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APPENDIX D

Electric Load Forecast 1994/95 - 2014/15

rates be set at a level sufficient for B.C.Hydro to earn a specified annual income equivalent to that allowed by the BCUC for the most comparable investor-owned utility on a pre-income tax basis, while limiting annual electricity rate increases beyond 1993/94 to inflation in B.C. plus 2%.

(b) **Light Fuel Oil Prices**

Crude oil prices are projected to remain below U.S. $20.00 (1993 $) per barrel in real terms for the rest of this century and then trend up to the U.S. $23.00 (1993 $) range by the end of the forecast period. The refinery and distribution margin is projected to trend down in real terms. The combined result is that prices are projected to remain close to current levels in real terms throughout the forecast period.

(c) **Natural Gas Prices**

Current Mainland natural gas prices for the residential and commercial sectors are comprised of approximately one third of wellhead (gas) prices, and two thirds gathering, processing, transportation, and distribution costs. For industrial (interruptible) gas, the wellhead (gas) price encompasses a much greater portion of the total cost; that is, fixed costs of supply are not allocated to interruptible gas prices.

Wellhead (gas) costs are projected to continue to increase in real terms throughout the forecast period. Gathering, processing, transportation, and distribution costs are projected to remain flat or decrease marginally in real terms. The combined result is Mainland average residential natural gas (burner tip) prices projected at 15% to 20% higher than today's (1994) prices by the end of the forecast period.

Vancouver Island natural gas prices are independent of Mainland rates. The Vancouver Island pipeline agreement was to have natural gas prices set at a discount off light fuel oil (LFO) prices for 10 years (i.e., through about 2002). At the end of the 10 year period, residential natural gas prices would be 90% of residential LFO prices.

Commercial natural gas prices are set at a discount off residential natural gas prices.

For the longer term projection, residential (burner tip) natural gas prices on Vancouver Island are assumed to remain at 90% of light fuel oil prices.

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7.3.2 Changing Gas Prices

NATURAL GAS SUPPLY AND PRICING OUTLOOK

The natural gas market structure has changed dramatically from one of formal contracts for firm supplies to a commodity market. Both buyers and sellers of natural gas rely on competitive supply and demand forces to meet their respective market requirements, and both are exposed to the resulting commodity prices. As the natural gas market continues in a state of flux, prices have fallen and the effects of a changing market structure continue to be felt. Premiums for long-term firm gas over spot gas continue to decrease.

The number of options for different types of gas purchase arrangements are also increasing. Aside from the different types of gas products – spot, seasonal, and long-term firm – there are now a variety of pricing mechanisms. Fixed prices for one-year or multi-year firm contracts are losing favour compared to the newer options in the market. Contracting for a standard quantity of gas under standard industry terms and conditions can take less than one week. Contracting for larger quantities with special terms and conditions can take less than six months.

The Huntingdon gas market hub, near Sumas, has become the key hub for pricing British Columbia natural gas and has a large and growing natural gas throughput. Presently, about 50 percent of the capacity at Huntingdon is tied to long-term sales contracts; the remainder trades on short-term contracts. Many of the long-term sales are unlikely to be renewed as the buyers and sellers will opt for the flexibility of shorter-term contracts. Three key variables determine Huntingdon prices:

- U.S. Gulf Coast prices, represented by spot prices at the Henry hub in Louisiana;
- the basis differential between Henry hub and Huntingdon hub spot prices; and
- the Canadian/U.S. dollar exchange rate.

The New York Mercantile Exchange (NYMEX) price for natural gas futures is considered indicative of what natural gas prices should be. NYMEX prices are generally equated to a forecast of Henry hub spot prices, which track closely with average U.S. wellhead prices. The basis differential reflects market access and pipeline capacity and tolls. This differential changes with changing market conditions. BC Hydro's current outlook on

Table 7.4: *continued*

INDIVIDUAL WEIGHT CONTRIBUTION TO WEIGHTING SUMMATION SCORE (by portfolio)															
CC MEMBER W				BCH MANAGER X				BCH MANAGER Y				BCH MANAGER Z			
REF	F1	F2F	BCH	REF	F1	F2F	BCH	REF	F1	F2F	BCH	REF	F1	F2F	BCH
0.00	0.00	0.00	0.00	0.04	0.65	0.13	0.82	0.03	0.18	0.02	0.18	0.11	0.58	0.05	0.58
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.05	0.15	0.06	0.03	0.02	0.05	0.02
0.19	0.04	0.39	0.10	0.03	0.01	0.06	0.01	0.06	0.01	0.12	0.02	0.05	0.01	0.14	0.03
0.29	0.29	0.00	0.50	0.04	0.04	0.00	0.04	0.08	0.08	0.00	0.12	0.05	0.05	0.00	0.08
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.14	0.00	0.15	0.04	0.04	0.00	0.04
0.00	0.00	0.00	0.00	0.02	0.01	0.03	0.02	0.16	0.08	0.20	0.12	0.02	0.01	0.02	0.01
0.48	0.33	0.39	**0.60**	0.13	0.71	0.22	**0.89**	0.55	0.54	0.49	**0.65**	0.30	0.71	0.26	**0.76**

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0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.05	0.15	0.06	0.03	0.02	0.05	0.02
0.19	0.04	0.39	0.10	0.03	0.01	0.06	0.01	0.06	0.01	0.12	0.02	0.05	0.01	0.14	0.03
0.29	0.29	0.00	0.50	0.04	0.04	0.00	0.04	0.08	0.08	0.00	0.12	0.05	0.05	0.00	0.08
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.14	0.00	0.15	0.04	0.04	0.00	0.04
0.00	0.00	0.00	0.00	0.02	0.01	0.03	0.02	0.16	0.08	0.20	0.12	0.02	0.01	0.02	0.01
0.48	0.33	0.39	**0.60**	0.13	0.71	0.22	**0.89**	0.55	0.54	0.49	**0.65**	0.30	0.71	0.26	**0.76**

the Canadian/U.S. dollar exchange rate is 0.75 to 0.78 for the period of this Plan.

BC Hydro regularly prepares and updates an outlook of natural gas prices. The present outlook assumes market prices at the Huntingdon hub, considering the three key variables described above, and includes a real price escalation of approximately 1.5 percent per year. Current lower gas price estimates increase the attractiveness of combined-cycle combustion turbine projects; however, the duration over which these prices will persist is uncertain. To test the sensitivity of the final portfolios to changing gas prices therefore, two alternative forecasts for natural gas commodity pricing were used:

- low gas price case: assumes prices remain at current levels in real terms; i.e., prices increase at the rate of inflation; and
- high gas price case: assumes a steady increase in prices real terms, reaching double today's price at the end of the planning period.

For the portfolio evaluations, as well as in this scenario, a single commodity price was used for all natural gas-fired resources, adjusted for transportation to the various regions. For projects in the Lower Mainland and on Vancouver Island, the Huntingdon hub price was used; for projects in the Kootenays, the Empress hub in Alberta was used. Use of a single commodity price ensures a level playing field for all projects.

IMPACT OF CHANGING GAS PRICE ON BURRARD REPOWERING

In the portfolio evaluations described in Chapter 6, repowering Burrard was shown to be more attractive than other options for the plant. Although BC Hydro expects flexibility in the terms and conditions of gas procurement for Burrard from the Huntingdon hub, it is important to test the sensitivity of the repowering options to changing gas price assumptions. A series of portfolios, using the Reference Portfolio as the starting point, were examined under the base case, high and low gas price outlooks described above. The portfolios included:

- repower 2 modules, retain 2 existing units upgraded with selective catalytic reduction and retire 2 existing units;
- repower 3 modules and retain the remaining 2 existing units for (upgraded with selective catalytic reduction) standby use; and
- repower 4 modules.

The results showed that regardless of the gas price assumed, repowering three modules remained an attractive option. Progressively repowering two and three units resulted in decreases both in system cost and rates. Repowering the fourth module however, while continuing to lower system cost, resulted in an increase in rates over repowering three modules. In all the repowering options examined, and for all price cases, system cost and rates remained lower than in the Reference Portfolio. Further detail is provided in Appendix F.

IMPACT OF CHANGING GAS PRICE ON FINAL PORTFOLIOS

Portfolios F1 and BCH perform similarly in the high and low gas price scenarios. F2F, with a limited number of natural gas-fired resources, is less sensitive to gas price risk.

In low gas price conditions, fewer hydroelectric and wood residue projects are added to Portfolios F1 and BCH. Although no more additions of natural gas-fired resources are made than under base case gas price assumptions, the gas plants have greater utilization. This results in a general increase in all air emissions. For example, greenhouse gas emissions in Portfolio F1 increase by 2 percent over the 20-year planning period, from 98 million to 100 million tonnes. In both portfolios, the present value of system cost decreases by approximately $500 million and rates by 1.5 percent compared to the same factors under base case gas price assumptions.

In high gas price conditions, more hydroelectric and wood residue and less natural gas projects are added to Portfolios F1 and BCH. The reduction in natural gas-fired capacity additions is approximately 700 MW in Portfolio F1 and 300 MW in the BCH portfolio. Four modules at Burrard are still repowered in both portfolios. The reduc-