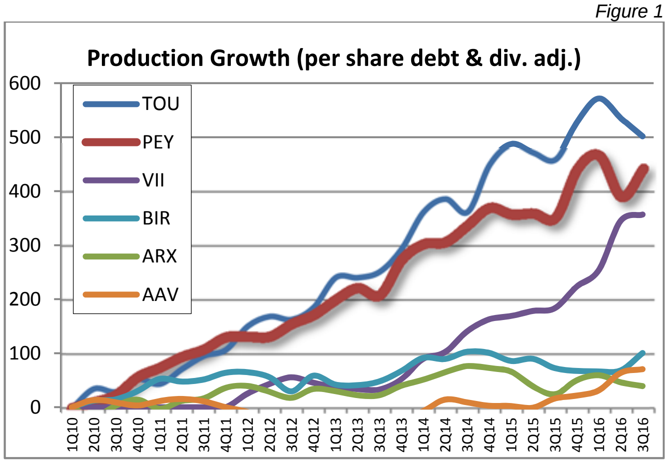
Peyto Exploration & Development Corp.
President's Monthly Report

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

Interesting how the perception of growth and the reality of growth are two different things. Not that we're focused on growth at Peyto anyway; our focus is on returns, with growth as a by-product. But with commodity prices turning, many investors turn to growth. However, when you truly compare growth over time, say production growth, on a debt and dividend adjusted per share basis, which is how I feel investors should compare it, sometimes the results are not what you expect (see Figure 1).

Figure 1



Source: GMP FirstEnergy

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) as well as any production deferrals.

Capital Investment*

*2015/16 Capital Summary (millions$ CND)**

	Q1 15	15	Q3 15	Q4 15	2015	Q1 16	Q2 16	Jul	Aug	Sep	Q3 16	Oct
Acq.	3	0	-6	0	-3	28	0	0	4	1	5	0
Land & Seismic	4	1	4	2	12	4	1	0	0	1	1	1
Drilling	70	59	88	71	287	63	30	20	21	23	64	26
Completions	43	33	44	54	173	33	8	5	11	11	27	10
Tie ins	7	11	15	16	49	12	3	4	6	3	13	4
Facilities	12	12	32	20	76	37	9	1	1	1	4	2
Total	**138**	**117**	**177**	**163**	**594**	**176**	**50**	**30**	**43**	**40**	**114**	**43**

Production*

*2015/16 Production ('000 boe/d)**

	Q1 15	Q2 15	Q3 15	Q4 15	2015	Q1 16	Q2 16	Q3 16	Oct	Nov
Sundance	56.5	57.1	58.2	62.9	**58.7**	60.9	54.3	57.7	60.5	58.6
Ansell	16.8	15.4	12.6	21.2	**16.5**	24.6	19.9	21.0	21.9	21.1
Brazeau	4.3	6.4	6.8	8.9	**6.6**	12.2	10.7	14.2	16.4	17.1
Kakwa	2.2	2.1	1.9	2.1	**2.1**	2.2	2.2	2.0	1.9	2.0
Other	1.7	1.6	1.5	1.7	**1.6**	1.7	1.2	1.4	1.3	1.5
Total	**81.6**	**82.6**	**81.1**	**96.8**	**85.5**	**101.4**	**88.3**	**96.4**	**102.0**	**100.3**
Deferral							**17.4**	**5.7**		

*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.***

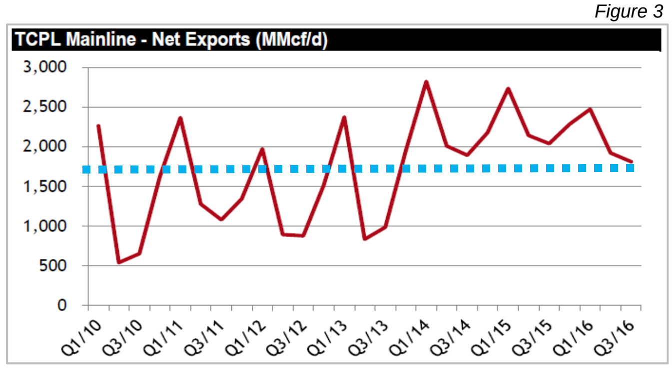
Sooner or Later

TCPL recently announced the results of their mainline open season with insufficient interest by the industry in their proposal for a 10 year, firm service, take-or-pay contract. There were many opinions offered in the aftermath about the fate of the Dawn market. Most of these concluded that western Canadian natural gas producers would all suffer as this market was conceded to cheaper supplies from the Marcellus and US NE. The result would be that natural gas would be backed up into Alberta and the AECO price would fall.

The presumption for this conclusion is that all volumes at AECO are created equal and all suffer equally, which thankfully for Peyto, is not the case. Obviously, some natural gas production in Western Canada is higher cost production and would be shut in first as the price falls. As soon as enough was shut in, the lack of take away capacity on the Mainline would be diminished to the point where gas is no longer being "backed up" and the price would recover. But whose gas is first? And where is it?

Looking at the flows on the mainline into Eastern Canada, it appears we're really talking about 1.7 BCF/d that needs to find a home. And if the toll to get it to Dawn is too high for that gas to be commercial, it will have to compete in another area or be shut in altogether.

Figure 3



Source: CIBC

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Interestingly, the WCSB has about just that amount of gas that is on the bubble to be shut in anyway. A report from EPAC (Figure 4) last fall indicated that in Western Canada we have some 230,000 natural gas wells that produce at rates of less than 20 mcf/d, or 1.6 BCF/d in aggregate. I would argue even with no toll beyond AECO, these wells are producing below their economic limit. Which means they are all losing money at natural gas prices of $3/mcf or less.

Figure 4

Largest Marginal Well Operators — EPAC

Marginal Well Production

Oil Production <5 BOPD

	Company	Wells	Share	BOEPD
1	Cdn Nat Rsrcs Ltd	13351	16%	32,239
2	Husky Oil Oprtns Ltd	9926	12%	23,617
3	Penn West Petrl Ltd	5353	6%	11,962
4	Crescent Point Enrg Corp	5099	6%	12,348
5	Harvest Oprtns Corp	2482	3%	6,123
6	Cenovus Enrg Inc	1736	2%	4,255
7	ARC Rsrcs Ltd	1663	2%	4,192
8	Apache Cda Ltd	1605	2%	3,727
9	Imperial Oil Rsrcs Ltd	1549	2%	3,730
10	Twin Butte Enrg Ltd	1526	2%	3,697
	Other -1248 operators	39092	47%	90,987
	Grand Total	83382	100%	196,878

Gas Production <20 MCFD

Company	Wells	Share	MCFD
Cdn Nat Rsrcs Ltd	49254	22%	344,153
Cenovus Enrg Inc	24937	11%	216,874
Husky Oil Oprtns Ltd	14895	7%	90,492
Crescent Point Enrg Corp	8342	4%	46,381
Penn West Petrl Ltd	8207	4%	50,267
Direct Enrg Marketing Ltd	6648	3%	56,540
Ember Rsrcs Inc	5670	2%	57,857
Enerplus Corp	5484	2%	45,673
Pine Cliff Enrg Ltd	4571	2%	42,965
ConocoPhillips Cda Rsrcs	4287	2%	35,918
Other - 1288 operators	96297	42%	642,842
Grand Total	228592	100%	1,629,961

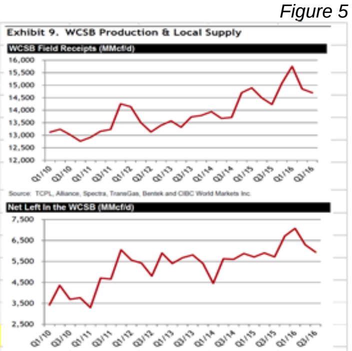
Source: EPAC

When you look at the sheer number of wellbores you start to get a sense as to why they haven't been shut in already. Can you imagine the abandonment cost required to put 230,000 natural gas wells to bed? At an AER prescribed rate of even $50,000/well, that's $11.5 Billion! For many producers, it's just easier to limp them along, losing a little money along the way, rather than spend the capital to abandon and reclaim them.

Sooner or later though, a lower natural gas price will have the inevitable effect of rendering these wells uneconomic and will result in their suspension and abandonment. Then, the problem of 1.7 BCF/d of insufficient market goes away. If we take a look at the current supply demand balance (Figure 5) from Western Canada and how much needs to travel on the mainline, we can get a sense of how necessary a deal really is.

Figure 5

BCF/d	Flows
Total Field Receipts	**14.8**
Alberta	10.0
BC	4.4
Sask	0.4
Total Demands	**14.8**
W. Canadian Consumption	6.0
T-South (1.3 BCF/d cap.)	1.1
Alliance (1.6 BCF/d cap.)	1.6
GTN (2.9 BCF/d cap.)	2.1
Northern Border (1.6 BCF/d cap.)	1.6
Great Lakes/Viking (2.9 BCF/d cap.)	0.7
Mainline to Dawn	1.7



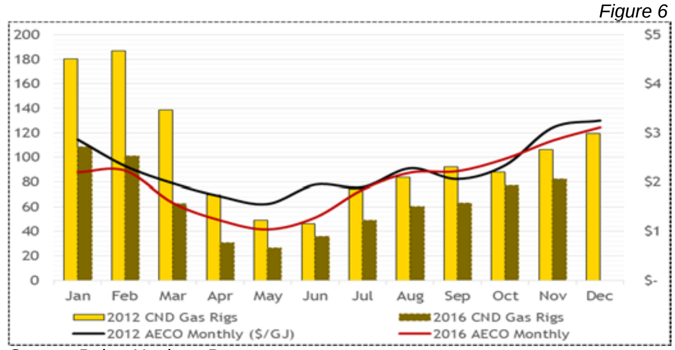
Source: Peyto, CIBC, NEB

The argument might be made that we need that mainline for growth in WCSB volume, not for the marginal gas well. But the reality is that unless TCPL expands their Alberta system Upstream of James River, there is no way to get the growth volume to the mainline anyway, because that's where all the growth is being conceived. Which again makes the mainline less necessary than many think. Either way, Peyto with the lowest supply cost is the best insulated from all this bottleneck.

Activity Levels and Commodity Prices

The prediction of 2016 effectively playing out like 2012 has been bang on. Natural gas prices have dropped and recovered similarly, although with a deeper trough this summer, and both rig count and gas prices have picked up to finish the year at or above where they began (Figure 6).

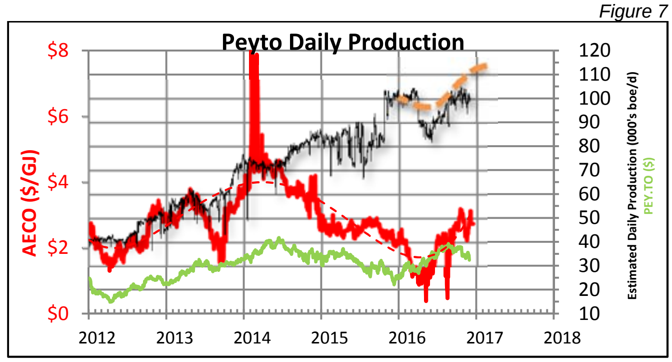
Figure 6



Source: Baker Hughes, Peyto

Our strategy to defer production until later in the year when gas prices were better, but take advantage of low rig counts in the summer to get cheaper services, has also paid off. The only hiccup has just been timing it all to perfection. We were supposed to be north of 110,000 BOE/d by now and taking advantage of the $3/GJ spot prices with flush production. We're not there yet, but it's coming, with 27 fracs lined up from now until the first week of January, we're going to have a very strong year-end surge. That's a downside of pad drilling - frac backlog. Of course, that target assumes we can stuff it in the pipe. High Nova line pressures and restrictions on firm service continue to frustrate those efforts somewhat.

Figure 7



Source: Peyto,TMX