June 12, 2018

VIA EMAIL

BCPIAC
Public Interest Advocacy Centre

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Our File: 7673

Patrick Wruck
Commission Secretary
BC Utilities Commission
6th Floor 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

Re: Pacific Northern Gas (N.E.) Ltd. ("PNG NE")
2018-2019 Revenue Requirements Application

Please be advised that we are counsel for the BC Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, and the Tenant Resource and Advisory Centre, known collectively in regulatory processes as "BCOAPO *et al.*" or "BCOAPO". The constituent groups of BCOAPO represent the interests of low and fixed income British Columbians, and more specifically in this process, the interests of PNG NE's low and fixed income residential ratepayers. As such, BCOAPO's member organizations have a direct and material interest in the outcome of this RRA.

As counsel for these groups, we make the following final submissions regarding PNG NE's application for approvals of a variety of items for its Fort St. John / Dawson Creek and Tumbler Ridge Divisions.

Background and Legal Basis for the Application

PNG NE is a subsidiary of PNG ultimately wholly owned by AltaGas Ltd. (AltaGas). This utility owns and operates natural gas distribution systems and a gas processing

plant in the north eastern part of the province and, due to its physically disconnected nature, it operates through two divisions: the Fort St. John / Dawson Creek division and the Tumbler Ridge division.

On November 30, 2017 PNG NE filed its 2018-19 Revenue Requirements Application with the British Columbia Utilities Commission ("BCUC") proposing a written process focussing on an Amended Application the Utility was intending to and did file on February 28, 2018, with an application soon after for approval of interim rates pending the Commission's final decision on this matter. BCOAPO filed written submissions on process in Exhibit C1-2 supporting not only PNG's proposal that this proceed by way of written process in the manner set out in the Draft Regulatory Timetable but that we should focus on the Amended Application provided we could refer to the original if there were material changes that took place between the first and second filing.

The Amended Application for the Fort St. John / Dawson Creek division indicated that the utility was projecting a revenue deficiency of $0.816M for 2018 and another deficiency of $0.842 M for the following test year using the proposed rate deferral mechanism to levelize the impact of the customer rate increases over the two years of the revenue requirement. Unfortunately, what may seem at first blush like a relatively small revenue deficiency in the world of utility regulation has a significant impact on the delivery rates of a system with a customer base as small as PNG NE. In the test period, its Fort St. John customers are facing a possible 6.2% delivery rate increase and another 6.0% one as of January 1, 2019. Those customers on the Dawson Creek system are looking at a possible 6.5% increase being approved on a permanent basis for January 2018 to December 31, 2018 and another 6.2% for the coming year.

For the average ratepayer, an increase of $25 to $27 one year over another may be disappointing but not daunting. However, to BCOAPO *et al.*'s constituents who live on largely flat and/or precarious incomes on the financial edge, these increases are daunting.

PNG NE's Tumbler Ridge Amended Application is forecasting a revenue deficiency of $207,000 for F2018 and $229,000 for F2019[1]. Like in the previous section, these figures are the result of the proposed rate deferral mechanism to levelize the impacts of the revenue deficiency over the two years. As a result, the Utility seeks to increase the Tumbler Ridge Residential rates by 18.1% in 2018 and a further 19.1% in 2019, for a cumulative increase of 40.65% in residential delivery rates over just two years[2].

In real terms, this means that a residential customer consuming 71.2 GJ will see their annual bill increase by $97 in 2018 while the same customer consuming almost the same amount (albeit slightly less at 70.3 GJ) will see their annual bill jump by $108 in 2019. Needless to say, this kind of jump in delivery rates and the annual bill increase per typical ratepayer figure are very concerning to us as the sole voice speaking for British Columbia's most economically vulnerable ratepayers. BCOAPO submits that this clearly fulfils the definition of rate shock and it is therefore incumbent upon the Applicant to mitigate, to the fullest extent possible, this shock primarily through effective cost controls and, secondarily, by way of proposals to smooth the lowered cost impacts.

For the Fort St. John's / Dawson Creek division, PNG NE is seeking BCUC approval of:

a) Recovery of the revenue deficiencies as described above, pursuant to sections 58 to 61 of the *Utilities Commission Act* for both F2018 and F2019;

b) The creation of a short term interest bearing rate deferral account in F2018 to levelize the impact of the revenue deficiencies in both test years, with the intention that this deferral account would be fully amortized at the end of the test period;

[1] Exhibit B-1-1, Tumbler Ridge, Page 3 of 87.
[2] Exhibit B-1-1, Tumbler Ridge, Table 2, page 7.

c) Changes and additions to the PNG NE suite of deferral accounts and amortization expenses pursuant to sections 58 to 61 as laid out in PNG's Final Argument

> (iv) Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2018 and 2019, pursuant to sections 58 to 61 of the *Utilities Commission Act*, as detailed in Section 2.9 – Amortization, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, including:
>
> a) Further to Commission Order G-105-17, approval pursuant to sections 58 to 61 of the Utilities Commission Act, to move the 2016 unaccounted for gas (UAF) losses above 1.5 percent from the temporary UAF deferral account to the UAF volume deferral account and to be recovered from customers via the Company Use rider, PNG(NE)'s historic mechanism for recovering/ refunding UAF losses/gains.
>
> b) Approval to eliminate the Legacy Deferred Income Taxes deferral account following the final amortization of the remaining balance in Test Year 2018; and
>
> c) Approval to eliminate the NPPRB Regulatory Asset deferral account following the final amortization of the remaining balance in Test Year 2018.

d) Approval of depreciation expenses based on a new depreciation study; and

e) Approval of a continuation of the UAF (unaccounted for gas volume) deferral account for the test years based on a 1% of deliveries loss factor requiring PNG NE to file for Commission approval to record any actual UAF losses that exceed 1.5% in this deferral account[3].

For the Tumbler Ridge Division, PNG NE is seeking the following approvals:

a) Recovery of the revenue deficiencies as described above, pursuant to sections 58 to 61 of the *Utilities Commission Act* for both F2018 and F2019;

[3] PNG NE Final Argument, pp 3-4.

b) PNG NE's proposal to create a short term interest bearing account in F2018 to levelize the impact of the revenue deficiencies for F2018 and 2019, with the intention that it would be fully amortized at the end of the test period.

c) PNG NE's proposals regarding its deferral accounts and amortization expenses for the test period pursuant to sections 58 to 61 of the *UCA* as laid out in the Utility's Final Argument

> a) Approval to fully amortize the Legacy Deferred Income Taxes deferral account balance in 2018;
>
> b) Approval to eliminate the Legacy Deferred Income Taxes deferral account following the final amortization of the remaining balance in Test Year 2018; and
>
> c) Approval to eliminate the NPPRB Regulatory Asset deferral account following the final amortization of the remaining balance in Test Year 2018.

d) The depreciation expense as set out in the new depreciation study; and

e) Approval of a continuation of the UAF (unaccounted for gas volume) deferral account for the test years based on a 1% of deliveries loss factor requiring PNG NE to file for Commission approval to record any actual UAF losses that exceed 1.5% in this deferral account[4].

Fort St. John / Dawson Creek

Absent any rate levelling, PNG NE has forecast revenue deficiencies of $0.515M and $0.970M in 2018 and 2019 respectively. The Utility's evidence is that to offset these deficiencies, residential rate increases of 7.5% and 3.7% would be required in 2018 and

[4] PNG NE Final Argument, pp 4-6.

in 2019. In order to smooth these increases PNG proposes to use an interest-bearing deferral account to capture a portion of the 2018 deficiency and transfer the balance to the 2019 requirement, allowing for more level rate increases of 6.3% and 6.1%. PNG states that the major drivers of the deficiencies are declining use per account (UPA) and capital expenditures[5].

BCOAPO takes no issue with PNG's UPA methodology in this proceeding.

While BCOAPO remains concerned with the magnitude of the smoothed rate proposals, a source of even greater concern is that the proposed increases do not cover all of PNG's potential claims for the 2018-2019 Test Period in respect of inter-affiliate charges nor do they cover PNG's claims to recover prior disallowed inter-affiliate charges - the collection of which would involve material retroactive recoveries from ratepayers[6]. BCOAPO takes this opportunity to make it clear that in no way does it support the recovery of the previously disallowed inter-affiliate charges in this proceeding to any extent in excess of what the regulator has approved.

Additionally, as large as the proposed rate increases are, BCOAPO notes that had PNG proposed to fully implement the Concentric depreciation study recommendations, the rates proposed would be even higher[7]. BCOAPO does not propose that the recommendations, especially with respect to negative salvage values, be implemented in any way other than proposed in this proceeding.

BCOAPO feels compelled to make submissions with respect to (i) actual rate base/capital expenditures and their forecasts, and (ii) the component of O&M expenses associated with vehicles. My clients note that both of these have increased substantially in recent years. To the extent that these are allocated costs, and given that there has been no major change in allocation methodology, BCOAPO's

[5] Exhibit B-1-1, page 6.
[6] Exhibit B-5, BCUC IR 1.21.1.
[7] Exhibit B-5, BCUC IR 1.25.3.

submissions apply in respect of these items apply to all divisions to which the costs have been allocated.

With respect to rate base/capital expenditures (cap ex), BCOAPO makes the following submissions. As a way to ground the examination of these expenditures, BCOAPO believes that it is useful to compare, at a high level, PNG NE FSJ/DC in 2018 with the same division's comparable expenditures in 2011, prior to its acquisition by AltaGas.

To do so, again at a very high level, BCOAPO has looked at some basic data from PNG's 2011 RRA (filed November 2010) with the 2018-2019 Application before us today. In the earlier RRA, the forecast 2011 utility rate base was $39,219,000 while forecast 2011 energy sales were 3,346 TJ and forecast 2011 deliveries were 4,511 TJ[8]. In this Application, the 2019 mid-year utility rate base is $77,075,000 while forecast 2019 energy sales are 4,029 TJ and forecast 2019 deliveries are 5,747 TJ[9].

In comparison, while rate base has almost doubled since 2011, sales and deliveries have only increased by about 30%. BCOAPO is concerned that a very large increase in rate base has occurred to support a far more modest increase in throughputs.

BCOAPO notes that PNG has agreed on the record that there is a financial incentive for the utility to over-forecast capital expenditures[10], thereby earning a test period return on a "phantom" investment that was never made. In addition, In that same IR response, PNG confirmed that there is no mechanism presently to correct any over-collection from rate payers during the test period. Therefore, absent the establishment of a deferral account to capture return (equity and debt) on investments that did not occur during the test period as a refund to ratepayers, the best we can do is to try to ensure that cap ex forecasts are as accurate as possible.

[8] 2011 RRA, Exhibit B-1, Tab 2, page 1.
[9] 2018-19 RRA, Exhibit B-1-1, Tab 2, page 1 and Tab 1, Schedule 1.
[10] Exhibit B-6, BCOAPO IR 1.5.1.

In this respect, BCOAPO notes that Table 36[11] shows that for 2016, while overall approved cap ex was $6,593,555, actual 2016 was $5,267,373, or about 20% less than approved. Table 36 also shows that almost half of the 2016 underspend can be attributed to the variance between 2016 Approved New Services spending of $1,482,013 and 2016 Actual New Services of only $850,222.

For 2017, there was a similar situation. The evidence is that although the 2017 Approved New Services spending was $1,512,610, 2017 Actual New Services spending was only $622,794: less than half of approved[12].

In fact, the Total Actual New Services spending for both 2016 and 2017 added together is less than the Approved Spending for just 2016 by itself.

Additional corroboration with respect to the forecast accuracy of distribution services is provided in response to a BCUC IR: although the 2016 and the 2017 forecasts for "New Distribution Service Lines" was 400 for each year, the Total Actual New Distribution Service Lines for 2016 was 207 and for 2017 was 127. In short, the 2016 actual was barely 50% of the forecast while the 2017 actual was less than 32% of the forecast[13]. BCOAPO submits that this is strong evidence of recent over-forecasting of the new services component of cap ex; as such, the new services forecast for the 2018 and 2019 Test Years should be reduced by at least 50% in both years, with appropriate adjustments made to the revenue requirement, revenue deficiency, and rates.

With respect to spending proposals associated with the GIS/digitization/asset management proposals, BCOAPO does not challenge that these projects may have increased benefits in terms of streamlining processes, improving communications and asset data access. However, BCOAPO does question whether these improvements should be wholly or even partially ratepayer-funded when this project involves no quantifiable ratepayer financial impacts and, to the contrary, necessitates an increase of

[11] Exhibit B-1-1, page 83.
[12] Exhibit B-5, BCUC IR 1.5.2.3.
[13] Exhibit B-1-1, BCUC IR 2.79.1.2 Table 1.

two new positions[14]. Indeed, with respect to the GIS project, BCOAPO is disappointed that the annual operating costs have already increased by 75%, from $125K to $200K[15].

With respect to Vehicle Maintenance costs, it is BCOAPO's understanding that these costs are included in the Automotive line item of Account 685 "General Operations." It is BCOAPO's further understanding that the forecast 2018 expense for this item is related to 2016 actual expenses inflated by 2%. Finally, it is BCOAPO's understanding that PNG is expecting to lower vehicle maintenance costs by performing more of this work in-house[16]. Given the preceding, BCOAPO invites PNG to explain why the 2018 Automotive costs in Account 685 are forecast to be $346,774, in considerable excess of the 2016 costs of $237,041 plus 2%.

Of course, any adjustment to decrease this line item should affect all divisions revenue requirement fairly as per the current approved allocation methodology.

Tumbler Ridge

BCOAPO would like to begin by noting that the unusually large 40.65% delivery rate increase over two years occurs even though the Applicant:

(i) Reserves the right to but has not in this case applied to recover previously claimed inter-affiliate fees to the benefit of AltaGas which would add further rate increases of 1.8% in 2018 and 0.9% in 2019[17];

(ii) Does not apply the depreciation study recommendations of its consultant in respect to negative salvage which would have added another 21.4% to the delivery charge in F2018 and 0.1% in F2019[18]; and

[14] Exhibit B-9, BCUC IR 2.84.1.1, 84, 85, 86 series of BCUC IR2.
[15] Exhibit B-9, BCUC IR 2.90.1.
[16] Exhibit B-5, BCUC IR 1.13.1 and IR 1.13.12.1, Exhibit B-11, BCOAPO IR 2.2.1.
[17] Exhibit B-3, BCUC IR 2.46.3.
[18] Exhibit B-3, BCUC IR 1.20.1.

(iii) Has proposed to fully amortize the Legacy Deferred Income Tax ratepayer credit in 2018 (rather than over three years) in order to mitigate the very large proposed increases which, if not amortized in 2018, would result in even higher rate increases in 2018 and 2019 of 20.3% and 19.3%[19]

These circumstances signal the very real potential of additional future rate increases proposed by PNG – independent of any other cost of service increases – because it seems unlikely that the Utility will fail to apply for further recovery of past inter-affiliate charges and depreciation changes at some point. That being said, we wish to make it clear that we are not proposing that the Commission approve a recovery of previously claimed inter-affiliate charges, nor does BCOAPO propose that the net salvage recommendations be implemented in this proceeding.

In reviewing the proposed increases, BCOAPO believed it might be useful to contrast the current Tumbler Ridge RRA for Test Years 2018 and 2019 with the 2011 Tumbler Ridge RRA filed November 30, 2010 prior to the acquisition of PNG by AltaGas.

In comparing Exhibit B-1 in the 2011 RRA with this Application's Exhibit B-1-1, counsel and her expert consultant were struck by the noteworthy increase in Total Cost of Service (excluding company use gas) from $1.113M in 2011 to $1.596M in 2018, an increase 0f 43.396% over 7 years which is equivalent to a compounded annual increase of 5.15% per year. Also, in reviewing the corresponding line items from the original 2011 submission and the amended 2018-19 application, two lines stood out: "Other Administrative and General" increased from $86,000 in 2011 to $144,000 in 2018, an increase of 67.4%, and "Return on Equity" almost doubled from $89,000 in 2011 to $169,000 in 2018. The change in the volumetric delivery charge (including company gas) proposed for residential customers has increased from $4.560/GJ to $8.911/GJ, an increase of almost 100% in this bill component.

[19] Exhibit B-8, BCUC IR 2.46.3.

With respect to "Other Administrative and General" expenses, BCOAPO has not been able to determine why this particular A&G line item – unlike other Operating, Maintenance, Administrative and General ("OMA&G") items which have remained far more stable – has increased by 67.4% over a seven-year period. BCOAPO invites PNG to, in its Reply, address this or at least provide a general rationale as to why the increase in this line item has been so severe especially as compared to other OMA&G line items.

Regarding the RoE costs, given that since gas deliveries have decreased while equity thickness and equity return have both increased, an increase in the equity return component of the cost of service is to be expected. However, BCOAPO cannot help but to note that, while both energy sales and gas deliveries have both decreased by approximately 40% since 2011, the mid-year rate base has more than doubled since 2011, from $2.194M in 2011[20] to $4.478M in 2018[21]
BCOAPO understands that the rate base is supported by schedules including 2017 closing balances (which we accept) as well as forecast capital expenditures and depreciation amounts.

In respect of forecast capital expenditures, BCOAPO notes the following:

- for 2016, of the $309K capital expenditures approved, only $193.5K was actually spent;
- for 2017, of the $334K capital expenditures approved, only $84.6K was actually spent; and
- for 2018, while seeking approval for $900K in cap ex, the year-to-date spending (as of the date when the response was provided), $0 had been spent[22].

For the full years 2017 and 2018 taken together then, only $278.1K or 43.25% of the approved project spending of $643K actually occurred, i.e., 56.75% of approved spending was not spent.

[20] 2011 RRA, Exhibit B-1, Tab 2, Schedule 2, page 1.
[21] 2018-19 RRA, Exhibit B-1-1, Tab 2, page 1.
[22] Exhibit B-8, BCUC IR 2.46.4.

This is an issue because BCOAPO notes that in response to Exhibit B-4, BCOAPO IR 1.5.2, the Applicant agreed that if the rate base is overstated, i.e. by incurring less than approved capital expenditures, the utility will over-collect on its return component. Given that the utility is forecasting, in 2018, approximately three times the cap ex that was approved for 2016 and 2017 (which forecasts the utility failed to meet) – and because on a year-to-date basis, the utility may reasonably be expected to underspend the 2018 forecast, BCOAPO submits that there is a real prospect of over-earning through the inflation of the rate base over the test period. As such, BCOAPO submits that, in line with actual 2016 and 2017 performance (and ytd 2018), and to be generous, the Commission should reduce the cap ex by only 50%.

CONCLUSION

Counsel has made it clear in this submission that her clients are concerned with the large proposed rate increases, particularly those for Tumbler Ridge. What is of additional concern is that PNG NE's customers are facing these significant increases despite the fact that PNG has declined to apply for (i) recovery of inter-affiliate charges previously disallowed, and (ii) full implementation of the depreciation study. Had either or both of these been proposed, the large rate increases would have been proposed to be even higher.

Given the alternative is an even rougher ride, BCOAPO cannot take issue with the smoothing proposals.

One issue that BCOAPO believes has increased significantly the revenue requirement since 2011 has been the (approximate) doubling of the rate bases for FSJ/DC and TR after the AltaGas acquisition of PNG in 2011. This has more than doubled the equity return component of the revenue requirement notwithstanding the fact that since 2011, neither utility energy sales nor gas deliveries have increased to anywhere near to such an extent for FSJ/DC while both have actually decreased in the case of Tumbler Ridge.

It is counter-intuitive that rate base nearly doubles when needs are stable or even decreasing.

BCOAPO acknowledges that the 2017 closing rate base – as a starting point for rate base going forward – reflects historical approvals, expenditures, depreciation, removals, etc. and as such, is not open to debate in this proceeding nor does it intend to engage in such a debate.

In this respect BCOAPO believes that part of this problem for 2018-19 rates is that there is a financial incentive for the utility to over-state capital expenditures to inflate the test period return component – and hence over-recovery of this component in rates – and as noted in its IR responses, PNG has agreed that there is no mechanism to reverse any such over-recovery after the fact. As such, BCOAPO urges that close attention be paid to recent actual-versus-approved cap ex and that this attention guide the approvals of current cap ex proposals in terms of amounts approved, perhaps in the manner we have suggested.

With respect to GIS/digitization/asset management projects, BCOAPO notes that while the utility has provided cost estimates for them and benefits to PNG in terms of streamlining processes, improving communications, and the like, BCOAPO has been unable to find any evidence of decrease in headcount or of any financial benefit to ratepayers whatsoever, despite claims of increased efficiency attendant upon project implementation. While BCOAPO does not dispute the need to modernize the records and asset tracking and management IT tools, BCOAPO simply believes that ratepayer-funded efficiency gains should yield tangible and quantifiable ratepayer benefits. And, as stated before, BCOAPO believes that amounts which impact the revenue requirement should be forecast as accurately as possible and recent experience should provide a guide.

Finally, given the steep increases in its services in recent years as well as the growing awareness of energy poverty and the financial challenges faced by British Columbia's low and fixed income population, BCOAPO is particularly disappointed that, absent government or regulatory direction that is not yet forthcoming, PNG appears unwilling to

contemplate any specific rate relief for its low income customers[23]. We urge the Utility to take the opportunity presented by the BCOAPO evidence filed in the BC Hydro RDA to develop a proposal of its own for all of its divisions to address these issues before the next RRA is filed.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Original on file signed by:

Leigha Worth
Executive Director, General Counsel

cc. Verlon Otto, PNG Director Regulatory Affairs

[23] Exhibit B-10, BCOAPO IR 2.1.1.