

BP Canada Energy Company Limited would like to thank you for the opportunity to provide input to this important review. As an Albertan, I am interested in ensuring that Albertans receive a fair share of the value of Alberta's resources. As a participant in the energy industry, I am interested in ensuring that investing in Alberta makes economic sense for my company. In both roles, I am interested in the ongoing prosperity of our province. You do not have an easy task. In this written submission, I would like to focus on the key points I believe are most important to ensure that our province's future is as bright as possible.

I will begin with a bit of perspective on BP's presence and activities in Alberta. Our current royalty expenditure reflects the magnitude of BP's existing productive assets. In 2006, these crown royalty payments, net of the gas cost allowance, amounted to \$288 million. BP's funding for operating expense and capital expense is reflective of both existing assets and future investments. In 2006, we spent \$972 million on operating and capital expenditures. As evidenced by these financial indicators, we are a significant contributor to the Alberta economy.

Please let me emphasize that BP Canada believes there is no need for sweeping changes to royalty regimes that are serving Albertans well and generating a fair share for the government and citizens. However, BP does believe occasional "check-ups" to ensure that the royalty regimes are working like they should are necessary and beneficial. Corporations undertake those sorts of reviews all the time, and so does the Alberta Department of Energy. I believe that the Department does an exemplary job of protecting the interests of Albertans in the development of our energy resources.

My input and views focus on three areas:

- Technology & Unconventional Gas
- "Full Cycle" Economics
- Cost Comparisons with U.S. Investing.

The considerations you face are certainly more expansive than this. However, having listened to the testimony from others and hearing your questions of me, I believe these specific items warrant further emphasis.

Technology & Unconventional Gas

To repeat a phrase from my presentation, the current Alberta gas royalty structure is a conventional regime in an increasingly unconventional world. By "unconventional" I mean shale, coal bed methane and gas referred to as "tight gas," i.e., gas produced from reservoirs having less than 100 microdarcies of permeability. While some may think of tight gas as a conventional resource, from the perspective of industry, it is not.

BP Canada produces about half a billion cubic feet per day of natural gas through our Western Canadian facilities. We operate a number of assets in northeast Alberta and all along Alberta's western border. These BP assets are exclusively producing conventional gas reserves. BP Canada's exploration focus, however, is turning to unconventional gas plays and we expect this focus to continue into the future.

A significant reason for the shift in focus is because large conventional gas pools are becoming harder to find in the Western Canada Sedimentary Basin (WCSB). According to Ziff Energy, Western Canada conventional gas production peaked in 1998 at about 16.6 billion cubic feet per day and has been declining slowly but steadily ever since. In 1996, new gas wells produced, on average, 750 thousand cubic feet per day. By 2006, that number had declined to 215 thousand cubic feet per day, a rate of decline averaging seven per cent per year. Over the period from

2000 to 2005, gas finding and development costs have tripled rising from an average of \$1.20 per thousand cubic feet to \$3.00 per thousand cubic feet, while operating costs have doubled rising from \$0.60 per thousand cubic feet to \$1.23 per cubic feet. This combined cost of \$4.23 does not include general and administrative costs, royalties, taxes or technology development costs, nor the future costs required to meet the recent climate change targets. This causes pause when I recall gas prices in the early part of this decade averaged well below that \$4.23 number.

When you see graphs showing flat production profiles for the WCSB over the past few years, those flat profiles were achieved only because increasing unconventional gas production helped make up for the decline in conventional production.

In 1998, there was essentially no unconventional gas being produced in the WCSB. As of 2005, about 10 per cent of WCSB production was unconventional gas, totaling about 1.6 billion cubic feet per day. Ziff Energy forecasts that in 2014, Western Canada gas production will be 14 billion cubic feet per day. Of this, 27 per cent is forecast to be unconventional gas, or about 3.8 billion cubic feet per day. Clearly, unconventional gas is going to be an integral part of the basin's future.

The Alberta government, therefore, has a golden opportunity to focus on royalty regulations which encourage and sustain development of unconventional gas resources.

Technology now allows us to explore, drill and produce reserves not thought accessible as little as five years ago. Technology also allows us to pursue these options with minimal impact on the environment. As I mentioned in my presentation, spending \$100 million on new technology in our Noel tight gas project in northeast British Columbia has enabled us to achieve sustained production rates 15 times that of a normal vertical tight gas well, at only 1.5 times the cost. Using horizontal drilling, we are also able to drill far fewer wells per section than in the past, creating a smaller, more environmentally friendly "footprint." These sizeable technology investments carry with them a high degree of risk, as not all trials result in breakthroughs. Regardless, whether the technology is successful or not, third party economic analysis seldom, if ever, considers these costs. On average, on a global basis, BP invests over \$900 million in research and development each year.

The potential benefits to Alberta of developing new technologies to access unconventional gas resources are significant. As I mentioned in my presentation, the unconventional gas-in-place in the WCSB is five times that of the conventional gas-in-place. Developing new unconventional technologies here will ensure a robust gas industry in Alberta far into the future. If Alberta has the vision to work with industry to provide incentives for such development, Alberta will have the competitive advantage of being a partner in the development. It is in the best interest of the Alberta government and Albertans to put incentives in place which facilitate this outcome. These concepts are recognized and have been successful in other jurisdictions around the world.

In my presentation, I briefly mentioned that British Columbia has taken significant steps to provide incentives for exploration for unconventional gas resources and that those steps are one of the reasons that BP has spent a great deal of capital in that province in the last few years.

If I look at BC, I see a number of royalty programs and other incentives aimed at encouraging activity. These include:

- The Summer Royalty Program
- The Deep Royalty Programs (Deep, Deep Discovery, Deep Re-Entry)

- The Marginal Royalty Program and the Ultra-Marginal Royalty Program
- The Low-Productivity Royalty Program; and
- The Coalbed Methane Program.

In Alberta, by comparison, there are only two programs that might be viewed as encouraging unconventional exploration. Those are the Deep Gas Royalty Holiday Program, which is being phased out, and the Royalty Adjustment Program for Deep Marginal Gas Wells.

I do believe that there is still an Alberta Advantage, gained through 60 years of industry development here. However, jurisdictions like BC are attempting to erode that advantage and attract exploration companies to spend money there. It is my belief that your role should not be limited to determining whether Albertans are receiving a fair share of their resources, but should also focus on improving the competitiveness of the royalty regime for unconventional gas, which is the future of the natural gas industry in Alberta.

“Full Cycle” Economics

I recognize the task of this panel is to review the Alberta royalty program. Royalties will be the only variable impacted when you make your recommendations. That said, it is unfair and unrealistic to ask that you review options from the perspective of royalties only.

BP’s commercial and planning personnel perform economic evaluations from a “full cycle” perspective. Royalty is only one of the factors considered. In the final analysis, it is the total economics of a project – incorporating royalties, taxes, capital expenditure, operating expenditures, etc. – which determines whether that project can compete with other projects for investment dollars. As the panel considers a path forward, please be aware of these other variables and recognize that “royalty only” is never a consideration for prospect selection. I emphasize this point as a result of the discussions and questions (during oral presentations) which seemed to focus on a gross basis regime versus a net basis regime. From a practical perspective, it is not the regime structure which influences the outcome in prospect evaluations and funding selection, but instead the “full cycle” economics of the project. While your recommendations cannot change the other variables, your royalty recommendations will affect total economics. It is through this royalty lever that you, the panel, can make a difference in the future of Alberta.

Cost Comparisons with U.S. Investing

Many of the respondents to this panel discussed the cost variable, illustrating the rising costs of oil and gas development. The volatility of the energy industry is no secret and rising commodity prices are usually accompanied by rising costs. These economics are not unique to Alberta, but are observed across the world.

You have seen data comparisons ranking countries across the world with regards to investment feasibility for oil and gas activity. These comparisons are intended to illustrate Canada’s ranking as compared to competing regions when attracting capital spending. Of course it is Alberta’s desire to be able to compete effectively for that funding. While it is true the energy industry is a global business and investments are done on a worldwide basis, a more practical approach is to review Alberta in comparison to its most probable competition for future investment.

Investments in Alberta oil and gas will likely compete with the United States, which continues to lure spending from Alberta. Higher costs, in comparison to the rest of the world, are being experienced in both Alberta and the United States. When reviewing cost data alone, certain

categories even have an advantage in Alberta as compared to the United States. Why then, do the drilling rigs and investment money seem to continue to move out of Alberta?

The reason is not found by reviewing costs alone, but by analyzing cost per unit. Alberta costs are competitive on an absolute basis, but because the gas pools being found are smaller, the per unit costs, where the units are reserves, are not competitive.

We cannot change the geology of Alberta. We cannot control the costs of industry services. We can however, be cognizant of the dynamics and do what we can to change the outcome on these "cost per unit" calculations. If the royalty or tax regime is favorable, this will help the numerator, which represents the "cost factor".

BP operates its North America gas portfolio as one. Therefore, we actively compare the relative profitability of natural gas resulting from the different basins including finding and developing costs, differentials to the Henry Hub marker price, and taxes and royalty. We conclude that faced with a similar opportunity, conventional natural gas is about twice as profitable in the southern United States as compared with Alberta.

Similarly, coal bed methane developed in BC and Colorado is roughly 2/3 more profitable than conventional gas developed in Alberta. A comparison of tight gas is a bit more complicated due to a temporary anomaly in the pricing differential for Wyoming. Once the Rockies Express pipeline is commissioned, tight gas in this region is expected to be roughly 2/3 more profitable than Canadian tight gas. Note that neither of these two examples include the upfront technology investment, which of course depresses the profitability of unconventional gas.

In every case, an investor with similar opportunities would have reason to pause before allocating capital funding to Alberta.

Conclusion

The prosperity of Alberta is very dependent on the energy business. As illustrated in the CAPP presentation to this panel, 40 per cent of Alberta's income is generated by the oil and gas industry. Alberta has long been a good investment choice for producers, with an advantage over similar investment options. That advantage however, has begun to erode. This royalty review creates a unique opportunity to get that edge back.

Thank you for the opportunity to respond. I am available at your convenience if you require further information.

Regards,

Randy McLeod