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ENERGY UPDATE
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North American Natural Gas Outlook

Market Dynamics Shift this Summer

May 23, 2012

Summary

With the end of the winter withdrawal season setting a new record high for natural gas storage levels, it is no surprise that the outlook for storage levels through the current injection season remains strained. While last year many producers did not anticipate natural gas prices remaining below US$4.00 per Mcf, the outlook this summer could see prices below US$2.00 per Mcf, and possibly lower at certain hubs as storage fills. While this price level for natural gas is unsustainable, given that U.S. natural gas storage levels are ~770 BCF above the prior year, demand will require low natural gas prices to stimulate power consumption, along with a sustained decrease in the U.S. natural gas directed rig count in order to keep storage levels within capacity limits. The recent growth in power demand has provided some reprieve to offset robust natural gas supply, and has provided some recent optimism for the outlook of natural gas. While we continue to forecast that power demand will remain robust this summer (up 16% year-over-year), we still believe that this will not be enough to move natural gas prices to a more sustainable level this summer, as the significant amount of coal to natural gas switching will mean higher natural gas prices, thereby pushing power generation back to favoring coal. Over the long term, we expect increasing power demand responses to the decline in natural gas prices, however, without a major external event (hurricane, environmental regulation change), a reduction in supply remains an imperative factor to rebalance the supply/demand equation.

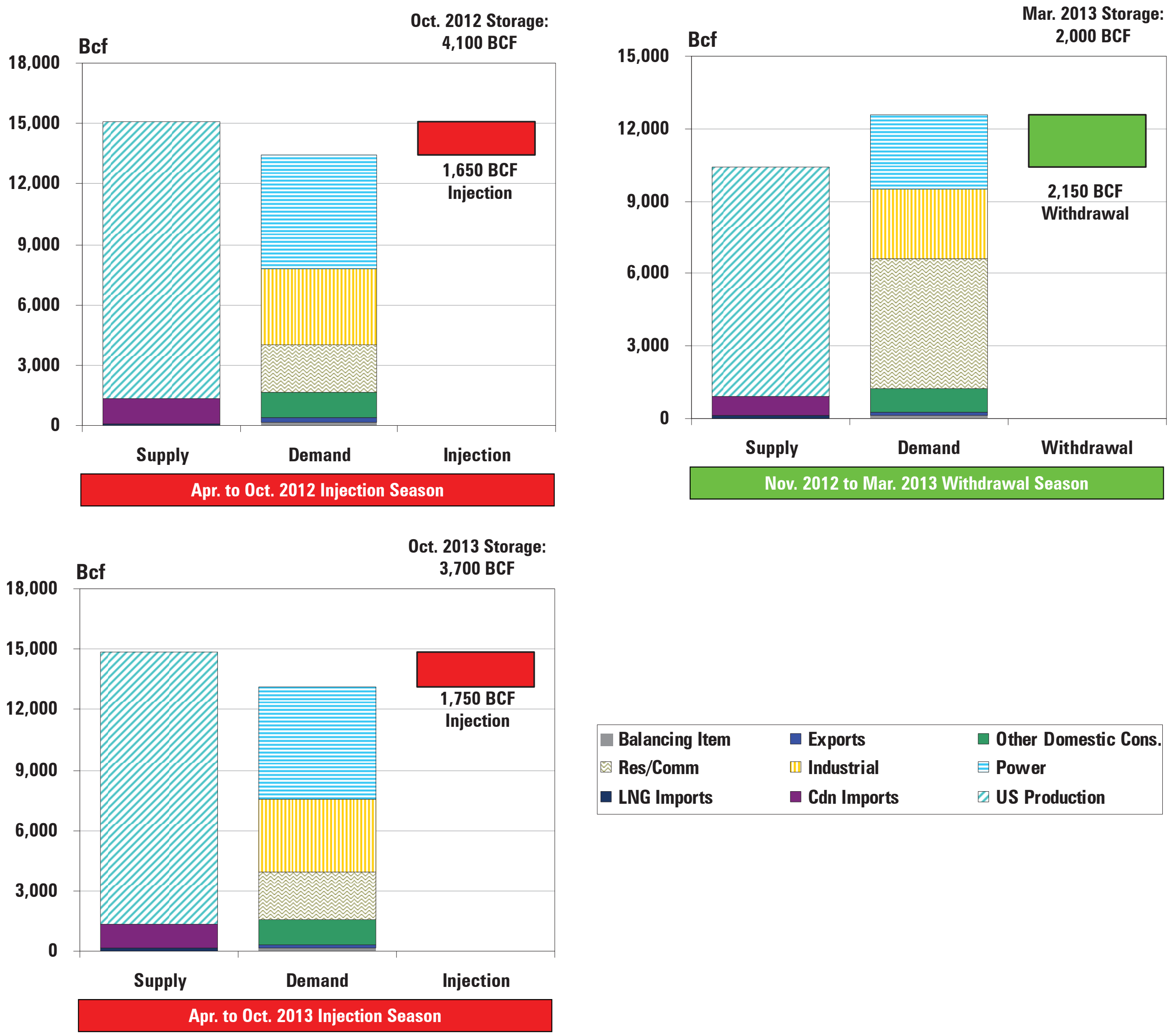
On the supply side, the significant year-to-date decline in the natural gas directed rig count has been a positive initial indication to eventually mitigate supply. Our updated forecast is for a 2012 average U.S. natural gas directed rig count of 600 rigs (1,900 rigs in total) and a U.S. base decline rate of 30%, which results in a decline in U.S. dry natural gas production of approximately 2.3 BCF/d year-over-year by the end of 2012, to 63.2 BCF/d. Further, our updated forecast for a 2013 average natural gas directed rig count of 620 rigs (1,975 rigs in total) and U.S. base decline rate of 29% results in a year-end 2013 exit production rate of 63.1 BCF/d. The key contributor to the forecast decline in natural gas production is expected to be a result of the significant drops in the Haynesville Shale rig count to 60 rigs and 55 rigs in 2012 and 2013, respectively, down from an average of 140 rigs in 2011. This decline, along with a pull back in a number of other natural gas fields, is partially offset by supply contribution from the Marcellus as well as associated natural gas from oil and liquids rich drilling.

Based on our revised supply and demand estimates, we forecast the 2012 injection season will end with natural gas in storage of 4.1 TCF, testing the U.S. storage capacity limits. However, with a lower production level entering the winter withdrawal season, the supply/demand balance is expected to improve in 2013, with our forecast for natural gas in storage at the end of the 2013 injection season of 3.7 TCF being in line with the historic five-year average. More concerning is the storage situation in Canada, as the decline in exports to the U.S. and the modest change in domestic demand has resulted in a significant accumulation of natural gas in storage. While the outlook for hydro and nuclear generation in the west could potentially increase demand for Canadian natural gas, we remain cautious in our near-term outlook for WCSB natural gas prices.

The important themes to focus on this summer include:

- Haynesville Shale rig count and production levels
- Marcellus production as behind pipe production is brought on-stream
- Associated natural gas production

U.S. Natural Gas in Storage Estimates



Source: Peters & Co. Limited estimates.

- Power demand
- Canadian natural gas flows

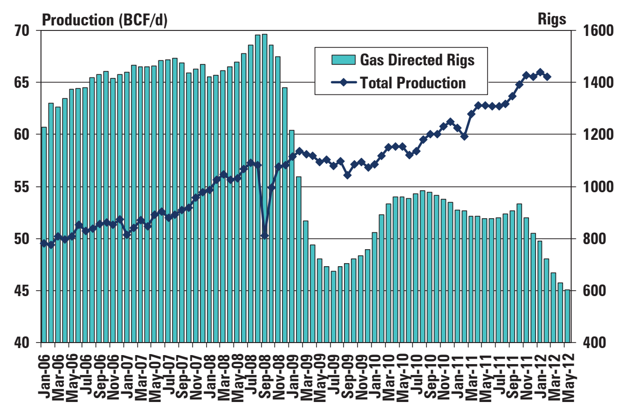
U.S. Supply

A Focus on the Haynesville Shale; Marcellus Growth remains Robust

The natural gas directed rig count has declined to ~550 rigs, down substantially from over 800 rigs in late 2011. However, as shown in the accompanying chart (page 3), the last material downturn in the natural gas directed rig count in 2009 only led to a modest (~2 BCF/d) decline in production, which was a result of lower activity levels in combination with shut in production volumes. Natural gas volumes continue to be buoyed by associated natural gas from many of the new oil plays.

Overall, the shift towards shale gas developments has changed the average productivities and the base decline rate of the U.S. natural gas supply. At the start of 2012, a select list of the major U.S. natural gas shale plays accounted for ~35% of U.S. natural gas production, up from less than 10% at the beginning of 2008, with the majority of the growth

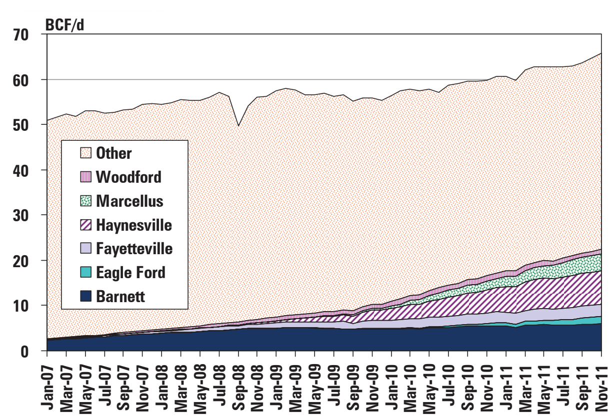
U.S. Daily Marketed Dry Gas Production vs. Gas Directed Rigs



Source: Energy Information Administration, Baker-Hughes.

coming from the Haynesville and Marcellus. This growth in horizontal multi-frac drilling activities has resulted in a higher base decline rate (~30%), and we expect this decline rate will be more apparent this summer given the expected pullback in activity levels.

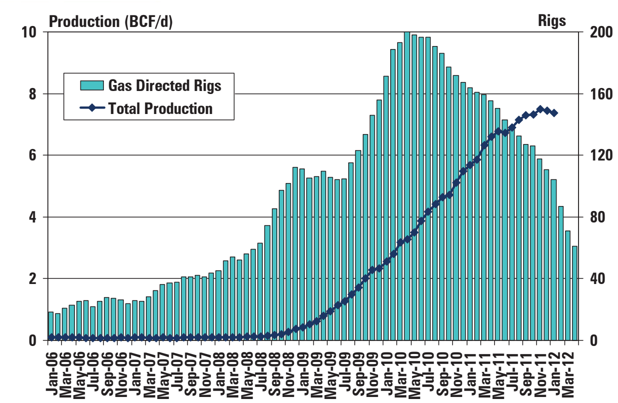
U.S. Dry Natural Gas Production



Sources: E.I.A., Drilling Info, Inc., and Peters & Co. Ltd. estimates.

One of the key reasons for the growth in supply over the past three years has been driven by prolific wells in the Haynesville Shale, in addition to the significant backlog of over 400 Haynesville wells which were drilled and awaiting tie in during 2010 and 2011. We believe that the majority of this backlog has cleared and, with the significant decline in the active rig count, we anticipate a decline in Haynesville production will occur this summer, providing a more bullish outlook for the supply/demand balance in late 2012/early 2013. Haynesville production at the beginning of 2012 was ~7.4 BCF/d (~11% of total U.S. supply) and we estimate that natural declines would result in a reduction of ~4 BCF/d over a 12-month period. Based on our estimate of per well productivities, we believe an active rig count of ~75 rigs would be required to keep production levels flat in this play, which compares to our current Haynesville rig count forecasts of 60 rigs and 55 rigs in 2012 and 2013, respectively. As a result, we believe the current rig count will only replace approximately 80% of declines, resulting in an overall decline of 0.8 BCF/d year-over-year. We estimate that a change in the Haynesville average active rig count by 10 rigs would result in an ~100 BCF change in natural gas supply in 2012, making U.S. natural gas production highly sensitive to activity levels in this play.

Haynesville Production vs. Haynesville Gas Directed Rigs



Source: Smith International.

U.S. Active Rig Count by Key Play

	Play	2011 Average	2012E Average	2013E Average
Gas	Barnett Shale	56	35	35
	Eagle Ford Shale	90	65	75
	Fayetteville Shale	30	30	30
	Haynesville Shale	140	60	55
	Marcellus Shale	102	90	95
	Other	468	320	330
Total Gas		**885**	**600**	**620**
Oil	Anadarko Basin	78	170	180
	Bakken	168	210	220
	Eagle Ford Shale	92	175	185
	Permian Basin	318	410	420
	Other	219	335	350
Total Oil		**874**	**1,300**	**1,355**
Grand Total		**1,760**	**1,900**	**1,975**

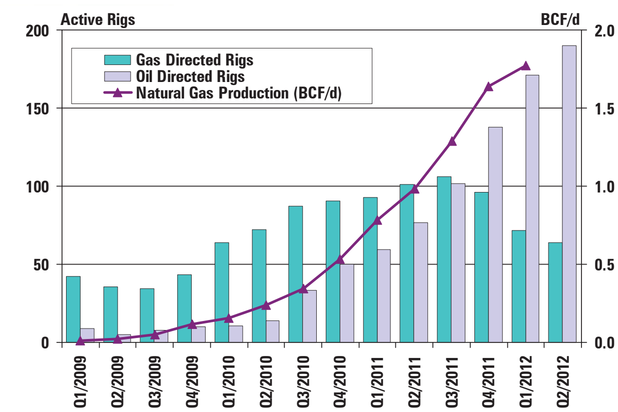
Source: Smith International and Peters & Co. estimates.

In the Marcellus, a number of pipeline and infrastructure expansions were added in late 2011, including the TGL 300 expansion (compression of 350 MMcf/d), Tioga pipeline extension (take-away capacity of 350 MMcf/d), and the North and South expansions (compression of 325 MMcf/d) which are estimated to have increased total dry natural gas production from the play to over 5 BCF/d currently. In contrast to the declining rig count in the Haynesville, the Marcellus rig count has remained fairly flat at between 90 and 100 rigs since Q4/10. As such, we continue to estimate that the backlog of wells awaiting completions and tie in total ~300 wells. While a number of operators have indicated plans for reduced activities in the area (Talisman and Ultra), other operators are indicating higher productivity wells, strong economics in the liquids rich window, and continued activity. Further, additional infrastructure expansions are planned over 2012 and 2013 which are expected to improve connections to premium-priced natural gas hubs in New York and increase NGL recoveries, particularly ethane. As such, we forecast that production growth in the Marcellus will remain robust in 2012 and 2013, with our forecasts for active rig counts in 2012 and 2013 of 90 rigs and 95 rigs respectively, and providing some offset to declines in other areas.

Associated Gas

While the U.S. natural gas directed rig count has experienced a decline since the start of 2012, associated natural gas production from oil and liquids rich natural gas directed drilling continues to contribute towards total U.S. natural gas supply. As an example, in the Eagle Ford shale there has been a substantial shift in the active rig count towards oil and liquids rich directed drilling and away from dry natural gas directed drilling. The accompanying chart shows that, to date in the second quarter of 2012, the natural gas directed rig count has decreased to approximately 60 rigs, down by ~40 rigs since Q3/11, while the oil directed rig count has increased to 190 rigs, up by 90 rigs since Q3/11. However, total natural gas production has not shown any decline corresponding to the decrease

Eagle Ford Oil and Natural Gas Activity



Source: Smith International and Drilling Info, Inc.

U.S. Production Summary

	Arkansas	Colorado	Louisiana	Marcellus*	New Mexico	Oklahoma	Texas	Wyoming	Total U.S.***
2010 Average Production (BCF/d)	2.0	3.7	6.1	1.4	3.7	5.0	20.8	6.9	***59.1***
2010 Exit Production (BCF/d)	2.3	3.8	7.2	2.0	3.7	5.0	21.4	6.7	***61.2***
2011 Average I.P. rate (Mcf/d) **	1940	410	5640	4000	260	990	1180	920	***1300***
2011 Beginning of year Decline Rate **	35%	31%	38%	54%	12%	14%	29%	22%	***28%***
2011 Average Production (BCF/d)	2.4	3.6	8.4	3.3	3.6	5.2	21.7	6.5	***63.0***
2011 Exit Production (BCF/d)	2.5	3.4	9.0	4.3	3.6	5.4	22.2	6.6	***65.5***
2011 Forecast Average Production YoY Change (BCF/d)	***0.3***	***-0.1***	***2.3***	***1.9***	***-0.1***	***0.2***	***0.9***	***-0.4***	***3.9***
2012 Average I.P. rate (Mcf/d) **	1620	360	5520	4800	250	840	1070	830	***1310***
2012 Beginning of year Decline Rate **	35%	31%	35%	51%	12%	13%	31%	25%	***29%***
2012 Average Production (BCF/d) ***	2.3	3.3	7.9	5.1	3.6	5.3	22.4	6.1	***64.6***
2012 Exit Production (BCF/d)	2.2	3.4	6.8	5.3	3.5	5.3	22.7	5.6	***63.2***
2012 Forecast Average Production YoY Change (BCF/d)	***0.0***	***-0.3***	***-0.5***	***1.8***	***0.0***	***0.1***	***0.7***	***-0.4***	***1.6***
2013 Average I.P. rate (Mcf/d) **	1560	320	5580	5000	260	830	1140	810	***1310***
2013 Beginning of year Decline Rate **	34%	29%	40%	45%	12%	16%	31%	23%	***29%***
2013 Average Production (BCF/d)	2.2	3.4	6.2	6.1	3.4	5.2	23.4	5.4	***63.3***
2013 Exit Production (BCF/d)	2.2	3.4	5.7	6.6	3.3	5.2	23.7	5.1	***63.1***
2013 Forecast Average Production YoY Change (BCF/d)	***-0.1***	***0.1***	***-1.7***	***0.9***	***-0.2***	***-0.1***	***1.0***	***-0.7***	***-1.3***

* Estimated total Marcellus values inclusive of all producing states.

** Average I.P. rate and decline rate values for total U.S. are estimated based on forecasts for all regions shown above and base assumptions for remaining producing regions. Regions shown above account for ~83% of total forecast U.S. production.

** 2012 production shut ins are incorporated in our total U.S. production estimates only, and are not forecasted on a state-level.

Source: Drilling Info, Inc., EIA, and Peters & Co. Limited estimates.

in natural gas directed rig activity. We estimate that ~85% of the 1.7 BCF/d current natural gas production is derived from oil and liquids rich natural gas drilling in the play.

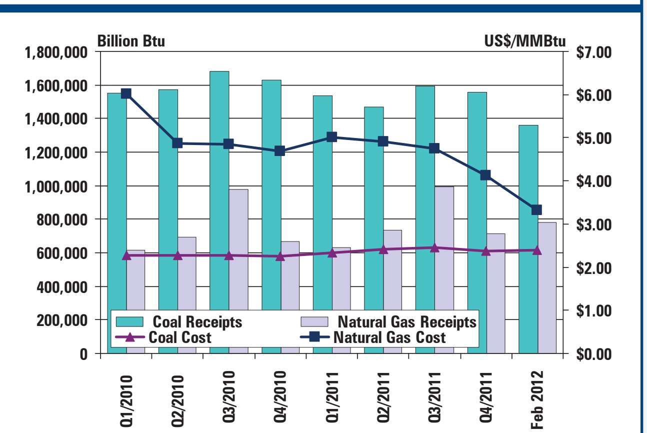
While the proportional oil and gas mix of total production from the entire play has increased to being over 50% oil-weighted, as producers target the oilier and richer parts of the pool, up from 40% oil-weighted in late 2010, there is significant associated natural gas coming from oil and liquids rich drilling activity. Based on our analysis, we estimate that natural gas production from oil and liquids rich drilling in 2011 added ~1 BCF/d of natural gas production and would equate to an additional 55 effective rigs operating in the dry gas play, highlighting that the effective natural gas directed rig count based on natural gas production additions from the entire field would be significantly higher than reported.

U.S. Demand

Hope in Power Demand?

With the continued decline in natural gas prices, natural gas fired power has become very competitive with base load coal fired plants. The EIA reported February power demand of 22.4 BCF/d, up by 5.2 BCF/d, or 30%, year-over-year. As shown below, while the average cost of purchased coal has stayed relatively flat over the past year, the average cost (including contractual supply) of natural gas has declined by ~34% year-over-year, corresponding with the year-over-year increase in demand. Growth in power consumption has played an important role in offsetting weak residential/commercial demand from a mild winter. Given the current forward prices for natural gas, we expect that demand from this sector will remain robust, and we have incorporated a year-over-year power demand increase of 16% this summer. While reduced snowpack levels and nuclear power outages this summer will increase power demand from other sources, historically, summer cooling demand has resulted in higher utilization levels for both base load (coal) and peak load (natural gas and other hydrocarbons) plants, providing less opportunity for one fuel source to displace the other. Additionally, with energy-equivalent coal and natural gas prices being very competitive in many regions, coal-gas switching will provide additional demand for natural gas in a low price environment, but coal pricing will also set a ceiling for natural gas prices when power producers see moderate shifts in relative pricing during off-peak seasons.

Receipts and Average Cost of Coal and Natural Gas Quarterly Averages



Source: E.I.A.

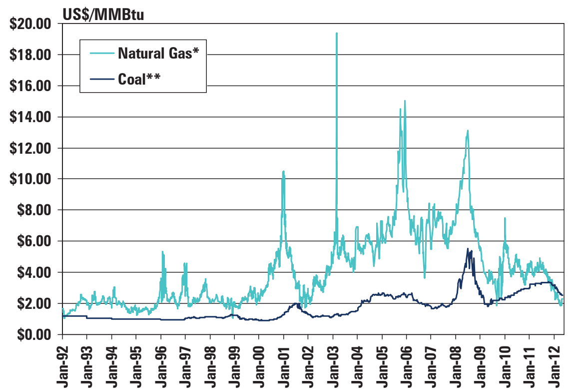
The chart (below left) highlights the historic fuel demand for coal and natural gas in the power sector. As shown, the latest reported EIA data shows the year-over-year increase in natural gas demand for power compared to the decline in the average fuel cost of natural gas relative to coal. With the continued decline in natural gas prices over recent months, this coal-gas switching trend is expected to remain. Notably, the average cost of coal and natural gas shown would be prices paid by power generators, including a mix of contracted and spot prices, provides a longer-term perspective on relative fuels costs. The second and third accompanying charts (page 6) show only the spot market prices and price differentials for natural gas and coal benchmark products. Interestingly, for the first time in approximately 20 years, since late 2011 spot natural gas prices have traded for a sustained period at prices below spot coal, corresponding to the recent increase in natural gas demand in the power sector. However, the spot price of coal has also been declining, resulting in a spot differential of only –US$0.50 per MMBtu.

Canadian Supply/Demand

Where will WCSB supplies go?

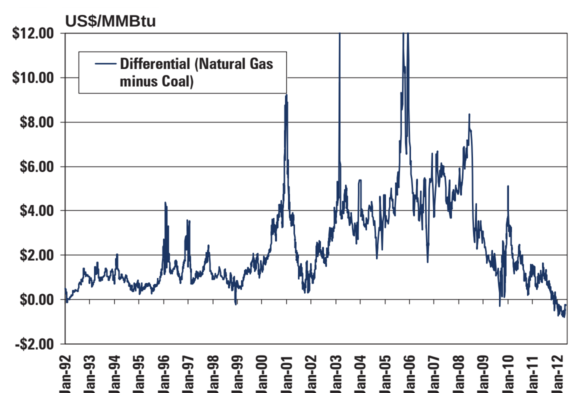
While power demand growth in the U.S. has provided some offset to the milder winter, Canadian demand was down 4% year-over-year this past winter as a result of lower residential/commercial heating demand and minimal increases in industrial consumption. Further, natural gas exports to the U.S. were down 17% year-over-year, resulting in record high Canadian storage levels. Canadian natural gas in storage is currently ~520 BCF, up by ~110%, or 270 BCF over the prior year, and compares to the estimated working

Coal versus Natural Gas Spot Pricing



Source: Bloomberg, Peters & Co. Limited estimates. *New York Henry Hub spot, ** Big Sandy barge spot using 12,000 Btu/lb conversion ratio.

Coal versus Natural Gas Differential



Source: Bloomberg, Peters & Co. Limited estimates. *New York Henry Hub spot, ** Big Sandy barge spot using 12,000 Btu/lb conversion ratio.

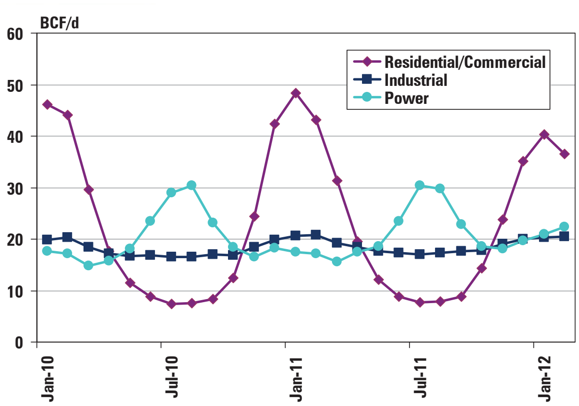
gas capacity of ~700 BCF. Based on our current activity level forecast for 11,400 wells (12% natural gas) in 2012 and 11,900 wells (13% natural gas) in 2013, we estimate that WCSB natural gas production will remain relatively flat in 2012 and 2013.

With our forecast for moderate demand growth this summer, driven primarily by oil sands demand, combined with the record high storage levels in Canada, Canadian storage levels could reach capacity by August. As a result, we expect that shut ins will be an important component of keeping storage levels within capacity this injection season, and the AECO-NYMEX differential may widen above the current level of ~US$0.50 per Mcf. One important factor will be the summer market for Canadian natural gas in the PacNW and California. With the expectation for lower hydro-generation due to lower snowpack levels, Canadian natural gas flows could be robust on the TransCanada GTN and Spectra Westcoast lines, potentially alleviating some storage concerns. Overall, the near-term outlook for Canadian natural gas remains weak, with more shut in volumes expected this spring. To date, major shut ins in Canada have been announced by Encana (~340 MMcf/d) and Progress (~30 MMcf/d), with minor shut ins announced by numerous other producers.

Natural Gas Price Sensitivity

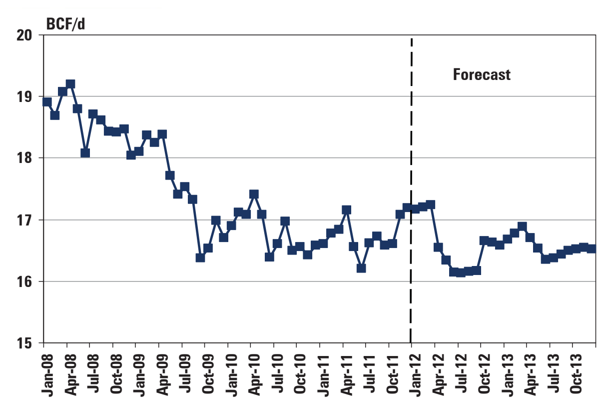
We have included a sensitivity analysis for our E&P coverage universe (page 8), highlighting each entity's sensitivity to a potential increase in the 2012 NYMEX

U.S. Natural Gas Demand



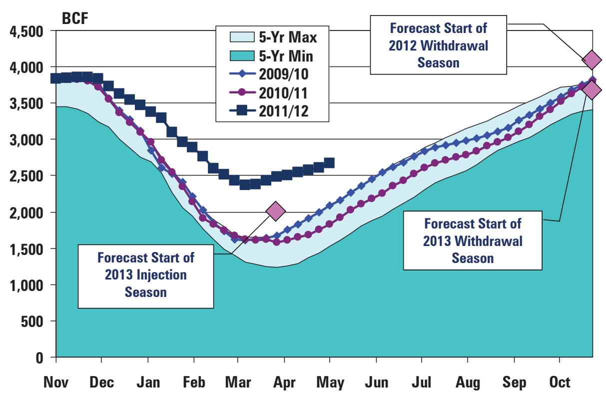
Source: E.I.A.

Western Canadian Raw Natural Gas Production



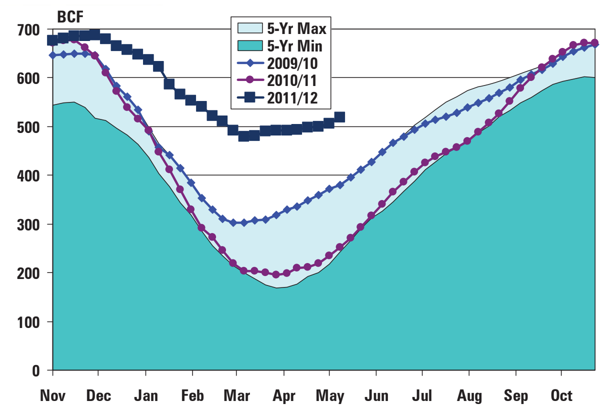
Sources: geoSCOUT and Peters & Co. Limited forecast.

U.S. Gas Storage



Source: Energy Information Administration.

Canada Gas Storage



Sources: Bloomberg and Canadian Enerdata.

Henry Hub and AECO-C natural gas prices. Our base case assumes current 2012 NYMEX Henry Hub and AECO-C strip prices of US$2.74 per Mcf and C$2.24 per MCF, respectively. Our high case assumes a US$0.50 per Mcf change to our base case NYMEX assumption and a C$0.50 per MCF change to our base case AECO-C assumption for the remainder of 2012.

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2012E Natural Gas Price Change Comparative - High Case (NYMEX Henry Hub: US$3.05/MMBtu, AECO-C Spot: C$2.56/Mcf)

			Base Case FY12 Estimates*						High Case FY12 Estimates**						% Change
Company	Ticker	18-May-12 Price	CFPDS	Cash Flow per BOE	Cash Flow	Net Debt	D/CF	EV/DACF	CFPDS	Cash Flow per BOE	Cash Flow	Net Debt	D/CF	EV/DACF	in Cash Flow
Canadian Large/Integrated Producers															
Talisman Energy Inc.	TLM	$10.05	$3.06	$19.97	$3,138	$5,305	1.7	5.0	$3.16	$20.60	$3,237	$5,205	1.6	4.8	3%
Penn West Petroleum Ltd.	PWT	$14.03	$2.64	$20.44	$1,251	$4,415	3.5	7.4	$2.71	$20.98	$1,284	$4,382	3.4	7.2	3%
Canadian Natural Resources	CNQ	$29.95	$6.57	$29.97	$7,388	$9,335	1.3	5.6	$6.67	$30.44	$7,505	$9,217	1.2	5.5	2%
Cenovus Energy Inc.	CVE	$31.56	$4.56	$31.56	$3,464	$3,589	1.0	7.3	$4.62	$32.09	$3,510	$3,543	1.0	7.2	1%
Husky Energy Inc.	HSE	$22.89	$4.23	$27.29	$4,151	$1,711	0.4	5.5	$4.28	$27.73	$4,199	$1,663	0.4	5.4	1%
Nexen Inc.	NXY	$16.12	$4.47	$35.60	$2,572	$4,107	1.6	5.0	$4.50	$35.86	$2,590	$4,088	1.6	4.9	1%
Crescent Point Energy Corp.	CPG	$39.94	$4.44	$42.86	$1,432	$1,729	1.2	10.0	$4.45	$43.02	$1,437	$1,723	1.2	10.0	0%
Imperial Oil Limited	IMO	$41.08	$5.60	$27.13	$4,773	$3,292	0.7	8.0	$5.62	$27.27	$4,788	$3,277	0.7	7.9	0%
Suncor Energy Inc.	SU	$27.40	$5.81	$33.37	$9,121	$5,580	0.6	5.1	$5.81	$33.37	$9,121	$5,580	0.6	5.1	0%
Canadian Oil Sands Ltd.	COS	$20.50	$2.87	$37.78	$1,473	$843	0.6	7.2	$2.84	$37.44	$1,459	$857	0.6	7.3	-1%
MEG Energy Corp.	MEG	$37.62	$1.13	$25.83	$255	$1,376	5.4	29.4	$1.12	$25.54	$253	$1,379	5.5	29.7	-1%
CDN Large/Integrated Median				*$29.97*			*1.2*	*7.2*		*$30.44*			*1.2*	*7.2*	*1%*
U.S. Large Producers - All values are NET of royalties, and stated in US$.															
EnCana Corporation	ECA.US	$19.63	$4.63	$18.76	$3,407	$6,237	1.8	5.6	$4.86	$19.73	$3,581	$6,063	1.7	5.3	5%
Devon Energy Corporation	DVN.US	$61.43	$12.68	$18.76	$5,387	$4,833	0.9	5.4	$13.02	$19.28	$5,522	$4,699	0.9	5.2	2%
EOG Resources Inc.	EOG.US	$96.31	$20.43	$33.59	$5,674	$6,136	1.1	5.6	$20.70	$34.02	$5,747	$6,064	1.1	5.5	1%
Apache Corporation	APA.US	$80.52	$26.31	$35.89	$10,616	$9,446	0.9	3.8	$26.53	$36.19	$10,705	$9,358	0.9	3.8	1%
U.S. Prod Median				*$26.18*			*1.0*	*5.5*		*$26.88*			*1.0*	*5.3*	*2%*
Intermediate Producers															
Paramount Resources Ltd.	POU	$26.96	$0.64	$6.54	$56	$82	1.5	26.9	$0.81	$8.31	$71	$67	0.9	22.9	27%
Progress Energy Resources Corp.	PRQ	$10.96	$0.63	$9.23	$152	$540	3.5	17.8	$0.71	$10.36	$171	$521	3.0	16.0	12%
Birchcliff Energy Ltd.	BIR	$6.01	$0.74	$14.07	$115	$506	4.4	10.6	$0.83	$15.57	$127	$494	3.9	9.6	11%
Celtic Exploration Ltd.	CLT	$12.53	$1.31	$16.27	$141	$367	2.6	11.2	$1.44	$17.91	$155	$353	2.3	10.2	10%
Tourmaline Oil Corp.	TOU	$24.73	$1.67	$15.62	$285	$292	1.0	15.0	$1.84	$17.12	$312	$265	0.8	13.6	10%
Peyto Expl. & Development Corp.	PEY	$18.30	$2.04	$18.04	$282	$630	2.2	10.3	$2.16	$19.11	$299	$613	2.1	9.8	6%
Bonavista Energy Corporation	BNP	$18.51	$2.55	$16.70	$428	$1,133	2.6	8.8	$2.69	$17.59	$451	$1,110	2.5	8.4	5%
Trilogy Energy Corp.	TET	$24.80	$2.77	$23.06	$321	$558	1.7	10.0	$2.89	$24.11	$336	$543	1.6	9.6	5%
Enerplus Corporation	ERF	$14.00	$2.68	$17.73	$531	$1,634	3.1	7.7	$2.81	$18.54	$556	$1,610	2.9	7.3	5%
Pengrowth Energy Corporation	PGF	$7.45	$1.34	$18.54	$603	$1,934	3.2	8.4	$1.39	$19.28	$626	$1,910	3.0	8.1	4%
NAL Energy Corporation	NAE	$6.38	$1.40	$20.56	$214	$617	2.9	6.6	$1.45	$21.33	$222	$609	2.7	6.4	4%
ARC Resources Ltd.	ARX	$20.27	$2.34	$20.11	$682	$1,090	1.6	9.8	$2.41	$20.64	$700	$1,072	1.5	9.6	3%
Crew Energy Inc.	CR	$5.09	$1.48	$17.88	$185	$358	1.9	5.1	$1.52	$18.33	$189	$353	1.9	5.0	2%
Whitecap Resources Inc.	WCP	$7.10	$1.79	$38.09	$210	$360	1.7	5.8	$1.81	$38.57	$213	$358	1.7	5.7	1%
Baytex Energy Corp.	BTE	$45.50	$4.70	$28.20	$560	$392	0.7	10.0	$4.74	$28.42	$564	$387	0.7	9.9	1%
Vermilion Energy Inc.	VET	$42.86	$5.19	$36.66	$508	$639	1.3	9.3	$5.23	$36.94	$512	$635	1.2	9.3	1%
PetroBakken Energy Ltd.	PBN	$11.12	$3.22	$38.08	$621	$1,922	3.1	5.6	$3.24	$38.34	$625	$1,918	3.1	5.6	1%
Legacy Oil + Gas Inc.	LEG	$7.60	$1.54	$37.74	$227	$490	2.2	6.5	$1.54	$37.91	$228	$489	2.1	6.5	0%
BlackPearl Resources Inc.	PXX	$3.76	$0.31	$25.10	$93	$22	0.2	12.7	$0.31	$25.11	$93	$22	0.2	12.7	0%
Connacher Oil and Gas Limited	CLL	$0.65	$0.12	($1.37)	$55	$905	16.4	8.7	$0.12	($1.37)	$54	$905	16.6	8.8	-1%
Interm Prod Median				*$18.29*			*2.2*	*9.6*		*$19.19*			*2.1*	*9.4*	*4%*
Junior Producers															
Compton Petroleum Corporation	CMT	$1.36	$0.43	$3.52	$15	$164	10.6	8.3	$0.56	$4.41	$19	$160	8.3	7.0	25%
Cequence Energy Ltd.	CQE	$1.40	$0.16	$7.55	$25	$77	3.1	11.3	$0.19	$9.24	$31	$72	2.3	9.2	22%
Fairborne Energy Ltd.	FEL	$1.75	$0.53	$10.16	$55	$149	2.7	5.3	$0.60	$11.51	$62	$142	2.3	4.6	13%
NuVista Energy Ltd	NVA	$3.22	$1.00	$10.92	$99	$304	3.1	5.5	$1.13	$12.31	$112	$292	2.6	4.9	13%
Yoho Resources Inc.	YO	$2.02	$0.23	$12.04	$12	$26	2.2	10.8	$0.25	$12.86	$13	$25	2.0	10.0	7%
Perpetual Energy Inc.	PMT	$0.85	$0.29	$5.40	$42	$402	9.6	7.3	$0.30	$5.73	$44	$399	9.0	7.1	6%
Storm Resources Ltd.	SRX	$1.90	$0.30	$18.68	$17	$51	3.0	8.9	$0.32	$19.80	$18	$50	2.8	8.4	6%
Delphi Energy Corp.	DEE	$1.24	$0.32	$13.43	$47	$120	2.5	6.0	$0.34	$14.20	$50	$118	2.4	5.6	6%
Chinook Energy Inc.	CKE	$1.17	$0.37	$17.65	$84	$87	1.0	3.9	$0.40	$18.65	$89	$82	0.9	3.7	6%
Angle Energy Inc.	NGL	$4.31	$1.14	$16.22	$94	$240	2.6	5.8	$1.20	$17.14	$99	$235	2.4	5.5	6%
Tamarack Valley Energy Ltd.	TVE	$0.16	$0.06	$24.77	$19	$38	2.0	4.9	$0.06	$25.84	$20	$37	1.9	4.7	4%
RMP Energy Inc.	RMP	$1.69	$0.45	$23.68	$45	$77	1.7	5.2	$0.47	$24.65	$46	$75	1.6	5.0	4%
Zargon Oil & Gas Ltd.	ZAR	$10.47	$1.99	$19.42	$60	$146	2.4	7.0	$2.05	$19.92	$61	$145	2.4	6.9	3%
Surge Energy Inc.	SGY	$7.33	$1.39	$30.02	$107	$195	1.8	6.8	$1.41	$30.52	$108	$193	1.8	6.6	2%
Twin Butte Energy Ltd.	TBE	$2.41	$0.54	$21.92	$107	$126	1.2	5.3	$0.55	$22.05	$108	$126	1.2	5.3	1%
Spartan Oil Corp.	STO	$3.73	$0.61	$52.61	$52	($8)	-0.1	5.9	$0.62	$52.92	$53	($8)	(0.1)	5.9	1%
Raging River Exploration Inc.	RRX	$2.00	$0.19	$49.40	$24	$34	1.4	11.0	$0.19	$49.45	$24	$34	1.4	11.0	0%
Pinecrest Energy Inc.	PRY	$2.03	$0.33	$61.24	$81	$63	0.8	6.9	$0.34	$61.24	$81	$63	0.8	6.9	0%
Junior Prod Median				*$18.16*			*2.3*	*6.4*		*$19.23*			*2.1*	*6.3*	*6%*

* Base Case FY12 Estimates: NYMEX Henry Hub: US$2.74/MMBtu, AECO-C Spot: C$2.24/Mcf
* High Case FY12 Estimates: NYMEX Henry Hub: US$3.05/MMBtu, AECO-C Spot: C$2.56/Mcf