BRITISH COLUMBIA UTILITIES COMMISSION

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LETTER NO. L-40-94

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December 1, 1994

Mr. C.P. Donohue
Manager of Regulatory Affairs
Pacific Northern Gas Ltd.
1400 - 1185 West Georgia Street
Vancouver, B.C.
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Dear Mr. Donohue:

Re: Pacific Northern Gas Ltd.
1994 Public Draft Integrated Resource Plan (IRP)

Commission staff have reviewed PNG's *1994 Public Draft Integrated Resource Plan* and have incorporated their comments into the attached Staff Evaluation Report. Although the review finds some areas of debate regarding IRP methodology, and makes some suggestions for future IRP's, the review concludes overall that PNG's IRP is acceptable considering that PNG is a small utility with limited resources.

As noted in the staff review, PNG is encouraged to proceed with its plans to establish a voluntary stakeholder committee as soon as possible, and is further encouraged to make copies of the staff report available to the committee in order to assist in clarifying issues or areas of debate. The Commission also notes that, in the interest of full communication of IRP issues, it intends to make copies of the staff report available to intervenors in any future Commission hearing dealing with PNG's IRP.

If you have any questions regarding the staff review, please direct them to Jim Fraser at 660-4740.

Yours truly,

Robert J. Pellatt

JWF/dlf
Attach.

PNG/Cor/Draft IRP

PACIFIC NORTHERN GAS LTD.
Public Draft Integrated Resource Plan

BCUC Staff Evaluation Report

Overview and Summary:

Pacific Northern Gas Ltd. ("PNG") distributes gas to consumers in the west central portion of B.C. through its PNG-West system. PNG-NE distributes gas to the Dawson Creek and Tumbler Ridge communities.

PNG filed its Preliminary Draft Integrated Resource Plan ("preliminary IRP") on January 4, 1994. Staff met with PNG on 24 February 1994 to discuss the preliminary IRP, and questions or concerns were conveyed to PNG at that time.

PNG revised the preliminary IRP and completed a Public Draft Integrated Resource Plan ("IRP", "the plan") dated July 1994. The IRP was filed with the Commission in August 1994. PNG intends to widely distribute the IRP to customers and other interested parties, to seek comments from IRP recipients, and to consider their comments in the final version of the plan.

A first impression of the document is that careful thought has gone into the presentation of the plan. PNG has bound its IRP in a soft plastic cover, and printed on both sides of the pages, resulting in a smaller document than the three-ring bound, single-sided format commonly used; certainly PNG's format appears cheaper to produce and distribute.

In general, PNG should be commended for preparing a high quality IRP with limited resources. The utility and its staff have apparently carefully considered where resources could best be focused, and in areas where analysis is less complete or sophisticated than the methodologies chosen by larger utilities, PNG has attempted to explain its rationale for its approach and has attempted to apply logic to overcome limitations in the approach. PNG also particularly credits BC Gas for access to its stakeholder process, and borrows from the BC Gas IRP analysis in some instances. Staff are encouraged by the progress made in a short time frame by a relatively small utility. In the staff review, where critical comment is offered, it should be viewed constructively, and placed in a positive overall context

The IRP appears to be aimed at an intelligent non-specialist audience. The first four chapters establish a context for utility planning: following the executive summary, chapter 1, the introduction presents the background of PNG's planning efforts to date and lays out the structure of the report; chapter 2 reviews IRP concepts; chapter 3 describes the PNG system, and chapter 4 gives an overview of utility regulation. Chapter 5 and subsequent chapters present the individual components of the IRP and the resulting Action Plan. This staff review will focus on the chapters containing the IRP components, and for convenience will be presented in a format generally corresponding to the BCUC's IRP Guidelines.

1. Objectives of the Plan

The PNG IRP distinguishes between fundamental principles, primary objectives, means objectives, energy programs and attributes. Fundamental principles are defined as requirements rather than goals, requiring no valuation, and which are used to continually asses the IRP process and plan.

PNG lists the following four fundamental principles which underpin its IRP:

- balanced consideration of supply and demand-side resources,
- consideration of all suitable energy types,
- full recognition and valuation of energy choice impacts, and
- opportunity for and reflection of public input into the IRP.

In order to develop its IRP objectives, PNG met with various representatives from key customers, political groups, and planning and economic development personnel. PNG also monitored and considered the BC Gas stakeholder process and the BC Gas IRP objectives arising out of that process. The primary objectives of the PNG IRP include:

- economic efficiency
- financial merit
- environmental performance
- social benefit

Although staff would prefer to see it explicitly stated, the obvious assumption is that PNG intends these objectives as items to be maximized.

The PNG IRP also lists a "relatively diverse array" of means objectives, along with a list of one or more attributes related to the measurement of each means objective. Both qualitative and quantitative attributes are listed.

Staff believe that the selection of objectives and attributes is generally well thought out, although some minor concerns and disagreements arise. For instance, a means objective linked to the primary objective of economic efficiency is "Avoid rate reallocation between customer classes". In some instances, rate reallocation between classes is appropriate, as for instance, when supported by cost of service studies. If PNG is referring to unintended rate reallocation, resulting for example when the rates of one customer class change by more than is intended or justified by changes in costs or other factors, the objective is supportable. A word or two of clarification could be sufficient to alleviate this ambiguity.

A more basic concern relates to the primary objective "financial merit" and the means objective is "maintain or enhance rate base". The means objective deserves particular attention for three reasons: first, because of what it implies about the current rate of return of the utility, second because it appears circular in the context of an IRP and third because similar views appear to have been adopted implicitly or explicitly by utilities other than just PNG. Therefore staff are commenting more extensively here than would ordinarily be the case.

Fundamental to the concept of utility regulation is the notion that a utility will provide service to its customers at the minimum cost compatible with its operating objectives and that, in turn, the utility's shareholders will be fairly compensated for investments in the capital necessary to provide the service. A necessary corollary to this notion is the requirement that only investment that is prudently incurred and 'used and useful' will be compensated[1] . In other

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1 The prudent investment test and the 'used and useful' criterion may not result in the same conclusion regarding recovery of investment costs. Bonbright et al. (*Principles of Public Utility Rates*, 2nd ed., p.292) cite testimony arguing that, because utility investment may take place over several years, utilities should not be penalized for prudently incurred investment that is rendered redundant or obsolete by unforseeable subsequent events. The 'used and useful' criteria may be applied more in situations of premature failure of investment (e.g. a nuclear plant) where the issue is how much of that non-useful investment should be carried in rate base. It might also be applied in situations where utility rate base had been rendered obsolete by a subsequent utility investment before it had been fully amortized resulting in

words, ratepayers should not compensate the utility for assets which are not necessary to the provision of service.

For this reason, the inclusion of an objective in an IRP "to maintain and enhance rate base" is somewhat circular. The IRP is intended to determine the correct type and level of investment in order to achieve the IRP objectives; if one objective is to hold static or increase the level of capital investment the exercise may be limited or even biased by the objective. For example, assume that the objective to maintain and enhance rate base is included in an IRP, and that two alternative resource portfolios are being evaluated. Also assume that one resource portfolio scores equal or slightly higher against all objectives except the one to "maintain or enhance rate base". In that situation, depending on the weight attached to the rate base objective, a portfolio that was sub-optimal from the ratepayers perspective could be chosen simply because of the utility's desire to maintain or enhance its rate base. Under either the prudent investment test or the 'used and useful test' the utility should not be compensated for at least that portion of the investment incremental to the optimal portfolio.

It could be argued that maintaining and enhancing the rate base is central to the financial health of the utility, which is a fundamental objective that enables it to provide continued service to the customer. However, data cited in an article on DSM Incentives[2] suggests an inverse relationship between construction expenditures for electric utilities and stock price, leading to a tentative conclusion that growth in rate base is not associated with the financial health of utilities. If that is the case, then the question arises about the attraction that maintaining and enhancing rate base holds as a utility objective.

A possible answer to that question is found in the conclusion of Averch and Johnson that, if the allowed rate of return was greater than the cost of capital but less than that which the firm would realize if it could maximize profit without regulatory constraint, then the utility would tend to over-invest in capital (rate base) relative to the level which would result in cost-minimization[3]. Although magnitude and impact of the Averch-Johnson effect is still debated, a corollary that could be drawn from it is that, if a utility set growth in rate base as an objective, then the awarded rate of return to the utility was too high.

Informal discussion between Commission and PNG staff suggest that the utility also has concerns about the appropriateness of the "maintain and enhance rate base" objective, and is open to suggestions for alternatives objectives that would reflect the financial health of the utility.

With respect to the remainder of the objectives, most are highly supportable. The means objective "Application of innovative technologies" which is linked to the primary objective "Environmental Performance" is perhaps questionable insofar as innovative technology does

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excess capacity. Many commissions have taken the view that a unless both tests were met some of the new investment would be excluded from rate base (Phillips, *The Regulation of Public Utilities*, 2nd ed., p.325-27).

2 Newman, P. , S. Kihm and D. Schoengold. 1992. "Spare the Stick and Spoil the Carrot: Why DSM Incentives for Utility Stockholders Aren't Necessary". In *Regulatory Incentives for Demand-Side Management*, S.M. Nadel, M.W. Reid and D. R. Wolcott. Washington, D.C. : American Council for an Energy-Efficient Economy.

3 See Phillips, p. 809-10 or Bonbright , p. 356-62 for a discussion of the Averch-Johnson effect.

not necessarily imply more environmentally benign technology. However, staff believe that is the intent of the objective, and that the issue here is merely one of clarity.

2. Long-Term Demand Forecasts

PNG's IRP uses three annual delivery volume and peak day forecasts that extend over a 15 year period. The mid-case forecast assumes that changes occurring in the industrial sector now will continue and that changes anticipated for the industrial sector, will occur during the forecast period. The high and low case forecasts assume, respectively, optimistic and pessimistic levels of industrial activity.

PNG's forecasts are based on a 'bottom-up' approach that is neither end-use nor econometric, although PNG is collecting end-use data. The spreadsheet model used to create the forecast provides considerable disaggregation of the residential sector and flexibility in its handling of key determinants of gas use in the residential and commercial sectors. The industrial sector forecast considers individual customer use as well as energy use expectations at the sub-sectoral level.

The residential forecast uses a "declining stock and additions" methodology, and is based on regional population forecasts prepared by the B.C. Ministry of Finance. The population projections are adjusted for PNG's high and low forecasts to reflect expectations concerning industrial activity. Gas account penetration and gas use per account for both existing and new stock are determined exogenously to the model. Forecast annual gas demand is calculated as the product of the estimated number of accounts and the average use per account. Forecast design day peak use is calculated as 1/365 of non-temperature sensitive deliveries plus temperature sensitive deliveries/annual heating degree days, times the design day degree days. PNG and BCUC staff have previously discussed the method of calculating temperature sensitive sales, and agreed that the approach gives reasonable results and appears acceptable at this time

The commercial forecast uses an approach similar to the residential methodology except that it considers demand for the sector as a whole, rather than on a use/account basis. Peak day demand is estimated in the same manner as residential demand.

The industrial sector forecast is based on an aggregation of requirements of PNG's 15 core customers into industrial sub-sectors. The sub-sectoral industrial output can be adjusted on a percentage basis to develop the high, low and mid-case forecasts. The industrial sector makes up approximately 87 percent of the PNG-West gas demand, and the utility's bottom-up approach recognizes this. Staff discussed with PNG with respect to the earlier preliminary draft IRP whether it would be cost-effective to apply end-use modeling techniques to its industrial sector forecasts. PNG indicated at that time that the current method drew on the expertise of the local PNG and industrial staff, and that in the utility's opinion little would be added by more formal modeling.

Staff recognize that PNG is a small utility and are reluctant to suggest measures that would add additional costs to its IRP process. However, if no formal method of collecting and tracking industrial energy use data is maintained, there may be no opportunities to improve industrial sector knowledge and forecasting ability over time. If such data is collected and analyzed in an organized manner, then the incremental effort to apply that in an end-use model may be relatively small. Moreover, PNG's long-term demand is strongly influenced by possible future events in the industrial sector. Therefore, staff believe that, as PNG is a small utility, it not be directed to adopt a more sophisticated modeling technique now, but that PNG should discuss the issue further in subsequent IRPs.

The PNG forecasts included estimates of future NGV sales and of company fuel and unaccounted for gas. On a small point, staff note that the forecast of company use gas is shown on page 25 as being directly proportional to annual sales. As fuel use is approximately proportional to the square of throughput, this would overstate company use gas costs for the low case.

Generally staff believe that the forecast methodology to be sound for a utility the size of PNG and with its customer make-up. The concept of developing demand forecasts for each of 7 areas makes sense; however staff would encourage PNG to also establish design day and peak day demand forecasts for each area.

3. Identification of Supply and Demand Resources

3.1 Existing Supply-Side Resources

With minor exceptions, PNG has limited its initial discussion of supply-side resources to its existing supply portfolio. The utility purchases gas delivered to core customers on the PNG-West system from CanWest Gas Supply Inc. (CanWest) and four independent gas producers. Four of its five supply contracts which make up 86 percent of its firm daily contract quantity are long-term contracts expiring in 1999 or later. PNG notes that these contracts, predate the deregulation of producer gas pricing and that the terms are longer than would likely be negotiated now. All contracts call for delivery of gas to Station 2 on the Westcoast Energy Inc. (WEI) mainline, with PNG assuming responsibility for contracting with WEI for delivery of the gas from Station 2 to Summit Lake. Transportation customers assume responsibility for delivery of their own gas to Summit Lake; such gas currently constitutes approximately 74 percent of PNG's total gas deliveries. Staff note that there are some changes in the 1994/95 supply portfolio, and that PNG's supply/demand resources include some load curtailments for peak shaving and some seasonal and peaking supply contracts.

PNG's Dawson Creek system, which serves core market customers only, has no peak shaving capability. Gas supply is purchased from CanWest under contracts involving WEI and Peace River Transmission Company (PRTC).

The Tumbler Ridge system utilizes gas produced in the immediate area and purchased under contract with CanWest. In warm months, unprocessed gas from a sweet gas well is utilized, during periods of high demand, sour gas must be utilized and processed in PNG's own processing plant. PNG is investigating improved supply arrangements.

Staff believe that further discussion of supply side alternatives to baseload supplies (e.g. seasonal, storage, additional industrial curtailments, LNG) is required for a fully developed IRP. For instance, information about peaking type supply alternatives would appear valuable when calculating avoided costs, especially for loads that have a similar high peak requirement. An evaluation framework and data-set developed to compare supply alternatives would also be useful when comparing individual contracts within a category (e.g. the Talisman and CanWest baseload contracts). Information about individual contracts should be kept confidential but a more comprehensive evaluation procedure developed as part of IRP would enhance PNG's ability to make sound supply choices and the Commission's ability to review the prudency of these decisions.

Staff also have the following more specific comments:

- On page xv of the Executive Summary, PNG refers to its gas purchasing strategy of minimizing purchases under higher priced contracts. Presumably, this refers to the commodity portion of gas prices. Total gas costs, including demand charges and any offsets from interruptible sales, is the appropriate measure when considering a gas contracting strategy and evaluating DSM alternatives.

- Although the 1994 prices in the draft for PNG-West appear representative, the final IRP should be based on actual 1994/95 gas costs and any adjustments to actuals that are necessary to set the starting point for long term price projections should be explained.

- As PNG mentions on page 53, the practice in PNG-NE of buying gas at a streamed commodity price for each customer class is unlikely to continue. Prices forecast on a conventional demand/commodity structure would appear to give a better basis for estimating avoided costs.

- Although 1993/94 purchases are being made at a high annual load factor under baseload type contracts, a seasonal contract is expected for 1994/95 as Methanex is increasing its firm volume and will need less interruptible gas. It appears that PNG has assumed 100% baseload gas in its analysis; this is not the least expensive way to serve low load factor customers, and avoided cost figures should reflect a portfolio of supplies.

- The Westcoast charges for moving gas between PNG-West, Dawson Creek and Aitken Creek storage are relatively small ($.10/GJ at 100% load factor) and exchanges at a similar rate could probably be arranged with regard to Tumbler Ridge supply. As PNG's service areas have dissimilar load profiles and supply arrangements for Dawson Creek and Tumbler Ridge are being restructured, the IRP model should be capable of evaluating integration of supply for all the divisions. PNG has been directed previously to consider such integration.

- PNG refers on page 47 to 7700 GJ/d of additional peaking; Staff analysis suggests that this refers to the Skeena and Eurocan curtailments and that the total for peaking should be 14,470 GJ/d.

- Presently, a -20 degree C design day is used for PNG-West, which is reasonably close to the minimum temperature at Prince Rupert but less applicable further inland. PNG reserves 9900 GJ/d additional peaking from curtailments to cover temperatures below -20 and, while this seems to work, PNG points out on page 24 that a more rigorous analysis may result in lower supply costs.

- Finally, staff note that, strictly speaking, the BCUC Rules regarding Energy Supply Contracts require a rolling four year term for baseload contracts, rather than the "average" four year term mentioned on page 45.

3.2 Demand-Side Resources

The PNG IRP is structured such that potential demand-side resources are listed following the discussions of gas supply, energy prices and avoided costs, and the methodology used to assess potential DSM programs.

4.0 Characterizing Supply and Demand Resources

Appropriate characterization of the cost-effectiveness of alternative resource options requires an estimate of future avoided gas costs, and PNG's IRP has followed its description of existing supply resources with projections of future energy prices and avoided costs. PNG has also concluded after review that differences between average and avoided cost of gas upstream of Summit Lake are small. Therefore, the utility has assumed that the costs of processing and transmission on the Westcoast system will remain the same in constant dollars over the study period. PNG has restricted its incremental avoided cost calculation to its own transportation and distribution system costs using only the mid-case forecast and all customer classes.

For the PNG-West system, the utility contends that its avoided cost estimates for the PNG-West system are comparable to BC Gas's CIAC and TIAC analyses with the exception that the BC Gas estimates focus on the upstream costs and the PNG estimates focus on their own system costs. However, the utility argues that combining the two estimates would not be beneficial for two reasons: First, that PNG's gas supply is less complex than BC Gas's and would not likely be improved by optimization modeling for particular classes, load shapes or end-uses, and second, because for the PNG-West system:

> "PNG is able to achieve a high load factor on its lowest-cost gas contract and its own system through the sale of surplus core market gas nominations to its interruptible customers. Comprehensive recognition of specific customer class load factors in PNG avoided cost estimates, and decision making based on such estimates, would likely disrupt the existing pattern of mutual benefit between core customers and interruptible sales to transportation system customers" (p. 66-67).

However, the IRP goes on to state that the BC Gas CIAC analysis is useful and provides:

> "... strong confirmation regarding the desirability of different load shapes, and the targeting of an optimal load pattern. IRP measures that serve to reduce peaks and fill valleys throughout all components of the energy production and handling system work towards a desirable reduction of average and avoided costs".

Staff find PNG's rationale for its approach to avoided costs to be somewhat unclear. Arguably, the avoided cost estimate should be based on the differential between the avoided cost assuming the appropriate load factor for the customer group and any revenue that would flow back to the related customer class for off-peak sales. Staff note that PNG receives no offsets for gas cost demand charges in its interruptible rates, although there is the question of whether PNG could collect such offsets without losing interruptible sales. PNG appears to suggest that, at least as a simplifying assumption, use of a single avoided cost for all customer classes based on the overall high load factor is sufficiently precise for IRP purposes. Although there may be merit in this approach, the level of discussion in the IRP is insufficient to assess the adequacy of this assumption at this stage. In the final IRP, staff would like to see this discussion of appropriate avoided costs expanded.

Also, staff believe that avoided costs should be calculated for all three cases, as the range of "possible futures" is wider for PNG than for most utilities. In particular, the low case involving major load loss in 2002 is a significant risk management concern and may affect DSM programs as well as capital expenditures (e.g. is compression [lower capital cost, quicker depreciation, higher operating cost] preferred over pipeline looping?).

Finally, contrary to the statement at the bottom of page xvi, intuitively one would expect avoided delivery costs to be less than average costs if a large load loss were experienced (the low case forecast). And, although PNG suggests that it is using avoided cost and marginal cost interchangeably, there are significant differences between the avoided cost estimates and the marginal cost estimate in Table 8-2. Clarification of the difference between the avoided and marginal cost calculations would be helpful.

5.0 Development of Integrated Resource Portfolios/Evaluation and Selection of Resource Portfolios

5.1 Demand-Side Management/Load Management/Fuel Substitution Model

Following the discussion of energy prices and avoided costs, the IRP discusses the standard tests used to assess DSM programs, and the specific spreadsheet model which PNG developed to assess demand-side management, load management and fuel substitution ("DSM/LM/FS"). Several publications describe the generic benefit-cost tests used for assessing DSM; these are well-known to utilities and regulators, these need not be repeated here. Prior to developing its own model, PNG reviewed several utility IRPs and determined that there was an inconsistent application of the standard tests between utilities. PNG particularly notes a wide variation in different utilities' assumptions regarding program impacts for "...apparently similar programs".

PNG attempted to meet several objectives in designing its DSM/LM/FS model; ideally the model would:

- be applicable to fuel substitution as well as DSM and load management,
- accommodate analyses of program impacts from the perspectives of users and suppliers of other fuels as well as from that of the utility and gas users,
- allow consideration of the impacts of the energy program and of factors influencing the utility, regulators, government and customers in encouraging establishment of programs.
- support analysis of alternative program strategies.

Although the DSM/LM/FS model has the ability to include monetized externality values, this capability has not been used in the present IRP. Only those readily quantifiable impacts have been monetized; all other externalities were evaluated qualitatively placing considerable reliance on the BC Gas multi-attribute trade-off analysis (MATA). PNG has invited constructive comments regarding its model design and the achievement of its objectives. Generally, the model developed by PNG follows the 'California standard tests'. However PNG has added some additional cost factors to its model including:

- delay of anticipated original equipment replacement when it has been prematurely replaced by new efficient equipment;
- sales taxes on fuel and equipment;

- income tax impacts due to rate base treatment of utility investment in DSM and resulting changes in the return on equity.

The Commission has not determined the extent to which it will allow rate base treatment of DSM investments: however, the example used to illustrate the standard test model appears to show that the model has the capability to include income tax impacts but does not necessarily attempt to anticipate the degree to which the Commission will allow rate base treatment in any particular case. Staff also note that, in line with earlier discussions, PNG has 'netted out' from the societal test, tax components of items included in the TRC test, and that other tax impacts are not included in the TRC test. It was unclear what assumptions were made about future taxes on vehicle fuels.

5.2 Potential Demand-Side Management Programs

PNG has put forward a slate of potential energy management programs that are analyzed primarily for applicability to the PNG-West system, and then secondarily to the smaller PNG-NE system. With the exception of one NGV proposal, the utility has proposed only residential DSM programs. PNG states that, because there are few large commercial and industrial operations in the PNG service area, energy management programs can be offered on a broad public basis only in the residential sector. Commercial and industrial energy management opportunities would be identified and assessed for individual customers. PNG has also included two energy management program proposals that might be considered supply-side possibilities; these are discussed separately in this report.

In assessing potential energy management programs PNG has not relied on monetized externality estimates but has used the results of the BC Gas stakeholder process and MATA results. Staff have concerns that the BC Gas MATA results were confused by the time constraints on the BC Gas stakeholder process and therefore may not be as reliable as they could be. However, with that reservation and in the absence of a cost-effective alternative, staff also believe that PNG has chosen a reasonable approach in adopting the work of another utility.

(A minor point: the IRP states (p.80) that "Failure of the RIM test must be recognized to mean no more than that under stated conditions of utility involvement, the utility's ratepayers will not benefit". This overstates the negative implication of a failure of the RIM test in conjunction with a positive TRC, which only implies that *non-participating* ratepayers will not benefit.)

For convenience, the DSM program proposals and the test results are summarized below.

	Program type	Program Description	Participant	RIM	TRC
PNG-West					
Setback thermostat	cons/load mgmt	$45 incentive	3.70	1.00	4.35
Efficient home	cons/load mgmt	$50 contribution	2.84	0.85	1.75
Existing furnace replace	cons/load mgmt	$450 grant, low-int loan	1.32	0.84	1.24
"	"	no grant, low-int loan	1.19	1.01	1.23
New furnace upgrade	cons/load mgmt	$450 grant, low-int loan	1.47	0.73	1.03
"	"	$100 grant, low-int loan	1.08	1.01	1.03
R-2000 type incentive	cons/load mgmt	$2500 grant	1.42	0.71	0.97
		no grant	0.92	1.06	0.97
Hot water tank convers'n	load building	$100 grant, low-int loan	1.82	1.79	4.83
NGV-light vehicle conv	load building	$600 grant, low-int loan	1.16	0.82	2.12

	Program type	Program Description	Participant	RIM	TRC
"	"	no grant, low-int loan	1.09	1.09	2.11
PNG-NE(Dawson Cr)					
Setback thermostat	cons/load mgmt	$45 incentive	3.19	0.90	3.36
		$20 incentive	2.86	0.99	3.36
Efficient home	cons/load mgmt	$50 contribution	2.49	0.75	1.32
		$25 contribution	2.15	0.98	1.32
existing furnace replace	cons/load mgmt	$450 grant, low-int loan	1.21	0.78	1.08
		no grant, low-int loan	1.08	0.98	1.07
Hot water tank conv.	load building	$100 grant, low-int loan	2.37	1.07	4.36
NGV-light vehicle conv.	load building	$600 grant, low-int loan	1.14	0.81	1.94

Staff have not considered these programs extensively, because the program description in the IRP is relatively general and because PNG has not requested approval of any programs at this stage. However, staff do have some preliminary observations and questions.

The Setback Thermostat Program resembles the BC Gas programmable thermostat program. The Commission raised concerns with the initial BC Gas proposal about the actual level of savings that might be achieved with programmable thermostats, but approved a revised pilot program designed to answer some of the concerns raised by the Commission. The PNG proposal offers a slightly lower incentive and consequently PNG calculates a RIM test result of 1.0. Staff will review the program further at the time PNG applies for approval of the program, perhaps with the benefit of some preliminary results from the BC Gas pilot program.

The Efficient Home Program overlaps measures that would be undertaken by a proposed provincial government BC21 residential retrofit program. Therefore, if PNG chooses to participate in the BC21 program, the Efficient Home Program would be redundant.

The High Efficiency Furnace Incentive Programs for Existing and New Homes is again similar to a program examined in the recent BC Gas Phase 3 Hearing. Staff note that the Commission raised concerns in the BC Gas Decision about the reliability of the furnace technology and the level of the rebate. The Commission also supported the provision of a $40/unit incentive for the dealer/installer to encourage the provision of high efficiency furnaces for consumers. PNG has provided sensitivity test results for a program assuming both a grant and low-interest financing for consumers, and a program assuming low-interest financing but no grant. This additional information is helpful, although staff have additional questions about the program. For instance:

- "what impact does the elimination of the grant have on participation levels?"
- "can reliability be assured?
- "what impact, if any, will changing efficiency regulations have on program benefits?".

The R-2000 program proposed by PNG is aimed at new construction, and proposes a grant of $2500 for implementation of R-2000 standards. The grant is approximately one-half of the incremental cost of achieving the R-2000 standards. PNG has also tested the program assuming no grant which increased the RIM test result to just over one, and decreased the participant test result to just under one. Staff have similar questions with respect to this program as the High-Efficiency Furnace Programs.

PNG has also proposed two load building programs a Hot Water Conversion Incentive Program and a Light Vehicle NGV Conversion. The Commission has previously expressed concerns about such programs as have intervenors in recent BC Gas hearings. Staff also question the need for an incentive program when PNG notes that "the benefits of conversion are relatively insensitive to the level of the grant". Another issue that staff believe should be explored is whether there would be additional benefits achieved from the promotion of conversion to high-efficiency gas water heaters.

With respect to the NGV Conversion Program, staff note that the program offers a positive TRC test result and, depending on whether a grant is offered or not, a RIM test result below or slightly above one. A loan financing level 50 percent higher than the $1600 maximum now offered was assumed for the tests. PNG indicates that it believes the test results may be understated. Staff believe that more information is required before additional incentives can be fully considered for PNG.

5.3 Resource Options for Further Study

PNG also includes, as a possible resource option, methanol storage at Kitimat, so that when additional capacity is required on the PNG system, methanol could be provided to Methanex from storage in exchange for a reduction in demand on the PNG system. PNG estimates that a one kilotonne methanol storage tank would cost roughly $500,000. Staff suggest that, although it may be cost effective for PNG to buy more service curtailment / firm gas supply from Methanex, it is not at all obvious that it would be efficient for PNG to own and manage methanol storage to accomplish this.

On the supply-side, if PNG could arrange for delivery from the discharge side of WEI's mainline compressor station at Summit Lake, even at some additional cost, PNG would reduce the need for one of its Summit Lake compressors and thus reduce its fuel use and fuel costs.

6.0 Action Plan

PNG's intends to incorporate responses to public concerns in its final action plan, so the Action Plan in this Draft IRP is tentative.

6.1 Residential Energy Management Programs

At this stage, PNG's IRP Action Plan includes all of the residential energy management plans discussed in section 5.2: PNG is also proposing to study the relationship between temperature and core customer gas demand.

6.2 Commercial and Industrial Opportunities

PNG has suggested in its Action Plan that there are other energy management potential opportunities among its commercial and industrial customers, and is proposing to spend up to $50,000 during each of 1994 and 1995 to study these energy management issues. These include:

- wood dry kiln efficiency and fuel choice,
- fuel choice in pulp and paper drying,
- use of wood residue, possibly supplemented with gas for electricity generation or cogeneration,
- substitution of gas for electricity in metallurgical processes,
- small gas cogeneration for large, high load factor heat and electricity loads,
- 'housekeeping' improvements at industrial and commercial sites.

PNG is also planning technical and economic studies relating to the viability of using CNG or LNG for fueling logging and pulp chip trucks, and of using LNG for a peak shaving and emergency backup resource. Keeping in mind the comments made earlier regarding residential energy management plans, staff are supportive of the activities planned by PNG in its Action Plan. Staff recognize that it is tentative in this draft and look forward to more detail in the final plan.

7.0 Public Involvement

Staff also note that PNG has included, as Appendix A, an "Invitation for Public Response" and plans for obtaining stakeholder input, including a short mail-in form encouraging potential advisory panel volunteers to register their willingness to participate. Staff would encourage PNG to form such a voluntary stakeholder committee as soon as possible. Ideally the committee would include representatives from key interests, such as customers, local businesses, local government, environmental groups, first nations groups, and others who would have an interest in PNG's IRP. Staff do not believe that PNG's public involvement process needs to be similar in scale to public involvement processes undertaken by larger utilities, and that the use of a professional facilitator or the payment of per diems to participants should necessarily be required. Although the level of activity of such a stakeholder committee will depend on the issues to be considered and the time commitments of the stakeholders, staff consider approximately one meeting per month as being representative of an appropriate level of activity such a committee would undertake. Staff are prepared to assist the utility in its public involvement process, where possible and as requested. Copies of this report should be made available to the stakeholder committee by PNG, in order to help the stakeholders better understand some of the issues involved in Integrated Resource Planning. The Commission will make copies of this report available to parties who register to intervene in the next public hearing concerning PNG's IRP.

8. Conclusion

Staff wish to conclude by reiterating the comments made at the outset, that the overall impression of PNG's IRP is positive. Many of the issues within the general process of integrated Resource Planning are subject to ongoing debate, and the comments made in this staff evaluation are intended to be construed as constructive contributions to some of those debates.

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