Information removed non-responsive

From: Daly, David [mailto:david.daly@capp.ca]
Sent: Thursday, March 28, 2013 02:38 PM
To: Sharla Rauschning
Cc: Jennifer Steber; Shannon Flint; Dunlop, Jenna <jenna.dunlop@capp.ca>; Ferguson, Alex <alex.ferguson@capp.ca>; Bleaney, Bob <bob.bleaney@capp.ca>; Collyer, Dave <dave.collyer@capp.ca>; Jackson, Teresa <teresa.jackson@capp.ca>
Subject: RE: GHG analysis

Sharla,

Thanks for this. We will go through the assumptions and provide our feedback. I understand that arrangements are being made for Shannon Flint to meet with CAPP this coming Tuesday to discuss.

Regards,

David Daly | Manager Fiscal Policy

CAPP CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

david.daly@capp.ca | (403) 267-1160 | www.capp.ca

From: Sharla Rauschning [mailto:Sharla.Rauschning@gov.ab.ca]
Sent: Thursday, March 28, 2013 2:26 PM
To: Daly, David
Cc: Jennifer Steber; Shannon Flint
Subject: GHG analysis

Hello David,

Further to your recent conversation with Jennifer Steber, Chief Assistant Deputy Minister of Oil Sands Division and Energy Operations, regarding greenhouse gas analysis, please find attached the working spreadsheet we sent to third party reviewers, and the PowerPoint presentation that I provided to the reviewers last week.

This spreadsheet was prepared by Alberta Environment and Sustainable Resource Development (AESRD) and Alberta Energy (AE) and contains our draft analysis on the impacts of four greenhouse gas reduction scenarios. The spreadsheet consists of the following sections:

a. The top part of the spreadsheet includes data and assumptions.

b. The middle part includes analysis of a number of scenarios that are under consideration.

c. The bottom part of the spreadsheet includes a comparison of scenarios.

There are also tabs for forecasted ERCB production, as well as oil sands and natural gas royalty rates.

The main outputs include: GHG reductions under each scenario, the cost to industry, and the impact on government royalties. We have asked the third party reviewers to focus on the reasonableness of the assumptions made, analysis undertaken and validity of the methodology used in the analysis.

ESRD and AE experts who prepared the spreadsheet are available to answer any questions you may have and clarify information as needed. Please let me know if you are interesting in scheduling a meeting to discuss the spreadsheet details.

Thank you,

Sharla Rauschning
Executive Director, Resource Development
Alberta Department of Energy
780-427-6230

	Low cost	High cost	justification/source
Internal reductions (linear cost curve)	14% at $40	7% at $40	example of cost curve applied at policy price
(Mt reduction/$)	0.35	0.18	Based on linearized reductions vs price from Navius scenario with costs in range (high cost scenario assur
Credit supply (Mt/$ policy price)	0.5	0.25	Based on linearized reductions vs price from Navius scenario with costs in range. Assumes facilities are pa
combined cost curve (Mt/$)	**0.83**	**0.42**	sum of internal and credit cost curves - assumes facilities only invest in reductions that make sense based
Fund Compliance Method	calculated		based on compliance demand vs credit supply
Fund Recycling	70%	0%	conservative estimate of fund collections and resdistribution used to give range of fund impact on cost
Max Credit price (discount from internal reduction price)	5%	5%	Assumed based on anecdotal SGER reports to reflect transaction cost and risk premium of offsets
In Situ intensity (2011 t/bbl)	0.077		AESRD - from sger 2011 compliance data (includes Nexen long lake upgrading- no defensible way to disa
Base Mine Intensity (t/bbl 2011, excludes upgrading)	0.040		AESRD - from sger 2011 compliance data (includes Nexen Long Lake - no method for disagreggating)
Base Upgrading intensity	0.045		AESRD - from sger 2011 compliance data (shell actual, suncor preliminary, syncrude assuming 50% split i
2020 Production forecast In Situ (Million barrels per year)	721		ERCB - from ST-98
ERCB 2020 Production forecast Mining (Million barrels per year)	590		ERCB - from ST-98
ERCB 2020 Upgrading forecast (Million barrels per year)	504		ERCB - from ST-98
ERCB total production forecast	1,311		= mining + in situ production
BAU 2020 emissions Extraction (Mt)	79		intensity (static) * ERCB forecast
BAU 2020 emissions Upgrading (Mt)	23		intensity (static) * ERCB forecast
total emissions (Mt)	102		=mining + upgrading
Aggregate Intensity	0.078		=total emissions/total production
Royalty Rate (post payout projected for 2020)	35%		from Alberta Energy projections for 2020 (see Royalty Info tab)
Portion of production at post payout rate	61%		from Alberta Energy projections for 2020 (see Royalty Info tab)
portion of emissions from upgrading (royalty exempt)	22%		
Gas Plants Intensity (Mt CO2e/bcf)	0.0042	0.0042	current intensities as collected under the SGER for 2010. High cost scenario uses 50% higher intensity. As
Gas Plant reductions (at $30 price)	0.60	0.300	
Gas plant reductions (Mt/$)	0.007	0.004	
Gas production forecast in 2020 (bcf/year)	2,695		ERCB - from ST-98
portion of processing above threshold	36%		
processing above threshold (bcf/yr 2020)	970		
Emissions from gas processing over threshold (Mt/yr in 2020)	4.1	4.1	
gas royalty rate	14.53%		
emissions reductions from other sectors under current policy (Mt)	2	1	from Navius current policy scenario (excluding oil sands), holding constant assumes that other than credits

nes double cost per reduction)
aying marginal price for credits rather than obtaining at cost from credit generating activities they own or are partnered in (high cost scenario assumes double cost per reduction). the avaiability of c
on credit supply and price, which may be less than the policy price.

ggregate)

in emissions between mining and upgrading)

ssumes all compliance comes at maximum price.

s sold to oil sands nothing changes for any of the other sectors. Changes are proposed for conventional gas but due to the small size of the sector relative to the oil sands this does not affect the a credits depends on policies for the offset system and other sectors.

ıggregate policy outcome, only the cost to the gas sector.

	Current AB System**		CAPP Proposal		Federal Proposal		Alberta 40/40		Alberta 30/40
Stringency target	**12%**	**12%**	**20%**	**20%**	**30%**	**30%**	**40%**	**40%**	**30%**
gas stringency target	**12%**	**12%**	**20%**	**20%**	**30%**	**30%**	**12%**	**12%**	**30%**
fund tier price 1 ($/tone compliance)					$30	$30			
Fund tier 1 access restriction (% of compliance)					30%	30%			
fund tier price 2 ($/tone compliance)	**$15**	**$15**	**$20**	**$20**	**$80**	**$80**	**$40**	**$40**	**$40**
Average Carbon price ceiling $/tonne compliance	$15	$15	$20	$20	$65	$65	$40	$40	$40
Max compliance costs $/tonne emitted	$2	$2	$4	$4	$20	$20	$16	$16	$12
price to satisfy upper tier demand	$15.27	$30.53	$25.44	$50.89	$26.72	$53.43	$49.52	$99.03	$38.17
price to satisfy full demand	$15.27	$30.53	$25.44	$50.89	$38.17	$76.33	$49.52	$99.03	$38.17
marginal price for internal	**$15**	**$15**	**$20**	**$20**	**$30**	**$53**	**$40**	**$40**	**$38**
internal reductions (% of total emissions)	5%	3%	7%	3%	10%	9%	14%	7%	13%
internal reductions $/bbl	$0.03	$0.02	$0.05	$0.03	$0.12	$0.19	$0.21	$0.11	$0.19
Expected oil sands direct internal reductions (Mt in 2020)	**5**	**3**	**7**	**4**	**11**	**9**	**14**	**7**	**13**
total credit supply (Mt)	7	4	10	5	14	13	19	10	18
credit supply to oil sands (% of total emissions)	7%	3%	9%	5%	14%	12%	19%	9%	17%
credit supply to oil sands (Mt)	7	4	10	5	14	12	19	10	17
credit price ($/tonne compliance)	$14.25	$14.3	$19.00	$19.0	$28.50	$50.8	$38.00	$38.0	$36.26
credit price ($/bbl)	$0.08	$0.04	$0.14	$0.07	$0.31	$0.47	$0.55	$0.28	$0.48
Fund payments (% of total emissions)	0%	6%	4%	12%	6%	9%	8%	24%	0%
fund from oil sands($ million)	**$0**	**$90**	**$77**	**$242**	**$174**	**$275**	**$309**	**$969**	**$0**
Fund recycle to oil sands Sector ($Million)	$0	$0	$54	$0	$122	$0	$216	$0	$0
fund ($/bbl)	$0.00	$0.07	$0.06	$0.18	$0.13	$0.21	$0.24	$0.74	$0.00
Access second tier?	no	yes	yes	yes	no	no	yes	yes	no
compliance cost range $/tonne emitted	$1.4	$1.6	$3.2	$3.6	$7.2	$11.2	$12.9	$14.4	$8.6
compliance cost after fund recycle	$1.4	$1.6	$2.7	$3.6	$6.0	$11.2	$10.8	$14.4	$8.6
Total policy cost $/bbl (after fund recycle)	**$0.11**	**$0.12**	**$0.21**	**$0.28**	**$0.47**	**$0.87**	**$0.84**	**$1.12**	**$0.67**

	Assumptions/methods
30%	input based on scenario design
30%	input based on scenario design
$40	input based on scenario design
$40	input based on scenario design (calculated as average for two tier)
$12	=price ceiling * reduction target
$76.33	based on cost curve and upper tier demand
$76.33	based on cost curve and full demand
$40	Based on combined cost curve up to either the price ceiling or the compliance demand. In two tier system if upper tier demand is satisfied at a price less than lower tier fund price, the k
7%	based on calculated marginal price
$0.11	internal reduction per cent and 1/2 price ceiling (based on linear abatement curve) applied to projected emissions and production
7	=per cent reduction*projected emissions
10	calculated based on marginal price
9%	portion of total credits available used by oil sands, based on calculated marginal price, remaining demand after internal reductions and fund price(s) - expressed as a per cent of BAU e
10	conversion of % to Mt
$38.0	max credit price - assumes industry is buying credits at a common market price rather than investing in projects to obtain reductions at the supply cost. Average supply cost would be 1/
$0.28	credit per cent and associated price applied to projected emissions and production
14%	remaining compliance demand
$562	calculated as percent use multiplied by projected emissions and fund price. 1st tier used up first where applicable.
$0	based on assumed recycle rates. recycling the fund in the same year basically assumes that the policy is in a steady state by this point and as such the fund is disbersing as much as it
$0.43	calculated as fund dollars/ total production
yes	check whether second tier used in two tier system.
$10.4	weighted average of costs for three options above
$10.4	subtract out fund recycle
$0.81	average compliance cost converted into price per unit using intensity

ower tier becomes the price ceiling. Assumes industry has knowledge of the expected marginal price (and that this price is stable), and has invested accordingly (rather than investing in reductions

ımissions for comparison against target. Assumes oil sands get preferential access to credits when limited due to greater purchasing power and to show the greater impact on gas plants which are

/2 max price based on linear cost curve

: is receiving in a given year

up to the policy price). Conservative assumption because it results in lower internal reductions therefore more payments into fund or credits.

more sensitive to increased cost.

Annual oil sands royalty impact in 2020 ($ million)	**$23**	**$27**	**$45**	**$61**	**$102**	**$188**	**$182**	**$244**	**$146**
industry share of policy cost $/bbl	$0.09	$0.10	$0.17	$0.23	$0.39	$0.72	$0.70	$0.94	$0.56
Total policy cost 2020 ($ million)	**$139**	**$161**	**$274**	**$367**	**$616**	**$1,135**	**$1,095**	**$1,470**	**$878**
Total industry costs 2020 ($ million)	**$116**	**$134**	**$228**	**$306**	**$514**	**$947**	**$913**	**$1,226**	**$732**
gas reductions	2.7%	1.3%	3.5%	1.8%	5.3%	4.7%	7.1%	3.5%	6.7%
gas reductions (Mt)	0.11	0.05	0.14	0.07	0.22	0.19	0.29	0.14	0.27
gas fund contributions tier 1 (% of emissions)	0%	0%	0%	0%	9%	9%	0%	0%	0%
credits used for gas compliance (% of BAU emissions)	4%	0%	0%	0%	16%	16%	0%	0%	23%
credits used for gas compliance (Mt)	0.2	-	-	-	0.6	0.7	-	-	0.9
gas fund contribution	5%	11%	16%	18%	9%	9%	5%	8%	0%
gas fund contribution ($ million)	$3	$7	$13	$15	$11	$11	$8	$14	$0
total gas impact ($ million)	$6	$7	$15	$16	$32	$50	$14	$17	$40
total gas impact ($/Mcf)	$0.01	$0.01	$0.02	$0.02	$0.03	$0.05	$0.01	$0.02	$0.04
gas royalty impact in 2020 ($ million)	$0.9	$1.0	$2.2	$2.3	$4.7	$7.2	$2.0	$2.4	$5.8
total industry cost 2020 ($ million)	$5	$6	$13	$13	$28	$43	$12	$14	$34
gas impact ($/Mcf) Ab alternate target							$0.03	$0.03	
total reductions from policy	**14**	**8**	**19**	**10**	**27**	**24**	**35**	**19**	**34**
total provincial emissions	**270**	**276**	**265**	**274**	**257**	**260**	**249**	**265**	**250**
gap from target	**10**	**16**	**5**	**14**	**(3)**	**(0)**	**(11)**	**5**	**(10)**
total check									
internal reductions (% of total emissions) CHECK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Current AB System**		**CAPP Proposal**		**Federal Proposal**		**Alberta 40/40**		

$176	policy cost multiplied by projected royalty rate
$0.68	remaining cost per barrel after royalty deductions
$1,063	
$886	
3.5%	internal reductions based on common marginal price
0.14	converted to Mt
0%	used if available and lower cost than marginal cost
0%	remaining credits after oil sands satisfied
-	credits are used only if there is not a credit undersupply for oil sands
26%	remaining compliance demand
$43	conversion to dollars based on fund price(s)
$46	roll up of cost of internal reductions, credit and fund
$0.05	total cost divided by production
$6.7	total cost times royalty rate
$39	
	paste values of alternative gas scenario.
19	reductions in sectors plus credits plus current policy projection for other sectors.
265	projected no policy scenario from Navius minus reductions in scenario under consideration
5	compare against 2008 strategy target of 260 Mt (50 Mt off BAU of 311)

0.00%	based on calculated marginal price

Stringency target	12% (for all large final emitters)	20% (for the entire upstream sector)	30% (for the entire upstream sector)	40% oil sands 12% or 20% for conventional oil and natural gas	30%
Carbon price ceiling $/tonne	$15	$20	$30 (30% of compliance) $80 (remainder)	$40 oil sands, conventional oil, and natural gas	$ - $40
Average compliance cost ($/tonne CO_2e total emissions)	$1.36 - 1.58/ tonne	$2.69 - 3.61/ tonne	$6 - 11/ tonne	$11 - 14/ tonne	$9 - 10/ tonne
Total policy cost $/bbl **$/Mcf**	$0.11 - 0.12/bbl $0.01 - 0.01 mcf	$0.21 - 0.28/bbl $0.02 - 0.02 mcf	$0.47 - 0.87/bbl $0.03 - 0.05 mcf	$0.84 - 1.12/bbl $0.01 - 0.02 mcf (20%/$40) $0.03 - 0.03 mcf	$0.67 - 0.81/bbl $0.04 - 0.05 mcf
Royalty impact (including impact to gas processing)	$24 - 28 million	$48 - 63 million	$107 - 196 million	$184 - 246 million	$151 - 183 million
Industry cost $/bbl	$0.09 - 0.10/bbl	$0.17 - 0.23/bbl	$0.39 - 0.72/bbl	$0.70 - 0.94/bbl	$0.56 - 0.68/bbl
Fund payments from oil and gas*	$3 - 97 million	$91 - 257 million	$185 - 286 million	$317 - 983 million	$0 - 605 million
Fund recycled back to oil sands	$0 - 0 million	$0 - 54 million	$0 - 122 million	$0 - 216 million	$0 - 0 million
Expected oil sands direct internal reductions	3 - 5 Mt	4 - 7 Mt	9 - 11 Mt	7 - 14 Mt	7 - 13 Mt

Total provincial reductions from policy	8 - 14 Mt	10 - 19 Mt	24 - 27 Mt	19 - 35 Mt	19 - 34 Mt
Approximate contribution to Alberta's 2020 CC target of 260 Mt or 50 Mt below business as usual (311 Mt- 50 Mt = 260 Mt)* **	270 - 276 Mt Gap 10 - 16 Mt	265 - 274 Mt Gap 5 - 14 Mt	257 - 260 Mt Surplus 3 - 0 Mt	249 - 265 Mt Surplus 11Mt - Gap 5 Mt	250 - 265 Mt Surplus 10Mt - Gap 5 Mt
Timing for Implementation of targets/price	Current	Ramp up to 20% and $20/tonne by 2020 (After 2020 retain 20% and review price)	2016	Fall 2013 - Pass regulations for oil and gas and increase stringency to line up to federal regulations to be issued in 2016 (graduated targets).	2016
Achieving Alberta's 2020 greenhouse gas reduction targets	No	No	likely	Yes	likely
Enabling path to achieving Alberta's 2050 greenhouse gas reduction targets	No	No	No	No	No
Cost effectiveness through compliance flexibility	Yes	Yes	Yes	Yes	Yes
Incenting technology	$3 - 97 million	$91 - 257 million	$185 - 286 million	$317 - 983 million	$0 - 605 million
Competitiveness	$0.09 - 0.10/bbl	$0.17 - 0.23/bbl	$0.39 - 0.72/bbl	$0.70 - 0.94/bbl	$0.56 - 0.68/bbl

Benchmarking with other leading jurisdictions	No	No	Policy likely establishes Canada as a leader	Policy likely establishes Alberta as a leader	
Equivalency	No	No	yes	Likely	yes

Information removed non-responsive.

From: Daly, David [mailto:david.daly@capp.ca]
Sent: April 9, 2013 4:49 PM
To: Shannon Flint
Cc: Jennifer Steber; Sharla Rauschning; Ferguson, Alex; Dunlop, Jenna
Subject: CAPP Comments on Climate Change Economic Modeling Assumptions and General Considerations

Shannon,

Further to comments you heard from our members at the conference call last week, attached please find additional comments and questions on the model inputs and assumptions. We have also included general comments on the assessment exercise.

I look forward to receiving your feedback or answering any questions you may have on our comments, as well as hearing the assessment of ARC Financial, Peters and Co., National Bank and Matco.

Regards,

David Daly | Manager Fiscal Policy

CAPP CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

david.daly@capp.ca | (403) 267-1160 | www.capp.ca

CAPP Concerns and Questions for AB and Consultants

Model Assumptions and Comments

General

- Appreciate the consultation. Just need more time and a few more meetings, discussions, and alternatives considered.
- Appreciate AB sharing their spreadsheet with CAPP. It is always difficult to follow others' spreadsheets without them to walk you through it.
- We do like that targets are based on intensity. This always needs to be the case as otherwise would be a disincentive to add volumes.
- Before introducing costly new burdens on the industry and the economy, more communication, public awareness campaign of current policies, regulations, and environmental issues is required.
- There are two critical assumptions in the province's model – that higher stringency requirements will deliver greater GHG reductions and that higher stringency requirements will not impair future production. Neither of these assumptions has been demonstrated to a moderate degree of confidence to industry.
- Metrics for competitiveness impacts need to include:
  - Impact on royalties as a percentage of cost
  - Impact on netbacks ($/bbl)
  - Impact on access to capital
  - Impact on industry growth, taking into account varying pipeline and commodity price scenarios
- The model assumes no changes in future production under any of the GHG policy options versus the status quo; this implies that there will be no impact on investment from any of these policies. We would highlight that anything more stringent than today's system will increase costs, possibly lowering investments and reducing production.

Natural Gas

- In "2020 Costs and Reductions", Row 24, "Gas plant reductions at $30 price", the assumption is questionable. It is incorrect to assume the linear cost curve for emissions reductions. This assumption drives the whole model.
- Calculations on Spreadsheet are not easy to follow. Don't understand where the $100 MM/yr. comes from on the "Gas Info" tab Row 14.
- Spreadsheet would be easier to follow if gas was kept totally separate from oil sands and then just added at the end.

Oil Sands

- Assumptions around the Tech fund are not clear.
  - Some cases assume Tech funds return to the oil sands industry at a rate as high as 70%. While possible in aggregate, Tech fund compliance remains a cost to the oil sands industry and should be treated so. If some funds do return to industry,

companies will have to put up their own money to get any support from the Tech fund (perhaps at a leverage up to 5 times the value of the Tech fund support). This requires more R&D spending to get a portion of this money back, increasing the costs across the oil sands and impacting near term competitiveness.

- Linear offset cost curves and internal reductions do not reflect industry reality.
- Model use of averages (e.g. average GHG intensity and average cost per barrel masks differential impacts on different types of oil sands facilities (e.g. mines, upgraders and in situ, in stand-alone or combination) across a range of producers, at higher and lower GHG intensities. This makes assessment on projects and production at the margin difficult.
- For in situ, a project with an SOR of 4 would pay double what a project with an SOR of 2 would pay. A range of values would better reflect the impacts on industry.
- Calculations on spreadsheet are not easy to follow. It would be helpful to have a simple sheet that just shows the total cost of compliance, with no offsets and no reductions.
- It would be helpful to have a more user friendly model, where assumption cells are colour coded so that you could do sensitivity testing.
- Assumptions should be listed, with a source / rationale listed.
- There are many assumptions/ unknowns:
    - Internal reductions based on offset price - What is basis for assumption that $40 /mt will result in 14% or 7% of compliance being achieved by internal reductions?
    - Linear scaling of internal reductions - It will depend on technology available and economics. Internal reductions are likely independent of offset price until a certain unknown price point.
    - Percentage of Tech fund returned to industry - Mechanism for return is unclear, as it requires project-by-project assessment. Plus there is time delay. Clarity of policy would help, particularly since this appears to deviate from current policy.
    - It seems that when the Tech fund gets larger the percentage that is returned to industry changes. (i.e. not a constant percentage). Need clarity.
    - Offset supply discount to compliance penalty is very uncertain. Likely can't count on any discount if restricted to Alberta credits. 5% is likely reasonable, but risk and administration could eliminate a lot of the benefit.
    - Assumption that there will be no change in activity is not valid. Although difficult to quantify, projects on the margin will be cancelled. Investment will go elsewhere
- Model assumes that as stringency increases, GHG emissions decrease. This may not be the case.
- Model assumes a simplified reduction cost curve. The reduction cost curve is a key input in determining the minimum stringency to achieve provincial GHG emission reduction targets and should be based upon a detailed sector-by-sector assessment.

Competitiveness and Policy Issues

- Disincentive to do upgrading in Alberta relative to upgrading in other jurisdictions. Have created a $0.72/bbl levy on crude upgraded in Alberta whereas there is no such levy in US.
- GHG policies should be done in concert with other jurisdictions. US has no carbon tax. Why be so far out in front of them? What is that based on? Does a 40% reduction in

intensity make oil sands production equivalent to conventional oil production in US? What about all the flaring going on in North Dakota?
- Proposed 40/40 is a 9 fold increase over current. Why such a dramatic step?
- Considering implications on the activity, investment, competitiveness, and unknown benefits, more study and analysis is required to get it right. Major policies like this one, should not be fast tracked. Adequate time is required for study, analysis and consultation.
- Clarity is required on the Tech fund and potentially a wider scope of uses for the funds. (e.g. Tech fund could be used to provide a subsidy to GHG reduction projects.)

Cost Burden is substantial and affects competiveness

- Oil Sands already economically challenged relative to other North America oil and gas plays.
- Recent royalty changes increased government take post-payout by as much as 60% and as much as 9 fold pre-payout. Regulatory requirements have also already added to cost and decreased economic viability. Additional burdens such as the carbon tax increase are further reducing economic viability.
- Upgrading in Alberta is already challenged. Note cancellation of Voyager upgrader and newer oil sands projects are coming without upgrading (e.g. Esso Kearl). Upgrading cannot afford this additional burden.
- On a pre-payout project, one estimate suggests the GHG burden would be equivalent to a 32% increase in royalty (based on $90 WTI).

Framing the right questions

- Will higher stringency requirements *'secure'* social license and forestall negative policy action elsewhere? Unlikely. The objection to the oil sands is ideological; not a concern that Alberta's current framework is not stringent enough. Put another way, if the 40/40 guidelines were enacted, oil sands opponents would claim that they too were insufficient
- Will higher stringency requirements deliver greater GHG reductions? Unlikely. The challenge with the oil sands is that current technology is not yet available for deployment to a significant degree.
- Will higher stringency requirements impact production and revenue? Very likely. Adding a regressive charge to the oil sands, one that bites harder at low prices than high prices, introduces additional cost and risk. This will impair recovery of marginal resource associated with existing projects. And make new projects less competitive from a portfolio perspective. And the higher costs associated with additional stringency can also impair the resources devoted to research.
- The third party evaluators have been asked to 'evaluate the model'. This is not likely the right question. Dollar per barrel costs are not an effective metric for competitiveness impacts. The question to answer is: *"What impact do these policy scenarios have on industry competitiveness?"* The evaluators should focus on the impact of the policy on investment and production in the province rather than reviewing inputs and checking the math.
- Industry cannot assess the underlying assumptions for "reasonableness" of the methodology without access to the background Navius work.

- The principle of broad-based GHG reduction efforts at the lowest cost is contravened by keeping natural gas stringency at 12%, singling out oil sands for achieving AB's 50 Mt emissions reduction target by 2020.
- The impact of GHG reduction targets needs to be viewed in context with all the other costs oil sands are facing, such as monitoring, the new provincial regulator and other environmental measures including investments in COSIA.
- AB's proposed targets far exceed many other jurisdictions, while the social license benefits are uncertain. This could lead capital to flow from Alberta to other projects in North America or abroad.
- The third party reviewers should provide broader comment on Alberta's model, including
  - Competitive impacts of these policy scenarios
  - Risks of the different approaches
  - Financing impacts
  - Rationale and risks associated with setting more stringent targets for oil sands.
- This analysis does not capture the risk associated with requisite prospective investments in new technologies. Despite an innovation focus, new technologies are years in the making. Timing and impacts of new technologies are unclear, affecting future investment.

Comments on CAPP policy analysis model

Key differences with GOA model:

	CAPP	GOA
Phase in	7 years for new emissions	Not considered
Internal abatement	2% fixed, $10/t cost	Responds to price linearly
Offset pricing	Multiple price points post 2020	Single discount rate
Offset supply	ICF discounted 50%	Navius
Years considered	2016-2035	2020
Recycling of fund dollars	Not considered	Ranged 70% to 0%
Royalties	Not considered	Projected royalty impacts

Results:

	20/20				40/40				EC 30/50			
	Albert Low	Alberta High	EC	CAPP	Albert Low	Alberta High	EC	CAPP	Albert Low	Alberta High	EC	CAPP
Internal Reductions (Mt)	7	4		2	14	7	7	2	9	9	8	2
Offsets (Mt)	9	5		3	18	9	14	6	12	11	13.3	7
Fund Payment ($M)	$ 87	$ 247		$ 228	$ 347	$ 988	$ 804	$ 978	$ 207	$ 251	$ 187	$ 529
Total Cost ($M)	$ 267	$ 368		$ 293	$ 1,070	$ 1,471	$ 1,640	$ 1,206	$ 473	$ 1,005	$ 930	$ 883

There is generally reasonable alignment on costs but not on potential emissions savings.

Discussion:

Assuming fixed reductions over time irrespective of policy price implies a number of things:

- Carbon costs will not be factored into decision making related to energy efficiency projects or those projects can produce only very modest impacts.
- Carbon costs will not be factored into decision making related to fuel switching opportunities or those projects can produce only very modest impacts.

- Investment of fund dollars in the oil sands is incapable of having an impact on greenhouse gas reductions and should be directed elsewhere.

In addition a fixed 2% reduction falls short of reductions anticipated by CAPP in the 2020 and 2030 time frame as presented to the PWG.

The assumed cost curves are shown below overlaid on results from *A Greenhouse Gas Reduction Roadmap for Oil Sands*, Suncor and Jacobs Consultancy, 2012.

Section 24(1)(a),(b)

Figure 9-1.
In Situ—Potential GHG Roadmap

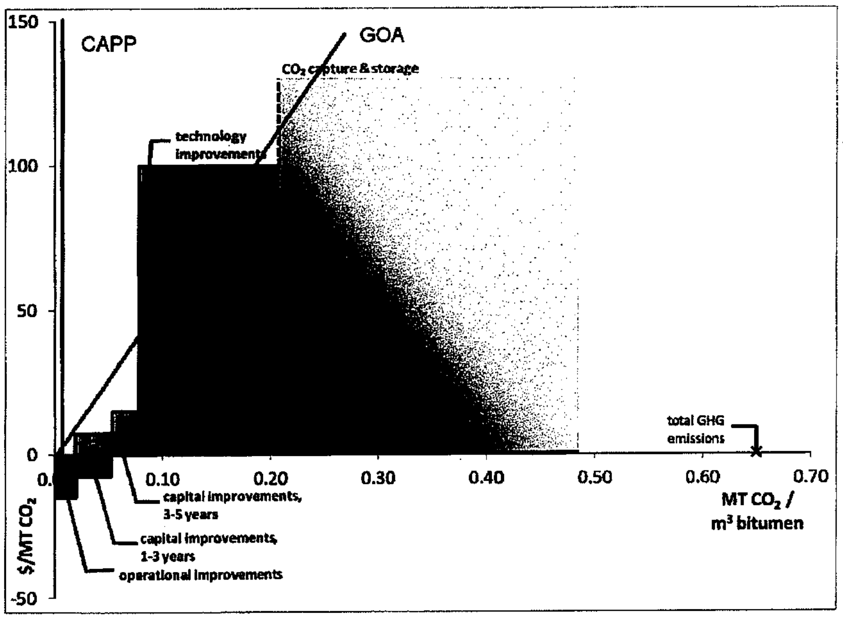

Figure 9-2.
Mining and Extraction—Potential GHG Roadmap

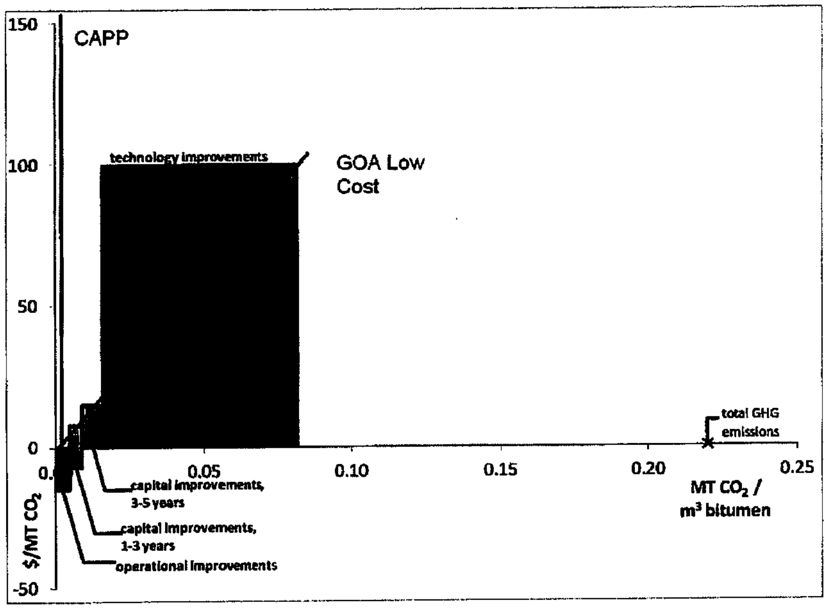

Figure 9-3.
Upgrading—Potential GHG Roadmap