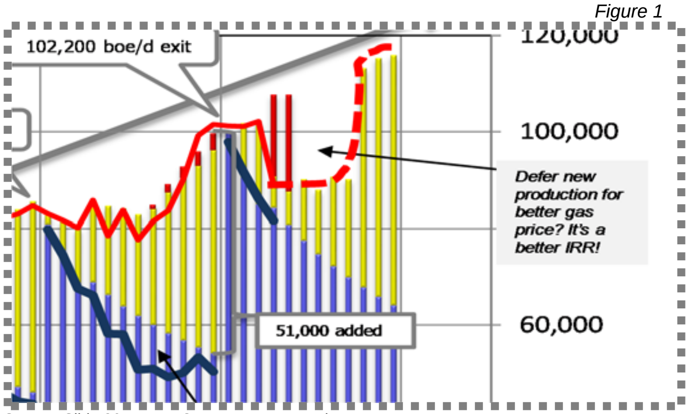
Peyto Exploration & Development Corp.
President's Monthly Report

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

It pays to be nimble. As a result of the severe drop in AECO natural gas prices for this summer, we've decided to defer bringing on any significant new production until the fall, when we can secure, with hedges, a much better price. We'll still drill, complete and tie in new wells to take advantage of discounted service costs, but we can improve the rate of return of those investments by as much as 20% just by delaying the onstream date for six months. The AECO forecast for the next 4 months is currently around $1.50/GJ, while the following twelve months is approximately $2.45/GJ. That dollar makes a big difference on returns, especially when it's for the flush production from a new well. The annual 2016 production and cashflows end up being pretty similar to what we expected before, the profile is just different, see Figure 1.

Figure 1



Source: Slide 36 - Peyto Corporate Presentation

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)**

	2014	Q1	Q2	Q3	Q4	2015	Jan	Feb	Mar	Q1	Apr
Acq.	0.3	3	0	-6	0	-3	0	10	18	28	0
Land & Seismic	21.3	4	1	4	2	12	3	0	1	4	1
Drilling	310.8	70	59	88	71	287	24	23	16	63	8
Completions	183.1	43	33	44	54	173	9	13	11	33	2
Tie ins	51.3	7	11	15	16	49	4	4	4	12	0
Facilities	122.2	12	12	32	20	76	16	13	9	37	3
Total	**690**	**138**	**117**	**177**	**163**	**594**	**56**	**62**	**57**	**176**	**14**

Production*

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

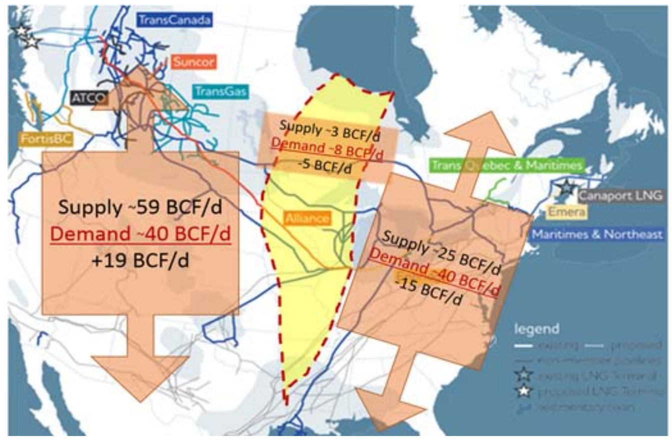
	Q1 15	Q2 15	Q3 15	Q4 15	2015	Jan	Feb	Mar	Q1 16	Apr	May
Sundance	56.5	57.1	58.2	62.9	**58.7**	61.3	61.2	60.1	60.9	54.9	54.0
Ansell	16.8	15.4	12.6	21.2	**16.5**	24.1	23.7	25.8	24.6	20.5	19.1
Brazeau	4.3	6.4	6.8	8.9	**6.6**	11.3	12.7	12.6	12.2	11.2	9.5
Kakwa	2.2	2.1	1.9	2.1	**2.1**	2.1	2.2	2.2	2.2	2.2	2.2
Other	1.7	1.6	1.5	1.7	**1.6**	1.7	1.8	1.5	1.7	0.6	1.2
Total	**81.6**	**82.6**	**81.1**	**96.8**	**85.5**	**100.5**	**101.6**	**102.2**	**101.4**	**89.4**	**86.0**
Deferral										**17.1**	**19.9**

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.

A Battle for the Middle

There's been a bit of a battle going on for market capture in the North American natural gas landscape. Have a look at Figure 2, with what I believe to be the "battleground" highlighted in yellow.

Figure 2



Source: EIA

West of that battleground there is more supply than demand. A quick check of the EIA data (only current to 2014 by State, unfortunately) shows Texas, Oklahoma, Wyoming and Colorado in the USA along with BC, Alberta and Saskatchewan in Canada and other associated gas in Mexico make up almost 60 BCF/d of supply but only around 40 BCF/d of demand.

Meanwhile on the East side of North America, its Pennsylvania, Ohio and West Virginia (collectively the Marcellus and Utica) along with Louisiana and the Gulf of Mexico offshore that make up most of the 25 BCF/d of supply, but they also have over 40 BCF/d of demand when you include Ontario, Quebec, and all of the Eastern seaboard.

In the middle, at the heart of the battle, you have Illinois, Minnesota and Wisconsin with over 8 BCF/d of demand and only Arkansas with much supply, at around 3 BCF/d.

Keep in mind this data is from 2014 which is the most recent regional demand data available on the EIA website. We've seen dramatic increases in supply since then (4-5 BCF/d) but we don't know how the regional demand picture has changed, other than it too is bigger (3 BCF/d). I suspect, however, the regional imbalances remain. Directionally though, this helps explain natural gas prices. What is interesting, is that with so much demand in the East, far outstripping current supply, there is still a localized glut of natural gas that has suppressed Marcellus prices. That rapidly growing supply still can't seem to find its way to the largest amount of demand along the East coast.

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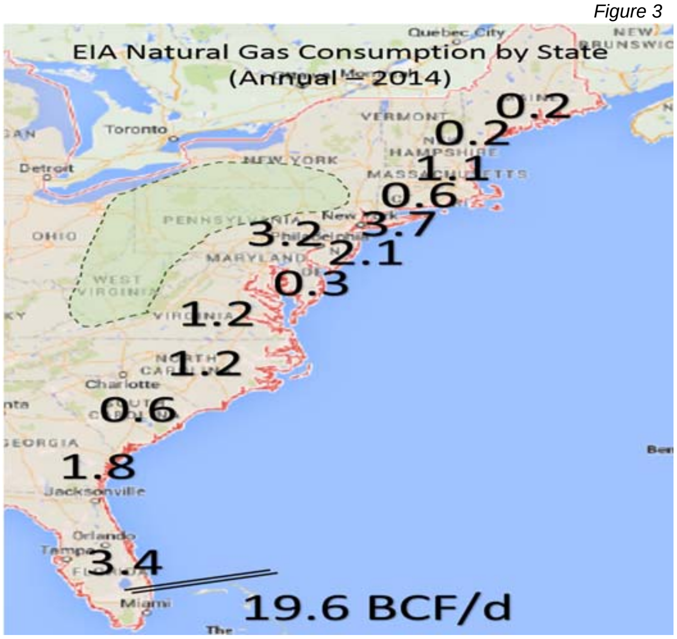
I also find in interesting that there is a perception that the middle ground will be fought over while there exists excess demand further eastward. Why would you fight for a lower priced, competitive market in one direction when you have an existing, uncontested market in the other direction?

Figure 3



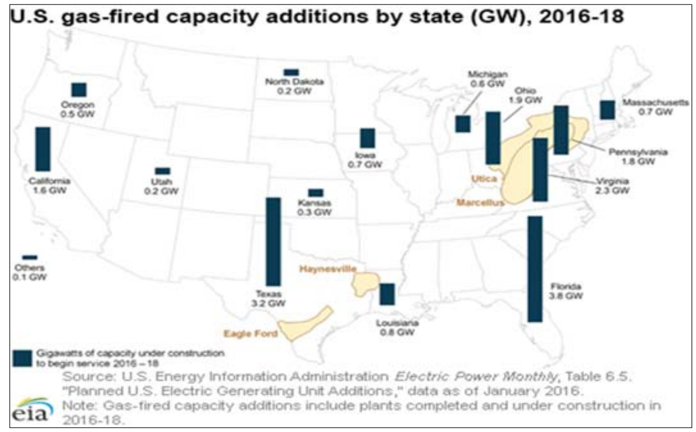
Source: EIA

Considering the size of the market on just the eastern coastline alone (see Figure 3), which is equivalent to all of the Marcellus and Utica production currently, you would think that would be the first order of business for capturing market share.

When thinking of broader North American natural gas flows, I think it's also important to keep in mind the value of the commodity when considering how far it can travel. If natural gas is only worth $3/MMBTU long term due to an abundance of supply, losing half the value of it in transportation cost to reach a far off market doesn't make much sense. A decade from now we may look back at the practice of shipping natural gas across the entire continent as ridiculous and unnecessary with the flows in the future being dominated by a north-south direction more than a traditional west-east one.

It's too bad we can't access more real time consumption data. As a producing industry we have enormous amounts of supply data that tends to dominate the discussion, but consumption data, both past and forecast, always seems to be lacking. Perhaps that's why we're always concerned about supply and supply growth rather than demand growth, like the upcoming power generation capacity set to add another 3 BCF/d of permanent demand (see Figure 4).

Figure 4



Source:EIA

Activity Levels and Commodity Prices

"History never repeats itself but it rhymes" is attributed by some to Mark Twain. And while who said it may be up for debate, the suggestion is still very appropriate, especially as it pertains to today's natural gas markets. Much of what we're seeing today, we've seen before in some form or another.

In the spring of 2012, for instance, we were concerned by the gas storage levels in North America that were 900 BCF too high exiting the heating season. Like today's 1.0 TCF, the result of a warm El Nino winter. At the time, there were calls for natural gas prices to go to zero because storage had never been so bloated. It was predicted that it would take years to work off so much gas. But by the fall of that year, we'd used more gas in place of coal for electricity generation and consumed more gas in industrial manufacturing, that the surplus was all but gone. With that experience of 2012, we are less worried about the same phenomenon today.

Then in 2013, the AECO to Henry Hub differential widened significantly as a result of a lack of existing long haul contracts on TCPL's mainline. Incredibly high interruptible rates were charged to encourage consumers to sign up for firm contracted deliveries. The result pushed AECO prices, in advance of the fall contract renewal dates, down substantially. Then, in October of that year, AECO prices rapidly recovered, in time for the November 1 contracts. Again we find ourselves in a similar situation with some 600 MMcf/d up for renewal. This helps explain why the differential is predicted to close significantly in the fall.

We should probably expect that prices will continue to be volatile as we move forward. All the more reason we need to remain nimble at Peyto, in control of as much of our value chain so we can to continue to maximize returns for shareholders.