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September 30, 2010

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: Terasen Gas Inc. ("TGI" or the "Company")
Application ("Application") for a Certificate of Public Convenience and Necessity ("CPCN") for the Kootenay River Crossing (Shoreacres) Upgrade Project

Response to the Commercial Energy Consumers Association of British Columbia ("CEC") Information Request ("IR") No. 1

On July 15, 2010, TGI filed the Application as referenced above. In accordance with Commission Order No. G-133-10 setting out the Regulatory Timetable for review of the Application, TGI respectfully submits the attached response to CEC IR No. 1.

If there are any questions regarding the attached, please contact Diane Roy at (604) 576-7349.

Yours very truly,

TERASEN GAS INC.

Original signed by: Diane Roy

For: Tom A. Loski

Attachment

cc (e-mail only): Erica Hamilton, Commission Secretary
Registered Parties

1. TGI Application, Page 9

The system serves approximately 5200 customers located in the City of Nelson and its surrounding area, downstream of the aerial crossing.

1.1 Has TGI forecast the population and demand to be served over the next 50 years?

Response:

Please refer to the response to CEC IR 1.1.2.

1.2 If TGI has population and demand forecasts could those please be provided.

Response:

The 20 year long term customer account and peak day demand forecast for the City of Nelson downstream of the Kootenay River aerial crossing is summarized in the table below. It is the peak day demand that drives the need for system capacity reinforcements.

City of Nelson	2010	2015	2020	2025	2030
Customer Accounts	5115	5327	5537	5748	5957
Peak day demand [TJ/d]	7.5	7.9	8.3	8.7	9.1

The account growth is expected to be primarily from heat sensitive residential and commercial customers. Total account growth is forecasted to be up to 0.9% per annum in the next 5 years and gradually levelling to 0.7% per annum in the long term. The peak day demand growth is expected to be approximately 1.1% in the next 5 years and gradually declining to 0.9% thereafter. TGI's forecasts look out 20 years and the Company has not forecasted the population and demand over the next 50 years.

1.3 What is the expected level of decrease in demand per year for these customers?

Response:

Please see the response to CEC IR 1.1.2.

1.4 What are the likely replacement costs for the system to deliver natural gas energy to these customers over the next 50 years?

Response:

As stated in the response to CEC IR 1.2.3, there are 173 km of mains in the Nelson distribution system. The replacement cost of the complete system is estimated to be approximately $10 million. Based on statistical review of service life data of distribution mains at Terasen Gas, and in consideration with the age of the mains population, it is estimated that approximately 70% (measured in value) of the distribution system would be subject to repair, refurbishment, or replacement over the next 50 years due to various factors such as main renewals or relocations at third party requests, third party damage, change and increase standards and codes, act of nature, obsolescence, and physical war and tear. The specific decision to repair, refurbish, or replace mains is and will be based on site and condition specific factors assessed and determined from the ongoing Integrity management program and maintenance activities.

1.5 Are there any existing plans for alternative heat energy supply for these customers?

Response:

At this time, Terasen Gas does not have any plans for alternative heat energy supply for these customers. However, we are aware that the City of Nelson has been exploring alternative energy options.

1.6 Might there be alternative heat supply options for these customers implemented over the next 50 years, which may render the natural gas service obsolete at some point during that time frame?

Response:

It is reasonable to assume that some form of alternative heat supply options may be implemented over the next 50 years either by Terasen Gas or by other businesses or the municipality. However it is difficult to forecast what form of alternative energy may be implemented within the 50 year timeframe or how many customers may switch to such service.

TGI believes that it is unlikely that the natural gas service will become obsolete because alternative energy options could include a district heating system where the heating source is natural gas. Even a move to a primary thermal heating source other than natural gas by the constituents of Nelson will not render the natural gas service obsolete as natural gas will likely be used for backup, reliability and/or a peaking supply. Alternative energy solutions and natural gas services are often complementary to each other.

1.7 Has TGI examined the financial sustainability of this Project investment and the potential for obsolescence relative to the market which is to be served and is to justify the amortization of the investment?

Response:

See the response to CEC IR 1.1.2 regarding demand and population growth in this region. See also the response to CEC IR 1.1.6.

In the case of this project there is no reliable way to predict if natural gas demand will diminish as a result of alternative energy options which have yet to be developed. Even if alternative energy options are implemented and demand diminishes, it is highly unlikely that the Project would become obsolete. As stated in the response to CEC IR 1.1.6, alternative energy options still rely on natural gas for peaking and reliability.

In addition, to paraphrase what is stated in Terasen Gas' 2010 Long Term Resource Plan, BCUC Project No. 3698604, Exhibit B-1, pp. 114, the utilities expect to continue adding new natural gas customers in view of new alternative energy initiatives, Energy Efficiency and Conservation activities, and implementation of new building codes and standards towards energy efficiency. As these new changes occur, the nature of demand may well become peakier as natural gas back stops the peaking needs of integrated, renewal thermal energy solutions.

2. TGI Application, Page 12

> The buried portions of the Savona Nelson Main Line between Savona and Castlegar have been inspected using In-Line-Inspection tools since 1988. The buried section between Castlegar and Nelson has been evaluated using over-the-line cathodic protection survey techniques with digs performed at selected sites to assess TGI's corrosion mitigation activities and to confirm asset fitness-for-service. To date, all buried portions of the TP pipeline between Savona and Nelson

2.1 The Castelgar Nelson line having been installed in 1957, while assessed and found fit-for-service, must have a useful physical life. What does TGI expect the remaining useful physical life of this line to be?

Response:

Terasen Gas has an effective Asset Integrity Management Program that ensures the pipeline remains safe, reliable, and fit for purpose. Numerous activities are applied to this pipeline, including corrosion monitoring, cathodic protection, leak surveys, preventative maintenance, pipeline patrol, class location surveys, public awareness, and damage prevention activities. Terasen Gas has also completed capital upgrades in certain segments when required based on condition assessments. For example, the Brilliant aerial crossing of the Columbia River, in the vicinity of the Kootenay River crossing at Shoreacres, was upgraded using HDD in 2008.

The average service life of TGI's transmission pipeline system is approximately 60 years, but individual segments may have a longer or shorter physical life. The specific decision to replace segments is based on site and condition specific factors, assessed and determined from TGI's ongoing asset integrity and asset management programs. At this point in time, the expected remaining life for this pipeline is indefinite.

2.2 What is the Castelgar Nelson line made of and what is a likely replacement cost for the line?

Response:

The Castlegar Nelson line is a 75 km long, NPS 6, API 5LX Standard, Grade 290 MPa steel pipeline. The rough estimate of the replacement cost for the complete line would be in the order of $50 million CDN in 2010.

2.3 What is the distribution system for the 5200 customers made of and does it have any of the long term corrosion issues causing US natural gas utilities to consider substantive replacement for safety reasons?

Response:

The distribution system at Nelson, ranging in sizes from NPS ¾ to NPS 8, is made of 90 km polyethylene and 83 km steel mains. The distribution system does not have any cast iron or bare steel mains that are known in the industry to have corrosion issues that are causes for substantive replacement.

3. TGI Application, Page 17

The Kootenay River aerial crossing has been in service for over 50 years, and is reaching the end of its useful structural life. Significant refurbishment would be required to extend the life of the pipeline crossing, and this would not address the immediate concern of the instability of the east slope.

3.1 What would be the expected cost of such significant refurbishment approximately?

Response:

As explained in Section 3 of the Application, the replacement of the existing crossing is necessary to address the slope instability at the east terminus and the deteriorating condition of the crossing. The safety and reliability of the aerial crossing cannot be considered in isolation of the slope instability. As further explained in Section 4.1.1 of the Application, based on technical obstacles, TGI rejected a refurbishment of the existing aerial crossing and any alternative using the same alignment. As it is not feasible to improve the slope instability to within acceptable limits using the same alignment, it is not possible to complete, and thus provide, a design or cost estimate to refurbish the crossing as a whole.

4. TGI Application, Page 19

> The linepack in the NPS 6 transmission line is limited. It is estimated that, following a failure of the crossing, loss of gas supply to customers would start in as little as one hour on a design peak day, and in approximately three hours on a normal winter day. The outage would last in the order of several weeks to several months to restore service to downstream customers. The east bank of the crossing is relatively remote and access would be difficult. Removing a failed structure in the presence of the unstable slope would have a significant impact on the east shore of the Kootenay River.

4.1. What has TGI's risk management back-up plan been for providing service in the event the crossing system collapsed and required several week to several months to restore service?

Response:

The proposal in this CPCN application to replace the existing aerial crossing is a risk management plan to ensure the integrity of an existing pipeline crossing and to prevent service interruption to the downstream customers.

In the event of a collapse of the current crossing system prior to the upgrade, it is very likely that gas service to the downstream customers would be interrupted for an extended period of time. Under such circumstance, TGI's emergency response would be to:

1. Initiate communication to discourage the use of natural gas
2. Isolate the damage section
3. Activate the safe shutdown plan for the distribution system as well as safe shutoff of customer gas appliances.
4. Provide Interim supplies in the forms of LNG and NGV mobile units, and propane service to meet energy needs of the critical customers
5. Construct an interim pipe crossing of the Kootenay River to reconnect supply of natural gas
6. Restore service through reactivation of the distribution system and safe appliance re-light for the customers

5. TGI Application, Page 28 and Appendix G

4.2.1.2 Preliminary Monte Carlo Analysis

As an additional review of the estimated capital costs, TGI carried out a preliminary Monte Carlo cost analysis on the three technically viable alternatives and the results are shown in Appendix G. This analysis further illustrates that HDD is the most cost effective of the three alternatives.

Based on this low probability of occurrence event, the results of this more conservative model indicate that the cost estimates only overlap if a comparison is made between the P90 (worst case outcome) for the HDD option versus the P10 (best case outcome) for the next lowest non-HDD cost option.

5.1 What is the probability of the HDD failing on the first attempt?

Response:

In order to determine the viability of the proposed HDD replacement of the crossing, TGI engaged Complete Crossings Inc ("Complete Crossings"), a qualified design and management firm specializing in HDD construction. Their assessment, entitled "Kootenay Shoreacres River Aerial Replacement Project Comparative Assessment", included in Appendix D of the CPCN, considered the available geotechnical data, access, construction methodologies, hydrological evaluations, survey data, and other relevant inputs. Complete Crossings' assessment states that "*Given the available data, all known significant technical issues can be mitigated by currently understood HDD mitigation techniques and therefore should be considered technically viable*." Hence, the probability of the HDD failing on the first attempt is low.

5.2 What is the probability of the HDD failing on the second attempt?

Response:

If the first attempt of the HDD crossing failed the HDD contractor and Terasen Gas would review the construction history to ascertain the likely cause(s) of the failed attempt. These causes may include changed subsurface conditions or the HDD contractor's methodology. The review would be used to make adjustments to mitigate the cause(s) on the second attempt. Notwithstanding the amount and degree of pre-construction planning that will be undertaken, continuous site specific information or more in-depth identification of the drilling challenges can only be gathered by proceeding through the HDD process. With the knowledge gained from the site specific conditions combined with the pre-construction information and process

modifications based on knowledge gained, the probability of a second failed attempt is further reduced in comparison to the first attempt.

5.3 What risks are there for cost over runs on the Pipeline TP and Pipeline IP options?

Response:

The significant risks for the reroute options are common to both the TP and IP options. The risks that may cause cost over runs include:

- The proposed pipeline corridor must cross or come close to a number of sites that have been identified in the Environmental Screening Report as contaminated. Offsite disposal for excavated materials and non standard construction practices to ensure the health and safety of the construction crew may be required.
- Some of the route will require blasting, the extent of which has been only preliminarily estimated without a geotechnical investigation.
- In order to carry the proposed pipeline, the bridges would require seismic retrofits for which a detailed design has not been completed and firm approval from the bridge owner has not been obtained.
- The option requires a number of highway, road, and railway crossings. Some of these may require non standard construction practices.
- The reroute options have to cross residential and Crown land. Costs and schedule for this are uncertain until property negotiations and First Nation's Consultation are complete.
- Construction contracts and materials purchase are subject to market conditions.
- Some portion of the route will have to be constructed in close proximity to the Kootenay River, thus adding additional permit requirements and involving construction windows. TGI expects this to be a risk to both cost and schedule.

6. TGI Application, Appendix H, Page 31 and Page 49

Terasen Gas Inc.
Shoreacres - Kootenay River CPCN Filing
Cost of Service Model_Large Angle HDD Class 3 estimate - Revenue Requirement Summary ($000's)

	Year (2011-2030)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Operating & Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Property & Other Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Depreciation & Amortization	58	677	677	677	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112
4	Income Tax	(49)	127	135	141	(38)	(27)	(17)	(7)	1	9	16	22	28	33	37	41	45	48	51	54
5	Return on Equity	132	317	291	266	251	246	242	238	234	229	225	221	217	212	208	204	200	195	191	187
6	Interest	144	344	316	289	272	268	263	258	254	249	245	240	235	231	226	222	217	212	208	203
7	Other Revenue	(283)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Total Revenue Requirement - Incremental	$0	$1,466	$1,420	$1,372	$596	$599	$600	$601	$600	$599	$597	$595	$591	$588	$583	$579	$573	$568	$562	$556
9																					
10	Total Volume (PJ)	157.7	158.1	158.4	158.8	159.2	159.6	160.0	160.4	160.8	161.2	161.6	162.0	162.4	162.8	163.2	163.6	164.0	164.4	164.8	165.2
11	Rate Impact ($/GJ)	0.000	0.009	0.009	0.009	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003

Appendix H

Table 4-3: Incremental Cost of Service and Rate Impact Summary

	HDD	TP Re-route	IP Re-route
Total Direct Capital Costs ($M) - As Spent	7.7	10.7	11.2
AFUDC ($M)	0.3	0.3	0.4
2012 Rate Impact ($/GJ)	0.0093	0.0112	0.0120
Levelized Rate Impact 25 years ($/GJ)	0.0046	0.0062	0.0071
Levelized Rate Impact 60 years ($/GJ)	0.0042	0.0059	0.0066
Levelized Incremental Revenue Requirement ($M)	0.7	0.9	1.1
Incremental Revenue Requirement NPV 25 years ($M)	8.7	11.9	12.5
Incremental Revenue Requirement NPV 60 years ($M)	9.7	13.4	16.2
Net Cash Flow NPV 25 years ($M)	5.9	8.3	8.4
Net Cash Flow NPV 60 years ($M)	5.9	8.2	9.9
2012 Incremental Rate Base ($M)	8.0	11.1	11.6

TGI Application, Page 31

At January 1, 2012, TGI proposes that the retirement costs and loss on disposal be transferred to the existing Removal Cost Deferral Account and Gains and Losses on Asset Disposition deferral account. Since neither of these two accounts currently has an approved recovery period, for purposes of determining the cost of service and cash flow impacts in this CPCN Application TGI has assumed a three year amortization period, although the actual amortization period will be determined as part of the Company's next Revenue Requirements application. The 2011 cost of service will be transferred to a rate base deferral account at the same time, also with a three year amortization period.

TGI Application, Page 49

6.1 Please describe why for the 2012 to 2014 the company chose early depreciation write-off amounts over 3 years.

Response:

For the purposes of this Application, TGI assumed a three year amortization period. This is because the total deferred charges are projected to be relatively small and therefore, choosing a longer amortization period would not have resulted in a significant rate difference over the life of the project.

As stated in the Application, the actual recovery period for the Removal Cost Deferral Account and Gains and Losses on Asset Disposition Deferral Account will be determined as part of the Company's next Revenue Requirements Application.

6.2 Please describe the causes and reasons for the 2011 to 2030 income tax amounts.

Response:

Terasen Gas is subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately includes these costs in calculating the total cost of service for a project. The income tax expenses (*refer to Appendix H, Table 1, line 4*) have been calculated using the flow-through (taxes payable) method, consistent with Commission approved past practice, at the currently enacted corporate tax rates of 28.5 per cent for 2010, 26.5 per cent for 2011 and 25 per cent starting in 2012.

Please find in Attachment 6.2 a schedule showing the detailed calculation for the income tax expenses as shown in Appendix H, Table 1.

6.3 Please discuss any potential intergenerational equity issues with respect to early rate impacts of $0.009/GJ to the later impacts of only $0.001/GJ and the significance of providing the levelized impacts for 25 years and 60 years in the summary table 4-3.

Response:

TGI believes that there are no material intergenerational equity issues associated with this pipeline system integrity project. Excluding the impact of the deferred charges that have been

amortized over a three year period, the annual rate impacts range from $0.004/GJ to $0.001/GJ, primarily as a result of the rate base impact from the declining net book value of the remaining plant. The rate impacts depicted in Appendix H Table 1 span 60 years and represent for project evaluation purposes the average service life of the pipeline asset over that period of time. The Company has included both 25 and 60 year levelized rate impacts to provide a rate impact view over the a common 25 year project evaluation period as well as over the full 60 year depreciated life of the pipeline asset. The results show that in all cases the rate impact on customers resulting from this integrity project is small.

7. TGI Application , Page 34

- This option meets the twenty year forecast capacity requirements, although it would likely require reinforcement shortly after this period.

7.1 What would the approximate cost of this later reinforcement be for this option to match the capacities of the other two options?

Response:

The additional reinforcement of the IP Re-Route option is a 12 km loop of the NPS6 IP line at an approximate cost of $6 million CDN in current 2010 dollars.

8. TGI Application, Page 46

Table 6-1: Capital Cost

	Large Angle HDD Option	Estimate in $2009 ($000's)	Estimate in $As-Spent ($000's)
1	**Pipe**		
2	Project Management, Engineering, Consultation, Inspection [2]	1,697	1,745
3	Temporary Workspace	463	483
4	Pipe & Coating Materials	266	276
5	River Crossing HDD Installation & Pipeline Construction	3,345	3,512
6	Tie in Construction	220	231
7	Permits [2]	169	173
8	CPCN Development Costs [1]	200	206
9	**Sub-Total - Pipe**	**6,361**	**6,627**
10			
11	**Land/Land Rights**		
12	Land/Land Rights	190	200
13			
14	**Abandonment & Removal**		
15	Aerial Crossing Removals	1,000	1,050
16	Retirement Costs	165	173
17	**Sub-Total - Abandonment & Removal**	**1,165**	**1,223**
18			
19	**Total Direct Capital Costs**	**7,717**	**8,049**
20			
21	**AFUDC**		254
22			
23	**Total Project Costs**	**7,717**	**8,304**

Notes

1. The CPCN Development Costs (line 8) include Legal, BCUC and Monte Carlo costs.
2. Line 2 (Project Management, Engineering, Consultation, Inspection) and Line 7 (Permits) of the table include the Project Development costs of $528K and $43K respectively. This amounts to a total of $571K of the Project Development Costs.

- All capital cost estimates are based on an in-service date of July 2011 and aerial crossing removal completed by October 2011.
- Cost estimates include all engineering, procurement and construction costs, regulatory and environmental costs, and workspace acquisition costs.
- Steel pipe costs based on March 2008 vendor pricing and subject to market variation.
- Includes First Nations OGC Pipeline Application review funding and archaeological monitoring and review. Does not include accommodations.
- Escalation rates are based on forecasted general construction price index. Excludes significant changes to rates for market conditions for specialist HDD contractors.
- Meets AACE Class 3 level.

8.1 How long can the removal of the aerial crossing be deferred?

Response:

TGI does not believe that it is acceptable to defer the removal of the aerial crossing once it is taken out of service. The slope instability on the east bank of the river, as discussed in Section 3.3 page 13 of the Application, poses an on-going risk of failure which, when occurs, would be detrimental to the fishery habitat and navigability of the Kootenay River.

9. TGI Application, Page 47

> The cost estimate for the Project has risen from $8.0 million at the Class 5 screening stage to $8.3 million at the Class 3 stage (in as-spent dollars). This is due mainly to an increase in the estimated cost to obtain a guaranteed completion contract for the HDD.

9.1 How much of the $0.3 million is due to the guaranteed completion contract?

Response:

Essentially all of the $0.3 million is due to an estimated increase to the risk transfer premium between a guaranteed completion contract versus a shared risk type of HDD construction contract. The estimated cost for obtaining a guaranteed completion is based TGI's experience and an assessment of the known risks to the HDD construction. Market conditions may cause the bids for this type of contract to deviate from this estimate. When the bids are received TGI will assess whether it is best to proceed with this type of contract.

9.2 Please describe the guaranteed completion contract and the relevant terms and conditions?

Response:

The two most common types of contract for an HDD project are a) payment only if the pipeline is satisfactorily completed ("guaranteed completion") and b) payment for work done – pipeline may or may not be satisfactorily completed ("shared risk"). Under a guaranteed completion type of contract for an HDD project, the contractor assumes more of the construction risk. Payment is based on satisfactory execution of the project by the contractor and may not vary with the length of time to complete the project or the efforts taken by the contractor to complete the project. The owner will only be responsible to the contractor for costs if the geotechnical conditions were found to be materially different from what was stated in the geotechnical information provided in the tender documents.

9.3 Please describe & quantify how often per year TGI, TGVI and TGW would potentially use HDD drilling technology on various projects?

Response:

HDD drilling technology has become increasingly more prevalent and sophisticated since the 1980's. With increased requirements to minimize disturbance to other infrastructure, environmental impact to water courses and fish habitats, and increased depth of cover requirements under river beds to achieve adequate seismic resistance, HDD drilling technology has become a common industry accepted method for crossings of TP pipelines. Small and intermediate HDD river, highway, and railroad crossings are now routinely engineered and constructed to Terasen Gas Standards.

Terasen Gas has engineered and constructed major water body crossings with HDD since 1991, and has utilized HDD on 27 major water crossings, and performed engineering studies on many more. On average, Terasen Gas has constructed 1 to 2 HDD crossings per year.

At present, 2 HDD crossings are underway across the Fraser River South Arm at Tilbury Island in 2010. Including the Project in this Application, there are two HDD projects planned in 2011.

9.4 Please describe & quantify how often TGI, TGVI and TGW have used HDD drilling technology in the last 10 years?

Response:

Please see the response to CEC IR 1.9.3.

Attachment 6.2

Terasen Gas Inc.
Shoreacres - Kootenay River CPCN Filing
Cost of Service Model_Large Angle HDD Class 3 estimate

Shoreacres - Kootenay River CPCN Filing: Income Tax Expense

Line	Particulars	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Income Tax Expense**													
2														
3	Earned Return	276,374	661,482	607,812	554,143	522,882	514,030	505,177	496,325	487,473	478,620	469,768	460,915	452,063
4	Deduct: Interest on debt	(143,894)	(344,402)	(316,459)	(288,516)	(272,240)	(267,631)	(263,022)	(258,413)	(253,804)	(249,195)	(244,586)	(239,977)	(235,368)
5	Add (Deduct): Amortization Expense	-	565,337	565,337	565,337	-	-	-	-	-	-	-	-	-
6	Add: Depreciation Expense	55,834	111,668	111,668	111,668	111,668	111,668	111,668	111,668	111,668	111,668	111,668	111,668	111,668
7	Deduct: Overhead Capitalized Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Deduct: Capital Cost Allowance	(324,476)	(612,607)	(563,696)	(518,691)	(477,280)	(439,176)	(404,115)	(371,854)	(342,169)	(314,854)	(289,720)	(266,593)	(245,313)
9	Taxable Income After Tax	(136,163)	381,478	404,663	423,941	(114,970)	(81,109)	(50,291)	(22,273)	3,168	26,240	47,130	66,014	83,050
10														
11	Income Tax Rate	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
12	1 - Current Income Tax Rate	73.50%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%
13														
14	Taxable Income	(185,255)	508,637	539,550	565,255	(153,293)	(108,145)	(67,055)	(29,698)	4,224	34,986	62,840	88,018	110,734
15														
16	Total Income Tax Expense	(49,093)	127,159	134,888	141,314	(38,323)	(27,036)	(16,764)	(7,424)	1,056	8,747	15,710	22,005	27,683

Line	Particulars	2024	2025	2026	2027	2028	2029	2030
1	Income Tax Expense							
2								
3	Earned Return	443,211	434,358	425,506	416,653	407,801	398,948	390,096
4	**Deduct: Interest on debt**	(230,759)	(226,150)	(221,540)	(216,931)	(212,322)	(207,713)	(203,104)
5	Add (Deduct): Amortization Expense	-	-	-	-	-	-	-
6	Add: Depreciation Expense	111,668	111,668	111,668	111,668	111,668	111,668	111,668
7	Deduct: Overhead Capitalized Expense	-	-	-	-	-	-	-
8	Deduct: Capital Cost Allowance	(225,732)	(207,714)	(191,135)	(175,880)	(161,842)	(148,925)	(137,040)
9	Taxable Income After Tax	98,388	112,162	124,498	135,510	145,304	153,978	161,620
10								
11	**Income Tax Rate**	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
12	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%	75.00%
13								
14	Taxable Income	131,184	149,550	165,998	180,680	193,739	205,304	215,493
15								
16	Total Income Tax Expense	32,796	37,387	41,499	45,170	48,435	51,326	53,873