CAARS

West Kootenay Power Ltd. 1994/95 Revenue Requirements, Rate Design, IRP June 17, 1994

1.0 INTRODUCTION

The West Kootenay Power Ltd. ("the Applicant", "WKP", "the Company", "the Utility") system serves some 116,000 customers. Approximately 40 percent are served indirectly through the sale of power to municipal distribution utilities in Grand Forks, Nelson, Kelowna, Penticton, Summerland and through Princeton Light and Power Company, Limited ("PLP"), a private company serving Princeton and vicinity.

Power is supplied from WKP's four plants on the Kootenay River, purchases from Cominco Ltd. ("Cominco") and purchases from the British Columbia Hydro and Power Authority ("B.C. Hydro"). WKP is a wholly-owned subsidiary of UtiliCorp British Columbia Ltd. ("UtiliCorp B.C."), which in turn is a subsidiary of UtiliCorp Inc. ("UtiliCorp") of Kansas City, Missouri.

1.1 Power Supply

In 1993 WKP had a peak load of over 600 MW. The four WKP plants on the Kootenay River, with a total installed capacity of 190 MW, supplied only 40 percent of WKP's capacity requirements. Purchases from Cominco supplied a further 46 percent and purchases from B.C. Hydro 24 percent. The gross load of 3,005 gigawatt hours ("GW.h") was supplied 51 percent from WKP's own generation facilities. Thirty-two percent was purchased from Cominco, and the remaining 17 percent from B.C. Hydro, with minor market purchases.

WKP purchases power from Cominco under two power supply agreements. The Long-Term Firm Power Supply Agreement provides for the purchase by WKP of 75 annual average megawatts ("aaMW"), on a take-or-pay basis, until September 30, 2005. The 1999 Firm Power Supply Agreement provides for the purchase by WKP of a further 38 aaMW, on a take-or-pay basis, until December 31, 1999. WKP is entitled to utilize, on an hourly basis, any unused Cominco capacity at no cost.

Purchases of power by WKP from B.C. Hydro have been largely for seasonal peaking purposes and vary from maximum levels in the winter to near zero in the summer. Prior to September 1993, power purchases were made according to the Power Purchase Agreement ("PPA") which provided for energy and capacity under B.C. Hydro Rate Schedule 3807 ("Rate 3807"). In accordance with a British Columbia Utilities Commission ("the Commission", "BCUC") Decision, and Order No. G-27-93 issued April 22, 1993, Rate 3807 terminated on October 1, 1993 and was replaced on that same date by Rate Schedule 3808 ("Rate 3808") and an amended PPA.

The area served by WKP is expected to have an increasing need for electricity due mostly to the growing population. The major growth area is centered in the Okanagan Valley. Increasingly, electricity to serve this area must be moved long distances from the generating sources on the Kootenay River, or be purchased from B.C. Hydro.

1.2 The Applications

WKP applied on November 30, 1993 for an interim refundable increase of 7.6 percent to be effective January 1, 1994, and a further increase of 5.6 percent effective January 1, 1995. The Applicant stated that the increases were necessary to provide adequate revenue to generate a fair return on the increased investment in plant and equipment, and to help offset higher property taxes on generating plants and substations. The Application also seeks approval to implement certain changes in Service Connection Fees in Rate Schedule 82 and to amend the Energy Management Service in Rate Schedule 90.

A reduced interim increase of 5.7 percent for 1994 was approved, subject to refund with interest, by Commission Order No. G-125-93 dated December 23, 1993, reflecting a general decline in interest rates and the reduced yields on the Government of Canada Long-term Bonds since the date of the 1993 Decision on WKP's revenue requirements.

On December 3, 1993 the Company made application for changes in Rate Design methodology and on December 30, 1993 it filed its Draft Integrated Resource Plan ("IRP").

The Applications and IRP, pursuant to Commission Order No. G-118-93 dated December 8, 1993, were set down for hearing on March 7, 1994 in Rossland, B.C.

Subsequent to the issuance of this Order, in an effort to streamline the regulatory process, the Commission approved the inclusion of WKP in a joint public hearing on capital structure and return on equity ("ROE") with BC Gas Utility Ltd. ("BC Gas") and Pacific Northern Gas Ltd. ("PNG"), set to commence April 5, 1994 in Vancouver. The general public and all intervenors were given notice of this change by Commission Order No. G-4-94, and consideration of the appropriate rate of return on common equity and capital structure for WKP was thereby deferred to the April 5, 1994 generic ROE hearing.

On March 1, 1994, WKP revised its requested increases downward for January 1, 1994 to 5.9 percent and upward for January 1, 1995 to 6.5 percent. The increase as revised for 1995 is higher on a percentage basis from the original application, but lower on a revenue basis due to the fact that the reduced increase in 1994 leads to a lower base upon which the 1995 increase is calculated. WKP stated that the reasons for the revision were to reflect changes in forecast power purchases, labour costs and alterations to the capital plan.

2.0 INTEGRATED RESOURCE PLANNING

2.1 Background

In early 1993, WKP prepared an interim draft IRP for the review of B.C. Hydro's Rate 3808 Application which, after the Commission's Decision, was revised for its own rate hearing. In February 1993, the Commission issued IRP Guidelines, with a subsequent direction that all utilities file detailed draft IRPs by December 31, 1993. WKP filed its draft IRP by the December 31, 1993 deadline.

In preparing its draft IRP, WKP engaged the services of external consultants to assist in developing both the public participation process and its social accounting framework. WKP acquired and developed IRP and demand-side management ("DSM") computer modeling systems. In June 1993, WKP issued a request for proposals to a wide range of potential Independent Power Producers. WKP also did an extensive review of its current DSM programs and performed a benefit/cost screening of 75 percent of all programs identified within its conservation potential study. Finally, to validate social attributes and rank resource options, WKP conducted a public consultative process involving 15 members of the public over a period of several months.

WKP's draft IRP presents six possible resource portfolios including WKP's preferred strategy and the strategy preferred by its consultative committee, which are similar except that the consultative committee strategy includes the 52 MW Similkameen project. A least financial cost portfolio was also included.

WKP is to be commended for the substantial effort to produce its draft IRP by the Commission's deadline of December 31, 1993. This significant progress in such a short time period is all the more noteworthy given the fact that this is a small utility and that utility staff and advisors were also engaged simultaneously in preparation of a rate design application and a general rate application. Moreover, as noted in the following chapters of this Decision, WKP's IRP has now reached an advanced stage of development, with estimates of avoided cost, a full slate of DSM options, analytical integration of supply and demand, application of a multiple account evaluation framework to account for non-monetized decision factors and incorporation of public involvement.

This chapter of the Decision is intended to provide direction to WKP to guide its efforts towards improving the draft IRP for submission for approval of a completed IRP by February 28, 1995. It should be noted that many of the directions and suggestions in

this chapter of the Decision have already been acknowledged and accepted by WKP during the course of the hearing (T. 992-1012).

2.2 Role and Value of IRP

In the hearing there was some discussion, between counsel for the B.C. Energy Coalition ("the Coalition") and Mr. Ash and Mr. Siddall of WKP, regarding the intended effect of the integrated resource planning process with respect to approval of individual projects. While counsel for the Coalition suggested that IRP is intended to reduce controversy at the project certification stage by the early incorporation and accommodation of concerns of interested parties, Mr. Ash and Mr. Siddall suggested that this would not be the case, partly because of the possible need to involve jurisdictions outside of British Columbia (T. 751-753).

The Commission finds itself generally in agreement with the line of argument put forward by the Coalition. While the IRP will not always reduce certification uncertainty and controversy, this is an intended benefit. The IRP process results in a valuable pre-screening of projects for their environmental and social impacts and general public acceptability. Those projects which fail these initial tests can be rejected, thereby avoiding unnecessary and costly hearings. While Mr. Ash is quite correct in pointing out that IRP approval does not imply automatic approval in the certification process of individual projects, support by the Commission for actions proposed in the IRP should provide utilities with some level of confidence with respect to the prudency of individual expenditures. It should also increase a utility's awareness of the challenges and risks associated with proposing a particular project or portfolio of resources. This should enhance the likelihood of approval of subsequent reasonable expenditures made to assess more accurately the resources put forward for pursuit in the IRP. This includes resources which would eventually require a Certificate of Public Convenience and Necessity.

2.3 Consultative Committee

To meet the Commission's guideline requiring public input into the IRP process, WKP assembled a consultative committee comprised of members of the public residing within the Utility's service area. This group was charged with the task of reviewing the demand and supply resource options and, through a multiple account evaluation process, selecting a preferred resource strategy.

There was considerable discussion in the hearing on the composition of the consultative committee. In cross-examination, the counsel for the Coalition, the counsel for the Consumers' Association of Canada (B.C. Branch) and several other senior citizens or low income groups ("CAC(BC) et al") and Mr. Scarlett of the Kootenay-Okanagan Electric Consumers Association ("ECA"), suggested that the consultative committee lacked clear environmental representation and that representation of this viewpoint could be achieved by selection of someone from outside the Utility's service area (T. 551, T. 1210 and T. 1863-1871). WKP initially suggested that an environmentalist perspective did not necessarily require explicit membership in an environmental organization. However, in its summary comments at the hearing, the Utility committed itself to add a representative from environmental interests when reconvening the consultative committee within the next six months (T. 1001).

In support of its suggestions for the WKP consultative committee, the Coalition submitted a document entitled Canadian Round Table on the Environment and the Economy, Building Consensus for a Sustainable Future: Guiding Principles, August 1993 (Exhibit 31). Based on that document, the Coalition also suggested that the consultative committee should have a neutral facilitator, should function more as a decision making collaborative than as a consultative committee, should be more in control of its process, and should be given more time (T. 1861-1889).

WKP did not explicitly commit to all of these suggestions, but Mr. Ash did comment upon WKP's desire to continue to make adjustments (T. 1001).

The Commission agrees that the public participation process needs further development, and suggests careful consideration of the following changes. The Commission recognizes that some of the criticisms relate to deadlines imposed upon WKP by the Commission.

1. **The consultative committee should be converted to function more along the model of a collaborative, with greater independent control over its process. However, participating members of the collaborative must be clearly aware that the outcome of the collaborative process cannot be binding on the Utility management. Ultimately, the Utility management and then the Commission have decision-making responsibility for determining the prudency of the Utility's IRP and the Action Plan contained therein. Neither management nor the Commission can avoid their responsibilities via a collaborative process.**

2. **The consultative committee should try for consensus. Where consensus cannot be realized, members may write dissenting positions.**

3. An independent facilitator should be retained by the consultative committee.

4. The consultative committee should have explicit representation from environ-mental and other key interests. The individuals providing such representation need not reside in the Utility service area, although this may be preferred.

5. The consultative committee should be given more time, recognizing the iterative process involved in conducting in-depth trade-off analysis of the major packages of resource options. However, public involvement processes must conform to Commission deadlines.

2.4 Multiple Account Evaluation Methodology

A multiple account evaluation process is a method of dealing with decision factors that are not reducible to a single dimension. Traditionally, cost-benefit analysis attempts to reduce all decision factors to a monetary dimension. To the extent that existing environmental regulations require specific investments (e.g. in pollution control equipment) these regulations result in the monetization and internalization of some environmental costs. However, in some jurisdictions, utilities and utility commissions are striving to go further by monetizing all environmental impacts.

Problems with this approach include the limits of natural sciences to detect all environmental impacts and the limits of social sciences to accurately estimate the economic value of such impacts. A multiple account evaluation process may include monetization of some impacts, but does not seek to reduce all impacts to a single monetary dimension. Instead, the multiple accounts represent different decision dimensions measured in different units, some of which may be qualitative. If these accounts can be reduced to a manageable set, it is possible for decision makers to make trade-offs between objectives when selecting among portfolios of resource options. This provides implicit values for non-monetized impacts; for example, it is possible to determine how much the decision maker is willing to pay to reduce or to mitigate a particular impact.

The multiple account approach is encouraged by the provincial government as indicated in its direction to B.C. Hydro and as discussed in the material provided by WKP (Exhibit 13, Tab 4, page 14 and Tab 9). This approach is currently favoured by this Commission, as noted in the Commission Guidelines (Exhibit 42, Guidelines 4 and 6).

WKP established a multiple accounts evaluation methodology for use by its management and the consultative committee. **The Commission is generally in support of the approach taken by WKP and notes the Utility's rapid application and development of software and staff skills to assist the process.** Nonetheless, the Utility was working under a severe time constraint and the hearing revealed some suggestions for possible improvement.

2.4.1 Presentation of Resource Options

WKP presented 55 supply-side resources, and two groups of DSM measures, those of WKP and those at the Cominco operations in Trail (Exhibit 11, Tab 8, Table VIII-1 and Tab 9). After discussion, Mr. Siddall of WKP agreed that some pre-screening of supply resources could get the total number considered by the consultative committee down to a more manageable level (T. 996). The Commission supports this pre-screening, but cautions that pre-screening should not result in the elimination of legitimate resource options.

Another concern identified was the manner in which DSM projects were pre-screened. These projects were selected for consideration in the multiple account evaluation methodology on the basis of the Total Resource Cost Test (Exhibit 11, Tab 6, Table VI-2), with only the surviving projects evaluated against supply-side options with regard to environmental, social and reliability attributes. DSM projects that failed the economic tests were not available for evaluation by the consultative committee, thus eliminating any opportunity for the consultative committee to choose those DSM projects which had desirable attributes in other accounts to offset their higher cost in the financial account.

In future, the Commission suggests that DSM resources should be disaggregated into sets of measures, distinguished by cost. This would allow the consultative committee and management to explore the extent to which they would be willing to include DSM projects that involved the trade-off of higher financial costs (hence higher rates) against non-monetized gains in the other accounts.

Another issue arose concerning the definition and characterization of resources. In particular, WKP characterized the Ashlu project as being a lost opportunity resource to the Utility, although recognizing that it might not be so from other perspectives (T. 931 and T. 1265-1266).

Defining lost opportunity resources from a social perspective is an important consideration. The Commission is of the view that the common definition of a lost opportunity is a resource which will be lost to the whole of society if it is not realized at a specific time. Thus, the examples in the BCUC IRP Guidelines refer to new

building conservation measures and cogeneration when pulp and paper mills are being retrofitted. WKP seems to be using the concept in a competitive sense: the resource may be realized by society at the right time, but not by WKP. This definition is troubling to the Commission because it could be used to justify preemptive investments in a competitive but rising costs market. The Commission does not accept that the Ashlu project should be advanced using the lost opportunity resource definition. However, the project may still merit inclusion in WKP's IRP resource portfolio depending on other attributes.

2.4.2 Single Costing Framework versus Multiple Accounts

In his pre-filed evidence (Exhibit 33), Mr. John Todd, an expert witness retained by the CAC(BC) et al, raised the issue of commensurability and measurability of objectives and attributes. Mr. Todd argued that all desirable and undesirable impacts of a resource development should be reduced to a single-costing framework and that the effect of not doing this is to undervalue social and environmental resources.

The following are extracts from Mr. Todd's pre-filed evidence:

> "Second, significant effort is required to refine the social/environmental costing framework. The relative uncertainty and lack of precision in these costs at this point in time is being used as a rationale for giving social/environmental costs a low weighting in resource planning. It is probable that B.C.'s social and environmental resources are being undervalued and, as a result, are not being used wisely. (page 2)
>
> In my view, these objectives are subsidiary to a single broad public policy objective. The "full cost" of power in British Columbia should be minimized, subject to any overriding policy objectives imposed on the company by legislation or regulation.
>
> ...full cost accounting provides a framework for dealing with these tradeoffs <u>by including all resources in a single costing framework</u>. Corporate, customer, social and environmental resources are optimally balanced by integrating them into a common framework that maximizes the provincial benefits derived from these resources. This approach builds on the traditional tools of economic analysis by explicitly including social and environmental costs in the planning process. In economic terms, external costs are internalized for decision-making purposes. (emphasis added) (page 3 and 4)
>
> The following comments show how the objectives can be integrated, and made more explicit, by using the concept of full cost accounting." (page 5)

However, under cross-examination, Mr. Todd agreed that he might internalize some monetized costs into the financial account and then make additional adjustments to other accounts for the costs that were not successfully monetized (T. 1102-1104). This is, in essence, the approach followed by WKP and elaborated upon in the Consultative Committee Report and in material prepared by the British Columbia Ministry of Energy, Mines and Petroleum Resources (Exhibit 13).

Further, under cross-examination, Mr. Todd also retracted his assertion that emissions in the environmental account are underweighted relative to emissions that are costed and included in the financial account (T. 1105). He acknowledged that additional information was required to determine if this were in fact the case.

The Commission agrees with the multiple accounts approach of WKP and notes, moreover, that Mr. Todd appeared to shift to this position under cross-examination.

2.4.3 Problems of Weighting and Aggregating Attributes and Accounts in the Multiple Accounting Framework

Several intervenors questioned the multiple account weighting and aggregating method applied by WKP, pointing out that some of the resulting rankings within individual accounts did not reflect real relative merits. For example, Table A-17 in Exhibit 11 shows DSM as scoring 23rd, below many supply projects, in the social focus, and Table A-16 in Exhibit 11 shows DSM as scoring 11th relative to other options with regard to environmental impacts. Under cross-examination, Mr. Siddall of WKP admitted that the method of ranking options needed to be refined to prevent such outcomes and undertook to make the necessary corrections and refinements (T. 686-691).

Counsel for the Coalition worked through the methodology that was used to convert the benefit/cost ("B/C") ratios of resources under the financial account to scores which could be combined with scores under the social, energy security and environmental accounts (T. 805). The best B/C ratio received a one and the worst a three, with the scores of intermediate projects calculated using linear interpolation, based on their relative B/C ratios. Thus, the scores of every resource were dependent upon the decision to include or exclude the resource that currently had the lowest B/C ratio. By including a very poor project, the scores of all other projects (except the top one) would be increased. In contrast, the social, energy security and environmental accounts did not involve interpolation. Counsel for the Coalition argued that this use of different aggregation methodologies between accounts could lead to problematic results. For example, even if the financial and environmental accounts were weighted equally, the project with the best financial score could win over the project with the best environmental score, but the converse could not happen. This is due to the fact that, while it is possible that no project would receive the highest attainable score in the environmental account, this could arise in the financial account since WKP's methodology ensures that at least one project gets the highest attainable score in the financial account.

As another option, an expert assisting the Coalition redid the analysis by assigning an interval scoring (high, medium and low) to each option (Exhibit 38). The revised analysis showed that this changed the ranking of projects (T. 820).

However, further discussion in the hearing highlighted problems with this alternative as well. Interval scoring can have the unintended effect of creating large scoring differences between projects that are almost identical, simply because they happen to fall on either side of the arbitrary interval (T. 821).

The Commission is of the view that intervenors have demonstrated several problems with the multiple account weighting and aggregating method applied by WKP. The Commission recognizes, however, that no method is completely free of problems. The Commission directs WKP to explore adjustments to the methodology that correct or mitigate as best as possible the problems identified in the hearing. These can then be addressed within the work of the consultative committee and also by interaction with the intervenors from this hearing. When the final IRP is filed for approval, the Commission will review the changes that are made.

2.4.4 The Outcome of the Multiple Account Evaluation

Six portfolios emerged from the multiple account evaluation of resource options. These were referred to as "Financial", "Waneta", "Stakeholder", "Thermal", "Build" and "Purchase".

Six resource options were used to develop these portfolios: Powerex energy purchases, Washington Water Power capacity purchases, Cominco DSM, increasing WKP DSM, turbine upgrade and transmission efficiency (Exhibit 11, Tab 8). In addition to these "obvious preferred resources" other resources were added to individual portfolios to meet the forecast of gross energy demand.

The "Financial" portfolio minimizes revenue requirements and gives a stable performance through a range of sensitivity tests (Exhibit 11, Tab 8, Table VIII-4). The portfolio includes two additional resources, Ashlu and Woodwaste 65 MW (also common to the Waneta and Stakeholder portfolios), and two other options, Unocal Combustion Turbine and Woodwaste 10 MW. The Stakeholder portfolio, put forward by the Consultative Committee, and the Waneta portfolio, advanced by the company, were similar to each other. Both portfolios included the Waneta expansion, but the Similkameen project was included only in the Stakeholder portfolio (Exhibit 11, Tab 8, Table VIII-1).

WKP management prefers the Waneta portfolio and proposes, in its Action Plan (Exhibit 11, Tab 9), to pursue that portfolio's resources. Management noted, however, that because each portfolio has so many similar options, the Utility's actions over the next two years are virtually identical no matter which portfolio is chosen. This reduces the urgency for the Utility and the Commission to settle definitively on one portfolio as representing the most prudent set of expenditures and actions.

Mr. Ash attempted to explain why WKP management opted to prefer the Waneta portfolio even though it ranked below the Financial portfolio.

> "...lost opportunity wasn't properly factored in there. Secondly, that the desirability of having a resource within your own service area was perhaps not factored fully into your methodology, and thirdly, that you haven't got economic development fully factored in there." (T. 942)

The Commission agrees with WKP that the required Utility actions over the near term are virtually identical no matter which of the six resource portfolios is chosen and as a result the urgency for the Utility and the Commission to settle definitively on one resource portfolio is reduced. Nonetheless, the IRP appears to indicate that the wisest set of resource choices are those contained within the Financial portfolio, rather than the Waneta portfolio put forward by the Company or the Stakeholder portfolio put forward by the Consultative Committee. The Commission is not yet convinced that concerns about lost opportunities or the desirability of having resources contained within the WKP service area are sufficient to outweigh the increased financial costs associated with these options.

The Commission notes WKP's concern that the ranking methodology chosen by the Utility did not fully incorporate all the Company's concerns and that this was the reason WKP put forward as preferred a portfolio other than that which emerged from the multi-attribute trade-off analysis process. Also, the Commission is not suggesting that the preferred resource portfolio need be the mechanistic outcome of the resource evaluation and account weighting exercise. But the exercise is valuable to the Commission and all interested parties in revealing the relative importance of utility management and stakeholders' various objectives and valuations in arriving at a preferred resource portfolio. Deviations from the outcome of the multi-attribute trade-off process must be clearly explained and defended.

2.5 Resource Ownership Policy

The Ashlu project raises the issues of utility ownership of, and purchases of power from, affiliated non-regulated generation. The latter is known as "self-dealing", and is related to fundamental changes that are occurring in the North American electric industry, as exemplified by recent changes in energy regulation in the United States initiated by the 1992 Energy Policy Act. A key issue with self-dealing is the potential conflict of interest when a utility must choose between a non-regulated power project it owns and one that is truly independent.

Another concern regarding ownership of affiliated non-regulated generation is the extent of financial leverage and associated risk that may affect rates. WKP tested alternative financial structures for the Ashlu project and contended that the project ranking in its IRP is unchanged even with a change in the capital structure of the project. WKP, therefore, intends to pursue an Energy Project Certificate and to include Ashlu in its IRP even if the self-dealing issue is not yet resolved (T. 870 and 915).

The Commission concludes that the issue of utility ownership of non-regulated generation and the related issue of self-dealing have not been sufficiently dealt with in the course of this hearing to enable the Commission to make a generic determination. The Commission will continue to explore the self-dealing issue. In the interim, WKP is directed to ensure that its customers are not at financial risk if its resource initiatives that involve self-dealing are ultimately disallowed by the Commission.

2.6 Demand-Side Management Programs

WKP applied in its previous revenue requirements hearing for approval to amend some DSM programs and to add six new programs. The Commission provided the requested approval in its Decision of June 9, 1993, but added the general observation:

> "...the Commission is not yet satisfied with the information and analysis provided in support of WKP's DSM programs."

On December 15, 1993, WKP applied for Commission approval of various amendments to, and an extension of time to June 30, 1994 of, its Power Smart Program - Rate Schedule 90 - Energy Management Service. By Commission Order No. G-1-94, the Application was approved and the Commission stated it would review the program at the March 7, 1994 hearing. During the hearing, WKP requested that the Rate Schedule 90 be approved for two additional years to June 30, 1996 (T. 28).

Specific observations made by the Commission are discussed in the sections that follow.

2.6.1 DSM Program Costs and Penetration Rates

In its June 9, 1993 Decision at page 9, the Commission stated:

> "First, the Commission expects WKP to provide a more complete explanation of the method it follows in estimating and evaluating DSM program costs and penetration rates. Use of a single technology as the sole indicator of avoided cost is but one mechanism for comparing supply and demand resources, and it is not necessarily the most useful in a dynamic resource planning context."

WKP used a combustion turbine for the capacity component and the B.C. Hydro Rate 3808 for the energy component of its avoided cost (Exhibit 11, A-2). However, WKP in Exhibit 4, Question 143 indicated its intention to use an avoided cost based upon the approved resource portfolio in future IRPs. This is a more versatile measure than a static measure of avoided cost represented by one or a few resources. The IRP is inherently dynamic and the avoided costs that can be determined from the preferred strategy will therefore assist in both the screening and the sequencing of DSM and supply-side programs. The use of a static measure of avoided cost may continue to serve the useful purpose of indicating the aggregate effect of DSM on the timing of large scale supply-side options.

In response to Question 17 in Exhibit 6, WKP explained that, with regard to fuel substitution DSM programs, it does not consider the full incremental costs incurred by the gas utility in taking up load from the electric utility. The impact on the gas company's peak is an important consideration in the Total Resource Cost Test ("TRCT") for fuel substitution programs. BC Gas' IRP may soon be in a position to provide the information that is needed. There is also a concern about ignoring the full social costs of increased natural gas use.

Exclusive reliance upon the TRCT may obscure issues such as equitable distribution of DSM costs and benefits and the possibility that the TRCT does not measure non-monetary transaction costs incurred by customers. These and other emerging issues should be carefully monitored by WKP.

With regard to fuel substitution programs with natural gas, the Commission directs WKP to ensure that any proposal to initiate fuel substitution programs be based upon tests that include all relevant costs. For example, in the case of programs to switch to natural gas, the test should include estimates of the full cycle long-run incremental capacity and energy costs of natural gas provision. In addition, externality costs, either monetized or accounted for in some other way, should be considered.

WKP's application to extend its current DSM initiatives to June 30, 1996 is approved. The Commission directs WKP to continue its six month progress reports to the Commission and further directs that the evaluation plan, five year evaluation budget and summaries of completed program evaluations be provided to the Commission as those documents become available.

2.6.2 Hindsight Evaluation of the Results of DSM

In its June 9, 1993 Decision at page 9 the Commission made the following observation:

> "...the Commission expects WKP to provide a more complete hindsight evaluation of the results of its DSM programs. This includes the important step of designing programs so that their operation provides feedback information to check against initial estimates of costs and penetration rates."

WKP indicated during the hearing (T. 886) that its evaluation of savings impacts from DSM are at a preliminary stage and that it has assumed in its IRP that customers will indefinitely persist in their energy efficiency efforts. This highlights two of the most critical reasons for a reliable impact evaluation process: to verify the existence of savings and the persistence of savings. To this end, WKP at Exhibit 6, Question 12 stated that they have approached B.C. Hydro for assistance in the monitoring and evaluation task, and that two WKP evaluation staff are to be hired (T. 613).

WKP recognizes that optimal program designs can minimize "free riders" whenever it is apparent that other policy measures, such as rate design, legislated standards and education are likely to induce a significant level of "naturally occurring conservation" (Exhibit 11, VI-1). However, in Exhibit 6, Question 12, WKP explained that it has not yet attempted to verify its estimate of free riders and suggested that a participant survey would be appropriate. Pre- and post-program information from both participants and non-participants would be useful in the identification of the extent of free riders. Other phenomena, such as "free drivers" and income effects, could be assessed concurrently.

The Commission's comment in its December 7, 1993 Decision at page 48, with regard to B.C. Hydro's DSM evaluation process, is worth repeating here:

> "The Commission is concerned that impact evaluation results be linked more strongly with the IRP and the economic tests of DSM programs. A closer linkage between evaluation and the design of program changes is also desirable. Program design should always include means of gathering more useful information about customer preferences and responses."

Process evaluations of the qualitative and market penetration aspects of programs are necessary, particularly in the early stages of a program and following changes in strategy, but performance and persistence can only be reliably measured with impact evaluations and this is the essential feedback to the IRP process. Market evaluations for programs that WKP has in common with B.C. Hydro are probably best left to B.C. Hydro. The limited WKP resources could be directed toward reducing DSM uncertainty with more extensive impact evaluations. As part of its final IRP, WKP is directed to provide a budget for DSM monitoring and evaluation over the next five years that should include process evaluations as needed and one impact evaluation for each of the programs that WKP sought to extend to June 30, 1996. The budget should be designed to be cost-effective, relying wherever possible on secondary information sources.

2.6.3 DSM Amortization Period

In the hearing, WKP witnesses expressed their preference for amortizing DSM expenditures over ten years instead of over 20 years in order to better match program costs and benefits (T. 888). WKP agreed that the Commission had already addressed this on page 19 of its June 9, 1993 Decision (T. 1152).

WKP has indicated that it will come forward in its next rate application for a revision in the amortization rate of its DSM program. The Commission reiterates its direction in the June 9, 1993 Decision that WKP "group projects with similar life expectancies" for the purpose of determining an appropriate rate or rates of amortization of DSM. "Life expectancies" refers to the useful economic life of the energy conservation measures originally installed with the Utility's support.

3.0 UTILITY EXPENSES

3.1 Power Purchases

The replacement of Rate 3807 with Rate 3808, as determined in the April 22, 1993 Commission Decision, provides WKP with long-run information on the price and conditions under which it may purchase electricity from B.C. Hydro. The cost of any purchases from B.C. Hydro in excess of the Customer Demand Limit specified in Rate 3808 will be negotiated by the two parties, with the Commission ensuring that the outcome reflects fair arrangements.

The Commission continues to recognize that competitive bids for future increments of power to WKP will require known wheeling costs on the B.C. Hydro system. The Commission directed B.C. Hydro in its last Decision to develop competitive options for industrial customers. More recently, the Commission wrote to B.C. Hydro on March 30, 1994 to require B.C. Hydro to make proposals for firm wheeling by May 20, 1994.

The application stated that the power purchases were one of the main cost drivers leading to the requested rate increase (Exhibit 1, Tab 2, page 5). However, the estimates of the combined power purchase and wheeling costs actually decrease in 1994 and 1995 over the 1993 costs although the rate per kW.h increases. WKP revised its initial power purchase and wheeling costs on March 1, 1994 for purchases from B.C. Hydro to reflect the revised rates applied for by B.C. Hydro in 1994. The Utility updated its power purchase and water fee costs for 1995 and the Commission schedules have been adjusted accordingly.

The application assumes that WKP will purchase from the "spot" market a portion of the forecast peak capacity requirements. The costs of these purchases at peak periods have been estimated to determine the forecast of power purchase costs. In the application WKP requested that the Commission approve an accounting order setting up a deferral account for the spot purchases so that any differences between actual prices and those reflected in the application would be dealt with at a later time. During the hearing, however, WKP admitted that it was not a necessity to set up the deferral account and that it was up to the Commission to make the determination (T. 1565-1566).

In a related matter, WKP is also forecasting summer energy surpluses resulting from the Cominco power supply agreements which could result in revenue to the Utility if it is able to negotiate sales of the surplus. As stated in prepared testimony:

> "While the marketing of these surpluses is uncertain, so is the revenue expected from them. Non-firm market prices are dependent on circumstances at the time and the summer period is a very volatile time for surplus." (Exhibit 3, Tab 1, page 16)

Consequently, WKP has requested an accounting order allowing for the fixing of the revenue from surplus energy sales, with any difference in revenue to be placed in a rate stabilization account for future consideration.

The Commission accepts the power purchase costs as revised by WKP. The Commission considered whether WKP should be faced with a strong incentive to seek the lowest price power or greatest sales price, or alternatively, whether the proposed deferral account should be allowed so as to protect the customer from the volatility of power purchase costs. The concerns the Commission has over the issue of consumer rate increases leads to the decision to opt for the latter. **The Commission therefore grants the request to fix the rate forecast for spot market purchases and revenue from surplus energy sales and the revised Exhibit 1, Tab 8, page 7 submitted on March 22, 1994. Any differences are to be placed into a rate stabilization account for future consideration.**

3.2 Operation and Maintenance

The Commission has been concerned about the increase in operations and maintenance ("O&M") expenses at WKP in the past as noted in the last Decision:

> "The Commission is alarmed about the rapid escalation in O&M costs. There is a pressing need for management to constrain controllable costs in these difficult economic times."

The applied for operations costs represent an increase over actual 1993 expenditures of 4.2 percent; however, the Commission has noted with dismay that the actual 1993 costs are significantly higher than those allowed for in the 1993 Decision. Taking this into account, forecast 1994 costs are 13.1 percent greater than those approved for 1993 and forecast 1995 costs are 21.2 percent greater than those approved for 1993.

This trend to rapidly increasing O&M costs is at odds with the pressures being put on all utilities in North America to reduce real O&M costs per customer, and in some cases reduce these costs in nominal dollars as well.

3.2.1 Labour

Labour expenses are forecast to increase in 1994 by approximately 0.5 percent over 1993 with a further increase of 3.5 percent in 1995. The Commission notes, however, that 1993 experienced a 12.1 percent increase over 1992 after accounting for strike effects and that this was 4.75 percent greater than that allowed in the last Decision (Exhibit 1, Tab 9).

The forecast increase for 1994 was mitigated by a $500,000 gain on investments in the WKP pension fund, which also serves to mask a $924,000 increase in labour costs due to the provision of a new pension plan for non-union members approved by WKP's Board of Directors in the summer of 1993. Although the new pension plan was introduced in order to bring the non-union employees pension fund up to the same standard as the recently negotiated union plan, the Commission questions the timing of this increase and whether or not WKP properly reduced costs in other operating areas of the Company in order to compensate.

The increases in expenses forecast and applied for by WKP are not, in the opinion of the Commission, reasonable in light of current inflation and customer growth. The fact that these increases are on top of greater than allowed-for expenditures in 1993 serves to emphasize that management must prioritize to a greater extent expenditure requests and draw a hard line beyond which costs are deferred or denied. Consequently, the Commission has disallowed a portion of the increases in O&M expenses in each of 1994 and 1995.

Management bonuses were again brought under scrutiny and WKP provided information that indicated that amounts accrued for bonuses in the last application were much greater than the amounts actually paid out (T. 1164).

The Utility operates two bonus plans. One for senior management, which has paid out approximately $50,000 in each of 1992 and 1993, and a second "Performance Based Incentive Plan" which is available to approximately 80 non-union employees. WKP has budgeted $240,000 in 1994 and $245,000 in 1995 for these two plans.

Several intervenors questioned the validity of the bonus plans and whether or not they should be rightly charged to ratepayers. Of particular focus was the portion of the bonus formula based upon the ability to earn a pre-established level of return on equity. It was strongly felt that this amount was more appropriately charged to shareholders, who ultimately realize the increased value of a higher return on equity.

The Commission agrees with the intervenors and is open to a further review of such incentive plans. In the Commission's opinion, remuneration of WKP employees is at such a level that they are sufficiently compensated for their performance. For those employees who excel at their jobs there is the prospect of moving up through management along with accompanying increases in salary. This prospect and the current rewards received should be enough motivation for employees and any additional remuneration associated with a bonus system must be justified in terms of clear benefits to customers.

The Commission places utilities, due to their monopoly markets, in a position mid-way between public institutions and private companies and the current levels of compensation to employees generally reflects this reality.

Placing a small portion of an executive's existing salary at risk may provide an incentive towards excellence, but the reward should only be paid for by customers if the measurement criterion responds to customer benefits well beyond what would have been expected from fully competent management. WKP should also review the non-monetary motivational alternatives that may be available to promote excellence throughout the organization. The Commission is concerned that the bonuses may work to the disadvantage of customers if the utility managers are motivated towards profit incentives that diminish utility functions of providing safe, secure and efficient energy services to customers at rates which reflect the lowest cost of service, including a fair return to shareholders. Finally, the Commission has a concern with the practice of employee bonuses at a time of dramatic price increases, when the Utility should be aggressively pursuing all means of reducing costs.

The Commission therefore determines that the two incentive plans to senior management and non-union employees are not to be recovered in customer rates at this time.

3.2.2 Materials

Materials expenses are forecast to increase by $340,000 in 1994 and a further $566,000 in 1995. In response to an information request, WKP identified the increases due to inflation as $106,000 and $131,000 for 1994 and 1995 respectively. The balance of growth in expenditures was made up of increases over and above inflation (Exhibit 4, Question 51).

Increased customer service expenses of $22,000 and $34,000 are found by the Commission to be necessary in response to growth in WKP's service areas. The balance of the increases, however, are not, in the Commission's view, necessary to maintain the quality of service that the Company currently provides. A customer survey commissioned by WKP indicates that 90 percent of the respondents were satisfied with the current level, 22 percent of which were completely satisfied (Exhibit 4, Question 61). The Commission's concern is that the Company may be striving for a level of customer satisfaction that is not worth the expenditures required to reach it, in light of the other cost drivers facing WKP.

The Commission determines that material expenses over and above those identified as due to inflation and customer growth, in the amounts of $219,000 and $401,000 for 1994 and 1995 respectively, are disallowed.

3.3 Other Expenses

3.3.1 Right-of-Way Clearing

A focus of WKP's maintenance plans for the next several years is an increase in right-of-way maintenance, primarily contracted brush clearing, which was also cited as a cost driver in this application. A recent court case (the "Neal Case") which found the Company negligent for not maintaining its powerline rights-of-way motivated WKP to increase its standards of safety and reliability.

The Commission agrees that public safety is of paramount importance and does not wish to discourage WKP from its enhanced brush clearing; however, there did not appear to be any comprehensive plan as to the extent of the enhanced right-of-way program and no definite end to the increased level of expenses. WKP testified that there is no overall program and they have not yet had the time to develop one (T. 1454).

The Commission directs that WKP develop such a plan and be prepared to have it examined at the next rate hearing.

3.3.2 Insurance Deductible

An issue related to the right-of-way clearing and canvassed by several intervenors and Commission counsel was the payment of $300,000 as the deductible portion of WKP's liability insurance; a direct result of the findings against the Utility in the Neal Case.

The Utility was challenged on the recovery from ratepayers of this amount. Some intervenors felt that the deduction was inappropriate as the courts had found the Company at fault and as a consequence, the shareholders should shoulder the burden of the payment. Other intervenors accepted the payment as a cost of operating the business, noting that WKP advised it was following the same standards as other Canadian companies and that denying the payment could lead management in the future to purchase higher cost insurance with lower deductible amounts.

The Commission shares this latter view and allows this payment to remain as an appropriate cost.

3.3.3 Property Taxes

WKP has forecast an increase in actual property taxes paid but a decrease in the regulatory property taxes upon which its rates are based. The increase takes into account plant additions and inflation but is also due to a new assessment of the Company's generating and substation facilities, which the Company has appealed. WKP anticipates a $500,000 reduction in the amount eventually paid and it has reduced its regulatory property taxes by this amount.

Due to the uncertainty of the success of the appeal, WKP has requested that a deferral account be established so that the actual property taxes paid, which differ from those forecast in the application, be deferred for future consideration. In testimony, it was revealed that $200,000 of the anticipated recovery has been successfully negotiated and further meetings with the British Columbia Assessment Authority are ongoing (T. 1150).

The Commission is encouraged by the success of WKP in obtaining a substantial decrease in its property tax assessment and determines that the Utility be granted the requested deferral account for its property taxes.

3.3.4 Head Office Costs

WKP completed construction of its new head office in Trail in 1993 and has been occupying the premises for several months. The Company anticipated that the cost of construction would be approximately $6,000,000 and the application indicates that actual final expenditures incurred by WKP were $6,537,185. The Company was successful in arranging a sale/leaseback of the property for $5,950,000 with the difference between this amount and the construction cost going to rate base. Lease payments on the head office are $200,000 for the first five years, and over the 20-year term of the lease will be $2,670,000 less than the amount originally forecast in March 1993.

In response to an information request from the Commission staff it was learned that WKP expects to incur costs for its old head office in the amounts of $203,000 and $121,000 in 1994 and 1995 respectively. The Commission was aware that the old head office had not been sublet but had not been apprised by WKP of the magnitude of the costs of holding the unused office space. During the 1993 hearing there had been no indication that these expenses were to be the responsibility of the Company. The Commission views that the ratepayers of WKP are not receiving any value for the money being spent on the previous premises and in light of the large increases in other expenses of the Utility, questions the validity of the recovery from customers.

The Commission directs that the expenses made in connection with the old head office be removed from the direct expenses in the application. However, they will remain deductible for purposes of calculating the regulatory tax provision.

At the last hearing WKP requested, and the Commission granted, an accounting order permitting the Utility to account for the lease at a levelized amount in accordance with Generally Accepted Accounting Principles ("GAAP"). Due to the concern management has with the increased costs the Company is incurring, WKP has returned in this hearing with a request to reverse the previous accounting order and allow the Utility to expense the actual lease payments. The result will be lower leasing costs to be recovered from ratepayers in the early years of the lease and higher costs to be charged later.

The Commission approves the request by WKP to deviate from GAAP and assume a cash basis for accounting for the stepped charges of its head office lease agreement.

3.3.5 Billing Disputes

At the last revenue requirements hearing the Commission was made aware of two billing disputes ongoing between B.C. Hydro and WKP. The disputes involved the issues of power purchases and demand billing, and take-or-pay provisions. WKP at that time had recorded a disputed amount of $2.4 million as a deferred charge in 1992. The Commission determined that it did not have jurisdiction to decide the outcome of the disputes and in its Decision directed that the amount recorded as a deferred charge should stay in that account outside of rate base until both of the billing disputes were resolved with B.C. Hydro either through negotiation or as a result of a court decision.

During this hearing WKP testified that, in addition to the two disputes from previous years, two additional billing disputes had arisen with B.C. Hydro to bring the total of amounts in dispute to approximately $9,000,000 (T. 1133). The Company is requesting a variance to the previous Commission Decision and is asking that it be allowed to amortize the $2.4 million over five years beginning in 1995. WKP testified that the current disposition is what would be reflected in any final judgement of the disputes and that it was not likely that there would be any further resolution of these issues with B.C. Hydro.

> "So in our view there's no motive for parties to go further, and certainly we're not pursuing the issue, and it hasn't been raised by B.C. Hydro for many months." (Ash, T. 1127)

Subsequent to the hearing, B.C. Hydro wrote to WKP, with a copy to the Commission, stating the position that the disputes are still active and would be the subject of upcoming meetings between the two utilities.

The Commission has not had compelling evidence put before it at this hearing that indicates a significant change in the status of the billing disputes since the last Decision.

The Commission does not vary its previous Decision and directs WKP to maintain the amount of $2.424 million outside of rate base as directed in its Decision of June 9, 1993.

4.0 RATE BASE

4.1 Major Projects

4.1.1 Okanagan Bulk Supply Transmission Plan

WKP submitted the Okanagan Bulk Supply Transmission Plan (Exhibit 12) to address concerns with respect to the reliability of supply to the Okanagan.

Under peak winter loads, an outage to the 230 kV No. 72 line feeding Kelowna from Vernon, would leave a power supply shortfall to the Okanagan of approximately 50 MW. The amount of this shortfall is calculated assuming line No. 43, feeding Oliver from Princeton, is rebuilt to 138 kV and is in service by the winter of 1994. This loss of load is determined by the voltage conditions (90 percent of normal) that could be sustained under an outage and allows for a larger temporary load loss while lines are switched.

WKP's normal reliability standards for its bulk transmission system would provide enough capacity to cover the loss of a major line but would not necessarily prevent a temporary loss of load due to switching requirements. This is a lower level of reliability standard than B.C. Hydro, as B.C. Hydro will not tolerate a loss of load during switching on their much larger 500 kV transmission system (T. 979).

WKP had previously submitted the South Okanagan Substation (including the rebuild of line No. 41 from Oliver to Penticton) as the preferred option to correct this reliability problem. However, with the rebuild of line No. 43 to 138 kV standards to address supply problems to Princeton, the power transfer capabilities to the Okanagan improve, thus requiring a reassessment of the options for correcting the reliability shortfall in the Okanagan (T. 73).

In the above plan WKP considered 15 individual projects and developed six strategies for consideration.

1. The South Okanagan Substation. This would involve a 500 kV tap to B.C. Hydro.
2. A new 230 kV line from B.C. Hydro at Nicola to Penticton.
3. North Transmission. This would involve rebuilding line No. 46 to 230 kV and the staged transmission additions of another 230 kV line from Ashton to Vernon (B.C. Hydro) and a new 138 kV line from Kelowna to Naramata.
4. Nicola - Princeton. This involves converting the B.C. Hydro line from Nicola to 230 kV and staging other transmission upgrades such as upgrading line No. 46 and rebuilding No. 41 line from Penticton to Oliver.
5. Line No. 11 Oliver to Trail with line No. 40 Oliver to Penticton. This would involve rebuilding these lines to 230 kV.
6. A new 230 kV line from Waneta to Penticton.

The plan was tested against a number of resource options within the service area to determine if acquisition of those projects could defer transmission requirements. These impacts were, in turn, tested within the context of the IRP to determine if those resources would be ranked higher as a result of the transmission benefits.

The plan concluded that there were no resources which would impact the transmission plan and be ranked high enough in the IRP to make a difference to the economics of the transmission plan. The plan also concluded that the North Transmission alternative was the most economic and flexible strategy to follow. One of the projects within the North Transmission alternative (and a number of other alternatives) is the rebuild of line No. 46 to 230 kV standards. This project alone would rectify the reliability shortfall to the Okanagan for approximately ten years or more (depending on load growth). Additional transmission projects would be needed after that time. WKP will be submitting an application for a Certificate of Public Convenience and Necessity ("CPCN") for the rebuild of line No. 46 with a contemplated in-service date of 1995 and with forecast expenditures of $6.5 million in 1994 and $12 million in 1995 (T. 976).

The Commission concurs with the conclusions of the plan and recognizes the need to improve the reliability of service to the Okanagan area. The Commission also recognizes that WKP has a number of other projects which are needed to improve reliability. In consideration of the very ambitious Capital Program outlined for 1994, 1995 and 1996, the Commission is concerned with the rate impact that all these projects together will cause. Insofar as the construction and capital expenditures of the line No. 46 project are concerned, given that a CPCN for this line has not yet been filed, that there may be studies required for environmental impacts in the provincial parks, and that negotiations for access to other parts of the right-of-way may be required, the Commission is of the opinion that this project is likely to be delayed for practical reasons. The Commission directs WKP to review its strategy with respect to the timing of the line No. 46 project with a view to its deferral, and/or reassess its relative priority with respect to other projects.

4.1.2 The South Okanagan Substation

Prior to the Okanagan Bulk Supply Transmission Plan, WKP had been pursuing an Energy Project Certificate for the South Okanagan Substation (at a forecast cost of $40 million) and had incurred costs for land and preliminary engineering and applications. It has now withdrawn that application (T. 145). Costs associated with the land for the South Okanagan Substation were placed in a construction work in progress ("CWIP") account in 1980, as were subsequent costs prior to the Commission's 1993 Decision.

Although the decision to rebuild No. 46 line to 230 kV standards has strong implications that the preferred course of action will contain projects associated with the North Transmission alternative, it may be ten years before a decision on the South Okanagan Substation will need to be made. WKP argues that, if there remains a possibility that the South Okanagan Substation will be a viable option in the future, then costs associated with the lands and project development will eventually be useful (T. 970).

As this project may yet surface in the future and the investment in land should retain its value, the Commission determines that the currently approved treatment of costs associated with the South Okanagan Substation will continue.

4.2 Capital Programs

Capital expenditures have evolved from $17.2 million in 1991 to $12.4 million in 1992, $19.4 million in 1993 and are forecast at $38.6 million in 1994. The 1995 capital expenditure forecast is $44.3 million (Exhibit 58, Volume 4, Question 6, page 14). In the 1993 rate hearing, WKP justified the increase from 1992 to 1993 as catch-up caused by the strike of 1992. At that hearing, WKP forecast capital expenditures for 1993 to be $28.2 million, for 1994 to be $38.8 million and for 1995 to be $30.8 million. These forecasts included the South Okanagan Substation and assumed that B.C. Hydro would pay half the costs ($7.5 million for 1993, and $12.5 million in 1994) (West Kootenay Power Ltd. 1992/93 Rate Application, Exhibit 6, pages 86-89).

From an analysis of Exhibit 1, Tab 3, it can be seen that the principal drivers of the capital expenditures for 1994 are projected additions to transmission plant of approximately $20 million (of which $6.4 million is line No. 46 rebuild and $6.6 million is line No. 43 rebuild); $15.7 million for distribution plant (caused by a number of new projects and the postponement of the Winfield Substation project); and $4.3 million for general plant. These high levels of projected expenditures are maintained in 1995.

Although the major cost drivers in the increases are the rebuild of No. 43 line and No. 46 line, the total increases are exacerbated by newly proposed transmission and distribution projects and deferred projects from the 1993 capital budget. The transmission budget includes 11 previously unidentified transmission line and terminal substation projects totaling approximately $1.7 million, and an additional $3.6 million in projects which have been deferred. The distribution sub-budget identifies five new projects totalling approximately $0.8 million. From a total of $11.9 million allocated for customer extensions and upgrade projects (Exhibit 1, Tab 3, page 8), approximately $2.9 million is to be used for upgrades (Exhibit 4, Question 17).

Mr. Ash indicated that one of the reasons for the large jump in capital additions is because of an under investment in the past and an inability to implement planned projects.

> "The only observation is that because of the lack of investment in the past we have reached a bit of a crunch in terms that we have quite a number of jobs that are in a must do situation. I mean we really shouldn't be in a situation where we have the line to Summerland, the completion of 138 kV grid, and a major resolution of our Okanagan capacity shortfall problem is (sic) all coming together at the same time. We should — some of these problems should have been addressed several years ago, so we are definitely behind the eight ball in some of these things." (T. 1628)

Expenditures on any portion of No. 46 line will not be "used and useful" until the project is complete and, as previously discussed, the Commission believes this is likely to be delayed. The Commission therefore has not allowed the projected 1994 and 1995 expenditures to be included in rate base.

Insofar as the remaining capital expenditures are concerned, the Commission's view is that WKP has inadequately planned, justified and prioritized a number of new transmission and distribution upgrading projects and additions to facilities. Consequently, the Commission has adjusted the Decision Schedules to reflect a decrease in projected capital additions of $3.5 million in 1994 and $1.5 million in 1995.

In past Decisions the Commission has been critical of WKP's capital planning and budgeting as lacking consistency and documented rationale. In his opening remarks, Mr. Bacon alluded to enhanced procedures for the preparation of 1995 budgets (T. 45) and Mr. Ash and Mr. Van Yserloo elaborated on the enhancements which are needed (T. 1378-1400, T. 1620-1628).

One of the tools WKP developed is the five-year distribution plan (Exhibit 64). This plan is a detailed examination of feeder and substation loading and performances in the Trail area. In addition to the detailed feeder performance analysis, it lists the projects planned for each of the following five years. This document should be a useful tool to help line managers prioritize distribution addition and upgrading work, and could ultimately help senior managers develop overall strategies for distribution capital additions.

Although this document is a good attempt to account for and rationalize upgrading and reinforcement projects, it could be improved if more deterministic goals were set for the reliability of a given feeder or substation (i.e. to give the color coding some rationale). It could also be improved by setting a level of feeder loading which would trigger an evaluation for reinforcement. Finally, another improvement would be to extend the project prioritizing method to ensure comparability from area to area.

The Commission recognizes that a great deal of work will be required to complete the five-year distribution plan for the entire WKP service area, and encourages WKP to continue this worthwhile exercise.

While the five-year distribution plans will be of benefit to WKP to help avoid the planning and capital spending conundrum described by Mr. Ash above, WKP still does not have an integrated strategy to deal with upgrades or additions to its 60 kV and 138 kV sub-transmission system.

WKP should develop a five-year strategy to deal with its sub-transmission system on a similar basis as it is planning for its distribution system. This work could also be incorporated with the IRP Transmission Efficiency Improvements project which was discussed as a resource acquisition project in Section VIII, page 2 and Section IX, page 6 of the draft IRP.

4.3 Deferred Costs

4.3.1 EMF Research

WKP is contributing an amount of $80,000 per year to joint research on Electromagnetic Force ("EMF") research being carried out at the Midwest Research Institute ("MRI") in Kansas City. The decision to help fund the EMF studies was made by UtiliCorp and approved by the WKP board (T. 1157). It is anticipated that the total research costs to WKP will approximate $300,000 over five years (T. 1285). The Commission was told that other utilities owned by UtiliCorp are also contributing to the research effort, with the size of the contribution based upon the number of customers being serviced.

Several intervenors questioned how appropriate it was for WKP to be funding research in the United States when EMF research is also being carried out by the Canadian Electrical Association, an organization to which WKP already contributes. In addition, the University of Victoria has recently set up a research department to study the effects of EMF on human beings, the same area of research being pursued at MRI. At the same time, the Commission concurs with the statement made in argument by the Utility that "given the importance of determining the effects of exposure to electro magnetic fields, WKP believes it has an obligation to support EMF research" (T. 1954).

The Commission is concerned both with the costs and justification for this investment. While ongoing research into issues like EMF is important to society, it is important that the research not duplicate other work and that it will provide new evidence to assist in the resolution of this complex issue. Even though WKP was invited to provide data to support the justification of this research, the information has not been produced.

The Commission finds that WKP has not provided evidence to discharge its responsibility to demonstrate the value of this research. When that information is submitted, the Commission will rule on the recovery of any or all of the proposed $80,000 per year contribution in support of MRI's research.

4.3.2 Gas Turbine

The Commission accepted the original costs of the gas turbine application and hearing in the amount of $1,516,000 for inclusion in rate base and ordered amortization over five years commencing in 1992. The additional costs of $502,000 incurred subsequent to that hearing were ordered retained in a deferral account, outside of rate base, until the relevance of a gas turbine project in the South Okanagan could be determined in a revised IRP.

The Commission is surprised to find that WKP is continuing to accrue AFUDC on the post-hearing cost of this project, given its relatively low ranking in the IRP analysis. **After reviewing the transcribed evidence and the written material submitted since the December 1993 Application, the Commission finds that it cannot approve the full costs of expenditures as prudently incurred. The Commission directs that investigation related to this project should be terminated until such time as it is a clear choice for approval based on the Utility's IRP. The Commission will allow recovery of $300,000 to be amortized over five years beginning in 1994.**

4.3.3 Application Costs

The last submitted estimate by WKP of application-related costs was $781,000. Although these expenditures covered revenue requirements, rate design, IRP and the ROE hearing, they are still quite substantial.

The Commission Decision Schedules adjust the forecast numbers to actual, wherever possible, and have removed the ROE hearing estimates for later disposition by that Panel. The Commission considers that legal costs paid to outside counsel can be

curtailed by a greater use of corporate counsel, who is already familiar with the Utility's current operations. The Commission has reduced the allowance for legal fees to reflect this.

4.4 Allowance for Working Capital

Working capital is the amount of money required to cover deposits, inventory on hand and accounts receivable, less funds on hand to pay for expenses. The actual allowance for working capital in 1993 was $10,496,000, an increase of 54 percent over that forecast for the year. WKP forecasts an allowance of $9 million in 1994 and $10 million in 1995.

The Wholesale Customers questioned the increase in the inventory allowance, a key component of the allowance for working capital. The inventory amount has increased from $5.4 million in 1993 to a forecast amount of $7.4 million in 1994. WKP responded that the inventory growth was a direct result of the increased capital plan due to the fact that the "inventory levels generally track those expenditures to some degree" (T. 1154).

WKP did not perform a separate calculation of the allowance for the 1995 year but based that amount on the 1994 estimate adjusted for inflation and rounding (Exhibit 4, Tab 1, Question 30). Commission staff prepared a calculation of the 1995 amount using the same methodology as the 1994 calculation and updating for the revised 1995 revenue and expense forecasts. The result was an estimated allowance for working capital of $9,019,840. WKP indicated in the hearing that they would calculate the 1995 amount in a similar fashion, but no response has been received by staff.

The Commission determines that the 1995 allowance for working capital should be adjusted from the estimate filed in the application of $10 million down to $9 million.

4.5 Warfield Garage Expansion

The Application indicates that WKP is planning on spending $207,000 on an expansion of the Warfield Garage ("Warfield") in order to accommodate the Power Smart staff now quartered in other facilities. Under cross-examination from Commission counsel, Mr. Ash stated that the Power Smart staff could be moved into the new head office which is located a relatively short distance away in downtown Trail and which currently has unused office space (T. 1524). Over the long-term WKP would prefer to have the Power Smart employees at the Warfield location because customer interaction is encouraged through that office.

In light of the unused and paid for office space in the new head office, the Commission does not agree with the urgency of upgrading the Warfield facilities. Over the long-term it may make sense to concentrate all customer services in one location; however, the utility should be exercising greater spending restraint at this time and the Commission views this particular expenditure as unnecessary.

The Commission determines that the amount of $207,000 planned for expansion of the Warfield Garage be removed from the rate base.

5.0 RATE OF RETURN ON EQUITY AND CAPITAL STRUCTURE

As indicated in Section 1.2 of this Decision, in an effort to streamline the regulatory process, the Commission approved the inclusion of WKP in a joint public hearing with BC Gas and PNG to set the appropriate rate of return on common equity and capital structure. The hearing commenced April 5, 1994.

In a Decision issued on June 10, 1994, the Commission found that the appropriate rate of return on equity for WKP was 11.0 percent for 1994 with a year-end common equity component of 38 percent. For 1995 the rate of return on common equity will reflect an adjustment process discussed in the Joint ROE Decision and a year-end common equity component of 35 percent.

The common equity components reflect the Commission Decision dated June 9, 1993 which was confirmed in the more recent Joint ROE/Capital Structure Decision.

This Decision is based on the findings as put forth in the Joint ROE/Capital Structure Decision. For purposes of calculating the schedules attached to the Decision, the ROE has been assumed to be 11.0 percent for 1995.

6.0 RATE DESIGN

6.1 Background

By way of application dated December 15, 1993, WKP applied for substantial changes to the design of the rates it charges customers for service. The proposed changes would affect both the amount of revenues to be recovered in total from certain customer classes (i.e. interclass revenue shifts) and the amounts to be recovered from individuals within a specific customer class (i.e. intraclass revenue shifts). Although previous applications by the Company have resulted in changes to WKP's rates, the proposals contained in this application constitute a fundamental change in the Utility's rate design.

In establishing the proposed rate design, WKP indicated that it had been guided by three fundamental principles. These were (Exhibit 9, Tab 2, pages 1 and 2):

1. Rate design must result in the most efficient allocation of the Province's resources and give customers a proper price signal;
2. Enhanced competition dictates the pursuit of cost-based rates for all customers; and
3. Interclass equity must be enhanced and maintained.

6.2 Interclass Revenue Re-allocation

6.2.1 Position of Utility

WKP presented two technical studies in support of its Rate Design application: an Embedded Cost study and a Marginal Cost study. As indicated in the table below, these studies indicated that the revenues generated from rates charged to serve residential customers were insufficient to cover the costs of serving this class of customer on both an embedded and marginal cost basis, while the revenues generated from rates charged to serve general service customers over-collected the costs of serving that class.

Revenue to Cost Ratios for
Embedded and Marginal Cost Studies

	Embedded Cost Study[1]	Marginal Cost Study[2]
Residential	83.4	91.6
Small General Service	142.2	156.9
General Service	144.6	132.0
Large General Service	98.6	95.7
Large Industrial	125.8	107.7
Wholesale	100.8	86.9
Lighting	224.2	259.7
Irrigation	81.9	116.4

1. Exhibit 10, Tab 7, Appendix C-19
2. Exhibit 10, Tab 8, Appendix D-10

In response to these studies, WKP proposed to increase the rates charged to residential customers by 1 percent per year for five years in addition to any general rate increases approved by the Commission. The Company proposed to use the incremental revenues from the residential class to reduce the rates charged small general service and general service customers by approximately 9 percent over the five year period. In this way, the Company indicated that it hoped to bring the revenue to cost ratios associated with these classes of customer closer to acceptable bounds for cost recovery (Exhibit 9, Tab 4, page 3). WKP considers acceptable bounds for cost recovery to be between 90 percent and 110 percent of costs (Exhibit 4, BCUC Question 100).

As a result of these changes, the Company estimated that residential class revenue to cost ratios would increase to 87.6 percent on an embedded cost basis and 95.8 percent on a marginal cost basis. Similarly, small general service and general service revenue to cost ratios would decrease to 129.2 percent and 131.4 percent respectively on an embedded cost basis and 141.9 percent and 120.2 percent on a marginal cost basis (Exhibit 4, BCUC Question 113, page 5 and Question 116).

WKP indicated that consideration was given to having the shift occur over a much shorter period; however, it was felt that the combination of the general rate increase and the shift in revenue responsibility would impose an undue hardship on residential customers (T. 76). Similarly, the Company indicated that the marginal cost study suggested that a larger than 5 percent increase for residential customers was unwarranted (T. 270).

6.2.2 Position of Intervenors

Counsel for CAC(BC) et al suggested that the 1 percent per year increase for five years for residential customers proposed by the Utility represented rate shock for customers on low or fixed income (T. 1721). Accordingly, he suggested that the residential rates increase by 0.5 percent per year, over and above any general rate increase, for each of the next five years, at which time the need for further increases would be reassessed (T. 1727). In support of this argument, counsel for the CAC(BC) et al noted that the marginal cost study indicated that the residential revenue to cost ratio was closer to acceptable bounds than suggested by the embedded cost study and that the marginal cost study was the more appropriate study to use since WKP's situation was dynamic in terms of growth, capital acquisition and direction (T. 1722). In addition, the CAC(BC) et al indicated that the marginal cost study revealed that wholesale customers did not cover their cost of service while the embedded cost study indicated that irrigation customers did not cover their cost of service (T. 1723). As a result, the CAC(BC) et al argued that rates for both these classes of customers should increase (T. 1728). The argument that wholesale customer rates should increase was supported by Mr. David George (T. 1834) who pointed out that, even after the proposed changes, general service revenue to cost ratios would be in excess of the Company's determined acceptable bounds (T. 243).

With respect to these concerns, WKP indicated that the rate design changes proposed for irrigation customers were expected to lead to a change in use characteristics and thus a change in the allocations used in the embedded cost study. Further, the Company indicated that it was in the process of renegotiating new contracts with wholesale customers and did not wish to change the rate design until these were in place (T. 102). In addition, the Company rejected a suggestion put forward by the CAC(BC) et al that it might be socially desirable to subsidize the rates of certain groups such as seniors or low income people, indicating that these issues were not generally within the purview of an electric utility and that it would be administratively complex to achieve (T. 95-96).

6.2.3 Commission Determination

Based on both the embedded and marginal cost studies, it is clear that the rates charged residential customers do not recover the costs of serving these customers while the rates charged general service customers substantially more than recover the costs associated with this class. Accordingly, the Commission agrees that substantial restructuring of the revenues to be collected from each of these classes is required.

The Commission does not agree that the 1 percent per year increase for five years for residential customers proposed by the Utility will result in rate shock for customers on low or fixed income, particularly in light of the revenue requirement adjustments made elsewhere in this Decision. Indeed the Commission is concerned that the Utility's proposal does not move quickly enough to address the revenue_to cost imbalances identified by the cost studies. Further, the Commission is not convinced that the evidence indicated that the rates charged irrigation and wholesale customers should be increased beyond the level of the general rate increase. Based on the embedded cost study, wholesale customers currently contribute their costs and, while the marginal cost study indicates that this may change in future, the Commission would prefer to see the results of the negotiations between the Utility and the wholesale customers before making any further determinations on this issue. With respect to irrigation customers, the Commission is mindful that the evidence indicated that a seasonally differentiated marginal cost study would show that irrigation customers were over contributing at a rate in excess of that currently shown by the study so that it is unclear that a shift in revenue responsibility towards these customers is appropriate at this time.

The evidence before the Commission indicates that the Utility's restructuring proposal is unlikely to result in revenue to cost ratios at the end of the five year period which fall within a 90 to 110 percent range (Exhibit 4, BCUC Questions No. 113 and 116). **Therefore, the Commission directs the Utility to increase the rates charged residential customers by 2 percentage points more than the level of whatever rate increase may be otherwise approved for each of the next three years, commencing January 1, 1995. The incremental revenues received from residential customers as a result of this order are to be offset by a decline in the rates charged small general service and general service customers so that the total revenues received by the Utility are unchanged by the restructuring. Following these changes, the Commission may wish to see new directional embedded and marginal cost studies, if such can be provided at low costs, so that it may determine if further rate design is warranted.**

6.3 Residential Customers

6.3.1 <u>Rate Schedule 1</u>

Currently, WKP provides service to residential customers under a schedule composed of a bi-monthly basic charge, set at $16.64, and a flat energy charge. The Company proposes to maintain the basic monthly charge at the current level but to implement an inverted rate structure for the energy charge portion of the tariff. Initially, WKP plans to invert the rate at 6000 kW.h bi-monthly consumption with the energy charge associated with the second step approximately 4 percent higher than that of the first step. Over the next five years, the Company plans to increase the amount of the inversion and to lower the consumption level at which it will begin to apply so that, as at January 1, 1999, the rate would invert at the 4000 kW.h level with the second step energy charge being approximately 13 percent higher than the first step.

Initially, the residential rate changes will affect only those customers who consume in excess of 6000 kW.h in any bi-monthly billing period. In the first year, bill impacts for these customers are expected to range from 0.6 percent to 2.6 percent depending upon the level of consumption (Exhibit 9, Tab 4, page 6). The Company has indicated that most of these customers are electric heat users and can modify their use of electricity (Exhibit 9, Tab 4, page 3) primarily through fuel switching and DSM programs (T. 287). By the end of the phase-in period, all customers who have bills in excess of 4,000 kW.h in any bi-monthly billing period, approximately 17 percent of bills on an annual basis, will be affected, with impacts ranging from 2.4 percent to 9.4 percent (Exhibit 9, Tab 4, page 6). The Company expects that these impacts will be sufficient to induce an approximately 5 percent decrease in residential electricity consumption (Exhibit 9, Tab 4, page 3).

WKP indicated that the decision to propose inverted rather than seasonal rates for residential customers reflected several factors. First, although WKP faces capacity constraints, which might more normally suggest seasonal rates, the Utility is located in a capacity rich area (the Pacific Northwest). As deregulation occurs and open access to wheeling becomes more prevalent, the WKP capacity constraints are expected to dissipate, with a resulting decline in capacity costs. As a result, over the longer term, inverted rates are preferred (T. 519). In addition, the Utility noted that customer advisory panels expressed preferences for inverted rather than seasonal rates.

The Company testified that the level and pace of inversion was influenced by a desire to keep the combined effect of all rate increases, whether from a general rate increase, inter-class revenue shifts or intra-class rate design changes, around 5 to 8 percent per year for individual customers (T. 291). Although the Company recognized that this proposal was not "theoretically pristine" in that it did not charge customers the full marginal cost, the Company indicated that it was comfortable that the direction of change was towards a proper price signal (T. 275).

WKP indicated that the decision as to the appropriate level for the bi-monthly basic charge was influenced by a number of conflicting goals including a desire to maintain continuity with past rate setting practices, avoid undesirable customer bill impacts, enhance conservation incentives, achieve revenue stability and reflect the cost of service (Exhibit 4, BCUC Question 102). Although the Company agreed that a lower basic charge and resulting higher energy charge would enhance conservation incentives, WKP expressed concern that a lower basic charge would result in seasonal customers (e.g. cottage owners) failing to make a reasonable contribution towards the cost of serving them (T. 305).

6.3.2 Position of Intervenors

Mr. George expressed concerns regarding the establishment of inverted rates for residential customers and seasonal rates for general service customers and encouraged the Commission to establish flat rates for each customer class (T. 1834). In contrast, the ECA supported inverted rates for residential customers (T. 1788). With respect to the basic charge, the ECA suggested that the charge be temporary so that once a customers has paid off the investment associated with serving him, the bill would be based entirely on the energy charge (T. 1789).

6.3.3 Commission Determination

The appropriate rate design for a utility should reflect not only current conditions but those which are reasonably foreseeable. In this regard, the Commission is cognizant of the evidence presented with respect to the changing constraints which WKP is likely to face over the near future. **As a result, the Commission finds that the inverted rate structure proposed by the Utility for residential rates is appropriate and directs WKP to implement the proposal as set out in its application.**

With respect to the level of the basic charge, the Commission recognizes that there are several conflicting goals to be considered; however, the Commission is concerned that the current level of basic charge restricts the Utility's ability to set its energy charges at a level which more properly reflects marginal costs. **Therefore, the Commission directs WKP to set its residential basic charge at $12.00 per bi-monthly period. In this manner, the Commission expects that WKP will be able to set its energy charge closer to the Long-Run Marginal Cost. The Commission recognizes that this will result in changes to the projected bill impacts for customers.**

6.3.4 Rate Schedule 9

For several years, WKP has provided electricity to certain of its employees at a preferential rate. By letter dated October 7, 1993, the Company applied to extend this rate schedule to International Brotherhood of Electrical Workers ("IBEW") employees who were previously excluded. The Commission denied this application and ordered that the subject of the employee rate be considered at the WKP's next rate design hearing.

Currently, Rate Schedule 9 consists of a three block inverted rate, with the rate associated with the third block less than the current flat rate energy charge. While WKP wishes to retain Rate Schedule 9, it is concerned that the amount of benefit from the preferential rate is open ended as there is an additional benefit as consumption rises. In order to eliminate this problem WKP proposes to increase the third block rate so as to equal the trailing block rate associated with Rate Schedule 1. In order that employees in total receive the same benefit under the new proposal as the old rate, WKP proposes to reduce the rate associated with the first two blocks.

WKP argued that the rate should be retained because it contributed to employee morale and commitment to the Company (T. 461). Further, WKP maintained that, though there were provisions in contracts to compensate employees if the Commission disallowed Rate 9, there would likely be different views as to the appropriate amount of compensation given that Rate 9 was a non-taxable benefit (T. 463).

The IBEW also argued for the retention and extension of Rate Schedule 9, stating that this would validate and strengthen the collective bargaining relationship between the Utility and its employees (T. 313). Further, the union indicated that compensating employees through the preferential rate had the possibility of being at lower cost to the employer than if a dollar equivalent were negotiated (T. 1947). The union rejected the idea that the preferential rate could lead to increased consumption by those who enjoyed the rate (T. 1948).

6.3.5 Commission Determination

The Commission is not convinced that retention and extension of Rate Schedule 9 is necessary for labour relations reasons. Further, the Commission believes that such a schedule is inappropriate for a utility whose long-run marginal costs exceed its average costs. **Therefore, the Commission orders the elimination of Rate Schedule 9 effective January 1, 1995. The Commission is aware that the elimination of Rate Schedule 9 will result in increased revenues to WKP; however, the Commission expects that these funds will be used to pay the compensation which employees will expect for the loss of the preferential rate.**

6.3.6 Load Control Program

The Company has applied to implement a load control program on domestic hot water heaters. Initially, the program will be available only to residents of Trail, since use of the radio control mechanism to interrupt hot water heaters may be difficult in more remote areas (T. 201). Under the program, customers who participate will receive a flat rate reduction of $4.00 per month which the Company believes will be sufficient to induce a sizable participation in the program (Exhibit 9, Tab 4, page 4). WKP demonstrates a positive benefit/cost ratio in Exhibit 26.

The Commission approves the load control program as outlined in the Application.

6.4 General Service Customers

6.4.1 Rate Schedules 20 and 21

WKP serves commercial customers through Rate Schedules 20 and 21. Rate Schedule 20 applies to small customers whose peak demand is generally less than 40 kW. The rate schedule consists of a six block declining rate, and has a minimum charge, currently set at $17.06, which allows for 100 kW.h of consumption per two-month period. Rate Schedule 21 applies to customers whose demand is generally greater than 40 kW but less than 500 kW. The rate schedule consists of an energy charge, consistent with that of Rate Schedule 20, and a demand charge of $4.04 per kW of billing demand above 40 kW.

WKP has indicated that it views flat general service rates as highly desirable (Exhibit 9, Tab 5, page 1); however, it is constrained in its ability to implement them by the need to reduce the overall revenue collected from this class of customer and yet send the correct price signal. Therefore, the Utility proposed to institute seasonal rates for these customers with the winter rates greater than the summer rates. In this way, customers would be sent the signal that power purchases by the Utility were more expensive in the winter than in the summer. WKP indicated that inverted rates were inappropriate for these customers because of their diversity of size (T. 123).

WKP maintained that, as the revenues generated by general service rates currently exceed costs as measured by both the embedded and marginal cost studies, it was inappropriate to flatten winter rates at this time (T. 473). However, in response to a Commission staff request, WKP produced evidence showing the bill impacts if summer and winter rates were flattened immediately and the winter summer differential was in the order of 10 percent. For Schedule 20 customers, the evidence indicated that the majority of bills would decline in both the summer and the winter by approximately 20 to 30 percent. The exceptions were extremely low use bills, (i.e. less than 25 kW.h per month), where increases of approximately 12 to 14 percent or a $1.00 to $1.20 per bill would be experienced and high use bills (i.e. 34,000 kW.h to 50,000 kW.h) where declines of 2 to 7 percent would be experienced in summer but winter bills would increase by approximately 2 to 9 percent (Exhibit 27A, Max Case 2i).

For Rate Schedule 21 customers, the impact on the energy portion of the bill mirrored that of Rate Schedule 20 customers for bills of 50,000 kW.h per month or less. For bills above 50,000 kW.h per month, about 6 percent of Rate Schedule 21 bills, the energy portion of winter bills increased from approximately 12 to 57 percent while the energy portion of summer bills increased from approximately 2 to 43 percent, with bill impacts increasing as consumption rises (Exhibit 27A, Max Case 2i). It should be noted that the actual bill impacts would be somewhat less, since the demand charge is currently flat, and therefore would not change.

6.4.2 Position of Intervenors

Mr. George expressed discomfort with the "confusion of schemes" presented by WKP in its rate design application and urged the Commission not to accept seasonal rates for general service customers unless they were also implemented for residential customers (T. 1834).

The ECA expressed concern that seasonal rates, which would result in higher winter bills, could cause cash flow problems for businesses which experience decreased revenues in the winter. If the Commission accepts seasonal rates, the ECA asked that the Commission order WKP to offer an annual bill averaging scheme for general service customers (T. 1788).

6.4.3 Commission Determinations

As indicated in Section 7.3, the Commission believes that, over the foreseeable future, proper price signals will be best provided by inverted rates. However, at the same time, the Commission recognizes that the size diversity within the general service class makes the implementation of an inverted rate problematic for this class of customer. Therefore the Commission accepts flat seasonal rates for general service customers as the best practically available option.

Although the Commission accepts the general theory which underlies the Company's proposal, the Commission is concerned with the slow pace by which WKP intends to flatten the general service rates. In particular, the Commission is not convinced of the necessity to retain a declining block structure for winter rates into the indefinite future. **Therefore, the Commission directs WKP to implement flat rates for both the winter and summer seasons in four approximately equal annual steps to commence January 1, 1995. In undertaking these changes, WKP is directed to ensure that articulation between Rate Schedules 20 and 21 is maintained. In addition, the Commission suggests that WKP offer annual bill averaging for its small general service and general service customers.**

6.5 Large General Service and Industrial Customers

6.5.1 Rate Schedules 24 and 30

WKP serves large volume general service customers, i.e. 500 kVA or more, via Rate Schedule 24 and very large volume industrial customers, i.e. 5,000 kVA or more served at transmission voltage of 60,000 kV or more, via Rate Schedule 30. Both schedules consist of a flat demand charge and a declining block rate energy charge. WKP expects that, over the medium term, only one customer will continue to be supplied on Rate 30 so that no specific changes to this schedule are proposed at this time. Instead, WKP proposes that new customers requesting to connect on Rate Schedule 30 be the subject of individual contract negotiations. The negotiated rates would be brought forward to the Commission for individual approval (T. 476).

As with Schedules 20 and 21, WKP proposes to convert Rate Schedule 24 to a seasonal rate. Specifically, WKP proposes to apply all future rate increases such that the differential between the average cost in the summer and in the winter grows by 2 percent at each application. Further, the Utility proposes to phase-in a flat energy rate for both the summer and winter seasons over the next five years.

6.5.2 Commission Determinations

As indicated in the discussion of general service rates, the Commission accepts that seasonal rates can provide proper price signals to customers with regard to the cost of serving them. Therefore, the Commission accepts the principal of seasonal rates for Rate Schedule 24 customers. However, the Commission is concerned that the pace at which the Utility wishes to achieve the associated flat rates is unnecessarily slow. **Therefore, the Commission directs WKP to implement seasonal flat rates for Rate Schedule 24 customers effective January 1, 1995 unless it can demonstrate that this would result in undue customer impacts.**

The Commission accepts the proposal with respect to Rate Schedule 30 but encourages WKP to take whatever steps possible to bring this rate into conformity with its rate design with respect to similar customers.

6.6 Wholesale Customers

6.6.1 Rate Schedule 40

Approximately 32 percent of WKP's expected sales are made to wholesale customers who are themselves distribution utilities. Currently, Rate Schedule 40 consists of a flat demand charge and a three-block declining rate. Although the embedded cost study indicates that the revenues raised by these rates are sufficient to recover costs (Exhibit 10, Tab 7, Appendix C-19), the marginal cost study showed that these rates are likely insufficient to recover the future costs associated with serving this customer class (Exhibit 10, Tab 8, Appendix D-10). As a result, WKP has indicated that the current declining block structure may not be appropriate (Exhibit 9, Tab 7, page 1) and has initiated discussions with its wholesale customers to discuss appropriate rate design.

The Utility indicated that the issues to be resolved were complex and should be resolved in concert with the wholesale customers (T. 149); however, should the Commission order that flat rates be instituted immediately WKP estimated the impacts would be in the order of 2 to 3 percent (T. 208). The greatest impact would likely be felt by the City of Nelson (T. 208).

6.6.2 Position of Intervenors

Counsel for the wholesale customers supported the WKP's position and urged the Commission to allow the negotiations to proceed unimpeded (T. 1696). He indicated that these negotiations would cover such areas as how to design wholesale rates so as to encourage conservation and demand-side management and appropriate terms considering that the market is changing so that there will be more options for both the supplier and the customer (T. 1696).

In contrast, the ECA urged the Commission to regulate wholesale customer rates directly, arguing that "orders related to rate design for WKP should also apply to the wholesale customers, for the sake of efficiency, and rates should in general be as close as possible to the same throughout the WKP service area" (T. 1790).

6.6.3 Commission Determinations

Although the Commission agrees with the sentiment expressed by the ECA; namely, that efficiency could be enhanced if the wholesale customers set rates for their customers which mimicked the rates WKP is being required to set for its direct customers, the ECA is reminded that such an Order is currently outside the jurisdiction of the Commission as set by the Utilities Commission Act.

The Commission directs WKP to bring forward an application with respect to the appropriate rates to be charged wholesale customers by November 30, 1994. This application should be based on the principle that flat rates will be achieved within one year.

6.7 Irrigation Customers

6.7.1 Rate Schedules 61 and 62

Currently, WKP serves irrigation customers under three rates. Schedule 60 is closed. Schedule 61 is a seasonal rate with a flat energy charge of 2.765 cents per kW.h during the irrigation season and 6.726 cents per kW.h during the non-irrigation season. In addition, there is a minimum billing component of $32.27 per connected horsepower ("hp") plus 0.853 cents per kW.h for energy use during the season. As a result, the minimum charge is $322.70 (Exhibit 9, Tab 9, page 1). Schedule 62, available only for motors larger than 10 hp, has an annual basic charge of $115.88 per irrigation season, a declining block energy charge, related to demand, which is applicable during irrigation season, and an off-season rate which mimics the applicable general service schedule.

WKP has indicated that it is concerned about the administrative complexity of these rates, particularly Schedule 62, and that the minimum bill components are not consistent with its energy management goals. As a result, the Utility initially proposed to combine all three irrigation rates into one rate, to be known as Rate Schedule 60, with a monthly basic charge of $8.53 and a flat energy rate of 3.0 cents per kW.h. This rate would apply during the irrigation season, April 1 to October 31, the period during which WKP has "non-ratcheted" power purchases from B.C. Hydro. At the closing of the irrigation season, customers would be served under the general service rate. WKP indicated that this proposal was revenue neutral, i.e. the revenue to cost ratio of 81.9 indicated by the embedded cost study would be unchanged.

Under this proposal, customers with exceptionally high intensities of use, e.g. large irrigation districts, would experience bill increases of up to 12 percent (T. 479). WKP expressed concern about the size of this impact but indicated that there were still several reasons to move ahead with the proposal. In particular, WKP noted the high minimum bill associated with Rate Schedule 61 and the extreme volume discount associated with Rate Schedule 62, neither of which was consistent with their energy management goals (T. 482). Further, for customers who could purchase under either rate, which rate was most advantageous would shift depending on the weather. The WKP panel indicated that they often felt they were being asked by these customers to predict the weather (T. 482).

Following the hearing, WKP submitted a response to an information request in which they indicated that an alternative proposal would be to decrease the cost of recovery from irrigation by 5 percent. WKP suggested that the lost irrigation revenue be offset by a one-time 0.15 percent increase to residential customers.

6.7.2 Position of Intervenors

The Fairview Heights Irrigation District ("Fairview Heights') disputed the findings of the embedded cost study and suggested that if substation costs were allocated on a coincident peak basis, irrigation customers would be found to have contributed revenues in excess of their costs (T. 1936). Further, they indicated that if the marginal cost study had been seasonally differentiated, the revenue to cost ratio arising from that study would have been in the order of 120 percent (T. 1937). Therefore, Fairview Heights suggested that the Rate Schedules be combined as proposed by WKP but that a flat rate be established at 2.7 cents per kW.h (T. 1937).

The Keremeos Irrigation District ("Keremeos") suggested that WKP implement a two-block declining rate for irrigation customers, with the second block break at 75,000 kW.h (T. 1942). However, WKP indicated that, although such a proposal could mitigate the impact on large volume Rate 62 customers, it would have adverse impacts on other irrigation customers (T. 492).

6.7.3 Commission Determinations

The Commission agrees with the Applicant that the present complexity associated with the three irrigation rates requires that the current rates be terminated; however, the initial proposal put forward by the utility has unacceptable rate impacts for high intensity irrigation customers. These impacts are mitigated if the 5 percent reduction in cost recovery proposed by WKP subsequent to the hearing is accepted. Further, the Commission notes that this proposal was welcomed by the both the Fairview Heights and Keremeos Irrigation Districts. **Therefore, the Commission directs WKP to implement a single Irrigation Rate, to be known as Rate Schedule 60 as outlined in the response to an Information Request, dated March 22, 1994. This schedule will reflect a 5 percent decrease in cost recovery from irrigation customers as set out in WKP's subsequent proposal. Further, the Commission directs that the decrease in revenues from irrigation customers be offset by a one-time 0.15 percent increase in rates to residential customers. This increase is in addition to the rate increases directed under Section 6.2.3 of this Decision.**

6.8 Extension Policy

As part of the current application, the Company is proposing only minor wording changes in its Extension Policy to increase consistency with the proposed connection fees application.

Under the current policy, the Company contributes a basic $2,000 for each permanent principal residence, unless it is part of a sub-development, and may contribute up to $3,000 more if matched by the customer (Exhibit 9, Tab Extensions, Schedule 73). Sub-developers pick up the full cost of the extension. WKP was unable to provide a rationale for the amount of the contributions but indicated that they were not based on expected recoveries from customers (T. 503).

Discussions at the hearing indicated that the current WKP extension policy may not be consistent with recent determinations made by the Commission that the main extension test used by BC Gas should reflect the total social cost of extension. **Therefore, the Commission approves the wording changes as put forward in the application. In addition, the Commission directs WKP to review the principle which underlies the determinations made by the Commission in the BC Gas Phase B Rate Design Decision dated October 25, 1993, (future determinations which are expected to arise from the 1994 BC Gas Revenue Requirements hearing) and to come forward with an extension policy by November 30, 1994 which reflects these principles. In devising the extension policy, WKP is directed to consider whether some communities may be better served in ways other than connection to WKP's grid, e.g. through the application of distributed generation technologies.**

6.9 Standard Charges

6.9.1 Service Size Connection Fees

In previous applications, WKP applied for a number of changes to its standard charges. The most significant of these relates to service size connection fees. Effective October 1, 1993, the Commission approved a new service connection fee of $200 plus $2 per amp over 100 amps for residential customers. The Commission further directed WKP to apply in its next rate application for a revision to its connection fee for general service customers so as to add a size of service component. The current service size connection fee for general service, industrial, lighting and irrigation customers contains only the $200 basic service connection fee with no component related to amperage size of service.

As part of this application, WKP proposed to increase the residential service size fee from $2 per amp to $3 per amp effective January 1, 1995. This proposal was supported by previous cost evidence submitted to the Commission and the advice of WKP's customer advisory panels. In addition, WKP proposed extending the service size connection fee to apply to all general service, lighting and irrigation customers who do not own their own transformation. WKP proposed that the charge for three-phase service be based upon a formula related to the capacity of the service. For large general service and industrial customers, the Utility proposed that the charge remain at $200 for the basic service connection fee only.

The ECA argued that the increased connection fees are unfair in circumstances where customers do not have access to natural gas service as an option (T. 1784).

6.9.2 Commission Determinations

To bring the connection fee closer to the actual cost of connection, the Commission accepts the connection fee proposal as put forward in the application. Further, the Commission directs WKP to make such changes to Lighting Tariff Schedules 50 and 51 as are occasioned by the new connection fee policy as well as the other minor changes identified in the application. In addition, the charge for a temporary drop service and relocation or upgrading of an existing service is to be increased from $120 to $200 consistent with the new service connection fee and if a temporary drop service is installed, the temporary drop charge be billed in addition to the new service connection fee. These changes are effective January 1, 1995.

6.9.3 Schedule 80 - Standard Charges

WKP applied to change the Terms and Conditions of its service with respect to accessing a customer's premises such that if the Utility experiences difficulty in reading the meter, WKP may, at its option, install a remote metering device for which the customer will pay. WKP proposes a charge of $170 consisting of the standard charge for disconnection/reconnection of a meter at $50 and the price difference between a standard meter and the remote meter of $120. The Utility proposed that this charge be effective July 1, 1994.

As well, WKP proposed increasing the return cheque service charge from $16 to $20 effective July 1, 1994. This increase would make the Company more consistent with procedures followed at other utilities.

Finally, effective July 1, 1994, WKP proposes to charge a collection fee to those customers who are consistently in arrears, requiring the Utility to visit their premises in order to post disconnect notices. Specifically, WKP proposed to charge customers $50 if in two successive billing periods it is necessary for the Utility to send a representative to the customer's premises to affix a disconnect notice. This cost is consistent with the cost for disconnection and reconnection of a meter which requires two trips by a customer serviceman or a meter reader.

The Commission approves the changes to Schedule 80 as set out in the Application.

6.10 Regional Rates

6.10.1 Regional Districts Proposal

Counsel for the City of Castlegar, City of Rossland, City of Trail, Town of Creston, Regional District of Central Kootenay and the Regional District of Kootenay Boundary ("the Regional Districts") argued that it was "unjust, unreasonable and unduly discriminatory for power consumers in the Kootenay area to pay the high cost of providing power to customers in the Okanagan" (T. 1912). Accordingly, he asked the Commission to consider "the imposition of a differential rate structure dividing the West Kootenay Power Ltd. service area into two sections, with the eastern boundary of the Okanagan watershed being the proposed dividing line" (T. 1912).

In support of this position, counsel for the Regional Districts indicated that the Commission had directed WKP to prepare evidence on this issue to be heard during the course of the Rate Design hearing at the time of the last revenue requirements hearing. As a result, the Regional Districts urged the Commission to withhold approval of the current Rate Design proposal until such time as evidence, including cost of service studies, was produced with respect to regional rates. Failing that, the Commission was urged to approve the current Rate Design on a short-term or interim basis only (T. 1914).

6.10.2 Position of WKP

WKP opposed the introduction of regional rates, arguing that "it would be unreasonable to foster 'postage stamp' rates elsewhere in the province and at the same time impose a number of different rates within the relatively small portion of the province served by West Kootenay Power" (T. 1657). Further, WKP rejected the notion that the costs of serving the Okanagan were necessarily greater than those associated with serving customers in the Kootenays. In particular, WKP noted that the increased density associated with serving customers in the Okanagan offset the increased transmission costs (T. 133). In addition, WKP noted that its advisory panels had supported the concept of postage-stamp rates throughout the WKP service area (Exhibit 5, BCPIAC Question 21). Finally, WKP argued that if regional rates were to be considered, evidence showing the need for regional rates should be tendered by the Regional Districts (T. 1660).

6.10.3 Position of Intervenors

Counsel for the wholesale customers urged the Commission to reject the proposal put forward by the Regional Districts, stating that there was no evidence indicating real and dramatic cost differences between serving the two regions (T. 1696).

6.10.4 Commission Determinations

After review of the issues raised in this hearing, the Commission finds that the conclusions reached in the June 9, 1993 Decision continue to be valid. Therefore, the Commission is not prepared at this time to explore further the issue of regional rates.

DATED at the City of Vancouver, in the Province of British Columbia this day of June, 1994.

Dr. M.K. Jaccard
Chairperson

K.L. Hall
Commissioner

M.R. Payne
Commissioner

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APPEARANCES

M. MOSELEY	Commission counsel
G. MACINTOSH, Q.C. R.H. HOBBS	West Kootenay Power Ltd.
B. MACQUISTEN	City of Rossland; City of Trail; Town of Creston; City of Castlegar; Regional District of Kootenay; Boundary and Regional District of Central Kootenay
D. GEORGE	Himself
D. SCARLETT	Kootenay-Okanagan Electric Consumers Association
C. REASONS M. DOHERTY	Consumers' Association of Canada (B.C. Branch); B.C. Old Age Pensioners' Organization; Council of Senior Citizens' Organizations of B.C.; Federated Anti-Poverty Groups of B.C.; Senior Citizens' Association of B.C.
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F. DOWNING	Himself
B. WALLACE	City of Kelowna; City of Penticton; District of Summerland; City of Grand Forks and Princeton Light and Power Company, Limited
N. GABANA	Himself
P. KANIGAN	Himself
C. REARDON M. ELIOT	B.C. Energy Coalition
B. ROBSON	International Brotherhood of Electrical Workers, Local 213
E. BEALLE W. MENNELL	Fairview Heights and Keremeos Irrigation Districts

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EXECUTIVE SUMMARY

On November 30, 1993 WKP applied for an interim refundable increase of 6.7 percent to be effective January 1, 1994 and a further increase of 5.6 percent effective January 1, 1995 (subsequently adjusted to 5.9 percent and 5.8 percent, respectively). The Commission approved a reduced interim increase of 5.7 percent effective January 1, 1994, subject to refund after a public hearing. On December 3, 1993 the Company made an Application for changes in Rate Design methodology and on December 30, 1993 filed its Draft Integrated Resource Plan, all of which were examined in the public hearing in Rossland, B.C. In an effort to streamline the regulatory process, the Commission approved the inclusion of WKP in a joint public hearing with BC Gas and Pacific Northern Gas to set the appropriate rate of return on common equity and capital structure. The return on common equity and capital structure components in these Decision Schedules reflect the findings as put forth in the Joint ROE/Capital Structure Decision dated June 10, 1994.

In this Decision, the Commission has approved a revenue requirement increase of 2.4 percent, effective January 1, 1994 and a further increase of 3.1 percent, effective January 1, 1995.

Revenue Requirements:

The Applicant stated that the increases were necessary to provide adequate revenue to generate a fair return on the increased investment in plant and equipment, and to help offset higher property taxes on generating plants and substations. The Application was predicated on certain accounting orders which the Commission has approved in this Decision.

The applied-for Operations, Maintenance and Administrative ("OMA") expenses represent an increase over actual 1993 expenditures of 4.2 percent. However, the 1993 costs are significantly higher than those allowed for in the 1993 Decision with the result that 1994 and 1995 costs are 13.1 percent and 21.2 percent greater, respectively, than those approved in 1993. The Commission's Decision disallows material expenses above those identified as due to inflation and customer growth and sends a clear message to WKP that costs must be constrained.

Over the two years covered by the Application, WKP is projecting system investment expenditures of $43.2 million in 1994 and $49.1 million in 1995. This represents a substantial increase in such expenditures and approximately equals the investment which occurred in the previous five years. The major increases are caused by the need to improve the power supply at peak winter loads to the Central Okanagan by the rebuild of lines No. 43 (Princeton to Oliver) and 46 (Vernon to Kelowna). In addition, newly proposed transmission and distribution projects, as well as deferred projects from the 1993 capital budget are included in the forecast.

The upgrade of No. 46 Line is the largest project forecast to begin construction in 1994. The Commission believes that the project is unlikely to be in service in the test periods, given that a CPCN application and other studies for this line have not been filed and, as a consequence, has not allowed its inclusion in rate base. Insofar as the remaining capital expenditures are concerned, the Commission believes that WKP has inadequately planned and justified a number of new transmission and distribution upgrading projects and additions to facilities and has reduced the applied-for amounts by $3.5 million in 1994 and $1.5 million in 1995.

Rate Design:

WKP proposed to increase residential customer rates by 1 percent per year for five years in addition to any general rate increases approved, using the incremental revenues to reduce the small general service and general service customer rates. The Commission generally agrees with the West Kootenay proposal for revenue shifts between classes; however, the Commission believes that even stronger and quicker shifts are appropriate.

The Commission has directed that, for each of the next three years, the Utility is to increase the rates charged residential customers by 2 percentage points more than the general increase that would otherwise be approved. The incremental revenues received from residential customers as a result of this Order are to be offset against the rates charged small general service and general service customers so that the total revenues received by the utility are unchanged by the restructuring.

The Commission finds that the inverted residential rate structure proposed by the Utility is appropriate, except that the residential basic charge is to be set at $12.00 per bi-monthly period. In addition, the Commission orders the elimination of the preferential Rate Schedule 9, effective January 1, 1995.

With respect to small general service and general service rates, the Commission accepts the principle of seasonal rates and has directed WKP to implement flat rates for both the winter and summer seasons in four approximately equal annual steps to commence January 1, 1995. The Commission requires that WKP implement seasonal flat rates for large general service customers effective January 1, 1995.

The Commission accepts that no specific changes should be made to the industrial or wholesale customer rate schedules at this time, but directs WKP to bring forward an application with respect to wholesale customers rates by November 30, 1994. This application is to be based on the principle that flat rates will be achieved within one year.

The Commission directs the Utility to implement a single Irrigation Rate, to be known as Rate Schedule 60. This schedule will reflect a 5 percent decrease in cost recovery from irrigation customers as set out in the West Kootenay proposal. Further, the Commission directs that the decrease in revenues from irrigation customers be offset by a one-time 0.15 percent increase in rates to residential customers.

The Commission is concerned that the current WKP extension policy may not reflect the total social cost of extension and directs the Utility to file a new policy by November 30, 1994.

Draft Integrated Resource Plan:

WKP is commended for the substantial effort to produce its draft IRP and the Commission has provided comments in the Decision intended to guide the Utility's efforts towards submission of a completed IRP by February 28, 1995. The IRP process results in a valuable pre-screening of projects for their environmental and social impacts and general public acceptability. Projects which fail these initial tests can be rejected, thereby avoiding unnecessary and costly hearings.

The Commission agrees with WKP that the required Utility actions over the near term are virtually identical no matter which of the six resource portfolios is chosen, but is concerned that the Utility prefers the Waneta portfolio despite the fact that the IRP decision analysis process seemed to lead to the Financial portfolio.

The Ashlu project proposed by WKP raises the issues of utility ownership of non-regulated generation and self-dealing. The Commission directs WKP to ensure that its customers are not at financial risk if such resource initiatives are ultimately disallowed by the Commission.

WKP applied for Commission approval of various amendments to its Power Smart Program - Rate Schedule 90 - Energy Management Program. The Commission approves the application to extend the current DSM initiatives and directs the Utility to continue its progress reports and to provide the evaluation plan, five-year evaluation budget and summaries of completed program evaluations to the Commission as those documents become available. In addition, as part of its final IRP, WKP is directed to provide a budget for DSM monitoring and evaluation over the next five years that should include process evaluations as needed and one impact evaluation for each of the programs that WKP has applied to be extended to June 30, 1996.

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