties.

ROYALTIES SERVE A PARTICULAR PURPOSE

Royalties serve a unique and particular purpose. Put simply, royalties are payments made to Albertans for hydrocarbons that are produced and sold from the province's resources. Royalties are very different from taxes.

Taxes are set by the government based on how much revenue it wants to raise to pay for expenditures such as health, education, and other public services. Taxes can be imposed on almost anyone or anything, and at almost any level, depending on how much money the government needs.

Royalties, on the other hand, are rooted in ownership. They are about Albertans, as owners, collecting value from our resources. **There is only a certain amount of value available to share between owners and developers. The value available to be shared can be calculated as: the price received for the resources, minus the costs to produce and sell them. That means, as Albertans, in addition to setting royalty rates correctly, we have a vested interest in things that affect both the prices received for our resources and the costs to produce them.**

DEVELOPING OUR RESOURCES REQUIRES PARTNERSHIP

A spirit of partnership between the Province of Alberta and energy companies is essential for success in developing our hydrocarbon resources.

Albertans (that is, all 4.2 million of us) own the oil, natural gas and oil sands resources that lie under approximately 81 percent of the province's land area. The Government of Alberta acts as our agent in managing those resources and collecting royalties for us.

However, the government does not develop Alberta's resources all on its own. The province engages energy companies as partners to find, develop, produce and sell the resources on our behalf.

As a partner, the Province brings many things to the table, including:

- Resources – We own them and make the choice to see them developed.
- Rule of law – Our province is a safe and stable place that has a functioning democracy, independent courts, a trustworthy justice system and the rule of law. When you look at the whole world, it's clear that this is a substantial benefit we bring.
- Infrastructure – We have well-developed transportation and utility infrastructure, which facilitates access to and the production of the resources.

- Regulatory processes – Our province has regulatory frameworks in place regarding the safe and responsible development of energy resources.
- Social fabric – With social systems such as health care, education, and community agencies, our province offers an excellent quality of life.
- Educated and skilled labour force – Our population is well-educated and skilled, and we have a labour pool with many professional, technical and other trained workers.

When we talk about companies directly involved in the energy sector, it's much broader than the downtown office towers of Calgary. It includes a wide array of businesses, big and small, in urban and rural areas across the province. For example:

- Geophysical and seismic firms
- Engineering and construction firms
- Oilfield service companies
- Surveyors
- Trucking companies
- Environmental service firms
- Fabrication shops
- Pipeline companies

As partners, energy companies also bring several things to the table:

- Expertise and execution – Since it is the focus of their businesses, energy companies have the experience, equipment and know-how to explore for, extract, process, transport and sell the resources that are trapped in the geological formations beneath our feet.
- Capital investment – Energy development requires billions of dollars in investment capital which, as a small jurisdiction, we do not have on our own. On the basis of their experience, companies have the ability to attract investors to bring capital into the province for use in developing our resources.
- Skills – Many aspects of resource extraction involve special skills, often in combination with highly sophisticated technology; the energy companies bring these skill sets.
- Customers – Importantly, we need customers to buy our resources. Companies take on the job of developing, marketing and selling to customers.

In short, our Province has the resources, the people and the communities. Energy companies have the money, the ability, and the business expertise to get those resources out of the ground and sell them. We come together to form partnerships, in which both sides need each other.

These partnerships have enabled Alberta to become a major energy producer. As of 2014, we were the eighth-largest producer of oil in the world, the eighth-largest producer of natural gas in the world, and the ninth-largest exporter of crude oil. These accomplishments are impressive, especially when you consider that we are a province of only 4.2 million people spread out over a vast area.

One thing is certain. Given how the global energy landscape is changing, things are going to become more challenging and our partnerships will be tested. Here are some tough facts:

- **Alberta's biggest customer is now our biggest competitor** — Over the past seven years, there has been a renaissance in oil and gas production in the U.S., and the dynamics have completely shifted. The U.S. is now producing huge volumes of oil and natural gas at lower costs from areas that are geographically much closer to the biggest markets. This is placing downward pressure on the prices we receive for our resources and it is backing our oil and gas products out of their traditional markets. The country that was once Alberta's biggest customer now competes with us head-to-head for energy investment and market share.

- **Innovation is essential** — The biggest disruptions in the energy business during the past seven years have been driven by technological innovations, a trend that will continue. To survive, Alberta's oil and gas producers will need to continuously strive to lower costs, improve productivity and be leaders in environmentally responsible development. Encouraging innovation will be essential.

- **Oil and gas are no longer scarce resources** — For the past 15 years, conventional wisdom was that oil and gas were scarce commodities that were quickly dwindling. In this context, Alberta's abundant oil sands resources appeared to be a remarkable outlier. The same technology disruptions that have brought about a renaissance in oil and gas production in the U.S. can be applied around the world. Alberta is now only one of many places where significant volumes of oil and gas can be produced.

- **Patterns in oil and gas demand are shifting** – While demand for oil and gas products remains relatively strong, the long term pattern appears to be shifting. As our capacity grows in renewable sources of energy, and as those sources become more economical, global demand for oil and gas is likely to moderate over the next several decades, and then ultimately enter a period of decline.

For Alberta to continue to have success in the future, the partnerships we build with energy companies must be more aligned, more productive and mutually beneficial than ever before. A sustainable stream of royalty revenue in an increasingly competitive world requires mutual trust and alignment of interests.

"A sustainable stream of royalty revenue in an increasingly competitive world requires mutual trust and alignment of interests."

ALBERTA'S ROYALTY REVENUES HAVE EVOLVED WITH THE MARKETPLACE

The Government of Alberta has been collecting royalty revenues since 1931. Annual royalty revenues first exceeded $1 billion in the mid-1970s.

As seen in Figure 1, annual royalty revenues have evolved over time, as have the proportions of royalties coming from each of Alberta's energy products.

Today, the majority of Alberta's royalty revenues come from oil sands production (i.e., bitumen). In fiscal year 2014/15, the Government of Alberta collected approximately $8.3 billion in royalty revenues; $5.1 billion of this came from oil sands production. Royalties from oil sands are expected to remain the largest proportion of total royalties for the foreseeable future. However, it is projected that Alberta's total royalty revenues in fiscal year 2015/16 will fall to approximately $2.8 billion – a decrease of 67% year-over-year.

TOTAL ROYALTY REVENUE BY PRODUCT STREAM
Annual Payments to the Province, Fiscal Year End March 31st

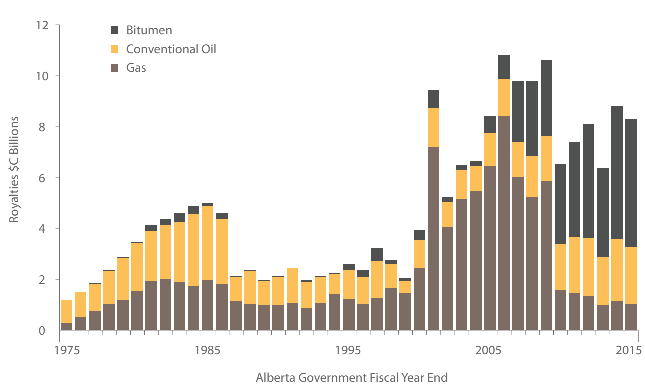


Figure 1

Source: Alberta Department of Energy

This is due to the fact that Alberta's royalty revenues are fundamentally tied to the marketplace. During periods of strong commodity prices, oil and gas production has also tended to be strong and Alberta has collected larger royalty revenues. During periods

SOME STARTING POINTS

of weak commodity prices, when oil and gas production has also tended to decrease, Alberta has collected much smaller amounts in royalty revenues. (A more detailed discussion regarding Alberta's royalty revenues over time is provided in Appendix C.).

Mid 1970s – 1985: Annual royalty revenues steadily climb due to growing production and strong commodity prices.
1986: Oil prices collapse, contributing to a drop in annual royalties from $5 billion to $2 billion.
Mid-1980s – Late 1990s: Annual royalties are generally stable. Conventional oil and gas basins mature during this time.
Early to late 2000s: Strong commodity prices lift annual royalties, reaching approximately $10 billion in 2006 - 2010.
2008 – 2010: U.S. shale gas production causes a 51% decrease in Canadian natural gas prices and a decrease in Alberta gas production.
2010 – 2015: Oil prices recover from global financial crisis, and oil sands production increases, lifting annual royalties to $6-$8 billion.
2015-2016: Falling oil prices result in a projected 67% decrease in annual royalties from fiscal years 2014/15 to 2015/16.

ALBERTA'S ROYALTY FRAMEWORK IS COMPLEX

Many lessons about Alberta's energy business have been learned over many decades, and these have helped shape how the royalty framework looks today. Alberta's royalty framework is complicated for a number of reasons.

First, Alberta is endowed with the full spectrum of hydrocarbon resources, including: natural gas, light oil, medium oil, heavy oil, and bitumen in our oil sands. This diversity of resources is an incredible asset, but it makes the construction of Alberta's royalty framework much more challenging. Extraction of each hydrocarbon product involves tapping into unique geology with specialized technologies and processes. Each product has unique costs, markets and transportation dynamics, and receives different prices. All of this uniqueness means that the royalty structures for each product are difficult to accommodate with one regime.

Second, under the current framework, the royalty rates for each oil and gas well change each month. Those rates are based on at least two other variables: the amount of oil or gas produced, and the price of the resource. In the case of crude oil and natural gas wells, an additional variable, the depth of the well, also influences the royalty rates that are payable. That's because the depth of a well is a key variable in determining a well's cost.

This reflects our province's geology and diversity of hydrocarbon products. It also reflects the reality that each oil and gas well and each oil sands project has different characteristics and scales of development. This makes our royalty framework flexible, but it also makes things complicated.

It also makes it impossible to answer the simple question, "Should royalty rates go up or down?"

The graphic representation in Figure 2 shows that the royalty rate of a natural gas well under today's structure can be at any point on a three-dimensional surface.

NATURAL GAS ROYALTY FUNCTION

Which Way Should the Royalties Go?

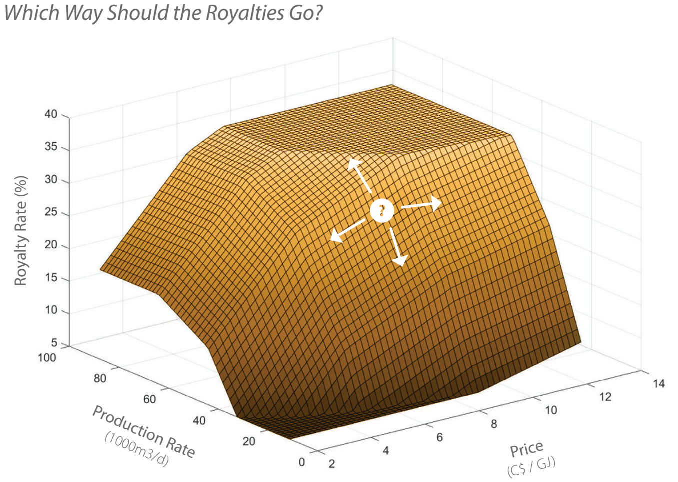


Figure 2

Source: Alberta Department of Energy

[1] Royalty function post termination of the drilling incentives; 4,000 meter horizontal well

Under this sort of system, where we are looking at many dimensions, the more appropriate question is, "How can we make sure the royalty framework is optimized and collects the appropriate amount of value across all dimensions?"

THE VALUE OF OUR RESOURCES IS BASED ON PRICE AND COST

To determine the value of our province's resources (and hence, what is available to share through royalties), we need to look at what goes into producing them. Put another way, we need to consider how we "divvy up the barrel".

A barrel of oil (or a cubic foot of natural gas) is sold in the marketplace, and a certain amount of revenue is generated from its sale. That finite revenue is divvied up amongst a number of slices:

DIVIDING UP THE BARREL

Value Components as a Fraction of Revenue

Note: *Fractions are not shown to actual scale*

- **Company's capital investment –** This is the initial investment made by an energy company to explore for oil and gas resources, purchase leases for those resources, and develop the infrastructure (an oil or gas well, or an oil sands project) to produce those resources. This includes upfront investment into things like:
  - Exploration costs
  - Land bonuses paid to acquire land rights from the Province
  - Engineering costs
  - Drilling, completion and tie-in costs of a well
  - Building costs for pipes and facilities
  - Labour costs
- **Operating costs of production –** Once a well or project is producing oil or gas, there are costs to keep it running. This includes things such as:
  - Utility costs, such as power and heat
  - Labour costs involved in operating the well or project
  - Processing costs to bring the raw oil or gas to a suitable condition for sale
  - Monitoring, reporting and administrative costs
  - Charges such as carbon levies
- **Provincial, federal and municipal taxes –** Provincial corporate income taxes, federal corporate income taxes, and various municipal taxes and local charges are assessed and collected. For example, Alberta's general corporate tax rate is 12 percent; the federal government assesses a general corporate tax rate of 15 percent. Municipal taxes vary throughout the province and are part of the operating costs above.

- **Other rents and fees –** Certain other fees are payable. The most common are surface access fees, which are payable to private landowners who own the surface land above the resources that are being produced. Access fees can also be payable to Métis Settlements or the Crown. Regulatory fees are also payable, such as fees assessed by the AER (which is entirely paid for by industry) and the National Energy Board.

- **Company's expected return on investment –** Another key slice of the barrel is the energy company's expected return on investment. When a company raises capital to invest in developing Alberta's energy resources, those investors base their decision on the prospect of earning a return on their investment. This is by no means certain. Not every well or project successfully recovers oil or gas; some are failures. Companies also face the prospect of volatile oil and gas prices, and their ability to turn a profit depends on their ability to control costs and manage through boom and bust cycles.

- **Royalties –** Payments are made to the resource owners, in this case Albertans, for hydrocarbons that are produced and sold from their jurisdiction.

As can be seen from the barrel diagram, there are a significant number of costs that go into extracting the resource from the ground and bringing it to market. These costs, and the revenue received from the sale of the resources at market prices, all impact the available value left to share.

Thus, **price** and **cost** are two key dimensions in the overall analysis of royalties. We examine these in greater detail in the next chapter. (See "How Prices Influence Royalties" and "How Costs Influence Royalties").

Another critical dimension is our province's ability to attract **investment**, a key slice of the barrel. Ongoing investment in our energy sector is essential for producing our crude oil and liquids, natural gas and oil sands resources. Without it, we won't produce resources for very long, our production will decline, and if we aren't producing resources we can't collect any royalties on them.

Our ability to attract investment is also important because the upstream energy industry accounts for 23% of Alberta's Gross Domestic Product.[3] Investments in energy development percolate throughout the broader economy, generating employment, income and opportunities for Alberta families and businesses, and generating taxes and fees for federal, provincial and municipal governments. We examine investment attractiveness in greater detail in the next chapter (see "Investment, Returns and Royalties").

[3] Alberta Treasury Board and Finance.

SETTING THE CONTEXT

IN THIS CHAPTER:

- *How resource prices influence royalties*
- *How costs of resource production influence royalties*
- *The relationship of investment, returns and royalties and how Alberta stacks up to other jurisdictions*

This chapter discusses how the prices we receive for our resources, and how the costs of producing and selling our resources, all influence royalties. This chapter also discusses the relationship between investment, returns and royalties.

HOW PRICES INFLUENCE ROYALTIES

When examining how to optimize the royalty framework, the prices received for our oil, natural gas and oil sands resources are a paramount consideration. This is because the prices we receive for our resources affect the value we can collect through royalties.

Maximizing the prices of our resources is to our province's benefit because, all other things being equal, this helps increase the royalties we receive.

There have been disruptive changes in the energy business during the past seven years. These changes have impacted the prices of Alberta's resources.

Key Points In This Section:

- Royalties to the Province move up and down with commodity prices.
- In the past seven years, new technologies have liberated large quantities of oil and natural gas in North America, crushing Alberta's commodity prices and royalty revenue.
- The United States used to be Canada's biggest customer; now it has become its biggest competitor for oil, natural gas, and investment capital.
- Alberta's natural gas prices fell in 2010. Oil prices came under siege in 2015. Higher commodity prices for sustained periods cannot be assumed.
- Higher-quality Alberta oil and gas prospects can compete at lower prices, but gaining greater access to high-value markets would help increase royalty revenue.

NATURAL GAS TOOK THE FIRST HIT

Just ten short years ago, royalties from natural gas represented the majority of Alberta's total royalty revenues and peaked at over $8 billion. Natural gas prices were strong and Alberta was a prime supplier to many natural gas markets in North America. In addition to serving the U.S. West Coast and U.S. Midwest regions, Alberta exported its natural gas as far away as central Canada and the U.S. East Coast.

Then, beginning in 2006, things started to change.

New advances in technology made it possible for energy producers to unlock large deposits of natural gas from shale rock formations in the U.S. These formations were known about for a long time, but had long been considered uneconomic to develop. With the advent of horizontal drilling and multi-stage hydraulic fracturing, these formations became viable, and states like Texas and Pennsylvania underwent a resurgence in natural gas production.

As seen in Figure 3, the impact of shale gas has been astounding.

US NATURAL GAS PRODUCTION HISTORY

By Source

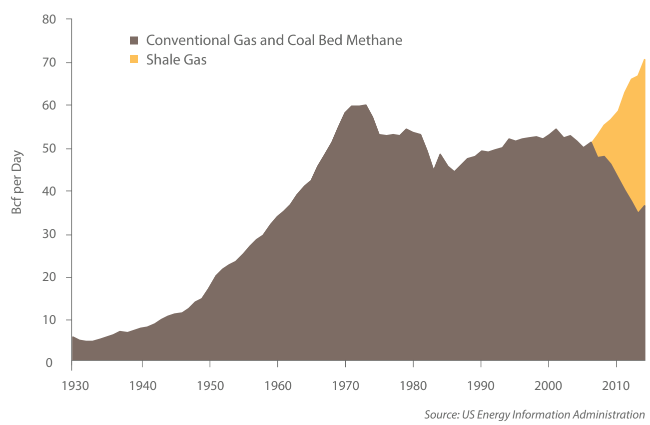


Figure 3. U.S. shale gas production is already almost four times larger than Alberta's entire gas production.

NORTH AMERICAN BENCHMARK NATURAL GAS PRICES
Henry Hub at Louisiana

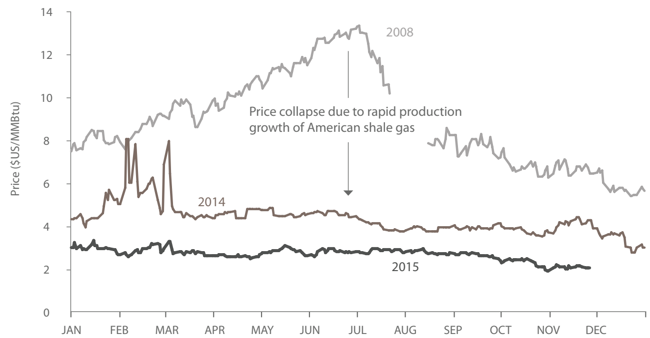


Figure 4 *Source: Bloomberg*

In seven short years, the U.S. has expanded its shale gas production to a volume that is nearly four times larger than Alberta's entire gas production. In 2014, average U.S. shale gas production was over 37 billion cubic feet (Bcf) per day. By comparison, Alberta's average gas production was approximately 10 Bcf per day.

The shale gas revolution has boosted total natural gas production in the U.S. to new highs, and flooded the North American continent with natural gas. Not surprisingly, this has dramatically impacted natural gas prices (as shown in Figure 4), which collapsed towards the end of 2008 and have remained low for many years since.

This has led to compounding challenges for Alberta.

First, U.S. shale gas supplies have increasingly eaten away at Alberta's traditional natural gas markets. Major sources of U.S. shale gas are geographically much closer than Alberta is to large U.S. gas markets. For instance, the Marcellus shale formation is located in Pennsylvania – practically on the doorstep of markets in the northeastern states, and a stone's throw away from central Canada. Marcellus shale gas is very attractive to these markets, because it does not cost much to transport the gas from its source to customers.

Consequently, Alberta's natural gas has gradually been "backed out" of markets in the U.S. East Coast, and may be facing a similar fate in central Canadian markets over the coming years.

Second, since Alberta is geographically distant from major gas-consuming markets, it costs more to transport the gas to customers and producers are reliant on a duopoly of federally-regulated pipeline companies. Natural gas producers must pay tolls to use the pipelines that carry gas throughout the continent; in general, the farther the gas must travel, the higher the toll. This means that Alberta's natural gas is priced at a further discount to already-low continental gas prices.

Third, due to the combined effects of low prices, high transportation costs, the onslaught of U.S. shale gas production, and the maturity of Alberta's conventional gas fields, our province's total gas production has contracted. Between 2007 and 2014, Alberta's total gas production fell by approximately 25 percent, as shown in Figure 5.

ALBERTA MARKETED NATURAL GAS PRODUCTION
Yearly

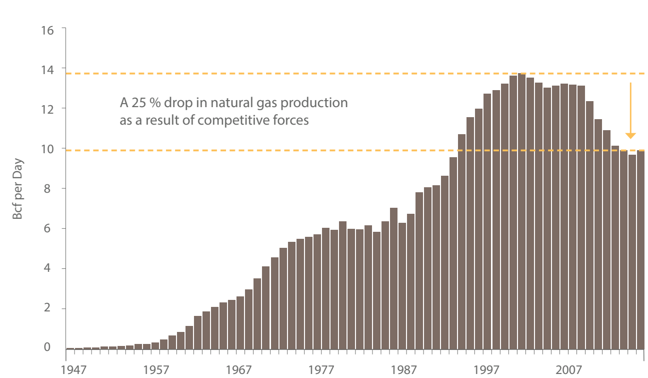


Figure 5 *Source: Canadian Association of Petroleum Producers*

Put it all together and Alberta's natural gas royalties have now slipped to less than a billion dollars a year – levels we haven't experienced since the early 1990s.

Nevertheless, there is some encouraging news. The same technologies that have unlocked U.S. shale gas are stimulating production growth from plays in the northwest part of the province. In high-quality plays like the Montney, Alberta's natural gas can compete continentally – but only if that gas can get to continental markets at competitive transportation costs. In this regard, our Panel recognized the relationship of market access to royalty revenue, which is not an issue that is exclusive to oil pipelines.

Prices for natural gas are not expected to recover to the $10 per gigajoule (GJ) level seen in 2008, and probably not even to the mid-$3.00/GJ range anytime soon. Our Panel believes that Alberta's royalties from natural gas can be increased from current levels, but only if our better quality plays can attract investment, our production volumes can recover, and our new supplies can make it to market more economically.

CRUDE OIL MARKETS TOOK THE NEXT HIT

Similar to natural gas, Alberta's crude oil production is now competing directly with new supplies of light crude oil from U.S. unconventional oil deposits.

NORTH DAKOTA OIL PRODUCTION

The Unconventional Oil Revolution Began in 2008

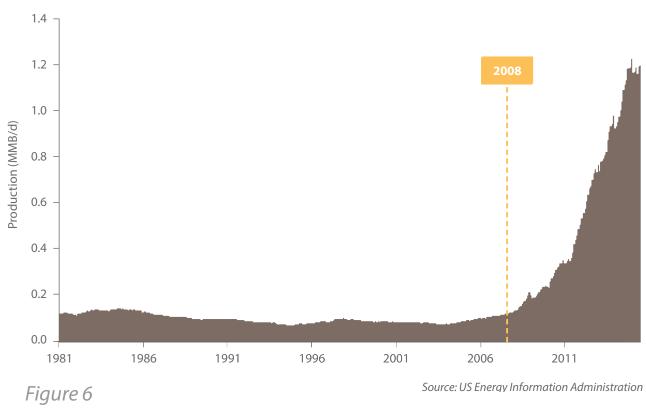


Figure 6

The same technologies that enabled producers to unlock U.S. shale gas have been successfully applied to liberate significant volumes of oil in a short period of time. North Dakota (Figure 6) and Texas (Figure 7) have emerged as particularly large sources of unconventional "tight" oil.

The chart in Figure 7 helps put things in perspective. The equivalent of Alberta's total oil production, 2.9 million barrels per day (bpd) – the result of many decades of hard work and gradual expansion in our province – was almost achieved by Texas' unconventional oil production in just four short years.

TEXAS OIL PRODUCTION

Texas Followed North Dakota Three Years Later

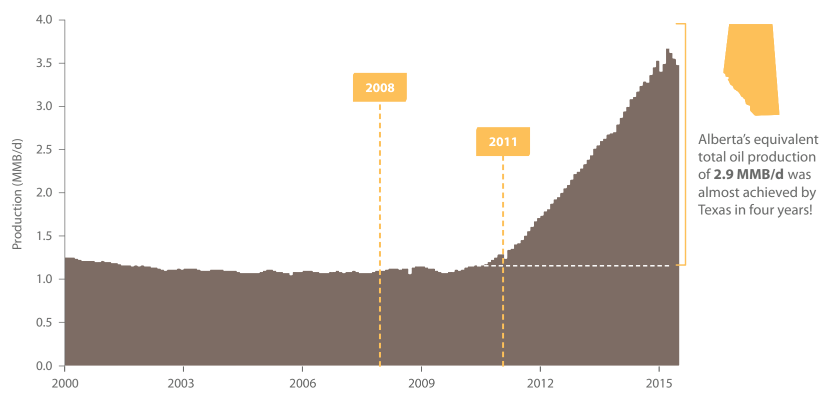


Figure 7

It goes without saying that, like shale gas, the U.S. unconventional oil revolution has shifted the dynamics of energy markets in North America.

As Figure 8 shows, since 2008, total oil production in the U.S. has increased to levels not seen since the mid-1970s. In 2014, U.S. oil production averaged 8.7 million bpd.

But change has come not only to the supply side of North American oil. Over the same time frame, since North Dakota began adding to oil supplies in 2008, total oil consumption in the U.S. has fallen and stopped growing, reversing a decades-long trend. Governments have also been taking active steps to reduce demand for fossil fuels.

Together, these changes in U.S. supply-demand trends have enabled the U.S. to markedly reduce the amount of light crude oil that it needs to import. Some analysts suggest that if trends

US OIL SUPPLY AND DEMAND TRENDS

With North Dakota and Texas Unconventional Oil Growth Markers

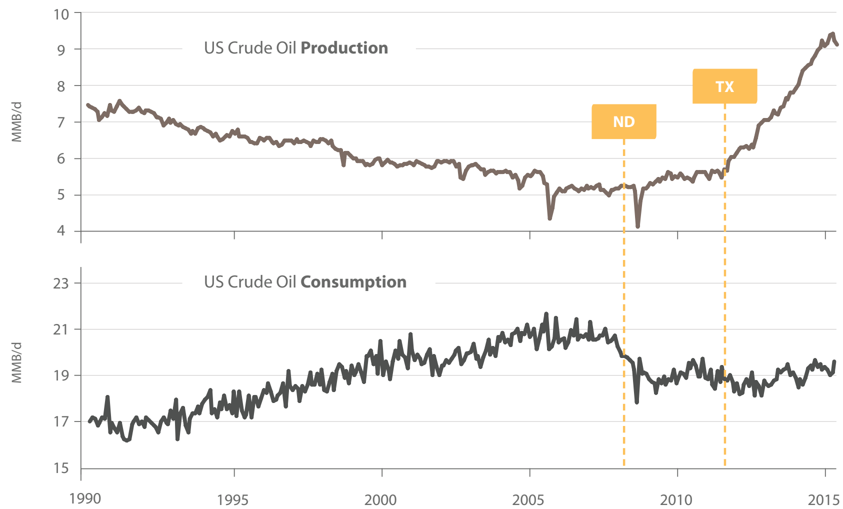


Figure 8 *Source: US Energy Information Administration*

As U.S. oil production has increased, total U.S. oil consumption has fallen and stopped growing.

continue, there is reason to believe the U.S. could achieve oil self-sufficiency within the next 10 to 15 years, putting greater competitive pressure on Alberta's industry and its royalty stream.

As with shale gas, U.S. unconventional oil sources are geographically much closer to major U.S. refineries and consumers than Alberta's crude oil supplies, and so have lower transportation costs.

All of this means that Alberta's crude oil supplies and Synthetic Crude Oil (SCO) supplies are competing head-to-head with U.S. unconventional oil for space in oil pipelines and refineries. This has placed downward pressure on the prices that Alberta receives for its crude oil products.

While there has been some easing of oil discounts over the past 18 months, Alberta Energy has estimated that discounts on Alberta's oil prices due to constrained market access have led to the forfeiture of more than $6 billion in royalties since 2010.

> **"Alberta Energy has estimated that discounts on Alberta's oil prices due to constrained market access have led to the forfeiture of more than $6 billion in royalties since 2010."**

Overlaying all of these dynamics is an international tug-of-war that is now underway for global oil market share. As has been reported by many media outlets, Saudi Arabia and other members of Organization of Petroleum Exporting Countries (OPEC) have continued to maintain strong production in an effort to push down global oil prices and challenge U.S. unconventional oil producers (and Alberta's oil producers too) for market share. Whether this approach will prove successful remains to be seen, and for how long OPEC will continue this approach is unknown. Nevertheless, consensus is that future periods of high prices are unlikely to be sustained for either oil or natural gas.

Even if global oil prices re-strengthen due to OPEC abandoning its approach, or due to other global factors, the fact will remain that the world has capacity in place to produce more oil and gas than the world should use, especially as countries around the globe seek to address climate change and move to a low-carbon future. Add to that, Alberta now has a big, determined competitor in our backyard. Refineries in the U.S. (and in Canada) now have greater choice in sourcing oil for their operations, and this will have price implications – and therefore royalty revenue implications – for Alberta for some time to come.

BITUMEN MARKETS ARE PROVING RESILIENT, BUT FACE CHALLENGES

While we are facing a competitive onslaught from U.S. oil and gas production, our oil sands industry is providing us with some economic shelter.

Alberta stands apart from the U.S. in our production of bitumen. This product differentiation is helping us maintain market share in both U.S. and Canadian refineries – for the time being.

Over the past decade, a number of refineries in Canada and the U.S. modified their operations to accept bitumen as a feedstock. (As a very heavy oil, bitumen requires additional processing, compared to light oil.) Many refineries undertook these modifications before the U.S. unconventional oil revolution, at a time when Alberta's oil sands appeared to be a lone source of ample, reliable and economic oil supplies. The modifications were neither cheap nor easy and, as a result, these refineries are now structurally committed to accepting Alberta's bitumen.

This is enabling Alberta to somewhat withstand the competitive pressures caused by U.S. unconventional oil. Although the U.S. has been able to dramatically reduce its total oil imports from around the world, U.S. oil imports from Canada have gradually increased. Much of this is attributable to U.S. refineries being reconfigured for Alberta bitumen.

NORTH AMERICAN BENCHMARK CRUDE OIL PRICES
West Texas Intermediate at Cushing, OK

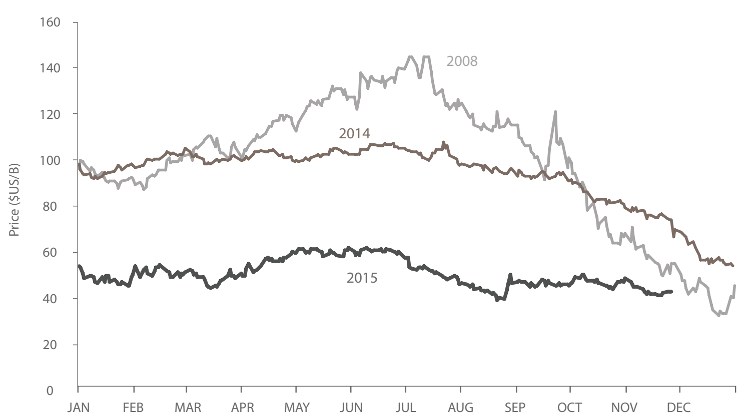


Figure 9
Oil prices markedly fell between 2014 and 2015.

Interestingly, this is an instance where the choice to export our product as a raw commodity (non-upgraded bitumen) rather than simple upgrading has, in hindsight, turned out to be somewhat of a benefit. While we upgrade close to 50% of our bitumen production to SCO, had Alberta upgraded all of our bitumen within our province, we would today produce only SCO, which directly competes with U.S. unconventional oil. In that case, Alberta's oil exports to the U.S. could very well be falling and, unlike many other places, we would not have the capability to ship it anywhere else.

While our bitumen markets are proving resilient in the short term, there is risk in the medium and long term. As huge supplies of U.S. unconventional oil have come online, they have appeared increasingly attractive to refineries. In the eyes of refiners, U.S. unconventional oil supplies are abundant, geographically close, have much better pipeline access, and are not perceived environmentally the same way as oil sands.

Over time, as refineries examine ways of expanding or improving the efficiency of their operations, there are many reasons to believe that they will lean more heavily towards U.S. unconventional oil and away from Alberta bitumen. Even refineries that modified their operations to accept Alberta bitumen may decide it is economically advantageous to again modify their operations to use more U.S. unconventional oil instead.

For now, a factor that makes bitumen particularly attractive to refineries is its low price. As a heavier oil which is more difficult to process, bitumen is not as highly valued by the marketplace as lighter oils. Consequently, bitumen is priced at a discount to light oils such as West Texas Intermediate (WTI), the North American benchmark. Coming from oil sands areas in northern Alberta, bitumen must also be transported farther than oil from other sources. It is therefore priced at a further discount to reflect transportation costs.

As a result, there is less value available for royalties on bitumen than widely-quoted oil prices suggest. It would likely surprise many Albertans to learn that oil sands royalties are not calculated on the basis of WTI, but on the basis of prices that can be $15 to $25 per barrel lower than WTI.

SOME IMPORTANT TAKEAWAYS

All of the above leads to some key points that merit consideration when examining how to optimize Alberta's royalty framework:

- **We cannot continue to operate with a perspective that the world needs to come to Alberta if it wants oil and gas**. Advances in technology have unlocked significant new sources of oil and gas supplies, particularly from unconventional deposits in the United States. The U.S. is now a rejuvenated force in oil and gas production, one that poses huge risks to Alberta's market share. This is problematic, since we have long relied on the U.S. as our primary (and to some extent, only) customer, and we do not have sufficient means to move and sell our oil and gas to other countries.
- Global forces, the competitive pressures of the U.S. shale revolution, and limited market access have placed significant downward pressures on the prices Alberta can receive for our natural gas, crude oil and oil sands resources. **This impacts the amount of value that Albertans, as owners, can collect through royalties.** Many of these challenges are structural rather than cyclical, and so we should expect the price pressures to exist for quite some time.

These difficult realities, however, can create opportunities for our province.

- Low prices give producers a powerful incentive to be innovative. Quite simply, our province will need to produce our resources more competitively, or we will continue to lose market share. In order to compete, producers will need to use innovative technologies and processes to improve efficiencies and lower costs. **Our public policies, including our royalty framework, need to consider the competitive positioning of other jurisdictions, at all price points.**
- Low prices give us a powerful incentive to expand our markets. With some exceptions, our country is largely structured to sell and ship our resources to one customer: the United States. **As the U.S. achieves greater self-sufficiency in oil and gas, the need to identify, sell and ship to more and different customers will grow increasingly urgent.** This is not just an Alberta challenge. It is a national challenge, and must be taken up as such.
- **Low prices may be a powerful attraction for "value-adding."** Going beyond simple upgrading, refineries and petrochemical plants use oil and natural gas as feedstocks. These feedstocks represent a very high portion of the overall costs of the facilities, so refineries and petrochemical plants are attracted to places with abundant, cheap supplies of oil and gas. While low prices will limit the amount of value in our resources that can be collected through royalties, our Panel believes they could facilitate an expansion of processing capacity in the province, thereby creating additional jobs and sources of tax revenue for Alberta.

HOW COSTS INFLUENCE ROYALTIES

Costs are as important as prices. That's because the amount of money that is available for royalties is determined by the price we receive for the resources, minus the costs of producing and selling them.

Just as maximizing the price of our resources is to our province's benefit, so too is minimizing the costs of producing and selling those resources. All other things being equal, lower costs translate into more value, greater returns, and sustained levels of investment.

However, since both prices and costs move dynamically, the amount available for royalties varies considerably over time, depending on a wide variety of conditions. Understanding those conditions, and how they have been trending, has been key to our Panel's recommendations.

Key Points In This Section:

- Revenue minus costs determines availability of dollars to share for royalties.
- Costs are influenced over time by price, technology, scale of development and the stage in life or "maturity" of a well.
- Capital costs relate to up-front investment; operating costs are those expenses needed to keep oil and gas flowing.
- Lower costs are a virtue, because they translate into greater profitability and more value available for royalties.
- Costs as a fraction of revenue are dynamic; a successful royalty regime tracks costs and adapts to changes.

THERE ARE TWO TYPES OF COSTS

When we think of costs it all seems the same: money out of our pockets. That's true in any business too. However, there is a distinction between two types of costs: capital and operating.

Capital costs are those large, upfront expenses needed to get the production of oil and gas going. Typically, capital costs involve exploration expenses, drilling wells, buying steel and concrete, and building pipes and facilities. Companies seek to have their upfront investment recouped as soon as possible, so they have the cash to invest in the next well or project. Finally, capital costs can be spent over many months or, for big projects like oil sands, over many years.

Operating costs are those that are associated with the production of the oil and gas, once all the capital equipment and infrastructure is built and the energy products are flowing. Large components of operating costs include energy (e.g., electricity), labour, municipal taxes, monitoring costs and surface access fees.

Our Panel found there are major differences in the trends between capital and operating costs over time, especially as a percentage of revenue – the measure to which royalty rates are applied.

Figure 10 shows the changes in capital and operating costs over time. (Accountants amortize capital costs over time, but for simplicity Figure 10 shows all cash costs – capital and operating – in the year in which they were spent.)

In the 1960s, there was a heavy emphasis on cash investment following the discovery of iconic oil fields like Leduc. As a fraction of revenue, annual capital expenditures were running around 80% of the top line during this period. As the wells started flowing oil and gas, operating costs took up another 20%. In the early 1960s, almost 100% of the value was taken up by costs. This high level of capital expenditures is typical during a period of big investment. A lot of capital is spent on infrastructure, new equipment and trial-and-error learning.

CAPITAL AND OPERATING EXPENDITURES AS A PERCENT OF TOTAL UPSTREAM REVENUE

By Expenditure Type

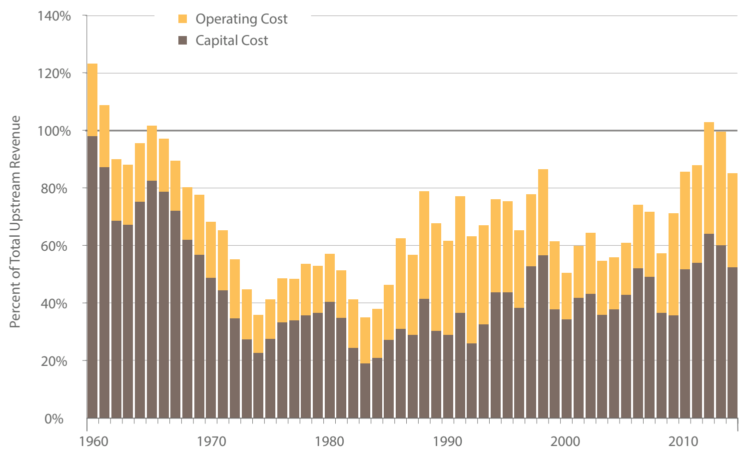


Figure 10

Source: Canadian Association of Petroleum Producers

The period between 1970 and the mid-1980s was characterized by lower capital expenditures and stable operating costs as a percentage of overall revenue. The 1970s oil price shocks contributed to higher top line revenue, and implied good profitability with room for greater royalties. Another factor that contributed to this desirable low-cost period was the relatively ease with which virgin oil and gas fields could be found and the young age of Alberta's production profile.

The late 1980s and 1990s were marked by lower commodity prices, combined with maturing production. Operating costs were routinely 30% to 40% of revenue. Capital investment slowed due to maturity (i.e., lower productivity), low commodity prices and weak potential for returns on capital.

Rapidly rising prices for both oil and gas triggered investment in the early 2000s. This was also the era of accelerating investment into long-lead-time oil sands projects. During this period, both capital costs and operating costs (per unit of oil or gas) rose quickly. However, because prices were also rising, the ratio of cost-to-revenue was dampened for much of last decade.

The past five years has seen costs as a percentage of revenue rise beyond 80%. Close to 100% of a barrel's value was consumed by costs in 2012 and 2013, the first time since 1960. Heavy upfront investment into major oil sands projects was a prime contributor to the capital cost fraction. Operating costs also rose on the back of chronic global and local inflation in services, wages, municipal taxes, regulatory compliance and surface access fees.

"Close to 100% of a barrel's value was consumed by costs in 2012 and 2013, the first time since 1960."

Over the past five years, oil prices were high and natural gas prices were low; the combined effect of all economic factors led to operating costs that were 40% of revenue.

In studying all of the factors that have led to wide variations in historic capital and operating cost trends, our Panel noted that a constant royalty factor on revenue would not be dynamic to change. As in the past, volatile commodity prices, technological change, geologic maturity, and the waxing and waning of investment will continue to alter the amount of value in Alberta's production that's available for sharing.

The changing nature of costs and prices has been a catalyst for ongoing royalty reviews – a process that has created consternation many times in the past. As such, the dynamic nature of those variables inspired our Panel to consider how Alberta's royalty regime could incrementally adapt to year-over-year changes in costs and prices.

AGEING OF OUR CONVENTIONAL OIL AND GAS PUSHES UP OPERATING COSTS

Alberta has been producing oil and gas for over 100 years, but the period during the 1970s was one of the most lucrative. Back then, conventional oil and gas was much easier to find and the prolific nature of virgin reservoirs was such that productivity was high and decline rates were low. Consequently, unit costs of finding, developing and producing oil and gas were low.

In conventional oil and gas production, a primary factor driving higher operating costs is ageing (i.e., the natural decline of production). By the 1990s, Alberta's vintage fields from prior decades were becoming mature, with thousands of wells entering the long tail of productivity where profitability is very thin.

Recognizing the growing issue of geologic maturity, and a desire to recover as much resource as possible from producing fields, in the 1950s the Government of Alberta instituted a sliding royalty scale that decreased royalty rates with ageing wells. This production adjustment function recognized that the dominant costs in late-life wells were fixed operating costs, including surface access fees and municipal taxes. In the absence of lower royalty rates, these late-life wells would have been prematurely abandoned, resulting in the loss of thousands of rural jobs.

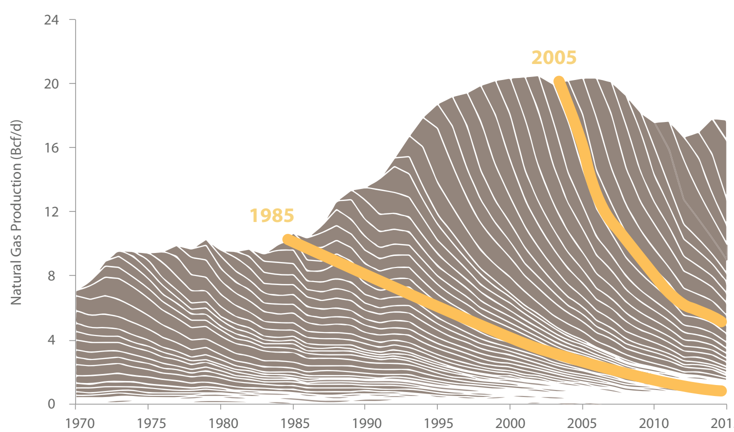
This production adjustment formula has been adjusted many times to progressively adapt to the growing number of ageing wells and fields. Our Panel noted that lower royalties and/or taxes for mature wells are commonplace in other jurisdictions as well.

After 1990, ageing of Alberta's conventional crude oil and natural gas wells began to accelerate. Figure 11 illustrates the vintage production profile of Alberta's conventional natural gas wells from 1970 to today.

Each slice represents a year's worth of production additions. As gas flows out of the ground, each slice of production in the stack declines and becomes thinner over time as the fields mature. The tails of each year's declining output represent the aged production, which is of progressively higher unit cost to extract.

WESTERN CANADIAN NATURAL GAS OUTPUT

Vintage Production by Year



Source: GLJ Petroleum Consultants

Figure 11

Oil and gas wells decline over time, and newer wells are declining faster.

Our Panel noted that new vintages of production began to decline more rapidly in the 1990s as a consequence of overall conventional resource maturity, and even more rapidly after 2005 as a consequence of innovative new drilling and completion processes. Such new techniques are able to tap into lower porosity rocks that were previously uneconomic. However, the amount of upfront capital investment needed to add production to the vintage stacks in Figure 11 has been increasing significantly since 2006.

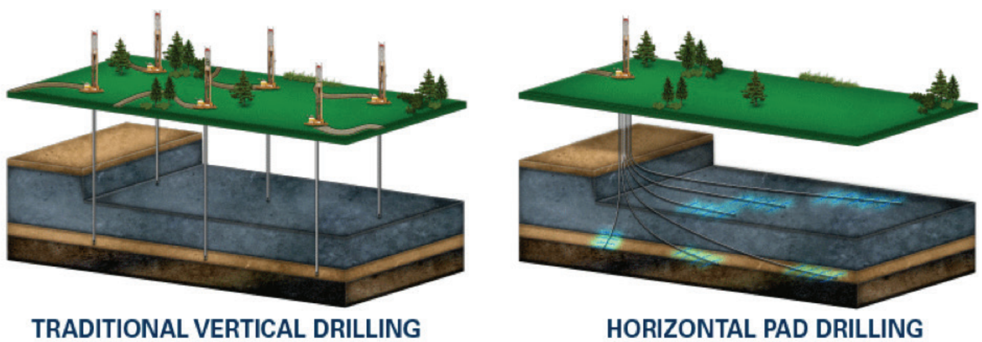
TRANSFORMATIVE PROCESSES IN OIL AND GAS HAVE ALTERED CAPITAL COSTS

For many Albertans, the image of oil and gas production that most readily comes to mind is probably the iconic pump jack set against a vast rural landscape.

Many Albertans also probably understand how conventional crude oil and natural gas is extracted. A drilling rig sets up on a well site, and drills a vertical hole down to a target reservoir where oil or gas is trapped underground. The pressure in the reservoir is greater than the pressure in the well that has been drilled, and so the oil and gas naturally flows out of the reservoir and into the well and is carried up to the surface.

This rather simple description of a vertical well was the standard way of extracting crude oil and natural gas from the ground.

Over the past seven years, technological advances have enabled producers to better target oil and gas reservoirs through greater use of horizontal drilling. Horizontal drilling is exactly as it sounds: producers can drill down and across through a much greater part of an oil and gas reservoir.



Source: Anadarko Petroleum Corporation

Horizontal drilling has several advantages.

Rather than a single entry to the reservoir (as with a vertical well), a horizontal well has the opportunity to create multiple lateral points in a reservoir where oil and gas can enter the well. This means the well can extract more oil and gas at a faster rate.

Horizontal drilling also offers producers more flexibility in where they drill wells. Rather than having to disturb the land directly above every entry into an oil or gas reservoir, a producer can position the well several kilometres away. Figure 12 shows the shift away from vertically drilled to horizontally drilled wells.

MARKET SHARE OF HORIZONTAL WELLS IN WESTERN CANADA

Percent of Total Wells Drilled Horizontally

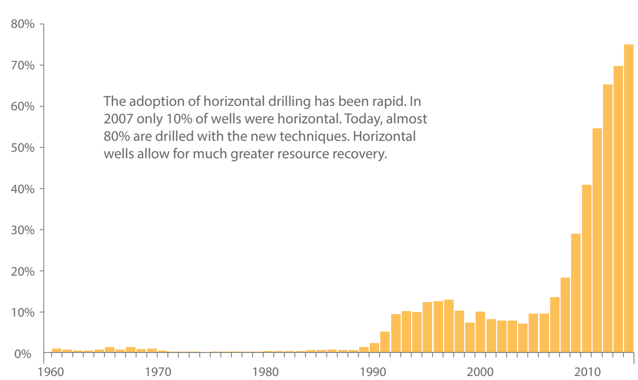


Figure 12

Source: geoSCOUT

SETTING THE CONTEXT

As a fraction of all wells drilled in Alberta, almost 80% today are horizontal – up from 10% less than a decade ago. This rapid shift has happened across North America. The resulting product streams are commonly called unconventional oil and gas.

DRILLING CAPITAL SPENDING PER WELL - ALBERTA

1990 to 2014; Excludes Oil Sands

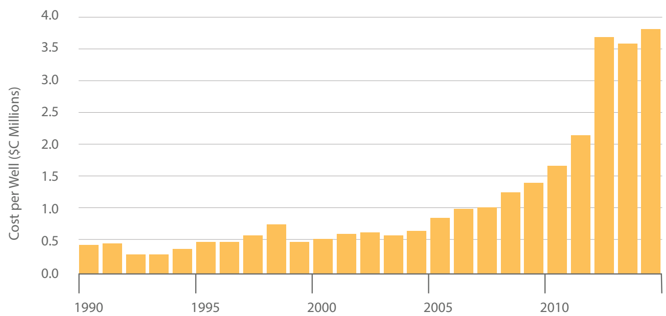


Figure 13

Source: Canadian Association of Petroleum Producers

Horizontal wells are more technically difficult and involve a lot more cost. The transition from vertical to horizontal meant that the average cost per well in Alberta quadrupled within 10 years. Accordingly, the up-front capital investment increased four-fold. Policy changes in the 2010 royalty system acknowledged this change.

In addition, producers can further minimize their land footprints through the use of "pad drilling". In this approach, multiple horizontal wells are drilled from a single site (or pad), branching out in different directions underground, like a giant pattern of bird's feet. Speaking of feet, the drilling rigs are even equipped with hydraulic feet that enable them to walk robotically around a pad.

In rock formations that have low porosity or permeability, horizontal drilling has been combined with hydraulic fracturing to enable the recovery of oil and gas that was previously uneconomic to access. In a single well, several stages of hydraulic fracturing can be used to pry open a very tight rock formation and recover large volumes of oil and gas. It's this combination of horizontal drilling and hydraulic fracturing that has brought about the U.S. shale revolution for both oil and natural gas; and it's what causes the steeply declining profiles in Figure 11.

All of these advantages, however, come with greater up-front expense. Horizontal wells are more technically challenging than traditional vertical wells and consequently cost a lot more to drill. As shown in Figure 13, the transition from drilling vertical wells to drilling horizontal wells has resulted in a four-fold increase in the average, upfront capital costs per well in Alberta. Whereas a single traditional vertical well could be developed for as little as a couple hundred thousand dollars, a single horizontal well today takes a capital investment of several million dollars to drill and complete.

Going forward, horizontal drilling and multi-stage hydraulic fracturing will be the new standard for the vast majority of crude oil and natural gas wells in North America, including Alberta. In addition to generating better resource recovery, they are ideal for deeper, tighter and more complex oil and gas formations. And they are essential for maintaining our long-term royalty stream from our crude oil and natural gas resource base.

"Going forward, horizontal drilling and multi-stage hydraulic fracturing will be the new standard for the vast majority of crude oil and natural gas wells in North America, including Alberta."

To work optimally, our Panel recognized that Alberta's go-forward royalty framework must reflect fundamental changes in how both conventional and unconventional hydrocarbons will be produced in our province over the coming years. And that the royalty framework must be dynamic to respond to changes in both capital and operating costs.

CHANGES IN OIL SANDS DEVELOPMENT ARE RESULTING IN CHANGING COSTS

Development of our province's oil sands resources is also changing.

Many Albertans are familiar with the big mining projects that have traditionally been associated with the oil sands, and the pictures of oversized shovels, excavators and trucks that are used in these operations. In fact, only 3% of the oil sands area is suited for these types of mining projects.

The large majority of Alberta's oil sands resources are too deep in the ground to be mined, and so they must be recovered through in-situ methods. The term "in-situ" means, "in its original place". For oil sands that cannot be mined at the surface, in-situ techniques involve drilling special injection wells to loosen up the viscous bitumen and make it flow to the surface. Injecting steam into the geologic formation in-situ is a common technique, but other innovative methods are being developed too.

This means that most oil sands projects in the future will not look like the large-scale mining operations of the past, but will instead be in-situ projects. There are no oversized shovels, excavators and trucks, or massive carvings through the landscape like an open-pit mine.

Since they are more like oil wells rather than mines, in-situ projects have different cost structures. Although the capital costs of an in-situ project can be substantial (i.e. hundreds of millions of dollars), they do not involve tens of thousands of people working on a project site all at once. For many in-situ projects, the highest operating costs are not labour but utility costs, since they often generate and use steam to recover the bitumen underground.

Future production growth from the oil sands is likely to be in the form of smaller-scale in-situ projects or the expansion of existing projects. Our Panel's discussions with oil sands producers and our analysis of Wood Mackenzie data suggests that new oil sands megaprojects are unlikely.

An advantage of smaller-scale oil sands projects is that they have lower upfront capital costs. This shortens the investment period and hastens the time to production.

Our Panel acknowledged the changing character of past, present and future oil sands developments and the changing nature of associated costs, all of which affected our Panel's considerations of the oil sands royalty structure.

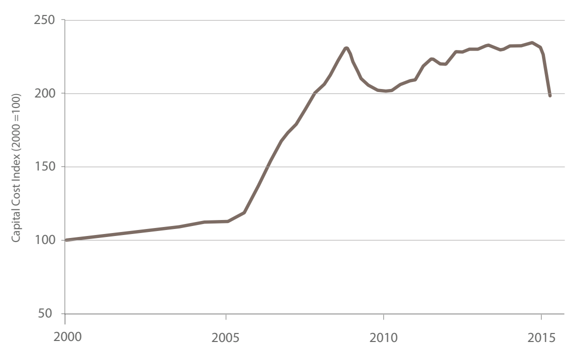
CHARACTERIZING, TRACKING AND INDEXING COSTS

A refrain repeatedly heard by our Panel was that Alberta is a higher-cost jurisdiction when it comes to oil and gas production – the implication being that royalty rates should simply be lowered across the board.

In reality, the situation is more complex and there is a broader discussion to be had about costs in Alberta's oil and gas industry.

IHS UPSTREAM CAPITAL COSTS INDEX

Global Data



Source: IHS CERA
https://www.ihs.com/info/cera/ihsindexes/index.html

Figure 14

Commodity prices influence capital costs. Costs are inflated during boom times.

Much of the cost inflation between 2004 and 2009 can be attributed to the higher commodity prices seen during this time period, particularly oil prices. During periods of strong prices, investors are willing to fund energy companies because returns on projects and drilling programs are expected to be more attractive. As a result, lots of energy companies undertake projects at the same time, and they all compete for the same skilled workers, the same rigs, and the same supplies such as steel, concrete, sand and gravel.

Buoyed by the flood of energy investment, other sectors in the economy also undertake capital investments in quests to build and expand. Adapting to the growth, governments also undertake capital investments in public works such as roads, schools, hospitals and other infrastructure.

The result is that companies, governments and other stakeholders in the economy make vast capital investments simultaneously, collectively driving up wages and the cost of materials and services.

This works both ways. When commodity prices collapse, as crude oil did in 2015, there is a flight of capital investment to other sectors of the global economy. This leads to falling costs, which can be seen clearly in Figure 14 after 2014.

The period between 2010 and 2014 saw little capital cost inflation, though investment and activity was robust. In large part, this stability is a "technology dividend" – the effect of new technologies working to reduce unit costs against the broader inflationary tide.

To a large extent, the price-cost association is a cyclical economic challenge, and in today's world of international finance it is a difficult one to avoid in most resource-based economies. New technologies are a force that can drive down costs, but they are difficult to predict.

Regardless of the dynamics, our Panel realized that considering the future relationship between costs and price was vital for calibrating royalty rates. More importantly, our Panel recognized that keeping track of indexed costs can be an important mechanism for adapting crude oil and natural gas royalty structures to year-over-year changes in capital costs.

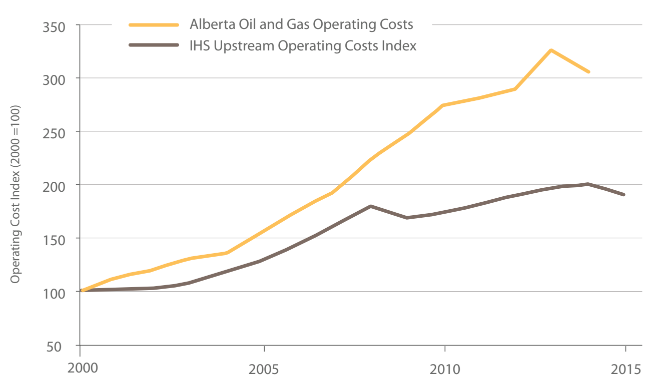
Operating costs are a different story.

On this front, Canadian oil and gas producers have diverged from their international counterparts, with much higher average operating costs relative to the global average (as shown in Figure 15).

Operating costs of Alberta oil and gas companies have also been rising faster than overall inflation rates. As shown in Figure 16, while they ticked down slightly between 2013 and 2014, the average operating costs of Alberta's crude oil and natural gas producers steadily outpaced the national and Alberta Consumer Price Indices, rising 9% each year between 2002 and 2014. (This doesn't include operating costs in the oil sands sector, which would very likely push up average operating costs and widen the inflationary gap.)

A COMPARISON OF INDEXED OPERATING COSTS

Alberta Oil and Gas versus Global IHS Index



Source: IHS CERA, Canadian Association of Petroleum Producers https://www.ihs.com/info/cera/ihsindexes/index.html

Figure 15

Operating costs in Alberta have trended higher than the global average.

This points to an uncomfortable reality: Alberta oil and gas producers are at risk of gradually putting themselves out of business unless operating cost inflation is arrested.

CONSUMER PRICE INDICES VERSUS ALBERTA OIL AND GAS COSTS

Operating Costs (Excluding Oil Sands)

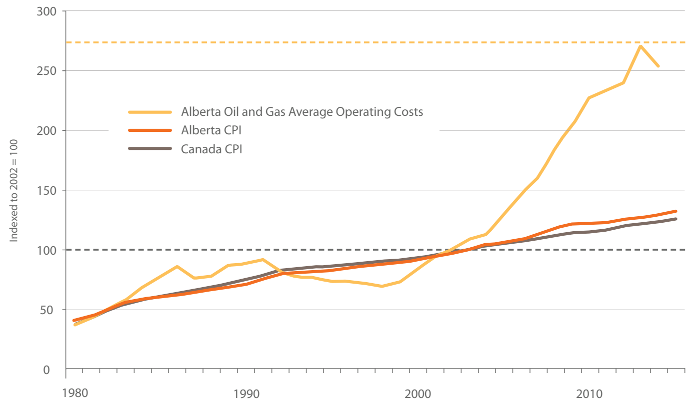


Figure 16

Oil and gas operating costs in Alberta have been outpacing general inflation.

We have limited influence on the prices we receive for our resources, but to a larger extent we can address the cost side of the equation. This is where we stand to realize the greatest gains in making our resources more attractive and competing head-to-head with U.S. unconventional oil and shale gas. Failure to take action is not a realistic option. Left unaddressed, rising costs of all types will increasingly make Alberta's resources less attractive to customers and our province will continue to lose market share, resulting in lower royalty revenues.

All that being said, it is important to recognize that not every producer's costs are the same.

NOT EVERYONE'S COSTS ARE THE SAME

Our Panel wanted to see how costs vary from producer to producer, from well to well, and from project to project.

Figure 17 shows that there is a wide distribution of operating costs (on a per-barrel basis) among Alberta producers of crude oil and natural gas (excluding oil sands). To a large extent this is a function of the diversity of oil and gas plays, different types of wells, and various localized above-ground conditions that exist across our province. Some wells have costlier operations by virtue of what they produce, while others have higher costs because they are mature.

The wide dispersion of operating costs in Figure 17 highlighted a major challenge for our Panel. Any consideration to raising royalty rates would acutely affect higher-cost producers on the right side of the distribution. Tens of thousands of wells are in this category. Many are good wells that still have long lives and all are associated with rural employment, municipal taxes and surface access fees. Our Panel recognized that disenfranchising wells with higher operating costs would have negative economic impacts for many rural communities in the province.

Since 2005, the operating cost distributions for crude oil and natural gas producers have

DISTRIBUTION OF OPERATING COSTS[1] IN 2005

The Actual Cost Distribution Data for 310 Companies and 26,000 wells

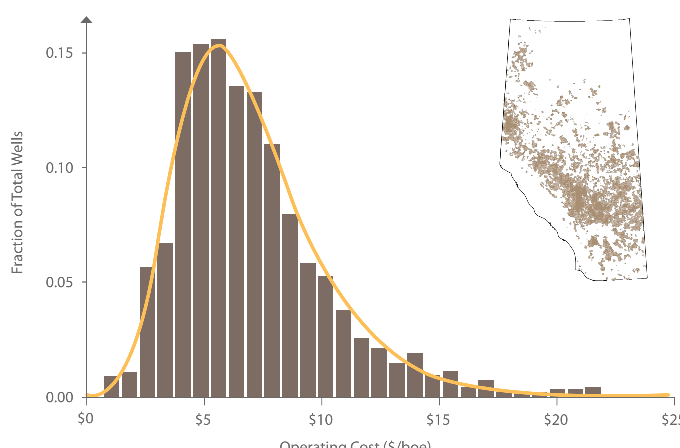


Figure 17

Source: GLJ Petroleum Consultants,
[1]All hydrocarbons excluding oil sands

SETTING THE CONTEXT

widened even further. As can be seen in Figure 18, in 2014 some producers had operating costs as high as $35 to $40 per barrel (of oil equivalent) for some wells. The increasing dispersion of costs was studied by our Panel. We concluded that the migration to the right (progressively costlier operations) should be arrested if our province and its energy industry are to compete in a world of lower oil and natural gas prices.

Similar operating cost dynamics were observed in the oil sands, though the limited availability of data precluded statistical analysis.

Figure 19 shows the migration of oil and gas capital costs. Unlike operating costs, the peaks of the capital cost distributions between 2010 and 2014 have remained relatively stable. This illustrates the technology dividend on the capital side. Factors such as faster drilling times, more hydraulic fracturing stages, pad drilling, and better logistics at the well site, have all served to hold capital costs in check.

THE EVOLUTION OF OPERATING COST DISTRIBUTIONS

2005, 2010 and 2014 Evaluation Years

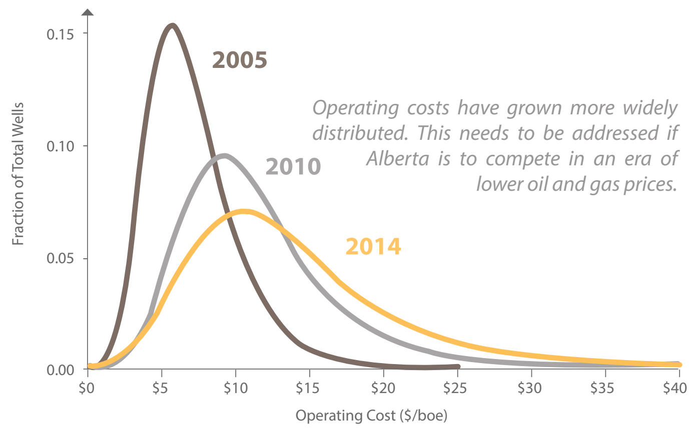


Figure 18

Source: GLJ Petroleum Consultants,
[1]All hydrocarbons excluding oil sands

Individual producers' costs are also dynamic underneath each year's distributions in Figure 18 and Figure 19. It is not necessarily always the same producers or the same wells at the lower or higher ends of these distributions from year to year. Innovative producers are always working to move from the higher cost side to the lower cost side of the distribution.

What drives such high-to-low cost movement? Technology, learning curve effects, financial discipline, logistics and many other factors are in play to improve an individual company's business processes.

A prime example is when a producer enters an oil or gas play that is new to them. Their first few wells may be quite costly, and they may find themselves at the high end of the capital cost distribution during this period. However, each time they drill, they learn more about the play. They use these learnings to innovate and change their techniques as they drill more wells, gradually improving their efficiency and cost effectiveness in the overall play.

CAPITAL COST DISTRIBUTIONS

Drill, Complete, Equip and Tie-In Costs per 2P Reserves BOE

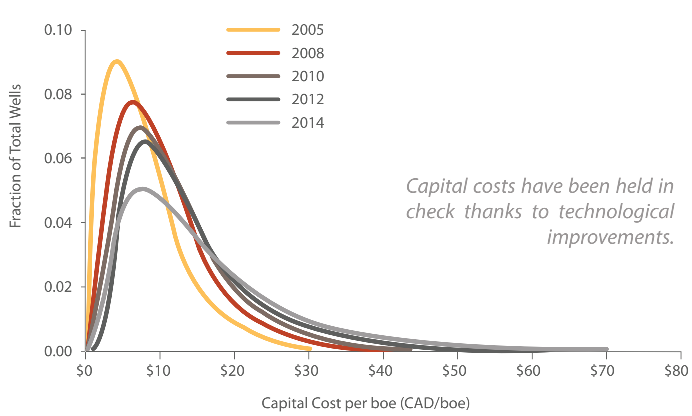


Figure 19

Source: GLJ Petroleum Consultants

Over time, learning and innovation can move a producer from the high end of the cost distribution to the lower end of the distribution. This is particularly important when exploring new plays, like deep oil.

THE ISSUE OF COSTS

Learning And Innovation Can Drive Down Costs

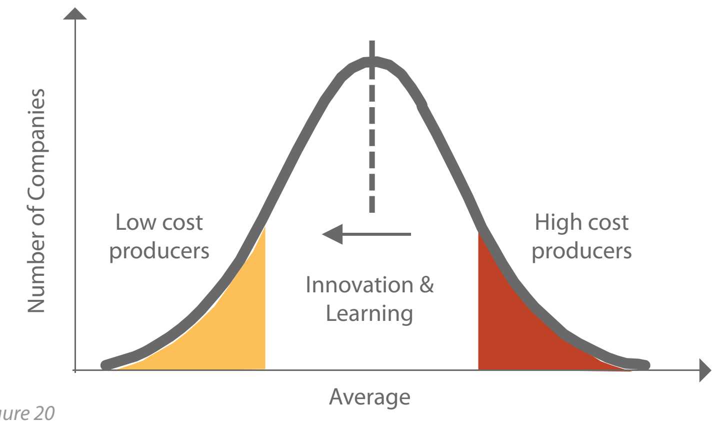


Figure 20

Without question our Panel found many factors that have led costs to be higher in Alberta compared to other jurisdictions, and many of these factors are difficult or impossible to control. For example:

- *Weather* — As a jurisdiction with a cold climate for several months of the year, our energy facilities need to be winterized; this adds cost.
- *Seasonality* — Related to our climate, there are times of the year when transportation restrictions (i.e., weight limits) are in place on many rural roads, limiting the ability of producers to move heavy equipment. This effectively means that energy activity is seasonal rather than year-round, and this has an efficiency cost.
- *Geology* – With the full spectrum of hydrocarbon resources, we have geology that is more complex, more diverse, and more technologically challenging.
- *Limited labour pool* — With only 4.2 million residents, Alberta has a relatively small pool of skilled workers. As a result, we have higher labour costs relative to other jurisdictions such as Texas, which has a population of almost 30 million.
- *Remoteness* — In addition to being spread out over a vast landscape, most of our energy resources are geographically isolated, making them more expensive to access. Some are in areas where the topography is challenging.
- *Regulatory approach* — With higher levels of assurance compared to our competitors, including strict environmental expectations, we impose additional layers of cost on energy producers that they do not always face elsewhere.

At the same time, there are many costs in our oil and gas industry that are controllable. As can be seen from the cost distribution charts above, there is a fairly wide spectrum of average operating costs among producers and potential room for some companies to maneuver when it comes to cost control.

All of this is to say that higher costs are not a given, and our Panel cautions against generalizing that Alberta is a "high cost producer".

ALBERTA NEEDS TO ENCOURAGE COST LEADERSHIP IN ITS ENERGY INDUSTRY

For Alberta to be successful in the future, the partnerships formed between our Province and energy companies need to be more aligned, more productive and more mutually beneficial than ever before. We need to partner with the best, most innovative and most cost-competitive producers. And we need to support all producers in becoming the very best, innovative and cost-competitive they can be because the lower their costs, the more value there will be for sharing.

Understanding costs greatly influenced our Panel's approach to Alberta's royalty framework. Our Panel realized it would be a mistake to take a knee-jerk approach and lower royalty rates across the board based on a simplistic belief that it costs more to drill here. Doing so would remove the incentive to reduce costs and, at worst, prop up inefficient operations that are unable or unwilling to improve performance. The mantra that "Alberta is a high cost basin" would become a self-fulfilling prophecy and in the long run we would make our province uncompetitive.

Equally, our Panel recognized that raising royalty rates may shut in wells that contribute to the well-being of the province, especially in rural communities. As well, our Panel realized that many existing wells and potential wells can be the beneficiary of innovation and learning that reduces costs.

Consequently, one of our Panel's goals in optimizing the royalty framework was to seek ways to encourage and reward the efforts of producers to relentlessly innovate, lower their costs and improve their productivity. Over the long term, such encouragement can lower the average costs of producing and selling our oil and gas, increase the amount of value available for royalties, provide more buffer against low commodity prices, and position our industry to compete better on a world scale.

INVESTMENT, RETURNS AND ROYALTIES

Our province's ability to attract investment in our energy sector was carefully considered when examining how to optimize the royalty framework. This was a leading principle in the feedback we received from Albertans.

Despite all our opportunities, our province is a relatively small place. For that matter, so is Canada. We simply do not have the necessary capital here at home to develop our resources all by ourselves. In fact, over half of the capital invested each year in Alberta's energy sector comes from sources outside of Canada.

This means that, in order to extract the best return for Albertans (as resource owners), we need to get into the minds of investors.

Key Points In This Section:

- Investors now have many options for investment around the globe. It is more important than ever that investors consider Alberta's energy development opportunities to be attractive options.
- Before investing in an energy project, an investor needs to see the prospect of achieving their desired rate of return. Investors are attracted to projects that not only offer the best returns, but also offer faster payback on their upfront investment.
- Albertans are currently being appropriately compensated for the production and sale of their oil, gas and oil sands resources. Albertans' share of resource production profits, for the types of plays being invested in, ranks neither as the best of its peers nor as the worst.
- In general, Alberta's resource development opportunities are not the most attractive for investment, especially in a North American context.

ENERGY COMPANIES AND INVESTORS

When examining our ability to attract energy investment, it's important to distinguish between energy companies and investors. Though the two are often seen as one and the same, they are separate groups of individuals, institutions and organizations, and they can have very different mindsets.

Developing oil, natural gas and oil sands requires a lot of money. A single oil sands project can run in the billions of dollars and take years to develop. Given the technologies now in use, a single horizontal oil or natural gas well can cost upwards of ten million dollars, and developing an oil or gas play with multiple wells can cost hundreds of millions of dollars when all is said and done. Energy companies cannot move forward on development opportunities without the backing of investors.

It is no longer like the 'old days' when an enterprising individual could approach family and friends to raise enough cash to drill a well. Today, energy companies of all sizes will raise money through international capital markets, dealing with a class of investors that includes big banks, investment firms, and institutional fund managers in Toronto, New York and beyond.

In today's connected world, these investors have many options from which to choose. This choice isn't only between a natural gas development in Alberta versus one in Pennsylvania. It's the choice between investing their money in energy at all, or investing it in manufacturing, real estate, consumer goods, or some other completely different sector.

This means it is more important than ever that investors consider Alberta's energy development opportunities to be attractive options. Energy companies may be the ones assessing and deciding which energy resources to develop and where, but they increasingly need to rationalize those choices to satisfy the demands of investors.

In fact, in the course of our Panel's work, we heard of instances where energy producers were favourably disposed to opportunities in Alberta but were rebuffed by investors. Those investors felt they could receive better value for their money in other jurisdictions.

Some energy companies told us they have had to adjust the way they consider energy opportunities in order to raise investment more successfully. There is a sense that some of the things energy companies have historically placed value upon – such as the potential to develop a very productive play over a long time horizon – are no longer valued by investors, who seem to be increasingly focused on fast payback of their money and short-term results.

Against this backdrop, it's essential to consider how investors make investment decisions when it comes to oil and gas development. When Alberta's oil and gas resources were the 'only show in town' this was not as critical, but with the competitive realities Alberta now faces, this needs to weigh heavily in our thinking as we optimize the royalty framework.

HOW INVESTMENT DECISIONS ARE MADE

Assessing the Risks of Resource Opportunities

Fundamentally, investors assess investment opportunities based on risks. In the case of oil and gas development, those risks generally fall into two categories: below-ground risks and above-ground risks.

Below-ground risks are those risks that can arise when accessing oil and gas resources and extracting them from the ground. For example, the rock formation may be more technically challenging than originally expected. There may be problems with equipment and tools while drilling the well. Or it may be exceptionally difficult for the producer to move up the learning curve and determine how to improve performance in the oil or gas play.

Above-ground risks aren't about getting the resources out of the ground, but about the prevailing social, economic and environmental conditions. These risks can be geopolitical in nature, such as the threat of war or civil unrest or the presence of corruption or piracy. These risks can be legal, such as worries about litigation or expropriation, or unresolved issues around the rights of First Nations, Métis and Inuit. These risks can also include the possible loss of social license, unexpected changes in taxes or regulatory requirements, or the inability to effectively transport the produced resources to markets and customers.

Based on an assessment of all the risks involved, an investor will typically determine an acceptable "hurdle rate" for the resource development opportunities offered by the jurisdiction. The hurdle rate is the minimum rate of return that the investor is prepared to receive on their investment. The higher the level of risk posed by a jurisdiction's opportunities, the higher the hurdle rate will be.

Generally speaking, if a resource development opportunity will achieve the required hurdle rate, an investor will be willing to consider the opportunity. However, this doesn't necessarily mean they will invest in it.

Considering the Realities of Oil and Gas Production

Each investor has a limited amount to invest and they will put their money in the places where they expect to receive the highest returns. If two different opportunities both achieve the hurdle rate but one offers better returns than the other, then the investor is likely to invest in the opportunity with the better return.

The realities of oil and gas production also impact the thinking of investors.

The amount of oil or gas produced from a well declines over time. Generally, a well's most productive period is during the first few years of its life. The decline curve of a well can be very steep. For instance, horizontal wells that incorporate hydraulic fracturing tend to recover huge amounts of oil and gas very quickly, but then decline sharply.

This has two significant consequences.

One consequence is that energy companies always need to be exploring for and producing new oil and gas supplies just to maintain their levels of production. It's a bit like being on a treadmill. An energy company must constantly be working to recover additional oil and gas reserves to make up for the oil and gas that's already been produced. It can't stop, or it will fall backwards (as will the Province, as their partner). This is why, each year, energy companies announce and implement capital investment plans that set out where they plan to drill and develop projects.

The second, related consequence is that investment in oil and gas development is in a continuous cycle. The cash flow that an energy company generates from a well's early life (i.e., after paying expenses and royalties) is vital for helping bankroll its next round of development. To facilitate this rapid re-investment of cash, energy companies and investors seek to recoup their investments as quickly as possible.

Investors are thus attracted to opportunities that not only meet their required hurdle rates and offer the best returns, but also offer faster pay back. (And thus, the ability to re-invest in another Alberta development project.)

Putting it in Perspective

All of the above helps explain why U.S. unconventional oil and shale gas opportunities have boomed.

In addition to being a stable democracy with an open market economy, the U.S. offers few above-ground risks relative to other jurisdictions. Its tax and regulatory regimes are favourable and it has a large labour market, so there are few challenges in accessing skilled workers. It has plenty of pipeline infrastructure and excellent access to refineries, which have excellent international market access.

The below-ground risks of U.S. unconventional oil and shale gas are also manageable. In places such as Texas, the consistent landscape and geology make drilling a very repeatable process, akin to manufacturing. Companies have been able to move up the learning curve quickly, enabling them to improve their efficiencies and reduce their costs.

As a result, many U.S. unconventional oil and shale gas opportunities achieve the hurdle rates of investors and, as they become more cost-efficient, can offer even better rates of return. Unconventional oil and shale gas wells also produce very significant volumes of oil and gas in the first few years of their lives, which enables investors to get their money back very fast and facilitates the rapid re-cycling of cash into new rounds of drilling.

Contrast this with opportunities in Alberta's oil sands today.

The below-ground risks of oil sands are minimal. The location and nature of the resource and the techniques for extracting the resource are all well known. Unlike an oil well, there is a high degree of certainty about how much oil will be produced from an oil sands project.

But while Alberta has a stable democracy and an open market economy, we have other above-ground risks that are arguably greater. We have a limited labour pool, which can make it more difficult to source skilled workers. Pipeline access for oil is limited, and there are risks that Alberta will not be able to effectively move its product to more markets and customers. There are outstanding legal issues relating to First Nations, Métis and Inuit, which complicate the approval and construction of projects, pipelines and other infrastructure. And our oil sands have attracted considerable negative attention about their environmental impacts.

Notwithstanding all this, oil sands projects may achieve the hurdle rates of investors. But rather than paying investors back fast, oil sands projects do almost the complete opposite. They require massive sums of upfront investment and take years to construct and payout. Once up and running, they gradually recover oil over several decades.

It's clear that different jurisdictions and different resource opportunities can have very different levels of attractiveness to investors.

We need to be savvy resource owners and be mindful of what investors (and hence, energy companies) are looking for today when deciding where to invest. That way, we can attract the capital we need to get our resources out of the ground and optimize returns for Albertans.

We also need to be mindful about a new class of investors that's gradually growing in number. Some institutional investors, such as large pension funds, endowments and foundations, are not only assessing investment opportunities through a purely financial lens, but also through a social and environmental responsibility lens. From an investment standpoint, it will be to Alberta's benefit over the longer term to be an environmentally responsible resource producer, and to have a royalty framework that encourages energy companies to innovate and improve their environmental performance.

HOW ALBERTA STACKS UP

Assessing Alberta's Investment Attractiveness

In order to understand and consider the investment attractiveness of Alberta's resource development opportunities, our Panel engaged Wood Mackenzie, an international consultancy, to assist in assessing governments' fiscal "take" from oil and gas development opportunities in Alberta, relative to those in other oil- and gas-producing jurisdictions. The results were shared with members of our Panel's Expert Groups, who contributed to their interpretation.

In addition, our Panel solicited advice and analysis from other analysts to help quantify the central variable that governs resource value-sharing: profitability.

Together, these analyses constituted a traditional review, or comparative fiscal analysis, that is typically undertaken by resource owners who want to assess their fiscal regime against competitive jurisdictions.

Overall, our Panel sought to answer two main questions:

- **Are Albertans, as resource owners, being appropriately compensated for the production and sale of their resources?** Put another way, are Albertans' returns reasonable when compared against other resource-rich jurisdictions that share their production profits with private enterprise?
- **How well do Alberta's resource development opportunities stack up in terms of attracting capital investment?** This is a critical question, because Alberta needs to be able to attract investment in its energy sector in order to produce its crude oil and liquids, natural gas and oil sands resources. Without oil and gas production there are no royalties to collect, regardless of whether our province's royalty rates would provide appropriate returns to Albertans.

Considering Alberta's Competitors and Comparators

In examining how Alberta stacks up, a natural question was, "Who should we compare Alberta's resources to?"

There are many jurisdictions that have energy resources, but it did not make sense to compare Alberta to every single one of them. In reality, Alberta is not competing with absolutely everyone else on earth. An energy company considering a development opportunity in Alberta is likely to be weighing that against comparable opportunities in only certain places.

Some competitor jurisdictions were easy to identity. For example, as next-door provinces, both British Columbia and Saskatchewan were chosen as peers for comparison. Both compete with Alberta for energy investment dollars, both have similar resource types as Alberta, and both are selling to the same customers as Alberta.

Two criteria were used in determining which jurisdictions should be used in the comparative fiscal analysis. Both criteria had to be satisfied:

- **Comparable resources –** The jurisdiction has geologic play types similar in character and development scale to those in Alberta. For example, Pennsylvania's shale gas is directly comparable to Alberta's unconventional gas plays. Texas, North Dakota and Colombia are considered peers to Alberta's lighter oil and liquids development. Oil sands comparables are of much larger scale; offshore Norwegian oil platforms, and Venezuelan heavy oil are examples.
- **Capital competitiveness –** Multinational companies that operate in Alberta have investment choices across North America and many other parts of the world. Where can they invest? Our Panel instructed Wood Mackenzie to consider only jurisdictions that are open for free market investment to companies that are currently operating in Alberta.

Based on these criteria, the following competitor and comparator groups were selected:

- **Natural gas** – British Columbia, Pennsylvania, Ohio, Texas, United Kingdom
- **Crude oil and liquids** – Saskatchewan, Colorado, North Dakota, Oklahoma, Texas, Argentina, Colombia
- **Oil sands** – California, Madagascar, Oman, Venezuela, Newfoundland and Labrador, Alaska, Deepwater Gulf of Mexico, Brazil, Kazakhstan, Norway

Results of Comparative Fiscal Analysis

Wood Mackenzie's report to our Panel is comprehensive in its comparative fiscal analysis, and includes many measures of relative profitability. Not all results were consistent, and as such, our Panel and our advisors were careful to consider all factors before coming to judgement. (See "Wood Mackenzie Data and Our Panel's Interpretation".).

The following are the major conclusions, as interpreted by our Panel:

- **Albertans are currently being appropriately compensated for the production and sale of their oil, natural gas and oil sands resources.** Albertans' share of resource production profits ranks neither as the best of its peers, nor as the worst. The revised oil sands royalty structure implemented in 2009 continues to strike the right balance.

- **Albertans' compensation was interpreted to be reasonable at all price scenarios tested, within the limits of the assumptions used.** All tests of reasonableness were taken in the context of Alberta's comparable peers as described earlier.

- **New U.S. resource plays in Texas and Pennsylvania – Alberta's largest-scale competitors – are more attractive for investment.** In other words, a company's share of profits is generally higher in those jurisdictions than in Alberta. Texas is particularly attractive for unconventional oil, while Pennsylvania is hard to beat for natural gas. Alberta's higher-performing wells can compete with these jurisdictions, mostly on the oil side.

- **Within Canada, Saskatchewan's royalty regime is more favourable to investment for similar-type unconventional oil wells. British Columbia's regime, in general, imposes lower rates for natural gas.** Saskatchewan appears to have structured its royalty regime to accept a lower government 'take' in favour of emphasizing the attraction of energy development activity, rather than optimizing for both.

- **Colombia and Argentina are international comparables for unconventional oil and natural gas. Both are inferior to Alberta from an investment perspective.** Alberta's closest comparables for both product and capital competition are decidedly in North America.

- **Oil sands projects are projected to deliver a reasonable share to Albertans going forward, but are weakly positioned from the standpoint of attracting new investment.** High costs make most new oil sands projects unattractive relative to other jurisdictions with similar characteristics. Only modularized Steam-Assisted Gravity Drainage (in-situ) projects at above $80 per barrel are projected to be able to achieve investment hurdle rates.

- **The prospect of investment into large-scale mining projects is very low, even at prices above $100 per barrel.** Multinational companies have more attractive large-scale investment choices in other jurisdictions, even after adjusting for above-ground risk factors. Light oil prospects in Texas have superior return metrics, faster payback periods, and lower risk.

OUR PANEL'S FINDINGS

IN THIS CHAPTER:

- *Our findings about royalty structures generally*
- *Our findings about the royalty structures for crude oil, liquids and natural gas*
- *Our findings about the royalty structure for oil sands*

The previous chapter has set the context. This chapter outlines our Panel's findings.

These findings have resulted from many discussions with Albertans, stakeholders and First Nations and Métis as part of our public engagement process, and much work and discussions with our Expert Groups as part of our technical review. Throughout this work, our Panel's focus was whether the current royalty structures are designed to ensure Albertans, as owners, receive optimal value from our resources.

WHAT WE FOUND ABOUT ROYALTY STRUCTURES GENERALLY

Our Panel found a number of things about royalty structures generally and the evolution of Alberta's royalty framework over time.

- **The "revenue minus costs" (RMC) model is a global standard for sharing profits from resource production between energy companies and resource owners.**

Every jurisdiction with oil and gas resources has a unique set of terms for sharing the value of their resources when they are produced and sold. To collect their share of value, resource owners in each jurisdiction use different government policy tools. There can be many differences among these terms and tools. However, a philosophy common to fiscal regimes around the world is broadly called the "R minus C" model, or "revenues minus costs" (RMC).

The premise of the RMC model is that, like any business, the amount of profit available is equal to the revenues a company generates from production, minus the costs that went into starting up and maintaining that production. The RMC model is also premised on the common-sense notion of sharing profits between operating companies and the owners of the resources. This is consistent with the fact that a resource owner and the energy company enter into a partnership in order to develop the resources. If the partnership makes a dollar of profit, then that dollar should be shared. **The sharing formula must balance investment appeal against the owner's desire to optimize value.**

This straightforward idea becomes more complex when one considers what is monetarily involved in producing oil and gas. Whether drilling an individual well or developing a large mega-project, the oil and gas business is characterized by two main phases: capital investment (which includes exploration, drilling, completions, and the construction of facilities), and production.

During the capital investment phase, an energy company will spend a large sum of money with little or no products being produced (and hence, no revenues coming in). There are little or no profits during this phase.

In the production phase, the well or project is operational and the oil and gas starts to flow, generating revenues to the company. During this phase the company's expenses are mostly operational in nature – for example, the costs of electricity to run the pump jacks, costs of monitoring and maintenance, payments of surface access fees, and payments of federal, provincial and local taxes. Assuming commodity prices are favourable, operating profits can be generated during this phase. Those profits can be calculated as: the revenues generated from the sale of the oil and gas produced, minus the operating costs.

The expectation under the standard RMC model is that a portion (or all) of the energy company's initial capital investment is paid back before operating profits are shared between the energy company and the resource owner. This two-phase sharing mechanism reflects the two-phase reality of energy development, and it recognizes there are no tangible profits generated until the company recoups its hard dollar investment (commonly called "payout").

However, this does not necessarily mean that the resource owner collects zero royalties until payout. In many RMC models, there is a nominal payment of royalties in the early pre-payout days of production, even though the company has not yet fully recouped its investment. Such arrangements mean that the time to payout is extended, because some of the early operating profits are being channeled to the resource owner.

In a typical RMC model, the terms change post-payout, at which time the royalty rate usually increases to a level that represents a greater share of profits for the resource owner.

- **Alberta's royalty framework has evolved to incorporate aspects of the RMC model in different ways.**

Since it was first instituted in 1931, the royalty framework has adapted to changes in commodity prices, character of production, and competitive forces. Along the way, the framework has incorporated aspects of the RMC model in different ways.

Since a generic royalty structure for the oil sands was put into place in 1997, Alberta has used a full RMC implementation for calculating oil sands royalties.

A full RMC implementation involves the validation of costs through audit of revenues and expenditures incurred by energy companies. Proper bookkeeping of capital costs is important, because the amount that a company spends upfront represents a dollar trigger (i.e., a "payout" point) that switches the royalty framework between pre-payout and post-payout profit sharing.

When first established, the generic oil sands structure used a flat royalty rate of 1% during a project's pre-payout period and, during the post-payout period, used a rate of 25% based on the project's net revenue. Alberta's royalty structure for oil sands was last adjusted in 2009. At that time, the government incorporated a price-sensitivity overlay to the structure. These changes saw the pre-payout and post-payout royalty rates increase from 1% and 25% respectively, with increases in oil prices above $55 per barrel, to maximums of 9% and 40% respectively, at oil prices of $120 per barrel and higher.

For crude oil and natural gas wells, Alberta has preferred to use a proxy RMC structure for administrative efficiency.

A proxy RMC structure is simpler to manage and requires less accounting rigor. Under this approach the cost of drilling and completing an individual well is estimated using statistical data captured from thousands of previously-drilled wells. This is used to develop a formula that representatively incorporates pre-payout and post-payout rates, and is used for all wells. Effectively, a trade-off is made between accounting precision and efficiency, so as to avoid the bureaucratic burden of a full RMC implementation for thousands of wells and companies. When designed appropriately, a proxy RMC structure can achieve, on average, the same amount of profit-sharing as a full RMC implementation.

Each year, thousands of crude oil and natural gas wells are drilled in Alberta. Administering a full RMC implementation for these wells would be very burdensome, while not changing the outcome. In addition, capital expenditures for individual wells are small compared to large multi-billion dollar oil sands projects, and payback periods for wells are also much shorter than for oil sands projects.

Long ago, Alberta instituted production- and price-sensitivity overlays to its royalty structures for crude oil and natural gas. This recognized that oil and gas wells in Alberta declined in productivity (and hence, profitability) with age, and put in place a mechanism where Albertans would receive more during times of buoyancy (high price) and less in times of distress (low price).

Alberta's royalty structures for crude oil and natural gas were last adjusted in spring 2010. The objective of the government at that time was to encourage investment in Alberta's energy sector in the face of low commodity prices, increasing competition from U.S. energy producers, and a dearth of investment capital due to the global financial crisis. In addition, the 2010 royalty framework adjustments acknowledged the advent of transformative oilfield processes – notably, horizontal drilling and hydraulic fracturing.

Key among the 2010 adjustments was the introduction of temporary programs for encouraging deep, horizontal drilling for crude oil and natural gas. These adjustments effectively mimicked the pre-payout concept used in RMC models around the world.

WHAT WE FOUND ABOUT CRUDE OIL, LIQUIDS AND NATURAL GAS

Based on discussions with our Expert Groups, the data we commissioned from analysts, and input provided by Albertans through our public engagement process, our Panel found several things about Alberta's royalty structures for crude oil, liquids and natural gas:

- **Out of date** – The formulas that govern the royalty rates are inconsistent with the current state of competition, oilfield technologies, processes and production profiles. This is significant, because the energy landscape has fundamentally changed during the past seven years. New, costlier technologies have become the standard. These technologies have enabled Alberta's biggest customer – the U.S. – to become our biggest competitor and gradually cannibalize some of our market share. Texas alone has, in just four years, expanded its unconventional oil production to a level that is greater than Alberta's entire oil production, including the oil sands.

- **Inconsistent across hydrocarbons** – Today, the lines between what is an oil well and a gas well are no longer distinct. Depending on location and geology, a well that is drilled several kilometers into the ground can yield natural gas, many grades of crude oil, or a cocktail of hydrocarbon liquids and gases in-between. A well drilled in the broadly defined "Deep Basin" region west of Edmonton can encounter a mix of all types of hydrocarbons. This is not reflected in Alberta's royalty framework today. Instead, there are inconsistencies between the royalty structures for the different hydrocarbons. For example, a company will pay a different royalty depending on what hydrocarbons a well encounters. This is causing inefficient allocation of capital, and higher-than-necessary investment risk, and is impeding Albertans from collecting optimum value from these resources.

- **Discounted rate model –** The current structure is such that "sticker" royalty rates are always being discounted by various cost-related factors (for example, declining production rate). The result is inflated royalty rate expectations that can't be achieved. It is more transparent (and believable) to have realistic effective rates.

- **Temporary programs set to expire** – The policy overlays instituted in 2010 are currently scheduled to expire, beginning in 2016. Temporary programs sometimes have a role to play in the royalty framework, but like any temporary program they need to remain relevant and not foster dependencies in the marketplace. In this case, the effects of the temporary programs have become essential – not due to the creation of an unhealthy dependency, but due to the character of the resource, the new environment of low commodity prices and aggressive competition from the U.S.. Our Panel has found that terminating temporary programs could reduce the value of oil and gas investment into Alberta. However, our Panel believes that while the effects of the temporary programs need to be maintained, a different approach is required.

- **Distorted** – The current formulas in the royalty structures contain several distortions that can unintentionally encourage on-the-ground practices that are barriers to efficient and environmentally responsible resource development. For example, a company can sometimes be encouraged to drill two short horizontal wells instead of one long well, resulting in unnecessary surface disturbances and other sub-optimal practices.

- **Not easy to harmonize** – Because the current royalty structures are inconsistent between hydrocarbons, and not all based on dollar metrics, it is difficult to harmonize them with other policy instruments. For example, incorporating carbon levies or providing synergies with downstream diversification opportunities is challenging under the current royalty structures.

- **Inflexible** – The current royalty framework is rigid and not adaptable to ongoing changes in costs, productivity and competitive positioning. In the past, greater value appears to have been placed on the certainty of formulas, than on ensuring the framework kept pace with changes in technologies and costs.

- **Inefficient** – Inconsistencies between royalty structures are creating barriers to maximizing recovery of oil and gas resources and minimizing environmental impacts. For example, there are barriers to investing in enhanced recovery methods, re-entering wells and re-stimulating existing wells (compared to drilling new wells). This, in turn, allows production to age prematurely, compromises streams of royalty revenue over the long term, and undermines opportunities to mitigate land disturbance.

- **Moderately competitive** – Our Panel has concluded that Alberta's total fiscal take (including royalties) from crude oil and natural gas wells is reasonably positioned against its most direct competitors – BC, Saskatchewan, North Dakota, Oklahoma, Pennsylvania and Texas. However, compared to these regions, Alberta is only modestly attractive for investment on a go-forward basis under all commodity price scenarios. Alberta is in the "middle of the pack" in terms of the investment returns our resource development opportunities offer, and in terms of total 'take' by the resource owner.

WHAT WE FOUND ABOUT OIL SANDS

Alberta's royalty structure for the oil sands represents much accumulated knowledge about this unique resource. Unlike the royalty structures for crude oil, liquids and natural gas, our Panel's findings in this area relate more to process than to structure.

- **RMC structure is appropriate** – The royalty structure for oil sands uses a full RMC implementation that is consistent with global constructs for pre-payout and post-payout profit sharing between operating companies and resource owners.

- **Lingering cost disputes** – There are long-standing, unresolved disputes between the Government of Alberta and some oil sands companies regarding cost deductibility. These allowances influence the trigger point between lower pre-payout and higher post-payout royalty rates. The disagreements over costs generate uncertainty about royalty payments, breed cynicism about the veracity of the process, and are administratively burdensome for the public service.

- **Price ambiguities** – Oil sands product streams are unique, often without peers in the North American market. As such, several products are difficult to price in transparent, liquid markets; bitumen grades are particularly challenging. Price ambiguity is causing inconsistent royalty treatments, especially between companies that have fully-integrated downstream operations (and price their oil internally), and companies that do not (and determine their price in an illiquid, opaque marketplace). Market benchmarks used to value oil sands products, notably West Texas Intermediate and Mexican Maya grades, are no longer appropriate for pricing Alberta's oil sands products.

- **Opaque information** – Product prices, the status and financial returns of projects, and the expected and actual amounts of royalties are not easily accessible and digestible. This is feeding an understandable level of cynicism and distrust.

- **Reduced profitability post-2008** – Compared to the 1999-2008 period, the profitability of oil sands projects post-2008 is substantially lower due to cost escalation, with an average internal rate of return (IRR) around 7%. The outlook for returns remains in single digits (using USD $80 per barrel, from the Government of Alberta commodity price deck.)

- **Investment emphasis is shifting** – Based on the current outlook, large-scale, multi-billion-dollar oil sands projects (in excess of 100,000 bpd) are unlikely to attract further investment. Macroeconomic factors, competition from U.S. unconventional oil, and environmental considerations are shifting investment toward smaller projects that require less upfront dollars and offer faster payback. Smaller-scale projects (35,000 bpd or less) are likely to be the 'new normal', assuming a recovery in oil prices and innovation that leads to lower costs.

OUR PANEL'S RECOMMENDATIONS

ESTABLISH GUIDING PRINCIPLES AND DESIGN CRITERIA FOR ALBERTA'S ROYALTY FRAMEWORK

Our Panel recommends that the design and operation of Alberta's royalty framework be guided by a set of lasting principles.

This will have several benefits.

The guiding principles will provide Albertans with a shared understanding of what we expect our royalty framework to support and help accomplish.

They will also allow us to establish performance measures that can be used to periodically assess whether the royalty framework continues to be in line with expectations. A number of measures have been suggested for illustrative purposes; however, this is likely to be something the government will want to examine in more detail.

The principles also have a reputational benefit. They serve as another means of articulating to Albertans, investors, energy producers, our fellow Canadians, and the rest of the world, what our province's energy industry stands for.

Albertans have had a direct hand in shaping these principles.

Our Panel gathered extensive input from Albertans through our website, our community sessions, and in meetings we held with numerous stakeholders, First Nations and Métis, and other concerned citizens. From this input, along with everything we learned and found about Alberta's energy business, competitive position, and current royalty structures, our Panel distilled the principles.

Our Panel took great care in reading thousands of comments made through our website and in written submissions. We learned that Albertans see the royalty framework as one piece of a broader picture – one mechanism among many policy mechanisms – which, when carefully structured and operated trustworthily, can help our province achieve great things.

The guiding principles below bring expression to the hopes and aspirations that Albertans share.

- **Optimize Returns to Albertans.** Innovation and Efficiency are prominent contributors to Albertan's returns. The framework encourages the application of new processes and technologies to improve the efficiency of developing Alberta's energy resources. This, in turn, reduces the costs of producing and selling Alberta's resources and enhances the royalties that Albertans can collect.

  Potential Indicators:

  - Research and development dollars spent in Alberta.
  - Average cost of wells.
  - Average net profit percentage of oil sands projects in post-payout.
  - Royalty revenue as a percentage of total resource revenue.
  - Production revenue from enhanced oil recovery wells.

- **Attracts investment and promotes job creation.** The framework supports the attraction of investment in the development of Alberta's energy resources, encourages the creation of jobs in the province, and supports a predictable business climate in Alberta.

  Potential Indicators:

  - Energy capital expenditures in Alberta as a percentage of the total energy capital expenditures in Alberta's comparator jurisdictions in North America.
  - Meters drilled in Alberta as a percentage of the total meters drilled in Alberta's comparator jurisdictions in North America.
  - People employed in the energy industry in Alberta as a percentage of total employment in the energy industries of Alberta's comparator jurisdictions in North America.

- **Supports downstream value-added industries.** The framework encourages investment in activities and technological advancements that add value to Alberta's energy resources such as upgrading, refining, petrochemical processing and fertilizer manufacturing.

  Potential Indicators:

  - Measure of value-added output as a percentage of total output.

- **Encourages environmental responsibility.** The framework encourages environmentally responsible development of Alberta's energy resources (e.g., clean air, clean water, reduced greenhouse gas emissions, biodiversity, minimal land footprint, etc.), and the conservation of those resources.

  Potential Indicators:

  - Independent annual ranking of Alberta against peer jurisdictions on environmental standards and performance.

Our Panel also utilized input from Albertans to establish design criteria for the royalty framework.

In their dialogue with us, Albertans provided much input on the characteristics they want to see in Alberta's royalty framework.

This input, along with what we learned about royalty structures and the changing energy landscape, went into developing these criteria. The changes and modernization we have included in our recommendations are based upon, and consistent with, these design criteria.

- **Modern** – The framework reflects the current state of industry conditions, including technology, processes, resource maturity, environmental considerations and capital availability.
- **Agnostic to various hydrocarbons** – The framework does not discriminate between hydrocarbon types and enables companies to migrate to and develop the highest-value products. (Put another way, the same general royalty framework is implemented for all hydrocarbons, recognizing that some factors are necessarily different.)
- **Adaptable to changing costs** – The framework adapts over time, using objective and reliable data, to account for the changing costs of developing Alberta's diverse energy resources due to technological advances, policy evolutions, and other relevant factors.
- **Emulates revenues-minus-costs** – The framework is consistent with global standards for the pre-payout/post-payout models of risk-sharing and profit-sharing, but without introducing costly process burdens for the thousands of wells drilled every year.
- **Responsive to changes in resource prices and maturity** – The framework is responsive to changes in resource production levels and changes in resource prices, and shares profitability appropriately at all price points.
- **Supports optimal outcomes** – The framework minimizes distortions that may promote suboptimal outcomes (including environmentally suboptimal outcomes) in exploration, development and market access.
- **Predictable** – Changes in the framework's royalty factors are made gradually, annually and predictably, to minimize perceived investment risks that would otherwise unduly diminish energy development activity.

- **Coordinated** – The framework is optimized to work efficiently and be coordinated with other policies including carbon levies, corporate taxes, municipal taxes, land management, and the promotion of value-added processing, recognizing that royalties are only one dimension of energy development and only one stream of revenue that Albertans raise from the oil and gas industry.
- **Competitive** – The framework's parameters, particularly pre-payout and post-payout royalty rates, are adjusted to ensure competitiveness in attracting capital investment relative to other oil- and gas-producing jurisdictions, notably those in adjacent provinces and the U.S. Various metrics of profitability are considered at the corporate level and producing well level, across the multitude of geologic plays in Alberta.
- **Transparent and accountable** – The framework is transparent in its operation and accountable for its results, enabling investors, energy producers, and Albertans to understand how royalties are calculated and to predict what royalties are payable.
- **Evidence-based** – The framework's methods of formula development are based on metrics that are supported by trusted and certified data sources and professional scrutiny.

MODERNIZE ALBERTA'S ROYALTY FRAMEWORK FOR CRUDE OIL, LIQUIDS AND NATURAL GAS

Our Panel recommends that Alberta's royalty framework be modernized for crude oil, liquids and natural gas.

Recommendation in brief:

- Apply all changes to new wells only. Existing royalties will remain in effect for 10 years on investments already made.
- Design a royalty structure for crude oil, liquids and natural gas that emulates a "revenue minus costs" approach, providing both the Province and investors with a clear line of sight on recouping upfront capital costs and ultimately, see them re-invested in Alberta.
- Harmonize the royalty structures across crude oil, liquids and natural gas to remove distortions in the current framework.
- Eliminate the multitude of expiring drilling programs, and replace them with a permanent formula to easily calculate Drilling and Completion Cost Allowances for each well, based on vertical depth and horizontal length.
- Calibrate the Drilling and Completion Cost Allowance each year to a Capital Cost Index, to reflect current average costs.
- Apply a flat royalty rate of 5% until cumulative revenues from a well equal the well's Drilling and Completion Cost Allowance, followed by higher post-payout royalty rates that increase with price.
- In the transition to the modernized framework, calibrate the combination of Drilling and Completion Cost Allowances and new post-payout royalty rates to target the industry returns and Albertans' share of value that are achieved under the current framework, taking into account that current incentive programs are not well designed for very high or very low prices.

Coming up with a framework that accommodated all factors and issues was challenging for our Panel, given the diversity of geology and hydrocarbons that are found in Alberta. It was also complex because Alberta is now in a position where we are balancing a legacy of decades of oil and gas production with modern competitive realities and opportunities. Our Panel has determined a straightforward way to accommodate this complexity.

How We Do It

Modernizing the royalty framework for crude oil, liquids and natural gas involves the following five actions.

1. Harmonize the royalty structures across crude oil, liquids and natural gas.

The royalty structures for all hydrocarbons would be harmonized – in other words, one royalty structure, regardless of what is produced out of the well. Total revenue (a blend of all hydrocarbon products) would be the top-line measure for calculating royalty rates. This would eliminate existing distortions, and energy companies would be encouraged to find, develop and produce the highest value hydrocarbons.

This is very important for Alberta's crude oil and natural gas development as many of the oil and gas plays that we expect to see developed in the future, including "Deep Basin" plays, will have wells that generate 'cocktails' of various hydrocarbons.

Harmonizing the royalty structures also reduces exploration risk, enabling producers to assess the highest value development opportunities based on market forces without worrying about how the well's products or productivity will be characterized by the royalty framework (as is the case now).

2. Retain and improve the existing structure to better function like "revenue minus costs" (RMC).

Alberta's royalty structures for crude oil, liquids and natural gas have incorporated elements of the RMC model over time. Our Panel believes there would be great benefit in permanently adopting a proxy RMC structure, where the average drilling cost for any new well would be estimated by proxy using a Drilling and Completion Cost Allowance formula, based on vertical depth and horizontal length.

Additional uncertainty would be removed by modifying the existing production formula such that declining royalties as a function of production rate are only triggered during the mature phase of a well's life, not during its early period. This, combined with the upfront recognition of drilling and potentially other costs, is expected to result in earlier capital payout for companies and higher post-payout royalties coming in sooner for Albertans. Both are desirable for each side of the partnership, yielding more predictable and stable royalties over the life of a well.

3. Calibrate to a Capital Cost Index every year.

Our Panel suggests that the proxy for costs be calibrated each year. Without this, the royalty structures will become stale after several years and eventually will be out-of-touch with the realities of the energy business.

Alberta Energy should consult with credible experts, including reserve engineers, to establish and maintain an Alberta Capital Cost Index that tracks year-over-year inflationary or deflationary changes. The Index should be set to 100 in 2017, and allowed to "float" depending on changes in industry costs.

This systemic annual indexing of drilling costs would accomplish several things.

First, the approach would enable our royalty structures to keep pace with changes in costs – positive or negative – due to evolutions in technology, process improvements or externalities that impact the economics of oil and gas development in Alberta. The structures will remain relevant over the long term and adapt to the evolution of costs. In this way, both sides of the partnership – Albertans and energy companies – can be assured that post-payout profits are being shared equitably as conditions change.

Second, this dynamic cost calibration would create an incentive for energy companies to innovate, reduce their costs, and stay competitive. Given an average Drilling and Completion Cost Allowance for its next well, an energy company will be encouraged to "beat the bar" of the average and improve its returns.

Third, the approach would improve the overall strength of Alberta's energy industry. With the average cost bar always in motion, our province will have a stable of increasingly savvy producers that develop our province's resources responsibly, effectively and competitively.

Creating and calibrating an Alberta Capital Cost Index should take place in accordance with the recommended Implementation Directives outlined in Appendix E. Note that once updated each year, the Capital Cost Index, would only apply to go-forward wells, not previously-drilled ones.

Our Panel recommends derivation and public announcement of the Alberta Capital Cost Index by March 31 of each year, for application on April 1 of the same year.

4. Implement strategic programs.

Given the diverse nature of our province's geology, geography and hydrocarbon products, from time to time, strategic programs may be required to promote expanded production potential that could generate greater long-term returns to Albertans.

The first three steps of modernization (set out above) will make it easier for Alberta Energy to establish strategic programs in a consistent fashion.

Our Panel believes the following are immediate areas for consideration of strategic programs:

- **Enhanced hydrocarbon recovery** – Alberta has significant amounts of oil and gas remaining in legacy fields that could be produced through enhanced recovery projects. Right now, our province's royalty structures can sometimes make it more economically advantageous to drill new wells (and hence, create new land disturbances) than to enhance hydrocarbon recovery using existing infrastructure (on existing land disturbances). Alberta has an existing Enhanced Oil Recovery (EOR) program. Several of Alberta's competitor and comparator jurisdictions also offer special programs for enhanced hydrocarbon recovery. Extending that type of treatment to cases such as new non-potable water flood programs, polymer programs, and across other hydrocarbons can improve those outcomes.
- **High-risk experimental wells** – These are wells that depart from the standard risk profile of oil and gas wells, but which have the potential to reduce costs or open up new play areas (or both). Such experimental wells can not only serve as important catalysts for more activity and investment, but also generate much knowledge that can be used by our province's entire industry in 'moving up the learning curve'.

Our Panel recommends that Alberta Energy establish strategic programs for these two areas by March 31, 2016, well in advance of the 2017 budget planning cycle.

5. In the transition to the modernized framework, calibrate post-payout royalty rates to target the industry returns and Albertans' share of value that are achieved under the current framework, taking into account that current incentive programs are not well designed for very high or very low prices.

The modernized framework is to be calibrated such that the returns for industry and the share of value captured by Albertans match the returns generated under the current regime, taking into account that at very high and very low prices the current incentive programs do not achieve their intended goals of accurately reflecting costs or stimulating development. For example, the existing horizontal well program for oil, which would be expected to reflect drilling costs, provides a lower royalty rate for the first 50,000 barrels at certain drilling depths. At prices of $30, $50 and $100 per barrel this would result in lower royalties on the first $1.5, $2.5 or $5 million, respectively, of revenue – all from the same program and presumably to reflect the same average drilling cost for wells of that kind. The same situation exists where a program is time-limited rather than based on a dollar amount. The modernized framework removes this uncertainty for both the developer and the Province and focuses on the average actual cost of that well – regardless of oil prices.

Under the modernized framework, Albertans and industry will benefit from the simplicity and predictability of the framework; the harmonization of royalties across hydrocarbons that removes the risk of producing an unintended product and having their royalty classification abruptly switch; and a framework that encourages more efficient operations at all depths and time paths.

Moreover, and most importantly, the new system is designed to increase the value we receive for our resources over time. As the Drilling and Completion Cost Allowance rewards efficiency and lower costs, companies will be more profitable and Albertans will receive an increased share of that value. Removing the highs and lows of royalty rates also makes the Province's revenues more predictable.

Both Albertans and industry stand to benefit from the modernized framework in its improved calculation of the base value of the resources, which enhances the efficiency, transparency and predictability of the system. The establishment of a Drilling and Completion Cost Allowance, based on an average of comparable wells and calibrated annually, also creates a "beat the average" metric that will leverage and reward the competitive entrepreneurial strength of Alberta's energy industry. We expect this will lead to greater levels of investment as companies recognize the modernized framework offers greater alignment with their costs and greater alignment with the production profiles of today's oil and gas wells.

Implementing and properly calibrating the modernized framework requires exhaustive testing and further detailed work. Our Panel recommends that a calibration team be established to deliver the detailed formulas no later than March 31, 2016.

6. Apply the Modernized Royalty Framework to new wells only.

These considerations, coupled with the complexity of applying the modernization to pre-existing wells, leads our Panel to recommend that this **Modernized Royalty Framework (MRF) be applied only to new wells spudded after the implementation date.**

We recognize that the lack of certainty around the treatment of wells that are being considered during 2016 could result in deferral of activity to 2017. This will stem from the question of whether wells drilled in 2016 (and those drilled in 2015 and earlier) would qualify for and have continuing benefits from the Natural Gas Deep Drilling Program and Emerging Research & Technology Initiative, whose regulations expire at the end of November 2016 and June 2018, respectively. To facilitate a seamless transition to the MRF, it is recommended that those programs be extended so they cover all wells drilled in 2016 and earlier. Our Panel believes this will provide sufficient certainty for wells currently in the planning stage to go ahead in 2016.

Since the MRF creates an "old well" and "new well" distinction, our Panel also recommends that a sunset provision be established to transition all old wells (drilled before the implementation date) into the modernized structure at the end of 10 years from the MRF implementation date. This will reduce administration and allow for simpler application of new programs to fields or pools with multiple wells.

How This Will Work in Practice

1. A company will plan to drill a well of certain vertical depth and can include lateral length. Both variables will be inputs into the Drilling and Completion Cost Allowance formula.
2. Using the Drilling and Completion Cost Allowance formula (previously called a Depth Function), the company will determine its Drilling and Completion Cost Allowance, C* (called "C-star") for the well.
3. The company will drill and complete the well and begin producing hydrocarbons.
4. Revenue from the well will be tracked by multiplying production volumes of the various hydrocarbons by their respective commodity par prices, as published by Alberta Energy.
5. The company will pay a flat royalty of 5% on early production revenue (0.05 x revenue) up until the point of payout.
6. Payout will be achieved when the cumulative revenue equals C*.

7. Upon achieving payout, the company will pay elevated post-payout royalty rates on all subsequent production revenues in the post-payout period.

8. Post-payout royalty rates will be determined by the commodity prices of the various hydrocarbon streams, using the Price Function. Similar to the current royalty framework, the post-payout royalty rate will vary according to the Price Function over the remaining life of the well.

9. Once hydrocarbon production from the well drops below a certain rate, called the Maturity Threshold (see details in Appendix E), the well will be classified as mature. Royalty rates will be adjusted downward, in proportion to declining production rates, to accommodate the mature economics of low productivity, much as they are under the current system.

10. **Note:** Once a well is drilled and is producing, C* remains fixed for that well and does not vary even though payout may extend into subsequent years where the determination of C* for new wells will vary depending upon the Capital Cost Index.

11. The company will be obliged to report its actual capital costs along with other mandatory well information to the AER. The cost and depth data from thousands of wells will then serve as statistical inputs to calculate the Capital Cost Index for the subsequent year.

As can be seen in the below illustration, the MRF will result in the calibration of new royalty curves for crude oil, liquids and natural gas.

The MRF is designed so that the structure aligns with the development of modern, unconventional oil and gas wells. This will enable energy companies to recoup their large, upfront capital investment during a pre-payout period. By doing so, companies can re-invest in the next well, and so on.

During the post-payout period, a more stable royalty rate (at a given commodity price) is proposed, rather than one that is tied to uncertain production. This will give Albertans and the company greater predictability of royalties during the mid-life cycle of a well. Right now, the system is such that there are high royalty rates for very brief periods of high production, followed by steadily declining rates at lower rates of production. Under the MRF, rates will be less erratic during the lucrative mid-life cycle of a well. That predictability is better for both Albertans and investors.

Once a well reaches the tail end of its life cycle, the royalty curves will adjust downward to recognize the higher per-unit fixed costs involved in keeping the well running. This will help extend the life of the well, helping to maintain local employment, surface fees and municipal taxes.

There will be new royalty rates under the MRF. However, the new rates will be calibrated to match the industry returns and Albertans' share of value that are achieved under the current royalty framework, taking into account that current incentive programs are not well designed at very high or very low prices.

ILLUSTRATION OF THE MODERNIZED ROYALTY FRAMEWORK

Royalty Rates Structure Over the Life Cycle of a Well

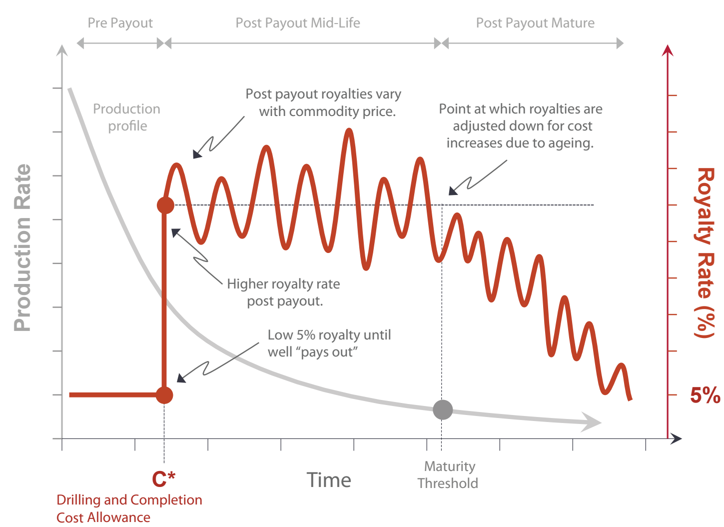


Figure 21

OUR PANEL'S RECOMMENDATIONS

Comparison of Existing and Modernized Royalty Frameworks

	Existing Royalty Framework	Modernized Royalty Framework (MRF)	Benefits of Migrating to the MRF
Framework Type	Uses implied Revenue-Minus-Cost (RMC) structures with temporary royalty credits, in an attempt to simulate capital cost recovery. Different structures are used for each hydrocarbon.	Explicitly emulates a RMC model. Capital costs for drilling and completing a well are allocated by proxy, similar to the depth function used in the current Natural Gas Deep Drilling Program. Drilling and Completion Cost Allowance is determined by statistical analysis of historical data. One framework is used for all hydrocarbons.	RMC-based frameworks are a global standard for profit-sharing between resource owners and energy companies. Harmonizing across all hydrocarbons simplifies the royalty framework and makes it easier to analyze.
Determination of Capital Costs	Different depth functions are used for oil and natural gas to estimate a royalty credit. There are no cost allowances provided for other hydrocarbons.	A single depth function that estimates, by proxy, a single Drilling and Completion Cost Allowance, C*, representing the completed well cost. The same C* is used, regardless of hydrocarbon target, vertical depth, or lateral length.	Using a single, more accurate depth function simplifies the royalty framework. Capital costs will be better estimated, ensuring that post-payout royalty rates are triggered at the right time.
Capital Cost Payout Trigger **(When the transition is made from pre-payout to post-payout royalty rates)**	For natural gas, the trigger is based on dollars of royalty credit. For crude oil, the trigger is based on barrels of cumulative volume credit with a time limit.	All triggers are expressed in dollars. Payout is achieved when the cumulative revenue generated from the well (no matter what hydrocarbons it produces) equals the Drilling and Completion Cost Allowance, C*.	Standardizing to dollars simplifies the framework for anyone analyzing the value of Alberta's resources. Basing the trigger in dollars makes things more accurate, and makes it easier to overlay strategic policies.
Pre-Payout Royalty Rate	A maximum 5% rate on revenue for crude oil and natural gas until royalty credit is consumed. A maximum 5% for propane and butane. A maximum 5% for pentanes plus.	A flat 5% rate on revenue is applied up to the payout point (C*), regardless of the type of hydrocarbons produced.	Maintaining a 5% rate allows a well to payout more quickly than a higher upfront rate, while collecting roughly the same royalty dollars on the well. As in the existing framework, the low rate recognizes there are large initial operating costs. The 5% pre-payout rate maintains continuity between the existing framework and the MRF.
Post-Payout Royalty Rate	Different price sensitivity functions for crude oil and natural gas. Liquids are subject to a flat 30% rate (for propane and butane) or a flat 40% rate (for pentanes plus), regardless of price.	New price sensitivity function(s) are calibrated to preserve expected life-cycle investment returns (at the well level) and Albertans' share of value that are achieved under the current framework, taking into account that current incentive programs are not well designed at very high and very low prices.	This provides a transition that is as seamless as possible from the existing framework to the MRF, on the date of implementation.

OUR PANEL'S RECOMMENDATIONS

	Existing Royalty Framework	Modernized Royalty Framework (MRF)	Benefits of Migrating to the MRF
Distortions at Very High and Very Low Prices	At very low prices the current system is prone to providing insufficient recognition of costs and at very high prices the reverse is true.	The calibration will seek to remove the distortions that occur at both ends of the price spectrum.	The recognition of drilling and completion costs will be based on average actual costs in the province and will be unaffected by commodity price changes.
Production Function	A declining function that gradually discounts the royalty rate over the entire life of a well.	A declining function that gradually discounts the royalty rate only after the well crosses a Maturity Threshold and becomes a low-productivity well.	Changing the timing of the declining function will reduce volatility in royalty rates during the mid-life of the well. This will also enable the payout point to be reached faster (and thus, trigger post-payout royalty rates earlier). Faster cost recovery is good for investment. A longer royalty-paid period benefits the province.
Stability of Royalty Payments	Payments are volatile due to the interplay between the production function and the price function. The bulk of the royalty payments are too concentrated in the period immediately following payout.	Greater stability in royalty revenue post-payout. Less variation in royalties during a well's mid-life productivity (i.e., after the well reaches payout but before it reaches maturity).	Royalties will be distributed more evenly across a well's mid-life productivity. The resulting reduction in volatility will reduce financial risk. Royalty payments will be more predictable for the Province and for the producer.
Minimum Royalty Rates on Maturity	5% for natural gas & ethane 0% for crude oil & condensate 30% for propane and butane 40% for pentanes plus	Maturity Thresholds to be determined by the Calibration Team. Suggested minimum royalty to be fixed at 5% for all hydrocarbons.	Minimum "floor" royalty on all wells, regardless of type. Only applies to new wells drilled following implementation of the MRF.
Adaptable to technological change, economic cycles and other inflationary/ deflationary forces?	Only with efforts to do additional royalty reviews and make changes based on them. Not an automatic process.	Yes. Drilling and Completion Cost Allowance will adjust annually (+/- 5% maximum per year) based on a Capital Cost Index to be instituted by Alberta Energy.	Truer representation of cost variations over time. Ensures fair sharing of value in excess of "revenue-minus-cost."
Potential changes to the Depth Function(s)?	None. Static unless a specific review takes place. Certainty has been valued over responsiveness in some cases.	Long-term dynamic. The depth function will be reviewed by Alberta Energy and expert committee every 3 to 5 years to ensure Drilling and Completion Cost Allowances are being estimated properly as a function of depth.	Truer representation of cost variations over time. Ensures sharing of value in excess of "revenue-minus-cost."

	Existing Royalty Framework	Modernized Royalty Framework (MRF)	Benefits of Migrating to the MRF
Treatment of Carbon Levy	No accommodation.	Carbon levies relating to capital cost expenditures will be captured in the Capital Cost Index, which will adapt over time.	The MRF adapts to all changes in costs over time, not just carbon levies.
Transition Considerations	Existing programs under the current framework will be maintained until the MRF is implemented.	The MRF will be applicable only to wells spudded after the date of implementation.	The MRF will preserve legacy royalty arrangements on capital that has already been committed. Starting fresh with the MRF will be administratively easier.
Accommodation of Strategic Programs like enhanced hydrocarbon recovery and experimental wells	Currently difficult due to the different royalty structures for each hydrocarbon. Also difficult due to different payout triggers.	All hydrocarbons are under one framework and metrics are based in dollars. Strategic programs can be structured around the Drilling and Completion Cost Allowance, C*.	Strategic programs are necessary to accommodate the wide spectrum of resource development circumstances. The MRF will make it easier to accommodate new policies.
Transparency	Somewhat opaque. Difficult to analyze a known but complicated set of interacting variables.	Transparent and dynamic. Alberta Energy will issue an Annual Report by March 31 each year, in conjunction with release of the new Capital Cost Index.	Greater transparency should help mitigate skepticism and cynicism about Alberta's royalty framework and the results it generates for Albertans.

Implementation

To provide clarity to the public, the industry and the investment community, our Panel recommends immediate approval of the modernization approach set out above, along with the associated Implementation Directives that will bring life to the framework. The Implementation Directives are contained in Appendix E.

ENHANCE ROYALTY PROCESSES FOR THE OIL SANDS

In developing recommendations regarding the royalty structure for oil sands, our Panel has considered the outlook for this unique resource.

New large-scale projects in Alberta's oil sands are not expected for the foreseeable future. There are many reasons for this. First, there have been structural changes in the oil industry, such that there are many other economically accessible sources of oil in North America. Second, the oil sands are a relatively higher-cost resource to develop. Third, there is currently no line-of-sight to increased international export capacity of bitumen, which would otherwise help boost bitumen prices. Finally, investors are trending away from high-cost projects with long payback periods towards opportunities such as horizontal oil and gas wells, which offer faster payback and require less upfront capital.

Future oil sands growth is likely to be in the form of smaller-scale in-situ projects (35,000 bpd or less). Some expansion and debottlenecking projects at existing oil sands facilities might also be undertaken. These should all be encouraged. New investments in large oil sands mining projects (100,000 bpd and more) are unlikely.

Overall, the opportunities to improve things on the oil sands side relate more to the process of calculating and collecting royalties, versus the royalty structure itself. Our Panel believes that action should be taken to enhance these processes.

How We Do It

There are four main areas where our Panel sees opportunities to enhance royalty processes around the oil sands.

1. Make no changes to oil sands royalty rates.

The analyses undertaken by our Panel show that there is little room for an increase in royalties at the price levels being projected by both industry and the Government of Alberta. Forecast returns have become marginal for existing oil sands projects, and have become uneconomic for new projects. Oil prices would need to remain at or above $100 per barrel for a sustained period of time for any significant oil sands projects to be considered.

For existing oil sands projects in the post-payout phase, the current sliding scale of royalty rates (25% to 40%) is comparable to other international producing jurisdictions.

The royalty increases implemented in 2009, combined with the transition of many oil sands projects to post-payout (i.e., higher royalty rates), are

FORECAST ROYALTY REVENUES FROM OIL SANDS PROJECTS

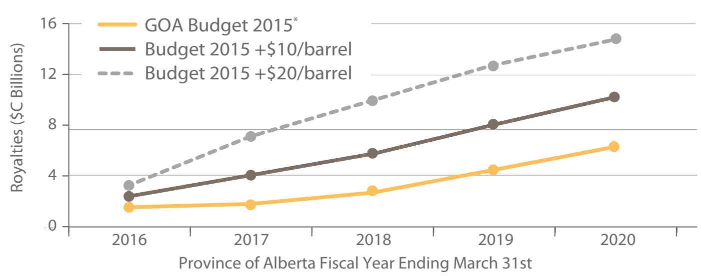


Figure 22

**Note: Based on Government of Alberta Oil Price Forecast*
Source: Alberta Energy

OUR PANEL'S RECOMMENDATIONS

expected to generate increased royalty revenues using the Government of Alberta's price forecast. As commodity prices rise, these revenues will increase significantly, as post-payout royalty rates increase with price through to $120 per barrel.

Our Panel considered royalty rate adjustments at all price points for the oil sands, especially above $100 per barrel, for projects that are in post-payout. There are schools of thought that insufficient royalties have been charged in the past. This analysis is based on pre-2010 data and it has validity; however, the rates introduced in 2009 corrected this, and the structural price changes that have occurred in the world since that time have diminished prospects for company returns even further.

Raising royalty rates at high commodity prices may yield more royalty revenue from existing oil sands projects, but will further diminish the already-lean investment potential of go-forward projects of all sizes. Additionally, in the post-2015 world, the probability of high prices that would see those adjustments actually kick-in is low.

2. Improve the decision-making on oil sands costs.

Our Panel frequently heard questions and concerns relating to the accounting of costs in oil sands royalty calculations. Many Albertans recognize the linkage between the costs claimed by oil sands operators and the amount of royalties that are paid.

There is a level of public distrust concerning the costs claimed by oil sands operators. It is a common belief that oil sands operators routinely "pad" their costs to extend their low-royalty, pre-payout periods. In fact, the Province has an *Oil Sands Allowed Costs Regulation*, which sets out the only costs that are deductible for the purposes of calculating oil sands royalties.

There is anecdotal evidence, however, that oil sands operators push the boundaries when it comes to costs, and that the Province has not enforced the rules with the 'iron fist' that Albertans might expect. The net result is people do not think the government does a good job of enforcing the rules and people do not trust companies to play by them.

While it is not our Panel's place to advise the government on how to organize its departments, by reviewing and improving this area of royalty administration there is an opportunity to help rebuild trust among the public, the Province and industry.

Whatever form proves to be the best solution, our Panel recommends the following criteria in establishing a means of improving decision-making on oil sands costs:

- Operate in a manner free of industry influence
- Have the ability and authority to promptly render decisions
- Issue advance rulings on projects, research, etc. to prevent "surprises"
- Be staffed with experts on oil sands operations and the *Oil Sands Allowed Costs Regulation*

We do not expect this would have any adverse impacts on the development or operation of new or existing oil sands projects. Though companies would face stern, fact-based decision-making in respect of their allowable costs, they would gain enhanced predictability, consistency and promptness when it comes to decisions about the applicability of the rules about costs.

Our Panel also recommends that the *Oil Sands Allowed Costs Regulation* be updated in consultation with the oil sands industry, to ensure it reflects current market conditions and the province's overall strategy.

3. Improve disclosure of royalty information by project.

In the course of our work, our Panel also found that a lack of publicly available information about oil sands operations is contributing to distrust among Albertans.

Oil sands operators are developing a publicly-owned resource, and as such, there is an expectation of transparency regarding the royalties they pay. A lack of information breeds suspicion, which in turn erodes the social licence that our province needs to develop this very unique resource.

Our Panel recommends that the Province annually publish a financial summary of each oil sands project, including the following items:

- Revenue
- Diluent cost
- Gross revenue net of diluent
- Bitumen production
- Gross revenue per barrel
- Operating costs
- Capital costs
- Return allowance
- Net revenue
- Royalty rate
- Royalty dollars collected

4. Modernize administrative components of the oil sands royalty structure.

Oil sands product streams are unique, often without peers in the North American market. As such, they are difficult to price and historically have required a number of mechanisms to estimate, typically by using market comparables of similar products for reference. Issues such as which benchmark product price to base royalties upon, and the method to value bitumen, are examples where markets have become more liquid over the past decade.

Better domestic pricing information has become available over the past 10 years, making benchmark prices candidates for updating. Additionally, production methods and the advent of new technologies also give reason to review current administrative rules that are part of the royalty framework. The modernization of these rules and valuation methodologies will increase public confidence in the royalty system and improve predictability for the industry.

As these administrative issues are intertwined with allowable costs, our Panel recommends that they be reviewed and updated as part of the same consultation process to review allowable costs in the oil sands.

SEIZE OPPORTUNITIES TO ENHANCE VALUE-ADDED PROCESSING

Our Panel recommends Alberta make a bold stretch and seize opportunities to enhance value-added processing in the province, and position our energy industry for long term success.

While these recommendations are not directly about Alberta's royalty framework, they would have a significant impact on the ability of Albertans to realize further returns on our resources.

Our traditional sense of upgrading and refining is bounded by the processing of bitumen into Synthetic Crude Oil or refining it into transportation fuels. While the economics have not been kind to those activities, it is more the renaissance of U.S. light unconventional oil production in startling quantities that now makes traditional upgrading a challenging prospect.

However, our Panel has identified two other areas which we believe have significant promise and may deliver the benefits Albertans aspire to – that is, to add value to the products we extract here in the province.

Both of these opportunities are in keeping with Alberta's long history of taking strategic actions to maximize the benefits Albertans can derive from our province's natural resources. Ever since the Province obtained ownership of its natural resources in 1930, government has played an active role in encouraging value-added processing of oil and natural gas.

On the natural gas side, in fact, the first petrochemical plant constructed in our province (Alberta Nitrogen Products Ltd.) was built by a Government of Canada Crown agency. It was a factor leading to Alberta's management of natural gas and the creation of what is now the AER. Later sold to private industry, this plant was developed to produce war materials from natural gas produced in the Turner Valley area.

In 1949, the Government of Alberta implemented a policy that no natural gas could be exported from the province until a certain amount of natural gas reserves had been proven (such that current and foreseeable natural gas needs, including industrial needs, could be met). There was also a limitation placed on exporting natural gas liquids without special permits. These policies were considered to be reassuring to industry, as they helped ensure a certain volume of natural gas would be available for use within the province.

These policies, combined with low prices for natural gas and natural gas liquids and limited options for transporting these commodities, led to the construction of a number of petrochemical plants in Alberta in the early 1950s. These include plants that produced cellulose, ammonia, nitric acid and explosives. In the mid-1950s and 1960s another group of petrochemical plants, principally in the Edmonton area, built on these to extend the value chain.

During the early 1970s the Government of Alberta took further steps to promote petrochemical value-added processing in Alberta. This included a number of mechanisms including, for one project, making a commitment to provide a supply of ethane (a component of natural gas) at long-term, stable pricing. The government even made guarantees to approve necessary supplies of water, and to not let ethane leave the province for competing petrochemical uses elsewhere. This resulted in major investments in plants to extract ethane, plants to convert ethane to ethylene, and a pipeline to transport excess ethane supply to other markets.

In the 1980s onward, government policies have tended to focus on ensuring Alberta's petrochemical industry have access to ethane supplies. This, combined with new natural gas discoveries, led to the construction of some additional petrochemical facilities. The economics of these projects were also supported by a decision to remove the education tax on machinery and equipment, as an overall incentive for industrial development in Alberta.

Even in recent years there has been work to support these goals. This includes the establishment of the Incremental Ethane Extraction Program (IEEP) in 2007, to support development of further ethane usage in Alberta.

On the oil side, the Government of Alberta has involved itself directly in the development of technology to support both production and value-added processing.

In September 1973, Premier Peter Lougheed announced the start of a $1-billion Athabasca oil sands complex, including an $800-million, 125,000-barrel-a-day mining and processing complex; a $90-million electric generation station to power the complex; about $90 million for a pipeline to Edmonton; and various startup costs. This became Syncrude, financed in part by the Province through the Alberta Energy Company (which was 50% owned by the Crown).

Then in 1974, the government established the Alberta Oil Sands Technology and Research Authority (AOSTRA), fore-runner to today's Alberta Innovates – Energy and Environment Solutions. AOSTRA undertook basic and applied research in the oil sands, with the goal of turning the oil sands into a commercial industry. The research done by AOSTRA resulted in the development of technologies that could extract oil from oil sands, strongly contributing to the oil sands industry Alberta has today. Through its research into different upgrading technologies, AOSTRA also led to improvements in upgrading at existing oil sands facilities.

Admittedly, many of these actions were taken in a different time – when the world was smaller and less connected. However, the spirit that drove these actions still exists today: a desire to deliberately and strategically leverage our oil and gas resources for the benefit of Albertans. Alberta has never purely "left it to the market" to determine the destiny of our resources, and in today's hyper-competitive world it's more important than ever that Albertans have control of that destiny.

Our suggested actions below outline pathways for doing just that.

How We Do It

There are two main opportunities that our Panel sees to make a "bold stretch" towards more value-added processing.

1. Develop a value-added natural gas strategy for Alberta.

As covered earlier in our report, the fact is that the U.S. will need less and less of Alberta's natural gas. In addition, significant natural gas discoveries in Africa (including Egypt), Western Australia and other jurisdictions, coupled with advances in floating liquefaction technologies, have added to the challenges facing potential exports of Canadian natural gas.

If Alberta natural gas will be challenged to be competitive in its raw form, then we can take the opportunity to think differently, and creatively, about optimizing our natural gas resources so that we can continue to attract investment in natural gas development. The new landscape of natural gas abundance can be an opportunity for Alberta, not just a challenge.

First, with lower carbon emissions, natural gas can be an effective bridge from the current hydrocarbon economy to a future world with extensive reliance on renewable energy sources, with policies in place to ensure alignment with longer-term climate goals. Natural gas can play an important role in helping our province achieve its goal to phase out coal-fired electrical generation in alignment with Alberta's Climate Leadership Plan, both in transition and providing peak and base-load support.

Second, natural gas resources are essential inputs to support significant value-added industry expansion – specifically in technically-rich sectors such as the conversion of bitumen to lighter products, petrochemicals, natural gas to liquids (diesel) processing, fertilizers, and consumer-oriented products such as biomedical equipment and pharmaceuticals. With vast supplies of low-cost gas, Alberta has a strong case to encourage value-added processing of natural gas and natural gas liquids within the province.

Together, these two pathways form the potential heart of a value-added natural gas strategy for the province. Such a strategy would incorporate both supply and demand: developing a virtually limitless supply of natural gas and natural gas liquids, and building domestic natural gas demand through strategically integrated opportunities.

This approach is not unprecedented. Other resource-endowed jurisdictions have faced and overcome similar challenges to those Alberta is now experiencing. Although there are many examples, South Africa, Saudi Arabia and Malaysia illustrate the potential.

In South Africa, the impact of trade sanctions led to an innovative and integrated energy ecosystem development. Endowed with coal and limited liquid hydrocarbons, South Africa was able to build a system that provided fuels, chemicals and fertilizers for agriculture. By taking a comprehensive view of leveraging its carbon based resources, the country was able to realize efficiencies and become a global competitor in both coal and natural gas-based petrochemicals.

In Saudi Arabia, natural gas was flared as a waste byproduct for more than 50 years. A strategy to monetize this "waste hydrocarbon" led to multiple industry expansions into steel, fertilizers and petrochemicals. In addition to being the leading oil producer in the world, Saudi Arabia is now home to one of the world's most advanced petrochemicals complexes and integrated value chains that delivers continued job expansion and economic growth.

In Malaysia, oil and gas represents the cornerstone of the economy. To derive additional economic growth from the oil and gas industry, the Malaysian government designed a specific strategy to leverage all the benefits of natural gas through the development of its RAPID petrochemicals complex project.

Alberta certainly has the natural gas reserves to pursue its own approach.

Although Alberta's historic natural gas fields in the southern parts of the province are depleting, Alberta has very rich deposits in early stage development in the Montney and Duvernay formations. Numerous developers are using innovative, high-technology methods to extract the resource efficiently from both a cost and environmental perspective. Pad drilling setups, which run multiple horizontal wells from a single on-ground location, obtain very large production rates and reserves and may disturb up to 10 times less surface area than conventional vertical wells accessing the same natural gas resource.

Together, the two formations could represent the equivalent of another century of natural gas development in Alberta. Rewarding innovative techniques to unlock these enormous gas reserves while minimizing their footprint, and then progressively reducing production costs, will be key to reliably feeding the power-generation and value-added industry expansion opportunities.

Our Panel believes a holistic and comprehensive analysis is required to allow a hydrocarbon value chain plan to be created. Among the questions that would need to be answered are:

- How can we lower our natural gas supply costs to a point that supports improved profitability for the oil and gas industry?
- Will scale drilling enable natural gas costs to become sustainably and globally competitive, and allow us to bridge from coal power generation to lower carbon emitting natural gas power generation at a competitive capital cost? Can this occur on a structural and long-term basis? What necessary guardrails and technologies will need to be in place to be consistent with emissions reductions in the 2030-2050 timeframe?
- How do we accelerate the expansion of Alberta's petrochemical industry that supports Alberta's natural gas industry and the nature and scale of drilling operations that will be required to be competitive?
- Alberta's natural gas is liquids-rich and accessing these natural gas liquids is key to supporting a viable petrochemical industry. Extracting the natural gas liquids through deep-cut gas processing facilities is capital intensive. How can we support the build-out of the necessary gas processing facilities in Alberta?
- Is our existing rail infrastructure able to move products derived from natural gas to ports and into ships that land in growing Asian and European markets in a cost competitive system? What products are best moved in this manner?
- Is our existing pipeline infrastructure adequate to create the economic incentives needed to minimize venting and flaring of natural gas and, if not, how do we mobilize the necessary investment?
- Can we find technology and scale advantages tied to low energy and petrochemical derivative costs that allow us to bring additional clean alternative power into the energy mix?
- Can this lower cost power enable local bitumen conversion to saleable fuels and petrochemical feed stocks that can compete globally?
- Can we create a reliable fiscal and policy regime that attracts global capital for such an endeavor and ensures Albertans maximize the value of their resource?

Our Panel recommends the Government of Alberta undertake a review of Alberta's natural gas options that:

- validates the new global competitive realities facing Alberta's natural gas industry;
- reviews previous work done to accelerate the analysis and evaluation of viable natural gas alternatives;
- seeks the input of the key stakeholders; and,
- focuses on innovation with a view to increasing competitiveness.

The objective of the in-depth review would be to propose an action plan to establish a fiscal and policy framework to encourage investment in Alberta in value-added activities for natural gas, while maintaining our goal to be a leader in environmental stewardship.

2. Examine opportunities to accelerate the development and commercialization of partial upgrading and alternative value-creation technologies for bitumen.

Many Albertans are familiar with the concept of upgrading, whereby bitumen is converted into Synthetic Crude Oil. As we outlined earlier in our report, Synthetic Crude Oil directly competes today with light U.S. unconventional oil, the production of which is expanding dramatically. In addition to the economics being challenging, we already upgrade nearly 50% of our bitumen and marketing greater volumes will be increasingly difficult.

Partial upgrading of bitumen, on the other hand, offers a potential opportunity to diversify our product range and alleviate some of the challenges facing the marketing of our oil sands resources.

The partial upgrading process removes various proportions of the heaviest fraction of the bitumen barrel. It produces a medium- to medium-heavy grade of oil, which could fill existing gaps in several North American refineries. Partially upgraded bitumen could be transported with less or no addition of diluent (compared to transporting raw bitumen). This would effectively expand the capacity of existing pipelines. With less space in the pipe taken up by diluent, there would be more space for oil.

Since some partial upgrading processes currently under development leave the "bottom of the barrel" in the ground, partial upgrading also has the potential to improve the economics and reduce the carbon footprint of bitumen extraction. Partial upgrading generates fewer carbon emissions compared to full upgraders. In addition, the capital intensity and operating costs of partial upgraders are lower, due to milder processing conditions and reduced requirements for ancillary processes that are required in full upgrading.

One significant advantage of partial upgrading technology is that it would uniquely benefit our province to the exclusion of other jurisdictions. From our consultations, we heard that the magnitude of investment required to "move the needle" on partial upgrading technology is approximately $300 million.

Our Panel recommends the Government of Alberta more closely consider the merits of the various technologies with a view to accelerating the commercialization of partial upgrading and of alternative value-creation technologies. This success of these technology investments would enable Alberta to realize expanded crude marketability, expanded export capacity and a lower environmental footprint for a portion of our bitumen production, as well as hedge against a future in which transportation fuel demand is disrupted.

OTHER MATTERS RAISED WITH OUR PANEL

In the course of our work, our Panel encountered and heard about a number of issues that impact Alberta's ability to be successful in the energy business over the long term. While these issues do not directly relate to the content of Alberta's royalty framework, they indirectly influence the returns that Albertans can realize from our resources.

Many of these items are very complicated and no actions are specifically recommended, as these items are not part of our Panel's scope.

Our Panel is aware that, in some cases, government departments and others are already examining or working to address these issues. Our intent is not to supplant their work. Rather, we feel an obligation to share what we have heard about these issues and to comment on their importance in enabling Alberta to have a successful energy industry and enabling Albertans to realize the value of their energy resources.

- **Abandoned Wells and Tailings Ponds** – A consequence of Alberta's many decades of energy development is substantial legacy infrastructure. Today there are hundreds of abandoned crude oil and natural gas wells awaiting reclamation. And although their associated projects are still operational, tailings ponds in the oil sands represent long-term reclamation endeavours. Albertans want to be assured that taxpayers will not be liable for the costs of reclaiming this infrastructure. They are also eager to see headway made in the reclamation of abandoned wells and tailings ponds. There may be opportunities to encourage energy producers to set aside funds early in a well's or project's life to enhance reclamation outcomes and help mitigate the risk that liability for reclamation costs will fall on taxpayers. In addition, against the backdrop of legacy infrastructure, our Panel heard that Albertans have questions about Alberta's groundwater. Expanding efforts to map and learn about Alberta's groundwater will support good decision-making about how to address abandoned wells.
- **Pace of Development** – One of our Panel's learnings was that the pace of development has an impact on Alberta's royalty revenues. When strong commodity prices spur a flurry of development activity, wage and price inflation is also spurred. This raises the costs of producing and selling our resources, and hence, cannibalizes the amount of value available for royalties. Inflation was a particular challenge when tens of billions of investment dollars were pouring into new oil sands developments. Given forecasts in the price of oil, a repeat of a hyper-inflation scenario appears unlikely. As our Panel noted, it is unlikely that there will be any new large oil sands megaprojects. The new cap on total carbon emissions from oil sands, called for in Alberta's Climate Leadership Plan, will also help manage the pace of development. While this issue may now have been solved for the reasons stated, given the substantial impact it has on resource revenue, the Government of Alberta may wish to examine market tools that could be used to manage the pace of development in the unlikely event it becomes an issue. Another area where pace of development created pressure was the cost of municipal infrastructure that was required to support industrial activities and rapid growth. Our Panel heard representations from municipalities, industry and researchers about the relation this has to municipal taxation. Municipalities can find themselves providing and maintaining infrastructure far in excess of their relative size and financial capacity to support resource development, maintenance and growth pressures. This leads to the current situation where mill rates for taxes can vary widely across the province, thereby placing current and future development at risk.
- **Gas Cost Allowance** – Today's Gas Cost Allowance (GCA), which ultimately impacts the royalties collectable by Albertans, is the culmination of many decades of knowledge and experience around gas development. Nevertheless, there may be opportunities to address aspects of the GCA to make it work more simply and optimally.
- **Bitumen Valuation Methodology (BVM)** – When bitumen is sold by a producer to a refinery in a non-arm's-length transaction, the BVM is used to determine the value of the bitumen that was sold. (This value is used to calculate royalties.) There are calls to address certain aspects of the BVM, based on its perceived fairness or legitimacy.
- **Alberta Energy Information** – An opportunity that can help support management of our resources, and improve transparency for Albertans, is to expand the capacity of Alberta Energy such that it provides a domestic equivalent of the U.S. Energy Information Agency (EIA). The U.S. EIA is well-respected, and its robustness supports better policy making and enhances

the perceived professionalism and calibre of U.S. energy production. Given the significance of the energy industry to our economy, it would make considerable sense for us to 'up our game' with our own Alberta EIA.

- **Market Access** – Alberta's oil and gas products have been constricted in reaching continental and global markets for several reasons. Some of these have nothing to do with new pipelines. (For example, high natural gas tolls for accessing eastern and U.S. markets – through existing pipelines – have been acting as a financial constriction, dampening Alberta wellhead prices.) We believe there is value in the Government of Alberta working with the Government of Canada to convene a multi-stakeholder group to bring about urgently-needed action for a pan-Canadian market access strategy.

- **Regulatory System (Timeliness)** – Despite the creation of the AER in recent years, there remain calls from several quarters to improve the speed at which project/well approvals and other regulatory decisions are made. We heard anecdotal evidence that in some of the jurisdictions with which Alberta competes, it takes a fraction of the time to approve a well or project as it does here. There may be a need to enhance the timeliness and efficiency of the regulatory system without compromising environmental, health, safety and other standards or expectations.

- **First Nations and Métis Revenue Sharing** – Representatives of First Nations and Métis communities consistently represented the issue of sharing resource revenues with their communities. There are outstanding and serious concerns about the impact that energy development activities have on their communities. These concerns could be added to other discussions undertaken by the government.

- **Oil Sands Minimum Resource Recovery Obligation** – Our Panel recognizes that the current requirement under the AER's Directive 82 to mine to the AER's stated economic limit made sense in terms of maximizing economic return to the Province and its citizens, and of minimizing wasting of resources in a world of oil and gas scarcity. However, our Panel heard that given the expanding world supply coupled with decreasing demand, the reality is that going after more marginal resources has the potential to impair economics by increasing unit costs, as well as increasing emissions intensity, tailings volume and overall footprint and associated reclamation costs disproportionately to the increase in resource revenue. Our Panel recommends the AER review its practices and identify opportunities to optimize overall economics, emissions outcomes and improved environmental performance.

- **Collaboration in the Oil Sands Area and Other Industry Growth Areas** – In this report, our Panel has emphasized the importance of encouraging oil, natural gas and oil sands producers to improve their cost competitiveness. In the case of oil sands, reductions in capital and operating costs are directly to the Province's benefit as they can help increase the amount of royalties Albertans collect from oil sands projects. Oil sands producers have a primary role to play in reducing their costs and improving their productivity, but their spending choices are not made in a vacuum. Those choices (which can sometimes result in higher-than-desirable costs) are made based on the realities they face on the ground, and in the Athabasca oil sands area those realities are influenced by the Government of Alberta. For example, our Panel heard that issues such as constraints on developable land, land valuation, and transportation bottlenecks in and around Fort McMurray have contributed to producers making the choice to fly workers in and out of work camps. These kinds of issues directly influence the socio-economic conditions of the Fort McMurray area and, similarly, other regions of the province that experience marked growth due to energy development now or in the future. This, in turn, impacts things such access to labour, accommodation costs, and local services, which all have cost impacts for producers. Addressing these types of issues is therefore important in supporting all operators in becoming cost-competitive producers. Our Panel heard that what is really needed to address these types of issues is not money, but a renewed commitment to strong collaboration among the Government of Alberta, the Regional Municipality of Wood Buffalo, (or other communities that similarly face significant growth pressures from energy development) community stakeholders and industry.

APPENDICES

APPENDIX A

Mandate of Alberta's Royalty Review 2015

Alberta Government

Alberta's ROYALTY REVIEW 2015

ROYALTY REVIEW

During the recent election campaign, the government promised that, if elected, it would launch a review of Alberta's royalty framework. This review, announced in June, fulfills that commitment.

Many Albertans have questions about the current royalty framework. They wonder whether, as owners, Albertans are getting full and fair value from the development of our resources. Some wonder whether the province received full value in the past when prices were high. Others point out that industry costs are getting higher and higher, the oil and gas business is becoming more and more competitive, and the province needs to maintain a competitive environment to continue to attract investment. Still others suggest that we need to maintain activity in the energy industry to continue to support Alberta's economy through the current downturn in prices. Clearly, there is a wide divergence of views that need to be addressed.

In addition to those questions, it's important to recognize that the energy business is changing as a result of emerging technologies, environmental and social pressures, an evolving investment climate, and world dynamics and tensions. These forces have led to global production and market changes that have resulted in lower prices. No one knows when prices will recover or by how much, or what the energy business will look like even a generation from now.

All of this uncertainty means a royalty review at this time is critical to achieve a common base of understanding, and to assess whether the royalty framework is designed so that it will, now and in the future, meet four related objectives:

- To provide optimal returns to Albertans as owners of the resource.
- To continue to encourage industry investment.
- To encourage diversification opportunities such as value-added processing, innovation or other forms of investment in Alberta.
- And to support responsible development of the resource.

The review is intended to identify opportunities to optimize all four of these important objectives.

BACKGROUND

Alberta has the third largest reserves of oil in the world and is the largest producer of natural gas in Canada. For over a century, oil and gas development and production has contributed to the prosperity of Albertans through provincial revenues, investment, employment and infrastructure development. It can continue to be part of supporting healthy economic development, creating jobs and building stronger communities. Direct revenue to the Alberta government from the oil and gas industry comes from a number of streams including royalties, corporate taxes and land sales. Recently, new carbon levies have added a fourth direct stream. In addition, the government receives revenue from income taxes of companies and people employed by the oil and gas industry, and the economic multiplier effects of exploration, production and investment in infrastructure. The activities of oil and gas companies, and the people who work for those companies, also help fuel the economies of many communities across the province.

Oil and gas prices are the major determinant of the health of Alberta's oil and gas economy, and the main variable that determines how much revenue the provincial government gets from oil and gas activity. Prices are volatile, as Albertans know only too well. So, too, are all the economic and financial metrics associated with the oil and gas industry.

Capital investment and re-investment are vital for maintaining the economic benefits Alberta derives from the capital-intense energy industry. Such investment is sensitive to market conditions such as commodity prices, interest rates, and the relative comparability to other oil and gas producing regions. Investment is also sensitive to local costs and factors such as royalty rates, taxes and other costs the provincial government oversees. These factors plus the availability of public and private infrastructure, political and social stability, and an educated and well-trained workforce, complete the overall equation for investment.

Alberta's oil and gas industry is composed of three distinct sectors: oil sands, crude oil and liquids, and natural gas. Their relative competitive positions are not always aligned. Each is subject to different market factors that can amplify or dampen the volatility of the overall business. Each is also subject to different forces that affect the viability and competitiveness of the companies engaged in those sectors. Such forces include, but are not limited to, changes in technology, capital markets, commodity markets, global geopolitics, sustainability constraints and social pressures. As such, each must be understood and incorporated in this review.

PURPOSE

In the course of undertaking this review, the Panel will engage with Albertans, the government and industry, along with other stakeholders, to build a common set of data and facts on which to weigh issues and find common ground. That common ground will come from understanding that the "best" arrangement is not one that just maximizes government revenue, or maximizes company returns, or encourages diversification, or addresses the pace of developing the province's oil and gas resources. All four outcomes have to be optimized. With that understanding in mind, the result can be the establishment of common goals which, in turn, breed trust and innovation. Add good old hard work and we can build a robust royalty framework that optimizes all four outcomes and helps build a strong economy for Alberta's future.

The Panel also acknowledges that this review will be conducted with regard to current economic conditions as well as considering the full picture of how the energy sector benefits Albertans. The review will be sensitive to current low oil and gas prices and the associated uncertainty for investors, and to the work underway on the climate change review. That context is an important one for this review and will help frame the conversations. At the same time, the Panel will consider how the royalty framework adjusts on the upside when prices recover.

OBJECTIVE OF THE REVIEW

Working with stakeholders, the objective of the review is to establish a strong understanding of the energy sector and, based on that, to find opportunities within a royalty framework to optimize the return to Albertans, and support continued industry investment, economic diversification and responsible development.

To achieve that objective, the Royalty Review Panel will undertake to:

1. Understand and assess the current Alberta royalty framework for each of the three distinct sectors in the province's oil and gas industry within the context of capital flows, available economic rent, employment, profitability, product competition for the attraction of capital, and government revenue.
2. Understand and assess how government revenue is generated from oil and gas land sales.
3. Understand and assess how a royalty regime can generate diversification opportunities, such as value-added processing, innovation or other forms of investment.

4. Understand and assess how Alberta's royalty framework compares with other jurisdictions.
5. Understand and assess the trends that are likely to affect the future (short- and long-term) for the three distinct sectors in the province's oil and gas industry, and their implications for government revenue.
6. Develop criteria for assessing the effectiveness of the royalty framework on an ongoing basis.

Developing criteria is an essential step to ensure that the royalty framework is durable and stable over the longer term and responsive to the ups and downs of the marketplace. One of the Panel's goals is to assure Albertans that a good framework has been put in place and they can be confident it will remain so.

THE PANEL

The Panel will consist of four members whose combined attributes cover the range of skills that will be required for this review. These skills include the ability to understand what is important technically, to capably consider the financial ramifications of the elements of the royalty framework, to critically assess complex issues and to develop sound public policy. The final and perhaps most crucial element will be the Panel's ability to engage all stakeholders in optimizing their interests in conjunction with others.

The Panel members will be:

Dave Mowat, Chair
President and Chief Executive Officer, ATB Financial

Dave Mowat is the President & CEO of ATB Financial, which, with assets of more than $43 billion, is Alberta's largest, provincially based financial institution. ATB employs almost 5,300 team members in 244 communities, providing personal, business, agriculture, corporate, and investor financial services to more than 710,000 Albertans and Alberta-based businesses.

Dave is an Albertan by birth: he was born in Calgary and raised in Sherwood Park. And he is an Albertan by choice: after getting a Bachelor of Commerce degree from the University of British Columbia and serving VanCity credit union as its CEO, he returned to Alberta, and now lives in Edmonton.

Over the last three decades, Dave has shaped and been shaped by every aspect of the banking world: venture capital markets, credit, retail, corporate, investments, and banking tied to each sector of the Alberta economy.

The thread that connects the various chapters of Dave's financial services career is a commitment to using his banking expertise and his networks to serve the greater good.

This is visible in the boards Dave sits on: STARS, Telus Community Foundation, Alberta Blue Cross, Citadel Theatre and the National Music Centre. And in the causes—he has served the United Way of the Alberta Capital Region as its campaign chair—he gives his time to. And it is apparent in the unique, community-building ventures that Dave and ATB help bring to life, including Empower U (a partnership that equips women with financial literacy skills), the ATB Financial Land Legacy Fund (a program that provides capital for purchasing land for habitat restoration before resale), and Light The Bridge (a citizens-led drive to raise $2.5 million to purchase and install LED lights on Edmonton's High Level Bridge).

That instinct for uplifting the community is reflected by the honours conferred both on Dave and the company he leads. He is Alberta Venture's Business Person of the Year. He has held the Charles Allard Chair in Business at MacEwan University. SAIT Polytechnic has awarded Dave an Honorary Bachelor of Business Administration degree. He was named to the Edmonton Journal's list of the city's Power 30 group. ATB was named one of the 2015 Best Workplaces in Canada by Great Place to Work, one of 2015 Best Employers in Canada by Aon Hewitt, and one of the Most Engaged Workplaces in North America by Achievers.

In business, in banking, in community, Dave helps open Alberta to the world of its potential.

In 2015, Dave Mowat was named chair of the Alberta Royalty Review panel.

Leona Hanson
Mayor, Town of Beaverlodge, Alberta

Leona Hanson is a seasoned business professional who has dedicated herself to the community for over two decades. She is currently the mayor of Beaverlodge, a town of 2,500 people 40 kilometers northwest of Grande Prairie.

She currently operates her own consulting business providing services to business and non-profit clients in a number of areas including business and human resources planning, account management, organizational reviews and operational planning. Leona was elected mayor in 2007 and acclaimed ever since. She holds an MBA in project management from Athabasca University.

Leona was the executive director of SMEDA Business Development Corporation, a Community Futures organization, for 17 years. In that role she led an organization committed to economic and community development through financing, training and coaching to small and medium-sized enterprise start-ups and expansions. She was subsequently an advisor to all Community Futures Development Corporations and Regional Economic Development Alliances across Alberta.

Leona is very connected to the small business community and has been for her entire career. She has seen firsthand the wide range of business that serves the energy industry in Alberta. Leona was selected for the panel for a number of attributes. She has a firsthand understanding of how the activities of the energy sector ripple throughout Alberta and particularly the rural parts of the province. She understands municipal and business finances well, and with eight years under her belt as Mayor, is skilled at finding consensus within varying viewpoints. She is smart and is a good listener which suits her well for the job at hand.

Peter Tertzakian
Chief Energy Economist & Managing Director, ARC Financial Corp.

Peter Tertzakian is the Chief Energy Economist & Managing Director at ARC Financial Corp., Canada's leading energy-focused private equity company, with $5.3 billion of capital across the eight ARC Energy Funds. He grew up in Edmonton and currently makes his home in Calgary.

With over 34 years of experience in both the energy and finance sectors, Peter plays a pivotal role on ARC's Executive, Investment and Strategy Committees. In addition, he is responsible for directing ARC's economic research and overseeing the publication of the *ARC Energy Charts*, a weekly journal on energy trends. His two books, *A Thousand Barrels a Second* and *The End of Energy Obesity*; both examine transitions of the global energy sector through economic, environmental and geopolitical pressures.

Peter has an undergraduate degree in geophysics from the University of Alberta, a graduate degree in econometrics from the University of Southampton U.K., and a master of science degree in management of technology from the Sloan School of Management at MIT. In addition to his principal role at ARC Financial, he has lectured at many leading universities and conferences around the world. His collective knowledge of energy innovation, history and economics gives audiences thought-provoking insights into today's pressing issues.

His career started as a geophysicist with the Chevron Corporation in 1982, where he spent eight years working in field operations, seismic data processing and geophysical software development. He moved from oil and gas to the financial sector in 1990. Since then, he has become a recognized analyst, economist and author who is routinely sought after as a speaker and educator. He is also an Adjunct Professor at the University of Calgary's Haskayne School of Business.

The panel appointed Peter for his passion for energy issues, his unique financial and operational expertise in the industry, and for his understanding of domestic and global economies. He has spent over 50 years in Alberta, has worked all across the province and understands the complexities of the exploration, production and transportation of its energy resources. He is an excellent fit for the panel.

Annette Trimbee
President and Vice-Chancellor, University of Winnipeg

Annette Trimbee is currently the president and vice-chancellor of the University of Winnipeg, a transformative downtown institution that serves nearly 10,000 students. Prior to this, her decades-long career in the public service of Alberta saw her hold a variety of portfolios as a deputy minister. A 2014 return to her hometown of Winnipeg brings her full circle; she is now leading the university she once attended as an undergraduate scholarship recipient.

Annette has served as the deputy minister of Treasury Board and Finance, Service Alberta and Advanced Education and Technology. She began her career in the public service with Alberta Environment and has also held leadership positions in Alberta Health and Wellness.

Her key accomplishments include the Alberta budgets of 2012 and 2013, aligning post-secondary system capacity through Campus Alberta, developing Alberta's Health Policy Framework, and building Alberta's integrated resource management framework and water policy legislation. She is currently working with the university's Board of Regents and a broad range of community stakeholders to set its strategic direction.

Annette holds a PhD in ecology from McMaster University, a MSc in botany from the University of Manitoba, and a BSc in biology from the University of Winnipeg.

Annette was selected to the panel for her deep experience in developing public policy along with the experience she gained as a deputy minister in key Alberta departments. She is smart, pragmatic, and a critical thinker who is intimately familiar with assessing complex issues. She believes that, as a university president, she has a responsibility to participate in work that has an impact on the wider world. She agreed to help tackle this task because of its significance to Canada, and in her own words: "I enjoy working with people to mobilize action towards a common cause."

RESOURCES

The Panel will have full access to the information and resources of the Government of Alberta and, as independent data or information from other jurisdictions is required, the Panel will be provided the resources to obtain it. The Panel will also invite industry, government and academic experts to contribute to and engage in the mutual understanding of the complex and varied nature of the topics to be considered. Three expert technical teams (for oil sands, crude oil and liquids, and natural gas) will be established to review and provide detailed analysis on key questions to be addressed as part of this review. These experts provide the Panel with a diversity of perspectives and they will be asked to participate on a “hats-off” basis. That is: to bring their expertise and work with other members to find workable solutions rather than simply representing a particular school of thought.

ENGAGEMENT

In the course of undertaking its review, the Panel will engage with Albertans, Aboriginal leaders, government, industry, and a wide range of non-governmental organizations including labour organizations, environmental organizations, and research institutes to gain a full perspective on questions the Panel has been tasked with addressing. A particular emphasis will be to engage as broad a spectrum of Albertans as possible, posing questions ranging from “what do you want to know about royalties” to “what types of assurance would you want to feel confident we have a sound royalty framework.” To support that conversation, the Panel will provide Albertans with a series of facts and information about this most important and complex part of our economy. The Panel will use a wide range of tools and techniques to provide information Albertans can trust and engage them in conversation about what the Panel is learning. We believe that Albertans will welcome that source of information and the opportunity to gain a better understanding of our province’s resources, the companies and people who develop them, and the impact they have on the economy. A key focus of the engagement process will be on confirming the criteria for judging the effectiveness of Alberta’s royalty framework on a longer-term basis.

The process will be a conversation and will continue throughout the term of the review. It will involve a combination of face-to-face meetings, interactive web-based information and conversations. The objective is to be open and transparent not only about the process, but also about the information gathered as part of the review.

TIME FRAME

The Panel will undertake its work with a sense of urgency balanced with ensuring any conclusions it draws have been examined and discussed in sufficient detail to strike the optimal balance of the four objectives. We expect the Panel's work to be completed by the end of the year.

Work has already begun on developing a sound base of information on each of the three streams – oil sands, crude oil and liquids, and natural gas. A website has been established at letstalkroyalties.ca and, over the course of the review, additional information on a wide variety of questions related to royalties will be added to the website. Albertans will have the opportunity to learn more and provide input and ideas on an ongoing basis.

The Panel will engage with Albertans, industry and a wide variety of organizations and individuals throughout September and October. The Panel's target is to develop ideas for optimizing the royalty framework for consideration by government by the end of this year.

THE ENGAGEMENT PROCESS

If there's one thing we know about Alberta's royalty framework, it's that it is complicated, and understandably so. Alberta's energy industry is composed of three streams – the oil sands, crude oil and liquids, and natural gas. It's overly simplistic to suggest that there's one royalty framework that fits all of those streams or that you can simplify the conversation to fit all three. Combined with that reality is the understanding that there are trends and factors influencing each of the sectors that may not apply to all.

To address this complexity and to ensure that all the appropriate parties are engaged, the royalty review will proceed with a number of parallel streams.

A TECHNICAL REVIEW

It's essential to engage experts – people who understand how the royalty framework works now, why it was designed as it is today, what changes might be considered, and what the implications of those changes would be. The intent is to establish three technical and analytical working groups – one focussed on oil sands, one on crude oil and liquids, and one on natural gas. These teams will examine technical questions, provide a common base of information, and assess the implications of any changes that would be proposed.

INDUSTRY ENGAGEMENT

There are a number of energy industry companies and related associations that will be consulted and engaged in the process. This includes not only the largest oil and gas companies doing work and making investment decisions in Alberta, but also smaller industry players and the associations whose members are engaged in seismic operations, drilling, working in the oil sands, or supplying the necessary goods, services and infrastructure to support the development of Alberta's energy resources. These key industry players will be involved through conversations, meetings, providing information to inform the review and encouraging their employees to engage as individuals.

KEY STAKEHOLDER ENGAGEMENT

In addition to industry members, there is a wide variety of other stakeholders who are involved in, have a vested interest in, have ideas about the industry, or who are impacted by developments in Alberta's energy industry. This includes (but isn't limited to) Aboriginal organizations and leaders, labour organizations (many of whose members work in the energy industry), municipal organizations, environmental and research organizations, and other key community groups. These groups will be similarly engaged in conversations, meetings and in providing information to inform the review. They will also be asked to encourage their membership to participate as individuals.

ENGAGING ALBERTANS

The Panel will provide a variety of methods to engage as many Albertans as possible in a conversation about royalties. It will start with asking Albertans what they want to know about royalties and move through providing that information, to a discussion on what a royalty framework should accomplish. As owners of the resource, Albertans are looking for this opportunity to consider the options we have to optimize the returns to the province while also ensuring continuing industry investment, encouraging diversification and addressing responsible development. The Panel will provide a consistent and common foundation of information to enhance public understanding, not only of the royalty framework but, more importantly, how the royalty framework can create opportunities to optimize returns to the province, to industry, and to future development of the resource.

This engagement will be centred around a “conversation hub” all Albertans can visit at letstalkroyalties.ca throughout the review. There they can provide feedback directly to the Panel, answer questions posed by the Panel, and/or engage in a public online discussion. The Panel, and its individual members, will also seek opportunities to talk to and hear from Albertans – one-on-one and in group settings. The website will post a record of places the Panel has been and will be visiting, and what they are hearing. The Panel’s determination to engage Albertans combined with tools now available to do that, promises to make this a very comprehensive process.

BUILDING AGREEMENT

The Panel will build consensus amongst key stakeholders on information, on the criteria for assessing Alberta’s royalty framework, and on adjustments that can and/or should be made to achieve the objective set for the Panel. The Panel’s goal is not so much a traditional report and recommendations as it is to build consensus on what opportunities there are to optimize and adjust the royalty framework as necessary to ensure it meets the objective. A report will summarize what the Panel learned and where there are opportunities for adjustments to the current framework.

APPENDIX B

The Panel offers its sincere thanks to the following people who volunteered their time and expertise to assist us in the review. They offered a diverse range of views that were invaluable. While their names appear here, the recommendations of our Panel are solely our own and no endorsement by these individuals or their organizations is implied.

Members of the Crude Oil and Liquids Expert Group

- Daryl Gilbert — Retired Founder, GLJ Petroleum Consultants
- Dave Middleton — Chief Operating Officer, Twin Butte Energy Ltd.
- David Shade — Project Manager, Indian Resource Council
- Geoff Ready — Engineer, ORLEN Upstream
- Hilary Foulkes — Retired Chief Operating Officer, Penn West Exploration
- Jennifer Winter — Associate Director, Energy and Environmental Policy, School of Public Policy, University of Calgary
- Kevin Neveu — President and Chief Executive Officer, Precision Drilling
- Michal Moore — Area Director, Energy and Environmental Policy, School of Public Policy, University of Calgary
- Robert Mansell — Interim Director and Academic Director, School of Public Policy, University of Calgary
- Terry Moore — Vice President, Engineering, Journey Energy Inc.

Members of the Natural Gas Expert Group

- Beverly Dahlby — Distinguished Fellow in Tax and Economic Growth and Professor of Economics, University of Calgary
- Blake Shaffer — Energy Economist, and current PhD Candidate, University of Calgary
- Brian G. Robinson — Director and Vice President Finance, Chief Financial Officer, Tourmaline Oil Corporation
- Dave Poulton — President, Environmental Law Centre Board of Directors
- Gerald H. Bietz — Retired Vice President, EnCana
- James Coleman — Assistant Professor, University of Calgary Faculty of Law
- Michael J. Tims — Retired Chair, Peters and Co.
- Pat Carlson — Chief Executive Officer and Director, Seven Generations Energy Ltd.
- Patrick Bryden — Director, Oil and Gas, Global Equity Research, ScotiaBank GBM
- Susan L. Riddell Rose — President and Chief Executive Officer, Perpetual Energy

Members of the Oil Sands Expert Group

- Beverly Dahlby — Distinguished Fellow in Tax and Economic Growth and Professor of Economics, University of Calgary
- Bill McCaffrey — President and Chief Executive Officer, MEG Energy Corp.
- Brian Maynard — President, Marathon Oil Canada Corporation
- Dave Collyer — Retired President, Shell Canada
- Jason Switzer — Senior Advisor to the Executive Director, Pembina Institute
- Jennifer Winter — Associate Director, Energy and Environmental Policy, School of Public Policy, University of Calgary
- Joe Dion — Chief Executive Officer, Frog Lake Energy Resources
- Regan Boychuk — Former Public Policy Research Manager, Parkland Institute
- Rich Kruger — Chairman, President and Chief Executive Officer, Imperial Oil Limited
- Richard Masson — Chief Executive Officer, Alberta Petroleum Marketing Commission
- Robi Contrada — Managing Director, BMO Capital Markets

APPENDIX C

Royalty Revenues and Realized Royalty Rates of Alberta's Royalty Framework

Royalty Revenues Over Time

Our Panel assessed Alberta's royalty revenues over time.

Alberta has been collecting royalty revenue since 1931. The stream of income first crossed over the $1 billion per year mark in the mid-1970s, where Figure C1 picks up the story.

TOTAL ROYALTY REVENUE BY PRODUCT STREAM

Annual Payments to the Province, Fiscal Year End March 31st

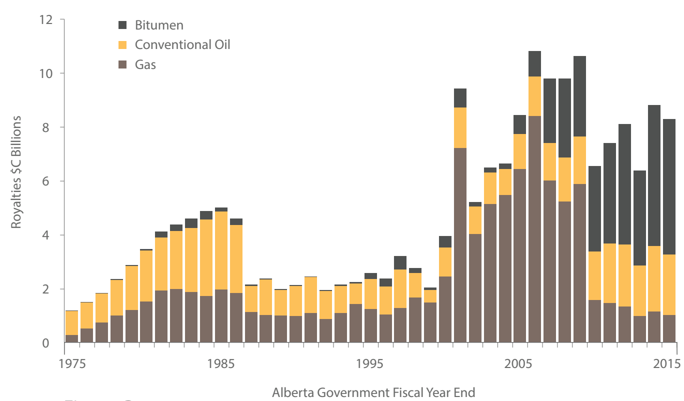


Figure C1

Source: Alberta Department of Energy

The brown segment of the bars in Figure C1 represents natural gas royalties, yellow is oil and black represents bitumen and SCO (i.e., upgraded bitumen) from the oil sands region.

Up to 1985, royalties were rising steadily on the back of growing production and robust prices. The effect of the collapse in oil prices in 1986 can readily be seen, when royalties dropped from $5 billion to $2 billion.

A relatively stable period ensued between the mid-1980s and the late 1990s. The basin began to seriously mature during the 1990s, driving up operating costs.

The bull run in both oil and natural gas prices during the 2000s led to a tripling of royalties, which averaged about $10 billion per year in fiscal years 2006 through 2009. A ramp-up in oil sands production began delivering significant royalties in 2007.

Then came the second big crash (the first was 1986), this time on the back of collapsing natural gas prices and production.

As a consequence of the U.S. shale gas revolution, a glut of natural gas from Texas and Pennsylvania pushed down the price of Canadian natural gas by 51%, from an average $7.75/GJ in 2008 to $3.79/GJ in 2009.

Alberta's high-cost production began seriously contracting in 2007 as a consequence of the U.S. shale gas push. Year-over-year production between 2008 and 2009 fell from an average 12.4 Bcf per day to 11.5 Bcf per day. Royalty rates are a function of both production and price, so the marginal rate fell from 43% in 2008 to 25% in 2010. (Note: Under the 2010 royalty adjustments, the rate of 25% at $3.79/GJ was unchanged.) All factors considered, natural gas royalties fell from $5.8 billion to $1.5 billion in fiscal year 2009-2010 – a 75% drop over the prior year.

By 2010, oil prices had recovered from the financial crisis. Combined with higher oil sands production, and increasing unconventional oil production, oil-sourced royalties somewhat offset the major fall incurred from natural gas. Annual royalty revenue between 2010 and 2015 was still running between $6 billion to $8 billion, but overwhelmingly on the back of oil sands and crude oil production and prices.

Today's royalty stream is still oilier than natural gas. But the 2015 fall in oil prices (and gas prices too) will be harsh on Alberta's royalty revenue. The 2015-2016 fiscal year will see a dramatic fall in royalties, estimated to only be $2.8 billion – a 67% drop over the $8.3 billion collected in 2014-2015.

Royalties as a Percent of Revenue

A simple measure of royalty performance is the amount received as a percent of top-line revenue from all oil and gas commodities.

ALBERTA OIL AND GAS ROYALTIES AS A PERCENT OF TOTAL UPSTREAM REVENUE

Oil, Natural Gas and Oil Sands Royalties (Net)

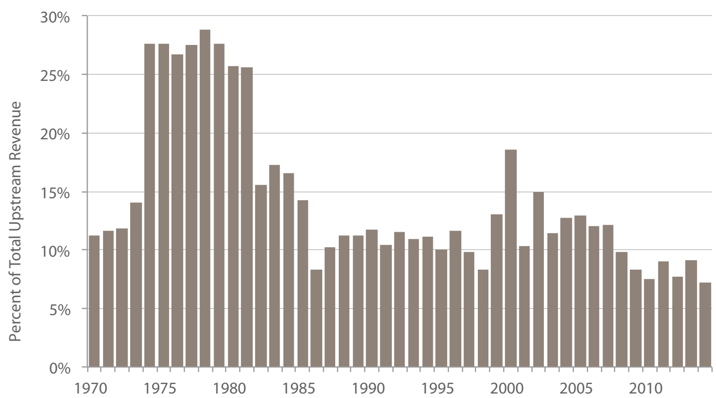


Figure C2

Source: Alberta Department of Energy, Canadian Association of Petroleum Producers

Figure C2 shows what fraction of total revenue has been taken as royalty payment to Albertans. A period of high royalty rates averaging about 27% was taken between 1973 and 1982, the era of the oil price shocks and easy-to-find oil and gas.

Between 1983 and 2005, realized rates were somewhat stable around 15%. But after 2005, the take shows steady erosion.

The drop in Alberta's realized royalty rate over time is concerning at first blush, but reinforces a number of points made earlier in our report (see "How Costs Influence Royalties"). The combination of maturing oil and gas fields, disruptive processes and price-driven inflation over the past half-century has raised both capital and operating costs as a percentage of revenue. The drop over the past five years is directly attributable to a jump in capital and operating costs over the same period. Since 2010, an average 90% of the value in a barrel has been taken up as cost, leaving only 10% to share between resource owner and producer.

In its independent analysis, Wood Mackenzie's "Split of the Barrel" analysis showed similar data in a global context. As a fraction of total value, Alberta's average capital and operating costs are among the highest relative to its competitive peers. This is true domestically (Alberta versus British Columbia or Saskatchewan), continentally (versus the U.S.), and internationally (versus jurisdictions like the North Sea).

To better understand the dispersion of costs into the Alberta economy, our Panel conducted a return-on-capital analysis of oil and gas producers and peripheral industries. The detailed study can be found in Appendix D.

Figure C2 excludes corporate taxes, land bonuses, surface access fees and municipal taxes in the value of what streams to Albertans. Municipal taxes have risen over time, and have become an increasingly significant fraction of each unit of production, especially in the later life of a well's productivity. Submissions to our Panel from municipalities and landowners pointed out that financial returns from locally producing wells enable wealth generation for the rural communities, even though such returns are not included in the royalty stream in Figure C2. Our Panel was urged by municipalities and landowners to preserve the status quo.

The Impact of Capital Spending On Realized Royalty Rates

In 2014, over $60 billion of capital was invested into Alberta. Figure C3 shows the trend in capital investment, split between the oil sands segment (bitumen and SCO) and the non-oil sands (crude oil, liquids and natural gas).

ALBERTA OIL AND GAS CAPITAL EXPENDITURES

Annual Dollar Amount by Product Type; 1990 to 2014

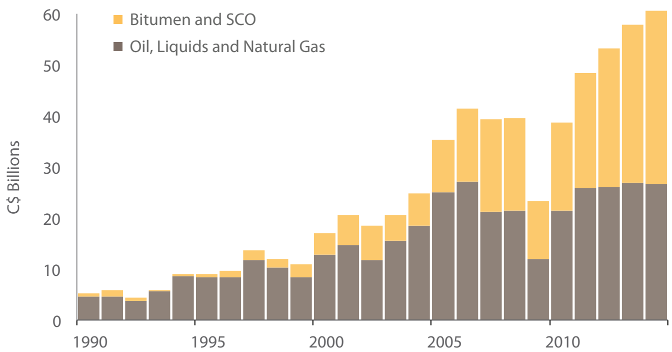


Figure C3 *Source: Canadian Association of Petroleum Producers*

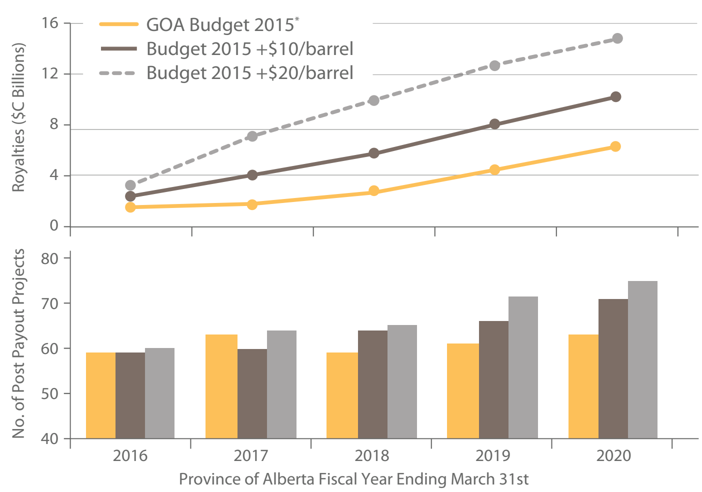
Royalty rates are low, typically 5%, during initial production to acknowledge upfront capital investment. During periods of high capital investment, it takes companies longer to reach payout. The overall realized royalty rate of the province appears disproportionately low relative to industry's revenues. Such was the case between 2010 and 2014, when oil sands spending was rising quickly. As projects reach payout, higher royalty rates will kick in, but for oil sands projects that will take time.

Ten oil sands projects from the 2009 to 2014 vintage will take an average 12 years to reach payout using the Government of Alberta's budgeted oil prices. Twenty-seven may never reach payout due to excessive cost overruns. This highlights the near term challenge: Alberta's realized royalty rate on oil sands production is expected to hover around 5% over the next several years based on current price expectations. By 2025, the realized royalty rate should rise to about 12% (see Figure C4).

The dynamics of average rates help explain the perception gap between Albertans who believe royalty rates have been too low and companies who have been investing heavily during their pre-payout period (when royalty rates are low). Over the past 20 years, Albertans have observed periods of very low royalty rates with most projects in pre-payout and growing investment as prices rose. Rates (and royalty revenues) rose toward the end of last decade as some of these initial projects reached payout. The result was substantially increasing oil sands royalties that rose from $59 million in 1998 to over $6 billion in 2014. Average royalty rates will rise as the number of projects and the volume of production that have reached payout increases. In the meantime, our Panel suggests better communication and transparency.

OIL SANDS ROYALTY REVENUE SCENARIOS

With Corresponding Number of Projects in Post-Payout



Source: Alberta Energy

Figure C4

*Note: Based on Government of Alberta Oil Price Forecast

APPENDICES

APPENDIX D

Oil and Gas Producers Versus Companies in the Broader Economy

Return on Average Capital Expended (ROACE) is a measure of profitability, or capital efficiency, that is commonly used to assess a company's financial performance. The concept is fairly straightforward. A company invests money into its operating infrastructure and equipment, and the question is, "How much money is it generating off of all that capital investment?"

Early in our process, our Panel examined the ROACE of a grouping of 54 publicly traded oil and gas producers with collective operations all across Alberta. Our Panel looked at the distribution of the capital efficiency of these companies for each year between 2007 and 2014. As well, the average of the distributions for each year was derived.

In addition to examining oil and gas producers, our Panel analyzed the capital efficiency of 31 companies in the broad economy – for example utilities and real estate – with at least 50% of their operations in Alberta. Finally, our Panel undertook the same analysis for 17 oil and gas service companies, those that sell their wares directly to oil and gas producers.

Figure D1 shows the ROACE averages for 54 oil and gas producers and 31 companies in the broad economy from 2007 to 2014.

Broad economy companies consistently outperform oil and gas producers every year except 2008, where they were effectively equal. Our Panel noted that oil and gas producers as a collective only achieved their cost of capital in 2008. On average, companies peripheral to the oil and gas industry log much better performance year over year.

RETURN ON AVERAGE CAPITAL

Comparison of Canadian Oil and Gas and Broader Economy

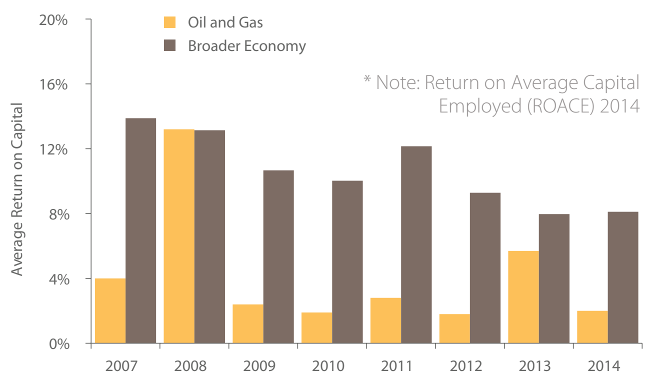


Figure D1 *Source: Scotiabank GBM*

RETURN ON AVERAGE CAPITAL

Comparison of Canadian Oil and Gas and Oilfield Service

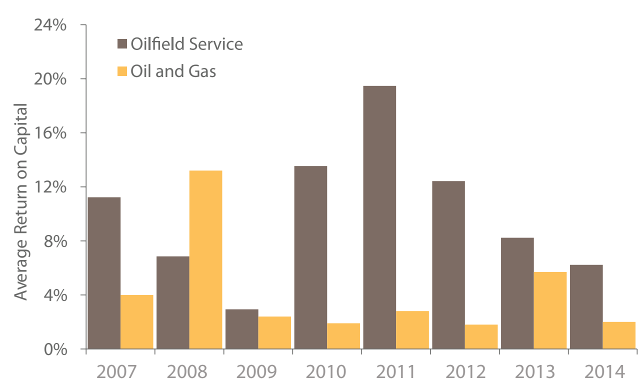


Figure D2 * Note: Return on Average Capital Employed (ROACE) 2014

Source: Scotiabank GBM

The same is true when the oil and gas producers are compared to the companies that are one-degree of separation away: oilfield services (see Figure D2). A large gap in profitability can be seen between the two.

None of this outperformance by companies outside the oil and gas producer group was a surprise to our Panel. Wood Mackenzie's analysis, as well as other independent analyses from banks and reserve engineers, demonstrated that oil and gas capital and operating costs are very high relative to other jurisdictions. What is cost to the producers is revenue to their suppliers. In other words, the value of a barrel of oil largely disperses and multiplies through the Alberta economy through businesses peripheral to the producers.

Not all companies are equal

Averages can be misleading. Our Panel looked at the distribution of ROACE performance by each company within their respective peer groups and constructed the histograms in Figure D3.

Our Panel noted that there is a wide dispersion of ROACE for oil and gas producers: some can achieve their cost of capital in good times and bad. However, the wide spread in performance is indicative of the diversity of cost challenges facing producers, as discussed in our Panel's report.

The performance of broad economy companies is tighter and more predictable. Utilities are especially predictable, others like those catering to retail markets less so.

Like producers, oil and gas service companies also have varied performance year-to-year. However, service companies are generally clustered further to the positive end of the spectrum than producers, especially in years when commodity prices are high, investment is robust, and availability of labour and services are scarce (thus driving up prices).

This year, 2015, is not yet tabulated. All companies with exposure to Alberta will shift toward lower returns, especially the oil and gas producers and service companies, which have direct exposure to commodity price.

RETURN ON AVERAGE CAPITAL

Comparison by Year and by Economic Sector

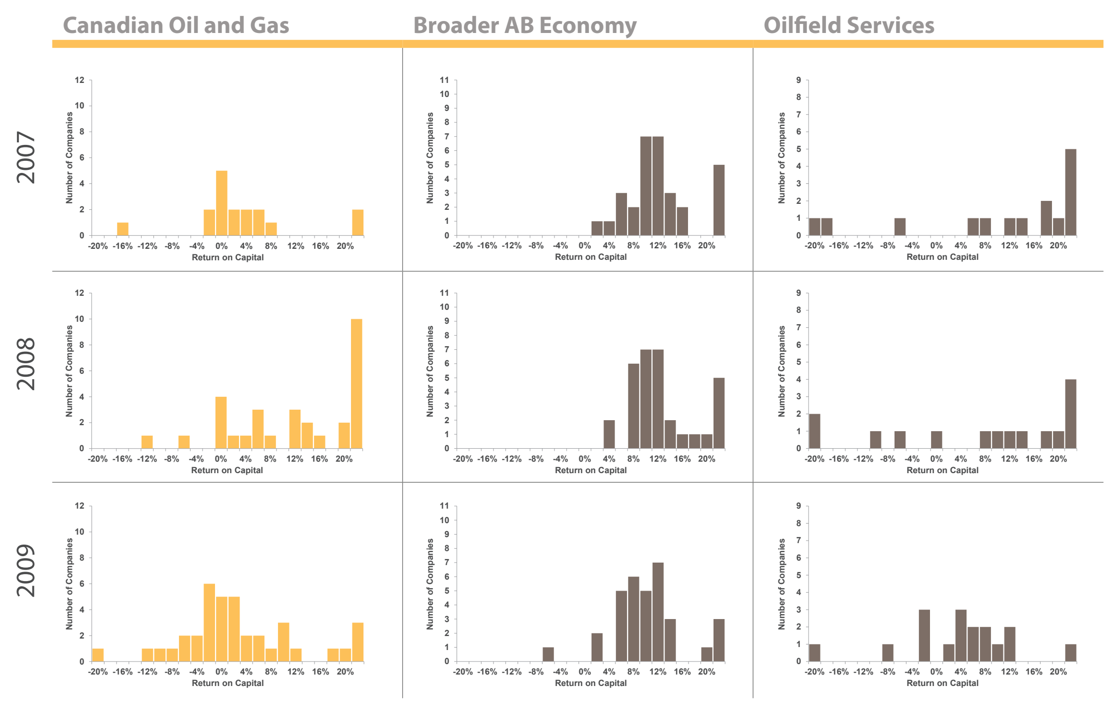


Figure D3

Source: Scotiabank GBM

APPENDIX E

Implementation of the Modernized Royalty Framework

Our Panel recommends that modernization of the royalty framework be effective upon the implementation date.

There will be many steps to finalize specific formulas and set up procedures to accommodate the MRF. To that end, our Panel believes there should be a short Calibration Period, ending no later than March 31, 2016, during which Alberta Energy can establish final parameters with encouragement to continue consultation with willing members of the Natural Gas and Crude Oil and Liquids Expert Groups. This "Calibration Team" is advised to use the Implementation Directives prescribed in this Appendix.

To limit uncertainty during the Calibration Period, our Panel has narrowed the scope of the Calibration Team's work as much as possible. The specific tasks for the Calibration Team are to finalize: (a) the Drilling and Completion Cost Allowance (C*) formula; and, (b) the post-payout price functions (royalty rates) within the constraint of matching average, expected industry returns and Albertans' share of value that are achieved under the current framework, taking into account that current incentive programs are not well designed at very high and very low prices.

Full details of the MRF should be released by the Calibration Team no later than March 31, 2016, well in advance of the 2017 budget cycle.

Implementation Directives to Support Modernization of the Royalty Structures for Crude Oil, Liquids and Natural Gas

1. Permanently adopt a proxy RMC royalty structure across all hydrocarbons, including crude oil, liquids and natural gas.

- Implement a tailored structure for Alberta, based on a standard pre-payout/post-payout RMC model.
- New qualification for all overlapping programs will cease December 31, 2016.
- This single proxy RMC structure shall serve for all hydrocarbons, except those under project status in the oil sands.

2. Determine a formula for C* (the Drilling and Completion Cost Allowance) through the use of statistical methods.

- Our Panel along with its Expert Groups extensively analyzed cost-versus-depth data from reserve engineering data and determined that one statistical function with two splines could fairly estimate a Drilling and Completion Cost Allowance for any well drilled in the province (not dissimilar to current natural gas and crude oil depth functions, but more accurate in assessing the capital cost of drilling and completing a well).
- The associated Expert Working Groups determined that C* should be of a functional form:

$$C^* = a1^*(TVD) + a2^*(TVD - V_{deep}) + a3^*(TVD^*TLL)$$

Where:

- TVD is the true vertical depth of the well
- V_{deep} is the vertical depth threshold applicable to all wells, beyond which a well begins to receive additional capital cost allocation
- TLL is the Total Lateral Length
- a1 is a capital cost allocation for every meter drilled vertically
- a2 is a capital cost allocation for every vertical meter drilled deeper than Vdeep
- a3 is a capital cost allocation for every meter drilled horizontally, for every meter drilled vertically.

Intuitively, this formulation (that relates cost with depth and lateral length) makes sense. The first term states that capital costs increase, the deeper that a well is drilled vertically.

The second one recognizes that costs per meter drilled increase substantially below a certain depth, V_{deep}. Initial statistical analysis of cost and depth data suggests that the transition to V_{deep} is estimated to be between 2,000 and 2,500 meters.

The third term, a3, is especially intuitive, because drilling the lateral section of a horizontal well becomes more expensive at progressively greater vertical depth. That's because of the added costs of overcoming higher pressures with depth for both drilling and multi-stage hydraulic fracturing.

- The formula for C* will replace all existing depth functions.
- Our Panel advises the Calibration Team, along with assistance from academics familiar with econometric and/or statistical methods, to finalize the coefficients for the Drilling and Completion Cost Allowance function to best represent the province's well costs.
- Finally, our Panel recommends that the coefficients of the Drilling and Completion Cost Allowance function (a1, a2 and a3) be recalibrated once every three-to-five years, using independent statistical depth and cost data, to ensure that the function accurately represents changing technology and other factors over time.

3. Apply C*, the Drilling and Completion Cost Allowance, universally to all wells.

- This would make the royalty structures consistent for all hydrocarbons (excluding oil sands). For simplicity, there would be no distinction between the capital cost of drilling for natural gas, crude oil or the many other hydrocarbon molecules that can be produced from a well.

4. Adjust C* every year with a Capital Cost Index.

- Our Panel advises Alberta Energy to consult with credible energy consultants and reserve engineers to establish and maintain an Alberta Capital Cost Index (ACCI) that tracks year-over-year inflationary or deflationary changes in the industry. The ACCI will initially be set to 100 in 2017, and allowed to "float" on an annual basis as a function of changes in industry costs. For example, if the ACCI is estimated at 97 for subsequent years, it will mean that capital costs are 3% lower than they were in 2017.
- Once C* is determined, it will be adjusted for inflation/deflation by multiplying it by (ACCI/100).
- Revised cost allowance data and functions for the following year should be published in an annual report, issued by Alberta Energy, no later than May 31st of each year.
- To prevent sudden shifts in the ACCI, our Panel recommends that incremental annual changes be limited to +/- 5%. This would enable the MRF to adapt gradually to technological changes, competition, economic cycles and other factors on an ongoing basis.

5. Use true revenue to determine the "R" in the proxy RMC structure.

- In the proxy RMC structure, "R" should be determined from the revenue realized from the hydrocarbon products sold from a producing well. Revenue from the well will be tracked by multiplying production volumes of the various hydrocarbons by their respective par prices, as published by Alberta Energy.
- Payout will occur when the cumulative revenue, R, achieves the condition $R \geq C^*$.
- Note that operating costs are not included in the calculation. Our Panel suggests that operating costs be accounted for in the pre-payout and post-payout royalty rates under the MRF, much as they already are in the current royalty framework.

6. **Establish the price function; preserve investment appeal.**

- To ensure seamless transition from the existing royalty framework to the MRF, our Panel advises the Calibration Team to derive independent price functions for each of natural gas and crude oil that preserves the investment appeal for drilling wells in Alberta. Price functions for other hydrocarbon liquids will be the same as that calibrated for crude oil.
- The Calibration Team is advised to sample a wide set of Representative Wells from at least 40 plays across Alberta and determine their future profitability metrics using the existing framework (for example as measured by IRR, NPV, PIR). The Calibration Team is encouraged to use Wood Mackenzie, GLJ Petroleum Consultants, Alberta Energy and other Expert Group analyses already undertaken during the 2015 Alberta royalty review process.
- The same set of Representative Wells should then be calibrated to the MRF so that deviations from future profitability are on average neutral. This will ensure a seamless migration and help to maintain or encourage capital investment at all commodity price points.

7. **Determine maturity thresholds to provide an allowance for low productivity wells.**

- The Calibration Team is advised to determine when a well crosses its Maturity Threshold, the point in time when the rate of production is too low to sustain a full royalty burden.
- Initial indications suggest that the Maturity Threshold for crude oil is between 20 bpd or less. For natural gas the threshold is estimated to be between 200 mcf/day or less.
- A declining linear function, proportional to declining production, is recommended after the Maturity Threshold is crossed.
- Under the current framework oil wells can pay zero royalties, while natural gas has a minimum 5%. Our Panel recommends a minimum royalty rate of 5% for all new wells under the MRF, regardless of hydrocarbon output.

8. **Incorporate strategic programs and special allowances.**

- Given the diverse nature of Alberta's hydrocarbon products, geology and geography, from time to time, strategic programs may be required to promote expanded production potential that could generate greater long-term returns to Albertans.
- Our Panel recommends that Alberta Energy, in conjunction with the Calibration Team, develop a special application process to deal with exceptional situations where the Drilling and Completion Cost Allowance formula for determining C* cannot adequately represent the costs of a well or series of wells. Such applications that constitute "Strategic Policy Overlays" should be implemented to promote expanded development and investment potential, leading to greater long-term royalty payments to Albertans.During Expert Group sessions, our Panel discussed the merits of enhanced hydrocarbon recovery and high-risk experimental wells as two promising areas for Strategic Policy Overlays and subsequent high-value royalty streams.
- The capital cost recovery mechanism under the MRF lends itself to strategic overlays.
- Our Panel recommends that Alberta Energy work with Expert Group and industry members to develop Strategic Policy Overlays for enhanced hydrocarbon recovery and high-risk experimental wells (for example deep drilling). The focus of program development for each should be on determining ways to adjust or allocate a special C* for each endeavour. The payout mechanism based on revenue would remain the same.
- Our Panel recommends that strategic programs for enhanced hydrocarbon recovery and high-risk experimental wells be introduced simultaneously with the final calibration of the MRF, on or before March 31, 2016.

9. Consider carbon levies.

- Carbon levies reduce the value of Alberta's hydrocarbon resources in an absolute sense, and impact attractiveness for investment.
- Because hydrocarbon development is a partnership between resource owners and producers, our Panel recommends that both share the impact of carbon levies.
- The impact of carbon levies on unconventional oil and gas (excluding oil sands) is not yet fully known, pending more information and analysis from the recent announcements under Alberta's Climate Leadership Plan.
- Government has deferred the impact of most of the carbon levies on non-oil sands production until 2023. As such, our Panel finds that there is limited need to address these carbon levies for current wells and the impact on new wells is expected to be minimized with this extended implementation.
- Our Panel recommends that Alberta Energy undertake a review of the Otherwise Flared Solution Gas Royalty Waiver Program before the end of 2016 to ensure that it is adequately adjusted to the Climate Leadership Plan.
- To the extent that the implementation of the Climate Leadership Plan results in charges that are not currently understood, our Panel advises the Calibration Team to incorporate allowances in the MRF to accommodate sharing of the carbon levy. Potential mechanisms that are being considered are adjustments to C*, or commodity Reference Prices, or the Price Function(s), or some combination of all of the above.
- Details are to be released in conjunction with the final calibration of the MRF, by March 31, 2016.

10. Provide for as seamless as possible transition for wells drilled in 2016.

- Assuming that the MRF will be in place for wells drilled on or after a certain implementation date in 2017, there remain some questions on treatment of wells that may be drilled during 2016. Our Panel recommends that the treatment of those wells should result in minimal or no incentive for companies to defer drilling to 2017 to avoid much much poorer outcomes.
- The key areas of risk are the:
  - expiry of the ***Natural Gas Deep Drilling Regulation, 2010*** on November 30, 2016, which would both restrict qualification of wells for the Natural Gas Deep Drilling Program and remove the benefits of the program for wells that had qualified previously and had not reached the end of their allowed royalty adjustment, and
  - expiry of the ***New Well Royalty Regulation*** on June 30, 2018, which would remove benefits of the Emerging Resource and Technology program for wells which had not reached the end of their allowed royalty adjustment.
- In each case, as the programs are in general necessary for a high cost well to be economic, an investor looking at drilling a well that potentially qualified for one of these programs, and knowing that benefits would terminate, would be incented to wait until the MRF implementation date to drill.
- Our Panel recommends extension of the ***Natural Gas Deep Drilling Regulation, 2010*** to allow wells drilled throughout 2017 to qualify, maintain current eligibility rules and for the final termination of benefits from the program for any remaining qualifying wells to be the end of 2022 (5 years).
- Our Panel recommends extension of the ***New Well Royalty Regulation*** to allow final termination of benefits from any remaining qualifying wells to be the end of 2022 (5 years).
- Our Panel considered alternative approaches such as application of the MRF to wells drilled in 2016 and calculating royalties manually until systems were put in place. This may be a feasible approach as well and worth considering, but doesn't address the issues of wells already drilled under the two regulations in earlier years, and could be hampered by the time required to provide certainty through calibration, finalizing all formulas and guidelines, and putting regulations in place.

11. Provide appropriate transition for existing wells to new regime rates in 10 years.

- Over time program benefits will terminate and wells will decline in production. It appears to our Panel it would make sense to have a crossover point where all wells would come under the MRF. This would allow Alberta Energy to not manage two different regimes, and more importantly, allow for a simpler and more seamless treatment for new program areas such as waterflood schemes that may involve a mix of old and new wells.
- Our Panel suggests that 10 years will allow industry plenty of time to adjust for any changes in royalty rates or administration, and the termination of any benefits from any existing programs.
- Existing wells that become part of a program under the MRF will need to be treated similarly to wells drilled after the implementation dateto make these type of multi-well programs readily workable. Our Panel recommends that existing wells be transitioned be transitioned to the new regime (without a C* other than the program C*) if involved in this type of program.

WOOD MACKENZIE DATA AND OUR PANEL'S INTERPRETATION

Wood Mackenzie Analysis

This Appendix contains the results of the comparative fiscal analysis undertaken for our Panel by Wood Mackenzie. Our Panel recognizes that an analysis of this nature can be interpreted different ways by different people. For this reason, the results in Wood Mackenzie's report are interspersed with pages of interpretive commentary from our Panel. These pages describe how our Panel interpreted the Wood Mackenzie results, which in turn informed our findings and recommendations.

Methodology, Assumptions and Risks

There are different methods for comparing fiscal regimes between jurisdictions – some theoretical, others more realistic.

Our Panel instructed its consultants to focus on a standard methodology that sampled representative wells in each competitor and comparator jurisdiction (called "type wells"). Each type well was analyzed having regard to the fiscal terms, local prices, costs and other factors that influence profitability in its respective jurisdiction. In this way, the analysis answered the question, "How attractive would an investment in that representative well, typically found in that jurisdiction, be to an investor?"

Our Panel directed Wood Mackenzie to consider three hydrocarbons: natural gas; unconventionally-drilled light oils; and oil sands. Within each of these, Wood Mackenzie was instructed to choose type wells that have "Marginal", "Moderate", and "High" economic viability.

Comparative fiscal analysis largely focuses on future profitability, over the expected lifecycle (called "full cycle") of a type well; future investment is heavily predicated on future profit expectations.

Estimating future profitability is difficult because of the risks associated with all the uncertainties of the investment, and the opportunity cost of being able to invest the money elsewhere. Investors are always trying to quantify the nagging feeling that there may be a better deal elsewhere that offers better returns.

A multitude of factors can affect the economic viability, and hence profitability of a well.

- **Price** – For go-forward comparisons of profitability, Wood Mackenzie was instructed to run their economic models using different price assumptions. For example, oil prices were pegged at \$40, \$60, \$80, \$100 and \$140 real price per barrel (i.e, accounting for inflation.) Local discounts from global benchmarks were applied in each jurisdiction for each commodity.
- **Costs** – These are difficult to predict under various price scenarios, but generally the global oil and gas industry is susceptible to high levels of inflation at higher commodity prices. This is especially true in Alberta. Our Panel carefully examined historical cost relationships using advice and data from Alberta-based expert consultants (GLJ Petroleum Consultants), and other private and public information from other sources. Such data was used to estimate current and future costs of Alberta wells, and passed on to Wood Mackenzie to ensure best estimates.
- **Foreign exchange** – Translation of US dollar-based oil prices into Canadian dollars is subject to forward-looking estimates in Canadian dollar profitability. The exchange rate is correlated with oil prices, in particular. Wood Mackenzie worked with our Panel to use reasonable estimates of foreign exchange under the different commodity price scenarios.

Comparative fiscal analysis is conducted on individual oil and gas wells, and individual multi-billion-dollar projects, such as oil sands facilities. These analyses provide a good sense of the profitability of a jurisdiction's energy development opportunities. However, the investors who provide investment capital do not invest in individual wells and projects; they invest in energy companies, who in turn use the capital to invest in wells and projects. It is therefore important to remember that the comparative fiscal results of wells and projects discussed in this section are not necessarily indicative of the overall profitability of the energy companies that invest in, and operate, these wells and projects.

Another important point to remember is that the world of royalties is not static. Jurisdictions around the world routinely ask questions similar to those our Panel considered. ("Are we being reasonably compensated?"; "Are we competitive?") Indeed, our Panel was informed by Wood Mackenzie that over 40 oil- and gas-producing jurisdictions in the world are currently undergoing fiscal reviews. Consequently, the answers to these questions are constantly changing – for Alberta, and for others – depending upon what a jurisdiction's peers are doing.

Measuring Profitability

Like artisans, financial analysts have many tools to work with to estimate future profitability and quantify the risks of investing. As long as consistency is used in evaluating all of the investment opportunities – for example, investing in Alberta versus Texas versus Colombia – then relative profitability can be ranked.

In addition, estimates of how profits are shared between a company and a resource owner may be made over the entire life cycle of a well or project.

The following are common metrics for benchmarking profitability and profit-sharing:

- **Nominal "Split of a Barrel"** – As its name implies, the undiscounted revenue from a notional "barrel" is broken down into its constituent value components. All components are expressed in percentage terms. Capital and operating costs are estimated over the life of a well. What is left over are the life cycle profits and how they are shared between owners and the company.

- **Internal Rate of Return (IRR)** – A standard metric to evaluate percentage profit returns on a common basis, accounting for the time value of money, independent of project size. A 10% IRR typically represents a breakeven "hurdle rate."

- **Profitability Index (PI)** – A ratio measuring future profitability adjusted for time, divided by the initial investment. A measure of 1.0 is the minimum acceptable PI. Higher values indicate superior profitability. Less than 1.0 indicates an investment that did not achieve a company's hurdle rate.

- **Payback Period** – The amount of time, typically measured in years, that it takes for a company's operating profit stream to pay back its initial investment.

- **Owner's Share** – The fraction of profits, in percentage terms, taken by the owner of the resource. An owner's take includes all rents taken from a barrel, including royalties and taxes. Note that the resource owner is not necessarily the State (or Province), but can also be a private individual or private organization.

Wood Mackenzie
A Verisk Analytics Business

Fiscal Benchmarking Results

Prepared for Alberta Energy

With Interpretive Notes by the Alberta Royalty Review Panel

Strategy with substance
www.woodmac.com

Executive Summary

- **To understand how Alberta compares as a place for oil and gas investment, the province was benchmarked against 21 international jurisdictions competing with it for capital**
- **In addition to geological differences, royalties and other fiscal terms impact a jurisdiction's competitiveness by determining how profit from oil and gas development is shared between the government and the companies investing**
- **Alberta's resources tend to be expensive to develop and produce, with a greater share of revenue received for each barrel of oil equivalent produced going to cover costs**
- **In general, Alberta compares similarly to other regimes on both investor returns and government take, though fiscal incentives and variable royalty rates limit economic upside for either investors or the government, depending on the resource type**
  - **Unconventional gas** economics in Alberta are challenged even at high prices, similar to other jurisdictions, and fiscal incentives granted for that reason limit the government's share in price upside
  - Alberta's **unconventional oil** is competitive with other international regimes, though price upside is more limited, and fewer incentives mean the government receives a higher share of profit than for natural gas
  - **Oil sands** economics are comparable with large-scale oil investments elsewhere (offshore and heavy oil), though linkage of royalty rates with price and project payout limits upside for the investor while ensuring the government a bigger share

Agenda

1 **International Fiscal Responses to Low Oil Price**

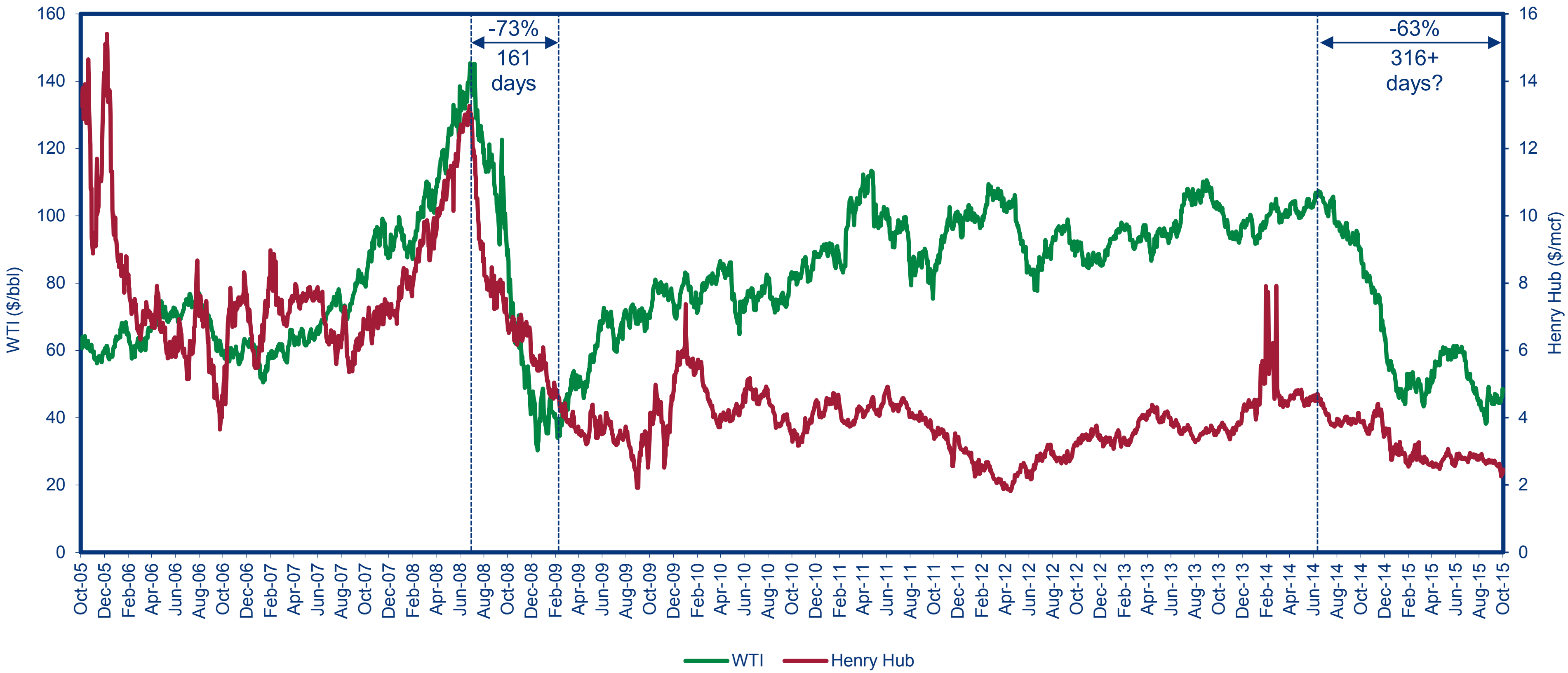
2 Benchmarking Methodology

3 Initial Benchmarking Results

US Benchmark Crude Oil and Natural Gas Prices

Monthly Averages; October 2005 to October 2015

10-Year US Oil & Gas Price Movements



Source: Wood Mackenzie

Page Interpreted: 3, "U.S. Benchmark Crude Oil and Natural Gas Prices"

1. The Financial Crisis in 2008 and 2009 hit commodity prices hard. Oil fell from its peak price of $147/B to under $40/B. Natural gas prices dropped from $14/mcf to less than $4.00/mcf.

- The drop in oil prices lasted 161 days at the time, before recovering on expectations of ongoing, robust Asian oil demand.
- Natural gas prices, however, didn't rebound.

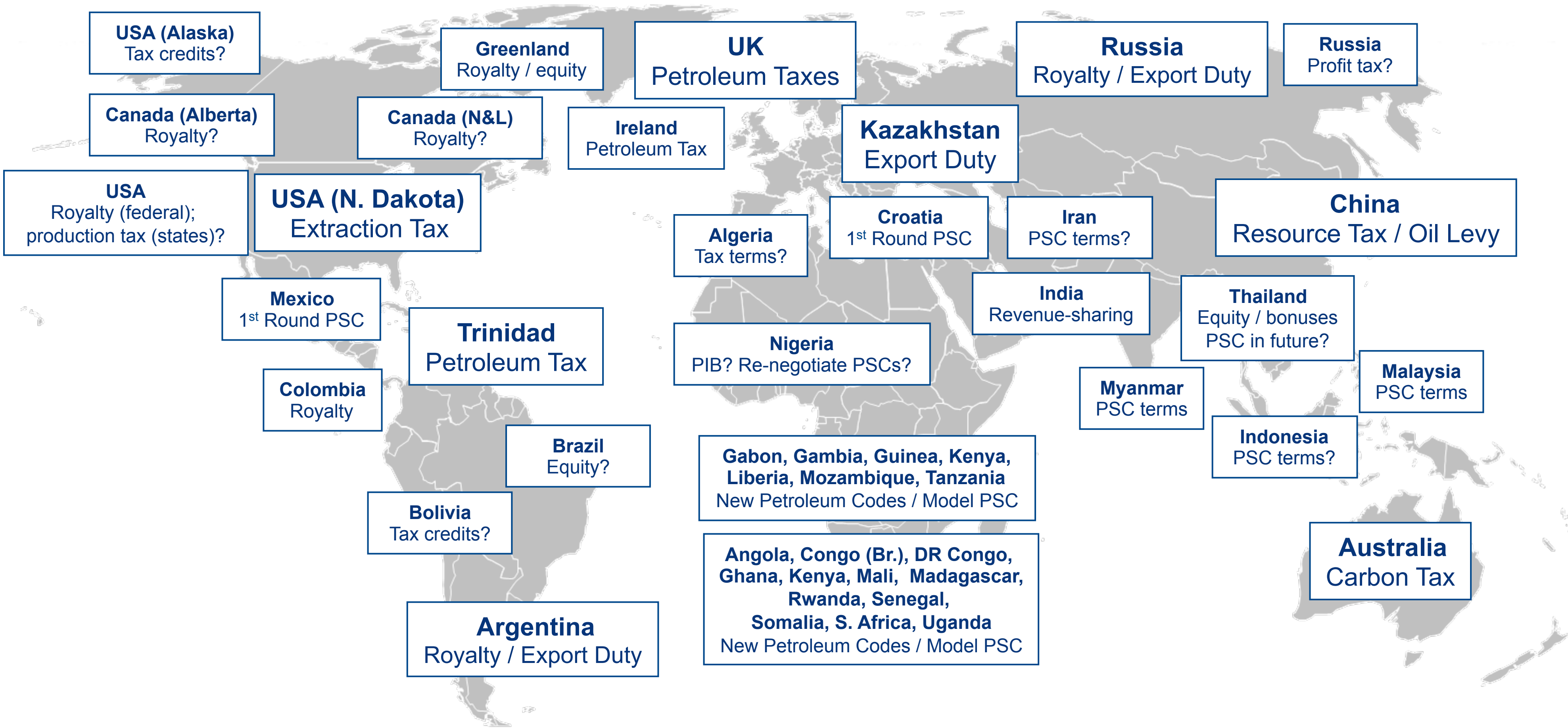
2. The period post Financial Crisis to 2014 is notable for the wide gap between North American oil and natural gas prices.

- Historically, oil and natural gas prices move together.
- On occasion, natural gas prices spiked up (February 2010 and February 2014), but these were mostly cold winter weather effects.
- Muted natural gas prices were, and still are, a consequence of the "shale gas revolution. "The unconventional processes of horizontal drilling and hydraulic fracturing have had the effect of liberating large quantities of natural gas inside a contained North American market.

3. Oil prices began dropping precipitously mid-year 2014. Unconventional processes that triggered the shale gas revolution, created a glut of oil in North America, especially the United States. A global price war ensued as a consequence of the disruptive technologies. The downturn is now over one year long; high prices may not be forthcoming for either commodity.

Jurisdictions Where Fiscal Terms Are Being Reviewed

Few Changes Expected for Existing Production; Terms Changing For New



Source: Wood Mackenzie; fiscal changes made in 2014 - 2015

Page Interpreted: 4, "Jurisdictions Where Fiscal Terms are Being Reviewed"

1. When oil and/or gas prices rise or fall quickly, there is often a call to government to review the jurisdiction's fiscal regime.

- High prices typically trigger a call to raise royalties and taxes.
- Low prices often trigger calls to ease the fiscal regime, especially for new projects and wells.

2. In a low price environment, changes are often limited to new projects.

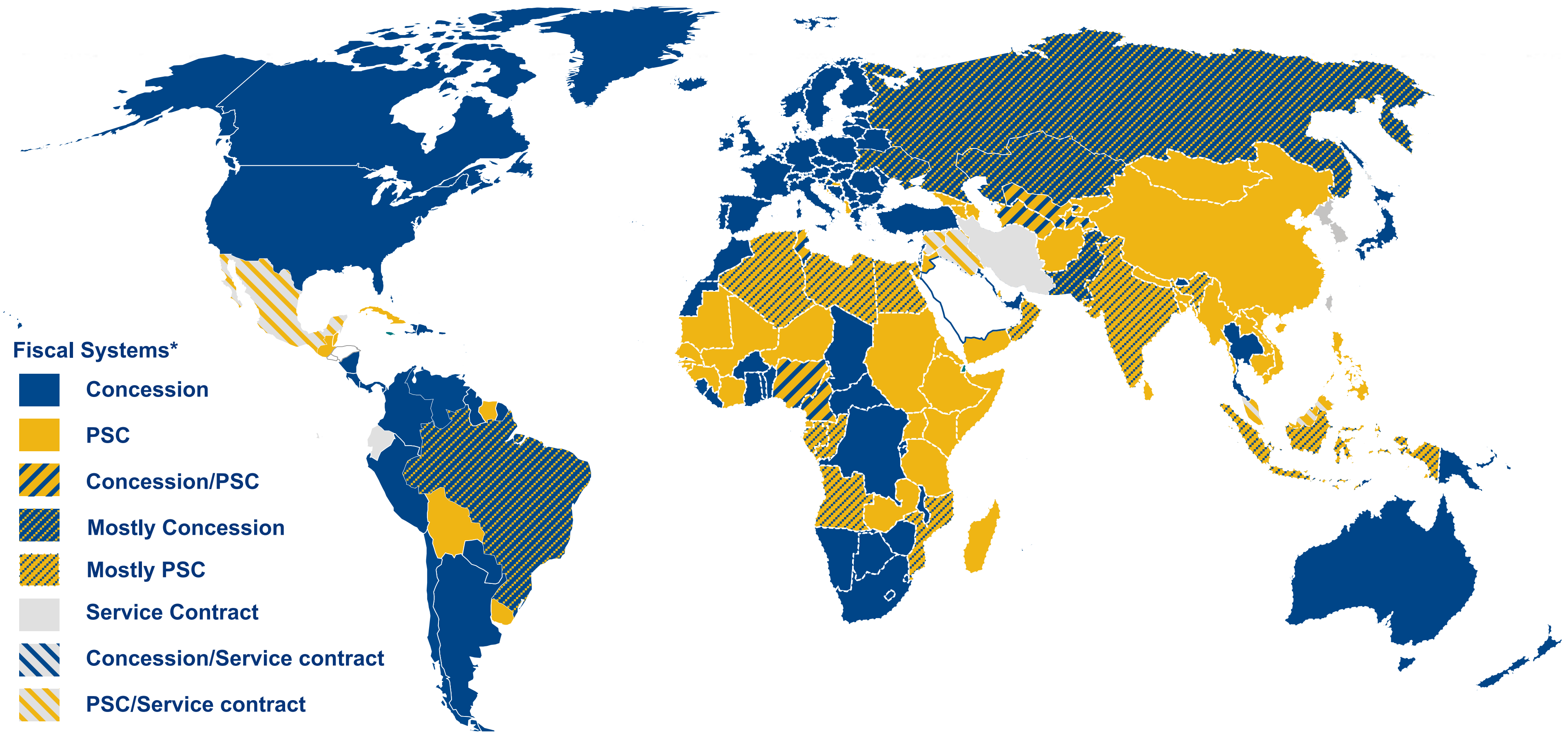
- Royalties and taxes on existing production are usually left intact, because capital costs have been sunk previously.
- Fiscal terms on new projects may be eased to encourage capital investment stimulus into the region.

3. There are almost 50 fiscal reviews on the go. Countries, states and provinces are all considering their options.

- Fiscal terms include royalties and taxes of various kinds.
- "Government take" is a term that is applied to all sources of revenue – royalties, petroleum taxes, carbon taxes, corporate taxes, etc. – taken from the production of a barrel of oil, or cubic foot of natural gas.

Global Fiscal Systems by Contract Type and Country

Three Main Fiscal System Classifications



***Excludes terms for domestic NOCs**

Page Interpreted: 5, "Global Fiscal Systems by Contract Type and Country"

1. There are three broad types of fiscal regimes for oil and gas:

- **Concession** – Resource owner concedes an area of land to a company, often through sale or auction. Upon purchase the company owns any subsurface reserves of oil and gas, if any are found through exploration and development. After production and sale of the hydrocarbons, the owner imposes royalties and taxes to participate in the profitability of the venture. Concession agreements have implied pre- and post-payout structures.
- **Production Sharing Agreements (PSA)** – Ownership of the oil and gas is not passed onto the company. The resource owner maintains ownership. Companies are contracted to find, develop and produce the oil and gas on the owner's land. Generally, after the company recovers its upfront capital expenses (pre-payout period), both sides share the post-payout profits according to a prescribed fiscal regime. The company is granted its share of the profits as physical volumes of oil and gas above ground, which is why the post-payout share is sometimes called "profit oil." In this way, both company and resource owner are exposed to commodity price risk.
- **Service Contracts** – Similar to the PSA above, except that the company never takes ownership of the oil and gas, either below or above ground. The company is paid a prescribed fee for the service of exploring, developing and producing on behalf of the resource owner.

2. The U.S. and Canada are concession based, because such regimes are generally found in jurisdictions with stable governments and rule of law. PSAs are more common for large projects in Africa and Asia. Few places have contract agreements, Iran being notable

Agenda

1. International Fiscal Responses to Low Oil Price
2. **Benchmarking Methodology**
3. Initial Benchmarking Results

Fiscal System Benchmarking Methodology

Five Primary Considerations for Alberta's Royalty Review 2015

1. **Regimes**
   » Which other oil and gas jurisdictions are the most appropriate comparisons for Alberta?

2. **Oil & Gas Plays**
   » What types of oil and gas assets make the most sense to use for purposes of benchmarking Alberta's fiscal terms against other jurisdictions?

3. **Type Wells and Projects**
   » Which specific assets within the selected oil and gas plays best illustrate a relevant range of investment options?

4. **Price and Cost Cases**
   » What combination of price and cost scenarios provides a representative range of potential future investment climates?

5. **Metrics**
   » Which economic metrics are most important to consider from either the province's or investors' perspective?

Page Interpreted: 7, "Fiscal System Benchmarking Methodology"

1. How do we compare different fiscal regimes for different regions against each other to determine the appropriate sharing of pre- and post-payout profits?

2. There is a wide diversity of geology and hydrocarbons, especially in Alberta. Which wells should be used for comparison?

3. What assumptions should be used for future industry fundamentals, including prices and costs?

4. There are a wide variety of measures for the profitability of an oil and gas project over its lifecycle. Which metrics and measures should be used when comparing the future profitability of an oil field in say Norway, versus Colombia, versus the Alberta oil sands?

5. The Panel worked with Wood Mackenzie's global expertise in conducting royalty reviews to design an appropriate review for Alberta.

Selecting Oil and Gas Plays, Wells and Projects

Considerations for Alberta's Royalty Review 2015

- **Alberta's conventional oil and gas potential is limited**
  - 70% of Alberta conventional gas resources and 85% of conventional oil has already been produced
  - Remaining conventional oil and gas reserves are now less than unconventional reserves
  - Conventional drilling and production are in terminal decline
- **Considerable upside to Alberta's unconventional oil and gas potential**
  - Major resource identified
  - Full reserve potential still being tested
- **Future investment will target unconventional oil and gas and oil sands, specifically:**
  - Deep tight plays
  - Long horizontal wells
  - In situ oil sands projects

Page Interpreted: 8, "Selecting Oil and Gas Plays, Wells and Projects"

1. The U.S. and Canada have been producing oil and gas for over 150 years. Many of the legacy fields had matured using "conventional" technology.

- Conventional processes refer to tapping into oil and gas bearing rock formations by drilling wells vertically (straight down), and producing from the zones that were viable for extraction.
- This conventional method necessitated a large number of wells to be drilled into a formation and is now largely obsolete.

2. Drilling straight down and then bending the well trajectory horizontally into the hydrocarbon bearing formation is called horizontal drilling. This is not a new technique, however, a convergence of better digital instrumentation, drill bits and other factors made the process much cheaper and more accurate over the past decade.

- Horizontal drilling, combined with multi-stage hydraulic fracturing – a method of improving the flow of hydrocarbons into the well bore – have made a whole new base of hydrocarbons economically viable for extraction.
- The application of these new "unconventional" processes to Alberta geology is still in its early days, but the resource potential is expected to be very large when it is proven up.

3. Future investment will be found in geology that is conducive to unconventional drilling and completion techniques.

- The oil and gas industry is transitioning to these new areas using these new techniques.

Selecting Regimes for Comparison

Considerations for Alberta's Royalty Review 2015

1. **Capital Competitiveness: which regimes compete most directly for capital with Alberta, based on the companies most active in the province**
   » Distinguish between key countries of investment both including and excluding the Majors and NOCs, which have wider portfolios than other Alberta players

2. **Comparable Resources: either play types (i.e. unconventional oil, unconventional gas, oil sands) or comparable development scales (e.g. deepwater for oil sands)**

Final benchmark regimes that are selected should be based on those that are most directly comparable from two criteria: Resource type and capital competitiveness.

Page Interpreted: 9, "Selecting Regimes for Comparison"

1. The Panel worked with Wood Mackenzie to determine which other oil- and gas-producing jurisdictions were most comparable to Alberta.

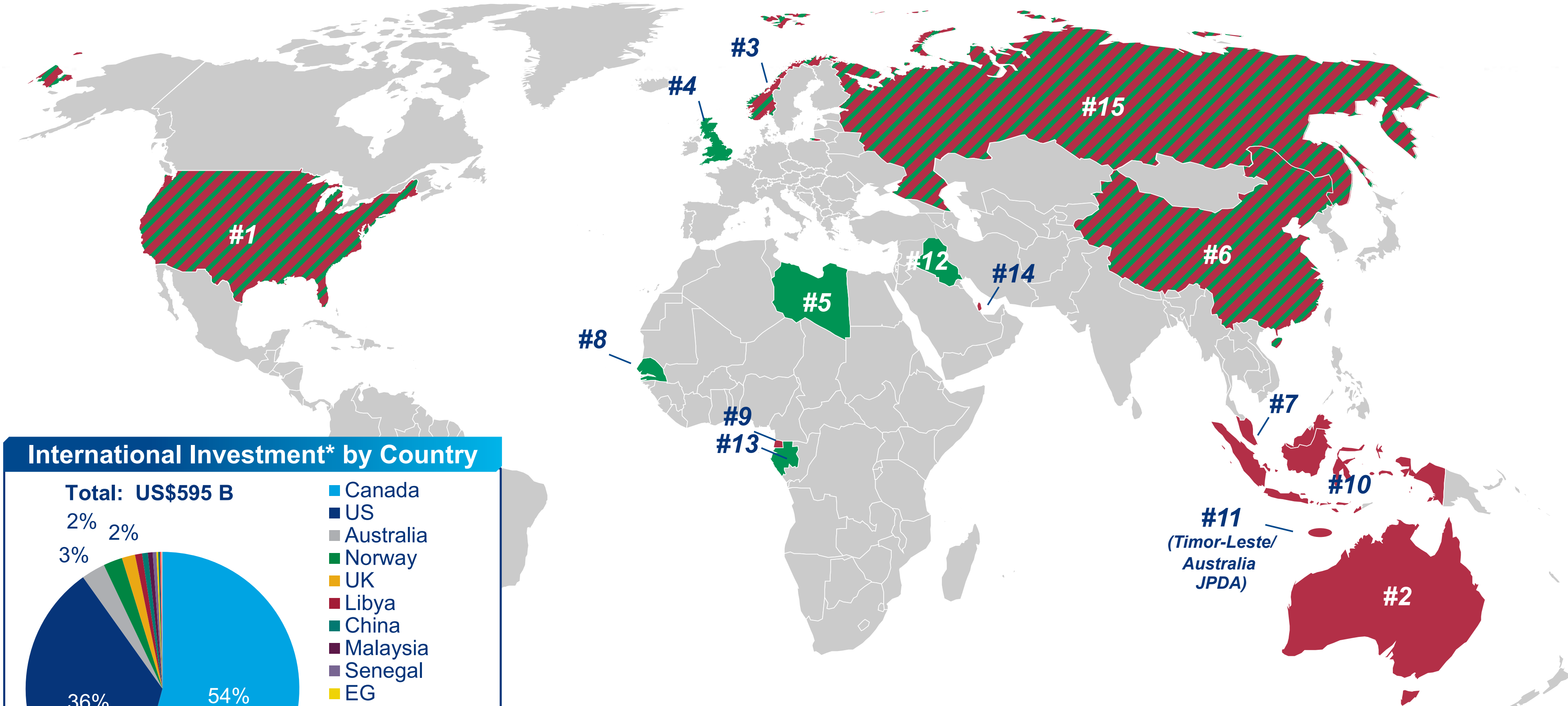
- Different geology and hydrocarbon types are "below ground" factors that make apples-to-apples comparison difficult.
- "Above ground" factors include fiscal regime, political risk, market access, commodity price volatility and social conditions that affect the ability of a jurisdiction to attract investment and set agreeable terms under one of the fiscal arrangements discussed earlier.
- Multinational oil and gas companies have a portfolio approach, allocating investment into global projects that have a favourable combination of above and below ground factors.

2. Scale is important to consider too.

- Oil sands projects are large-scale, with investment measured in billions of dollars. Upfront investment is exposed to above ground risk factors for several years until construction of facilities is complete. Payout of the investment typically takes many years after investment. Comparable projects for oil sands are big, deep offshore platforms.
- Unconventional wells cost an order of magnitude more than their conventional predecessors. However, individual well costs are still measured in millions of dollars, rather than the billions for large-scale projects. Development and payout periods for unconventional wells are much shorter than for large-scale projects.
- Fair comparison of fiscal regimes must consider scale of development.

Investment Alternatives of Companies Operating in Alberta

Excluding Multinational and National Oil Companies



International Investment* by Country

Source: Wood Mackenzie

* *Based on Wood Mackenzie forecasts of future investment*

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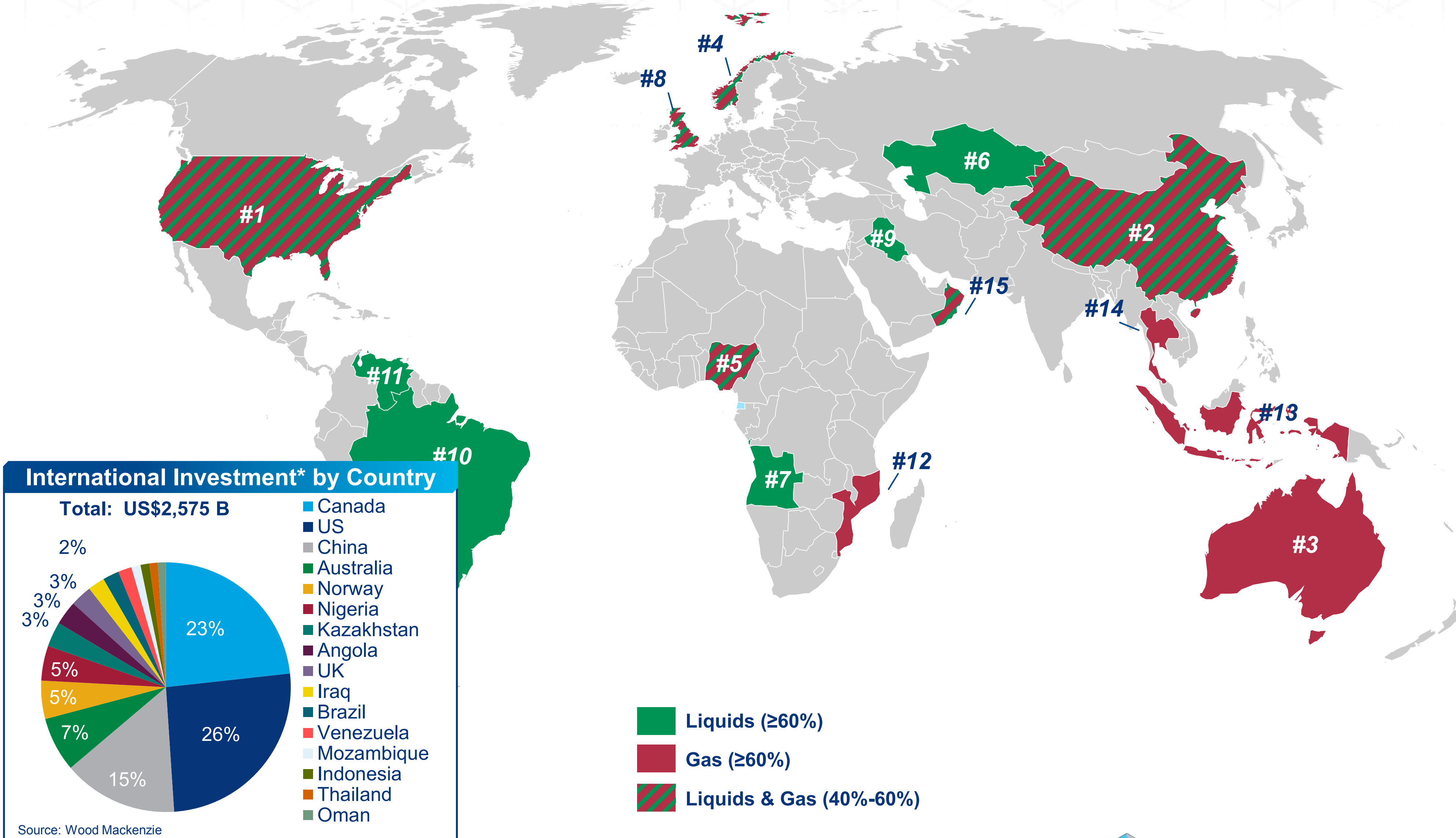
Investment Alternatives of Companies Operating in Alberta

Multinational and National Oil Companies



* *Based on Wood Mackenzie forecasts of future investment*

Pages Interpreted: 10 and 11, "Investment Alternatives of Companies Operating in Alberta"

1. After considering all comparative factors, our Panel and Alberta Energy conferred with Wood Mackenzie to arrive at the top 15 jurisdictions that were most analogous to Alberta.

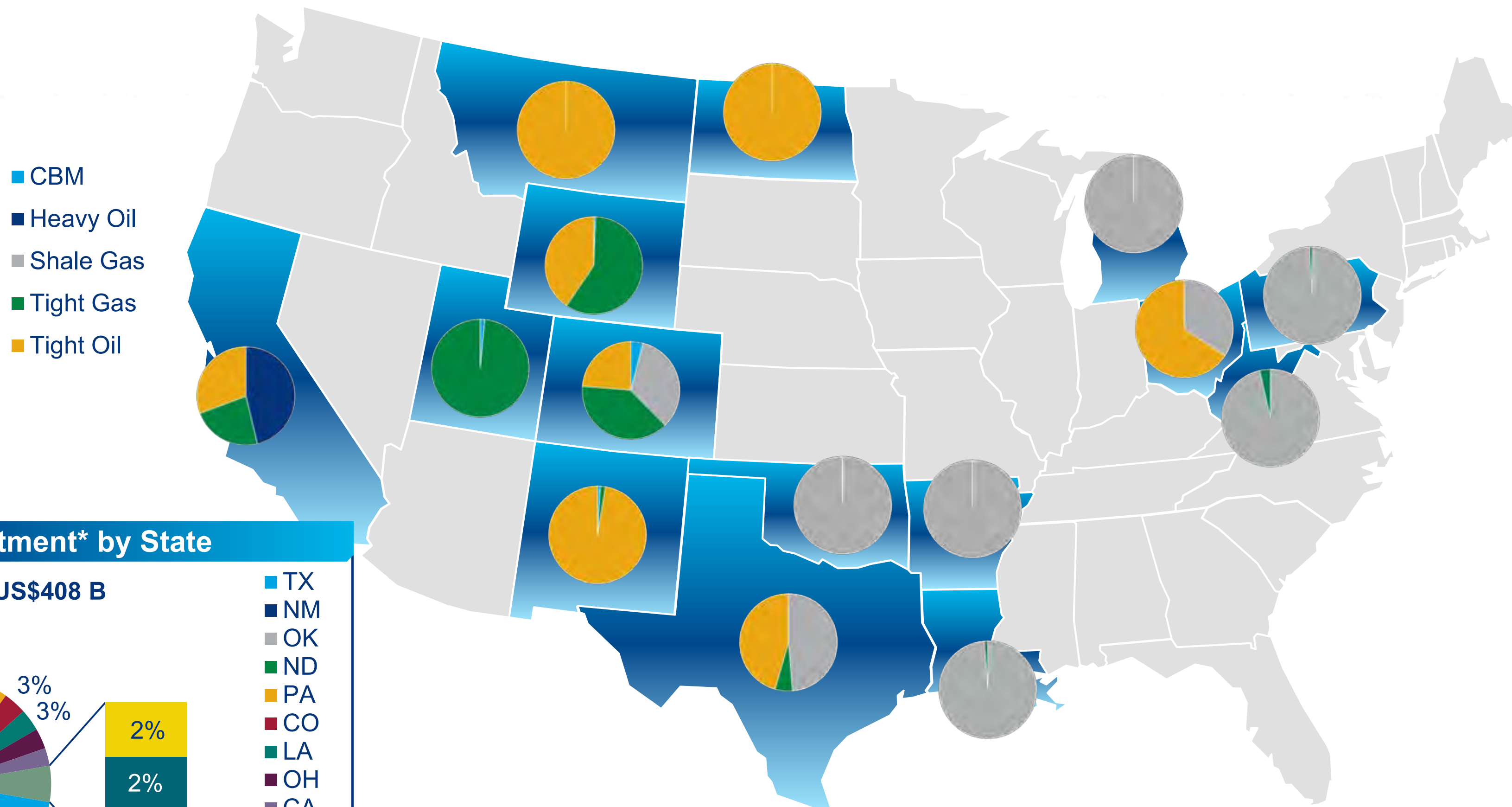
- The jurisdictions on this map are also colour coded to reflect which ones are most suitable for comparison to oil and which ones to natural gas.
- Both oil and natural gas have different fiscal terms in most regions.

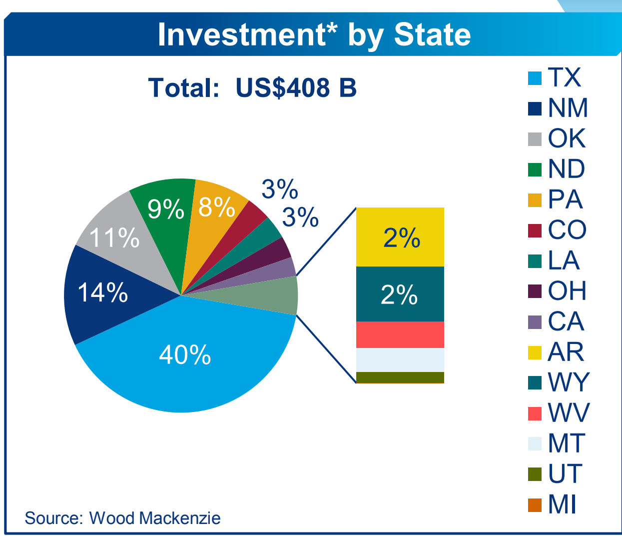
2. This pie chart represents the amount of investment exposure to each region, by the major companies that are active in Alberta.

- The bulk of investment that's not in Canada (23%) is, not surprisingly, in the United States (26%).
- China, Australia, Norway and Nigeria are the next most common, but are considerably smaller. Exposure to these countries is dominantly by the state-owned-enterprises (SOEs) and big multi-nationals that operate in Canada, for example companies like Shell and China's CNOOC that have investment choice globally.
- Whether or not the big multi-nationals and National Oil Companies (NOCs) are in the set, the overwhelming first alternative for investment capital is Canada's biggest competitor: the United States.
- The set is slightly smaller if only multi-national and NOCs are considered (slide 11).
- As such, our Panel focused the bulk of its comparative analysis on U.S. state fiscal regimes; for example Texas, Oklahoma, Pennsylvania and North Dakota.

Unconventional Resources in the United States by Type

US States That Have Comparable Resources to Alberta





* *Based on Wood Mackenzie forecasts of future investment*

Interpreted page: 12, "Unconventional Resources in the United States by Type"

1. Within the United States, our Panel worked with Wood Mackenzie to understand which states were the most comparable and competitive with Alberta.

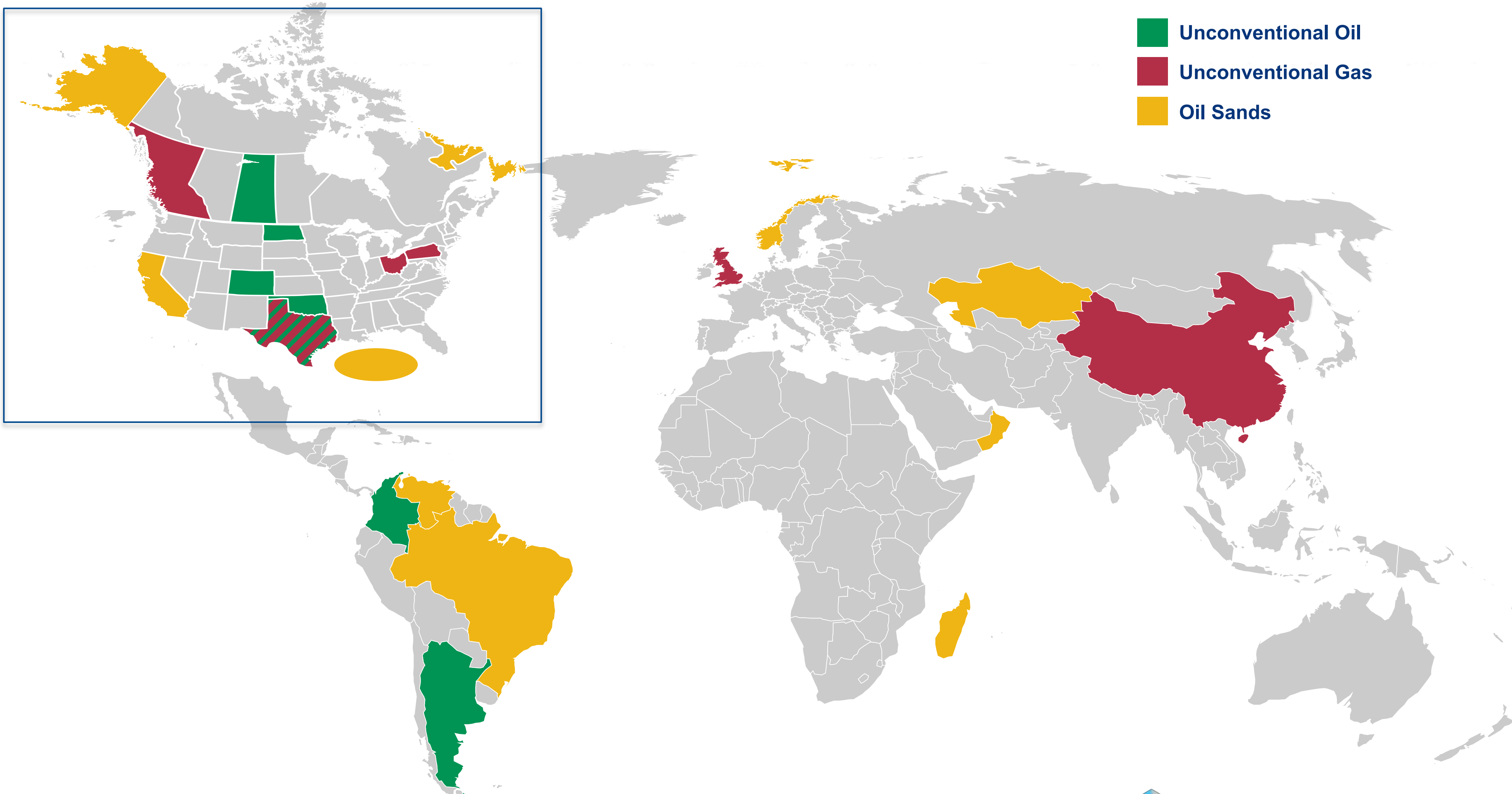
- Each state has different geology and hydrocarbon content.
- Pennsylvania is dominantly natural gas and competes with Alberta in North American markets. Large-scale development of shale gas and associated pipeline infrastructure is pushing Pennsylvania gas into central Canada too – another traditional Alberta market.
- North Dakota is dominantly oil and a good analog for Alberta's unconventional oil development.
- Texas has some of the most prolific quantities of both oil and natural gas using the new unconventional technologies. Given its size, Texas is also a prime competitor for capital investment.

2. The investment pie chart helped our Panel choose the most relevant U.S. states.

- Texas is front and center based on investment potential.
- Oklahoma, North Dakota and Pennsylvania were chosen, because they are currently sizeable competitors and have comparable geologic situations.
- New Mexico, though projected to attract significant future capital, was not chosen because much of its resources are emerging and others are very similar to Texas'.
- Alaska and California were also chosen, the latter for its heavy oil comparability, and the former for its high-cost frontier characteristics.

Oil and Gas Regimes Considered for Comparison to Alberta

Highlighted by Resource Type



Interpreted page: 13, "Oil and Gas Regimes Considered for Comparison to Alberta"

1. Global choices for comparable regimes are shown on this map.

2. British Columbia and Saskatchewan were obviously comparable for unconventional oil and gas wells within Canada. Newfoundland and Labrador's large-scale offshore projects were considered peers of large-scale oil sands development.

3. China is comparable for natural gas because of its large potential for shale-type unconventional development. However, China is dominated by state-owned enterprises that have unique internal fiscal regimes. Some private investment opportunities may be found in China, however there are many market barriers. Consequently, our Panel chose to limit China as a pragmatic comparison.

4. Colour coding within each comparable jurisdiction is by product/project type.

- Oil sands are compared with large-scale megaprojects or very heavy oils.
- Unconventional oils are compared with similar sized capital spends, payout times and well types. Most notably: Texas, Oklahoma, North Dakota, Colorado and Saskatchewan. Colombia and Argentina provide the best international comparisons.
- Unconventional natural gas is compared with its peers, most notably with its closest competitors: Pennsylvania, Texas, Ohio, and British Columbia.

Choice of Representative Plays, Wells and Projects in Alberta

By Hydrocarbon Type and Range of Quality

- **Wells typical of high, medium and marginal unconventional sub-plays modelled for each asset group**
- **Each of the type wells modelled sits in the middle of the range of all type wells drilled in the sub-play**
- **Modelled on both a full-cycle and development basis**
  - » Full-cycle is more representative of relatively undeveloped plays
  - » Development basis is more representative of relatively well-developed plays
- **Production and cost assumptions are informed by a mix of historical results and current producer plans**
- **Elements of government / owner share of value modelled include:**
  - » Royalties, bonuses, lease rentals
  - » Private royalty payments in US jurisdictions
  - » Severance taxes
  - » Federal and provincial taxes
  - » Municipal taxes included in operating costs

Criterion	Alberta Sub-Play or Project
Unconventional Gas	
Highly economic well	Montney Kaybob Elmworth
Moderately economic well	Deep Basin Wilrich
Marginally economic well	Montney Simonette
Unconventional Oil	
Highly economic well	Cardium Pembina West
Moderately economic well	Montney Waskahigan
Marginally economic well	Viking Tier 2
Oil Sands	
Small future or pilot project	10 kb/d SAGD
Expected future project	35 kb/d SAGD
Larger / expanded project	105 kb/d SAGD (in stages)
Large mine project	140 kb/d Mining

Interpreted page: 14, "Choice of Representative Plays, Wells and Projects in Alberta"

1. There is a wide spectrum of geology in comparative jurisdictions, especially within Alberta.

- Our Panel recognized that costs and hydrocarbon quality (which dictates price) varied greatly across geologic plays in the Province.
- Even within specific play regions (sub-plays), there is a wide variance in well performance, hence costs.
- Our Panel had to consider the question: "To what type of well do we calibrate the royalty system?" Calibrating to the best wells would marginalize many good quality ones in the midrange. On the other hand, calibrating to the marginal wells would skew profit sharing in favour of the companies.
- Our Panel asked Wood Mackenzie to test "High", "Medium" and "Marginal" wells in several representative Alberta plays to get a full range context. The ultimate benchmarks for calibration were chosen to be wells of mid-range quality in each jurisdiction.

2. Oil and gas projects vary in their stage of maturity.

- Some plays are established and are evaluated on a "development basis", which means that companies have gone down the learning curve of development. Previously built surface facilities in the area make incremental wells less costly to develop.
- In contrast, "full cycle" wells include exploration costs, representing ones that are drilled in relatively new areas, and are therefore of higher cost. The Panel considered both half and full cycle economics in their comparative analysis.

Interpreted page: 14 continued, "Choice of Representative Plays, Wells and Projects in Alberta"

3. Royalties are almost always part of a broader package of government take called the "fiscal regime."

- There are many types of policy mechanisms for the resource owner to receive value from a unit of hydrocarbon production.
- Royalties, land bonuses (proceeds from auction), monthly rentals, and a multitude of taxes are all part of a typical fiscal regime.
- Municipal taxes represent significant take from the locality and are included in operating cost assumptions.
- In the United States, private landowners are significant owners of the resource below the ground and therefore take a big share of the post-payout profits. In Alberta, most private individuals do not own any subsurface minerals. The "Crown" owns almost all of it and the government acts as the agent to collect royalties and taxes on behalf of the people (the resource owners).
- To fairly compare government take between jurisdictions, all sources of revenue in the fiscal regime are considered, including royalties. This standard practice is how Wood Mackenzie conducted the royalty review.

4. Oil sands project differentiation is mainly by size, measured by productive capacity.

- Four projects of different size were considered: 10,000; 35,000; 105,000; and 140,000 barrels per day.
  - The largest project is of the mining variety; three smaller ones are in-situ, steam assisted gravity drainage (SAGD).

Recommended Scenarios for Commodity Prices, Costs and F/X

For Comparing Fiscal Regime

Recommended Price and Cost Scenarios					
Price Cases (flat, real)	**1**	**2**	**3**	**4**	**5**
Oil (WTI) US$/barrel	$40	$60	$80	$100	$140
Gas (HH) US$/mcf	$2	$3	$4	$5	$6
Bitumen US$/barrel	WTI * 0.60				
Condensate US$/barrel	WTI * 1.05				
NGLs US$/barrel	WTI * 0.50				
AECO US$/mcf	HH * 0.80				
Costs					
Cost Index Benchmarked to $60/bbl WTI Price*	-7%	0%	13%	27%	53%
Foreign Exchange Rates					
C$/US$ (2016 onward**)	1.33	1.18	1.08	1.01	0.91

Note: On average, Wood Mackenzie project economics reflect ~$60/bbl oil
** Provided by ADOE using a public index of global capital costs*
*** 2015 exchange rate is 1.21 in all price-cost scenarios*

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Interpreted page: 15, "Recommended Scenarios for Commodity Prices, Costs and F/X"

1. Alberta has a wide variety of hydrocarbon types.

2. Our Panel considered a wide range of price scenarios for each of oil and natural gas.

- Benchmark oil prices were varied in five scenarios ranging from $40/B to $140/B.
- Natural gas prices varied under five scenarios too, ranging from $2.00/mcf to $6.00/mcf.
- For simplicity, other hydrocarbon products were varied by scaling factors multiplied by the oil and gas benchmarks. These ratios were derived by Wood Mackenzie based on experience, historic relationships, and knowledge of future expectations.

3. Costs vary with price in the global oil industry – high prices drive high costs and vice versa.

- Using historical cost knowledge and future expectations, our Panel conferred with Alberta Energy, Wood Mackenzie and GLJ Petroleum Consultants (Alberta-based reserve engineers) to estimate future cost behaviour as a function of the different price scenarios. Publicly available data from trustworthy agencies were also used.
- $60/B was chosen as the price to which costs would be indexed. At $140/B, costs are estimated to be 53% higher than those at $60/B. Similarly, at $40/B, costs are gauged to be 7% lower than those at $60/B. Wage, service and other input costs were analyzed.

4. Exchange rates vary with oil prices in countries with a high component of oil in their economy's GDP. Oil and gas are traded globally in U.S. dollars, so conversion is necessary for analysis.

- The schedule of exchange rates relative to the U.S. dollar was adopted for Canada as noted. Other jurisdictions were done in U.S. dollar equivalents as well.

Metrics for Measuring Profitability and Resource Owner's Take

Select Definitions

Metric	Rationale
IRR (%)	Metric to evaluate company returns on a common basis, irrespective of the size of the project; 10% IRR represents breakeven*, anything above is economic rent
Profitability Index	Quantifies the value created per unit of investment, allowing for comparison on a common basis irrespective of size, similar to IRR
Government Take (%)	Most relevant metric for the government to understand the percentage of future profits accruing to it in the form of royalties, taxes, etc.
State Take (%)	Where the government participates directly in oil and gas projects, either through a National Oil Company or otherwise, reflects the percentage of profits accruing to the government, including profits accruing to the state entity
NPV	
Absolute ($M)	Most relevant for Method 1, since common type wells/project sizes will be used, such that NPV can be compared on a like-for-like basis for each resource category
Per Unit ($/boe)	Most relevant for Method 2, since type wells and project sizes will be varied across regimes to reflect the true variation in resource potential
Breakeven Price ($/boe)	Metric to evaluate the relative economics of type wells and projects, irrespective of oil price assumptions

** 10% is standardly used as a hurdle rate for investment by the industry, though individual companies may use rates both higher and lower, depending on their weighted average cost of capital*

Interpreted page: 16, "Metrics for Measuring Profitability and Resource Owners' Take"

1. There are many financial measures for assessing profitability and the resource owner's "take".

- As long as consistency is used in evaluating all the comparable plays – say investing in Alberta versus Texas versus Colombia – then relative profitability can be ranked.
- How profits are shared between company and resource owner (the take), may be made either in a specific time period or over the entire lifecycle of a well or project.

2. In this slide Wood Mackenzie discusses some of the various metrics used in royalty review benchmarking. Here are some definitions that are relevant to the analysis:

- **Nominal "Split of a Barrel"** – As its name implies, the undiscounted revenue from a notional "barrel" is broken down into its constituent value components. All components are expressed in percentage terms. Capital and operating costs are estimated over the life of a well. What's left over are the lifecycle profits and how they are shared between owners and the company.
- **Internal Rate of Return (IRR %)** – A standard metric to evaluate percentage profit returns on a common basis, accounting for the time value of money, independent of project size. A 10% IRR typically represents a breakeven "hurdle rate."
- **Profitability Index** – A ratio measuring future profitability adjusted for time, divided by the initial investment. A measure of 1.0 is the minimum acceptable PI. Higher values indicate superior profitability. Less than 1.0 indicates an investment that did not achieve a company's hurdle rate.
- **Payback Period** – The amount of time, typically measured in years, that it takes for a company's operating profit stream to pay back its initial investment.

Interpreted page: 16 continued, "Metrics for Measuring Profitability and Resource Owners' Take"

- **Owner's Share** – The fraction of profits, in percentage terms, taken by the owner of the resource. Owner's share includes all rents taken from a barrel, including royalties and taxes. Note that the resource owner is not necessarily the state. In some jurisdictions, notably the United States, surface landowners also own the mineral rights beneath them. In Alberta, the Crown owns all mineral rights on Crown land and is therefore the sole owner. "Owner's Share" in this document refers to both the state's share plus any other private owners' shares.
- **Net Present Value (NPV)** – The lifecycle cash profitability of a project in dollars, after considering all costs, royalties and taxes, and after discounting for the time value of money. The discount or "hurdle" rate used should represent a project's cost of capital. Companies should be indifferent to two or more projects with the same NPV overall, or on a unit basis.
- **Breakeven Price** – The price scenario under which a well or project exactly achieves its hurdle rate or "breaks even".

Choice of Standard Discount Rate for Comparative Analysis

For All Plays, Wells and Projects Across All Jurisdictions

- 10% – standard after-tax discount rate, typically used as reflective of the industry's weighted average cost of capital*
- 15% – provided as a sensitivity. Quite often the minimum return acceptable to companies on exploration or development projects, particularly for more complex project types, such as deepwater
- 0% – more representative of government perspective and appropriate for understanding cash splits without the time value of money (i.e. split-of-the-barrel analysis as in Slide 20)

* *Individual companies may use rates both higher and lower, depending on their specific weighted average cost of capital*

Interpreted page: 17, "Choice of Standard Discount Rate for Comparative Analysis"

1. Discount rates used by companies vary depending upon above and below ground risks.

2. Oil and gas companies typically use 10% as standard (after-tax) discount or hurdle rate.

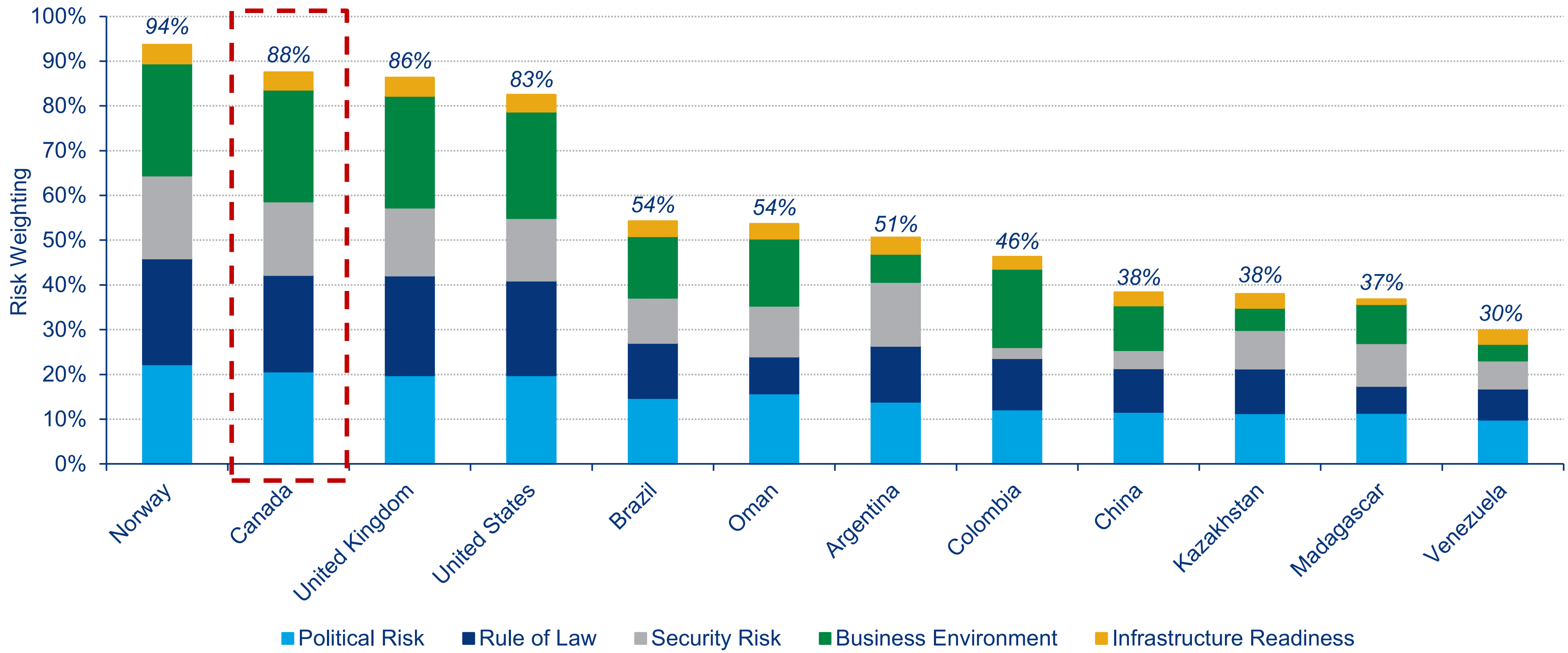
- Some companies with differing risk tolerances tend to use 15% to reflect a higher threshold for investment.
- Any project or well that is projected to return less than 10% after taxes is considered subeconomic.
- Large companies that have a wide portfolio of opportunities use the 10% standard.
- Smaller entrepreneurial companies usually have a cost of capital that is far greater than 10%, due to their size, financial capability and the riskier nature of projects they tend to pursue.
- Higher discounts are also used for larger projects that have significant geological or circumstantial complexity, for example deep-water projects may use 15% after-tax.
- Additional investment risk can be accommodated in profitability estimates by considering local political, security and other risks (see next slide).
- Access to capital varies depending upon commodity prices. Higher prices make investment dollars more readily available; while down cycles make capital scarce.

3. For consistency, our Panel advised Wood Mackenzie to use 10% after-tax as a benchmark standard discount rate for all project comparisons, independent of above ground risk adjustments.

Accounting for Above Ground Risk Factors

Maplecroft data was used to construct weighted risk components for variances in non-fiscal, above-ground factors for investing in different global jurisdictions

Risk Weightings by Comparison Country



Source: Maplecroft

Page interpreted: 18, "Accounting for Above Ground Risk Factors"

1. Local politics, government (rule of law), security, business environment and availability of infrastructure to develop and produce hydrocarbons all contribute to above ground risk.

- Wood Mackenzie's global consulting practice can make estimates of non-technical, above ground risks.
- Experts who study global issues objectively quantify such risks.

2. This chart assesses relative business risk between the jurisdictions that are comparable to Alberta.

- A lower percentage score implies a riskier investment profile.
- Investing in Canada is considered mildly more risky than investing in Norway.
- Investing in the U.S., UK and Canada are of similar risk profiles with minor variation.
- From Brazil to the right of the chart, risks are considerably higher.

3. Additional risk equates to additional cost.

- The bulk of our Panel's analysis was done using an unadjusted, standard 10% hurdle rate across all jurisdictions. Nevertheless, our Panel acknowledged that the additional risks as shown in this chart equate to higher costs that negatively affect lifecycle profitability.
- As a final test, the risk adjustments on this page were taken into account at the end of the comparative analysis to note the comparative effects on NPV profits (see Slide 50).

Agenda

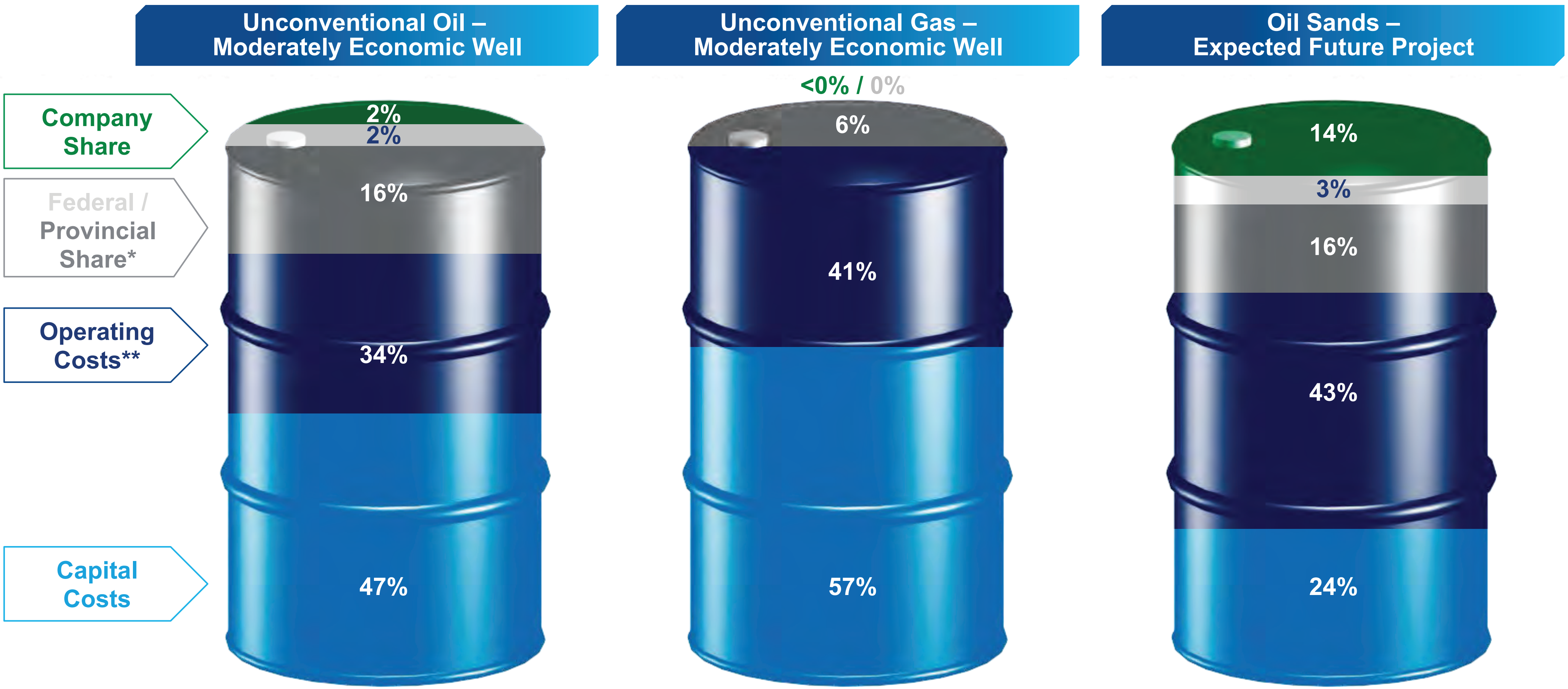
1 International Fiscal Responses to Low Oil Price

2 Benchmarking Methodology

3 **Initial Benchmarking Results**

Split-of-the-Barrel Analysis for Alberta - Moderately Economic Wells

Under the US$60/bbl WTI and US$3.00/mcf Henry Hub Commodity Price Scenario



Note: Split of the barrel based on nominal, undiscounted revenues

** Includes royalty related to provincial ownership rights, as well as other items of government take, such as provincial and federal taxes and lease costs*

*** Includes tariffs, municipal taxes and regulatory costs, in addition to other fixed and variable operating costs*

Page interpreted: 20, "Split-of-the-Barrel Analysis for Alberta – Moderately Economic Wells"

1. Our Panel asked, "Where does the value of a barrel go?" This slide shows a Split-of-the-Barrel analysis when oil prices are a constant $U.S. 60/B (WTI) and natural gas $U.S. 3.00/mcf (Henry Hub).

2. This first barrel shows where the value goes for a "Moderately Economic" unconventional oil well.

- Costs eat up much of the barrel (81%). This is not surprising, as our Panel noted that Alberta is a higher-cost jurisdiction where a large part of the value in a barrel flows to service companies and the broader provincial economy.
- At $60/B, Alberta gets 16% of the value of a barrel through royalties and taxes, while 2% goes to the federal government.
- The company's share at 2% is lower than Alberta's 16% share.

3. Unfortunately, there isn't a lot of profit for a moderately economic natural gas well in Alberta.

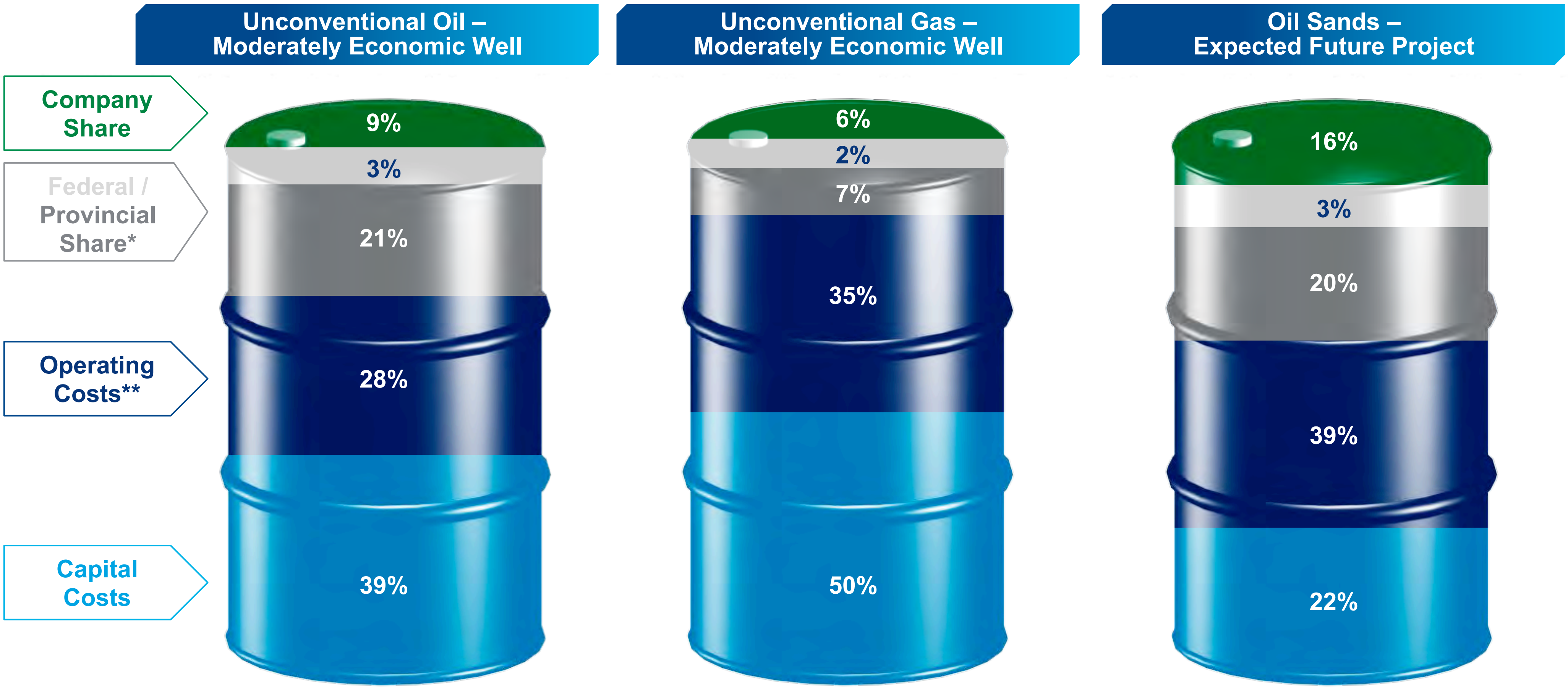
- At $3.00/mcf an average gas well is marginal on its own. Alberta takes 6%, while costs eat up 98%. The producer loses money (<0%) after costs, royalties and taxes are removed from the total value. Such wells are only economic if they also produce some oil and other higher-value hydrocarbon liquids.

4. A future 35,000 barrel per day oil sands project yields an undiscounted 14% profit to the producers. But this is deceiving, because oil sands projects take a long time to build out, so the discounted time value of money is important (we shall see the effect of this in later slides).

- 16% goes to the Province; 3% to the federal government.
- Costs are once again a significant portion of the barrel.

Split-of-the-Barrel Analysis for Alberta - Moderately Economic Wells

Under the US$100/bbl WTI and US$5.00/mcf Henry Hub Commodity Price Scenario



Note: Split of the barrel based on nominal, undiscounted revenues

**** Includes royalty related to provincial ownership rights, as well as other items of government take, such as provincial and federal taxes and lease costs***

***** Includes tariffs, municipal taxes and regulatory costs, in addition to other fixed and variable operating costs***

Interpreted page: 21, "Split-of-the-Barrel Analysis for Alberta – Moderately Economic Wells"

1. This slide is the same as the previous, except run at higher prices: $100/B oil; and $5.00/mcf for natural gas.

2. The split-of-the-barrel for oil looks better for both the producer and for Alberta, because costs are a smaller proportion at higher price.

- The amount of share available at $100/B is only moderately higher than at $60/B, because of cost escalation that happens when prices become lofty at $100/B.

3. Higher gas prices introduce some profitability at higher price, but the available share is still weak.

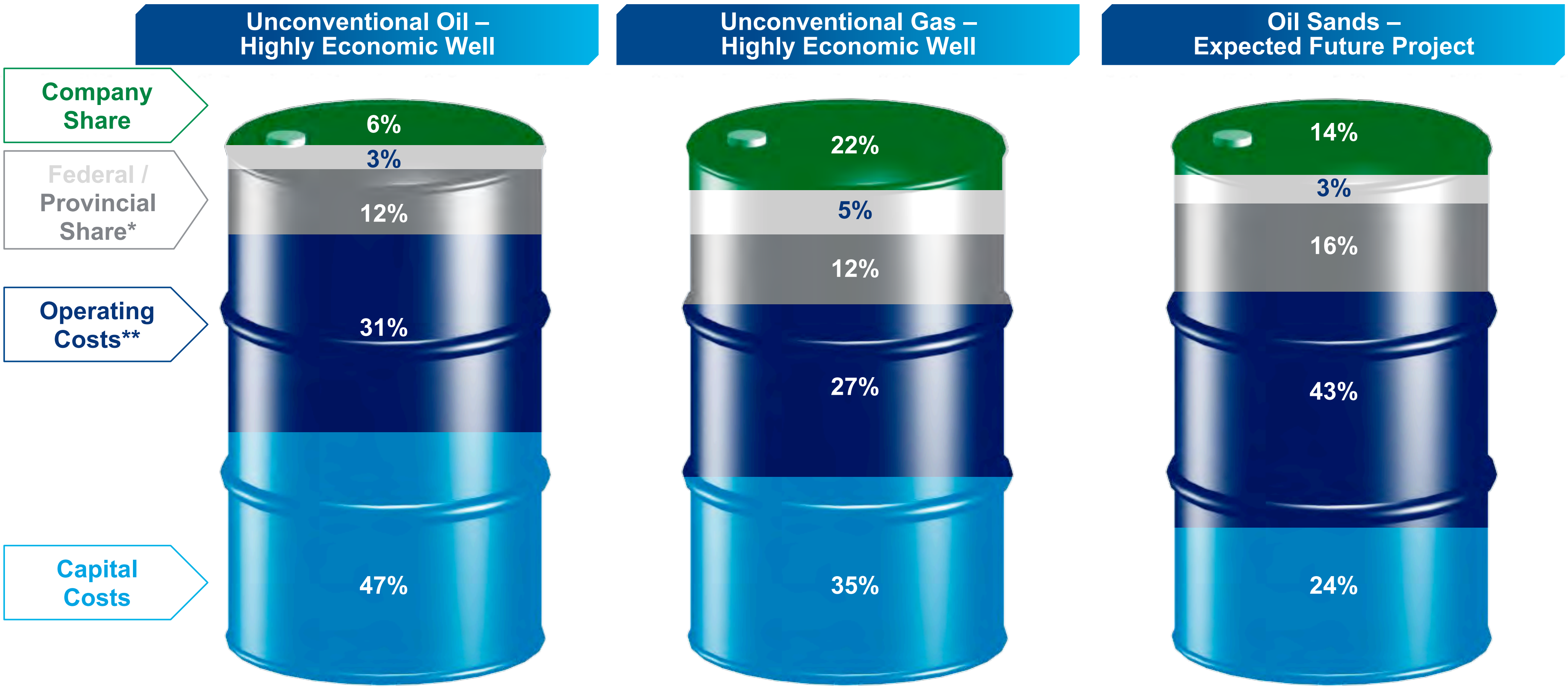
- "Dry" or pure natural gas without any liquids content (associated heavier hydrocarbons such as oil) is a difficult business.
- Moderately economic dry gas wells don't deliver much profit to the company or to Albertans.
- Only high quality wells of lower cost are able to deliver superior splits.

4. Oil sands projects have the best metrics using split-of-the-barrel profitability, but this is deceiving.

- The time value of money, which is a cost, is not considered in this chart. In other words, the discount rate, or hurdle rate, is zero (see Slide 17). Long development times mean that costs are underestimated and lifetime profits overestimated.
- Even so, the split of profits between company and Alberta is pretty close.

Split-of-the-Barrel Analysis for Alberta - Highly Economic Wells

Under the US$60/bbl WTI and US$3.00/mcf Henry Hub Commodity Price Scenario



Note: Split of the barrel based on nominal, undiscounted revenues

** Includes royalty related to provincial ownership rights, as well as other items of government take, such as provincial and federal taxes and lease costs*

*** Includes tariffs, municipal taxes and regulatory costs, in addition to other fixed and variable operating costs*

Interpreted page: 22, "Split-of-the-Barrel Analysis for Alberta – Highly Economic Wells"

1. This slide is the same as the previous, except the unconventional oil and gas wells are of a "Highly Economic" nature, in other words the geological quality is at the high end of the range. Prices used are $60/B for oil and $3.00/mcf for natural gas.

2. Compared to Slide 20, which ran the "Moderate" wells at the same prices, the split of the barrel looks better with these higher well qualities.

- The unconventional oil well is showing 6% for the company, while Province and federal government is at 12%.
- This demonstrates that $60/B delivers returns for better quality oil wells, but that the numbers are still not that high.

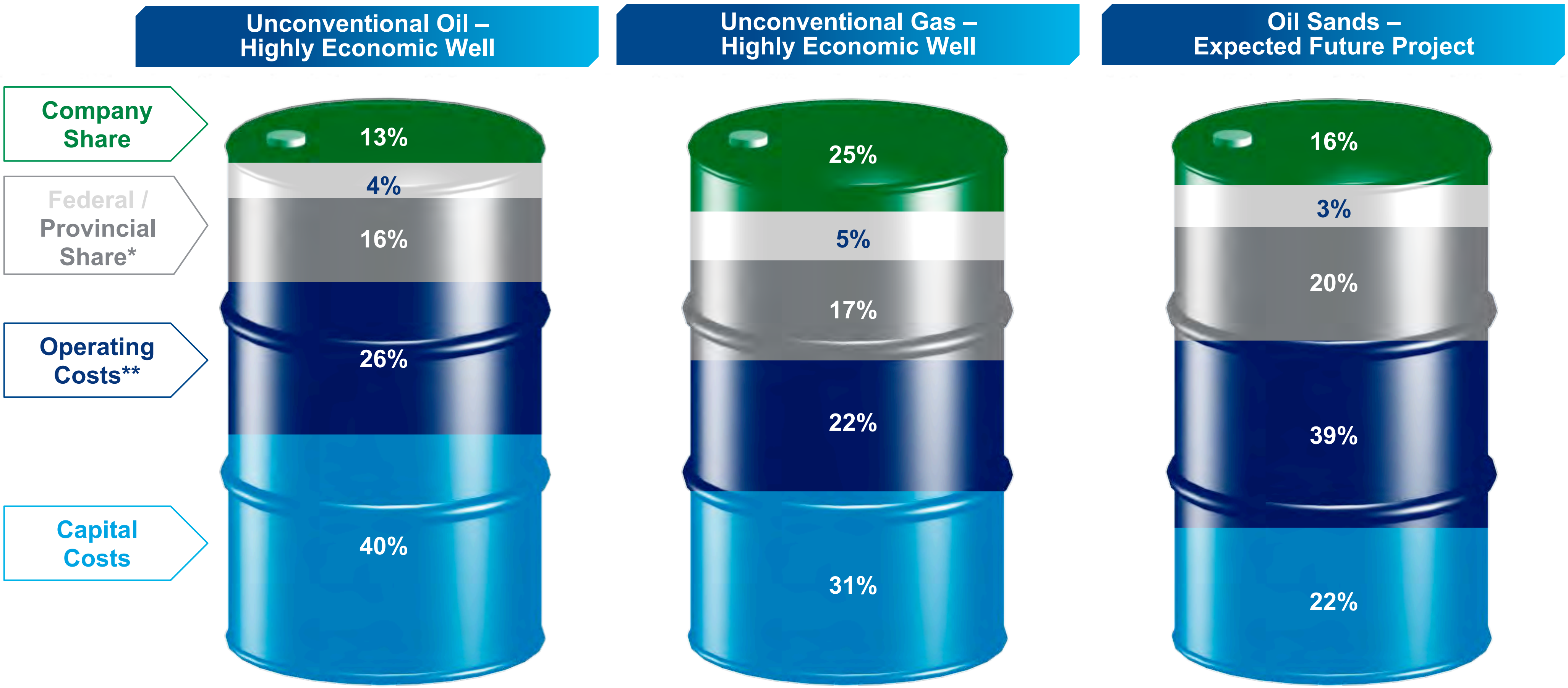
3. Superior quality gas wells at $3.00/mcf start to show much better economics.

- The split-of-the-barrel favours the company, but overall government take (17%) is balanced against the company (22%).

4. The oil sands example is the same as in slide 20.

Split-of-the-Barrel Analysis for Alberta - Highly Economic Wells

Under the US$100/bbl WTI and US$5.00/mcf Henry Hub Commodity Price Scenario



Note: Split of the barrel based on nominal, undiscounted revenues

** Includes royalty related to provincial ownership rights, as well as other items of government take, such as provincial and federal taxes and lease costs*

*** Includes tariffs, municipal taxes and regulatory costs, in addition to other fixed and variable operating costs*

Interpreted page: 23, "Split-of-the-Barrel Analysis for Alberta – Highly Economic Wells"

1. Now we look at the highest case scenario: superior unconventional oil and gas wells at the higher end of the price ranges ($100/B for oil and $5.00/mcf for natural gas).

2. The oil well shows better economics, but cost escalation associated with higher prices keeps the cost fractions relatively high.

- Combined government take is 20%, while the company share is 13%; however the Alberta - company split is fairly close.

3. One would expect the superior natural gas wells to deliver even more profitability to both resource owner and company than at the $3.00/mcf case (Slide 22). However, cost escalation dampens the upside.

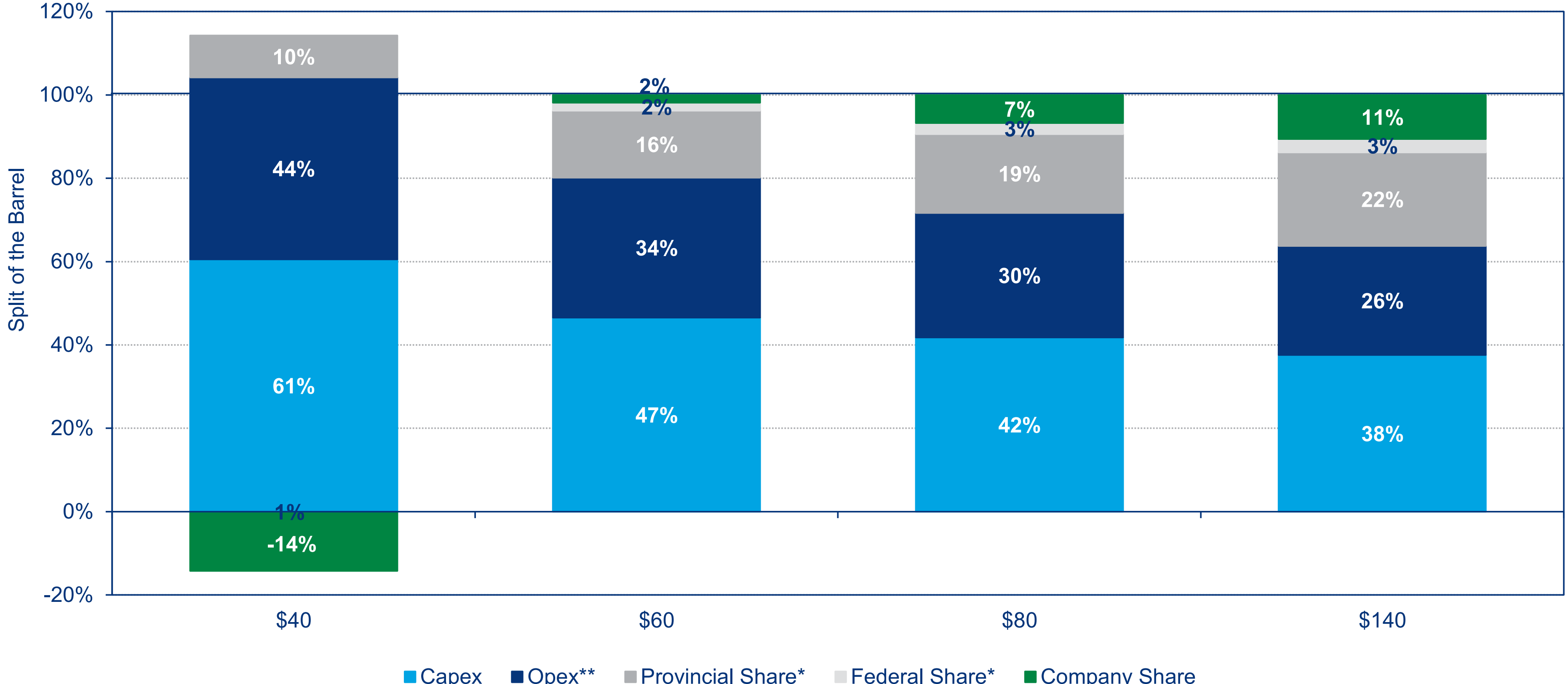
- The split between total government take and company is relatively balanced in this scenario.

4. The oil sands project is run under the same assumptions as in Slide 21.

Split-of-the-Barrel Analysis Under Different Oil Price Scenarios

For a Moderately Economic Unconventional Oil Well in Alberta

Split of the Barrel across Oil Prices – Alberta Moderately Economic Unconventional Oil Well



Source: Wood Mackenzie

Note: Split of the barrel based on nominal, undiscounted revenues

** Includes royalty related to provincial ownership rights, as well as other items of government take, such as provincial and federal taxes and lease costs*

*** Includes tariffs, municipal taxes and regulatory costs, in addition to other fixed and variable operating costs*

Interpreted page: 24, "Split-of-the-Barrel Analysis Under Different Oil Price Scenarios – Moderately Economic Oil Well"

1. This chart shows how the split-of-the-barrel values vary under the full spectrum of oil prices, for an unconventional oil well of moderate resource quality.

2. At $40/B there are no profits to be had; in fact, the split is less than breakeven.

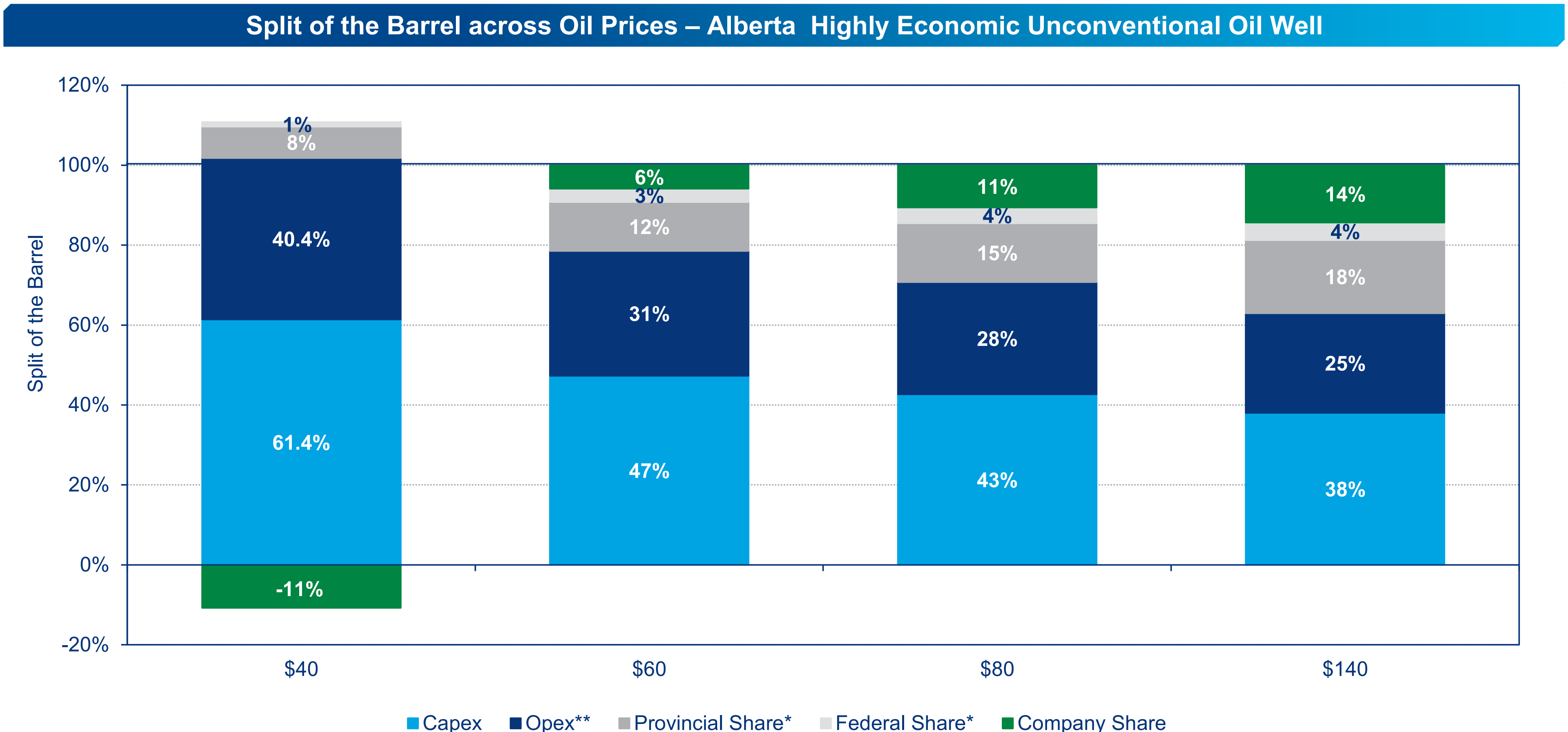
- The corporate share is negative at -14%, which is the unrealistic scenario where the well would be allowed to operate at a loss over the life of its production.
- Costs take up the vast majority of the value of the barrel.

3. At the highest oil price, $140/B, the profitability is more balanced between producer and government take.

- More profit is not available proportionally to $80/B, because costs inflate in tandem with oil prices.

Split-of-the-Barrel Analysis Under Different Oil Price Scenarios

For a Highly Economic Unconventional Oil Well in Alberta



Source: Wood Mackenzie

Note: Split of the barrel based on nominal, undiscounted revenues

** Includes royalty related to provincial ownership rights, as well as other items of government take, such as provincial and federal taxes and lease costs*

*** Includes tariffs, municipal taxes and regulatory costs, in addition to other fixed and variable operating costs*

Interpreted page: 25, "Split-of-the-Barrel Analysis Under Different Oil Price Scenarios – Highly Economic Oil Well"

1. This chart shows how the split-of-the-barrel values vary under the full spectrum of oil prices, for an unconventional oil well of high resource quality.

2. At $40/B there are little profits to be had for the company.

- The corporate share is 5%, which is still an unrealistic scenario for investment.
- Costs take up the majority of the value of the barrel.
- 14% of the value goes to government take.

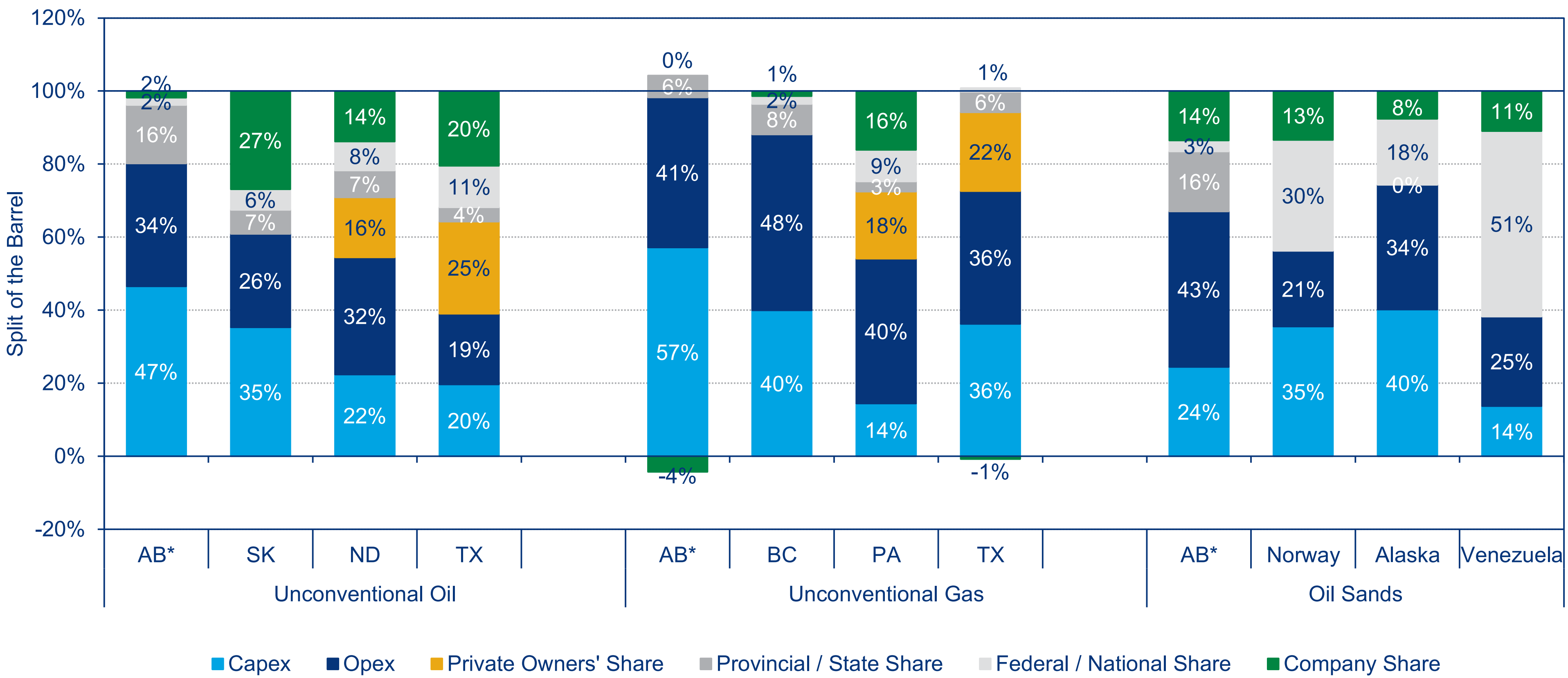
3. At higher oil prices ($80/B and $140/B), the profitability remains relatively balanced between producer and government take.

- As with the previous slide, more profit is not available proportionally as compared to $60/B, because costs inflate in tandem with oil prices.

Split-of-the-Barrel Analysis for Select Comparable Regimes

By Commodity Type Under US$60/bbl WTI and US$3.00/mcf Henry Hub Prices

Moderately Economic Unconventional Alberta Wells and a 35k Oil Sands Project



Source: Wood Mackenzie

Note: Split of the barrel based on nominal, undiscounted revenues

** Alberta benchmarked on basis of moderately economic unconventional oil and unconventional gas wells, and a 35 kb/d SAGD project, which is the expected size of future individual oil sands phases*

Interpreted page: 26, "Split-of-the-Barrel Analysis for Select Comparable Regimes"

1. In this multi-dimensional chart, our Panel considered Alberta's split-of-the-barrel analysis as compared to some of its comparable peers.

- Mid-range pricing was used: $60/B for oil and $3.00/mcf for natural gas.

2. Notes on moderately economic unconventional oil wells:

- In Alberta, high costs eat up most of the barrel (81%). Our Panel notes that this is consistent with other findings in their report, notably that the value in a barrel dissipates (and multiplies) into the Alberta economy through high-cost labour and services.
- Companies operating in Saskatchewan are profitable somewhat at the expense of the resource owner, which only takes 7%.
- Corporate profitability in Texas is also high. The state and government take is only 15%, which is almost the same as Alberta. However, landowners in Texas take a very large 25% of the barrel (private citizens own mineral rights). Texas landowners are able to take much more, because the costs of oil and gas exploration and development are relatively low in the state. As well, Texas is very close to the major North American markets for oil, so transportation costs are also lower in Texas. Lower transportation costs mean greater value for the owners.

3. Notes on moderately economic unconventional natural gas wells:

- Alberta dry gas is uneconomic, as previously mentioned. High transportation costs (pipeline tolls) are a large part of the operating expenses.
- BC gas is more favourable, but hardly exciting when compared against the rent available in Pennsylvania's Marcellus gas fields.
- Texas is giving most of its available value in a cubic foot of natural gas to landowners.

Interpreted page: 26 continued, "Split-of-the-Barrel Analysis for Select Comparable Regimes"

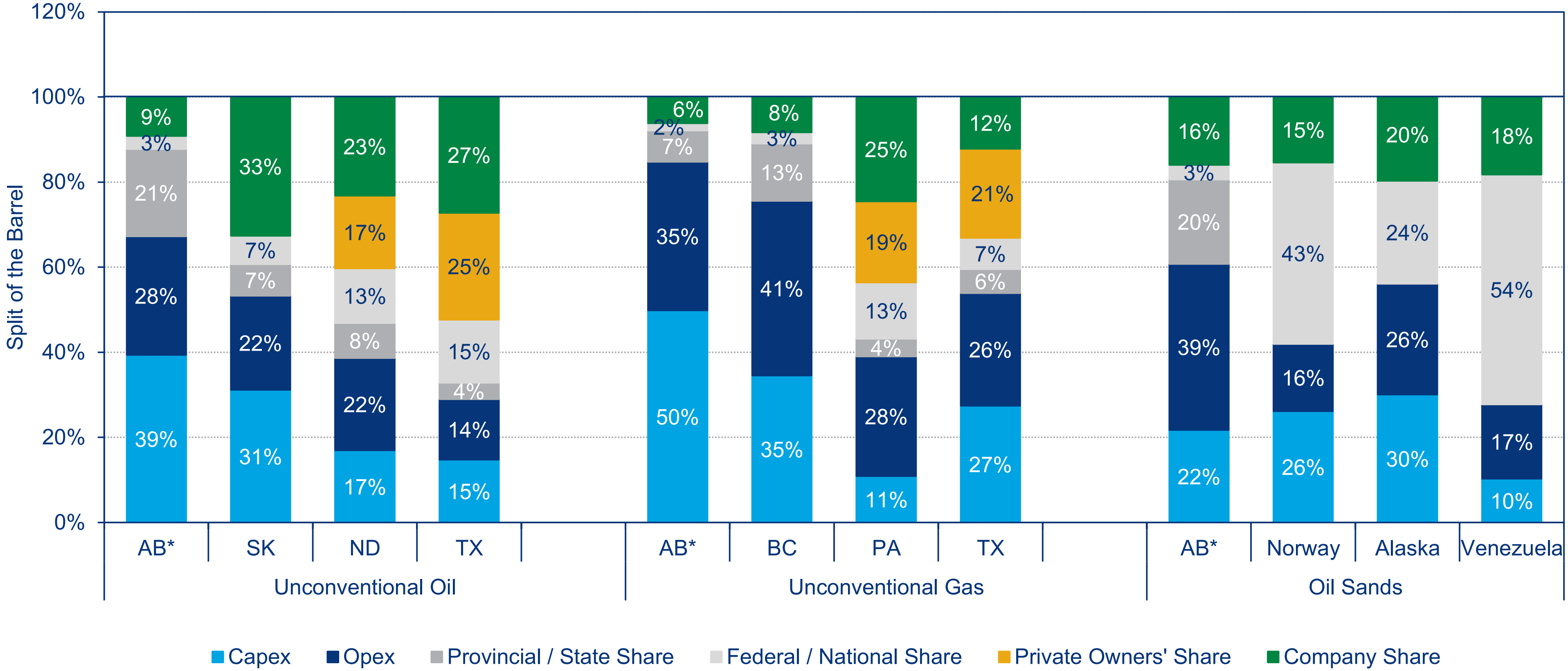
4. A 35,000 bpd SAGD oil sands project has seemingly attractive economics and returns using the split-of-the-barrel approach.

- The government's portion (federal plus provincial) at 19% is balanced by a 14% share taken by the company.
- Costs are again high in Alberta, only superseded by Alaska. This is not surprising, given Alaska's expensive frontier and climate.
- Alberta is often compared to Norway. A more direct comparison to Alberta's oil sands is Venezuelan oils of similar character and quality. Projects in all three jurisdictions require large upfront capital expenditures and long lead times.
- Venezuela has tidewater access and therefore can realize undiscounted global prices. However, Venezuela's above ground political risks offset the potentially low-cost advantage of its vast resources. Discount rates in Venezuela need to be adjusted for risk factors related to instability and other above ground issues (see Page 50).
- Operating and capital costs in Norway take up far less of the barrel when compared to Alberta's oil sands or its unconventional oil. Corporate share is similar. Norway's state take is 30%, which is higher than the 19% for the oil sands. But again, that's because costs generally take up a greater percentage of a barrel in Alberta as compared to Norway. As well, Norway has tidewater access, so it realizes greater value by selling oil at full global prices. By comparison, Alberta's landlocked oils are significantly discounted.

Split-of-the-Barrel Analysis for Select Comparable Regimes

By Commodity Type Under US$100/bbl WTI and US$5.00/mcf Henry Hub Prices

Moderately Economic Unconventional Alberta Wells and a 35k Oil Sands Project



Source: Wood Mackenzie

Note: Split of the barrel based on nominal, undiscounted revenues

** Alberta benchmarked on basis of moderately economic unconventional oil and unconventional gas wells, and a 35 kb/d SAGD project, which is the expected size of future individual oil sands phases*

Interpreted page: 27, "Split-of-the-Barrel Analysis for Select Comparable Regimes"

1. This chart is the same as the previous one, using "Moderately Economic" wells, except this one is run at $100/B and $5.00/mcf.

2. For a moderately economic unconventional oil well:

- Profitability rises across the board, especially in North Dakota, Saskatchewan and Texas.
- Saskatchewan's provincial take is still only 7% as compared to Alberta's 21%.

3. For a moderate unconventional natural gas well:

- Alberta becomes marginally economic as previously mentioned, but not attractive in the absence of liquids.
- Pennsylvania's corporate share improves to 25%, still the best of the natural gas peer group.

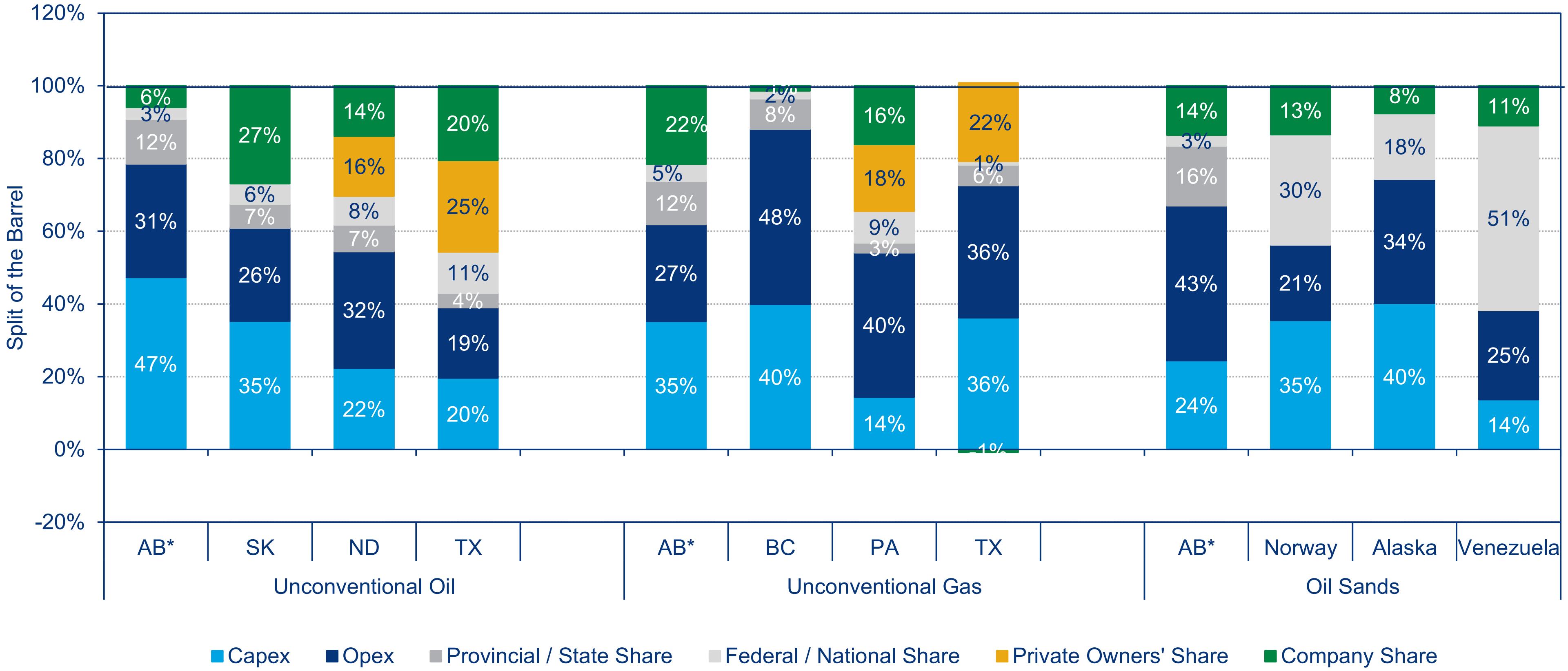
4. For a 35,000 bpd SAGD project:

- Corporate share of the barrel is comparable across all four jurisdictions.
- Venezuela's government takes the most, largely as a function of low cost structure.
- Norway's take is high proportionally as well, due to its favourable coastal market access and lower sensitivity to inflationary forces.

Split-of-the-Barrel Analysis for Select Comparable Regimes

By Commodity Type Under US$60/bbl WTI and US$3.00/mcf Henry Hub Prices

Highly Economic Unconventional Alberta Wells and a 35,000 B/d In Situ Oil Sands Project



Source: Wood Mackenzie

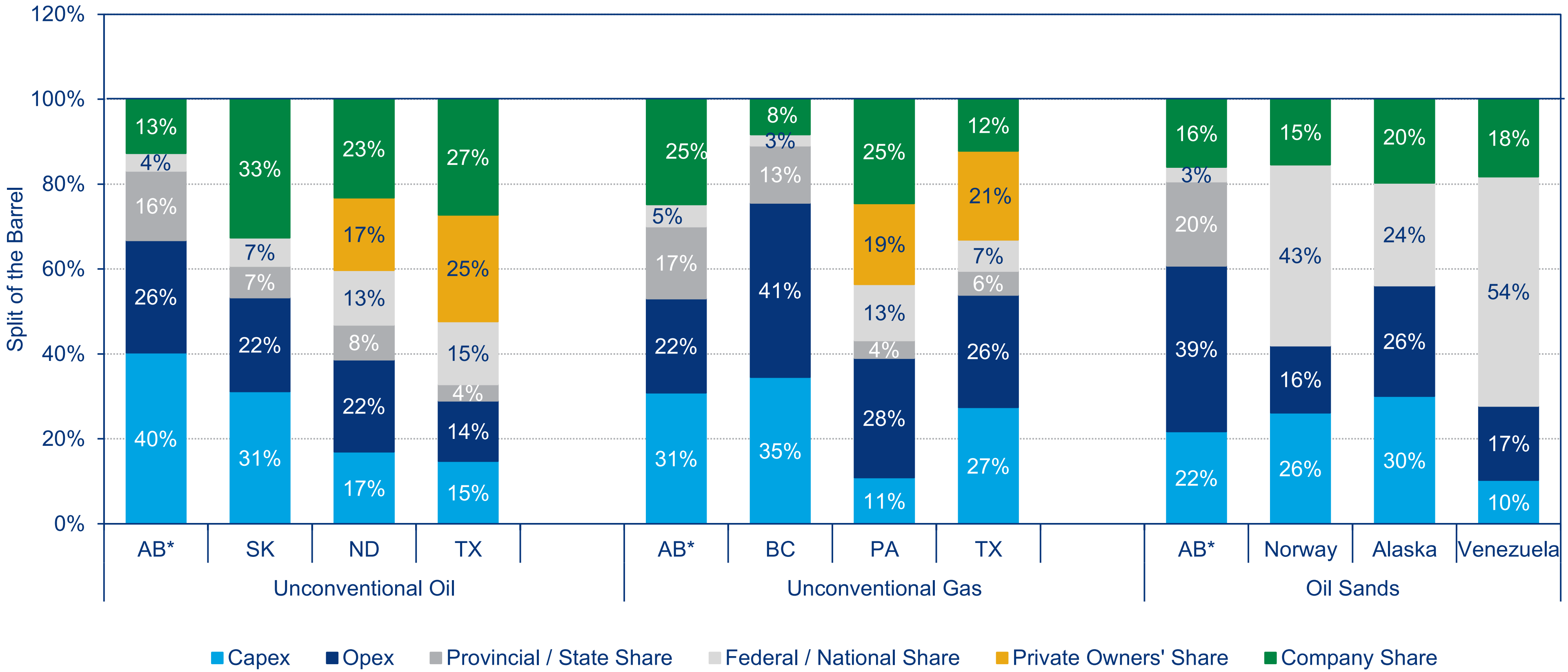
Note: Split of the barrel based on nominal, undiscounted revenues

** Alberta benchmarked on basis of highly economic unconventional oil and unconventional gas wells, and a 35 kb/d SAGD project, which is the expected size of future individual oil sands phases*

Split-of-the-Barrel Analysis for Select Comparable Regimes

By Commodity Type Under US$100/bbl WTI and US$5.00/mcf Henry Hub Prices

Highly Economic Unconventional Alberta Wells and a 35k Oil Sands Project



Source: Wood Mackenzie

Note: Split of the barrel based on nominal, undiscounted revenues

** Alberta benchmarked on basis of highly economic unconventional oil and unconventional gas wells, and a 35 kb/d SAGD project, which is the expected size of future individual oil sands phases*

Interpreted page: 28 and 29, "Split-of-the-Barrel Analysis for Select Comparable Regimes"

1. Slides 28 and 29 show the same analysis as 26 and 27, except the unconventional wells are of a "Highly Economic" classification.

2. Slide 28 uses the $60/B and $3.00/mcf scenarios.

- Saskatchewan, North Dakota and Texas demonstrate superior unconventional oil profitability; however caution is advised in making generalizations across all plays due to the variability of Alberta geology.
- Notably, some Alberta highly economic natural gas wells can demonstrate profitability as good as Pennsylvania.

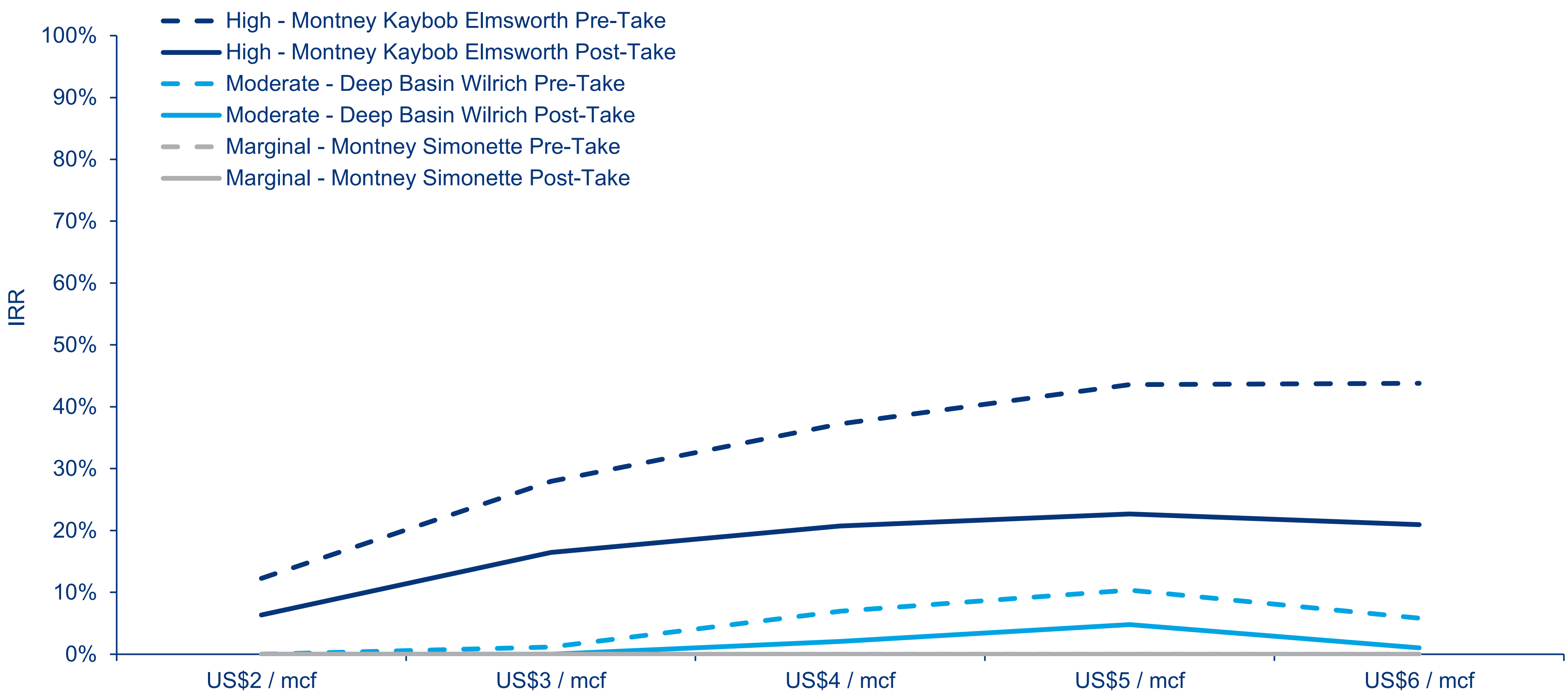
3. Slide 29 uses the $100/B and $5.00/mcf scenarios.

- High case price scenarios improve profitability across all jurisdictions, but not proportionally relative to the lower price scenarios. Again this is due to cost inflation associated with higher prices in all jurisdictions.

Profitability Analysis for Alberta Gas Plays of Varying Quality

Pre and Post-Take IRR Across the Price Range

Mid-Range Unconventional Natural Gas Wells Within Each Sub-Play



Source: Wood Mackenzie

Interpreted page: 30, "Profitability Analysis for Alberta Gas Plays of Varying Quality"

1. This page compares three different unconventional natural gas plays across Alberta.

- A representative (Moderate) well was sampled from each play area.
- The Montney-Kaybob-Elmworth play is the best quality play; the Deep Basin Wilrich the second best; and the Montney-Simonette the least favourable.

2. The expected profitability of each play area is shown under varying prices.

- The metric used is Internal Rate of Return (IRR), which accounts for the time value of money. Returns above 10% exceed a company's hurdle rate.
- Note that the IRR metric as applied to wells and projects is not indicative of a company's overall profitability. IRR analysis is used to assess whether a project is economic, and whether it ranks above or below other comparable opportunities.
- The IRR of each well is evaluated before and after the resource owner's take (royalties, taxes, rentals and fees).

3. The Montney-Kaybob-Elmworth play is of high quality and exceeds hurdle rates pre- and post-take at prices above $3.00/mcf. Breakeven appears to be about $2.75/mcf.

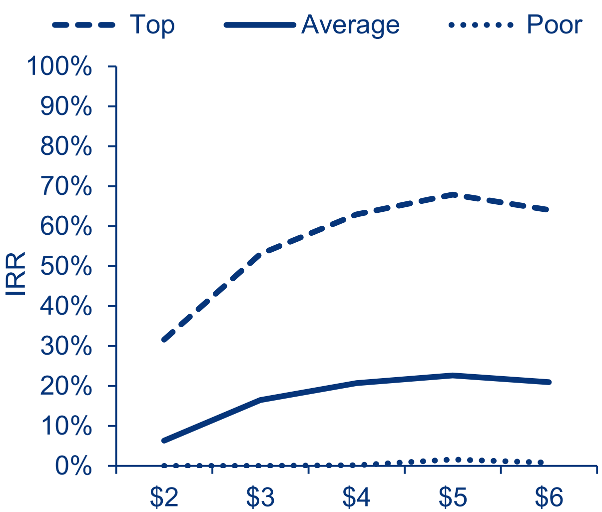
4. Plays with moderate or low economics do not achieve their hurdle rates at any price, either pre- or post-take.

Profitability Analysis for Alberta Gas Wells of Varying Quality

Variation in Quality and Profitability Within Each Play Area

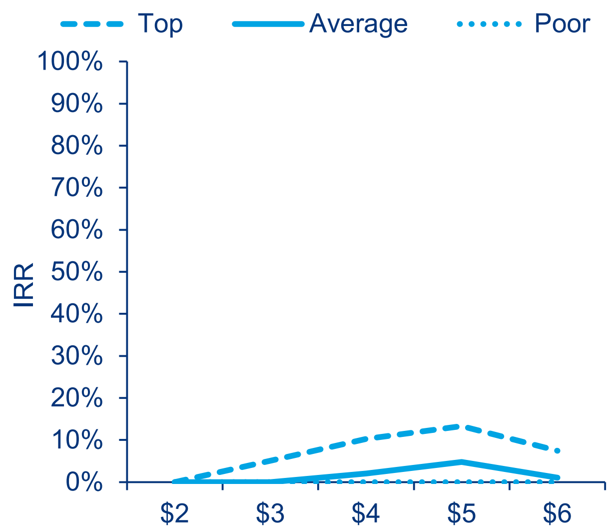
Top, Average and Poor Performing Plays Within Each Sub-Play at Varying Price

Highly Economic – Montney Kaybob Elmworth



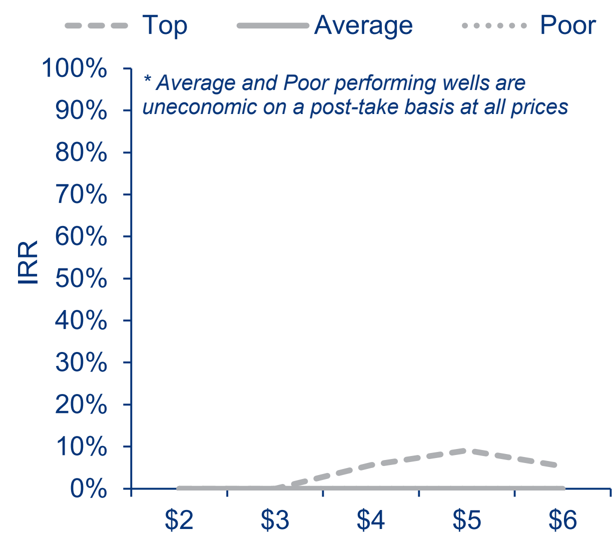
Source: Wood Mackenzie

Moderately Economic– Deep Basin Wilrich



Source: Wood Mackenzie

Marginally Economic– Montney Simonette



Source: Wood Mackenzie

Interpreted page: 31, "Profitability Analysis for Alberta Gas Wells of Varying Quality"

1. Not only did our Panel ask for a variety of wells across different geologic play types that were spread across the province, we also wanted to see variations within each play – in other words, a range of profitability within the sub-plays.

- Internal rates of return were tested in each of the three plays on the prior slide: the Montney-Kaybob-Elmworth; the Deep-Basin-Wilrich; and the Montney-Simonette.

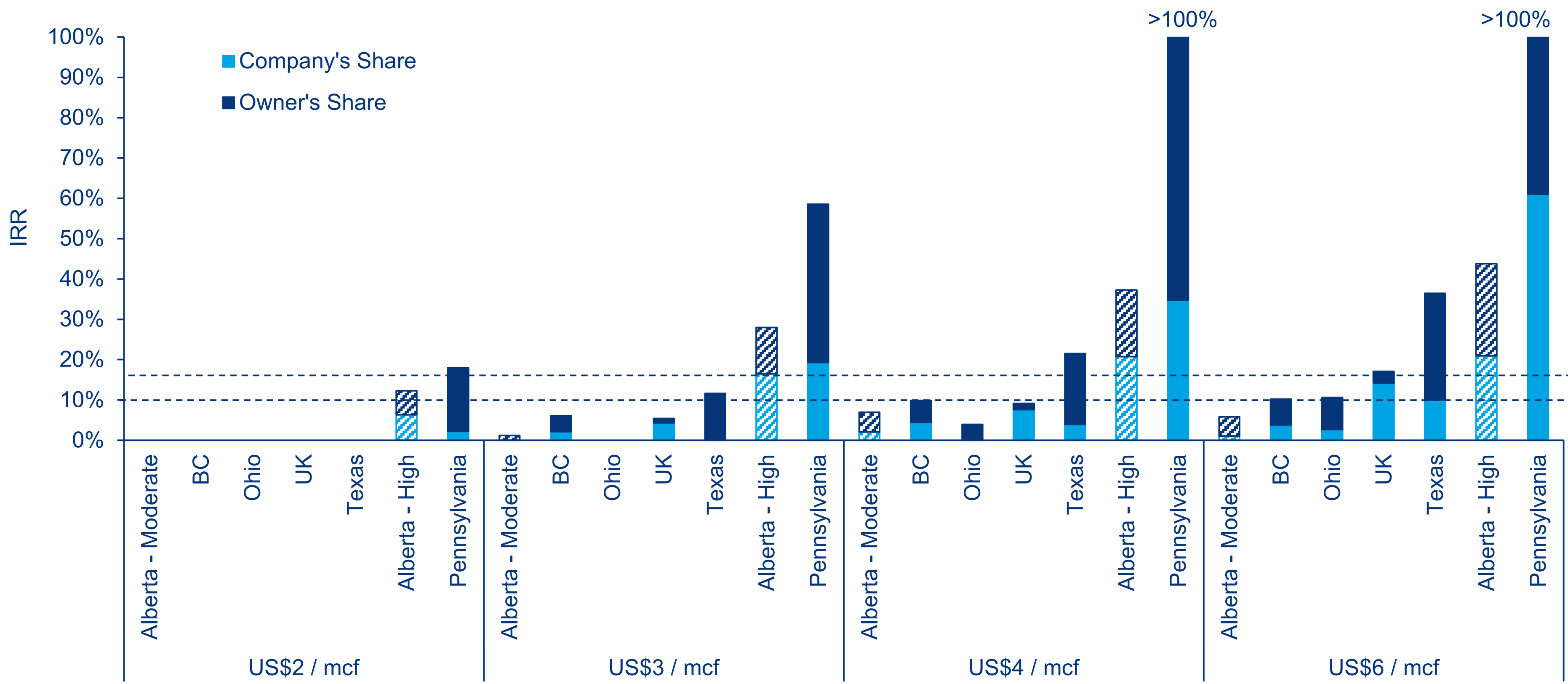
2. Based on these results our Panel observed that:

- Not only is there a very wide spectrum of profitability in plays across the province, but also within sub-plays.
- On an IRR basis, the range of profitability is negative to 70% depending on well type and commodity price.
- There are diminishing returns to profitability with price, due to inflationary effects at higher commodity prices.
- Some plays in the province will be marginal at all price points. The royalty structure is not likely to be able to support such plays, nor should the province be expected to support marginal economics.

Profitability Analysis for Select Comparable Regimes

Unconventional Gas, Pre and Post-Take IRR Across the Price Range

Comparison of Alberta 'High' and 'Moderate' Wells



Source: Wood Mackenzie

Note: Price scenarios represent assumed, real price over the life of the well; 'Owner's Share' equal to IRR of well before tax and royalties

** Alberta benchmarked on basis of highly economic (Montney Kaybob Elmworth) and moderately economic (Deep Basin Wilrich) unconventional gas well*

Wood Mackenzie
A Verisk Analytics Business

Interpreted page: 32, "Profitability Analysis for Select Comparable Regimes – IRR"

1. This chart compares Alberta's "Moderate" and "High" play natural gas wells against their comparable peers in North America, at the different price point scenarios.

- The tops of the bars in the chart represent the "pre-take" IRR; in other words, the overall profitability of the wells before royalties and taxes are paid.
- Each bar is split in two. The top bar (dark blue) is the resource owner's share of the profitability; the bottom (light blue) is the company's share.
- So the post-take IRR is the same thing as the company's share.

2. At 2.00/mcf, none of the jurisdictions are economically viable post-government-take. Pennsylvania beats the 10% hurdle rate pre-take, but not post-take.

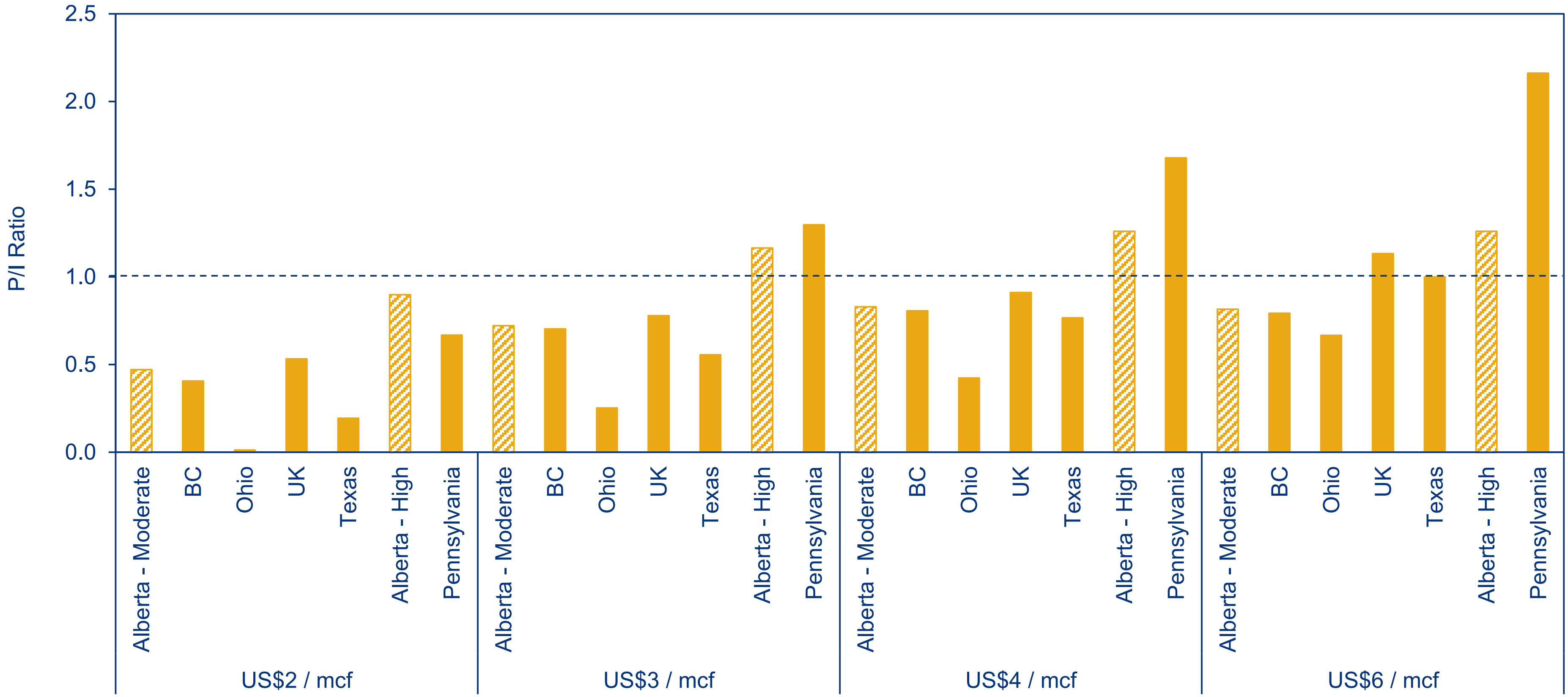
3. At $3.00/mcf, Alberta and Pennsylvania plays demonstrate ability to "beat the bar" post-take and are not far different from an IRR perspective. However, the Panel noted that it was only the "High" quality Alberta play that was able to do so (even beating the Texas play).

4. At the higher end of the price range, Pennsylvania's play returns are unbeatable pre- and post-take. Being close to market, and not being as sensitive to price inflation, are distinct competitive advantages for Pennsylvania.

Profitability Analysis for Select Comparable Regimes

Unconventional Gas Profitability Index Ratio (PIR) Across the Price Range

Comparison of Alberta "High" and "Moderate" Wells



Source: Wood Mackenzie

Note: P/I is based on NPV10
** Alberta benchmarked on basis of highly economic (Montney Kaybob Elmworth) and moderately economic (Deep Basin Wilrich) unconventional gas well*

Interpreted page: 33, "Profitability Analysis for Select Comparable Regimes – PIR"

1. On this chart, our Panel asked Wood Mackenzie to assess lifecycle profitability by using the profitability index (PI) ratio method, again across the four price scenarios.

- Recall that a PI ratio of 1.0 means that the company is achieving its hurdle rate of 10%.
- The bars are post-take profitability from a company's perspective.
- This chart is similar to the one on 32, except a bit simpler to see which plays can beat their post-take hurdle.

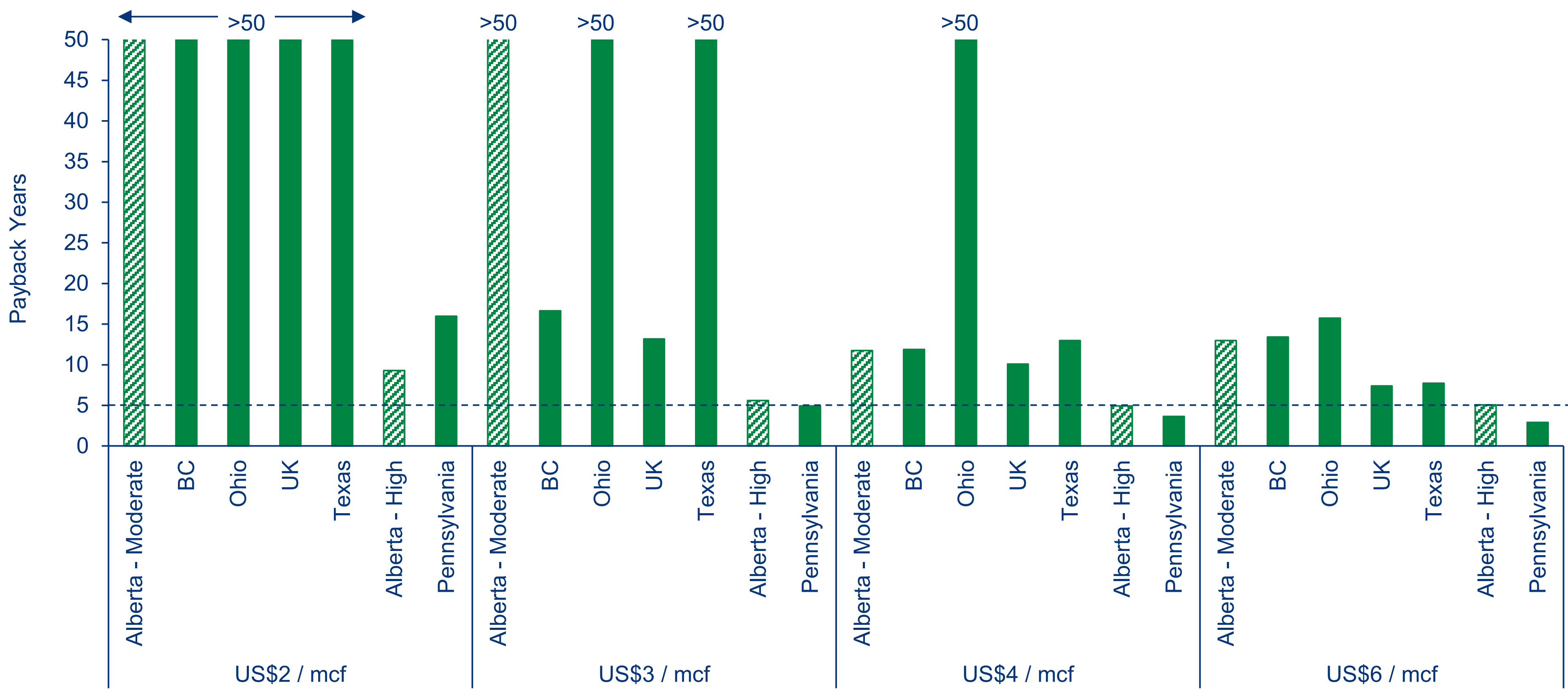
2. Because this chart restates Slide 32, the conclusions are the same.

- From a play perspective, the post-take profitability of Alberta's best is not far different from that of Pennsylvania's moderately good in the mid-range pricing scenarios.
- Profitability metrics for BC's play is very close to Alberta's "Moderate" case play under all price scenarios. That said, none are above the hurdle rate.
- Finally, note that BC's play is not as profitable (post-take) as Alberta's "High" using the IRR and PIR methods.

Profitability Analysis for Select Comparable Regimes

Unconventional Gas Payback Times Across the Price Range

Comparison of Alberta "High" and "Moderate" Wells



Source: Wood Mackenzie

* *Alberta benchmarked on basis of highly economic (Montney Kaybob Elmworth) and moderately economic (Deep Basin Wilrich) unconventional gas well*

Interpreted page: 34, “Profitability Analysis for Select Comparable Regimes – Payback”

1. How fast does a project pay back its capital investment?

- The time to payout is important to both company and resource owner. For the company, any payout time greater than four or five years is of marginal interest.
- Payout is important for the resource owner, because royalty rates are typically prescribed to rise as soon as the company is paid out on its investment.

2. At $2.00/mcf, most wells never pay out (>50 years to pay out). Alberta’s best and Pennsylvania’s can do it within a generation, but that’s not appealing as an investment.

3. At $3.00/mcf, Alberta’s High case does pay out in a reasonable time frame, as does Pennsylvania’s.

4. Above $4.00 the payout times improve again, but natural gas has to be considered a long-term investment opportunity.

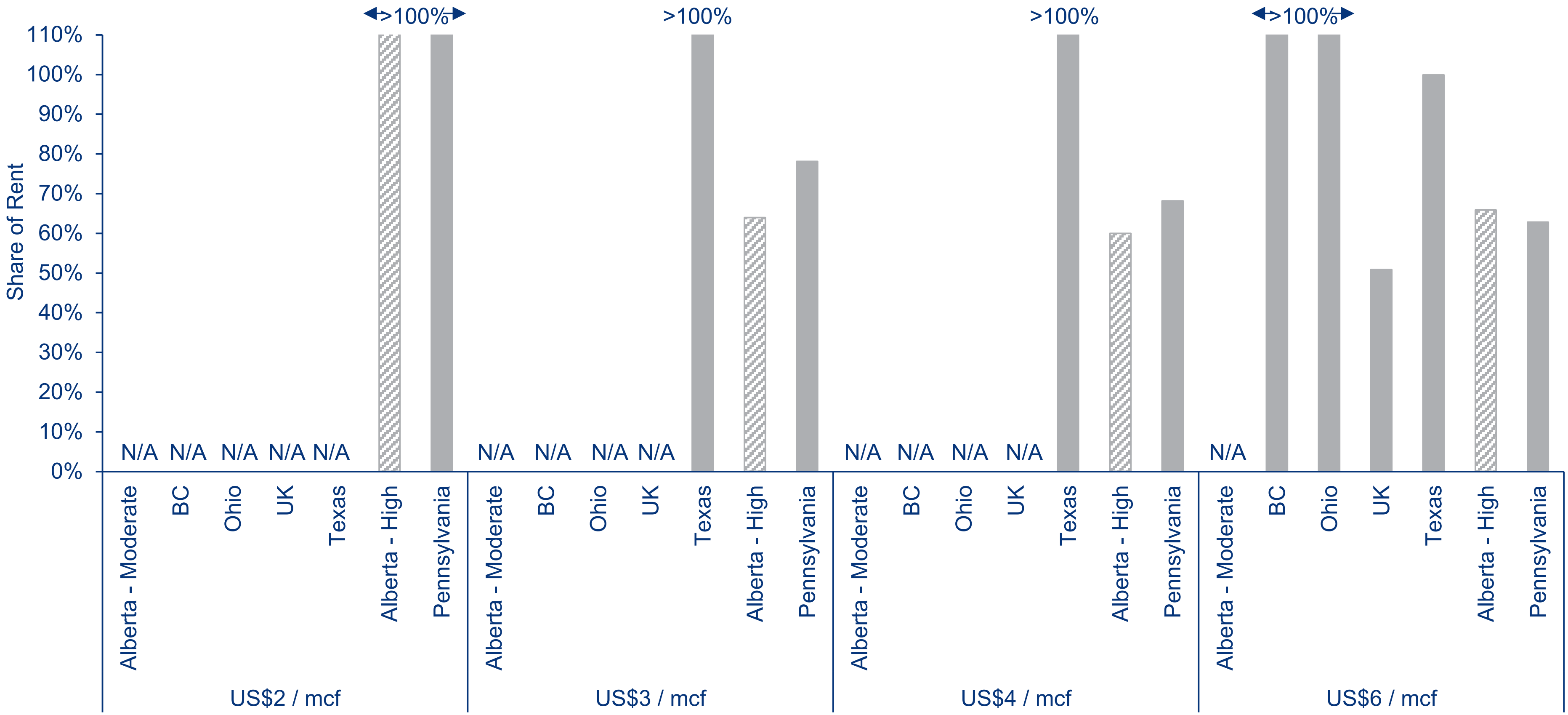
5. Our Panel notes that:

- Learning curve effects, scale and innovation within a sub-play can improve the economics of natural gas wells.
- Such learning and innovation should be encouraged, because individual gas wells on their own are very marginal at today’s prices.
- Alberta’s best wells look competitively positioned, but transportation costs are a major hindrance to the viability of anything less than the best.

Profitability Analysis for Select Comparable Regimes

Unconventional Gas: Share of Resource Owner's Value Above the Hurdle Rate

Comparison of Alberta "High" and "Moderate" Wells



Source: Wood Mackenzie

Notes: Price scenarios represent assumed, real price over the life of the well; Government / Owners' Share of Rent represents the share of profits above an assumed 10% hurdle rate; "N/A" represents projects that are uneconomic on a pre-take basis, while ">100%" represent cases where company NPV10 is negative on a post-take basis, but not pre-take basis, such that Government / Owners' Share exceeds economic rent

** Alberta benchmarked on basis of highly economic (Montney Kaybob Elmworth) and moderately economic (Deep Basin Wilrich) unconventional gas well*

Interpreted page: 35, "Profitability Analysis for Select Comparable Regimes – Share of Value"

1. What is the resource owner's share of the "rent" (based on IRR) at various prices?

- In other words, how is the "pie" sliced up over the life of a well or project, AFTER the company has paid out and earned its 10% hurdle rate?
- In this instance, the term "rent" applies to any profits that are left over after the hurdle rate has been achieved.
- We can refer back to Slide 32 to understand how this slide can be interpreted.
- In Slide 32 the top (dark blue segment of each bar) represented the resource owner's take. The bottom (light blue segment) represented the company's share.
- Any bar that pops up above the 10% line has available rent.
- The owner's share of the rent, therefore, is the dark blue part of the bar, as a percentage of the dark blue plus any of the light blue that's above the 10% line. In other words, the owner's share of rent = (dark blue bar) / (dark blue + (light blue – 10%)).

2. Wells that are uneconomic before any owner or government share are denoted N/A. Recall that most average dry natural gas wells have poor profitability.

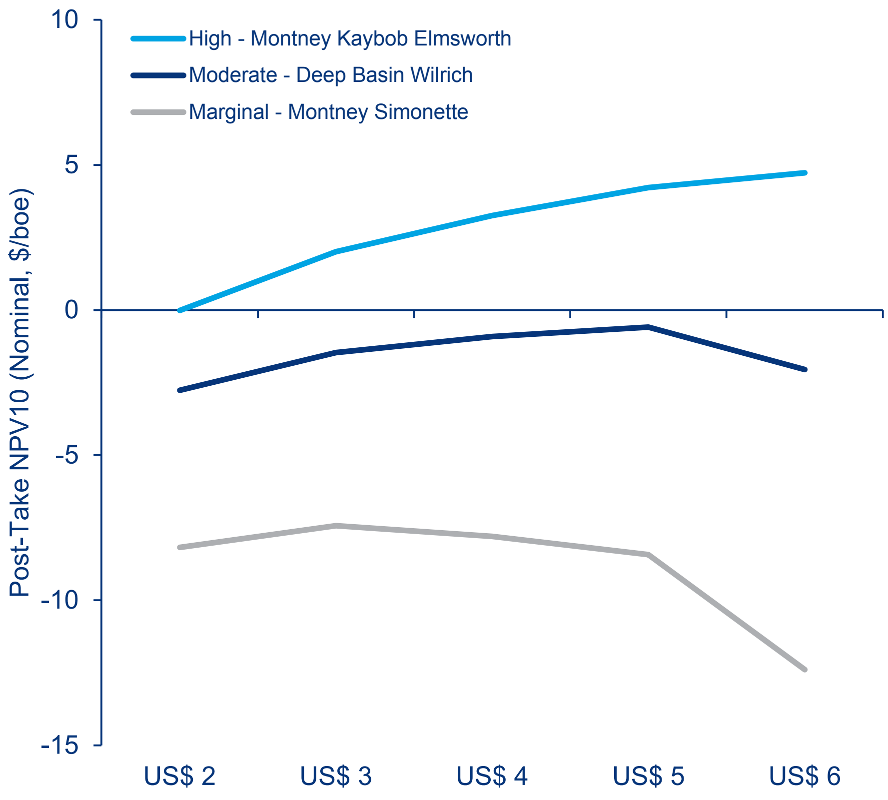
3. The general observation is that the resource owner's take is quite high for any well that has rent to spare.

- Using this method of assessing comparative take between jurisdictions, Alberta and Pennsylvania are comparable across the range, certainly within the margins of forecasting error. Our Panel once again notes that only Alberta's "High" case play has rent to spare.

Profitability Analysis for Select Comparable Regimes

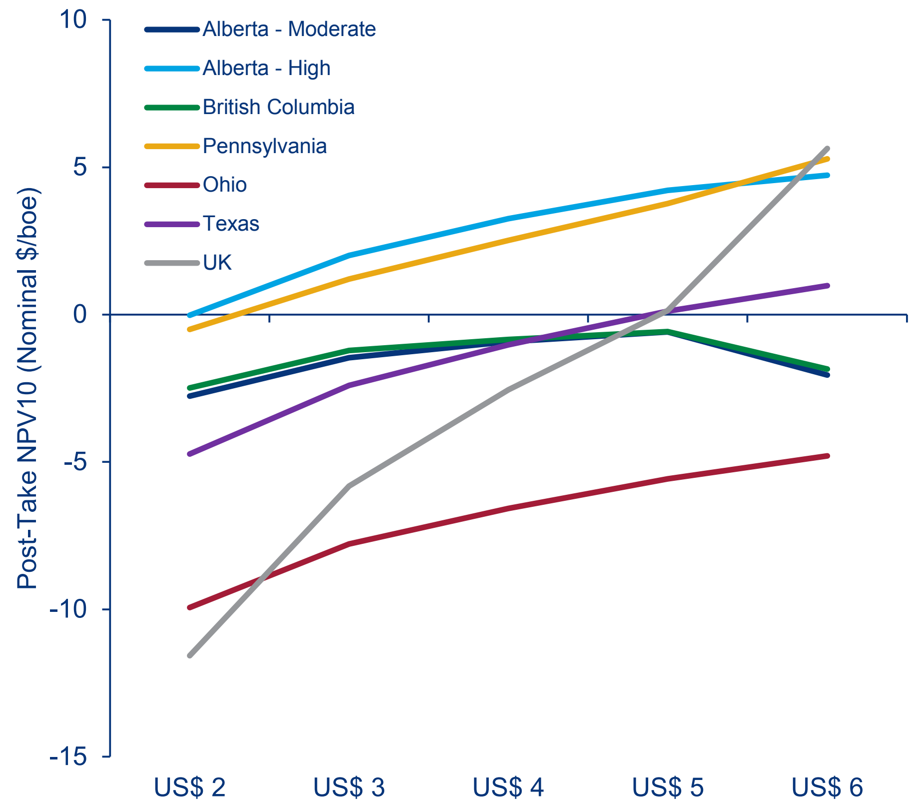
Unit Net Present Value (NPV10) for Unconventional Gas Across the Price Range

Comparison of Alberta Unconventional Gas Plays



Source: Wood Mackenzie

Comparison of Peer Regimes



Source: Wood Mackenzie

Note: Price scenarios represent assumed, real price over the life of the well

** Alberta benchmarked on basis of highly economic (Montney Kaybob Elmworth) and moderately economic (Deep Basin Wilrich) unconventional gas well*

Interpreted page: 36, "Profitability Analysis for Select Comparable Regimes – NPV"

1. Finally, our Panel looks at the net present value, or NPV metric, as a measure of ranking profitability between jurisdictions.

- NPV is regarded as the purest measure of expected profitability, and the best to assess relative investment ranking.
- The discount rate used to measure the time value of money is 10%.
- The analysis is post-take, to assess the investment rank of each comparable well.

2. Alberta's three plays, "High", "Moderate", and "Marginal" are measured in this chart.

- Once again, our Panel observed that only the "High" case would make the cut for investment, because it is the only one that exceeds the breakeven line of zero. Even then, it is only for prices above about $2.75/mcf.

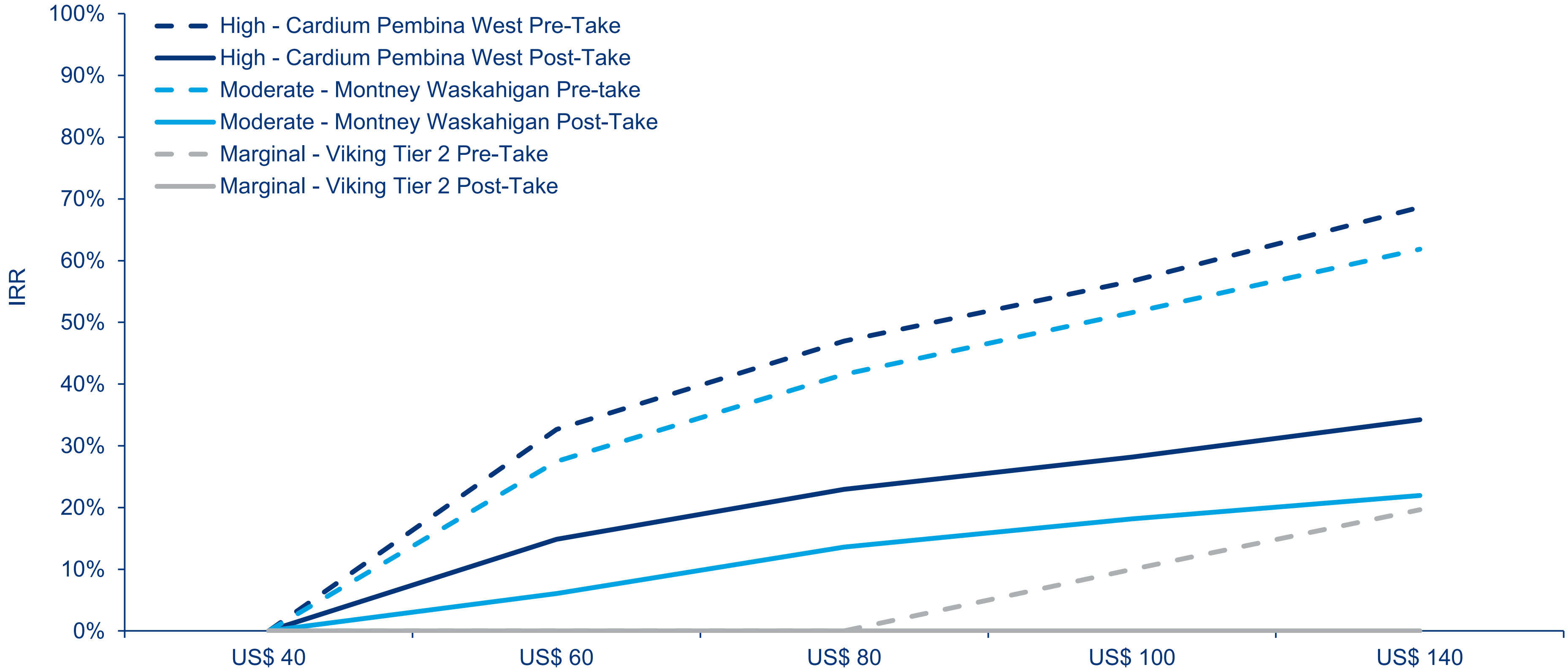
3. The right hand chart illustrates the NPVs of all comparable wells, across the price range.

- Alberta's best and Pennsylvania fare well, and are very closely comparable.
- The dry gas well play in Texas becomes investible above $5.00/mcf.
- International jurisdictions, like the UK, become investible at higher prices.
- Ohio's play is high cost and seemingly un-investible at the moment. But this is potentially deceiving, because there is conjectured to be tremendous potential in Ohio's Utica play. Once learning curve effects and scale are achieved, Ohio could be a major competitor to Pennsylvania, and Alberta too.

Profitability Analysis: Alberta Unconventional Oil Plays of Varying Quality

Pre and Post-Take IRR Across the Price Range

Mid-Range Unconventional Oil Wells Within Each Play



Source: Wood Mackenzie

Interpreted page: 37, "Profitability Analysis: Alberta Unconventional Oil Plays of Varying Quality – IRR"

1. This page compares three different unconventional oil plays in Alberta.

- A type well representative of the play area was sampled from each play.
- The Cardium-Pembina-West play is the best quality play; the Montney Waskahigan the second best; and the Viking-Tier-2 the least favourable.

2. The expected profitability of each play area is shown under varying prices.

- The main metric used is Internal Rate of Return (IRR), which accounts for the time value of money. Returns above 10% exceed a company's hurdle rate. Hurdle rates can range, so 10% and 15% were considered.
- Note that the IRR metric as applied to wells and projects is not indicative of a company's overall profitability. IRR analysis is used to assess whether a project is economic, and whether it ranks above or below other comparable opportunities.
- The IRR of each well is evaluated before and after the resource owner's take (royalties, taxes, rentals and fees).

3. The Cardium-Pembina-West play (dark blue) is of high quality in this set, and exceeds hurdle rates pre- and post -take at prices above $U.S. 50.00/B.

4. The "Moderate" Waskahigan play (teal coloured) is also of good quality, but post-take hurdle rates are achieved closer to $60.00/B.

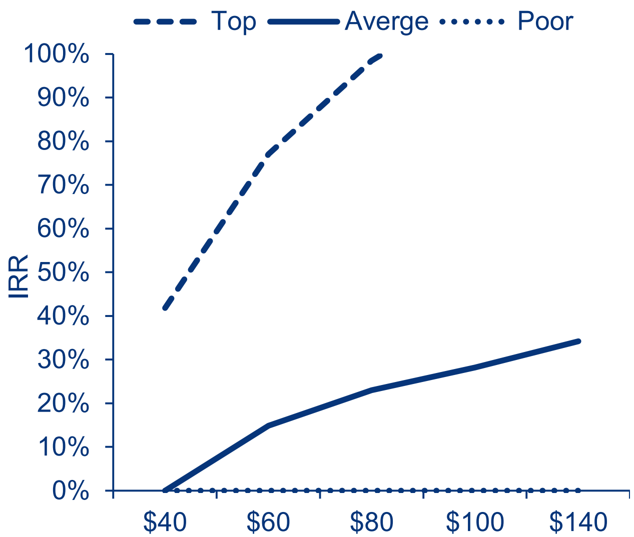
5. The Viking Tier 2 "Marginal" play is sub-economic throughout the price range.

Profitability Analysis for Alberta Unconventional Oil Wells of Varying Quality

Variation in Quality and Profitability Within Each Play Area

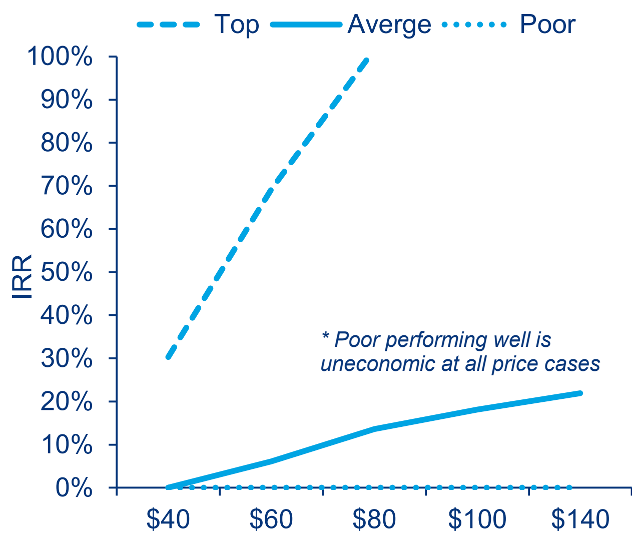
Top, Average and Poor Performing Plays Within Each Play at Varying Price

Highly Economic – Cardium Pembina West



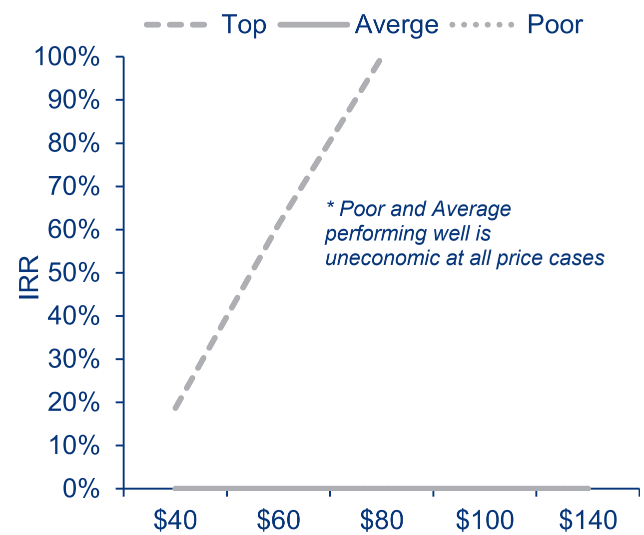
Source: Wood Mackenzie

Moderately Economic– Montney Waskahigan



Source: Wood Mackenzie

Marginally Economic– Viking Tier 2



Source: Wood Mackenzie

Interpreted page: 38, "Profitability Analysis for Alberta Unconventional Oil Wells of Varying Quality"

1. Not only did our Panel ask for a variety of wells across different geologic play types that were spread across the province, we also wanted to see variations within each play – in other words, a range of profitability within the sub-plays.

- Internal rates of return were tested in each of the three plays on the prior slide – the Cardium Pembina West; the Montney Waskahigan and the Viking Tier 2.

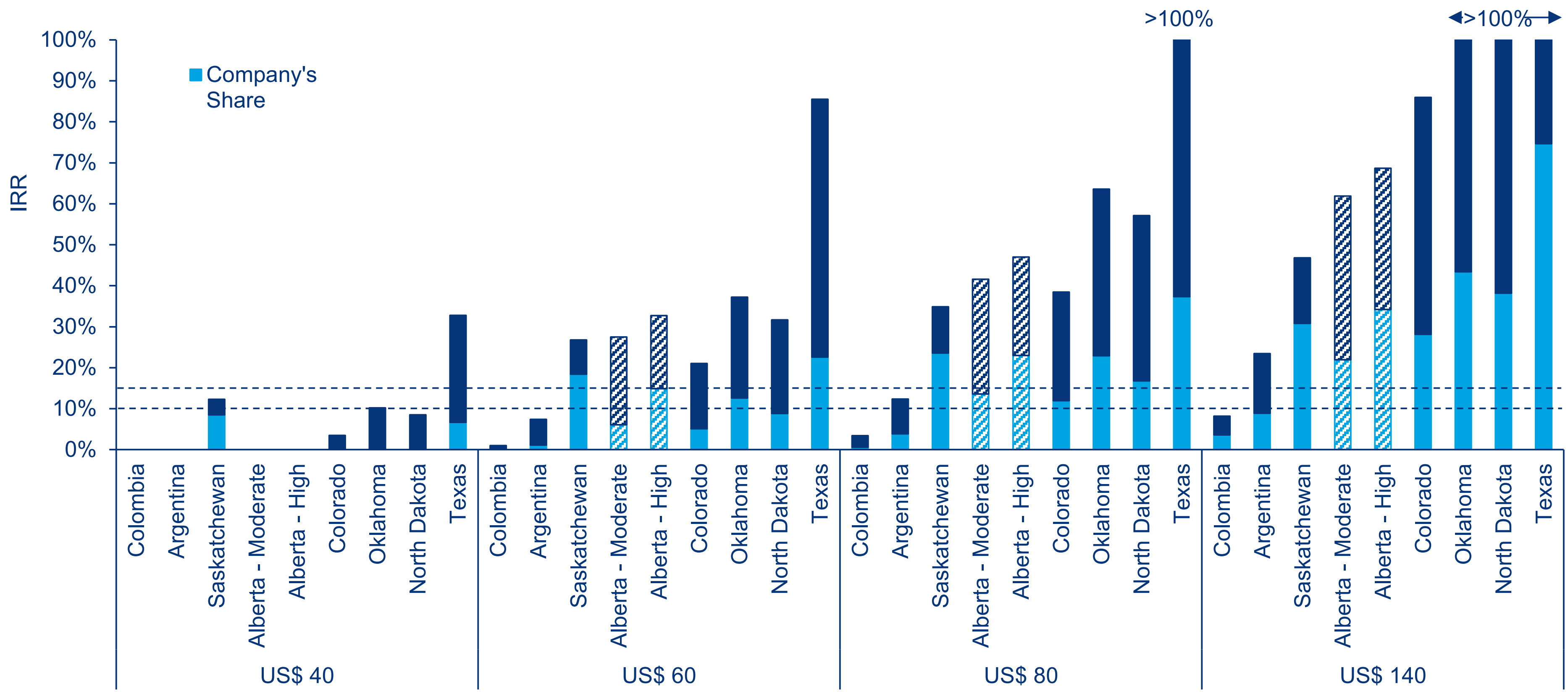
2. Based on these results our Panel observed similar conclusions to natural gas:

- Not only is there a very wide spectrum of profitability in plays across the province, but also within sub-plays.
- On an IRR basis, the range of profitability is negative to 100%, depending on well type and commodity price.
- Returns for top-quality wells in each play increase with price, but the moderate plays diminish. This indicates that Alberta does have some highly prospective wells that can withstand cost inflation – a desirable characteristic for both company and Province.
- On the other hand there are wells in every play that will be marginal at all price points. The royalty structure is unlikely to be able to support such plays, nor should the Province be expected to support marginal economics.

Profitability Analysis for Select Comparable Regimes

Unconventional Oil, Pre and Post-Take IRR Across the Price Range

Comparison of Alberta "High" and "Moderate" Wells



Source: Wood Mackenzie

Note: Price scenarios represent assumed, real price over the life of the well ;'Owner's Share' equal to IRR of well before tax and royalties

** Alberta benchmarked on basis of highly economic (Cardium Pembina West) and moderately economic (Montney Waskahigan) unconventional oil well*

Interpreted page: 39, "Profitability Analysis for Select Comparable Regimes – IRR"

1. Like the natural gas chart, this chart compares Alberta's "Moderate" and "High" play unconventional oil wells against its comparable peers, at the different price point scenarios.

- The tops of the bars in the chart represent the pre-take IRR; in other words, the overall profitability of the wells before royalties and taxes are paid.
- Each bar is split in two. The top bar (dark blue) is the resource owner's share of the profitability; the bottom (light blue) is the company's share.
- So the post-take IRR is the same thing as the company's share.

2. At $40.00/B, none of the comparable plays are economically viable post-government-take. Alberta ("High" case) and Texas beat the 10% hurdle rate pre-take, but not post-take.

3. At $60/B the returns start to perk up. Alberta's plays ("High" and "Moderate") achieve the post-take hurdle rate of 10%. Saskatchewan, Oklahoma and Texas plays "beat the bar" too.

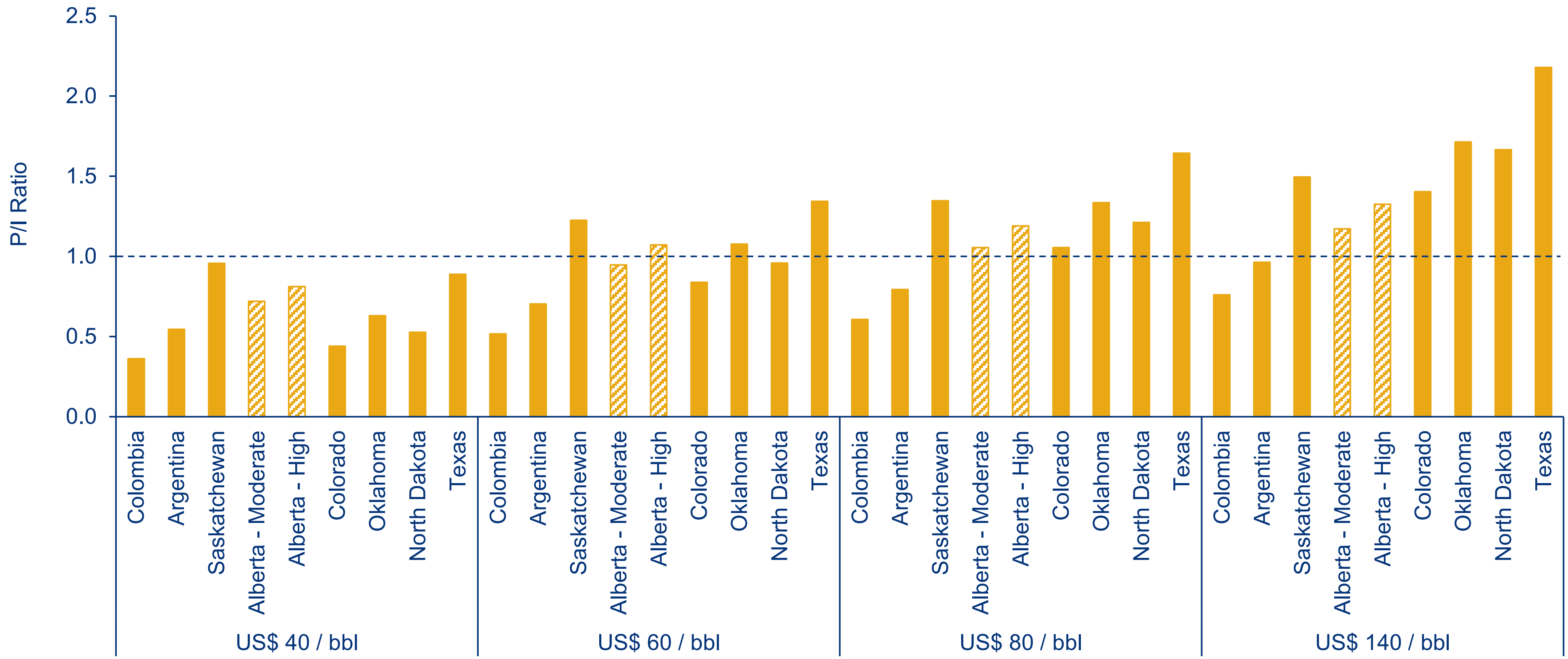
4. At $80/B almost all jurisdictions are able to achieve post-take 10%, except the Latin American peers – Columbia and Argentina. Returns in Texas are unbeatable pre- and post-take. Easy geographic access, plenty of infrastructure, lack of seasonality, close to market, and not as sensitive to price inflation, are among the distinct competitive advantages for Texas.

5. At the high end of the price range, $140/B, all jurisdictions are able to earn competitive returns. North American returns are generally "off the charts," beyond 100% IRR. At high prices, Alberta's pre-take returns are inhibited relative to the others. That's likely because of currency effects that accompany ultra-high prices.

Profitability Analysis for Select Comparable Regimes

Unconventional Oil Profitability Index Ratio (PIR) Across the Price Range

Comparison of Alberta “High” and “Moderate” Wells



Source: Wood Mackenzie

Note: P/I is based on NPV10
** Alberta benchmarked on basis of highly economic (Cardium Pembina West) and moderately economic (Montney Waskahigan) unconventional oil well*

Interpreted page: 40, "Profitability Analysis for Select Comparable Regimes – PIR"

1. On this chart, our Panel asked Wood Mackenzie to assess lifecycle profitability by using the profitability index (PI) ratio method, again across the four price scenarios.

- Recall that a PI ratio of 1.0 means that the company is achieving its hurdle rate of 10%.
- The bars are post-take profitability from a company's perspective.
- This chart is similar to the one on the previous page except a bit simpler to see which plays can beat their post-take hurdle.

2. Because this chart restates the previous one, the conclusions are mostly the same:

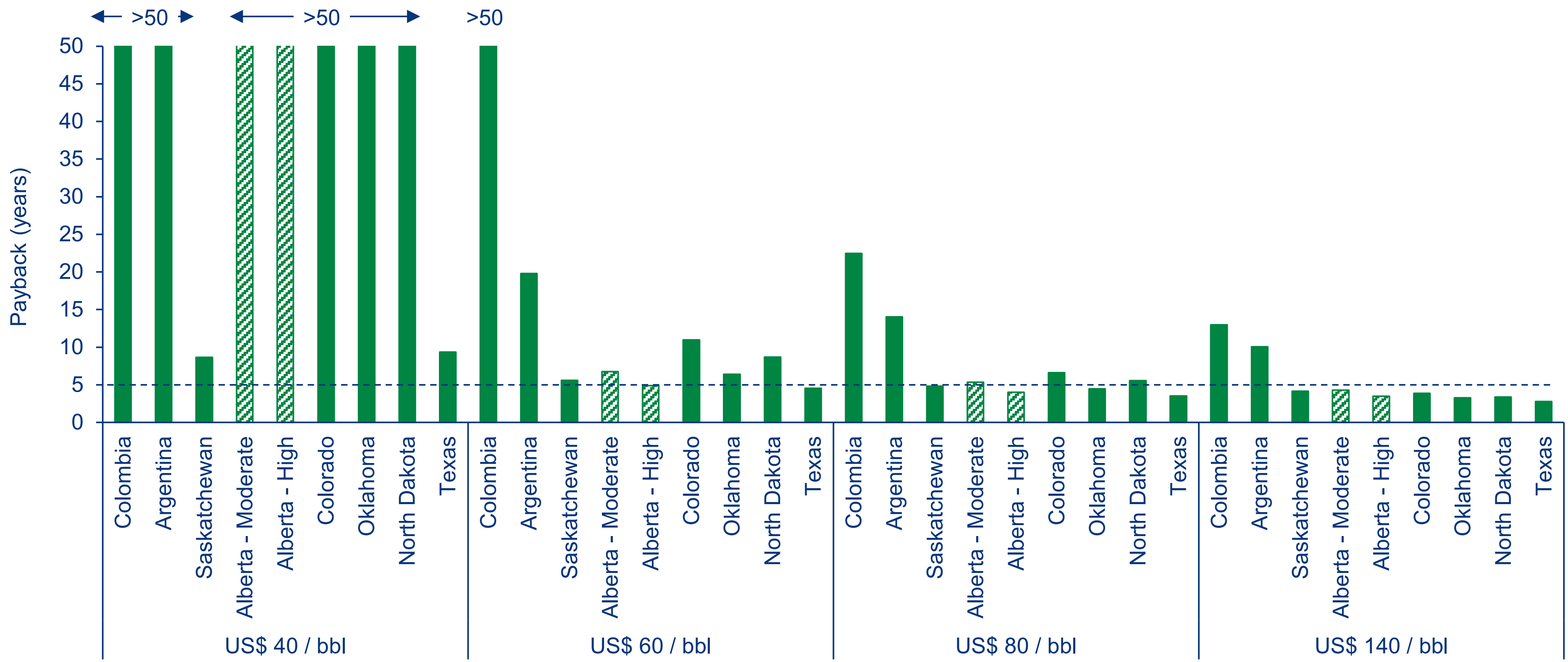
- From a play perspective, the post-take profitability of Alberta's "High" and "Moderate" plays come into positive territory around $60 to $80/B.
- Profitability metrics for Alberta's closest competitor plays – in Saskatchewan, Texas, North Dakota and Oklahoma – pull away after $80/B.
- Alberta's top end royalty rate at higher prices keeps the post-take PI ratio for its plays close to 1.0. This indicates the excess rent is contained by price inflation, but also by higher top-end royalty rates (price function) relative to its comparable peers.

3. Saskatchewan play PI ratio keeps up with all American oil producing states, except Texas, which remains the leader at all price points.

Profitability Analysis for Select Comparable Regimes

Unconventional Oil Payback Times Across the Price Range

Comparison of Alberta "High" and "Moderate" Wells



Source: Wood Mackenzie

** Alberta benchmarked on basis of highly economic (Cardium Pembina West) and moderately economic (Montney Waskahigan) unconventional oil well*

Interpreted page: 41, "Profitability Analysis for Select Comparable Regimes – Payback"

1. How fast does a project pay back its capital investment?

- The time to payout is important to both company and resource owner. For the company, any payout time greater than four or five years is of marginal interest.
- Payout is important for the resource owner, because royalty rates are typically prescribed to rise as soon as the company is paid out on its investment.

2. At $US 40/B, most wells never pay out (>50 years to pay out). Alberta's best and Texas can do it within 10 to 15 years, but that's not appealing as an investment.

3. At $U.S. 60/B most jurisdictions start to gain appeal from a payback perspective, but none other than maybe Texas and the highly economic Alberta well are compelling.

4. Above $U.S. 80/B the payout times improve again, with most jurisdictions in acceptable territory, the Latin American countries being the exceptions.

5. Our Panel notes that:

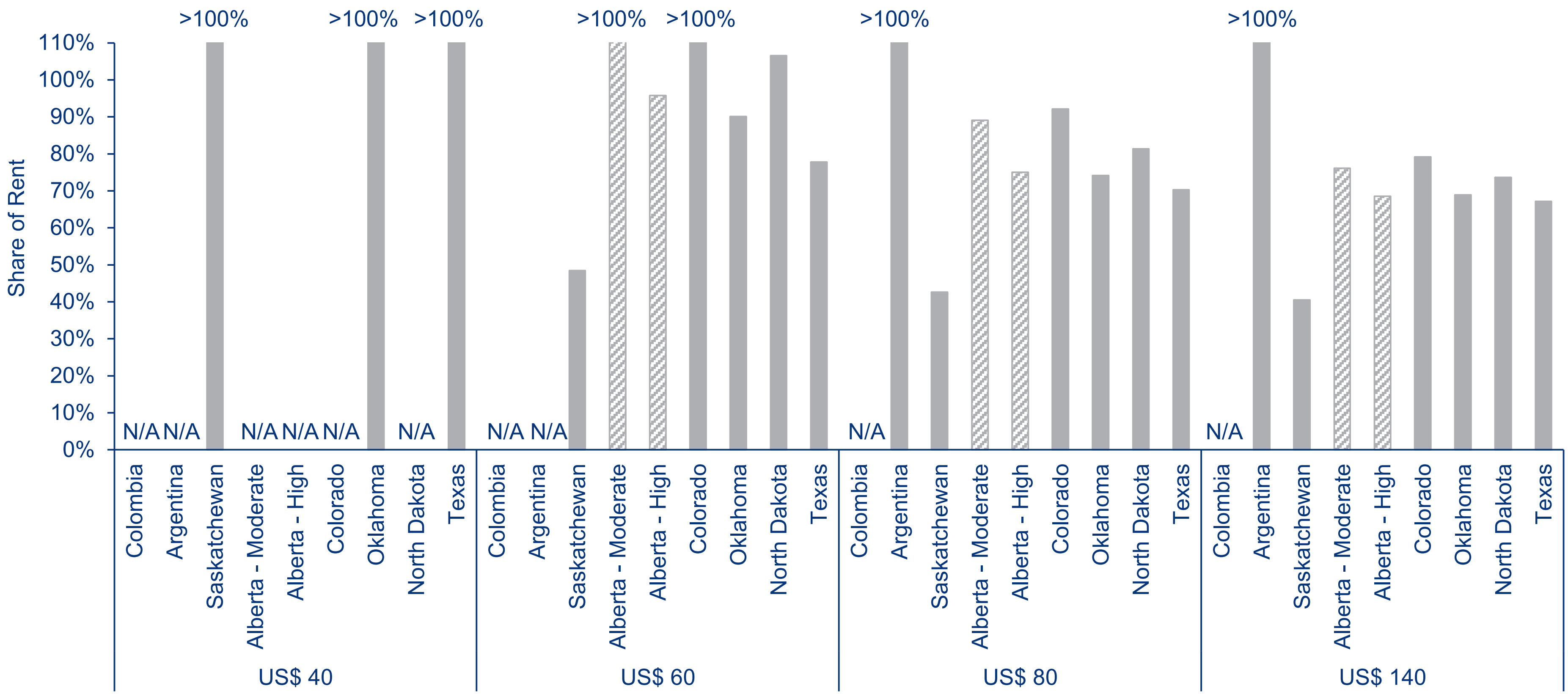
- Learning curve effects, scale and innovation within a sub-play can improve the economics of unconventional oil wells.
- Such learning and innovation should be encouraged, because individual oil wells on their own are marginal up to $U.S. 60/B.

6. Alberta's best wells look competitively positioned, but market access discounts and susceptibility to inflation temper better returns at high end of the price range.

Profitability Analysis for Select Comparable Regimes

Unconventional Oil: Share of Resource Owner's Value Above the Hurdle Rate

Comparison of Alberta "High" and "Moderate" Wells



Source: Wood Mackenzie

Notes: Price scenarios represent assumed, real price over the life of the well; Government / Owners' Share of Rent represents the share of profits above an assumed 10% hurdle rate; "N/A" represents projects that are uneconomic on a pre-take basis, while ">100%" represent cases where company NPV10 is negative a post-take, but not pre-take basis, such that Government / Owners' Share exceeds economic rent

** Alberta benchmarked on basis of highly economic (Cardium Pembina West) and moderately economic (Montney Waskahigan) unconventional oil well*

Interpreted page: 42, "Profitability Analysis for Select Comparable Regimes – Share of Value"

1. What is the resource owner's share of the "rent" (based on IRR) at various prices?

- In other words, how is the "pie" sliced up over the life of a well or project, AFTER the company has paid out and earned its 10% hurdle rate?
- In this instance, the term "rent" applies to any profits that are left over after the hurdle rate has been achieved.
- We can refer back to Slide 39 to understand how this slide can be interpreted.
- In slide 39 the top (dark blue segment of each bar) represented the resource owner's take. The bottom (light blue segment) represented the company's share.
- Any bar that pops up above the 10% line has available rent.
- The owner's share of the rent, therefore, is the dark blue part of the bar, as a percentage of the dark blue plus any of the light blue that's above the 10% line. In other words, the owner's share of rent = (dark blue bar) / (dark blue + (light blue – 10%)).

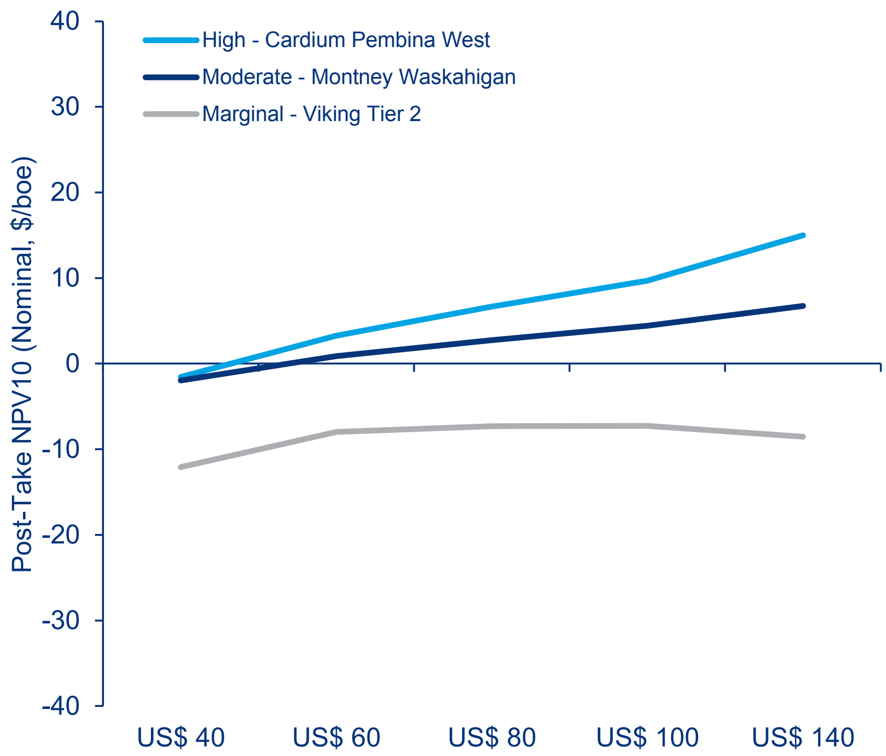
2. Wells that are uneconomic before government and owners' share are denoted N/A. Recall that most average dry natural gas wells have poor profitability.

3. The general observation is that when excess rent is available, Alberta's share is closely aligned with its North American peers. This suggests that Alberta's sharing of the excess is appropriately calibrated under the current price function.

Profitability Analysis for Select Comparable Regimes

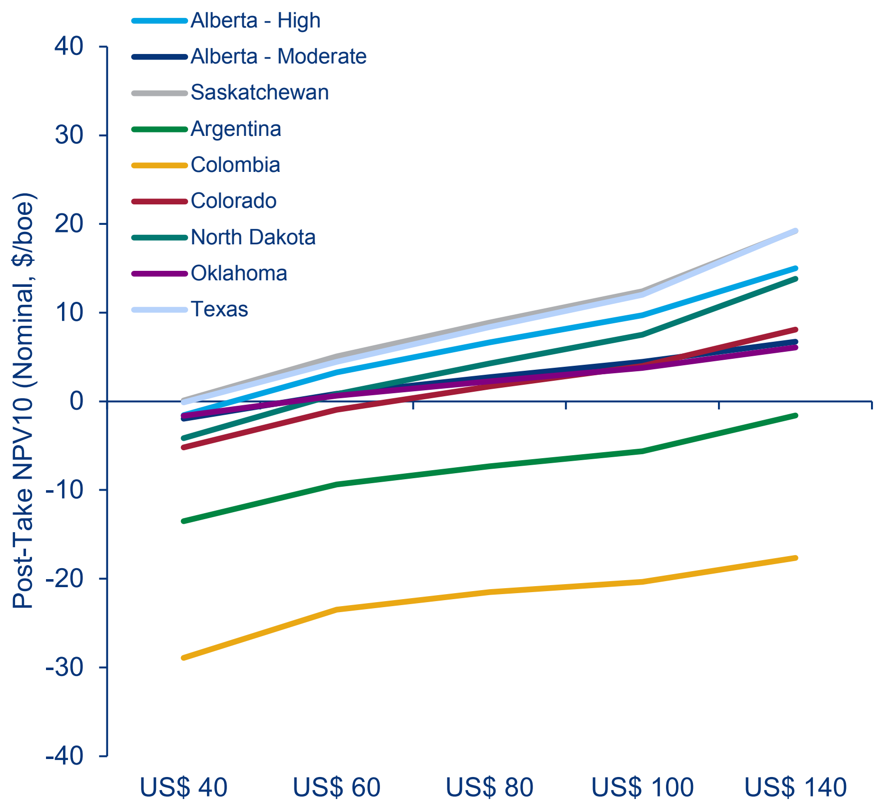
Unit Net Present Value (NPV10) for Unconventional Oils Across the Price Range

Comparison of Alberta Unconventional Oil Plays



Source: Wood Mackenzie

Comparison of Peer Regimes



Source: Wood Mackenzie

Note: Price scenarios represent assumed, real price over the life of the well
** Alberta benchmarked on basis of highly economic (Cardium Pembina West) and moderately economic (Montney Waskahigan) unconventional oil well*

Interpreted page: 43, "Profitability Analysis for Select Comparable Regimes"

1. Finally, our Panel looks at the net present value, or NPV metric, as a measure of ranking profitability between jurisdictions.

- NPV is regarded as the purest measure of expected profitability, and the best to assess relative investment ranking.
- The discount rate used to measure the time value of money is 10%.
- The analysis is post-take, to assess the investment rank of each comparable well.

2. Alberta's three plays, "High", "Moderate", and "Marginal" are measured in this chart.

- Once again, our Panel observed that both the "High" and "Moderate" cases make the cut for investment above $60/B. The "Marginal" case is uneconomic at all prices.

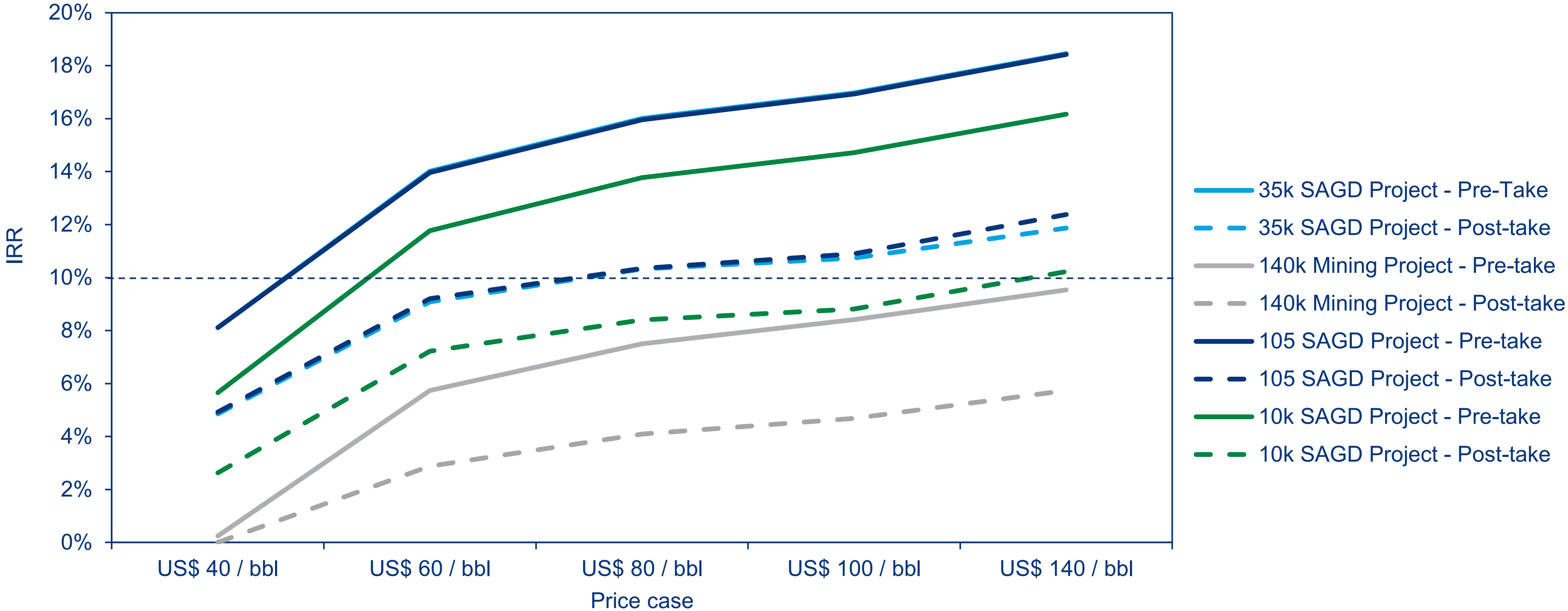
3. The right hand chart illustrates the NPVs of all comparable wells, across the price range.

- Alberta average-and-above wells are mid-range relative to peers.
- Texas and Saskatchewan display the best NPV10 ranking, progressively improving with rising prices.
- International jurisdictions that are most comparable to Alberta's unconventional oil plays – notably Colombia and Argentina – are largely uneconomic at prices below $90/B.

Profitability Analysis for Alberta Oil Sands Projects of Varying Size

Pre and Post-Take IRR Across the Price Range

Four Oil Sands Projects – three steam assisted gravity drainage (SAGD) and a mining project



Source: Wood Mackenzie

Interpreted page: 44, "Profitability Analysis for Alberta Oil Sands Projects of Varying Size – IRR"

1. Four different oil sands projects are compared on this chart.

- Differentiation was characterized by size of project.
- Three projects were SAGD: 10,000 bpd (10K); 35,000 bpd (35K) and 105,000 bpd (105K).
- The largest one was a mining project, sized at 140,000 bpd (140K).

2. The expected profitability (pre- and post-take) of each play area is shown under varying prices.

- The metric used is Internal Rate of Return (IRR), which accounts for the time value of money. Returns above 10% exceed a company's hurdle rate.
- Note that the IRR metric as applied to wells and projects is not indicative of a company's overall profitability. IRR analysis is used to assess whether a project is economic, and whether it ranks above or below other comparable opportunities.
- The IRR of each well is evaluated before and after the resource owner's take (royalties, taxes, rentals and fees).

3. The 35K and 105K SAGD projects are most attractive in this project set, but neither exceed post-take hurdle rates pre- and post-payout at prices above $US 50.00/B.

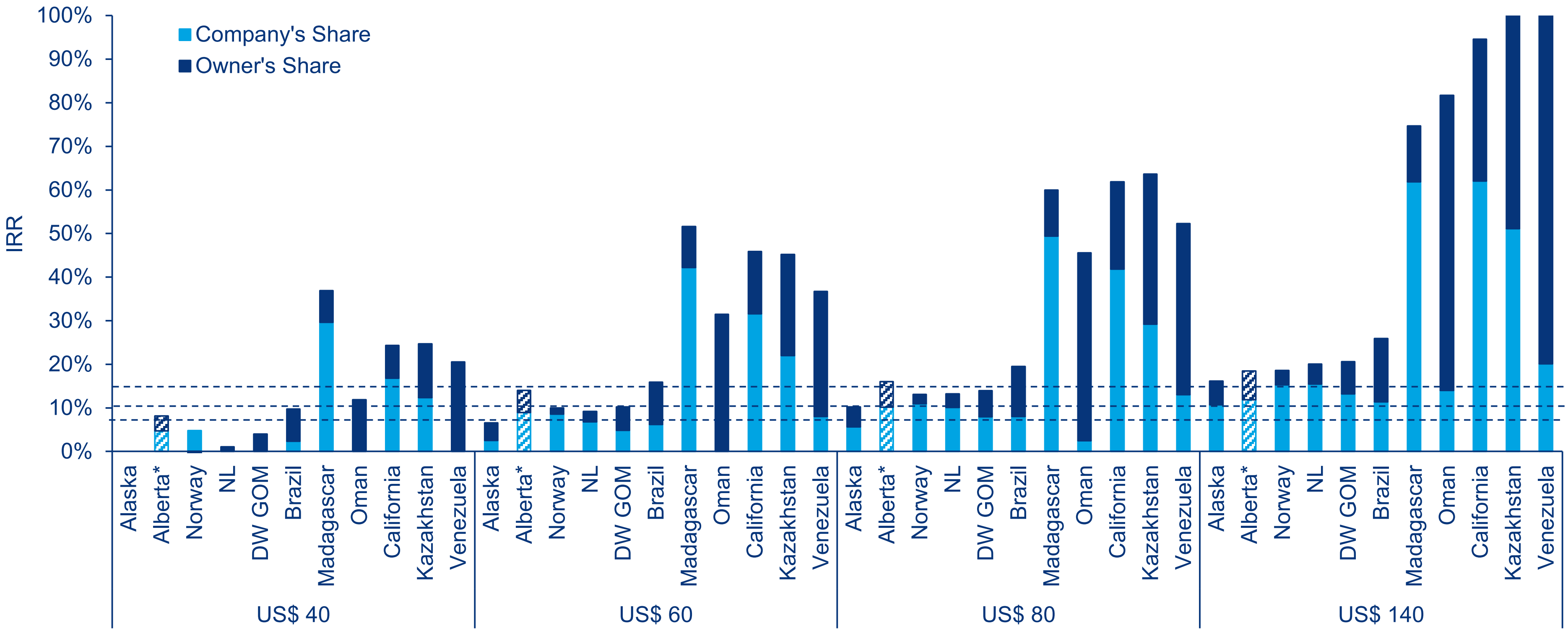
4. The 10K SAGD project struggles below $120/B primarily due to lack of scale. The economics of smaller-scale projects may improve over time with innovation.

5. New oil sands mining projects are not economically viable (post-take) under any price scenario.

Profitability Analysis for Select Comparable Regimes

Large Oil Projects, Pre and Post-Take IRR Across the Price Range

Comparison of Alberta Oil Sands 35k SAGD Project



Source: Wood Mackenzie

Note: Price scenarios represent assumed, real price over the life of the well; 'Owner's Share' equal to IRR of project before tax and royalties
** Alberta benchmarked on an expected 35k SAGD future oil sands project*

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Interpreted page: 45, "Profitability Analysis for Select Comparable Regimes – IRR"

1. This chart compares a 35K Alberta oil sands project against its comparable peers, at different oil price point scenarios.

- The tops of the bars in the chart represent the pre-take IRR; in other words, the overall profitability of the wells before royalties and taxes are paid.
- Each bar is split in two. The top bar (dark blue) is the resource owner's share of the profitability; the bottom (light blue) is the company's share.
- So the post-take IRR is the same thing as the company's share.

2. At $40.00/B, there are a few jurisdictions that have attractive, comparable economics.

- California's heavy oil fields demonstrate pre- and post-take IRRs that exceed a 10% hurdle.
- A host of comparable international countries appear to demonstrate more attractive returns. However, above ground risks have not been factored into the analysis for Madagascar and Venezuela's oil sands, nor for Kazakhstan's large scale developments.
- International jurisdictions vie for the same investment dollars as Alberta's oil sands; however, in the absence of correcting for above ground risk the dynamic range between returns in Madagascar and Alberta is smaller than is illustrated in this chart.

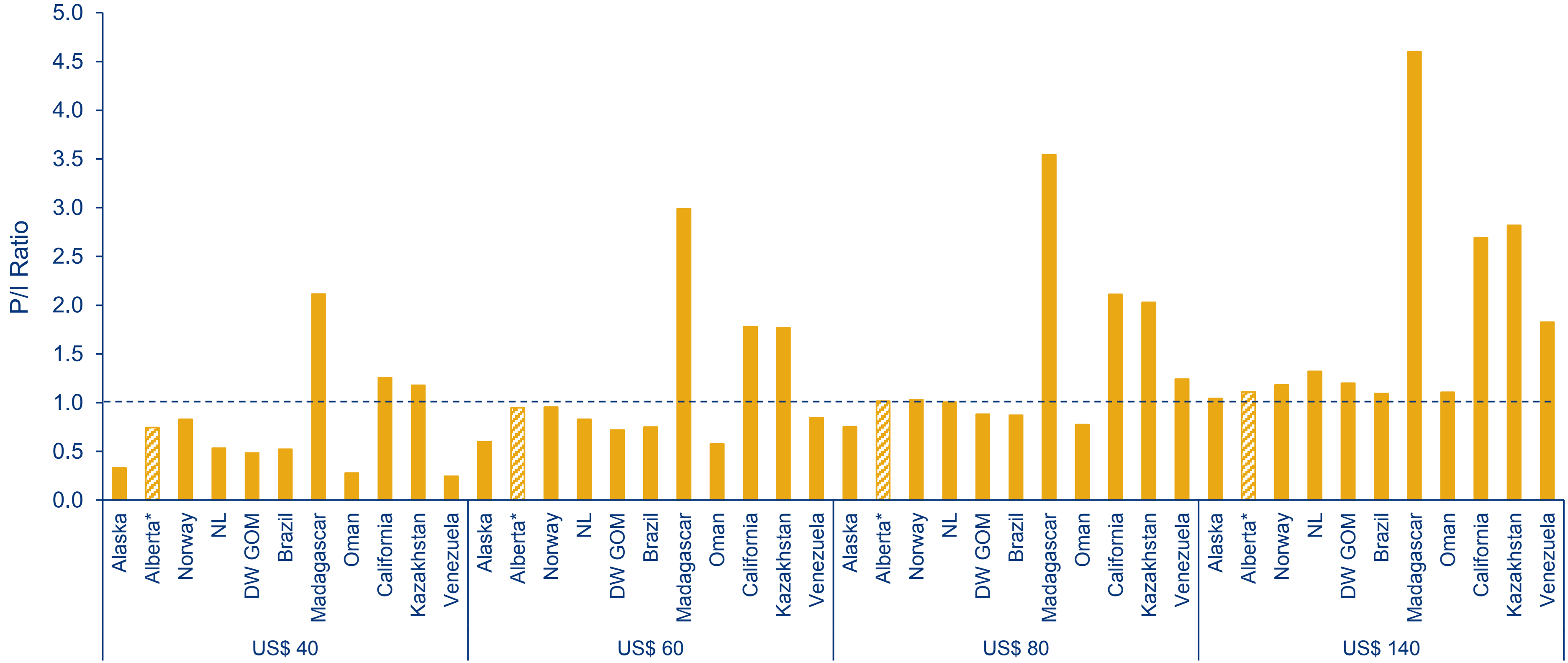
3. Post-take profitability appears around $US 80/B for a 35K SAGD project. At that price point the returns are similar to those of offshore projects in Norway and the Netherlands. Deep Water Gulf of Mexico exhibits similar profitability at $U.S. 80/B too.

4. On this chart, the conclusions at $US 140/B are largely similar to those at U.S. $80/B.

Profitability Analysis for Select Comparable Regimes

Large Oil Projects Profitability Index Ratio (PIR) Across the Price Range

Comparison of Alberta Oil Sands 35k SAGD Project



Source: Wood Mackenzie

Note: P/I is based on NPV10
** Alberta benchmarked on expected future oil sands project*

Interpreted page: 46"Profitability Analysis for Select Comparable Regimes – PIR"

1. As with the unconventional oil and natural gas cases, our Panel asked Wood Mackenzie to assess lifecycle profitability by using the profitability index (PI) ratio method, again across the four price scenarios.

- Recall that a PI ratio of 1.0 means that the company is achieving its hurdle rate of 10%.
- The bars are post-take profitability from a company's perspective.
- This chart is similar to the one on Slide 45, except a bit simpler to see which plays can beat their post-take hurdle.

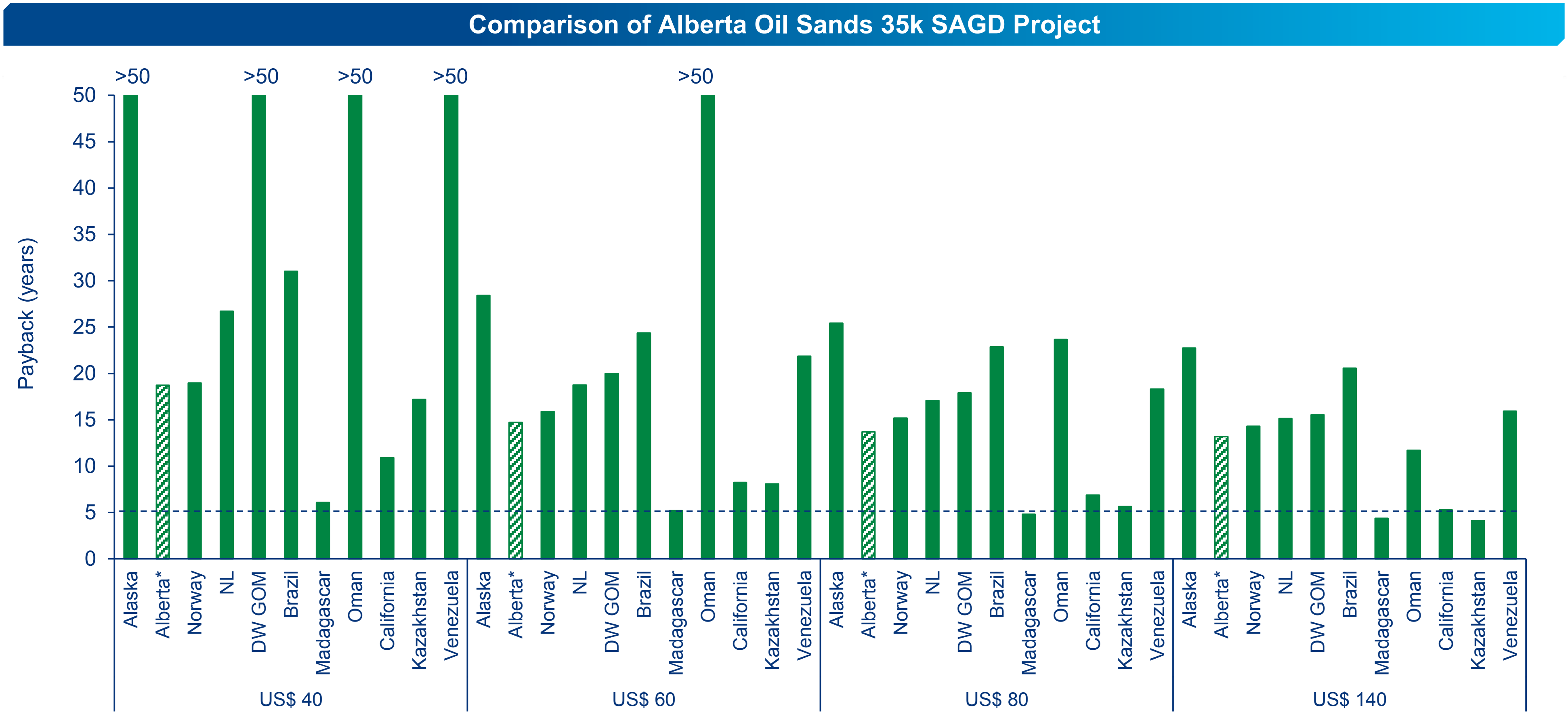
2. Because this chart restates Slide 45, the conclusions are mostly the same:

- The post-take profitability of a 35K SAGD project in Alberta comes into positive territory around $60/B, more convincingly around $80/B.
- Profitability metrics for Californian heavy oil are superior in North America.
- Internationally comparable projects in jurisdictions like Madagascar, Kazakhstan and Venezuela are superior, but require downward adjustment to compensate for above ground country risks.

3. Offshore projects in Norway and Netherlands have similar PI ratios.

Profitability Analysis for Select Comparable Regimes

Large Oil Project Payback Times Across the Price Range



Source: Wood Mackenzie

** Alberta benchmarked on an expected 35k SAGD future oil sands project*

Interpreted page: 47, "Profitability Analysis for Select Comparable Regimes – Payback"

1. How fast does a project pay back its capital investment?

- The time to payout is important to both company and resource owner. For the company, any payout time greater than four or five years is of marginal interest.
- Payout is important for the resource owner, because royalty rates are typically prescribed to rise as soon as the company is paid out on its investment.
- Payout times are much longer for megaprojects than for unconventional oil and gas wells, because of the billions of dollars of upfront investment and long construction times before any oil is produced.

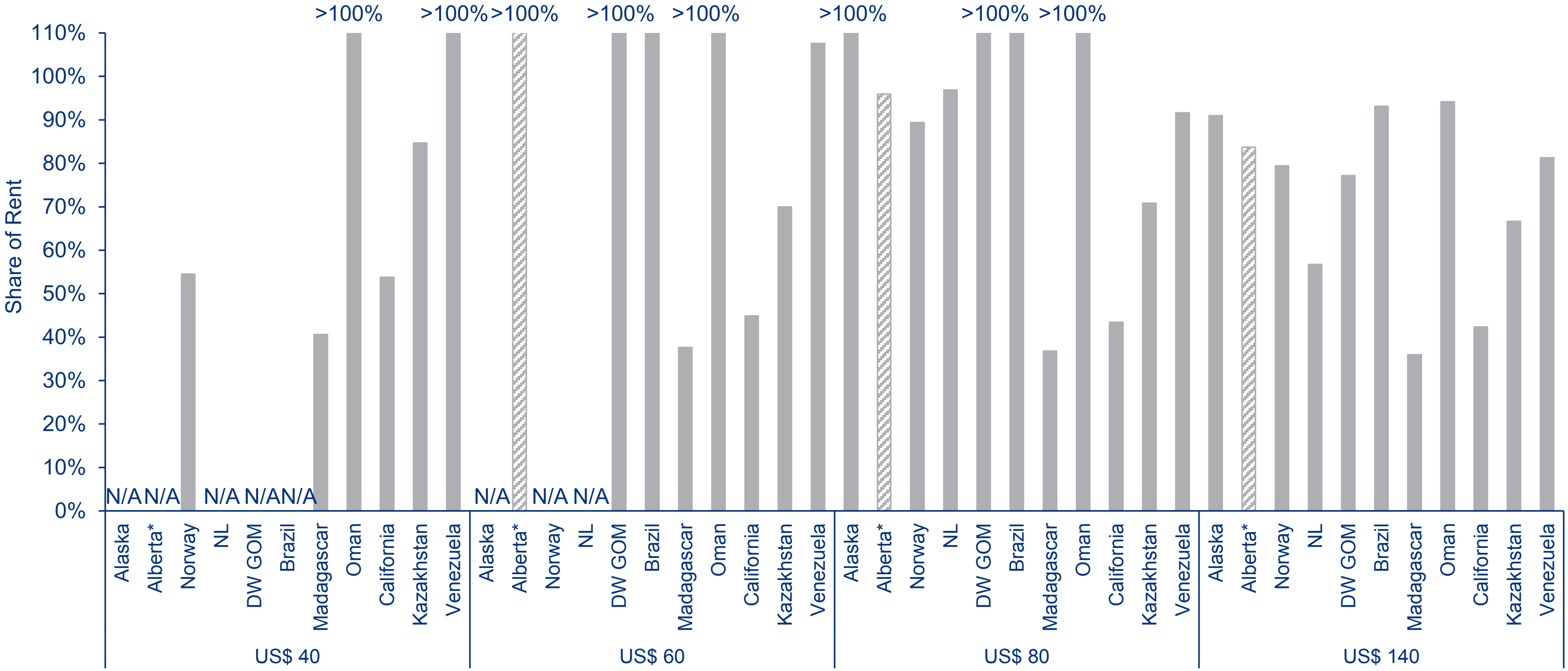
2. Payback periods between various projects begin to converge at higher prices. Even so, payback times in excess of 10 years are common.

- Such long payback periods mean that royalty rates stay low for 10 to 15 years. This can give the impression that the resource owner "isn't getting enough." But as this chart shows, the phenomenon is not exclusive to Alberta's oil sands projects.
- Post-payout, royalty rates kick up for all projects considered.

Profitability Analysis for Select Comparable Regimes

Large Oil Projects: Share of Resource Owner's Value Above the Hurdle Rate

Comparison of Alberta Oil Sands 35k SAGD Project



Source: Wood Mackenzie

Notes: Price scenarios represent assumed, real price over the life of the well; Government / Owners' Share of Rent represents the share of profits above an assumed 10% hurdle rate; "N/A" or ">100%" represent cases where company NPV10 is negative, such that Government / Owners' Share exceeds economic rent

**Alberta benchmarked on basis of an expected future oil sands project*

Interpreted page: 48, "Profitability Analysis for Select Comparable Regimes – Share of Value"

1. What is the resource owner's share of the "rent" (based on IRR) at various prices?

- In other words, how is the "pie" sliced up over the life of a well or project, AFTER the company has paid out and earned its 10% hurdle rate?
- In this instance, the term "rent" applies to any profits that are left over after the hurdle rate has been achieved.
- We can refer back to Slide 45 to understand how this slide can be interpreted.
- In Slide 45 the top (dark blue segment of each bar) represented the resource owner's take. The bottom (light blue segment) represented the company's share.
- Any bar that pops up above the 10% line has available rent.
- The owner's share of the rent, therefore, is the dark blue part of the bar, as a percentage of the dark blue plus any of the light blue that's above the 10% line. In other words, the owner's share of rent = (dark blue bar) / (dark blue + (light blue – 10%)).

2. Uneconomic wells that have no rent to spare above the 10% hurdle are denoted N/A.

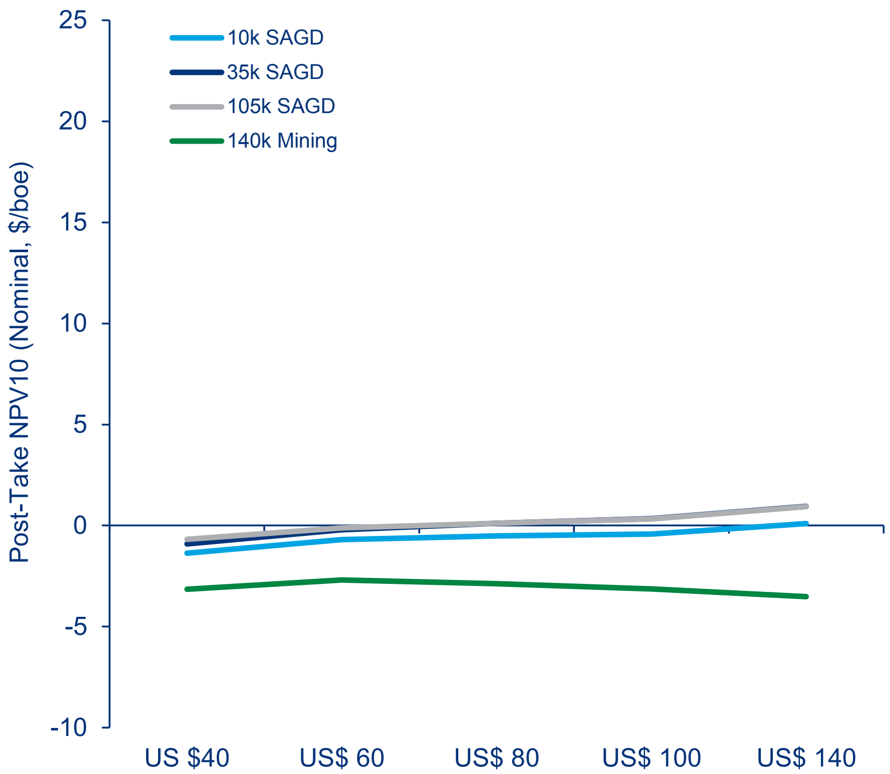
3. Our Panel was most interested in the owner's (Albertans') share at higher prices.

- The general observation was Alberta's share of excess rent, at prices above $U.S. 80/B – and even at $140/B – is closely aligned with large-scale projects in Norway and the Deep Water Gulf of Mexico. This suggests that for new oil sands projects, Alberta's sharing of any excess is appropriately calibrated under the current price function.

Profitability Analysis for Select Comparable Regimes

Unit Net Present Value (NPV10) for Large Oil Projects Across the Price Range

Comparison of Alberta's Oil Sands Projects

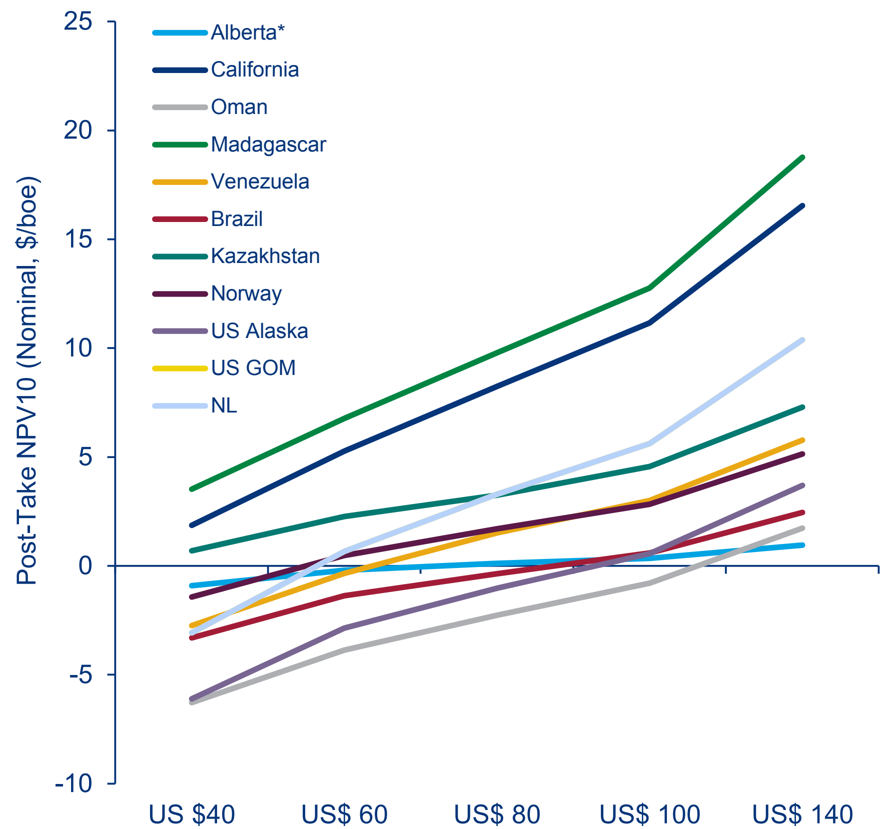


Source: Wood Mackenzie

Note: Price scenarios represent assumed, real price over the life of the well

** Alberta benchmarked on basis of an expected future oil sands project*

Comparison of Peer Regimes



Source: Wood Mackenzie

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Interpreted page: 49: "Profitability Analysis for Select Comparable Regimes – Unit NPV"

1. Finally, as with the unconventional oil and gas wells, our Panel looks at the net present value, or NPV metric, as a measure of ranking profitability between jurisdictions.

- NPV is regarded as the purest measure of expected profitability, and the best to assess relative investment ranking.
- The discount rate used to measure the time value of money is 10%.
- The analysis is post-take, to assess the investment rank of each comparable well.

2. Alberta's four oil sands projects are measured (post-take) in this chart.

- Once again, our Panel observed that only the 35K and 105K projects make the cut for investment above $60/B, more convincingly at $80/B.
- A 10K modularized project is uneconomic today below $120/B, but may improve its returns under prices with innovation.
- A 140K mining project is uneconomic at all prices.

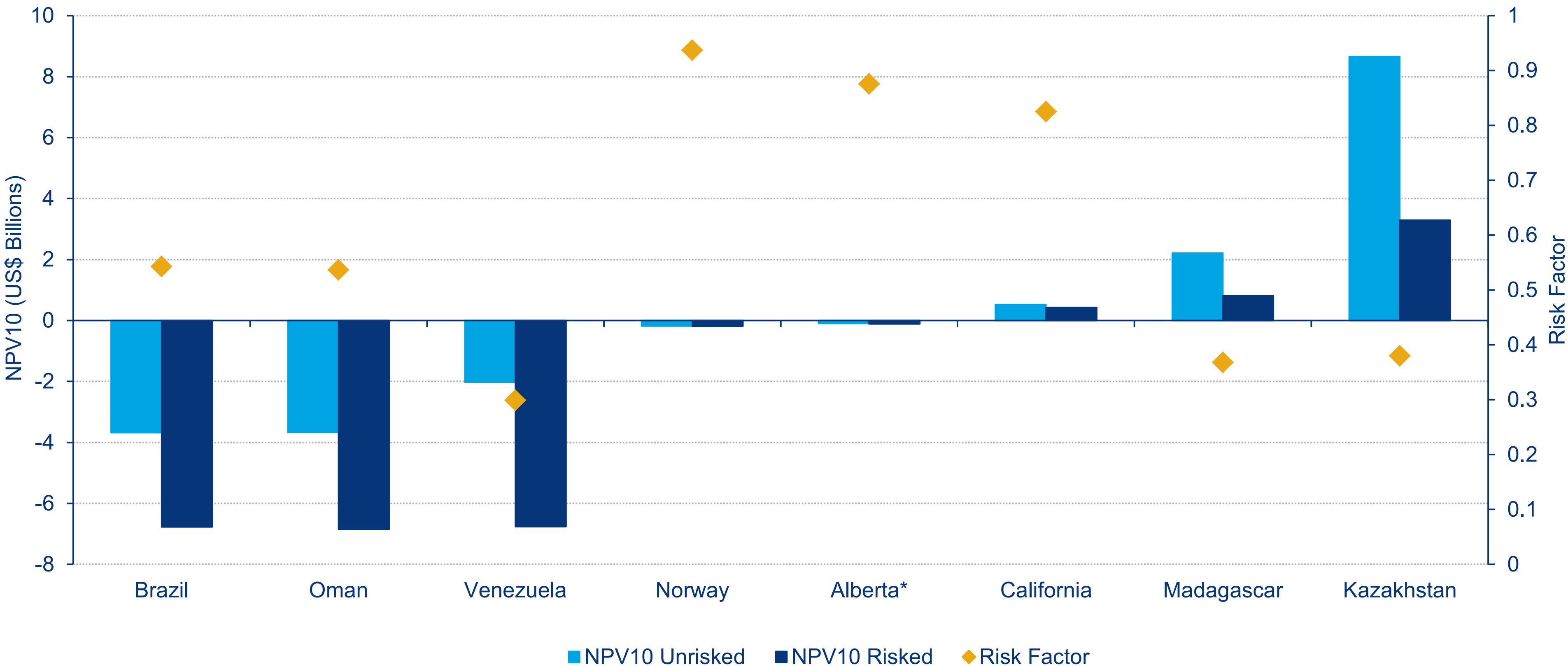
3. The right hand chart illustrates the NPVs of all comparable projects, across the price range.

- Alberta's 35K SAGD project, the best of the oil sands group, ranks low compared to its peers from the perspective of an NPV10 investment rank; its best positioning in the pack (7th out of 10) is when oil prices are at $80/B.
- California and Madagascar display the best NPV10 ranking, but the latter must be adjusted for above ground risk.

Factoring Above Ground Risk into Profitability Analysis

For Select Regimes with Large Oil Projects (Alberta 35k SAGD)

Comparison of Risked and Unrisked NPV10 **at US$60/bbl WTI



Source: Wood Mackenzie

** Alberta benchmarked on basis of an expected future oil sands project*
*** NPV10 calculated at US$60/bbl (flat, real)*

Interpreted page: 50, "Factoring Above Ground Risk into Profitability Analysis"

1. Above ground factors like political instability, threat of expropriation, corruption and civil unrest add to investment uncertainty and enhance risk.

- Implicitly increased risk translates into increased cost and reduced expectations of profitability.
- The effect of elevated risk factors is more acute on large-scale megaprojects where large amounts of capital are exposed before payout.

2. Wood Mackenzie's consulting practice provides estimates of above ground risk.

- Risk factors were determined for the comparable countries; NPV10 profitability estimates were adjusted accordingly.

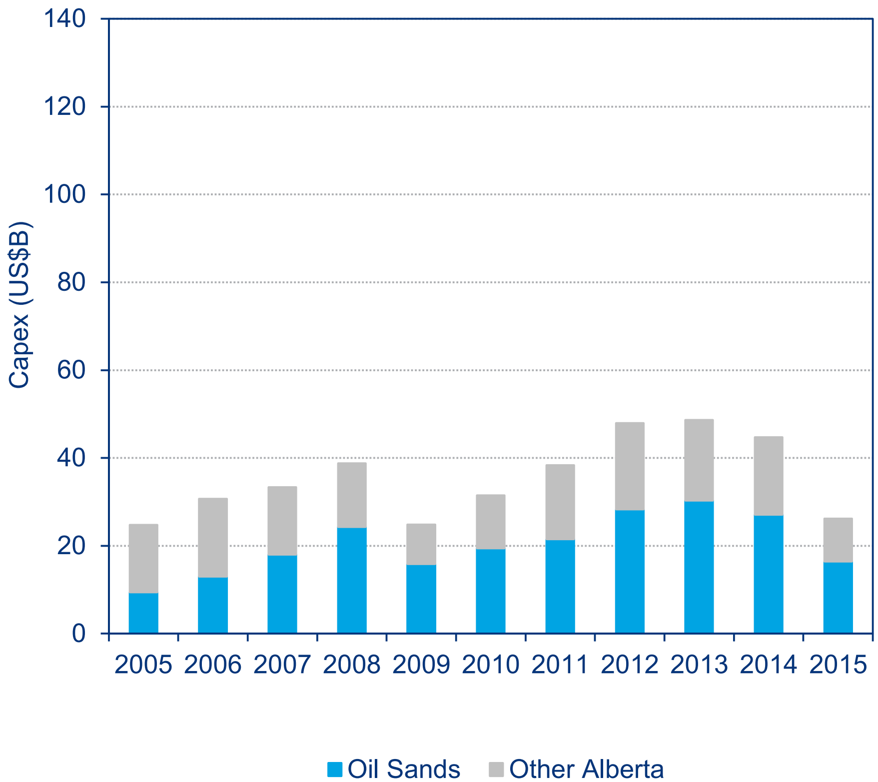
3. Brazil, Oman, Venezuela, Madagascar and Kazakhstan have risk factors of 0.6 or lower (smaller numbers represent higher risk). Accounting for risk factors lowers these projects NPVs by half or more.

- Even after compensating for risk, at $60/B countries Madagascar and Kazakhstan may still be in a position to attract investment capital more favourably than Alberta, Norway and California.
- Despite such favourable economics in risky jurisdictions, our Panel believes that Alberta's principal competition for capital is in western countries, notably the United States.

North American Oil and Gas Capital Investment

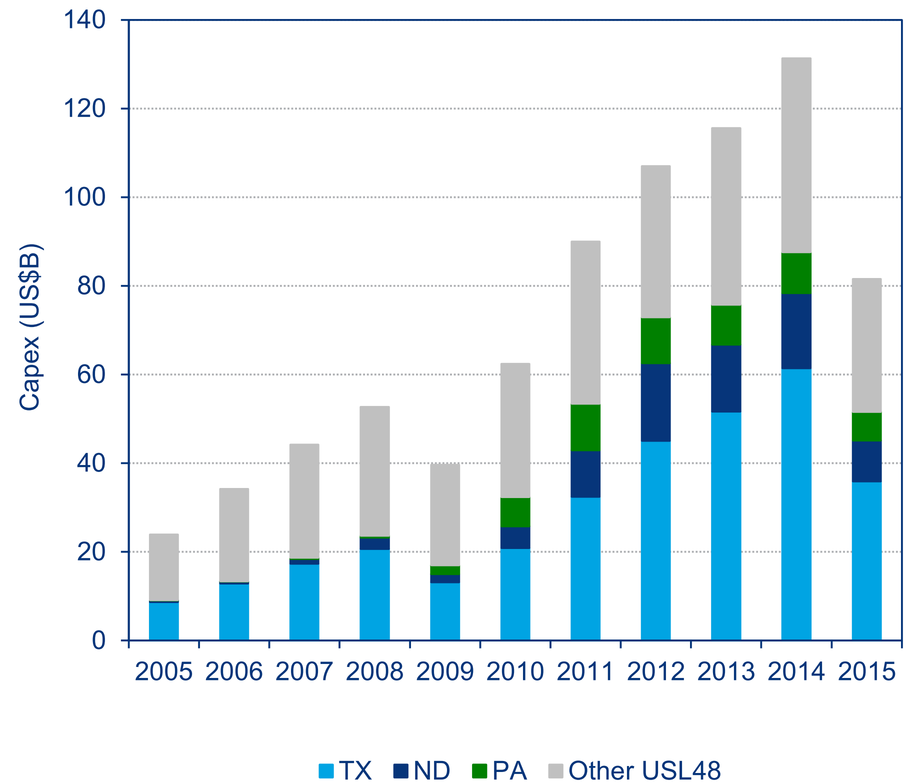
Upstream Capital Investment Trends in Alberta and the Lower 48 States of the US

Alberta Capital Investment: 2005-2015



Source: Wood Mackenzie

USL48 Capital Investment: 2005-2015



Source: Wood Mackenzie

Notes: Oil sands capital investment based on the ~35 oil sands project included in Wood Mackenzie's data coverage and reflects only development spend and abandonment provisions. USL48 data covers top producers in each basin, but is not exhaustive.

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Interpreted page: 51, "North American Oil and Gas Capital Investment"

1. These charts show trends in upstream oil and gas capital investment over the past 10 years.

- Alberta was compared against the Lower 48 states in the United States.
- As discussed in the main body of this report, the United States is Alberta's biggest competitor for capital.
- These capital expenditure numbers are from Wood Mackenzie's database and do NOT include all oil and gas investment – only a subset of the top producing companies is included.
- The charts are meant to illustrate trends, not absolute dollars spent.

2. The United States has three times the investment potential of Alberta.

3. Investment in the United States has been growing more rapidly than in Alberta, reflecting the attractive fiscal regimes relative to other jurisdictions, but also the large geologic potential with the new unconventional technologies.

- Faster payback and greater capital efficiency in the U.S. Lower 48 is most likely to take away from oil sands investments, where paybacks are slow and costs are high.

4. 2015 capital expenditures are down by at least 30% in both charts, due to the drop in oil and gas prices. 2016 is likely to be down more, potentially by another third.

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