Energy Investment Research

Tristone Capital Inc.
Mackenzie Valley Pipeline
April 24, 2007

TRISTONE CAPITAL

The Delta is Too Large...Now What?

- Based on the new capital costs of the Mackenzie Gas Project, we estimate total supply costs at US$5.78/mcf. Under the current fiscal regime, there is no economic incentive to build the Mackenzie Valley Pipeline (MVP).
- **Chicken or the egg dilemma clouds supply/cost picture.** A notable change in the March 2007 update is the downsizing of the initial capacity to 960 mmcf/d from 1.2 bcf/d. Why? Third party producers, better known as the Mackenzie Delta Explorers Group, won't dedicate supply to the pipeline until there is access and tariff certainty on the gathering system. With no third party supply commitments, Imperial has downsized initial capacity, which further burdens pipeline economics beyond the cost increase.
- **Step one: Resole the dilemma.** We believe the gathering system should be regulated under the NEB Act. Today it is not. It falls under COGOA, which allows Imperial et al to set access and tariffs. We believe regulating the gathering system would provide the Explorers Group access and fee certainty, making the pipeline a 1.2 bcf/d project and immediately benefiting from economies of scale for all in this basin-opening venture. We see this reducing the combined toll from the Delta to Alberta by US$0.18/mcf, a move in the right direction, but still in need of fiscal enhancements.
- **How can the fiscal equation be enhanced?** As a starting point, a cash outlay is a non-starter – the Feds don't appear to be there and the taxpayers certainly are not going to fund a private industry project. Additionally, the Feds add no value as a straight up equity partner. We see accelerated CCA and a loan guarantee to increase the debt/equity ratio of the pipeline to 80/20 D/E (which reduces cost of service and the toll), having the potential to reduce supply costs combined by a further US$0.19/mcf.
- **The common infrastructure challenge.** Imperial Oil has indicated ~$2 billion of common infrastructure costs burden the project. We see some potential to offload some of these costs, with governments issuing a bond to build common infrastructure and in turn charge a toll for use. We estimate that for each $1 billion of common costs offloaded from the pipeline, the impact on the toll is significant at US$0.24/mcf.
- In our opinion, there are fiscal solutions to bring supply costs down 9-13% and generate acceptable returns. Failure to come to terms will likely result in gas remaining dormant in the Delta for at least another 10-15 years.

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Pipeline Uneconomic on New Capital Costs of $18 Billion

In March, Imperial Oil announced new cost estimates for the Mackenzie Valley Pipeline project, with the total cost up 134% to $18 billion. This number may sound a little different from the $16.2 billion in the media, but the $18 billion figure includes another $1.8 billion for Allowance for Funds Used During Construction. Exhibit 1 segments the new cost estimates by field development, the gathering system and the pipeline components. The largest increase came from the anchor field development, which increased from $700 mm in 2003$ to $4.9 billion in 2006$. The actual pipeline cost increase was largely as expected, up 114% from $4.5 billion to $9.6 billion. The gathering system costs increased 40% to $3.5 billion (Exhibit 1).

Exhibit 1: Mackenzie Gas Project Cost Breakdown 2003$ vs. 2006$

	C$Million		
Component	**2003$**	**2006$**	**% Change**
Gas Pipeline	2,034.8	3,767.0	85%
Measurement & Regulation	6.1	4.0	-34%
Compression Facilities	278.0	593.0	113%
Other Facilities	12.9	63.0	388%
SCADA & Telecommunications	11.0	56.0	409%
Engineering & Project Management	193.9	740.0	282%
Owners' Costs	461.9	1,140.0	147%
Subtotal	2,998.6	6,363.0	112%
Contingency	692.2	1,244.0	80%
Risk Allowance	146.8	224.0	53%
Subtotal	3,837.6	7,831.0	104%
Allowance for funds used during construction	650.8	1,772.0	172%
Pipeline Total	4,488.4	9,603.0	114%
Anchor Field Development	700.0	4,900.0	600%
Gathering & Processing Infrastructure from Anchors to Inuvik	2,500.0	3,500.0	40%
Total Cost of Five MG Project Components	**7,688.4**	**18,003.0**	**134%**
Total Cost of Five MG Project Components (US$)	**5,492.1**	**15,482.6**	**182%**

Source: Tristone Capital

In Exhibit 2, we show the detailed cost breakdown of the pipeline in 2006$. Of the total cost estimate, $14.3 billion is initial spending to begin sales with 960 mmcf/d, including 830 mmcf/d from the three anchor fields and 130 mmcf/d of third-party gas. The third party gas figure feels somewhat arbitrary, as the total commitment made by the Explorers Group, most recently as December 2006 at the NEB's Inuvik hearings, was 175 mmcf/d to the system. Another $1.9 billion of future spending is geared up for the first four years once onstream, to drill infill wells and add up to three more compressors along the main line. Allowance for Funds Used During Construction, including $1,655 million initially and another $117 million for the expansion, rounds the Mackenzie Gas Project total capital cost to $18 billion.

Of note, approximately half of the cost increase is associated with the pipeline, 40% with the anchor field development and another 10% with the increased cost of the gathering system. The increase in cost estimates for the pipeline are most relevant as those are the costs which drive the cost of service and the ultimate toll for the pipeline. However, field development and gathering system costs will also impact the total supply cost for the project.

Exhibit 2: Segmented MGP Capital Expenditures in 2006C$

Project Component	C$MM			Bcf	C$/Mcf	
	Initial	Future	Total	Recoverable Raw Gas	Unit Cost	Owners
Anchor Field Development:						
Taglu	1,800	750	2,550	2,800	0.91	IMO 100%
Parsons Lake	1,200	350	1,550	2,300	0.67	COP 75% / XOM 25%
Niglintgak	800	-	800	1,000	0.80	SHC 100%
Sub-total	3,800	1,100	4,900	6,100	0.80	
Mackenzie Gathering System:						
Gathering Pipelines	1,350	-	1,350			
Inuvik Area Facility	1,200	-	1,200			
NGL Pipeline	950	-	950			
Sub-total	3,500	-	3,500	6,100	0.57	
Mackenzie Valley Pipeline:						
Pipelines	6,400	-	6,400			
Compression & Other Facilities	650	800	1,450			
Sub-total	7,050	800	7,850	6,100	1.29	
Three Component Total	14,350	1,900	16,250			
AFUDC	1,655	117	1,772	6,100	0.29	
Total	16,005	2,017	18,022	6,100	2.95	

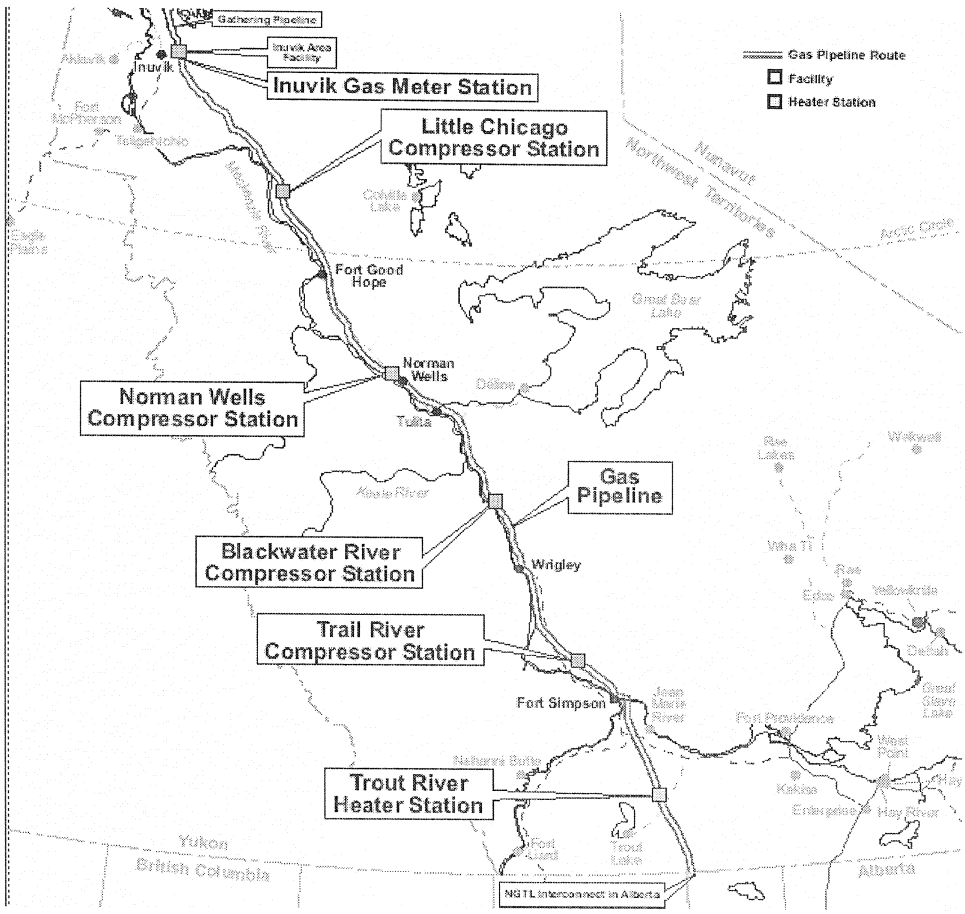
Source: NEB August 2004 MVP Application to NEB; March 2007 MGP Updated Costs, Tolls and Fees

Main Line Toll Has Doubled on New Cost Estimates

Under the revised MVP filing at the end of March 2007 the new toll for the Mackenzie Valley Pipeline is $2.96/Gj (US$2.68/mcf), which is double from the $1.44/Gj in the 2004 application (2003$)[1]. Under the new filing, only one compressor station is contemplated for the initial 960 mmcf/d of capacity, located at Blackwater River (Exhibit 3). Note that in year four, Imperial Oil forecasts building up to three more compressors to increase pipeline capacity to 1.2 bcf/d in order to accommodate additional/third party gas. As a result, the toll is projected to fall to $2.64/Gj (US$2.39/mcf) in year four, with higher throughput on the line.

[1] Assumed 90% long haul and 10% short haul for 15-year firm service contract.

Exhibit 3: Pipeline Route and Compressor Staging



Source: NEB August 2004 MVP Application to NEB; March 2007 MGP Updated Costs, Tolls and Fees

In Exhibit 4, we summarize the new toll for the pipeline, assuming the new base case 960 mmcf/d pipeline in year 1 of operations (2015). We also show the gathering system fees for each of the three anchor fields. Note that we have converted Gj's to Mcf's and represent all costs in US dollars (using YTD 2007 US$/C$) for comparability to alternative supply options later in this report. To derive the new toll on the pipeline, we have assumed the new inputs as per the March 2007 project update, including D/E of 70/30, ROE of 10.67%, cost of debt of 5.3%, annual DD&A of 4.8% and a tax rate of 30.5%. Based on the new capital cost of the pipeline, we estimate the average MVP toll for 15-year firm service at US$2.50/mcf.

As the table shows, the weighted average cost to ship gas from the Delta to the receipt point in Alberta is US$3.45/mcf and ranges from US$3.82/mcf for Niglintgak (farthest north) to US$3.22/mcf from Parson Lake. With Taglu representing 43% of the 960 mmcf/d initial throughput, its US$3.51/mcf cost approximates the weighted average shipping cost.

Exhibit 4: Gathering Fees Plus MVP Toll by Field

	US$/Mcf			
	Niglintgak	Taglu	Parsons Lake	Weighted Average
Niglintgak to Taglu	0.32	na	na	
to Junction	0.52	0.52	0.24	
Junction to Inuvik	0.35	0.35	0.35	
Total Field Gathering Cost	1.19	0.87	0.59	0.82
MVP 15-Year Long-haul Toll	2.50	2.50	2.50	2.50
MVP 15-Year Long-haul Premium	0.14	0.14	0.14	0.14
Total Transportation Cost to Alberta	3.82	3.51	3.22	3.45

Source: March 2007 MGP Updated Costs, Tolls and Fees. May not add due to rounding.

What Assumptions Changed in the Updated Pipeline Filing?

Within the new cost estimates, we note a few key assumptions / components of the project have changed and their change has had a profound impact on the calculated tolls and tariffs. These include:

New pipeline capacity is lower; gathering system fees the root of the dilemma – The initial pipeline capacity is now 960 mmcf/d versus 1.2 bcf/d in the 2004 application. This is due to the construction of only one compression station at Blackwater River instead of four compressors, as planned in the 2004 application. The reason – none of the Mackenzie Delta Explorers Group (PCA, DVN, ECA, CVX, APC, BP) have dedicated third party volumes on the pipeline. This is because under the current regulatory system, the Canada Oil and Gas Operations Act (COGOA) does not provide the NEB with the authority to regulate pipeline access, tolls and tariffs.

The NEB does exercise this authority over pipelines regulated by the NEB Act. This is relevant because the MVP falls under the NEB Act while the gathering system does not – it falls under COGOA. Under COGOA, third party producers seeking access to the gathering system would have to negotiate with Imperial and partners to gain access and to fix fees at rates potentially higher for subsequent applicants. The Explorers argue that COGOA allows Imperial and partners to set the tariff on the gathering system from the three anchor fields and as such, control access and the cost to move gas to the Inuvik central processing facility.

This has created a case of 'chicken or the egg', as producers aren't willing to sign up for capacity until there is access and tariff certainty, and Imperial Oil and partners are unwilling to spend capital to accommodate third party gas until there are firm 15-20 year transportation agreements. The impact is that basing the initial economics on lower throughput further burdens project economics and raises the gas price required to make the pipeline economic under today's costs. We note that the March 2007 filing envisions expansion to 1.2 bcf/d in

year four of the pipeline at a cost of $906 mm, which based on Imperial Oil's figures, would reduce the toll to C$2.64/Gj (US$2.39/mcf) from C$2.96/Gj (US$2.68/mcf) in year one.

The Delta Explorers are currently in Court challenging to have the gathering system regulated by the NEB to ensure reasonable access and costs to the system, arguing it is part of basin-opening infrastructure and should fall under NEB regulation.

We agree with the Explorers position on this, and reading between the lines of the March 2007 Federal Budget – so do the Feds. See page 7 of this report for the impact of regulating the Mackenzie Gathering System.

The toll from Colville Lake is lower – In the 2004 application, the toll for short haul gas (i.e. Colville Lake in the Central Mackenzie Valley (CMV)) was 80% of the long term toll. This figure is now 72.4%. The application assumes 125 mmcf/d of firm service short-haul contracts in year 4, which equates to 90% long-haul (Delta gas) and 10% short-haul (CMV), consistent with the split we use to derive the new 15-year toll of C$2.96/Gj (US$2.68/mcf) in year one.

Tax rate is lower – the assumed tax rate in the revised filing is 30.5% versus the 2004 filing at 36.12%, reflecting the fact that Large Corporations Tax is no longer in effect, as well corporate tax rate changes.

Cost of capital is lower – The deemed cost of debt (which is the expected debt rate for the Aboriginal Pipeline Group) is now 5.3% versus 6.1% in 2004. The return on equity is now pegged at 10.67% versus 11.77% in 2004, which is based on the 2007 NEB multi-pipeline rate, plus 2.21%.

The latter two changes have the impact of lowering the cost of service and therefore the toll on the MVP.

First Gas Now 2015 at the Earliest

With the new cost estimates, Imperial also outlined the revised project schedule, which would see first gas by the beginning of 2015 at the earliest. Imperial indicated that its timeline incorporates receiving permits from the NEB in 2008; deciding on construction by 2009 and awarding contracts in order to start construction in 2010. This schedule is subject to a favourable response from the Federal Government on all regulatory and fiscal fronts. It is also subject to resolution of Access & Benefits Agreements and/or a Land Claim with the Deh Cho. This is a whole other can of worms we won't explore in this report.

New Cost Puts Pipeline Breakeven Cost at US$5.78/mcf

In Exhibit 5, we sum the cash expenses and capital costs to determine the total supply cost for Delta gas. In addition to the US$3.32/mcf shipping cost (US$2.50/mcf toll + US$0.82/mcf weighted gathering fee) to move the gas to Alberta, we add other cash expenses, as outlined in the March 2007 update, which include gathering system and pipeline operating costs, G&A and royalties, the long-haul premium of US$0.14/mcf, which is additive to the MVP toll and shipping to the US market through Alberta to Chicago. Total cash costs are estimated at US$5.07/mcf. When including F&D costs for the anchor fields of US$0.69/mcf and US$0.86/mcf for third party gas field development (weighted average F&D of US$0.71 at start-up), the total supply cost under the new estimates is US$5.78/mcf.

Exhibit 5: MVP vs. N.A Full Cycle Gas Costs vs. LNG in 2006$

	MGP	Indigenous Gas		LNG
Royalty / Severance / Tax	0.18	0.32	Cost of Upstream Gas	1.50
Operating	0.26	1.01	Taxes in Export Country	0.38
G&A	0.13	0.28		0.10
Gathering & Processing	0.82	1.25	Liquefaction	1.20
Anchor Pipeline Toll + Premium	2.64	-	LNG Shipping	0.90
Intra-Alberta T-port	0.15	-	Regasification	0.45
AECO-HH Basis	0.90	-	Market Access	0.30
Cash Costs	5.07	2.86		4.83
F&D Costs	0.71	3.14		0.50
Full Cycle Costs	5.78	6.00		5.33

Source: Company reports; Tristone Capital estimates

This figure compares with our estimate of full cycle North American supply costs of US$6.00/mcf in 2006. So, under the current fiscal regime, the obvious question for Imperial and partners is why risk allocating billions of dollars of capital on a project that still has some risk of cost inflation, regulatory, First Nations and timing uncertainty, when the partners can drill for gas in North American or elsewhere (LNG) with better cost and market certainty today. We agree with Imperial Oil that the current economics don't go around and that there is little incentive to move forward under the current fiscal regime.

In Exhibit 5, we also provide our estimate of current LNG total supply costs. The LNG business has also experienced cost escalation, with record liquefaction trains under construction putting a pinch on labour and raw materials. We estimate LNG supply costs today at US$5.33/mcf, but would caution the cost of upstream gas continues to move higher. While our estimate is US$1.50/mcf, we are increasingly seeing LNG indexed to NYMEX or an equivalent spot market price, with source countries capturing a larger piece of the economic rent via price linkage to more liquid markets. As such, we expect cost of upstream supply will continue to migrate upward, which suggests there is no cheap gas on a global basis.

Four Options That Could Skate the MGP Onside

While the new cost structure generates insufficient returns, we do see room to manoeuvre to reduce the cost of service of the pipeline, with the cumulative impact of the following four viable options making a much stronger economic case for the system to be built:

1. **Regulate the gathering system** – In the March 2007 Federal budget, the Government announced that it will consult stakeholders in the project on potential legislative amendments to two Acts – one is the Mackenzie Valley Resource Management Act – to establish a 'one project, one environmental assessment' process; and the second – COGOA (see page 5), to address the fact that the Act does not provide the NEB with the authority to regulate the gathering system access, tolls and tariffs. We read this as the government facilitating legislative amendments in an effort to address the discrepancies between the two acts. Said in plain language, we believe the Federal Government will enact legislation that will regulate the Mackenzie Gas Gathering system, thereby providing the Mackenzie Explorers Group with certainty on access and tolls. In doing so, this will resolve the 'chicken or the egg' dilemma and provide clarity for the Explorers to dedicate gas volumes to the pipeline, which will have the affect of reducing shipping costs for the whole system.

   To quantify the impact, we estimate that rolling in the C$3.5 billion gas gathering capital cost into the rate base, the combined toll on the 1.2 bcf/d start-up scenario would be US$3.14/mcf, which compares with the MVP toll of US$2.50/mcf plus the weighted gathering system fee of US$0.82/mcf or a total of US$3.32/mcf. While the difference of US$0.18/mcf is not that significant, the cause-effect of this decision is. Specifically, with clarity on access and tolls on a regulated gathering and pipeline system, we believe Explorers will dedicate sales volumes to the system, which has the effect of reducing the overall tolls quite dramatically. Under a 1.2 bcf/d pipeline from the onset of first gas in 2015, we see a supply cost of US$5.58/mcf, which is US$0.22/mcf lower than the US$5.80/mcf we currently estimate from the Imperial Oil cost, tariff and toll update. The remaining US$0.04/mcf reduction is a result of lower unit cash costs due to the higher throughput on the pipeline, which is slightly offset by higher F&Ds of $1.00/mcf assumed for non-anchor field development costs as they would represent 31% of volumes on the 1.2 bcf/d pipe versus 13.5% under the 960 mmcf/d scenario.

2. **Accelerated Capital Cost Allowance (CCA)** – Under the Income Tax Act, a portion of depreciable property is deductible as CCA each year in computing income tax. Under current tax laws, the CCA rate is designed to depreciate the pipeline by 8% of the balance annually over the life of the pipeline.

Accelerated CCA is an available fiscal enhancement, which could increase the CCA rate to better match the economic life of the gas fields, which is about 15 years, as opposed to matching the physical life of the pipeline, which is about 30 years. The effect of accelerated CCA would be to defer income taxes, which in turn, would reduce the cost of service and the pipeline toll. We estimate that doubling the CCA rate would reduce the cost of service by US$0.07/mcf.

3. **Government provides loan guarantee; increase debt financing component** – The government could also provide a loan guarantee for the pipeline, much like the US has done for the Alaska Highway gas pipeline. In doing so, the producers could increase the debt/equity ratio from the assumed 70/30 split, as cost of debt is about half of the cost of equity for the project. More debt would reduce the overall rate of return for the project, thereby lowering the cost of service and the toll.

In our opinion, holding any other fiscal enhancements constant, each 10% increase in the debt/equity ratio would reduce the toll by ~US$0.19/mcf.

4. **Governments subsidize cost of common, long-term infrastructure** – As we highlighted earlier, Imperial Oil estimates common, long-term infrastructure costs in the range of $2 billion. The simplest form of government fiscal aid is in the form of direct funding. Recall last year Imperial Oil had indicated fiscal aid in the range of $1.2 billion was required to cover these costs; however, we believe the $2 billion level is the targeted aid package on the agenda today. A cash outlay seems a low probability event, given comments from the government to the tune of "the project is not going to proceed as a social project" and the unwillingness of Canadian taxpayers to foot the bill for a private sector project.

5. **Municipal/Territorial/Federal financing of common infrastructure** – An alternative solution to funding the $2 billion common infrastructure problem is to have one or a combination of Municipal/Territorial/Federal governments issue bonds to fund regional development of roads, barge landings, airstrips etc. In turn, the issuer of the bonds charge a toll to access the common infrastructure, thus providing an income stream (return) to the bondholders. This would share the cost burden of common infrastructure between the construction of the pipeline and future exploration and development, be it oil and gas or mining. Importantly, it would allow the government to avoid the political minefield of direct pipeline subsidies. Underpinning the loan with a government guarantee would have the affect of lowering the cost of debt associated with this scenario.

The impact on the toll is quite significant, given the sensitivity to changes in capital costs. Ignoring any other fiscal enhancements, we estimate that for each $1 billion offloaded from the pipeline cost, the toll would decline by US$0.24/mcf.

We would also point out that in the total cost estimates, contingency capital, risk allowance and additional funds used during construction amounts to C$3.24 billion or 33% of the pipeline cost estimate. Should Imperial Oil and partners manage to control costs on what now appears to be a robust cost estimate, the reduction in this cost overrun capital would have the same impact on the toll.

6. **Government equity stake** – While this has been suggested in media, there is little substance to this type of arrangement. The project sponsors are well capitalized to undertake the multi-billion dollar investment to move an economic project forward and simply bringing in an equity partner adds no value to the economic equation.

7. **Government guarantees capacity on the pipeline** – This is also a non-starter. While the guarantee could allow Imperial and partners to move forward with construction, other producers will still evaluate Delta gas monetization versus allocating capital to other potentially higher return projects within their upstream portfolios. The downside being that if the government guarantees third-party capacity and it doesn't materialize, under this type of take-or-pay contract, the government would pay demand charges on the pipeline i.e., if it guaranteed 250 mmcf/d of third party gas and it wasn't delivered, it would pay the demand charge or toll of US$2.50/mcf, which would equate to over US$225 mm per year in expenses.

Fiscal Enhancements Can Reduce Supply Costs by 9-13%

In Exhibit 6, we summarize the supply costs for the MGP, starting with the base case new cost, toll, tariff and throughput assumptions as presented in the March 2007 cost, toll and tariff update. These are shown in column (i). As we move from left to right in the table, we layer on the effect of: ii) regulating the pipeline and incorporating third party gas so start-up is 1.2 bcf/d; iii) include accelerated CCA; iv) include debt guarantee which moves the debt/equity split up to 80/20; and v) assume $1 billion of common infrastructure costs are removed from the capital cost of the pipeline.

To a large degree these successive changes to the fiscal terms represent most to least likely in terms of implementation. However, we believe that prior to the assumption of offloading any capital costs (iv), supply costs can be reduced by 9% to US$5.28/mcf and could go as low as US$5.04/mcf with ~$1 billion reduction in capital costs.

We note that any further increase in leverage (higher D/E split) and/or further capital cost offloading/reduction could reduce the supply cost below US$5.00/mcf. We believe that with a supply cost in the low US$5.00/mcf range (column iv and v), the Mackenzie Gas Project can compete with alternative supply sources and generate an acceptable rate of return for the project proponents.

Exhibit 6: Impact of Regulating Gathering System / Fiscal Enhancements

	US$				
	i	ii	iii	iv	v
Royalty / Severance / Tax	0.18	0.18	0.18	0.18	0.18
G&A	0.13	0.10	0.10	0.10	0.10
Pipeline Opex	0.13	0.10	0.10	0.10	0.10
Gathering System Opex	0.13	0.11	0.11	0.11	0.11
Gathering & Processing Fee	0.82	3.14	3.07	2.88	2.64
15-Yr Blended MVP Toll	2.50				
15-Yr Long-haul Premium	0.14	0.12	0.12	0.12	0.12
Intra-Alberta T-port	0.15	0.15	0.15	0.15	0.15
AECO-HH Basis	0.90	0.90	0.90	0.90	0.90
Cash Costs	5.07	4.80	4.73	4.54	4.30
F&D Costs	0.71	0.74	0.74	0.74	0.74
Full Cycle Costs	5.78	5.54	5.47	5.28	5.04

Source: Tristone Capital

With $800 mm invested/committed by the Government of Canada and another $600 million invested by Imperial and the MGP partners since 2002, we believe there remains political will and proponent commitment to find a solution to reducing the cost of delivering Delta gas to market. However, should some combination of fiscal incentives prove unattainable, we would expect the MGP project sponsors to at least finish the regulatory process, such that they have authorization to build the line in the event of future changes in the market, cost structure and/or fiscal terms. We do believe that the NEB will introduce a Sunset Clause with a permit, which would require Imperial to break ground on the pipeline by a drop dead date, which if timing holds, would be the end of 2010. We would expect any slippage due to environmental and/or regulatory delays to be reflected in timing of any Sunset Clause.

In our opinion, there are fiscal solutions to bring this project over the hurdle. Failure to come to terms will likely result in gas remaining dormant in the Delta for at least another 10-15 years.