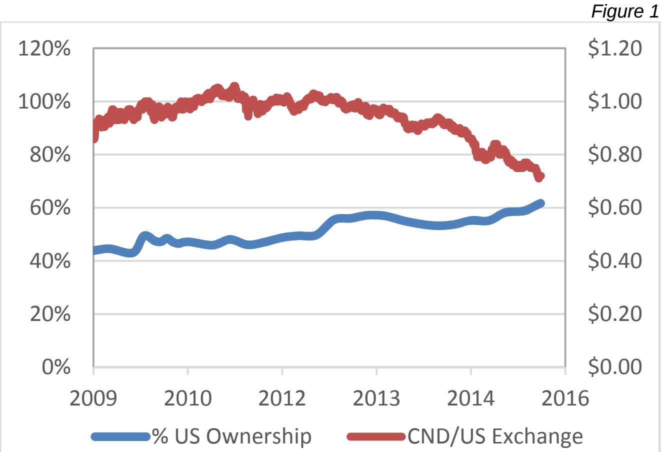
Peyto Exploration & Development Corp.
President's Monthly Report

February 2016 — From the desk of Darren Gee, President & CEO

While the markets have been particularly volatile of late, it is encouraging to see our deep value, US investor base taking advantage and increasing their Peyto holdings. As illustrated in Figure 1, our US ownership (or as best we can tell with the geographic data we receive) has climbed steadily as the Canadian dollar has fallen. You can't blame them for loading up. In US dollars, Peyto is the same price today as it was back in 2012. And while natural gas prices might be looking similar to that year, our production has increased 2.5 fold since then.

Figure 1



Source: Peyto, Bank of Canada

As in the past, this report includes an estimate of monthly capital spending as well as our field estimate of production for the most recent month (see Capital Investment and Production tables below).

Capital Investment*

*2014/15 Capital Summary (millions$ CND)**

	Q1	Q2	Q3	Q4	2014	Q1	Q2	Q3	Oct	Nov	Dec	Q4	2015
Acq.	0	0	0	0	0.3	3	0	-6	0	0	0	0	-3
Land & Seismic	7	8	0	6	21.3	4	1	4	0	2	0	2	12
Drilling	80	68	83	81	310.8	70	59	88	28	27	16	71	287
Completions	36	48	46	54	183.1	43	33	44	23	19	13	54	173
Tie ins	16	10	11	14	51.3	7	11	15	7	6	3	16	49
Facilities	40	16	40	26	122.2	12	12	32	4	5	12	20	76
Total	**179**	**151**	**180**	**180**	**690**	**138**	**117**	**177**	**62**	**58**	**44**	**163**	**594**

Production*

2014/15 Production ('000 boe/d)*

	Q3 14	Q4 14	2014	Jan	Feb	Mar	Q1 15	Q2 15	Q3 15	Oct	Nov	Dec	Q4 15	2015	Jan
Sundance	57.2	59.4	54.4	57.8	56.5	55.3	56.5	57.1	58.2	62.3	63.2	63.3	62.9	58.7	61.3
Ansell	14.3	16.5	15.2	17.2	16.7	16.6	16.8	15.4	12.6	16.4	23.0	24.2	21.2	16.5	24.1
Brazeau	1.2	3.2	1.8	3.9	4.4	4.7	4.3	6.4	6.8	8.2	8.5	10.0	8.9	6.6	11.3
Kakwa	2.4	2.3	2.4	2.2	2.1	2.3	2.2	2.1	1.9	1.8	2.4	2.1	2.1	2.1	2.1
Other	2.4	2.0	2.5	1.9	1.9	1.4	1.7	1.6	1.5	1.4	1.9	1.9	1.7	1.6	1.7
Total	77.5	83.3	76.3	83.0	81.6	80.3	81.6	82.6	81.1	90.1	99.0	101.5	96.8	85.5	100.5

This is an estimate based on real field data, not a forecast, and the actual numbers will vary from the estimate due to accruals and adjustments. Such variance may be material. Tables may not add due to rounding.

Alberta's Ever Changing Royalties (yet again)

Over the last decade, we, Alberta's oil and gas producers, have seen our fair share of royalty reviews (pardon the pun). The latest being last week's results from the Alberta Royalty Review Panel, launched back in June 2015. Prior to that, we saw a new royalty framework introduced by the Stelmach government in 2007, modified in 2008 for unintended consequences, and further enhanced in 2009 with a 3-point incentive plan in response to reduced industry investment from lower commodity prices and the fallout from the Great Recession of '08. The 2009 Royalty program has been, more or less, what we've been working with for the last 6 years (with a 2011 tweak). As of last Friday, we also have the Modernized Royalty Framework ("MRF") to look forward to.

To compare and contrast the two frameworks, specific to Peyto, we first have to look at the old system. The basic premise for the 2009 royalty scheme was not much different than in many other parts of the world – have a minimum amount of royalty collected until a company has been able to recover most of their capital, then enter a profit sharing mode whereby both producer and royalty owner share in the profits that are generated at any given production rate and commodity price.

Specific to natural gas and Peyto, the old royalty system had two parts. For a new conventional Alberta gas well, there was a 5% royalty for the first year (or 18 months for a horizontal well) up to a maximum cumulative recovery of 0.5 BCFe (combining both natural gas and NGLs). That point (1 yr/0.5 BCFe) was to get you closer to payout, and then a calculation that incorporated productive rate and natural gas price kicked in with royalties up to a maximum potential rate of 36% (at a price over $7/GJ).

In addition to the conventional new gas well royalties, the province also wanted to encourage deeper drilling in the basin that was both riskier and more expensive. For this there was a Natural Gas Deep Drilling royalty credit program. This program ran concurrently with the new gas well royalties and basically covered all the drilling that Peyto (or anyone else) did in the deeper part of the basin. So long as wells were deeper than 2,000 m, they were eligible for a progressively increasing capital credit, based on their total measured depth. This capital credit was then applied to royalties owed in the first 5 years of production, which lowered royalties to the minimum 5% level.

Deep Basin Wilrich (3,000mTVD, 4,300mMD)

NGDDP Credit	$/m		
0-2,000m	$0	$	-
2,000-3,500m	$625	$	937,500
3,500-4,300m	$2,500	$	2,000,000
		$	2,937,500

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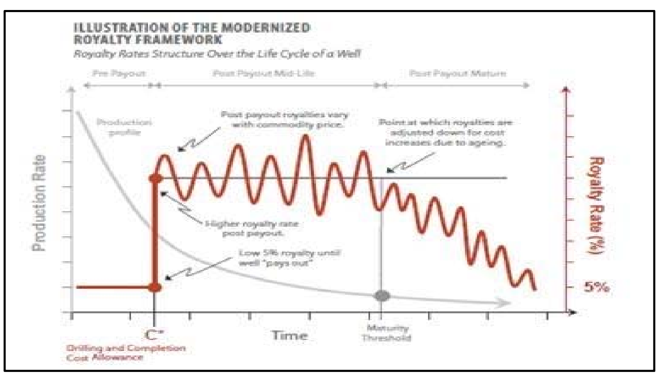
If it wasn't used up in 5 years, whatever remained was lost. Once it was used up (or expired), the traditional calculation of royalties as described above, kicked in. For illustration, a new horizontal Wilrich well in the Alberta Deep Basin would have a royalty credit as shown above.

Unfortunately, at current commodity prices, the majority of the $2.9MM royalty credit goes unused, so the program isn't particularly meaningful. The following royalty schedule shows how, at $3/GJ gas and $60/bbl oil, less than 13% of the capital credit is actually used in the first 5 years, assuming the conventional new gas well royalty program is used first.

	Production	Revenue	Original Royalty		New Well Credit		NGDDP Credit		Royalty Savings		
	(boes)	$	%	$	%	$	%	$	New Well	NGDDP	
2016	127,020	2,832	21%	$ 585	9%	$ 250	5%	$ 129	$ (335)	$ (121)	
2017	65,700	1,457	12%	$ 176	12%	$ 176	5%	$ 66	$ -	$ (110)	
2018	49,275	1,094	10%	$ 110	10%	$ 110	4%	$ 49	$ -	$ (61)	
2019	38,325	851	10%	$ 85	10%	$ 85	4%	$ 38	$ -	$ (47)	
2020	30,660	683	10%	$ 68	10%	$ 68	4%	$ 30	$ -	$ (38)	
2021	25,185	557	10%	$ 55	10%	$ 55	10%	$ 55	$ -	$ -	
2022	20,805	464	10%	$ 45	10%	$ 45	10%	$ 45	$ -	$ -	
2023	17,520	393	10%	$ 38	10%	$ 38	10%	$ 38	$ -	$ -	
2024	15,330	338	9%	$ 32	9%	$ 32	9%	$ 32	$ -	$ -	
2025	13,870	292	10%	$ 28	10%	$ 28	10%	$ 28	$ -	$ -	
				$ 1,222		$ 887		$ 510	**$ (335)**	**$ (377)**	**$ (712)**

That was the old program. The 2016 Modernized Royalty Framework proposes something very similar in many respects. A 5% new well early time period, which is supposed to coincide with payback of some of the capital, and then a profit sharing period of higher royalty based on commodity price, with a tailing off period at lower productive rates to account for higher op cost older production. The determination of the early time period will be a calculation much like the NGDDP but based on industry capital costs that vary from year to year - what the crown is calling C*.



$$C^* = \underbrace{a1^*(TVD)}_{\text{Capital cost allowance allocation for each vertical metre drilled}} + \underbrace{a2^*(TVD - V_{deep})}_{\text{Additional capital cost allowance allocation for each vertical metre drilled in excess of the vertical depth threshold. } a2 \text{ and } V_{deep} \text{ account for the increase in costs from deeper drilling}} + \underbrace{a3^*(TVD^*TLL)}_{\text{Capital cost allowance allocation for the product of vertical and horizontal meters drilled. } a3 \text{ accounts for the increased drilling and completion costs for lateral sections placed at greater vertical depths}}$$

Conceptually:* *Vertical Drilling Capital Cost Allowance + ***Horizontal Drilling and Completion Capital Cost Allowance***

Notes:

- C* is the Drilling and Completion Cost Allowance
- TVD is the Total Vertical Depth of the wellbore
- TLL is the Total Lateral Length of the wellbore
- Values for *a1*, *a2*, *a3* and V_{deep} will be finalized during the calibration period

Obviously, both the determination of C* and the royalty rate at various prices will be hugely important to determining whether this framework is better or worse than the previous one from a company returns perspective - and both of those have yet to be finalized. But the basic structure of the program looks very similar to before.

Unfortunately, there are still many questions left unanswered:

1. What about the other costs of Land, Seismic, Equipment, Tie-ins, Facilities? How are we accounting for returns that need to be generated on this capital? Through the old Gas Cost Allowance?
2. Can one equation capture all types of wells, in all areas of Alberta, just with depth? What about the more remote, deeper and more completion intensive formations, like the Duvernay, for example?
3. Which period will be used to determine C*? 2014, 2015? Which operator's costs? The most recent capital costs levels are slowly putting the service industry out of business aren't they?

Thematically, I would say the new framework looks positive, and should benefit the more efficient, lower cost producer. That's us. The province clearly wants to encourage the improvement of industry margins so there is more profit to share. It's a page right out of Peyto's playbook. It also won't impact our 2016 capital program since it only affects wells drilled in 2017 and beyond. But there are still many unanswered questions. So I guess we just continue to wait.

Activity Levels and Commodity Prices

It's about that time winter showed up. Then again, Joe Bastardi at Weatherbell Analytics did predict back in August 2015 that this winter would be later, rather than earlier. In fact, his public winter 15-16 forecast was as follows:

August 2015

- ***Overall, a snowy, colder than normal winter is expected in the South and East***
- ***Core of winter will be later rather than earlier***
- ***December could be very warm with February very cold***
- ***El Niño is a big influence but not the only factor***

http://www.weatherbell.com/public-winter-15-16-forecast

So far, he's been right on the later than earlier, and the December being very warm. Hopefully he's also right on the February cold and the colder winter overall. We could use a bit of bullishness on natural gas consumption. Right now the future strip for natural gas is pretty flat going out a couple years, climbing to $3/GJ CND by 2018. I suppose the same goes for oil, taking until then to get back over $40/bbl US. I don't mind the cheap oil, as that seems to translate into much lower costs. But I could do with a little stronger gas price. Not too strong, though, as to encourage our competition, but just a little stronger to bolster our earnings.

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