2002 Update to the 2000 Strategic Resource Assessment

Seattle City Light
Strategic Planning Office

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Table of Contents

Section 1. Summary of 2000 Strategic Resources Assessment 1

Section 2. Changes Since the 2000 SRA

Customer Load 5
Energy Prices 6
Resource Portfolio 6

Section 3. City Light's Load Forecast

Updated Load Forecast 8
High and Low Projections 9
Loss or Addition of Very Large Customers 10

Section 4. Price Projections

Introduction 12
Impact of Near Term Price Volatility 13
Seattle City Light's Methodology to Forecast Prices 14

Section 5. Review of Resource Portfolio in 2002

Composition 15
Variability 15
Review of Performance of Resources Acquired since the 2000 SRA
Klamath Falls 17
State Line Wind 18
BPA 20
Appendix: Brief Description of Other Components of City Light's Portfolio 21

Section 6. Conservation

Conservation Acceleration (ConXL) 24
City Light's Conservation Programs 24
Energy Codes, Appliance Standards and Market Transformation 25
Meeting SRA Direction 26
Energy Savings Achieved under ConXL 26
BPA's Conservation Augmentation (Con Aug) 27

Section 7. Load Resource Balance and Projected Monthly Energy Surplus/Deficits

Definition of Load Resource Balance 29
Definition of Critical Conditions 29

Base Forecast of Energy Surplus/Deficits 30
Alternative Scenarios: Changes in BPA and Klamath Falls Contracts 31
Variations in Load Resource Balance with Changes in Projected Customer Load 35

Section 8. Costs of City Light's Resource Portfolio

Introduction 37
Base Projections 38
Customer Load Changes 39
Market Price Changes 40
Changes in Water Conditions 41
Impacts of Changes in Combined Factors: Summary Conclusions 42
BPA Costs in 2011 44
Appendix: Impact of Loss of Customer Load on Average Customer Rates 45

Section 9. Strategies for Maintaining Load/Resource Balance

Background 47
Combustion Turbine 47
Spot Market Purchases 49
Forward Contracts 49
Options 50
Seasonal Exchanges 50

Section 10. Risk Management

Background 52
Current Approach 52
Going Forward 53

Section 11. Environmental Implications of Resource Portfolio

Environmental Characteristics of Resource Portfolio 54
Status of Goal of Meeting Load Growth with Conservation and Renewables 57
Greenhouse Gas Mitigation Program 58
Seattle Voluntary Green Power Program 61

Section 12. Potential Market Changes

Background 62
Impact of Transmission Constraint on Boundary 64

Appendices

Appendix 1: Status of BPA Contract 67

Appendix 2: Klamath Falls Contract: Renewal Choice 69

Appendix 3: Time-Based Rates 72

Appendix 4: Boundary Relicensing 77

Section 1. Summary of 2000 Strategic Resources Assessment (SRA)

In the summer of 2000 Seattle City Light completed its analysis of options to meet its customers' electricity needs while remaining one of the lowest-cost, most reliable and environmentally responsible utilities. In view of the increased volatility and high levels of natural gas and electricity prices in the market at the time, the 2000 SRA strategy to meet customer load was to reduce dependence on market purchases even under severe drought conditions and to increase conservation and acquire resources that met the City's environmental values.

In early 2000, under severe drought conditions the Department would depend on market purchases to meet a considerable portion (about 20%) of its customer demand. The sale of the Centralia plant, effective in May 2000, increased dependence on markets at a time when concerns about market volatility were increasing. If no new resources were added, the utility's resource gap was expected to increase to about 40% of customer load as a result of projected customer demand growth and the anticipated loss of power from some contracts that would terminate in the near future. City Light's goal was to have sufficient owned and contracted resources to meet its customer demand in even the driest years. The 2000 resource strategy was thus to achieve balance between resources and customer loads under very dry ("critical") conditions. This would require significant resource acquisitions. As a result of high economic growth and the rapid development of energy-intensive industries (such as high tech and communications), customer load was anticipated to increase by a total of 200 MW between 2000 and 2011. In addition, discrete additions of loads exceeding 10 MW each were projected over the next few years as a result of an anticipated boom in internet farms in the service territory. Consistent with the City Council Earth Day Resolution (April 2000), City Light planned to meet all load growth with conservation and renewable resources and to mitigate any greenhouse gas emissions resulting from its resource portfolio. The resources acquired in 2001 included the doubling of the conservation program, a contract for a share in the output from a wind project (State Line), a new contract with the Bonneville Power Administration (BPA) and a contract for a share in the Klamath Falls Project, for which greenhouse gas emissions will be fully mitigated.

City Light's conservation program before the 2000 SRA had the purpose of achieving about 6 aMW of annual energy savings per year. Subsequent to the 2000 review, the conservation program goal was doubled to 12 aMW annually. A review of conservation opportunities in the service territory indicated that this increased goal could be achieved in a cost effective fashion; about 3 aMW of energy savings are expected to be achieved from the implementation of building codes and an additional 9 aMW will result from conservation programs.

The 2000 SRA recommended the purchase of renewable resources up to about 100 aMW. This amount was projected to provide the power for the demand not met by the increased conservation investments through 2011. In July 2000 City Light issued a Request for Proposals for renewable resources. It received about sixty responses, but there were just a few resources that would be available in the near future. The most economic and viable

option was the State Line 263 MW wind project, built in Walla Walla County (Washington) and Umatilla County (Oregon). City Light signed a twenty-year contract to buy a share of the energy and environmental attributes from that project at a fixed price. The Department's share is equivalent to 50 MW of capacity from January through July 2002 and increased to 100 MW effective August 1, 2002. In 2004 City Light will also receive the energy and environmental attributes associated with an additional 50 MW of installed capacity either from State Line or from a wind project with similar attributes. In addition, in 2004 the seller (Pacific Power Marketing) has the option to put to City Light an additional 25 MW of wind capacity. If this option is exercised, by the end of 2004 the Department will receive the energy and environmental attributes from 175 MW of wind installed capacity, or about 59 average MW annually, over half of the 2000 SRA's goal of 100 aMW.[1]

A new, ten-year contract with BPA, effective October 1, 2001, replaced the contract that had been amended in 1996 and had reduced purchases from BPA to 195 average MW. In 1996 BPA costs were higher than market prices and City Light was concerned about the impacts of deregulation and potential stranded costs due to load loss. The analysis of the 2000 SRA indicated that BPA was again a competitive supplier, with costs that were anticipated to remain quite stable at levels lower than market prices. There were also indications that there would be market supply constraints, since demand in the western region was increasing rapidly as a result of economic growth while very few energy plants were being developed. The 2000 SRA advised to buy as much energy from BPA as possible. The final BPA contract includes a combination of slice and block purchases. The slice portion entitles City Light to a 4.6676% share of the federal energy system in exchange for the payment of the same share of BPA's revenue requirements. The amount of energy received under the slice varies as BPA's generation fluctuates as a result of weather, water conditions and fish requirements. In good water years there is a considerable amount of surplus energy, which can be sold in the market. The slice purchase has thus added to the variability of City Light's resource portfolio, but this increase has been one-sided. The minimum of energy generation has not gone down and the maximum is now significantly higher than before. The block portion of BPA purchases is shaped according to City Light's monthly needs, resulting from the difference between its load and its other resources. The block amount in the contract is about 164 aMW through September 30, 2006, with a projected increase of about 115 aMW starting October 1, 2006. The block amount has declined by about 20 aMW, as described in the next section.

Finally, the Klamath Falls contract, effective July 1, 2001 through June 30, 2006, entitles City Light to 100 MW of the capacity of this 500 MW combined cycle combustion turbine. This project already mitigates some of its impact on greenhouse gas emissions. City Light has committed to mitigate the remaining greenhouse gas emissions through its

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[1] Since wind is an intermittent resource and the State Line Project is located outside the Department's available transmission grid, City Light has also signed a ten-year integration and exchange agreement with PacifiCorp. Under this agreement, PacifiCorp receives City Light's share of the output from the State Line Project, stores it, and two months later delivers it flat to the Department at the Mid Columbia hub (Mid C).

Greenhouse Gas Mitigation Program for as long as the project is in the utility's resource portfolio. The current contract can be extended for an additional five years, with the decision required by the end of 2004. At the time the contract was signed, City Light chose to mitigate anticipated peaks in the cost of natural gas by entering into an eighteen-month hedge contract, which terminates at the end of 2002.

With the resource acquisitions described above City Light achieved the goal of being in load resource balance under very dry, or critical, water conditions. Dependence on market purchases has been considerably reduced. While in 2000 City Light's market purchases were equal to 28% of customer load (328 aMW of purchases compared to 1,164 aMW of load), the same percent is projected to be less than 8% in 2002, mostly for shaping. The cost of meeting customer load is thus less volatile. The resources added in 2001 increased the average cost of the utility's portfolio when measured in terms of the generation from that portfolio; the new additions are more costly than the average portfolio cost, which is strongly influenced by the low cost of City Light's own hydro plant. This gross cost measure, however, does not include the impact of market power purchases or sales on the cost of meeting customer demand. When the cost of market purchases, net of the revenue from market sales of energy surplus, is considered, the cost of meeting customer load in 2002 is lower than in 2000, shown in the table below.

Cost of Meeting Customer Load in 2000 and 2002

	2000	2002
Costs in dollars		
Own Resources and Firm Contracts	$133,357,871	$273,349,892
Market Transactions:		
Purchases	$212,278,905	$12,934,656
Sales	($103,300,934)	($113,323,088)
Total Net Power Costs	$242,335,842	$172,961,461
Customer load in MWh	10,224,758	9,957,857
Power Cost per MWh of Load	$ 23.70	$ 17.37

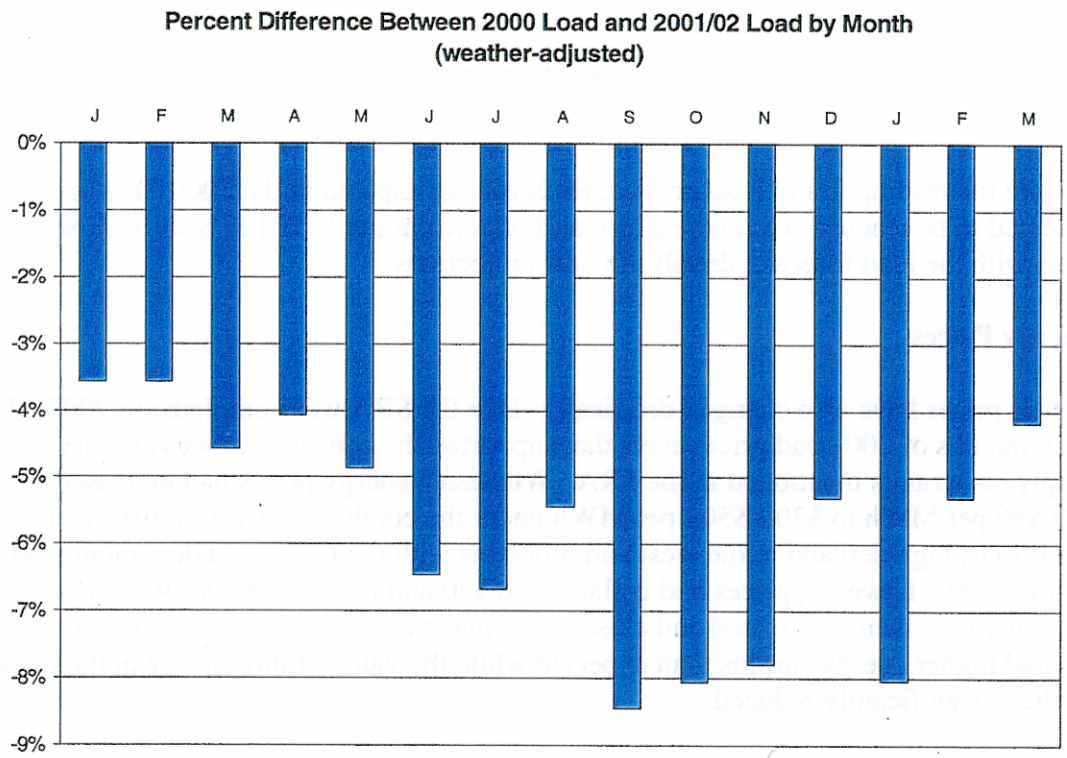
The numbers above were derived using actual data for 2000 and projected numbers for 2002; portfolio costs include estimates of the annual portion of generation capital expenditures associated with the utility's own resources. In all cases they exclude overhead costs such as administration and general and tax expenses. Market prices have a strong impact on the net costs of the portfolio as defined above; with the new portfolio, high market prices reduce the power costs to the utility's ratepayers. For example, if market prices in 2002 were around $60/MWh (somewhat lower than the average for 2000), net portfolio costs in 2002 would be dramatically reduced to about $3 per MWh because of the large revenues from market sales. In 1998 and 1999 portfolio costs were somewhat lower than the value projected for 2002. They were about $16.30/MWh in

1998 and about $12.30/MWh in 1999, when water conditions were considerably above average and the utility had a large amount of surplus revenue.

Section 2. Changes Since the 2000 SRA

Customer Load

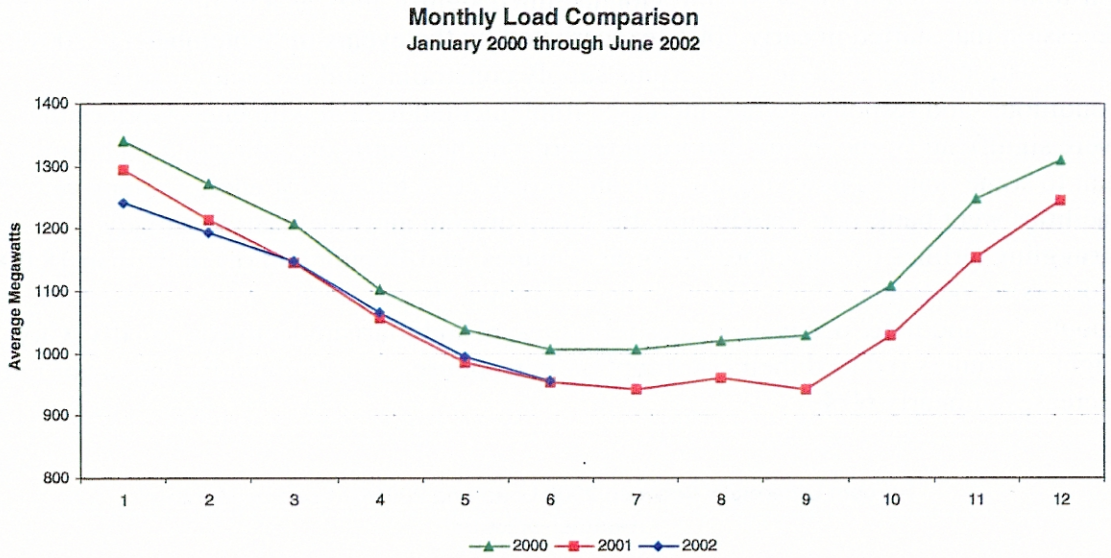
Customer demand in the western region declined significantly as a result of the economic recession that started in early 2001 (exacerbated by the events of September 11, 2001), conservation appeals in view of serious supply constraints and extreme weather conditions, and response to rate increases implemented to deal with energy prices that were significantly above any historical record. In the Seattle area the dot.com bust put a halt to some planned new construction and prospective tenants for energy-intensive facilities went bankrupt. In addition, the sharp drop in air travel caused already struggling airlines to cancel orders for new planes, and Boeing laid off more than 18,000 workers in the Puget Sound region. The downtown office vacancy rate increased to about 15% and hotel occupancy rates fell as travel and tourism declined. Finally, City Light customers reduced their consumption in response to the cumulative impact of rate increases of nearly 60%.



The most dramatic monthly decrease was observed in September 2001 when consumption was 8.4% lower than in the comparable period in 2000.

Seattle City Light's system load reached its highest level of about 1140 aMW (weather-adjusted) in 1999 and 2000. Load subsequently fell by 5.6% to 1077 aMW in 2001. Year-to-year monthly comparisons indicate that the decline in load ended in March 2002.

For March though June, monthly load in 2002 was at about the same level as in 2001. Load began growing again in the second half of 2002; customer load through the end of August was almost 1% above 2001 levels.



Despite the resumption of load growth, the levels anticipated in the 2000 SRA are not expected to be reached within the planning horizon, ending in 2012. Section 3, which deals with the load forecast, details the new projections.

Energy Prices

Energy prices have also changed drastically since the SRA was completed in 2000. The early months of 2001 had price levels that supported the concerns about volatility and supply constraints mentioned in the SRA. Wholesale energy prices had increased from $30-$50 per MWh to $300-$500 per MWh under the combined effect of historically dry conditions, high demand in the west and problems with the California deregulation effort. By mid-2001, however, prices had collapsed to $20 and less per MWh. With lower customer load than anticipated and close-to-normal water conditions in 2002, City Light has had higher energy surplus than expected while the value of this energy in the market has been significantly reduced.

Resource Portfolio

There have also been some changes affecting the resource portfolio as described in the SRA. One of them is the reduction in the block purchase from BPA. City Light has agreed to reduce its BPA block purchases in exchange for BPA funding of its conservation program for two years. The conservation program financed by BPA is estimated to result in energy savings for City Light that are equivalent to roughly 20 MW, so block purchases are reduced by this amount annually. This arrangement reduces the

amount of market purchases that BPA has to make to meet its obligations[2] and helps to finance City Light's conservation program. Since conservation savings have an expected life of fifteen to twenty years, the reduction in BPA block purchases is effective through the end of the BPA contract in 2011.

Another resource change relates to the Priest Rapids contract. The 2000 SRA assumed that City Light would no longer receive power from this resource after the expiration of its contract with Grant County PUD in October 2005. Negotiations in 2001 and 2002 resulted instead in a new agreement that entitles City Light to receive some amounts of energy and revenue from Priest Rapids through 2023. The new agreement with Grant includes three contracts. One of them provides City Light with a share of 6.14% of the revenues collected from Grant's market sale of a Reasonable Portion of the project output (set at 30%). The second contract entitles City Light to purchase 6.14% of the remaining firm and nonfirm power (70% of the output) after Grant County has served its load. Finally, the third contract allows City Light to purchase 6.3% of additional nonfirm power as it becomes available. All firm and nonfirm purchases by City Light will be priced at Grant's production cost. The energy amounts in the Department's portfolio are projected to be reduced from the current levels; firm amounts range between approximately 2 MW and 4 MW through 2009, with a small increase in 2010 and eventually gradual reduction as Grant County loads increase.

Finally, the 2000 SRA projected that the utility would have to buy about 100 aMW of renewable resources to meet load growth through 2011. While City Light has already contracted to acquire at least 51 aMW (potentially 59 aMW) of wind energy, there has been no load increase since 2000. The Department now has to determine how much more energy from renewable resources is likely to be required over the next ten years in view of the slowdown in customer load growth and the need for renewable resources under two programs established since the 2000 SRA. One of these is the Department's, new voluntary green power program, which will buy small amounts of renewable energy with the funds provided by program participants (Section 11 describes this voluntary program). In addition, some customers have expressed interest in energy purchases that meet the LEED (Leadership in Energy and Environmental Design Standard) certificate standards.

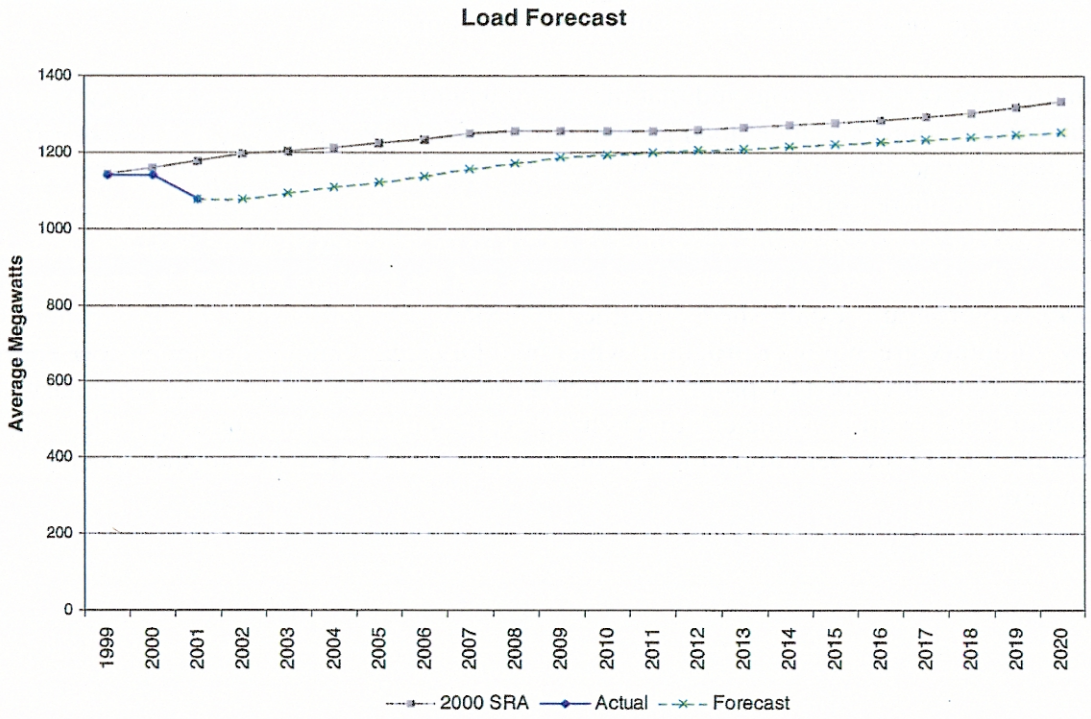
[2] The 2000-1 BPA contract negotiations resulted in oversubscription as the demand for BPA power exceeded available supply and BPA had to purchase energy in the market to meet its obligations. Closure of direct service industries and temporary reductions in the energy taken by utilities helped mitigate this problem for the following fiscal year. Conservation measures by BPA customers also contribute to reduce the need for BPA's market purchases.

Section 3. City Light's Load Forecast

Updated Load Forecast

The load forecast is derived from a model that incorporates over 70 variables reflecting economic and demographic conditions such as income, employment, industrial output, household size, etc. Projections are developed for all sectors of the economy and for different types of residential customers (single family, multiple housing, etc.). The projections reflect customer load under normal weather conditions.

Load is expected to rebound as the local economy recovers. Load recovery in the forecast is patterned after the recovery observed following the decline in load in the early 1980s. Load is expected to resume growing in the last half of this year when the area economy is expected to pick up. Base projections indicate that by 2006 load will reach the level it was at in 1999 and 2000 (about 1140 aMW). By 2011 load will reach nearly 1200 aMW– almost 60 aMW less than in the projected 2000 SRA, as shown in the graph below.



In the 2000 SRA, load was expected to increase at a modest average rate (0.7% over 2002 through 2011) from its level of 1138.5 aMW (weather-adjusted) in 1999. The 2002 forecast projects a strong rebound from a low starting point of 1076.7 aMW in 2001, with an average annual growth rate of 1.2% over 2002 through 2011, as shown below.

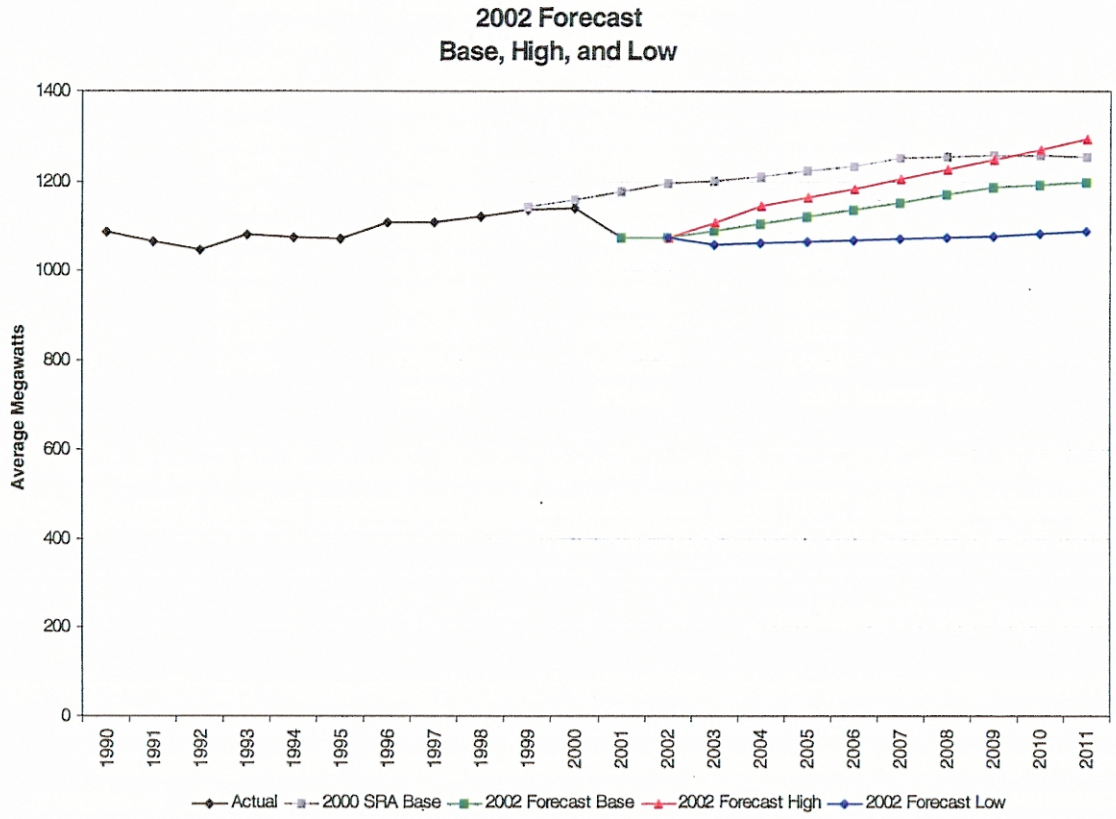
	2000 SRA aMW	2002 Forecast aMW	Difference aMW
2002	1195	1075	-120.5
2003	1201.6	1092.2	-109.4
2004	1211.2	1107.4	-103.8
2005	1223.7	1122.8	-100.9
2006	1234.5	1138.4	-96.1
2007	1250.6	1154.3	-96.3
2008	1255.6	1170.3	-85.3
2009	1256.5	1186.6	-69.9
2010	1256.4	1192.5	-63.9
2011	1255.8	1198.5	-57.3
Avg annual rate	0.60%	1.20%	

Despite the projected stronger annual average growth, customer load levels are not expected to reach the 2000 SRA projections during the forecast horizon because recovery starts from a drastically reduced level in 2001.

High and Low Projections

As the events occurring after the 2000 SRA illustrate, many factors can affect customer load and cause significant variations from base projections. It is therefore useful to analyze potentially different paths of customer load growth. These high and low scenarios are mainly linked to different assumptions of economic growth. In addition, the review of the effects of a one-time change in customer load (either an increase or a reduction) contributes to the robustness of any resource strategy.

The long-range load forecast is built on a baseline forecast of the economy. High and low load forecasts are based on high and low scenarios for the economy. The probability that economic growth will fall between the high and low economic scenarios is 95%. The high load growth scenario assumes a strong rebound from the recession, with load growing at an average annual rate of 2.1% over 2002 through 2011. The low load growth scenario assumes a prolonged period of very low growth, with load growth averaging 0.1%. These high and low load growth rates bracket the growth rates for earlier ten-year periods. The average growth rate for the ten years ending 2000 was 0.6%, and for the ten year period ending 1994, it was 1.2%. The following graph shows these scenarios compared with the base 2000 SRA projections



Loss or Addition of Very Large Customers

The 2000 SRA addressed the possibility of some very large customers coming online within a short timeframe. To date, these energy-intensive high-technology loads have failed to materialize. The infrastructure to serve at least 50 aMW of new load at a location in Tukwila has been built, so there is still a possibility that equipment could be plugged in on short notice.

There is also a possibility that some large industrial load could be lost, for example through a plant closure. The long-range load forecast would have to be shifted down. Similarly, the addition of a very large new load would require shifting the projections up, because load changes of this magnitude are not anticipated by the forecast. If 50 aMW of load were gained or lost in 2005, the change in load would nearly fall within the range of the high and low load forecasts respectively, at least in the mid term.

The addition of a large customer that meets the definition established in the New Large Load ordinance would not, by definition, have a significant impact on the rates paid by other ratepayers. As discussed in the Appendix to Section 8 (Cost of City Light's Portfolio), the loss of a load of 100 MW would have an impact of less than $2 per MWh on the average annual rate paid by the remaining customers.

Section 4. Price Projections

Introduction

City Light uses three kinds of price projections: spot market, forward and long-range market. For near-term decisions the utility relies considerably on the forward curve, which reflects the prices agreed upon in forward contracts. These quotes show the prices at which parties are willing to commit now for obligations to be met at some date(s) in the future. Spot prices, on the other hand, reflect the prices of current transactions. Although in the near term, over several months, the forward curve provides an acceptable representation of conditions in the forward market, it is sometimes the result of a relatively small number of transactions (a "thin" market). As the horizon lengthens, the forward curve becomes less and less reliable because it reflects an increasingly smaller number of transactions, as utilities perceive a much higher risk in committing to a price in the more distant future.[3] In any case, the forward curve represents the price that would prevail if parties agreed on the future transaction at the present time. They may change significantly from day to day and may be quite different from the spot market price at the future date to which they refer.

For long-term decisions such as resource acquisitions the value of resource options has to be measured by market price projections that reflect market fundamentals, including long-term trends in demand and supply. Assuming a relatively competitive market, over the long run prices are expected to reflect marginal cost, the least costly addition to supply in order to meet customer demand. This approach, however, is not sufficient. Given market imperfections, such as oligopolistic power, institutional factors (e.g., FERC's role), the cycles of over and underbuilding when large discrete investments are made (as in the case of power plants), load fluctuations, external events and risk, electricity market prices in any year deviate from the marginal cost of energy (usually assumed to be that of a combustion turbine). In fact, it may be argued that even over the long run energy prices tend towards a level that exceeds the marginal cost because typically entry into the market is constrained by the ability to finance the large investments required for a power plant and the risks involved. Instead of the large number of small suppliers typical of competitive markets, energy markets have a mix of small, medium and large size providers. The latter are capable of exercising at least some degree of oligopolistic power, which can also intensify short-term fluctuations and keep prices above the levels that would be set in a competitive market.

At any time energy prices may be above or below the long-term market prices. It is not possible to anticipate the precise impact of the interaction of the factors affecting energy prices at a given moment. At times different factors causing deviations from the long term price trend may offset each other; at other times they may accentuate fluctuations and volatility. On the demand side, the demand for power, which in many areas is shielded from wholesale market prices by fixed retail rates, is affected by economic

[3] The market has become much thinner since mid 2002, as a result of the financial difficulties and confidence issues associated with a number of utilities. The number of players in the energy market has been considerably reduced.

cycles, temperature, etc. On the supply side many factors are at play. For example, the availability and/or prices of the fuel used to produce energy (e.g., natural gas, water, etc.) can limit or expand the energy supplied by existing plants and thus can push market prices higher or lower.

Impact of Near Term Price Volatility

While long-term decisions should be based on the long-term projection of market prices, the assumption on the near-term prices can have a considerable impact on decisions. It may make sense to include forward quotes for the immediate eighteen months or so after a resource is anticipated to be on line. The evaluation of a resource, however, may be unduly influenced by near-term projections, as is illustrated below.

Prices Projected at Different Times
from 2000 through July 2002
nominal dollars per MWh

	April 2000 (Strategic Resource Plan)	May 2001	July 2002
2002	29.67	117.35	25.50
2003	32.45	52.51	30.55
2004	35.58	44.27	30.28
2005	38.79	41.66	30.51
2006	41.03	40.36	30.52
2007	43.08	42.35	31.40
2008	44.74	43.93	32.90
2009	46.21	45.35	33.99
2010	47.65	46.75	35.24
2011	48.99	48.06	36.78
2012	49.89	48.95	38.31
2013	50.43	49.48	39.71
2014	51.40	50.45	40.96
2015	52.72	51.75	42.39
2016	54.54	53.56	43.70
2017	56.83	55.82	45.12
2018	59.35	58.30	46.44
2019	62.17	61.07	47.57
2020	65.39	64.24	47.75
Levelized at 5%	$45.47	$54.06	$35.62

The different assumptions about the prices result in considerably different estimates of the projected levelized annual value of energy in the market. The first two columns above, for example, end at about the same level but start at different near-term prices; this difference is sufficient to cause considerably different estimates of the levelized value of

a resource over the period. The evaluation of potential resource acquisitions, therefore, is strengthened by the analysis of different scenarios of prices, especially in the near term. Similarly, the value of City Light's resource portfolio is strongly influenced by the assumptions on market prices. A more robust analysis needs to consider several levels of market prices, as well as other variables that affect the value of the portfolio to ratepayers (see Section 8).

Seattle City Light's Methodology to Forecast Energy Prices

Long-Term Market Price Forecast

Long-term monthly spot market prices at the Mid Columbia hub (Mid-C) are projected by combining the market forward curve and the long-term monthly price forecast. Market forward prices are available for the next eighteen months and annual forward prices are available through 2006. Monthly prices from 2007 through 2020 are estimated using the utility's own price-forecasting model. A final smoothing method is used to correct for anomalies between short-term forward and long-term forecasts.

Forward Price

The utility (Power Management Branch) produces weekly forward curves of monthly prices for the next eighteen months. This forward curve is produced based on market information provided by brokerage houses and the Department's forward traders. All forward prices collected daily are stored in a large database. This database is updated at least once a day. Annual market forward prices are provided by brokerage-houses. The price forecasting model uses seasonality coefficients and converts these annual prices to monthly forward curves. A final monthly forward curve through 2006 is created with information from the forward market.

Price Forecast Fundamentals

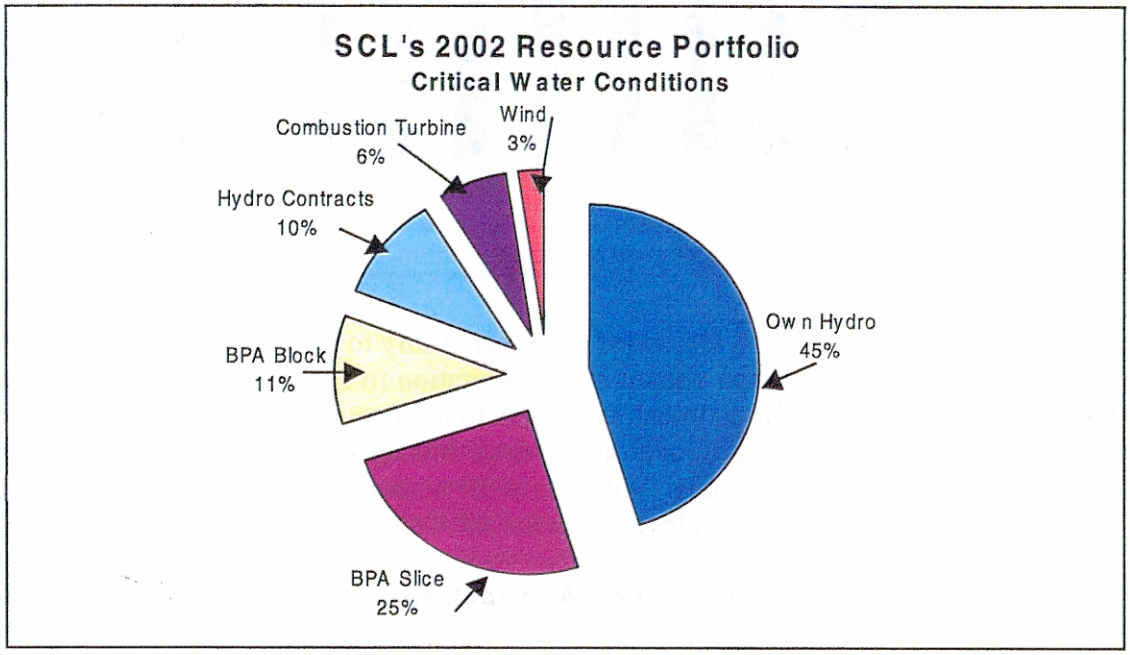
The price forecasting model is based on an established historical relationship between market prices and natural gas prices, temperatures, seasons, northwest water conditions, and a time-trend. The annual natural gas price forecast through 2020 is provided by EIA (Energy Information Administration). A normal temperature is assumed for long-term forecasting. The model produces fifty forecasts, one for each water year. The average of the forecasts for all fifty water years is the expected price (base case) for each period.

The final forecast for each water year is made by adjusting the forward curve (base case) to the forecast for each water year. This is then combined with the forecast from the forecasting model to have a continuous forecast for each water year. The forecast for the driest year should not be interpreted to be necessarily equal to the high price case. There are other factors, like high prices of natural gas, which can have a significant impact on electricity prices.

Section 5. Review of Resource Portfolio in 2002

Composition

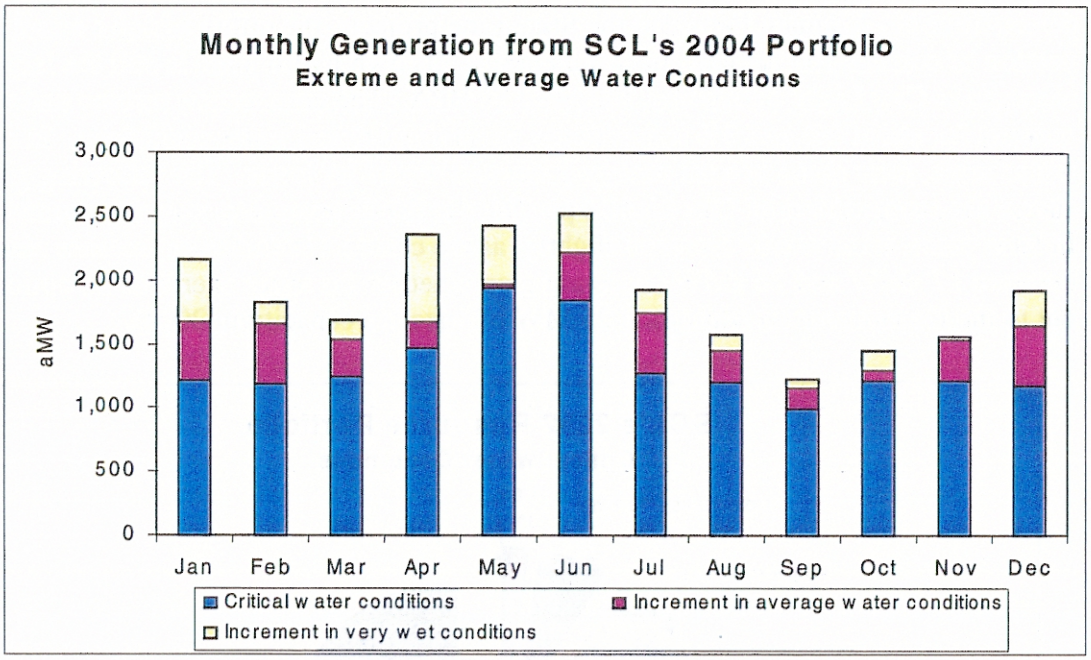
City Light's resource portfolio is largely hydro based. With the contracts to acquire power from the Klamath Falls and the State Line projects, the utility added a small portion of combustion turbine and wind energy. Its own hydro plant is still the largest resource in City Light's portfolio, followed by BPA. The combustion turbine and wind account for about 6% and 3% respectively, assuming critical water conditions. In most water years, their share in total energy generated would be lower. The following graph shows the composition of City Light's portfolio in 2002, assuming very dry conditions. In later years, wind would increase slightly, as the contract includes an increase ranging between 17 aMW and 26 aMW (depending on whether the seller exercises its option to put to the Department an additional 25 MW of installed capacity in 2004).



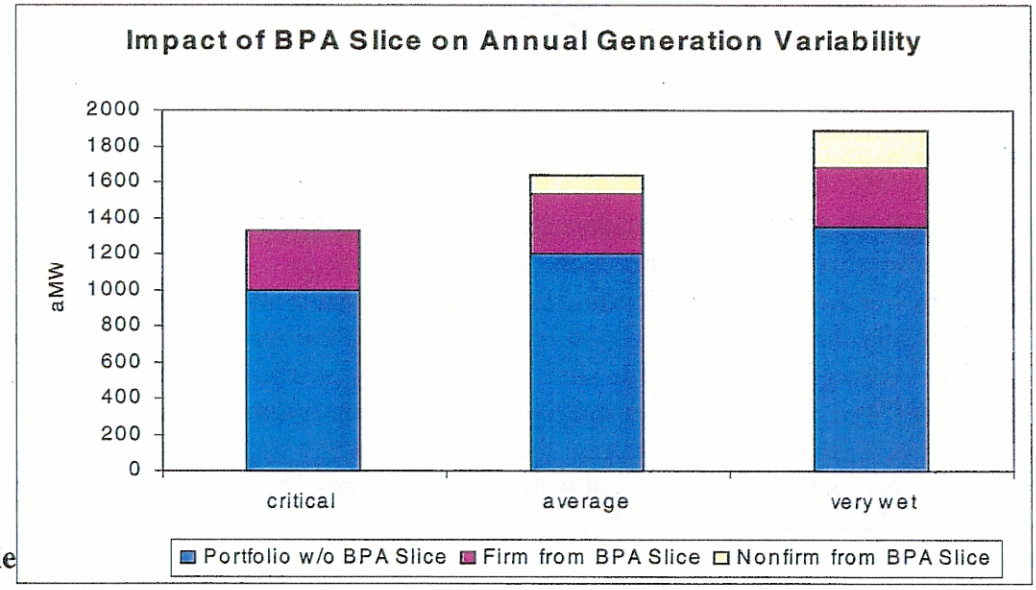
Variability

Since most of BPA's slice resources are also hydro, City Light's resource portfolio has the typical variability of hydro generation. Output can change from year to year, depending on weather and water conditions, and in any year it also varies from month to month. Typically the highest generation levels are during the spring and early summer runoff. This hydro generation profile shapes the monthly profile of the whole portfolio. Since most of City Light's resources are hydro and the non-hydro new acquisitions changed the portfolio only at the margin, the utility's strategy to acquire sufficient resources to meet its load under critical water conditions results in significant energy surplus during the months of higher hydro generation.

The following graph shows monthly generation from City Light's portfolio under very dry (or critical), average and very wet water conditions. The graph refers to 2004, when wind generation has achieved its maximum potential of 59 aMW, Klamath Falls is still part of the portfolio, and BPA purchases are consistent with the current contract.



The contract signed with BPA has added some variability to the utility's portfolio because it entitles City Light to a share in the generation from the federal system. As a result of this contract, the Department has access to nonfirm energy from the slice that ranges from zero under critical conditions to about 200 aMW in a very wet year. The following graph shows this impact. Without the BPA slice, generation in a very wet year would be about 36% over critical level; with the BPA slice, this increase is about 42%.



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Klamath Falls

The 2000 SRA recommendations included the Klamath Falls contract as a source of energy to provide a hedge against adverse water conditions, fast load growth and daily peak demands. In agreement with the Earth Day Resolution, greenhouse gas emissions would be fully mitigated.

City Light's purchases from Klamath Falls commenced in July 2001. Through April 2002, the project was operating at below the original budgeted 95% availability factor. In general, new combustion turbines such as Klamath Falls experience relatively low availability factors during the first two or three years of actual operation. This is due to initial operational problems of this type of plant and the greater frequency of outages needed to make turbine and other plant adjustments. Nevertheless, the availability factor for the plant has been aided by a contract provision that allows the Klamath owners to re-supply energy (from the market) when the plant is out of service for a planned or unplanned outage. The projected availability for Klamath Falls is at 87%.

Through July 2002, the Department purchased about 670,000 MWh under this agreement. The utility elected not to receive power from Klamath Falls during May and June 2002 due to lower than expected customer load, low market prices and about average water conditions. This decision allowed City Light to avoid some of the costs of this resource, but it still had to pay fixed costs.

From the beginning of the contract through the end of July 2002, City Light spent about $40.3 million for this power. Of this amount, about $29 million was for the gas hedge, which City Light signed in July 2001. The gas hedge contract was expected to protect the utility from the impact of the high natural gas prices prevailing at the time the contract was negotiated. In later months, however, natural gas prices declined drastically. From July 2001 through July 2002 the gas hedge caused Klamath Falls costs to be about $14.5 million higher than they would have been if natural gas had been bought in the spot market. The impact of the hedge on 2002 costs has been significant. For the first seven months of 2002 City Light received almost 360,000 MWh of energy from this contract at a total cost of $21,836,000. The average unit cost of this power was thus about $60 per MWh. If the utility had not had its gas hedge contract, however, total costs for the seven months would have been $7.6 million lower and the average cost of the power would have been about $39.50/MWh. At the termination of the hedge in December 2002, City Light probably will not enter into another 18 month gas hedge. It may consider a shorter-term gas hedge agreement, depending on the evaluation of current and projected natural gas prices and the utility's risk aversion.

The Klamath Falls project, as a condition of its permit, already includes mitigation of approximately 26 percent of the project's CO_2 emissions. The City of Seattle in its Earth Day Resolution[4] committed to establishing a long-range goal of meeting the electric energy needs of Seattle with no net greenhouse gas emissions and City Light plans to

[4] Resolution 30144, dated April 10, 2000.

offset the remaining greenhouse gas emissions associated with its purchase, but has not yet signed the contracts to achieve this goal (see Section 11). The estimated cost of this program, less than $1 million per year, is not included in the actual costs described above.

While total Klamath Falls costs are anticipated to decline after the expiration of the current gas hedge (December 2002), they are expected to remain above market prices for the next few years. The variable cost of this resource, however, under the base assumption of natural gas prices (about $3.5 per MMBtu over 2003-4) would remain below expected market prices (the current base forecast) nine to ten months of the year in both 2003 and 2004. Therefore, it would be run most of the months. With higher projections of natural gas prices (about $3.7-$3.8 per MMBtu) and no significant electricity price changes, it would be cost effective to use this resource only seven to eight months in the year.

State Line Wind

In March 2001, following a review of numerous renewable resource projects proposed to City Light in the fall of 2000, the Department signed a Letter of Interest with PacifiCorp Power Marketing to purchase wind energy and environmental attributes from the State Line wind project. The terms of this Letter outlined the underlying provisions of the purchase. Since wind generation is intermittent and the project is located in the eastern region of the state, City Light also had to procure shaping and transmission services. In October 2001, City Light signed 3 agreements:

(a) Purchase of energy and environmental attributes from PacifiCorp Power Marketing associated with up to 175 MW of generation capability from the State Line Wind Project and/or other qualifying wind projects starting January 1, 2002,[5]
(b) Purchase of an integration and exchange service from the merchant function of PacifiCorp to convert intermittent wind energy associated with up to 150 MW of generation capability from the Project into a firm, flat energy product, and
(c) Sale of an integration and exchange service to PacifiCorp Power Marketing to convert intermittent wind energy from the Sate Line Wind Project into a firm, flat energy product.[6] City Light uses a portion of the service provided in the PacifiCorp Integration and Exchange Agreement to meet its obligations under this Agreement and charges an additional fee to PacifiCorp Power Marketing.

The power purchase and the sale of integration and exchange services to PacifiCorp Power Marketing are twenty-year agreements terminating in December 31, 2021. Integration and exchange services with PacifiCorp are set by a ten-year contract terminating on December 31, 2011. According to this latter agreement, delivery of the wind power will be at the Mid-Columbia hub. When the agreement with PacifiCorp ends

[5] The energy and environmental attributes associated with 50 MW was available in January 2002, with an additional 50 MW received beginning August 2002. In 2004, there will be an addition of 50 MW. Finally, also in 2004, the seller has the option to put to City Light the sale of energy and environmental attributes from an additional 25 MW of wind capacity.
[6] PacifiCorp Power Marketing requested this service during the negotiations for the sale of power from State Line to City Light.

Seattle City Light risks not having access to firm transmission to receive this energy near or at its service territory. It is still early to review options to replace the contract with PacifiCorp, especially in view of potential changes to regional transmission rules.

City Light's purchase of energy and environmental attributes associated with the first 50 MW of wind capacity commenced January 1, 2002. Through August 2002 roughly 50% of the energy generated has been on peak and 50% has been generated off-peak. Under the PacifiCorp Integration and Exchange Agreement, City Light is receiving this power at the Mid-Columbia hub two months after it is generated, net of losses and after certain other adjustments associated with scheduling.

The overall capacity factor through the end of July 2002 was lower than anticipated although it exceeded 37% during on-peak periods over some winter months. The Department still expects to have the actual capacity factor be close to the expected 33.7% level because the low factor in the first months of the contract was influenced by the fact that in February turbines were off-line due to maintenance and other adjustments. The State Line Wind Project is a new facility (it went into service in December 2001) and initially will have greater frequency of outages to make turbine adjustment. Information regarding periods of when the turbines will be off-line is available to City Light.

As of the end of August 2002, City Light had received about 57,720 MWh, generated between January and June at the State Line Project. The estimated average cost of this power was about $43 per MWh. This amount includes the cost of the power purchase, which depends on the amount of energy received but has a fixed price, and integration and exchange costs, which include fixed and variable components.

Starting on August 1, 2002 the wind purchase increased from 50 MW to 100 MW of wind-generated capacity. The increased amount of wind energy will be received starting in October because there is a two-month lag between generation and delivery to City Light. The unit cost of this power increases by about 23% beginning in August and for the remainder of the year, as specified in the power purchase agreement. The impact on 2002 costs will be to increase the full annual average cost of State Line for the twelve-month period to about $52-$54 per MWh (including the cost of power, shaping, wheeling, transmission losses and assuming an average generation variability of about 15 MW measured over two-hour periods). Effective January 2003, however, the contract rate will be reduced to the original level and average annual costs will be about $45-$50 per MWh, depending on the costs resulting from the variability in wind generation. The projected cost of this power, including wheeling and shaping, is thus anticipated to remain above expected market prices for the near term, but it will change little over the twenty years of the contract. The prices of power at busbar will not change, and only some components of the integration and exchange service costs will increase for the life of the contract with PacifiCorp (ten years). These numbers exclude the value of the environmental attributes associated with the wind project, estimated to be between $5 and $7 per MWh, which would bring the price of this resource to about $38 - $40 per MWh.

BPA

The purchase of power from BPA includes two components, slice and block. The purchase of the slice requires City Light to pay its share of the BPA costs (such as operating expenses, fish protection, payments to Treasury, etc.), which can change from year to year in a true-up after BPA's books are closed for each year. The rates for the block purchase are set by contract. In both cases, however, BPA has the right to add a Load-Based Cost Recovery Adjustment Clause (LB-CRAC) to recover any additional costs of meeting its total amount of load. There are two additional CRACs (as detailed in Appendix 1) that apply only to non-slice products like the block, which are currently forecasted to be collected in each of the next four years.

As a result, the cost of BPA power has been somewhat higher than anticipated in the 2000 SRA (about $21/MWh at average water, without any CRACs). During the first year of the new BPA contract (October 1, 2001 through September 30, 2002) total estimated BPA costs are about $123 million for the 518 aMW City Light received over the period, not including the expected $7 million slice true-up adjustment to be applied to the first quarter 2003 bills. About 78% of this energy was received under the slice portion of the contract, at an average cost of about $28/MWh, while the average cost of the block was about $26/MWh. However, BPA has lost so much money at these rates that it imposed an 11% Financial-Based CRAC on the block starting October 1, 2002 and may further surcharge the block with a Safety Net CRAC starting May 1, 2003.

In 2003 the CRACs are projected to be around 35% for the slice (plus a $6 million true-up) and a total of 56% for the block. At this level of CRACs and slice true-ups, the cost of BPA power will be equal to projected market prices. The slice would cost about $31/MWh at average water, the same as the market price forecast for similar purchases. The block would cost about $30/MWh, $3.4 million below the $32/MWh forecast for similar market purchases.

In 2004 the CRACs are projected to be 28% for the slice (plus an $8 million true-up) and a total of 53% for the block. Under these assumptions, the slice would cost about $30/MWh at average water, about $6.4 million below the $32/MWh forecast of market prices). The block would cost about $30/MWh, $1.4 million below the $31/MWh forecast of market prices.

The total BPA purchase of slice and block, even with all the surcharges, is forecasted to cost City Light customers $11.2 million less than market for the 2003-04 biennium. These are preliminary assumptions and depend on BPA's ability to control its costs.

Appendix: Description of Other Components of City Light's Portfolio

The Department's own hydro resources include four large projects (Boundary and the three Skagit Projects) and three small facilities (South Fork of the Tolt, Newhalem and Cedar Falls). It also has several hydro contracts and a contract with King County (Metro) to buy a small amount of energy from wastewater treatment.

Boundary - The Boundary Project is located on the Pend Oreille River in Northeastern Washington. It is City Light's largest resource and has a peaking capability of 1,055 MW and average generation of about 490 aMW annually. It is a "run-of-the-river" project and is affected by the other projects in the river basin. Since this project is located in the Columbia River Basin, it is also subject to the flow regulations established by the Biological Opinion issued by the National Marine Fisheries Service for the protection of fish populations. Like all hydroelectric projects, it is licensed by the Federal Energy Regulatory Commission (FERC). The current license expires in October 2011. Under the current license, part of Boundary output must be sold to Pend Oreille County Public Utility District (PUD) No. 1 to meet its load growth. In addition, about 5 aMW of energy must be delivered to the PUD in compensation for the encroachment of their Box Canyon Dam caused by the Boundary Project. Energy from Boundary is wheeled to consumers over BPA's transmission grid.

Skagit – The Skagit project includes the other three large projects owned by the Department: Ross, Diablo and Gorge. They are located on the Skagit River, about 80 miles northeast of Seattle. These three projects are operated as a single system. Ross has a major water reservoir and water released from Ross flows to Diablo and Gorge. The combined one-hour peak capability is 690 MW. The license for these projects was renewed in 1995 and will be in effect for 30 years. City Light has committed to several mitigating measures relating to fisheries, wildlife, erosion control, archaeology, historical preservation, recreation, visual quality and environmental education. Generation from the Skagit is transmitted to Seattle over transmission lines owned by the Department.

South Fork of the Tolt – This project was in commercial operation in 1995. Its one-hour peaking capability is less than 17 MW. The costs of this project are reduced by billing credits from the Bonneville Power Administration (BPA). Billing credits for the development of new generation resources were authorized by the Northwest Power Planning and Conservation Act of 1980. BPA thus had the authority to pay these credits to its customers to encourage the development of new resources; the credits basically compensate the utility for the difference between the costs of the new resource and the cost of buying the same power from BPA. Power from this project is delivered over a line owned by Puget Sound Energy.

Newhalem – This project is located on the Newhalem Creek, a tributary of the Skagit River. It was built in 1921 to provide power for the construction of the Skagit Projects. In 1970 it was modernized and now operates under a FERC license that will expire in 2027. Power is delivered through the Department's owned transmission lines.

Cedar Falls – The Cedar Falls Project was built in 1905 on the Cedar River, about 30 miles southeast of Seattle. It was constructed before the adoption of the Federal Power Act of 1920 and therefore does not require a license from FERC to operate. Power is transmitted by Puget Sound Energy.

Bonneville Power Administration – This is City Light's largest power purchase contract. The current contract, which allows the Department to receive power from 29 hydroelectric projects and some thermal and renewable projects in the Pacific Northwest, is described in Section 1, with a description of recent changes to the contract in Section 2. Energy is delivered through BPA's transmission grid.

High Ross – In the early 1980s City Light intended to raise the height of its Ross Dam to maximize the potential output of the plant. The Canadian Province of British Columbia protested on environmental grounds. After a period of negotiations that ended with the signing of the 80-year High Ross Agreement in 1986, City Light agreed to abandon its plans and to purchase instead power from British Hydro (Powerex). Power would be delivered and priced to mimic the generation and costs that would have resulted from the construction of the High Ross Dam. The output received from this contract has a relatively high cost through 2020; at that time the cost is drastically reduced to a few dollars per MWh because the cost portion equivalent to the service on the debt that would have been issued to build the High Ross Dam will terminate. Power is wheeled by BPA.

Lucky Peak – The Lucky Peak Hydroelectric Project was built by irrigation districts in mid 1980. Power operations started in 1988 under a FERC license that terminates in 2030. Generation of electricity is secondary to irrigation purposes and most of the electric output is available in the summer months. Project costs have been reduced as a result of the refinancing of outstanding long-term bonds in early 2002. The power from this project is wheeled over facilities owned by Idaho Power and BPA.

Priest Rapids – The current contract with Grant County will expire in 2005 and will be replaced with the new contract described in Section 2. The contract terminating in October 2005 entitles City Light to an eight-percent share of the output from the Priest Rapids Project.

Grand Coulee Project Hydroelectric Authority (GCPHA) –City Light has 40-year contracts to buy a half of the output from five hydroelectric projects in the Columbia Basin River built by irrigation districts. The City of Tacoma buys the remainder of the output from the projects. The contracts expire over the period 2022-27. Electric generation is mainly in the summer months and is wheeled by local entities and BPA.

Columbia Storage Power Exchange (CSPE) – City Light is one of 41 public and private utilities which, with BPA, have entered into exchange agreements with CSPE, an entity responsible for purchasing and marketing Canada's share of the benefits from the developments of water projects in Canada. Payments for this power were in the form of debt service payments on bonds issued by CSPE. Since full payment has already

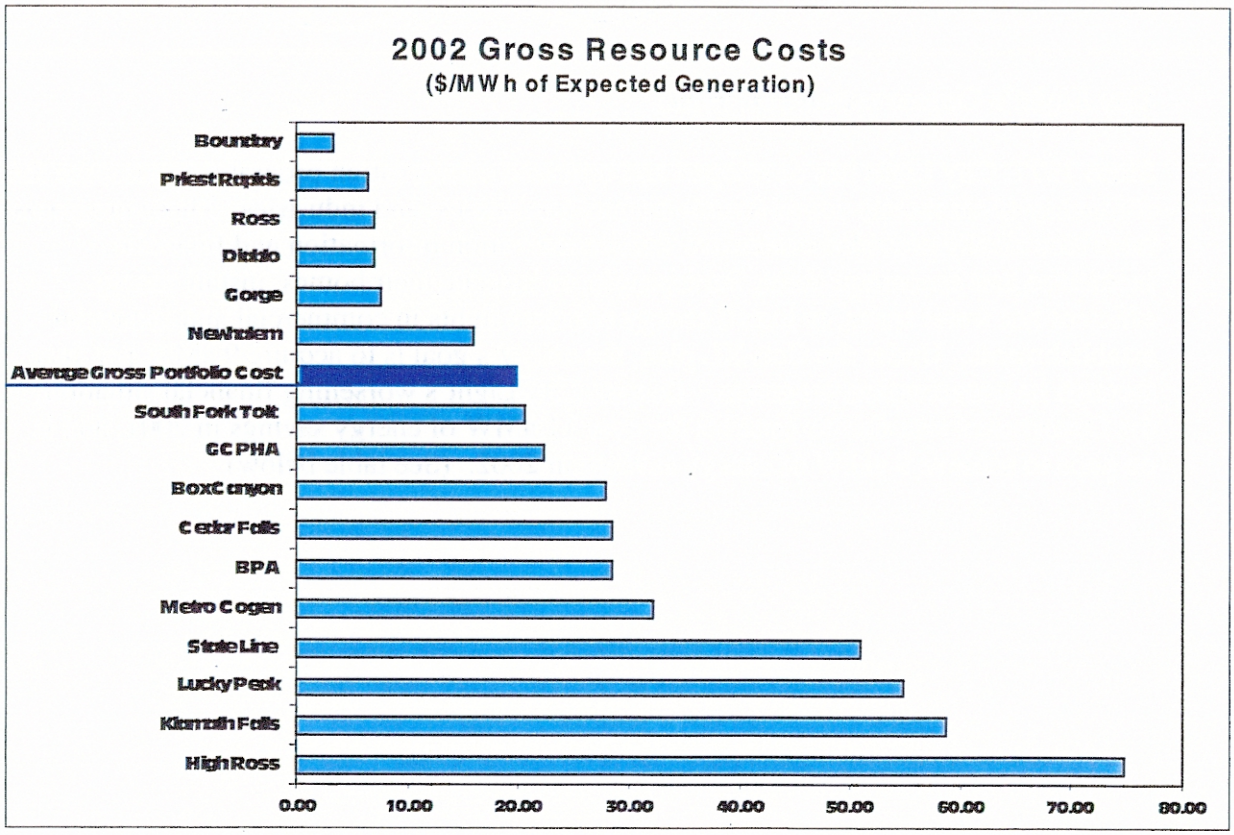
occurred, no payments have been required since 1998. A relatively small amount of energy will be received through the first quarter of 2003.

Box Canyon – Under a contract extending until August 1, 2005 City Light buys about 9 aMW and 12 MW of capacity from the Box Canyon Project, owned by Pend Oreille County PUD No. 1. BPA wheels this power.

West Point Sewage Treatment Plant Cogeneration (Metro) – City Light purchases about 1.2 aMW of energy from this project, owned by King County, that uses the methane gas from the wastewater treatment project to generate electricity. The current contract terminates in September 2003. City Light is reviewing its options to extend and potentially expand the contract.

Summary of Portfolio Costs – The following graph depicts the unit costs of each of the utility's resources, as projected for 2002 and measured in terms of costs per MWh of expected generation (the average over all water years of record).

The graph below shows costs in terms of the expected generation from each resource. The power costs to customers are computed instead in terms of costs per MWh of energy sold to customers. This measure is derived by adding all resource cost and power market purchases, offset by the revenue from sales of energy surplus in the market. As indicated in Section 1, this cost in 2002 is projected to be around $17.40 per MWh of customer load. The costs of both State Line and Klamath Falls are expected to be lower in 2003 and later years; the contract price for State Line will be lower and the current natural gas hedge for Klamath Falls terminates in December 2002.

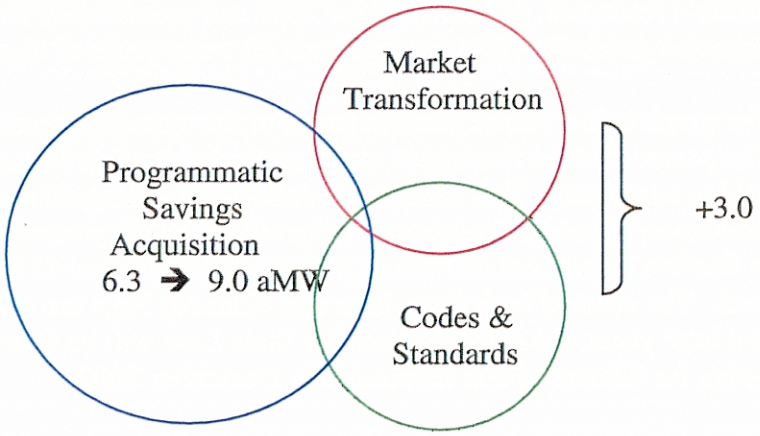


Section 6. Conservation

Conservation Acceleration (ConXL)

In response to the 2000 SRA direction to meet load growth with conservation and renewable resources, City Light launched a Conservation Acceleration Plan in 2001, based on information gathered in an extensive study conducted in cooperation with the Northwest Power Planning Council. The acceleration program (ConXL) is made up of the three components reflected in the chart below: (1) City Light's Conservation Programs; (2) Enhanced Energy Codes and Appliance Efficiency Standards; and (3) Market Transformation Activities.

Conservation Acceleration Targets in aMW



City Light's Conservation Programs

Since 1977, City Light has developed and operated conservation programs to increase the efficiency of electricity use in Seattle homes, businesses, and industries. These programs have historically provided customers with conservation information and financial incentives that encourage them, for example, to insulate their homes, install energy efficient hot water tanks, or install energy efficient lights in commercial and industrial establishments. Under the Con-XL plan, the utility's goal is to acquire 9 aMW per year through its conservation programs. Despite City Light's worsening financial situation, the Department was able to contract for over 11 aMW of energy savings in 2001, and is on pace to achieve 9 aMW of energy savings in 2002. (See table below).

City Light's Energy Conservation Programs: Energy Savings (aMW)

Customer Group	2001 ConXL Savings	2002 ConXL Savings (as of 6/30/02)	Total ConXL Savings
Commercial/Industrial	7.6 aMW	3.7 aMW	11.3 aMW
Residential & Small Commercial	4.1 aMW	1.0 aMW	5.1 aMW
Total ConXL Savings	11.7 aMW	4.7 aMW	16.4 aMW

Energy Codes, Appliance Standards and Market Transformation

Energy Codes

The value of energy codes is that they provide clear, lasting market signals. Energy codes are a powerful public policy mechanism for influencing the design of new and renovated buildings. They have a profound effect on the market for energy efficiency products and services because they apply to all buildings, and they are permanent.

Under ConXL, City Light and the Department of Design, Construction, and Land Use (DCLU) continued efforts to increase energy efficiency through the design, implementation, and enforcement of both the Washington State Energy Code and the Seattle Energy Code. Both of these codes have been updated twice since the 2000 SRA to reflect enhanced energy efficiency provisions. Most significantly, the City Council recommended through Resolution 32080 that the Seattle Energy Code should strive to be 20% more efficient than the ASHRAE 90.1-1999 standard. This was a significant leap in energy efficiency for commercial buildings located within the city limits. After a longer than usual public process, provisions reflecting this standard were implemented on October 1, 2001. The second update of the Seattle code took effect on July 1, 2002. This update incorporated changes in the Washington State Energy Code and increased the requirements for the efficiency of exterior lighting in commercial buildings. The new 2002 Seattle Energy Code also addressed some technical details related to RS-29 and for alterations to mechanical systems.

Appliance Standards

Appliance and equipment efficiency standards have proven to be one of the most successful strategies for improving energy efficiency in the United States. Seattle City Light has historically played a role pushing for more efficient appliances by offering incentive programs that support newer, more efficient, efficient technology, by being an active participant in regional technology forums, and by working with other national agencies to lobby for efficient technology. The Department of Energy has successfully

enacted efficiency standards that have recently or will be implemented in the next few years. These efforts include but are not limited to refrigerators (July 2001), Electric Water Heaters (2004), and Clothes Washers (2004 & 2007)

Market Transformation

Market transformation activities focus attention either on specific energy efficiency technologies and services or on specific markets. Usually, markets for products and services do not necessarily respect political or utility boundaries. Therefore, a regional approach is called for to move the market. In 1996, the Northwest Energy Efficiency Alliance (the Alliance) was founded as a non-profit group of electric utilities, state governments, public interest groups and industry representatives committed to bringing affordable, energy-efficient products and services to the marketplace.

City Light has been a member of the Alliance since its inception and has participated in a number of Alliance initiatives in the commercial and residential sectors. In October 2001, Seattle City Light became a voting member of the Board of Directors and currently pays $970,000 per year to the Alliance. This financial commitment has forced the utility to start to evaluate in detail the energy savings potential from market transformation activities. As a Board member, City Light will be in a position to influence future market transformation initiatives and leverage the regional marketplace to create long-lasting market benefits to customers in the City of Seattle.

Meeting SRA Direction

The annual goal under the ConXL plan is 12 aMW of energy savings consistent with the direction in the 2000 SRA. In the first year and half of ConXL activity, City Light has relied heavily on energy savings from its conservation programs to achieve most of this annual goal. The remainder of energy savings will come from a mixture of market transformation, energy codes, and appliance efficiency standards. Based upon studies and information within the region, City Light's staff estimates that ConXL activity in these three areas will produce energy savings at a rate of 3 aMW per year by the year 2005. (See Table below.)

Energy Savings Achieved under ConXL

The following table summarizes the achievements of the conservation program and presents action plans for the near future.

Energy Savings Achieved under ConXL

SCL's Conservation Programs: 9 aMW per year in 2002 and beyond	
Program & Services	• Have contracted for 16.4 aMW over the period 1/1/2001 and 6/30/2002 • Over 80% of savings acquired from medium and large commercial and industrial customer sectors. • Strategy emphasizes: (1) enhanced program and service offerings; (2) targeting largest customers; (3) capturing lost opportunities; (4) filling in service gaps; and (5) increasing commitment to low income customers. • Average cost to SCL approximately 25 mills per kWh
Energy Codes and Standards: 2 aMW per year by 2005/6	
Energy Code	• Update to Washington State Energy Code became effective July 1, 2001. Applies to residential structures in Seattle. • Update to Seattle non-residential code, meeting City Council's recommendation to be 20% more efficient than the ASHRAE 90.1-1999 standard, became effective October 1,2001. • Federal Appliance Standards provide minimum energy efficiency standards for many appliances. Three technologies impacted by new standards are: ▪ Refrigerators: July 2001 ▪ Electric Water Heaters: 2004 • Clothes Washers: 2004-2007.
Market Transformation: 1 aMW per year by 2005/6	
NEEA	• SCL became board member for the Northwest Energy Efficiency Alliance (NEEA) in Oct 2001. • Working with NEEA to develop strategy to capture energy savings from new market-driven energy efficiency products.

BPA's Conservation Augmentation (Con Aug)

In late 2000, Bonneville unveiled an initiative to augment its power supply by at least 166 aMW of region-wide conservation over the period fiscal year (FY) 2002 through FY 2006. Under BPA's Conservation Augmentation (Con-Aug) program it hopes to purchase 20 aMW per year from its wholesale customers who submit conservation proposals for potential Bonneville funding.

Early in 2002 the Department and the Bonneville Power Administration executed a Con-Aug agreement under which the BPA will purchase energy conservation savings from City Light over a two-year period. Under this agreement, BPA will pay the Department up to $26.6 million over the next two BPA fiscal years (10/1/01 to 9/30/03) for 9 aMW in annual energy savings from City Light's conservation programs. In exchange, City Light

agreed to reduce its power purchase from BPA by the amount of energy savings purchased by BPA under the agreement.

Money received by the utility under BPA's Con Aug agreement will help fund ConXL programmatic activities over the next two years. This is particularly significant given the Department's current financial situation and Seattle's long-standing policy objective of restoring BPA's financial support for regional conservation programs.

Beyond the current period of time covered by the ConAug agreement with BPA, there is uncertainty as to the level of BPA funding which may be available to City Light. BPA is experiencing its own financial difficulties and recent projections indicate they could have a budget shortfall of approximately $1 billion through 2006. Bonneville has very recently communicated that they are postponing any ConAug program changes and limiting any new funding commitments pending the Administrator's decision on future BPA conservation funding this December.

Section 7. Load Resource Balance and Projected Monthly Energy Surplus/Deficits

Definition of Load Resource Balance

The 2000 SRA sought to reduce dependence on market energy purchases and balance loads and resources under critical water conditions. Both loads and resources have significant seasonal variations; therefore this directive required the utility to analyze both annual and monthly data on customer load and generation from resources under dry or critical conditions. Since the majority of the utility's resource portfolio is hydro, ensuring that enough resources are available to meet customer load over the year results in energy surpluses in the months of highest water availability, in late spring and early summer, even in the driest years. This energy in surplus of customer load can be sold in the market; the revenue from these sales reduces the cost of the resource portfolio to customers.

Definition of Critical Conditions

The 2000 SRA used the regional definition of critical conditions. This critical year has been defined as the one that reproduces the water flows of the water year 1936-37, to which current flow and fish regulations are applied.[7] The 1936-37 water year, however, had some anomalies affecting the monthly profile of generation; July and August output from some of City Light's projects, for example, was higher than in many years of the fifty years of water record. Using this monthly profile would overestimate City Light resources in these months and underestimate them in others; it would thus not be an accurate measure of the fit between loads and resources in a typical dry year. This update to the 2000 SRA recommends a new definition of critical generation: it has the same annual amount of output as the 1936-37 water year definition, but a different monthly profile. The monthly profile has been updated to reflect the generation patterns of the Department's plant. The updated monthly profile results from the average of the monthly profiles in the ten percent worst years for each resource for which generation changes considerably with water conditions: Boundary, Skagit and BPA slice. The analysis in this 2002 SRA update uses this new definition.[8]

The following graph shows the monthly energy surpluses and deficits projected for 2003 using the two definitions. The annual amounts are the same under both definitions; only the shape of the monthly profiles is different. Unless otherwise indicated, all other graphs in the report use the updated critical generation definition recommended (defined as "Seattle Shaped Critical" in the graph below).

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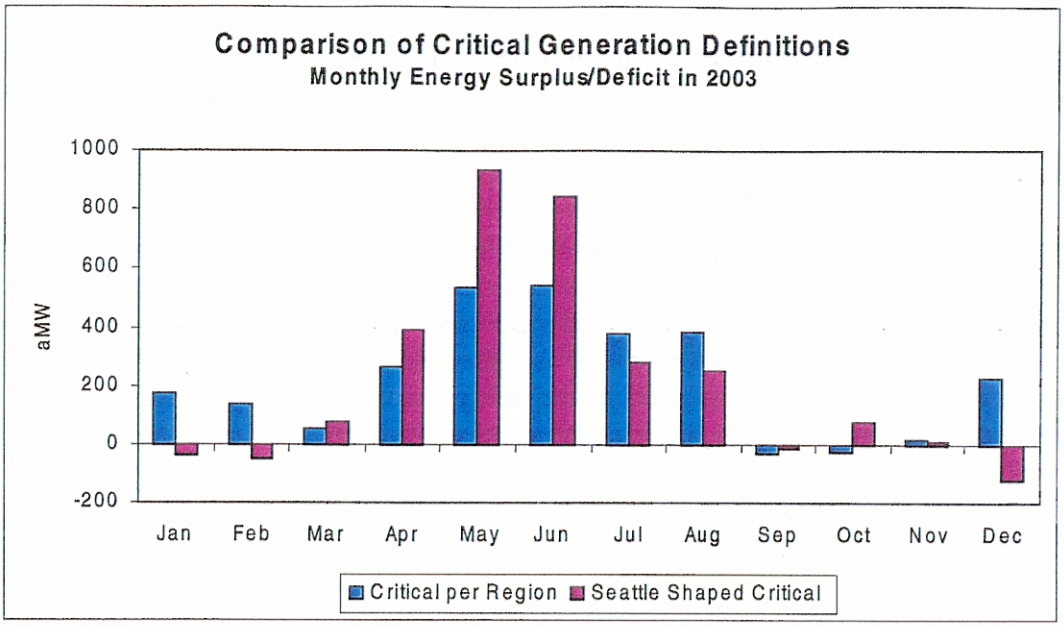
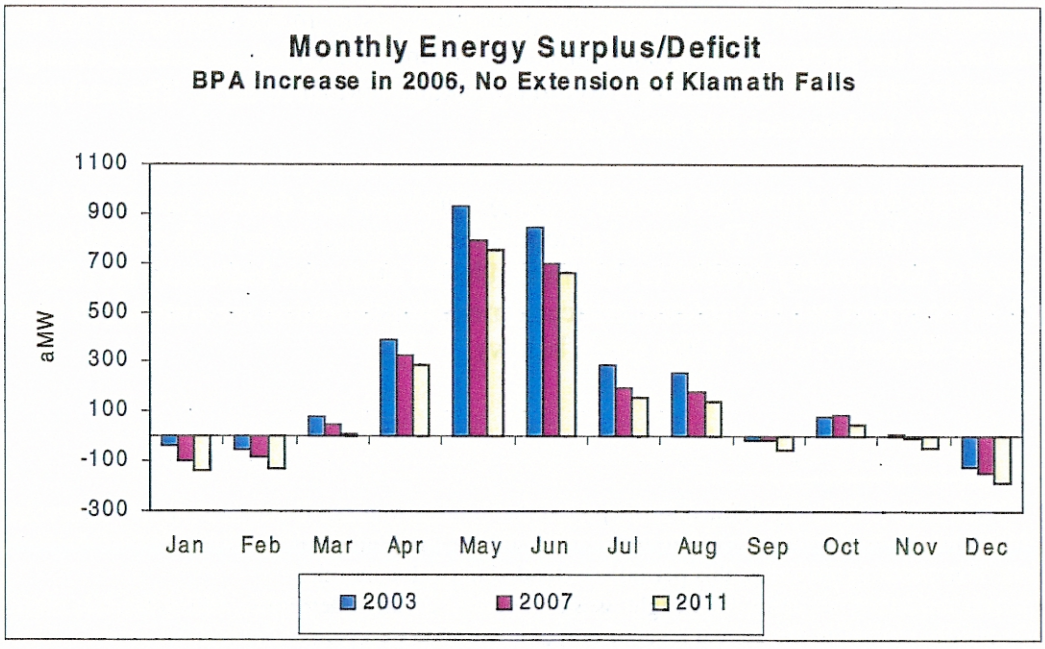
[7] The critical year, technically defined as the period that it takes to make the region's hydro reservoirs go from full to empty, is actually a seven-month period since the implementation of the 1995 Biological Opinion. For planning purposes, this period is extended to twelve months.

[8] For power marketing purposes, City Light uses a more conservative definition, which has this same monthly profile applied to the annual level of output at the 95% exceedance for each resource.

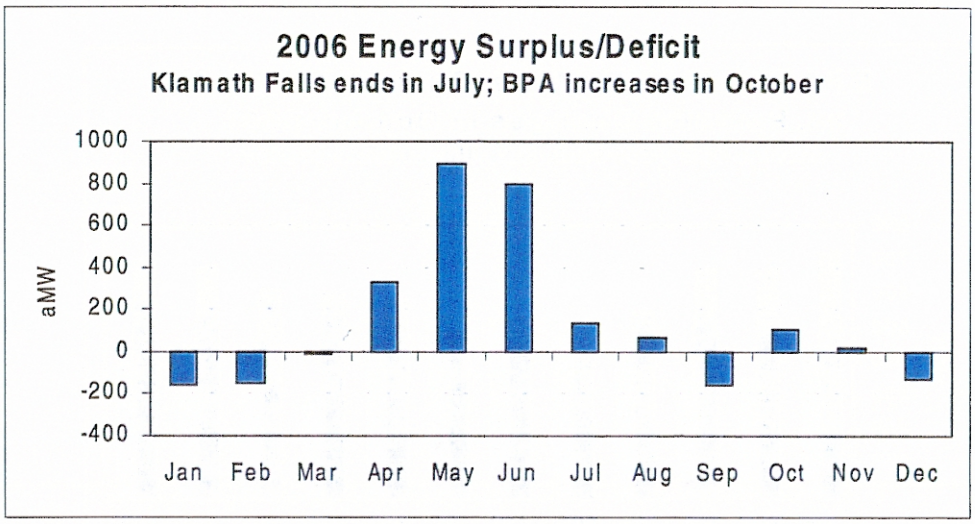


Base Forecast of Energy Surplus/Deficits

The following graph shows the projected energy surpluses and deficits each month in three selected years, 2003, 2007 and 2011. As seen below, the utility projects to have sufficient resources in its current portfolio to meet customer load for several years. Meeting a few potential monthly resource deficits in the next few years would not require additional resource acquisitions. Section 9 discusses alternatives to resource acquisition to deal with these deficits. While this is the forecast given the current portfolio, there could be significant changes affecting the BPA contract that might cause the utility to be in resource deficit sooner than expected. Alternative scenarios with potential changes to the current BPA contract are reviewed later in this Section.



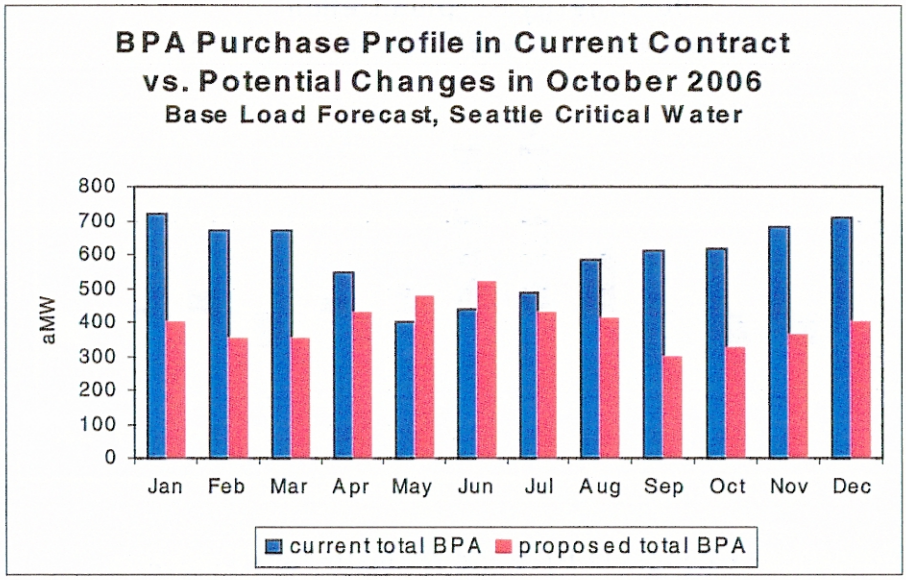
The year 2006 is somewhat different from other years in the period because it is affected by two changes: the current portfolio includes the termination of the Klamath Falls contract by the end of July, which reduces the portfolio by about 87 aMW each month, and the increase of 115 annual average MW in BPA block purchases effective October 1, as anticipated in the existing contract. There will be a two-month period between the loss of 87 aMW from Klamath Falls and the increase in BPA block purchases. If 2006 is a dry year, the utility will have to acquire about 155 aMW of energy to meet the gap in September, after the Klamath Falls contract has terminated and before the new BPA purchase is available. Assuming the BPA increase is received as expected, the deficits in January and February will be reduced to less than 100 aMW in 2007 and the September deficit will only be about 17 aMW, as was seen in the previous graph, which shows 2003, 2007 and 2011 .



Alternative Scenarios: Changes in BPA and Klamath Falls Contracts

Both the Klamath Falls and the BPA block purchases could actually change. City Light could choose to extend its purchases from Klamath Falls beyond July 2006 and there could be changes to the BPA contract as a result of an ongoing review in the region, which has the goal of replacing the existing contracts with twenty-year contracts with BPA. A group of participants in the regional discussion have a proposal out for public comment that could have the impact of reducing the current amount of BPA purchases that City Light receives and/or change their monthly profile. Discussions are still ongoing and other proposals are likely to be offered. City Light has its current ten-year contract with BPA, but in 2004 it will have to decide whether this contract is preferable to a new twenty-year contract that will cause some changes to the terms under which it currently receives BPA power. While it is still early to anticipate the final outcome of the regional review, for analysis purposes this report reviews a scenario reflecting the main aspects of the regional proposal mentioned above, as well as another scenario with few changes form the current BPA contract. Only the first of these two scenarios would have a significant impact on the Department's load resource balance. In this scenario, in

October 2006 BPA purchases would be adjusted to reflect City Light's BPA entitlement, which depends on the difference between its customer load and the output from its resources in a critical year (the "firm" output). Since the Department's customer load projections have been reduced since the negotiation of the current BPA contract, the assumed change in the BPA contract would reduce the amount of BPA power for City Light. Under the base assumption of customer load for 2007, total purchases would decline by about 18%, or 198 aMW annually. In addition, this BPA scenario also assumes that the block product will no longer be available and all BPA purchases will be in the form of slice. The following graph illustrates the impact of this potential scenario on the monthly amounts of BPA power available to City Light. As the graph indicates, in this case City Light would have less power from BPA throughout the year and the largest amounts of energy would be available in the spring and summer, while the smallest amounts would be received when the Department's customer load is highest.



Three scenarios are reviewed in the following paragraphs:

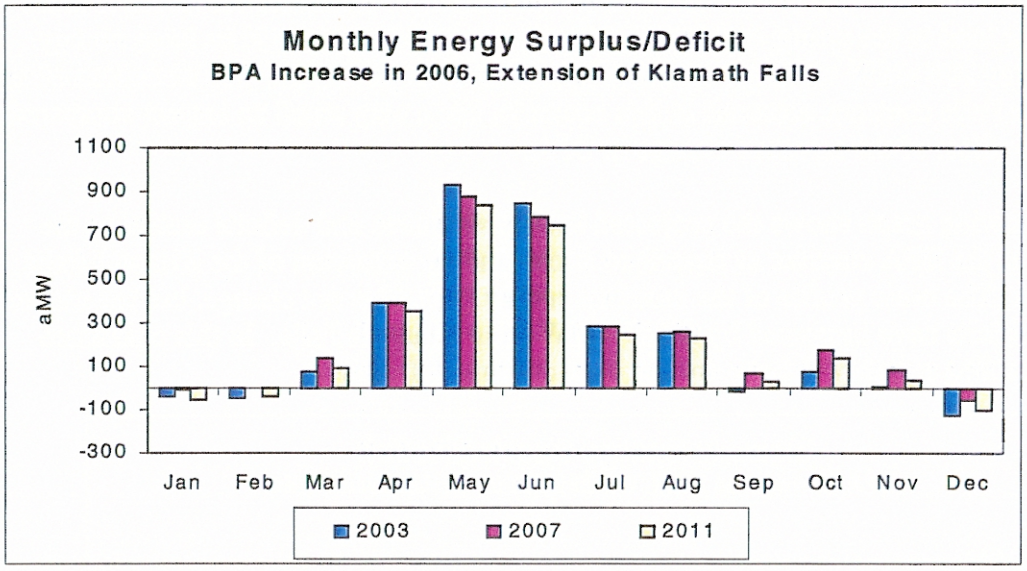
- continuation of the current contract and extension of Klamath Falls contract[9]
- change in BPA contract and extension of Klamath Falls contract
- change in BPA contract and no extension of Klamath Falls contract

The graphs show the monthly energy deficits and surpluses assuming critical water conditions and the base projection of customer load for the same three years depicted above, 2003, 2007 and 2011.

The Department would have the largest amount of resources if BPA purchases were as determined in the current contract (increasing by an average of 115 MW annually in

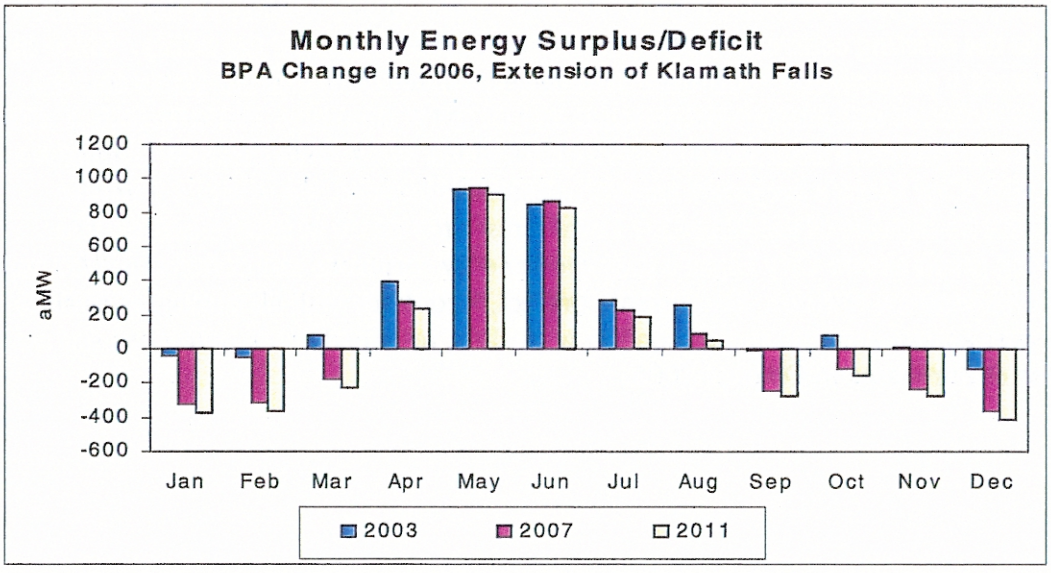
[9] The extension of the Klamath Falls contract is assumed to reflect the current amounts received from that resource, extended for the remainder of the forecast period.

October 2006) and the current purchases from Klamath Falls contract were extended beyond June 2006, as shown below.



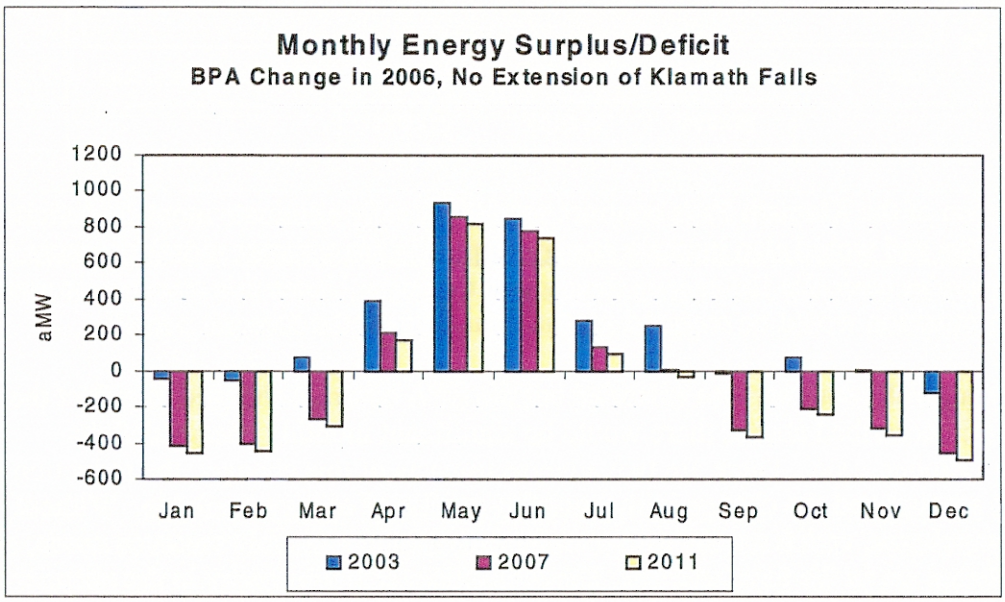
The extension of the Klamath Falls contract would basically eliminate monthly deficits in winter months and would also increase energy surplus in the summer months because this contract provides basically flat energy throughout the year. Under this scenario no new resource acquisition would be required for the remainder of the forecast period.

If the Klamath Falls contract was extended but the BPA contract changed to reflect the BPA scenario described above, there would be significant monthly energy deficits starting in October 2006. There are two adverse impacts of this change: the reduction of the annual amount and the change in the monthly profile of energy available. Without the block purchases, which are shaped to match City Light's monthly resource needs, all BPA purchases are in the form of slice. Therefore there is more energy in the summer and less in the winter, because the BPA slice has a monthly profile similar to that of City Light's hydro plant.

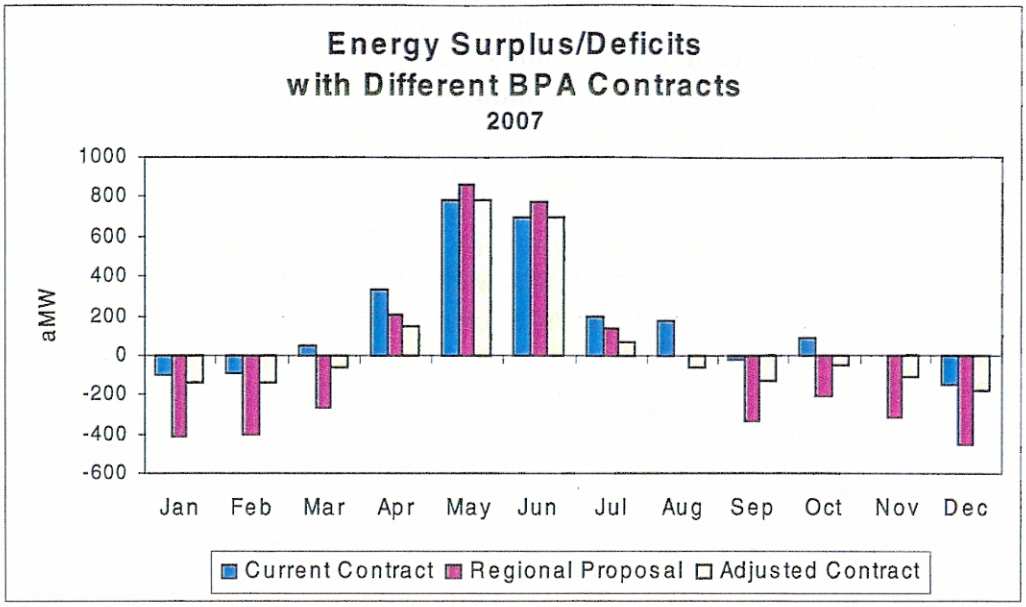


In this scenario, in a dry year City Light would only have sufficient resources to meet customer load in the spring and earlier summer months; there would be large energy deficits, of 200 aMW and higher, from September through March. The extension of the Klamath Falls contract, assumed in this scenario, has a very small an impact compared with the effect of the assumed change in BPA.

The following graph shows the projected energy surpluses and deficits assuming the change in the BPA contract as described above and no extension of the Klamath Falls contract. The basic profile of the monthly energy gaps does not change, but the amounts of the deficits have increased by the 87 aMW from Klamath Falls. In this case there would be five monthly deficits around or exceeding 400 MW.



Given the potential adverse impacts of a significant change in the BPA contract, City Light is focusing its efforts on shaping a twenty-year contract with BPA that would be closer to the existing contract and thus be an acceptable choice for the utility. Since the Department's projections of customer load have been reduced, it is not likely that the amended contract will include the increase of 115 aMW annually. Nevertheless, if other contract changes were minimized and the shape of the block were adjusted to improve the match with City Light's projected monthly customer demand, the utility's portfolio would still be capable of meeting City Light's resource needs in most months. The following graph shows City Light's projected energy surpluses and deficits in 2007 under three BPA contract options: the current contract, a contract with all purchases as slice with lower annual amount, and a scenario with slice, reshaped block purchases and no increase of purchases in October 2006.



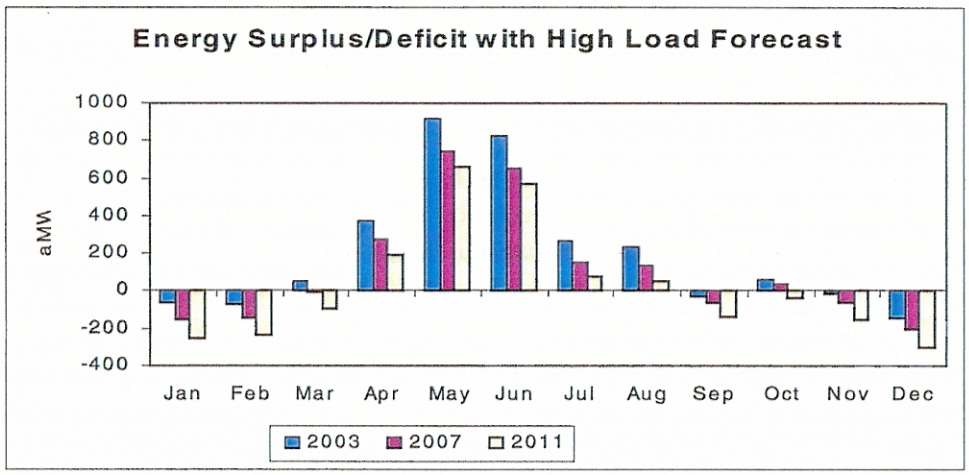
As shown in the graph, the third alternative would result in a similar monthly profile as with the current portfolio, except that there would be somewhat larger monthly deficits (and smaller surpluses in spring and early summer). If this scenario were the final outcome of the regional discussions for City Light, the Department would have to evaluate the net impact of these small increases in monthly energy deficits in exchange for a longer-term contract with BPA that would ensure its access to BPA power for a period of twenty years from the date the new contract is signed (assumed to be 2004).

In summary, under critical water conditions and assuming the base forecast of customer load and the utility's current resource portfolio, City Light would not need additional resources for the remainder of the forecast horizon, except to meet monthly deficits of 100 to 150 aMW a few months of the year. The extension of the Klamath Falls contract would not necessarily be the best resource to meet the projected energy gaps. There is, significant risk associated with potential changes to the BPA contract. If the contract with BPA were changed to include only a slice product reflecting City Light's projected entitlement in 2007, under dry conditions the utility would have large energy deficits in several months of the year. The extension of the Klamath falls contract beyond 2006 would have little impact to change these results. If, on the other hand, City Light's contract with BPA were amended only to forego the increase of 115 aMW annually effective September, 2006, the impacts would be much smaller, especially if the amendments also included a reshape of the block product to improve the match with City Light's needs.

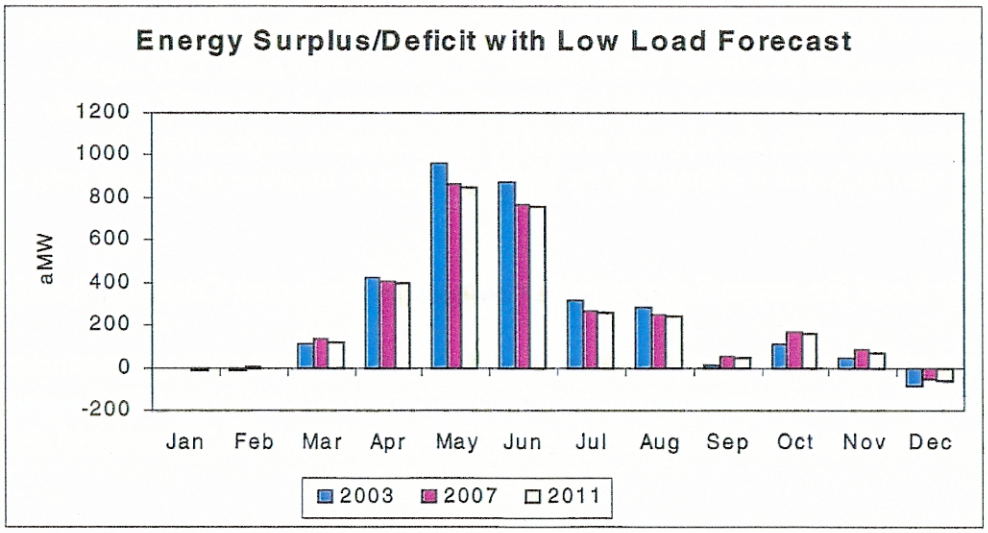
Variations in Load Resource Balance with Changes in Projected Customer Load

The profile of energy surpluses and deficits would also change with different customer load projections. A one-time large increase or reduction would basically shift the graphs up or down, increasing deficits and reducing surpluses, or vice versa. There could also be

less drastic changes, depending on the path of load projections. This section reviews the monthly energy surpluses and deficits assuming the high and the low load projections described in Section 3 and the critical generation. Resources reflect the current portfolio under Seattle's critical conditions (1936-37 water year shaped per City Light's resources over the worst ten per cent of water years), with BPA block increasing in October 2006 and Klamath Falls contract terminating in 2006. The high and low load projections start between 2% and 3% higher and lower respectively than the base projections in the near term and each ends up about 9% from the base in the later years in the forecast. The differences in load projections are sufficient to cause some changes in the profile of monthly energy surpluses and deficits. The years chosen to illustrate these impacts are also 2003, 2007 and 2011. It must be noticed, however, that there are no significant differences affecting 2003 because the high and low load projections assume it takes a while to get on a separate path of demand growth.



The graph above suggests that the utility could deal with projected monthly resource deficits in dry years in the near and mid future without additional resource acquisitions, even with high load forecast, but it would have to develop strategies to meet these deficits in later years. There would still be significant late spring and early summer energy surpluses. If customer load were below projections, then City Light's current portfolio would support the goal to meet customer demand in dry years throughout the decade.



Section 8. Cost of City Light's Resource Portfolio

Introduction

The total net cost of City Light's resource portfolio to its customers is measured by the costs of the resources, reduced by the revenue from the sale of energy surplus in the market (or, alternatively, when the utility is in deficit, increased by the cost of market purchases required to meet load). This amount represents the portion of direct power costs that has to be recovered from customer rates. It does not include allocation of overhead costs, so the actual "unbundled" power portion of customer rates would be higher.[10]

The 2000 SRA's strategy to meet customer load under critical water conditions results in some amount of surplus energy in all years. Thus, a portion of the output from City Light's portfolio will be sold in the market. It must be noted that the analysis in this report assumes that the utility will be able to sell its surplus power whenever it is available. This may not be always an option, especially under potential changes affecting electricity markets, in particular the effect of a Regional Transmission Organization and FERC's proposal for a Standard Market Design. Moreover, these changes could also impact the utility's ability to bring the energy from its distant resources (such as Boundary, its largest and lowest-cost resource) to its customers. Since it is impossible to project what changes may take place at this point, the analysis in this Section assumes a continuation of current market conditions. For illustration purposes, Section 12 reviews the impact of a potential transmission constraint that would cause 50% of the Boundary runoff to be spilled.

Even without the impact of market changes, there is considerable uncertainty about the value of the revenues from surplus energy sales that offset the costs of the portfolio. The amount of energy surplus each year is a function of water conditions on the resource side and customer load on the demand side. In addition, market price changes can cause wide swings in the value of the surplus and thus portfolio costs. While City Light now has sufficient resources to meet its customer load and has greatly reduced its market purchases, the utility cannot eliminate the impact of uncertain market conditions on the value of its portfolio. It has, however, mitigated the effects of such market conditions by limiting the impact of upward swings in prices. Normally high prices are correlated with low water conditions and low prices with wet years. In dry years, a utility with resource deficits would have to pay higher prices just when it has to buy more energy, which exacerbates the upward effect on its total expenses. If, on the other hand, it has surplus to sell, the higher market prices will partially offset the impact of the lower amount of surplus energy available to sell in the market; this, in turn, mitigates the adverse impact on market revenues and thus the cost of meeting customer demand.

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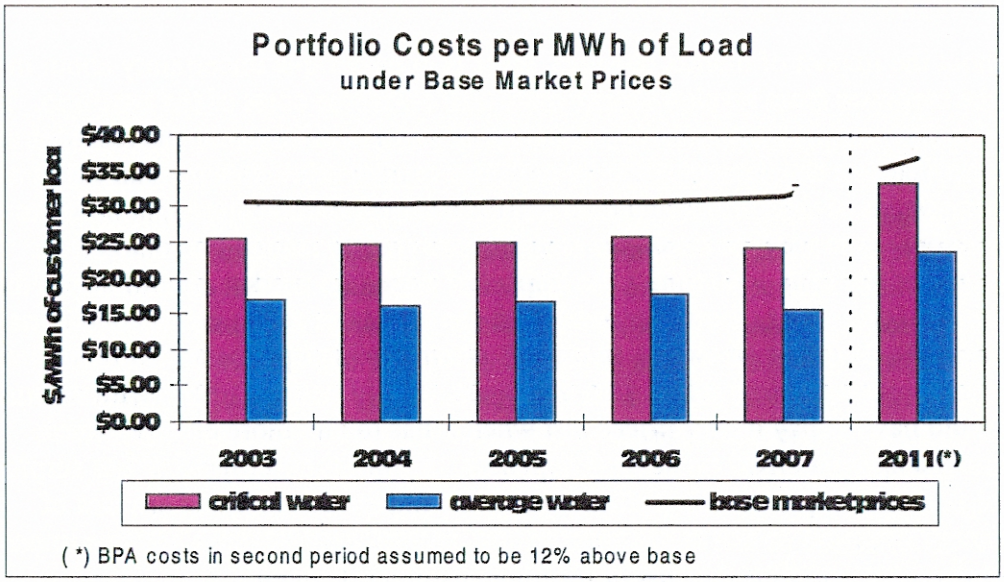
[10] City Light "unbundles" its revenue requirements by allocating all its costs to two large functions: power and retail. The allocation of overhead costs such as taxes, interest and administration and general expenses is done on the basis of different values, such as labor hours, dollars of direct expense, etc. This allocated costs are not included in the estimates in this report, except in the Appendix to this Section 8.

The following paragraphs review different scenarios that may affect the cost of the portfolio to the utility's customers, defined as annual projected portfolio costs divided by total customer load.[11] The main factors for which variability is considered are: customer load, water conditions, and market prices. In addition, portfolio costs could change depending on the options around the Klamath Falls contract (extend it or not after 2006) and the BPA block purchase (the alternative scenario for the BPA contract is a slice product equal to City Light's entitlement in 2007, as described in Section 7). BPA costs for the second half of the forecast period can also be examined as remaining unchanged, declining by 10% or increasing by 12%. The costs are reviewed for several years, 2003 through 2007 and in 2011. While some conditions, such as critical or wet conditions and high and low market prices, are likely to prevail for only one or two years, the scenarios assume that when these conditions occur they remain for the period under analysis. The results thus reflect what would happen in any of these years under the conditions identified. In fact, over the period analyzed there would be a combination of dry and wet years and price levels.

Base Projections

The projected cost of the portfolio per MWh of customer load is shown below, compared with the average annual market energy prices forecasted for the same period. The results reflect base customer load projections and two cases of water conditions: average water and dry conditions. In both cases the analysis assumes the base projection of market prices. In fact, market prices would be higher under drought conditions. The impact of changing both water conditions and market prices is discussed later in this Section.



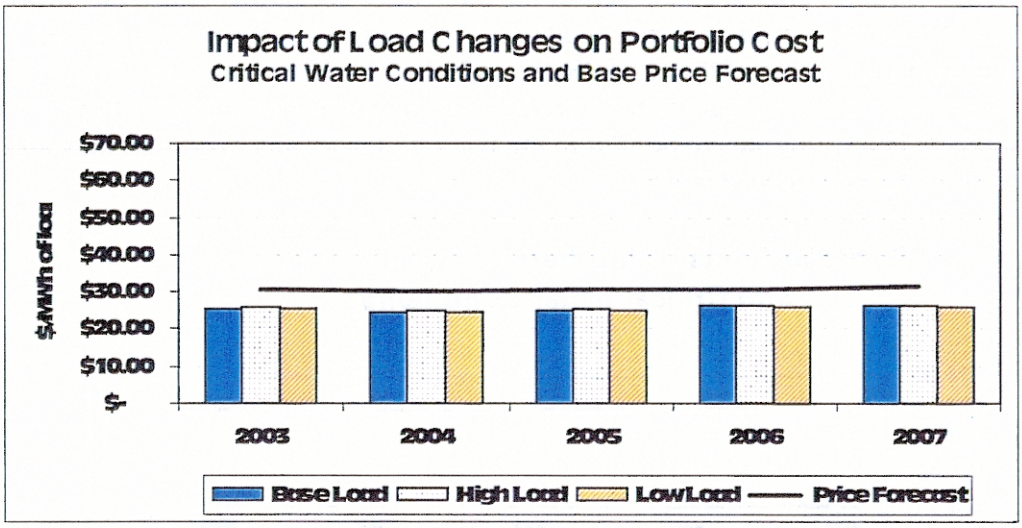
As the graph above indicates, the cost of the current portfolio to customers would remain competitive with projected market prices under average and even critical water

[11] It would be more accurate to divide the costs by customer load reduced by losses and use of energy by the utility, but the simpler approach used here is adequate for estimating cost impacts and comparing portfolio costs with market prices at Mid C, which also exclude the effect of losses.

conditions through the forecast horizon. There is, however, significant uncertainty around the numbers calculated above. The next paragraphs estimate the impact of the potential volatility of selected variables and thus determine the range of changes in portfolio costs under different conditions. In each case only one variable is changed to identify its impact. In fact, changes in some variables would be accompanied by changes in other variables.

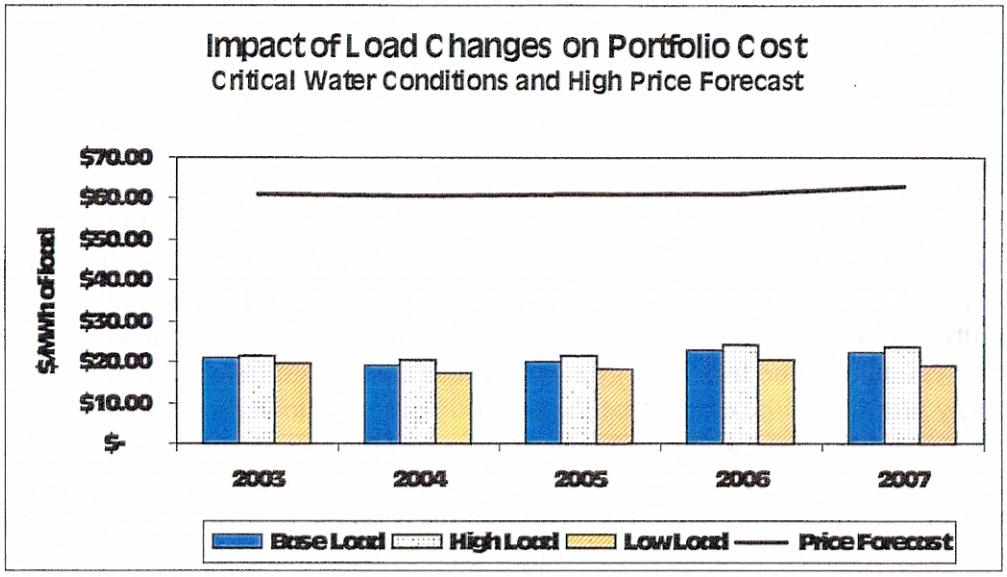
Customer Load Changes

The costs in the paragraphs above are estimated assuming base customer load projections. Higher load would reduce the available energy surplus to be sold in the market and/or increase power purchases. On the other hand, higher load tends to reduce costs per capita because net portfolio costs can be distributed over a larger number of MWh. In turn, the impacts are affected by the level of market prices; with lower market prices, the foregone revenue from energy surplus sales is less significant than in a market of high energy prices. To the extent that the portfolio costs are lower than market prices, overall power portfolio costs would be lower if more surplus energy could be sold in the market. On the contrary, if portfolio costs are higher than market, lower load implies higher costs for the remaining customers. These impacts on the portfolio costs, however, do not necessarily translate into the rates actually paid by customers because the latter also include all distribution, customer service, administration and general and other overhead costs, which do not change significantly with changes in customer load. For illustration purposes, the rate impact of the loss of a large load is reviewed in the Appendix to this section. The following graphs show the impacts of load changes on portfolio costs per MWh of customer load assuming critical water conditions and base and high market price projections. They do not reflect total customer rate changes.



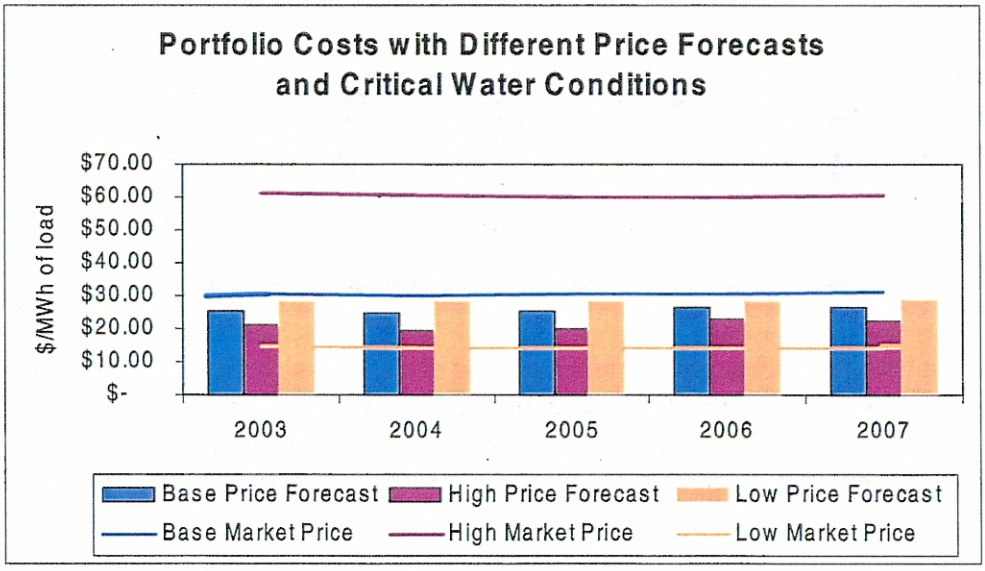
As shown in the graph, changes in customer load would not significantly affect the cost of the resource portfolio, given the base market prices forecast. Impacts would be somewhat larger with higher market prices, as shown below, because the revenue foregone or earned with changes in load will be greater with higher market prices. The

high market price level in the graph, however, is not necessarily the level associated with drought conditions; it is simply a case of very high prices, equal to about twice the levels in the base price forecast. Even in this case, the effect of customer load changes on portfolio costs is limited.



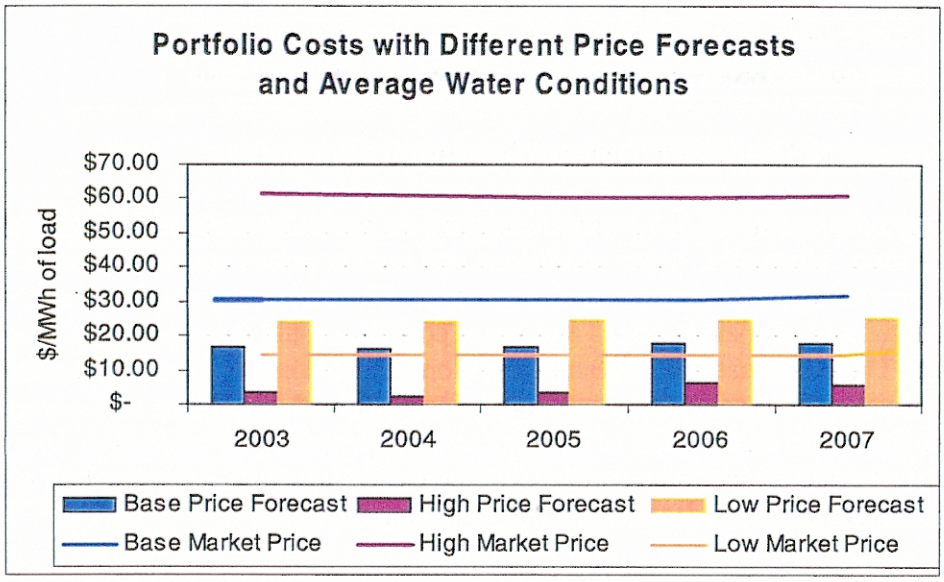
Market Price Changes

The following graphs illustrate the impact of potential changes in market energy prices on the cost of the resource portfolio to City Light's customers. These changes are normally associated with different water conditions, but for illustration purposes, the following graph assumes critical conditions in the three price scenarios. Since the utility has sufficient resources to meet customer load in most months over the period, market price changes affect the value of the portfolio through their impact on revenue from surplus energy sales. Price change impacts are greater when water conditions allow larger amounts of energy surplus to be sold in the market. Under any condition they are larger than the impacts of load changes.



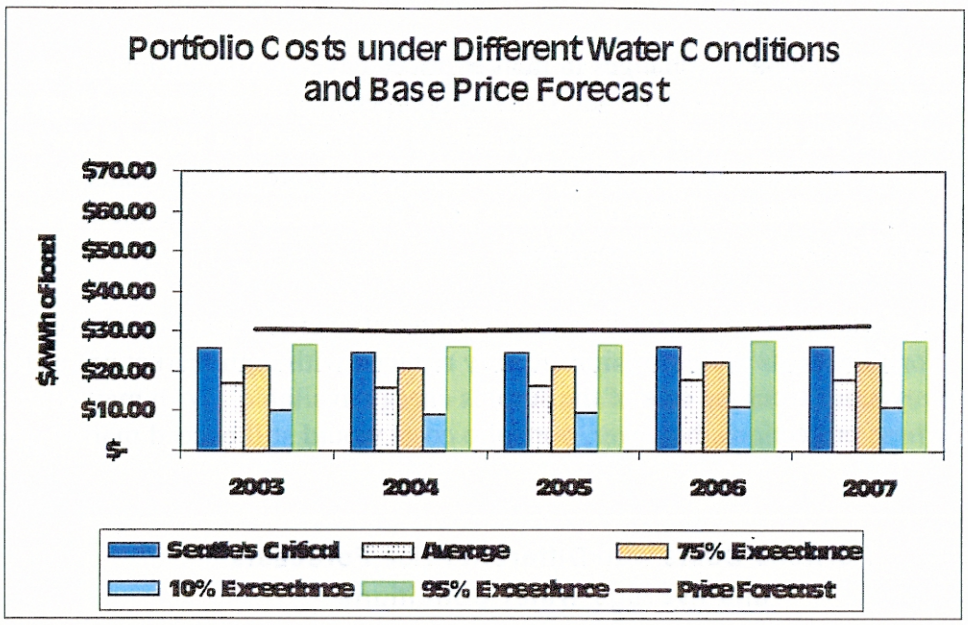
As the graph above suggests, changes in market prices have significant impact on portfolio costs. Moreover, the portfolio remains competitive under base and high market price projections, but in critical conditions portfolio costs would be below a low level of market prices, projected to be 50% of the base market price projection. Later in this Section there is an estimate of how much base price projections can decline before the resource portfolio loses its competitiveness.

The impacts of market price changes are much higher if average water conditions are assumed. Portfolio costs would be significantly reduced with high market prices because of the high revenues from the sale of the surplus energy available. With market prices at 50% below base projections, however, portfolio costs would still exceed market prices.



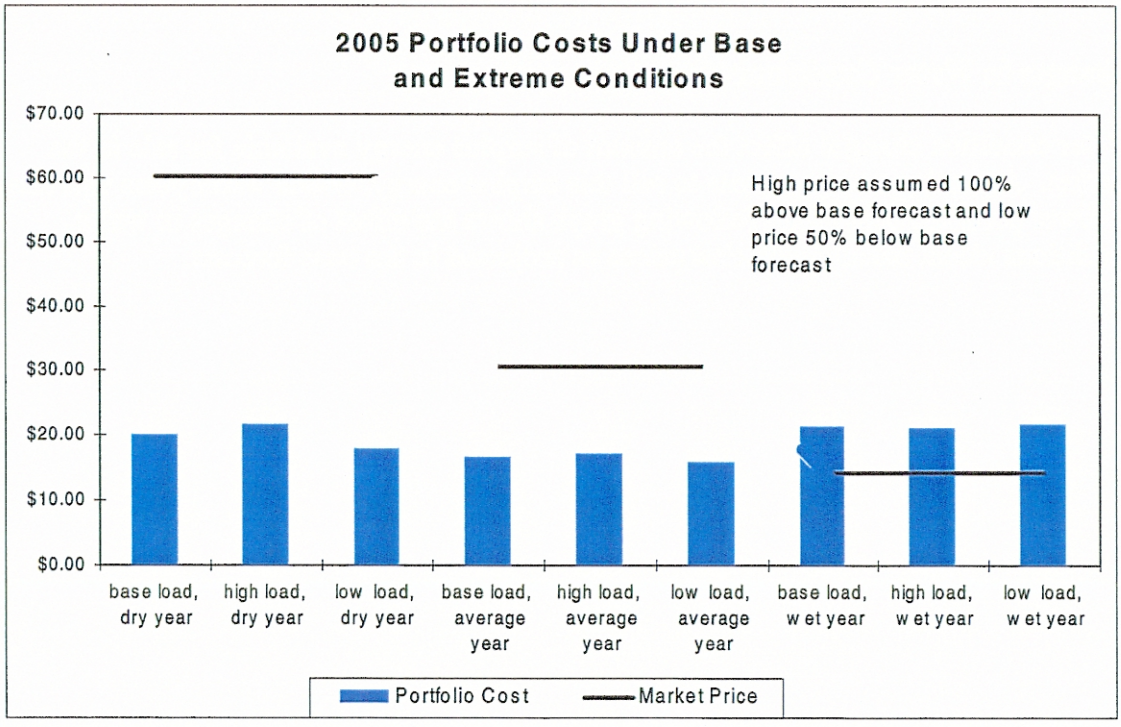
Changes in Water Conditions

Water condition changes affect the amount of surplus energy available for sale in the market. Assuming no constraints to sell this surplus energy, wetter water years will result in lower portfolio costs. The following graph shows the effect of changes in water conditions alone, assuming market prices as projected in the base forecast.



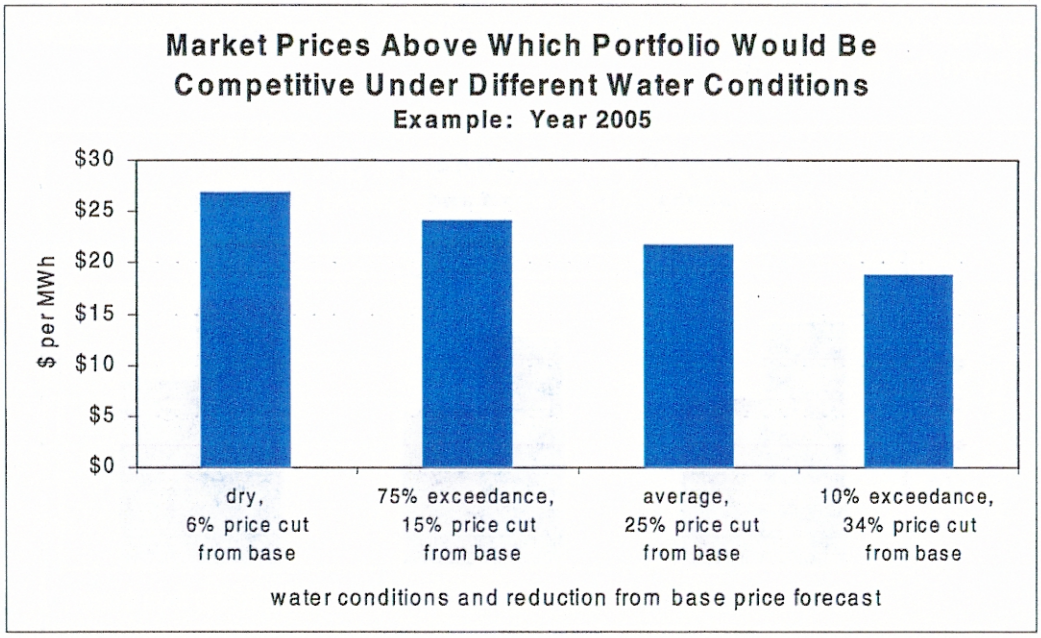
Impact of Changes of Combined Factors: Summary Conclusions

The prior paragraphs examined the potential impacts on portfolio costs of changing only one factor at a time. Normally, water conditions and market prices are related, with higher prices prevailing in dry periods and vice versa. The following graph shows three potential combinations of market prices and water conditions and three potential levels of customer load. The combinations of water conditions and prices are: average conditions and average prices, critical conditions and high prices, and wet conditions and low prices. To these three situations three levels of load are superimposed: base projection, low and high. The market price projections assume extreme cases: low prices are one half of base prices and high prices are 100% higher than the base levels.



The first three columns illustrate the scenarios with very dry conditions and very high prices. Regardless of customer load levels, the costs of the portfolio would be considerably below market prices. The next three columns show portfolio costs under average conditions and base price forecast; the portfolio is competitive regardless of the level of customer load. Finally, the last three columns illustrate the impacts of very low market prices, which would be accompanied by very wet conditions (10% exceedance of occurrence). In this case portfolio costs would be below the projected market prices. As in the other cases, changes in customer load do not have a significant impact.

The analysis above suggests that the utility's portfolio would be competitive under base and high price scenarios, but there is risk that prices would be above market in a scenario with very low market prices. The graph illustrates a scenario in which low market prices are 50% below the base forecast each month and would average about $14.20 per MWh over the year, as compared with a base annual average of $30.50/MWh. The following graph indicates the levels of reduction from market base price projections that would support the utility's portfolio to remain competitive. The graph illustrates these levels under different water conditions, although low market price levels are normally associated with wet years.



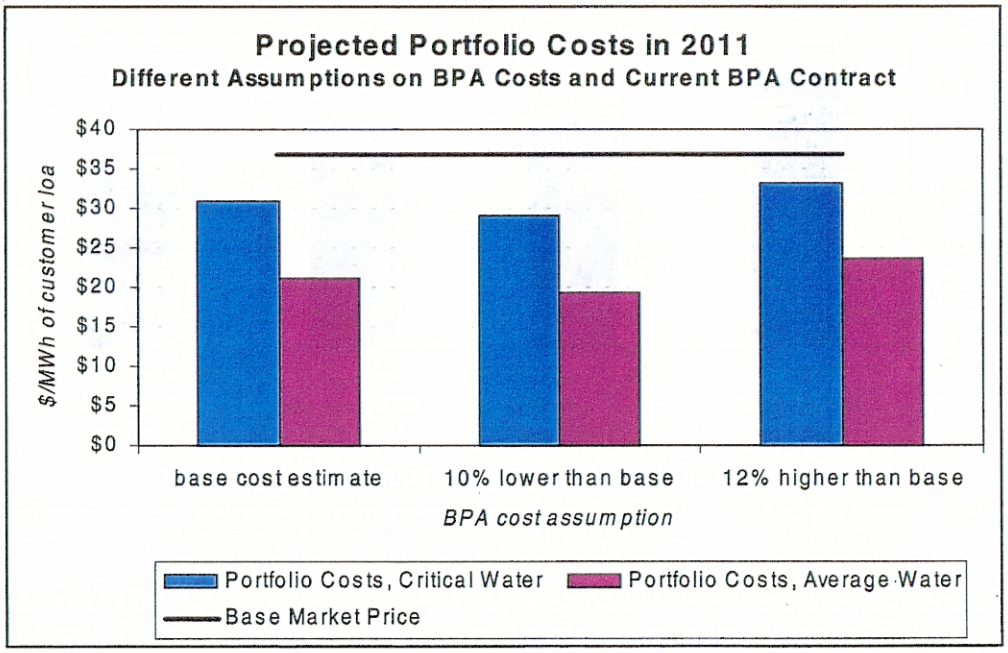
As the graph above illustrates, if there were dry conditions and low market prices, an unlikely combination, a reduction in projected base prices greater than 6% would be sufficient to make City Light's portfolio non competitive. This situation, however, has a very low probability of occurrence because low market prices normally occur in wet years. The last two columns in the graph above show scenarios with higher probability of occurrence. Under average water conditions, City Light's resource portfolio would remain competitive if market prices declined 25% from their base projected levels. In a very wet year, market prices would have to decline by more than 34% to have an adverse

impact on the competitiveness of the utility's resource portfolio. A reduction of 34% in average annual projected 2005 market prices would result in an annual average price of about $20.15 per MWh for the same year. This simplified analysis does not include the effect of potential strategies to maximize the value of the energy surplus over the hours and months of the year. It simply assumes that energy surpluses are sold at the prevailing market prices whenever they are available.

Portfolio costs include an assumption of about $10 million in true up costs for BPA in 2005 (in addition to the projected CRAC). This assumption results in an increase of $1.30 per MWh of customer load, so it does not have a significant effect on the conclusions from these last paragraphs.

Impact of BPA Costs in 2011

These paragraphs examine the impacts of potential changes in BPA costs on the portfolio costs to customers by the end of the forecast period. BPA costs are reviewed under three scenarios: base forecast, 10% below base and 12% above base, for both slice and block. BPA purchases are assumed to continue as established in the current contract, with a slice and a block product and the block amount increasing by an average of 115 aMW. The following graph shows the results for 2011, compared with the average annual market price projected for the same year.



The changes assumed for BPA costs have a measurable impact on the portfolio costs to customers, but in any of the scenarios reviewed the portfolio would remain competitive unless market prices were about 10% below the base forecast and BPA costs were 12% higher than estimated.

Appendix: Impact of Loss of Customer Load on Average Customer Rates

While the utility may expect its portfolio to be competitive in terms of costs per MWh of customer load under most scenarios, the full rate impact of the loss of a significant portion of customer load has to take into consideration costs other than those of the resource portfolio that are normally recovered from customers. These costs include transmission, distribution, customer service, administration and general, taxes, interest on debt issued and a contribution to finance part of the capital program. The latter, in turn, depends on the utility's financial policies. The analysis in the previous paragraphs indicates that as long as resource portfolio costs are competitive with market prices, and assuming no transmission constraints, loss of customer load does not increase portfolio costs because the increased surplus energy can be sold in the market. The impact of other costs, such as distribution and overhead, is different. Since most of these costs are still incurred after the customer loss occurs, they now have to be recovered from a lower number of total megawatt hours of energy sold to customers. While annual portfolio costs are reduced by the higher revenues from market sales, most other costs remain the same. There are thus two opposite impacts on customer rates. The following paragraphs summarize the example of potential impacts on customer rates assuming that when there is a significant customer load loss market sales increase (or market purchases decrease) and there is no change in retail costs.[12]

Two extreme cases were reviewed: the first one examines the rate impact of the loss of 50 MW of demand from industrial customers; the second one adds to this the loss of 25 MW of load in each of the next two years, for a total of 100 MW of load loss. The analysis assumes the 50 MW loss taking place in 2005, when the Department's new financial policies are in effect.[13] In the second example, the reductions in customer load add up to 50 MW in 2005, 75 MW in 2006 and 100 MW in 2007 and later years.

In both cases, net revenue from market sales increase, distribution and most retail costs do not change and total revenue from customers decline (so do taxes, which are largely revenue-based). The total revenue required from customers is not as high as before because there is larger revenue from market sales. The remaining customers, however, now have to pay a higher share of these revenue requirements because total sales to customers are lower. The impacts on customer rates are shown in the table below.

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[12] There may be a small reduction in distribution and customer service over time, and there will be a decline in taxes and some revenue-related expenses (such as uncollectible accounts), but the total impact will be small.

[13] Council Resolution 30428, approved on December 10, 2001 and anticipated to be implemented on January 1, 2004, requires customer rates to be set so that each year there will be a 95% probability that net revenues available to fund the utility's capital program will be positive.

Rate Impacts of Customer Load Loss

	2005	2006	2007	2008	2009
Rate Impact in $/MWh					
50 MW loss	$1.32	$1.10	$0.63	$0.58	$0.47
100 MW loss	$1.24	$1.76	$1.58	$1.17	$0.98
Percent Rate Impact					
50 MW loss	2.22%	1.89%	1.21%	1.11%	0.88%
100 MW loss	2.09%	3.03%	3.03%	2.24%	1.84%

As the table above indicates, the loss of 50 MW of load would cause the rates to the remaining customers to increase by about 2% in the first year, followed by smaller rate increases in the next few years. The loss of an additional 50MW in the next years would cause an increase in customer rates of about 3% for two years, and smaller rate increases after the initial change. The impacts translate in levels of $1 to less than $2 per MWh in average system rates.

Section 9. Strategies for Maintaining Load/Resource Balance

Background

Comparisons of projected loads and current resources over the next ten years suggest that City Light can meet its loads under critical conditions in the next few years and can probably meet temporary energy deficits by taking advantage of the flexibility of its own and contracted resources to shift generation from one month to another or purchasing power in the market for short periods. This may not be sufficient to meet monthly resource deficits in later years as customer load grows, even though the utility will still have energy surplus in late spring and early summer. New strategies will also have to be devised if City Light's resource portfolio changes significantly as a result of the ongoing regional review of BPA contracts or if other conditions change significantly.

One of the main issues to examine before developing strategies deals with the guidelines to frame the resource strategy in the future. The current strategy is to have sufficient resources to meet customer load under severe drought conditions. In most years the utility will have more energy than it needs to meet its customer load and will sell its surplus in the market. While this strategy minimizes the risk of not being able to meet customer load at all times and mitigates the impact of market volatility on power costs, it also causes the utility to incur costs it may not be able to recover. In general, a strategy leading to the acquisition of resources to meet load under critical conditions would make the utility vulnerable to low market prices while a strategy that increases the dependence on market purchases to meet customer load part of the time would cause the utility to be vulnerable to high market prices. An approach to balance these risks might be to plan acquiring the resources needed to meet customer load under less restrictive conditions than the critical year, such as 80% exceedance or 70% exceedance; the risks would not be eliminated, but the weights of the risks associated with potential different outcomes would shift. Additionally, in any of these cases the Department faces the risk of potential limits to market access as a result of the final outcome of regional market design and transmission proposals. This uncertainty adds value to strategies that rely on resources located within or near the service territory. Finally, recent changes in the electricity markets, especially the financial demise of many participants, have increased the risks associated with strategies that rely on the creditworthiness of contractual partners.

Combustion Turbine

One of the strategies to meet temporary energy deficits may be to rely on a combustion turbine. Typically, a combustion turbine has relatively low capital costs and high variable costs. Therefore it does not need to be run at all times of the year to be profitable and could thus be an option to meet monthly resource deficits. The choice of the technology would depend on the amount of time the turbine is expected to run and projected natural gas prices. If the turbine were run all the time, a combined cycle combustion turbine would typically be the best option because it is a more efficient unit than a simple cycle turbine. If the turbine were run instead just a portion of the time, a simple cycle unit would result in lower annual costs. City Light has recently updated the

estimates of the costs of combustion turbines. The following example illustrates annual costs and costs per MWh assuming a fuel cost of $3/MMBtu and estimated greenhouse gas mitigation costs of $1.43/MWh and $1.05/MWh for simple cycle and combined cycle turbines respectively. For illustration purposes, the table below shows costs at 90% and at 20% capacity factor, assuming a cost of natural gas of $3 per MMBtu.

Estimated Costs of Combustion Turbines with Fuel at $3/MMBtu

	Simple Cycle	Combined Cycle
Capacity (MW)	96	107
Annual capital costs (000$)	65,000	74,200
Other annual fixed costs (000$)	1,150	4,940
GHG mitigation ($/MWh)	1.96	1.44
Fuel and variable costs ($/MWh)	37.00	28.20
Annual value of reserve (000$)	442	442
Costs at 90% capacity factor		
Total annual costs (000$)	35,000	34,900
Costs per MWh ($/MWh)	46.20	41.38
Costs at 20% capacity factor (000$)		
Total annual costs (000$)	11,600	15,000
Costs per MWh ($/MWh)	69.10	80.21

Higher natural gas costs increase the advantage of the combustion cycle turbine; lower natural gas costs make the simple combustion turbine option more attractive because its lower efficiency has then a lower impact on total costs. For example, at $8/MMBtu, the simple cycle version, with its less efficient use of fuel, becomes more costly than the combined cycle option, even at 20% capacity factor.[14]

The paragraphs above review the costs of the turbines without consideration of the option to sell the output when it is not used by the utility. In fact, once the investment in a combustion turbine has been made, with production variable costs at lower levels than market prices, sufficient market demand and no transmission constraints, the utility could have the turbine running throughout the year and sell its surplus output in the market. This option, however, would increase the risk of lower than projected energy market prices, which would reduce the value of this alternative.

An additional question is that of contract versus ownership. The contract option allows a utility to avoid the cost and risk of the investment in the plant, but it provides less operational flexibility. The greater operational flexibility of an owned turbine comes at the cost of the initial capital investment and higher risk. Further analysis is needed to

[14] This scenario, however, is not highly probable because natural gas prices are not expected to stay at that high level.

determine costs and benefits; this analysis will be done when City Light reviews its options in relation to the extension of the Klamath Falls contract.

Spot Market Purchases

Instead of building or contracting for the output from a resource, the utility can rely on spot market purchases to acquire power only when needed. The advantage of this approach is that it requires no initial investment or fixed costs, so there is no risk of stranded costs. In addition, there is no need to project the amounts and timing of energy deficits far in advance. On the other hand, it is risky in terms of costs. Energy spot prices may vary significantly over time and it may not be possible for the utility to avoid purchases at times of high prices. This risk would increase under a strategy that directs the utility to acquire firm resources to meet customer load under conditions other than drought, such as 75% exceedance. This uncertainty could be mitigated by using a financial agreement to hedge against those costs, such as a collar or a hedge, but this will incur an additional cost that may or may not be justified, depending on the market conditions at the time. Moreover, there is the additional risk that power and/or financial instruments may not be available as needed, especially because wholesale markets have become thinner since the 2000-2 crisis. Potential creditworthiness problems of trading partners add to the uncertainty of this option.

Finally, as is the case in all options that rely on market power, the availability and cost of transmission of the energy to be delivered to the service territory bring additional uncertainty.

Forward Contracts

Since the Department has a history of the generation from its resources over many water years, it can develop reasonable estimates of the periods over which it will have resource deficits under critical water conditions. It could then sign forward contracts to have energy delivered at a set price during those deficit periods. The price risk here is that spot prices may actually be lower at the time the energy is delivered, in which case the utility would have been better off relying on the spot market. However, there is no risk that the prices will be higher and there is probably reasonable assurance that the energy will be delivered (unless the counterpart goes out of business). On the other hand, currently credit and counterpart risks are much greater than in the past.

As opposed to the case of spot market prices, there is also uncertainty around the precise amount of power needed. The contract may specify an amount of energy to be delivered that is either lower or higher than that required to meet the energy deficit of the utility. In cases of divergence, the utility would probably have to either buy or sell the difference at spot market prices. The uncertainty about the amount needed to meet the resource gap diminishes as the utility gets more information on the water conditions and probable generation it will have that year. It is not certain, however, that a party will always be available to participate in a forward contract with the Department.

Options

An option contract would allow City Light to mitigate the risks associated with the contracts described above. The option would allow the utility to exercise the right to buy a specified amount of power at a given price. The Department would choose to exercise this option only if it did not find a better alternative to fill its resource deficit. This reduction in uncertainty would be available at a cost, the premium paid for the option. The remaining issue given today's energy markets is the availability of this type of contract and the reliability of potential contract partners in a market where the number of participants has been drastically reduced.

Seasonal Exchanges

City Light could also choose to exchange power with a partner that has a different load resource profile, such as a utility that tends to have resource gaps in spring and summer. In this case, the Department would commit to provide energy in specified months in spring and summer in return for energy deliveries in other months, such as December through February. If the value of the power were basically the same throughout the year the amounts of energy exchanged could be the same. Since this is not the case, the differences may be resolved by either changing the amount of energy delivered or adding monetary compensation. City Light has had several seasonal exchange agreements. While some have terminated, there are still two contracts: an exchange with Tacoma, which terminates in 2003, and a contract with the North California Power Agency (NCPA), which extends to 2014. Under the exchange with Tacoma City Light receives 50 MW in August and delivers it back to Tacoma in October. There is no monetary exchange. The exchange with NCPA provides for City Light to send energy and capacity to California in the summer in exchange for a slightly different amount of energy and capacity in the winter.

While these exchanges can be a useful tool to meet monthly resource gaps for a utility that has surpluses in other months, their value also depends on market prices. The same exchange contract may have different value for a utility under different market price scenarios. For example, excluding the cost of transmission, in 2003 the exchange with NCPA would have an additional net value for City Light under the current price forecast, but if prices were instead as forecasted in early 2001, the Department would deliver higher value than it receives. The following table illustrates these impacts.

	Current Price Forecast	2000 SRA Price Forecast	Early 2001 Forecast
Energy delivered in MWh	90,566	90,566	90,566
Energy received in MWh	126,839	126,839	126,839
Value of energy delivered	$ 2,697,136	$ 3,077,804	$ 7,207,515
Value of energy received	$ 4,535,523	$ 4,038,388	$ 9,369,017
Value delivered per MWh	$ 29.78	$ 33.98	$ 79.58
Value received per MWh	$ 35.76	$ 31.84	$ 73.87

The example above applies to only one year. The net value of the contract in different years is likely to be different, with some years resulting in a net benefit while others would cause a net loss in terms of value of energy received and delivered.

Section 10. Risk Management

Background

City Light's risk management policies and procedures are detailed in its Risk Management Manual dated August 2001, with subsequent amendments to them by the utility's Risk Management Committee recorded in the minutes of its meeting. The policies cover all aspects of power, transmission, and ancillary services trading, and a complete description is beyond the scope of this document. The following highlights the policies that are critical to City Light's overall risk exposure.

Current Approach

Since City Light's trading authority extends 18 months into the future, its trading strategy covers two water years. The goal is to cover 75% of all monthly open positions (i.e., surplus or deficit) in that timeframe in the forward market, and it accomplishes that goal in stages.

For water years beyond the current year, City Light assumes 95% exceedance generation on its three major hydro resource – Skagit, Boundary, and Slice – and 95% exceedance loads. These assumptions result in forecasted monthly open positions for October through the following September. By construction, the resulting forecasted short positions will occur less than 5% of the time, while the forecasted long positions will occur more than 95% of the time. The utility sells the long positions beyond the current water year and within the 18-month trading window in the forward market, but does not buy the forecasted short positions. It executes these trades as quickly as the market will bear.

As the utility moves into the new water year, it relies on the Weekly Marketing Plan (WMP) to guide trading. The WMP focuses on the open position up to two months into the future, and relies on the best available information at that time, including observed precipitation, snow pack surveys, and long-range forecasts from the National Weather Service and others. It covers 50% of any forecasted position forward, closing that position incrementally over the following eight weeks. Each week the window rolls forward and the process repeats.

The utility continues trading under the WMP until late in the calendar year when it has accumulated sufficient information about precipitation and snow pack to form a preliminary forecast of hydro generation for the remainder of the year. At that time, it covers 50% of the forecasted position for all months in the remainder of the water year as quickly as the market will bear. The utility relies on the WMP to handle the remaining 50%. In this way, City Light covers around 75% of the forecasted position in the forward market before the start of the month in question.

Going Forward

The current risk management approach grew out of City Light's experience with volatile markets during the energy crisis. Then, City Light was dramatically short. Today, it is long in most months even under extremely low water conditions. The strategy is very heavily weighted toward avoiding spot market price risk. Inevitably, this strategy will forego opportunities to generate revenue.

The current strategy is entirely driven by quantities – forward prices play little if any roll. It still assumes that forward positions the utility creates are fixed. In effect, these become part of the underlying portfolio. However, the utility also faces risks in the forward market and at present there is no mechanism for managing that risk.

While the strategy is probably appropriate given the current financial circumstances of the utility, it may not be appropriate for the long run. A key task for the utility in the future will be to develop a strategy that reflects all of the risks and opportunities, and allows policies makers to choose where on the risk-return frontier they prefer to be. City Light plans to hire a consultant to review these options with the utility's staff.

Section 11. Environmental Implications of Resource Portfolio

Environmental Characteristics of Resource Portfolio

City Light did an in-depth analysis of the environmental implications of its resource portfolio in the April 1997 SRA Final Environmental Impact Statement (EIS) and the August 2000 EIS Addendum. There have been no major changes, so there is no need for a new Addendum at this time. The following paragraphs include a general description of the range of impacts of the current portfolio.

Owned Resources

City Light's power is primarily generated by its own hydroelectric projects: Boundary, Skagit, Tolt, and Cedar Falls. These resources are generally considered to be renewable because they are fueled by water, although hydroelectric projects can have negative environmental impacts. Potential impacts include effects on fisheries, wildlife, and habitat both upstream and downstream of plant operations as well as on recreation, cultural resources, erosion, and aesthetics.[15] City Light is extensively involved in the protection of threatened and endangered species in its project areas.

Skagit: The new license for the Skagit Projects (approved by FERC in 1995) requires important environmental protections, including enhancements for wildlife habitat, cultural resource mitigation, recreation and visitor amenities, erosion control, archaeology and aesthetics, including landscaping projects and powerline revegetation. This license incorporates a landmark multiparty settlement agreement negotiated by City Light.

The Department committed $17,000,000 (1990 dollars) to purchase land for wildlife use and over 8,000 total acres have been purchased in the Skagit, Sauk, and South Fork Nooksack river basins. Vegetation is being established in the Ross Lake National recreation Area through a combination of natural re-vegetation, native plantings and removal of invasives. Seattle City Light's Wildlife Research Grant Program has awarded over $270,000 to Skagit Valley College, Washington Department of Fish and Wildlife, National Park Service, Oregon State University, and Washington State University to support the understanding and management of wildlife and ecosystems in the North Cascades area. The Department is also building an Environmental Learning Center at the Skagit, which will be operated by the North Cascades Institute.

Boundary: The Department has begun its work in preparation for the process to relicense the Boundary project, which will start in 2006. The current license expires in 2011. Energy generation at Boundary is affected by the Columbia River Biological Opinion, a

[15] Puget Sound chinook salmon and bull trout were listed as threatened species in 1999. The largest chinook population in Puget sounds inhabits the Skagit, and smaller populations are also in the watersheds where the South Fork Tolt and Cedar River projects are located. Bull trout are found in the Skagit, Cedar and Boundary Project watersheds.

set of guidelines created to protect fish in the watershed and meet requirements of the Endangered Species Act. City Light has been performing studies in preparation for relicensing. Water quality studies are currently underway, as well as studies on bull trout, in cooperation with state agencies and Indian Tribes. These studies are designed to determine the reason for the decline of bull trout; adverse factors identified are: high water temperature, interaction with exotic species, habitat modifications and fragmentation due to the presence of dams, and altered water flow and water quality due to the presence of dams. With the exception of more studies, no further action associated with relicensing preparation is planned for the immediate future. Future studies will include testing ways to lower dissolved gas levels in the Columbia River Basin; supersaturation of total dissolved gas is an issue that has received considerable attention in Canada and the United States.

Cedar Falls: In 2000 City Light did an intensive environmental review and mitigation planning process on Cedar Falls, which resulted in the Cedar River Habitat Conservation Plan (HCP) in 2000. One of the components of the plan is the investment in downstream improvements that will allow migrating anadromous salmonids access to this reach of the Cedar River for the first time in decades.

South Fork of the Tolt: The South Fork Tolt Hydroelectric project, completed in 1995, was granted a 40-year Federal Energy Regulatory Commission (FERC) license in 1984. In 1988 Seattle City Light filed with the FERC a settlement agreement signed by the City, fish and wildlife agencies and Tulalip Tribes for the purpose of protecting and enhancing fishery and wildlife resources affected by the construction and operation of the new plant. The agreement also established the Tolt Fisheries Advisory Committee (TFAC), which is comprised of the parties that negotiated the settlement and oversees the implementation of and compliance with license required mitigation and related operational issues. Other mitigation measures that are part of the license include wetland mitigation and monitoring and two recreation development projects.

Contracts

City Light also has long term contracts to buy electricity from a variety of sources. The potential environmental impacts of those sources are described below.

BPA Slice: The BPA contract defines the BPA slice product as the output of the Federal Columbia River System hydroelectric projects, the WNP-2 nuclear plant, and small amounts of biomass, wind, and irrigation hydropower. Potential environmental impacts of the federal hydroelectric projects include those listed for City Light owned hydropower facilities. BPA is also governed by the Endangered Species Act and the Columbia River Biological Opinion. The potential environmental impacts of nuclear power are land and water impacts from fuel extraction, water use during electricity production, and fuel and fuel waste handling during and after electricity production.

BPA Block: The BPA block product contains the remaining output of the Federal Columbia River System hydro projects, after slice electricity has been subtracted, and any

purchases that BPA makes to meet it load obligations. The potential impacts of market purchases are summarized below.

Irrigation Hydropower Contracts: The Department has long term contracts to purchase electricity from irrigation projects in Washington (primarily the Grand Coulee Hydroelectric Authority) and Idaho (Lucky Peak). Irrigation is the primary purpose of the projects, so the addition of hydroelectric facilities had only limited incremental impact. These resources are viewed as having little additional environmental impact, beyond that of the existing dams, and may displace fossil fuel.

Other Hydropower Contracts: Seattle City Light also has contracts to receive electricity from Pend Oreille PUD's Box Canyon project and Grant County PUD's Priest Rapids project. The potential environmental impacts of these resources are similar to that of hydro plants described above. The Department tracks developments in environmental processes and licensing for these facilities. Finally, City Light has a contract with BC Hydro (Powerex) that is also treated as a hydro resource, since it seeks to mimic the generation that would have been produced by an expansion of the Ross Project.

Klamath Falls: The Klamath Falls Combustion Turbine project is a high efficiency electricity plant in Klamath Falls, Oregon, that also provides cogeneration through waste steam delivery to an industrial facility nearby. As a part of that process, the plant owners committed to complete projects that would mitigate 26% of the expected greenhouse gas emissions over a thirty-year time period. This mitigation will be overseen and verified by the State of Oregon. Seattle City Light will mitigate for the remaining emissions associated with its share of the plant output, estimated at between 210,000 and 247,000 metric tons CO2 equivalent per year. (See the Status of Greenhouse Gas Mitigation Program below).

State Line Wind Project: This project underwent extensive environmental review in the states of Washington and Oregon as a part of its licensing process. Avian use of the site was monitored before construction of the project and impacts to avian species will be monitored as the facility operates. Construction was not done in areas where there was concern about potential avian interactions with the turbines and in areas used by a sensitive species in Oregon. The facility uses only a minimal amount of water and other resources in the maintenance process and allows operation of agricultural activities with little impact.

Market Purchases: City Light purchases electricity on the short term market to make up for seasonal or temporary resource deficits or to maximize the benefits from its own hydro plants. Under current resource and load forecasts, over the next several years, the utility expects to make few market purchases. Under current practices it is impossible to know exactly where the electricity purchased is being generated. In the past, City Light has used a theoretical construct called the "melded resource" to represent the resources that are available to buy on the market. This "melded resource" is made up of primarily fossil fuel resources, with their impacts on air, land and water resources. As new plants are built in the northwest and other regions where the Department trades, the mix will

move toward having lower average air, land and water impacts, since new plants are likely to be much more efficient and undergo more thorough environmental and siting review than older existing sources. At this time there is no plan to update the melded resource mix.

Metro Methane: City Light purchases electricity from reciprocating engines run on methane produced at the King County West Point Wastewater Treatment Facility. Electricity produced with wastewater gas is generally considered to be a renewable resource. If the methane were not used for electricity, it would be flared.

Exchanges: It is difficult to determine the environmental impacts of exchange contracts; they vary with hydropower levels and the resource mixes of the exchange utilities. At the worst impact level, it could be assumed that the electricity City Light receives is from the market. The historic view of these exchanges is that they have allowed the parties involved to avoid or delay building additional generating resources and have allowed for the export of surplus hydropower from the region to serve other areas.

Conservation: Potential adverse environmental impacts of energy conservation measures are generally quite small. These impacts fall into three categories: (1) impacts from production of material and equipment used for conservation measures, (2) indoor air quality impacts from decreased air infiltration from the outdoors (weatherization programs) and (3) disposal of equipment used in conservation measures, such as compact fluorescent bulbs.

Status of Goal of Meeting Load Growth with Conservation and Renewable Resources

The 2000 SRA affirmed the utility's goal of meeting all load growth through 2011 with conservation and renewable resources. At that time, load growth from the end of 2000 to 2011 was projected to be about 200 aMW; the resource plan was to meet about 100 aMW of this load with cost-effective conservation and 100 aMW with new renewable resources.

While the target date for meeting the above goal is 2011, the utility anticipated that this target would not be perfectly met every year of the period, particularly because the acquisition of renewable resources will not be gradual, as customer load growth, but instead tends to proceed through the addition of fairly large discrete amounts.

Customer load declined sharply in 2001 and is now projected to remain below the levels expected by the 2000 SRA for the decade. Given current projected load and actual and planned acquisitions of conservation and renewable resources, City Light expects to meet its target by 2011 as anticipated.

If customer load were higher than in the base forecast, the utility would have to acquire more renewable resources or conservation. If on the other hand, load were below

projections, the utility would exceed its target halfway through the planning period, as may be seen below.

Projections of Customer Load, Conservation and Renewable Resources

	Base Customer Load	High Customer Load	Low Customer Load	Cumulative Conservation	State Line Wind	Conservation and Renewables
2000	1140.1	1140.1	1140.1	0.0	0.0	0.0
2001	1086.7	1086.7	1086.7	10.0	0.0	10.0
2002	1091.0	1091.0	1091.0	16.0	23.9	39.9
2003	1120.2	1138.5	1088.5	28.0	33.7	61.7
2004	1147.4	1186.0	1103.0	40.0	54.9	94.9
2005	1174.8	1216.3	1118.0	52.0	59.0	111.0
2006	1202.4	1248.1	1133.0	64.0	59.0	123.0
2007	1230.3	1280.9	1148.0	76.0	59.0	135.0
2008	1258.3	1314.5	1164.0	88.0	59.0	147.0
2009	1286.6	1348.6	1180.0	100.0	59.0	159.0
2010	1304.5	1383.1	1196.0	112.0	59.0	171.0
2011	1322.5	1418.0	1213.4	124.0	59.0	183.0
cumulative 2000-11	182.3	277.8	73.3	124.0	59.0	183.0

The customer load projections reflect demand before conservation savings. The base forecast now assumes that demand growth will be 182 aMW between 2000 and 2011; 124 aMW of this growth will be met with conservation and 59 aMW with energy from State Line wind. If customer load instead grew much faster and reached 278 aMW over the period, new resources would have to be acquired. On the other hand, on the path of low demand growth, by 2004 Seattle City Light would have acquired all the conservation and renewable resources it needs to meet demand growth through 2011.

Greenhouse Gas Mitigation Program

Background.

City Light is committed to pursue resource strategies that are environmentally sound and thus will mitigate all greenhouse gas emissions from its portfolio over the long run. The current framework for action is established by Resolutions 30144 (Earth Day, April 2000), 30256 (October 2000, mitigation of emissions from the Klamath Falls purchase), and 30359 (October 2000, directing Seattle utilities to further develop policies and programs for the stewardship of the region's resources). In the near term City Light is pursuing projects to mitigate greenhouse gas emissions associated with the utility's share of output from Klamath Combustion turbine. All emissions associated with meeting the electricity needs of Seattle City Light customers are targeted to be mitigated in 2003.

The table below illustrates the difference in greenhouse gas (GHG) emission levels, and corresponding differences in mitigation costs, for several resources City Light currently has in its portfolio or may consider adding to its portfolio:

	Metric tons CO2/MWh	Mitigation Cost/MWh[16] (at $4/metric ton mitigation)
Market	0.55	$2.20
Simple Cycle Combustion Turbine	0.49	$1.96
Combined Cycle Combustion Turbine	0.36	$1.44
Klamath CT (26% mitigated)	0.28	$1.12

The Department's program has the following goals:

1) Mitigate for 100% of Klamath CT, assuming project developer has mitigated 26%
2) Mitigate all GHG emissions from the utility meeting electricity needs of Seattle City Light

Klamath Falls Combustion Turbine Contract

City Light receives electricity from Klamath Falls based on 100 aMW capacity share. The actual amount of electricity City Light receives depends on how the plant actually runs. As stated in the resolutions identified above, the Department had estimated the amount and cost of mitigation based conservatively on a 100% capacity factor. However, the plant will always run at a lower level; the typical capacity factor of a combined cycle combustion turbine is 95% or less, and this may be even lower due to planned and unplanned outages and maintenance.

An additional feature of the Klamath Falls contract complicates the calculation of how much GHG emissions are associated with the energy City Light receives. Under certain circumstances, the seller has the right to "re-supply", that is, deliver electricity to the Department that is not produced at the Klamath Falls plant. This could happen if the operator needed to perform unplanned repairs or if alternative supplies of electricity were less expensive than the run cost of the plant. The seller is not obligated, nor is it likely that it would be possible, to disclose when they are providing re-supply and where it comes from. The amount of electricity from re-supply can be estimated based upon the delivery point of the electricity. The source is treated as the market mix, which City Light assumes to have a certain emission factor. This market mix emission factor is much larger than the emission factor for the Klamath Falls combustion turbine with mitigation.

Based upon the Department's information and best estimates, for the period July 2001 through June 2002, the GHG emissions associated with the Klamath Falls contract, including both electricity from Klamath and re-supply, were approximately 213,000 metric tons. This is less than the original estimate of 247,000 metric tons. This estimated amount is based on the assumption of 52 aMW from Klamath and 18 aMW from re-supply.

[16] Mitigation costs per ton are based upon the 2003-2004 budget estimates

All GHG Emissions from the Portfolio

Seattle City Light created a Greenhouse Gas Advisory Committee composed of experts on climate change, customers, and utility executives to discuss the approach to define and meet the goal of supplying Seattle's electricity needs with net-zero GHG impacts. The group met monthly from January through July 2001. Their comments and recommendations were summarized in a memo to the Superintendent on June 25, 2001. In that memo, the Advisory Committee recommended that the Department mitigate approximately 611,000 metric tons each year to reach the net-zero goal, assuming the expected resource portfolio at that time.

GHG Inventory

Seattle City Light had its GHG inventory verified for the year 2000 and estimated for the year 2002 by a consultant team of the Institute for Lifecycle Energy Analysis (ILEA) and the Tellus Institute. The verification report estimated that the Department's GHG inventory for 2002 would be 295,076 metric tons. This is less than half the estimate from the Advisory Committee memo, primarily due to the following changes: the actual amount of electricity that City Light receives from Klamath CT is lower and includes "re-supply" from market resources, the amount of BPA market augmentation has dropped significantly from earlier estimates, City Light has had very limited market purchases (compared to large market sales), and upstream emissions and rounding have been lowered.

Climate Trust Projects

The Department entered into a partnership with the Climate Trust, a non-profit organization based in Portland, Oregon, to identify and contract for greenhouse gas offset projects. A joint Request for Proposals (RFP) was issued in January of 2001, and City Light is in the process of working with the Climate Trust to complete contracts for three projects. The projects are:

1. an industrial process efficiency modification that will use waste fuel and heat,
2. energy efficiency at data centers, and
3. material substitution to lower GHG in industrial process.

These projects are likely to be located in regions outside the Northwest, with some opportunities to work in this region, and perhaps in the service territory. The Department is also reviewing several forest sequestration projects proposed for Washington State.

Potential Local Projects

In its RFP, City Light indicated a preference for local GHG mitigation projects and has been working to identify potential local projects in parallel with the Climate Trust/City Light RFP process. The Department has conducted extensive outreach in a variety of

areas, including cement material substitution, biodiesel, transportation, wastewater methane, dairy methane, sequestration and others.

The Department and a national expert on cement material substitution recently held a workshop on this subject for local users and suppliers of cement and concrete. It was very well attended and provided a valuable forum for discussion of the potential for this type of project to result in emission reductions and the barriers that exist to more widespread use of cement substitute materials. (Cement substitute materials, such as fly ash and slag, contribute less GHG due to displacement of the chemical process of manufacturing cement itself, which releases CO2, and by requiring less energy/electricity to produce). City light was chosen to participate as the host of this regional workshop because of contacts made in researching mitigation projects and in part due to its reputation as a utility that is committed to GHG mitigation. One of the conclusions derived after two informative sessions was that cement substitution, to a certain extent, is already done, and that standard practices and specification habits are responsible for impeding more use of cement blends.

The initial findings of all potential local projects have indicated that these opportunities are often very expensive on a per ton basis compared to opportunities in other regions or countries. In addition, many possible local projects could not offer enough tons to justify the transaction costs. There are several reasons for this. One, the Northwest is a relatively clean base of electricity, so displacing the energy mix here does not result in as many tons of emission reductions as the same project in a region with a higher emission factor for its electricity mix. Second, transportation projects, a type that is of interest and direct application in Seattle, tend to be especially expensive and it is sometimes difficult to develop reliable methods to quantify, monitor, and verify GHG emission reductions. Third, biofuels that are potentially available in Seattle and nearby are largely more expensive and untested, with the exception of wastewater gas. The transportation sector is unlikely to accept biofuels on any significant scale without a clear understanding of the costs and operational issues. In addition, there is currently no distribution infrastructure for these fuels, and it is uncertain how much it would cost and who would be willing to risk paying for it. On the other hand, these barriers are ones that governments may have the resources to overcome, with cooperation and funding among a variety of sources. City Light continues to work with potential project proponents to explore opportunities.

Seattle Voluntary Green Power Program

In accordance with state law effective on January 1, 2002, Seattle City Light started the Seattle Green Power program, a voluntary program that gives City Light customers the opportunity to make payments above their regular billing to help develop a more diverse range of new clean, renewable energy sources. According to City Ordinance 113944, 40% of the funds collected from customers will be used for solar installations on public facilities and 60% will be used to acquire other qualified renewable resources.

As of mid-year 2002, City Light has enrolled about 2400 customers and has collected about $50,000, including 300 one-time payments. The utility is still trying to reach a

consensus on likely participation. Preliminary estimates that participation in this program could build to a stable level of about 2% of our customers by 2006 are based on the assumptions of some marketing effort, general improvement in the regional economy and City Light's scheduled rate reductions. At this level the Department would collect about $335,000 per year by 2006; about $134,000 would be available for solar investment and $201,000 for other new renewable resources. This would allow City Light to install about 13 solar packages annually producing about 16,000 kWh and to purchase about 2,000 MWh annually (or ~ 0.25 aMW) of new non-solar renewable resources (based on a price equal to about twice the price of wind.)

City Light plans to install about five solar projects in 2002 partnering with Seattle Public Schools and Seattle Parks & Recreation. The Memoranda of Agreement (MOA) with the Seattle Schools and Seattle Parks & Recreation have been signed. Solar installations are underway at three schools and two parks. In addition, a commitment has been made to the University of Washington for future siting of solar equipment at Merrill Hall Center for Urban Horticulture.

Currently, there are no non-solar renewable projects available in Seattle. The earliest online date for new non-solar generation is likely to be 2004 or 2005. Three of the most promising options located in or close to Seattle include 1) a methane recovery project, 2) a landfill gas to energy project and 3) a biogas to energy project. However, there is no certainty that any of these resources will be developed or that City Light will be able to purchase the small amount of output required for this program. Consequently, City Light will have to develop a near-term strategy to use or carryover VGPP funds until these resources can be built. Other options include purchasing green power or green tags from the Northwest power market and/or expanding the solar program, if possible.

City Light will continue to site and install solar packages locally and to analyze the non-solar projects mentioned above because they are our most promising local opportunities. By year-end 2002, the Department will try to develop a specific non-solar resource proposal that best meets the long-term goals and objectives of this program. In addition, City Light will continue to monitor the renewables market more broadly in the event that development of these projects doesn't happen.

Section 12. Potential Market Changes

Background

On July 31, 2002 the Federal Energy Regulatory Commission (FERC) issued its Notice of Proposed Rulemaking (NOPR) titled "Remedying Undue Discrimination Through Open Access Transmission Service and Standard Market Design". This NOPR follows FERC Orders 888 and 2000, which established open wholesale transmission access. The main purpose of this ruling is to encourage competitive electricity markets with the belief that they will benefit consumers by allowing them access to the most cost effective sources of power. This new proposal affects wholesale transmission and seeks to establish a model for standard electricity markets in the country.

Owners of transmission assets would be required to either divest or transfer operational authority to Independent Transmission Providers (ITPs), which may be, but are not required to be, Regional Transmission Organizations (RTOs). In each region the ITP would control the electrical transmission grid and operate daily wholesale energy markets, tap the cheapest resources and move energy in a non-discriminatory way. The grid operators would adjust power delivery fees to reflect costs created by transmission bottlenecks. Congestion would be managed by the use of Locational Marginal Pricing (LMP); separate prices at all nodes of the grid would make it clear where congestion points are and would cause users to pay the prices for the congestion they cause. Congestion Revenue Rights (CRRs) are proposed to be allocated to loads, so when CRRs are collected under the LMP scheme they would be returned to the loads that paid the costs. Part of these revenues, in theory would also be allocated by the ITP to make the investments in the grid that are necessary to relieve congestion.

The electricity markets assumed are day ahead and real time spot transactions, with most transactions being bilateral. While self-supply is recognized, the proposal appears to assume that every supplier will want to bid its generation portfolio into the market and use any cheaper generation in the market, if available. There will also be a Market Monitoring Unit (MMU) to control for attempts to exercise market power, but its functions have not been clearly defined. There is a price cap of $1,000 per MWh, and an Automatic Mitigation Procedure, similar to that in use at the New York Stock Exchange, to reduce bids that appear to be outside acceptable limits (such as those based on withholding generation rather than true scarcity)

FERC will require a resource adequacy test of 12% of installed capacity. The Pacific Northwest region is not capacity constrained, so this test can be met. It is not clear how a resource adequacy requirement would affect resource planning in the region. The NOPR also includes a Regional Advisory Committee (RSAC) to determine other adequacy levels, if desirable.

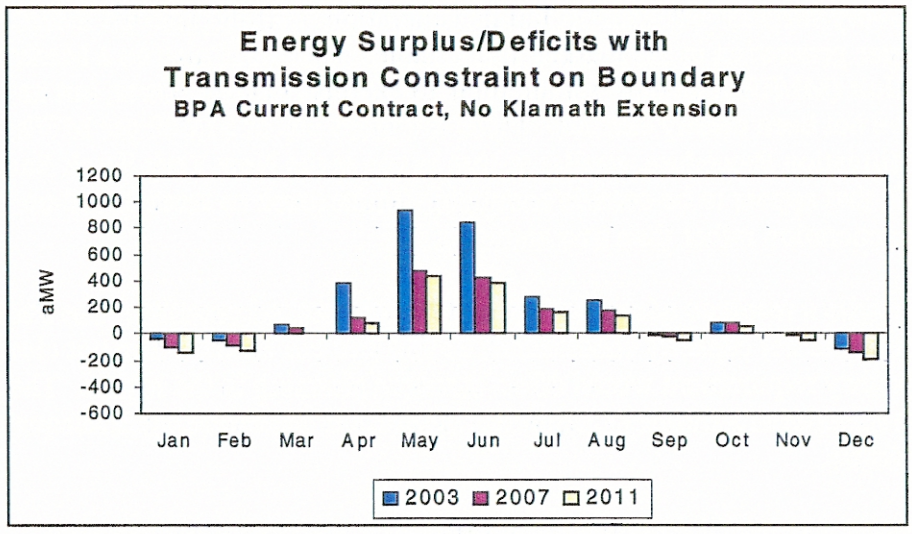
One of the major concerns for the Pacific Northwest is that the NOPR assumes generation adjustments that are possible with thermal units, but not with large, interdependent hydro systems such as the Columbia and Snake Rivers. Furthermore,

economic returns from electricity generation do not have priority for water use in the region; there are other goals, such as such as fish protection, recreation, etc., which are not recognized by FERC's Standard Market Design. In addition, the largest part of the region's transmission grid is owned by BPA and FERC has only limited jurisdiction over Bonneville. There remain issues associated with native load preference, preemption of state authority, the length of time for which rights to CRRs could be extended, potential market power manipulation, etc.

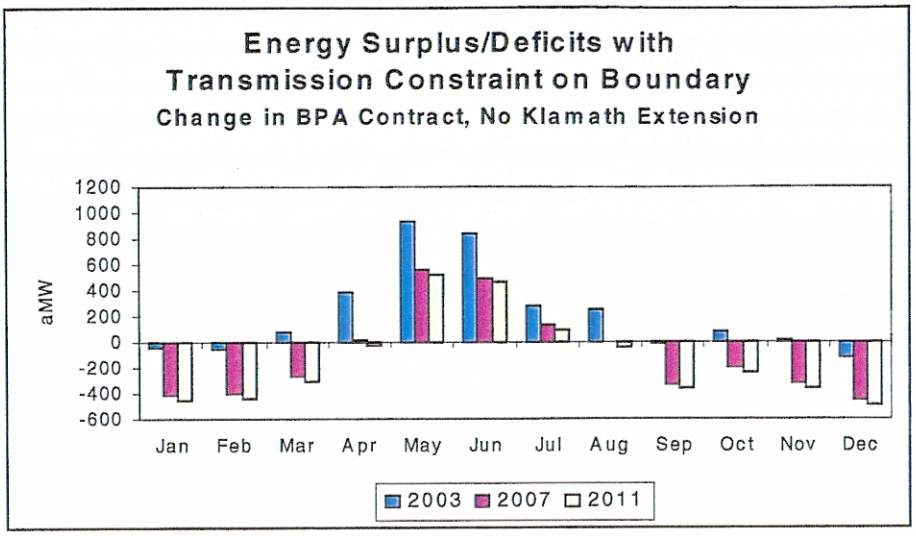
FERC's 600-page NOPR is a complex document with many unclear points. Many arguments against a number of provisions have been raised by consumer advocates that fear that it will actually cause electricity rates to increase, by state governments that feel FERC is curtailing states' power and by a number of other organizations and groups. The original period for comments has been extended twice; FERC is now receiving comments until February 2003. It is still early to estimate where the process will end. City Light will continue its involvement in regional efforts and will continually monitor potential impacts on its portfolio and resource strategies.

Impact of Transmission Constraint On Boundary

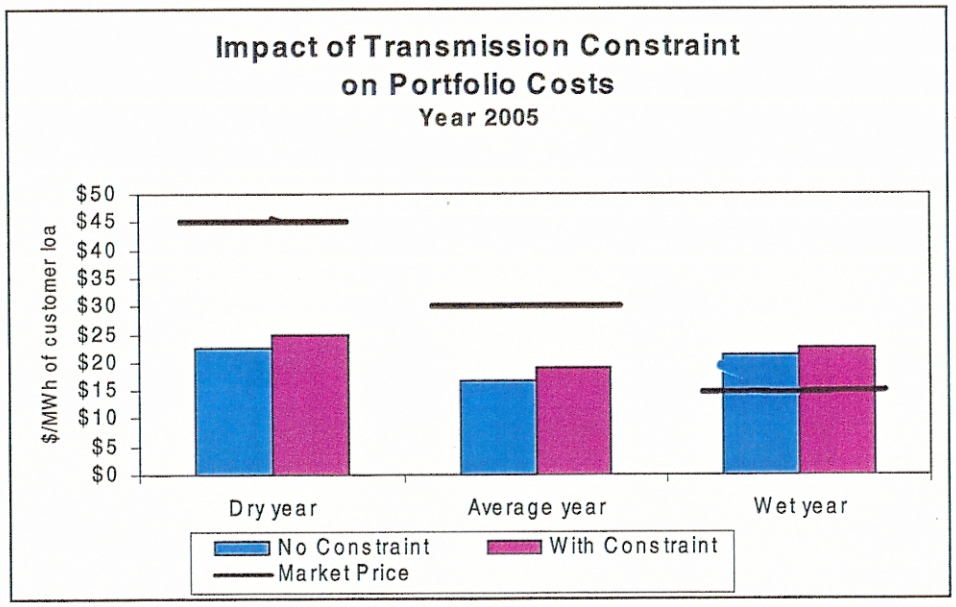
An example of one of the potential impacts of the market design changes being discussed would be to limit the Department's access to the transmission grid, either to sell its surplus energy or to bring the energy from distant resources to its customers. These paragraphs review a scenario in which starting in 2004 transmission constraints would cause the City Light to spill part of Boundary flows during the runoff months (April through June) and cut generation by one half. Since the Department anticipates having considerable energy surpluses in these months, it would still meet customer load in dry years (assuming the current portfolio). In April, however, the energy surplus would be eliminated.



If instead the current BPA contract were amended to include only slice as described in Section 7 there would be higher surpluses in May and June, but not in April, as shown below.



The impacts on portfolio costs would be considerable because the Department would not have as much revenue from surplus energy sales to reduce its power costs. The following graph shows this impact in 2005 under three water conditions: dry, average and wet. The market prices assumed are: 50% higher than base in dry years, base level in average years and 50% below base in wet years. Impacts would be similar other years.



Impacts on portfolio costs range between 5% in a dry year and 15% in an average year. These impacts would be somewhat different with different price assumptions. For example, the closer the prices are to the base case the higher the impact in wetter years because of the larger amount of revenue from surplus energy sales foregone with the transmission constraint. With market prices at or above base levels, the resource

portfolio costs would remain below market even with the transmission constraint simulated here. With very low prices (50% below base), the portfolio would not be competitive regardless of the existence of this transmission constraint. Section 8 reviews the amounts of price reduction from base projections under which the portfolio would still be competitive. Assuming wet conditions (normally associated with low market prices) and no transmission constraints, City Light's resource portfolio would remain competitive with prices that are 34% or less below the base price forecast. If the transmission constraint described here was in effect, then market prices could only decline by 30% or less for the portfolio costs to be at or below market.

Appendix 1: Status of BPA Contract

Background

One of the major decisions evaluated in the 2000 Strategic Resource Assessment was entering into a new power contract with the Bonneville Power Administration (BPA). SCL's 1981 contract ended September 30, 2001, and BPA set a deadline of October 31, 2000 for its new subscription contracts to deliver power from October 2001 through September 30, 2011. By federal law, Seattle City Light has a preference right to purchase power from the federal dams on the Columbia River and its tributaries at cost. The 2000 SRA concluded that BPA power would be well below the cost of power purchased on the wholesale market. Ordinance 120068 enacted August 24, 2000 authorized City Light to sign a new BPA contract for as much power as BPA offered.

Changes Prior to Signing the Contract

Using City Light's load forecast and 1998 resource declaration, BPA calculated the Department's net requirement to be 493.8 aMW. BPA wanted to limit its sale of the new Slice product to not more than 2,000 aMW. Because BPA's customer utilities collectively asked for more than 2,000 aMW, BPA offered City Light a contract that was two-thirds Slice (330 aMW) and one-third Block (163.8 aMW). City Light signed this contract on October 25, 2000.

Rate Case Re-opened

In August 2000 BPA realized that its customers were requesting more power than BPA had assumed in its rate case completed in May 2000. Combined with the runaway electricity prices at the time, BPA estimated that it might need as much as a $5 billion rate increase. The contract allowed BPA to re-open its 2002-06 rate case to adjust for this problem, which it did in December 2000. City Light played a major role in crafting a solution with other customers which BPA accepted. The Slice product originally had included a fixed quantity and price for BPA augmenting its system output to serve its total commitments. BPA changed that fixed augmentation cost to the same Load-Based Cost Recovery Adjustment Clause (LB-CRAC) that it decide to apply to other products, including the Block portion of City Light's purchase, which would be re-calculated every six months. The Block would also be subject to a Safety Net CRAC that could increase the amount BPA could recover from its Financial Based CRAC if BPA forecasted a less than 50 percent probability of having enough cash to pays its bills.

Load Reduction Agreements Reduce LB CRAC

As soon as the mechanisms were in place for BPA to recover its augmentation costs, it asked its customers to reduce their demand on BPA to minimize the amount of surcharge it would have to impose. Seattle City Light agreed to the 10 percent reduction BPA requested, approximately 25 aMW from October 2001 through March 2002 and 75 aMW from April through September 2002. The reduction was from City Light's firm Slice and

the only compensation was to be forgiven the Slice rate for that amount of energy. Thanks to similar reductions by other customers, the first BPA LB-CRAC was only 46 percent instead of the 400 percent contemplated in the re-opened rate case. This surcharge fell to 49% for the second six months, but because of long-term deals BPA struck with some parties, it is expected to remain at about 30% for the next four years.

Conservation Funding for Reducing Block Purchase

As part of BPA's augmentation, it committed to acquiring 20 aMW of conservation per year during 2002-06. City Light is committed to acquiring 9 aMW annually (plus another 3 aMW expected through new codes). To reduce City Light's cash needs for conservation investments, BPA provided the Department nearly $28 million for two years of SCL's conservation program. In return, City Light agreed to reduce its BPA Block purchase by almost 10 aMW the first year and about 19 aMW the remaining nine years of the contract. In 2003, City Light will seek similar BPA funding for future years' conservation investments.

2003 Load Forecast and Revised Monthly Shape of Resource Declaration

Every August, Seattle City Light must provide BPA an updated load forecast for the upcoming federal contract year. The Department used the same forecast as contained in this report. In addition, City Light revised the monthly shape of its resources committed to serving load. The previous declared resource monthly shape assumed 1936-37 month-by-month water conditions, and the PNCA regulation that includes significant interchanges with other PNCA parties. Under the new PNCA agreement such interchanges are not likely to occur. Instead, City Light asked BPA to shape the 1936-37 annual quantity of firm energy by the monthly shape of the ten percent driest years (as discussed in Section 6).

Potential Additional Rate Surcharges 2003-06

In July BPA announced a new financial crisis for 2003-06 that may lead to higher rate surcharges. BPA is not controlling its spending as expected, and estimates exceeding its rate case levels by $570 million. In addition, in the re-opened rate case it agreed to increase cash payments to the Investor-Owned Utilities (IOU's). BPA had hoped to cover these costs with higher surplus sales, but market prices have fallen too much to support the anticipated level of revenue.

BPA plans to announce the FB CRAC will trigger October 1 on all non-Slice products, and has begun the Safety Net CRAC process to increase those rates even further. Although Slice is not subject to those surcharges, the spending increase and reduced fish credits would affect the Slice true up to BPA actual net requirement. City Light staff will participate actively in these issues.

Appendix 2: Status of Klamath Falls Contract: Renewal Choice

Background

In November 2000 City Light signed a power purchase contract with PacifiCorp Power Management (PPM) for the purchase of the power associated with 100 MW of capacity from the 500 MW Klamath Falls combined cycle combustion turbine. The contract will expire at the end of June 2006 unless City Light opts for an extension for an additional five-year term. The decision to extend this contract has to be communicated to PPM by the end of 2004.

This contract was included in the 2000 SRA resource options to help City Light meet its customer load under critical water conditions. In agreement with the Earth Day Resolution (April 2000), the greenhouse gas emissions from the utility's share of this project will be fully mitigated (see Section 11). Information on actual and projected costs of this contract are described in Sections 5 and 8 respectively.

The Klamath Falls contract only allows for limited flexibility. City Light choices are:

- take all or none of its share of the output, and it cannot choose not to take its share more than nine months out of the year
- take power only during heavy load hours, and if this choice is exercised, it can only be done three months out of the year

Should the Contract be Extended?

At the time the contract was signed City Light projected considerably higher customer load than it has been realized. Natural gas prices, as well as market energy prices, were very volatile and there were concerns about insufficient energy supply in the region. Today's situation is quite different. Energy prices have stabilized; there are some concerns about supply constraints in view of the withdrawals or postponement of projected energy plant developments, but customer load is anticipated to stay at relatively low levels for several years. Since actual load could be different from current projections, the decision on the Klamath Falls contract has to be based on the review of different potential scenarios.

Need to Meet Base Load

Klamath Falls is basically run as a resource to meet base load. The projections of the utility's load and resources suggest that under the Department's base load projections the current portfolio could meet customer demand under critical conditions in most months over most of the next decade. In October 2006, under the current BPA contract, BPA block purchases would increase by about 115 aMW on the average for the year. With the increase in BPA purchases as established in the current BPA contract, by the end of the forecast period there would be only three months with energy deficits of 130 aMW or more. If BPA purchases were not as in the current contract and instead were reduced to

reflect City Light's adjusted entitlement and composed of only slice purchases, as illustrated in Section 7, there would be several months with energy deficits. The extension of the Klamath Falls contract in its current form, however, would not be sufficient to fill in the energy deficits occurring with this change in the BPA contract. It appears, therefore, that the extension of the Klamath Falls contract is not likely to be the best option to meet base load. With the current portfolio, if updated customer load projections indicated higher customer demand than currently expected, the option of extending the Klamath Falls contract would have to be compared with that of acquiring other resources, especially renewable energy sources.

The Need for A Dispatchable Resource

Independently from projections of loads and resources, it may be argued that City Light needs a dispatchable resource in its portfolio. Dispatchability refers to the inherent flexibility of a resource that can be exercised under a variety of operating scenarios. This classification does not preclude the potential for operating such a resource as base-loaded, but the term typically refers to a more intermittent function. As a fundamental characteristic, a dispatchable resource may be started and stopped on short notice in response to short notification or hour-ahead type requirements. Once the need for the resource dissipates, the resource would typically be shut down. One scenario, for example, might entail a short-term need for a resource combined with a low gas market price, which may result in maintaining the "dispatchable" resource as a low-cost component to allow hydro storage enhancement. A thermal type dispatchable resource, such as a simple cycle combustion turbine (SCCT), may be used to offset an operating constraint caused by a low water condition, or may be used for pure peaking service to meet high load hour requirements. Typically, the SCCT is considered dispatchable due to its ability for short startup time, while combined cycle combustion turbine (CCCT) is more appropriately utilized as a base-load resource due to heat up and other long startup requirements associated with the steam cycle. Since Klamath Falls is a combined cycle combustion turbine (CCCT), it would be run less economically if it was not operated most hours in the year and it would be very difficult to change the contract to allow this resource to be used as dispatchable by City Light.

An owned simple cycle combustion turbine would provide more flexibility and, if located in the service territory, avoid the uncertainties associated with transmission availability. There are questions, however, about the risk associated with this kind of investment, impact on cashflows, and the utility's ability to recover its costs if market prices remain depressed for an extended time. A few years ago, the Department evaluated and issued an Environmental Impact Statement for a site on the Duwamish shore, considered the most appropriate site in the service territory. There are still questions about the cost, permitting and construction of the required extension of existing gas pipelines to reach the site. Before a decision is made, the utility must evaluate its requirements for a peaking resource. This will require the analysis of peak demand, peaking capability of the current portfolio and other options to meet peak demand. The analysis will have to be performed by the end of 2003 or in early 2004 for a combustion turbine to be built and available in 2006.

The Option to Firm Up Surplus Energy Sales

In general, a combustion turbine could be used to firm up surplus energy sales. City Light could estimate a level of surplus energy for the year and commit to deliver firm energy at that level to another utility. If actual water conditions are worse than expected, then the Department could run a thermal resource, such as a combustion turbine, to fill in the gaps resulting from a poorer than expected water year. This situation is close to that of using the output from a combustion turbine to fill in temporary energy gaps between customer load and resources. If sales are committed based on the expectation of average or better water conditions in an effort to maximize revenue, the turbine may be expected to be run more often than if sales are firmed assuming less than average water conditions. As an option to having a combustion turbine, a utility could go to the energy markets to buy the power needed to meet its sale commitments when its own generation falls short of expectations. Therefore, the choice of using a thermal resource to firm up surplus energy sales will be strongly influenced by the costs of this resource compared with expected market prices and the utility's risk aversion.

Appendix 3: Time-Based Rates and Automated Meter Reading

Background

Some utilities use time-based rates to encourage customers to use electricity efficiently and to shift use from high- to low-cost periods. City Light has time-based rates only for its largest customers.

Time-based Rate Definitions
Time-of-use pricing (TOU) varies retail electrical prices in a preset way within blocks of time. The price is the same on a high consumption cold morning as on a lower consumption mild morning.

Real-time pricing (RTP) changes retail prices for different hours based on the wholesale price of electricity, or on a combination of generation, transmission or distribution issues.

Summary Conclusions

A cost-benefit analysis of time-based rates, concludes:

- Time-based rates may offer opportunities for some large commercial/industrial customers to reduce costs and may be an appropriate strategic approach to help City Light and other Northwest utilities manage electricity costs and to some degree electricity supply. There may be more cost saving potential in reducing distribution system costs than in reducing power costs.
- Time-based rates may promote a small amount of consumption shift from peak to off-peak, by both commercial/industrial, and residential customers. Implementation costs significantly reduce this value.
- The wholesale peak to off-peak price differential is about $8/Mwh. The differential is how utilities value shifted load. The impacts on distribution system planning and benefits that might accrue from the potential deferral of costs may be higher, especially in the case of already congested local distribution systems.
- Time-based rates are not beneficial for residential customer given the infrastructure costs that could total $50-100 million. A residential customer may be able to shift only about 5%, or 500+ kWh/year. The value of this shifted energy is less than $5/year per residential customer.
- For City Light, the strategy that has the potential to maximize the value of electricity appears to be a combination of the following:
  --Continued emphasis on incentive-based conservation programs
  --Public appeals to curtail consumption during an energy crisis.
  - Time-based pricing for large commercial and industrial customers.
- Regional benefits from time-based rates could accrue from the potential leveling of price spikes, additional electricity available for peak periods, relief of transmission systems during crisis, and additional revenue from surplus sales. However, load reductions can not be counted on in advance, benefits may not materialize and new generating resources and transmission capacity may still be needed.

What is Needed to Implement Time-of-Use or Real-Time Pricing?

Expensive metering and communications equipment ($2000-3000 per installation) is necessary at large customer facilities. Callable meters have been installed at City Light's large customers' facilities. Residential metering to enable TOU/RTP can be $175-275 meter. The total metering, communications and billing system costs could total $50-100 million.

Targeting Larger Business Customers

City Light's largest customers have simple peak and off-peak rates.[17] They represent 1% of customers but 27% of load. While overall load growth has declined since 1981 the commercial sector grew 8.1 aMW annually and industrial/governmental sector grew 2.3 aMW annually. Many customers participated in conservation programs when incentives reduced capital outlay costs and provided short payback. They also have agreed to curtail approximately 75 MW, with short notice, in response to emergencies.

Customers also reduced consumption by 5-10% when concerned about blackouts. Large rate increases, i.e., Seattle's 58% surcharge, also are an inducement to conserve. However, the blackout warnings, media coverage and rate increases were blunt instruments that did little for the power manager who had to balance hourly loads with hourly supply. Additionally, time-based rates may have minimal impact on the total amount of resources needed, only perhaps on the kind and time availability of resources needed in the region. A good public information campaign combined with conservation incentives, and internet-based daily price postings, may be sufficient to induce large customers to shift load. Prearranged plans can ensure, with a few telephone calls, a rapid, large, and geographically specific reduction in system load in crisis situations.

If a large customer could be encouraged through rate design to shift 1% of consumption from peak to off-peak the utility's $2000-3000 meter investment is paid for in three to five years. A 1% shift by a typical large customer (or approximately 70 MWh/customer annually) could be worth as much as $575/year per typical large customer. Using all high demand and large general service forecasted customer load for 2002, a 1% shift from peak to off-peak, would give a $140,000/year market value.

Encouraging large customers to shift peak usage also may be of value to the general operation and integrity of the "stressed" downtown network distribution system. A time-of-use rate induced 1% shift, or 2 to 3 MW, could be of considerable value to the network's reliability, particularly if the utility could manage the timing of the shift. The unknown factor is whether large commercial and industrial customers can shift consumption and/or demand. That may be a factor related in part to the rate design and the size of the differential pricing strategy adopted.

[17] KW and kWH used between 6 a.m. and 10 p.m., Monday through Saturday, excluding major holidays.

Can Time-based Rates be Justified for Residential Customers?

The amount and value of electricity that a residential customer can shift is small relative to the $175-275 cost of an interval meter. City Light customers already use 43% of electricity in broadly defined off-peak hours. The peak period represents 67% of the hours in a week, hours when residential customers are most likely to use electricity. Table 1 estimates that 5% of residential electricity could be shifted from peak to off peak. Space heating, clothes washing/drying, water heating are uses that may be shifted. Lighting, refrigeration and cooking are less flexible. About 555 kWh or five percent of a heating customer's electricity use could be shifted. The annual value of a 555 kWh reduction is about $4.25 per year when valued at the differential between the forecasted peak and off peak market prices ($7.67 per MWh) for 2003. A non-electric heating customer's ability to shift end-use consumption is negligible (<1%).

Table 1--Estimate of Possible Residential Energy Shift

(1) Average Residential Heat Customer Use by End Use (1998)	(2) % of total End Use	(3) Potential for shifting electricity	(4) Annual Amount of Shift from Peak to Off Peak (kWh) (10,902 kWh* Col(1) * Col(2))
Space Heat	50%	(5%)	272 kWh
ClothesWash/Drying/Dishw.	5%	(25%)	136
Water Heat	20%	(20%)	109
Other	7%	(5%)	38
Light	4%	(0%)	0
Refrigeration	8%	(0%)	0
Cooking	6	(0%)	0
Weighted % reduction	N/A	5%	N/A
Estimate of Annual Value	$0.00767	X 555 kWh	=$4.25 annual value

No residential customer could save enough money to pay back the cost of a $175 interval meter over the meter's10-year useful life. If customers could shift 25% of use to off-peak, payback could be in 8+ years (Table 2).

Table 2--Simple Payback for $175 Meter Investment

Payback with 5% Shift	Payback with 10% Shift	Payback with 25% Shift
$175/$4.25 = 41 yrs	$175/$8.50 = 20 yrs	$175/$21.25= 8 yrs

Puget Sound Energy Time-of-Use Pilot

First-year results reported by Puget Sound Energy (PSE) for its time-of-use pilot show a 5% shift by residential customers from peak to off-peak economy periods (350-500 kWh range). The pilot also reportedly achieved an additional 1% conservation benefit. Washington Utility and Transportation Commission (WUTC) staff had concerns about

the program, given the $1.26/month/customer metering, data storage, billing costs, as compared to the value of the peak vs. off-peak price differential. WUTC estimated that the differential would need to be $30-43/Mwh for the program to break even. (Example: $1.26/(29Kwh/1000Kwh)=$43/Mwh).

Given that the peak- off-peak mid-Columbia index differential for 2003 is estimated to be under $8/Mwh WUTC analysis indicated that under current market conditions virtually all PSE customers would be better off returning to the flat rate option. WUTC allowed the pilot to continue if participants pay $1/month for the implementation costs. The settlement stipulates that participants be periodically informed whether they would be better off to remain on the program or return to a flat rate. Metering costs attributable to the pilot are a small portion of the costs incurred when PSE installed its fixed radio network metering system.

Northwest and Other Parts of the United States

Utilities with different load profiles, resources, weather, housing stock, heating type, etc. have shown shifts from peak periods ranging from 4 to 23%. Many of the utilities were not hydro-based and may have achieved large shifts by defining peak differently, and more narrowly. Their benefits may depend on foregoing running higher-priced, less efficient generating plants, which under 'base-load" situations would not be run.

In What Circumstances do TOU/RTP Make Sense?

According to the Chartwell Automated Meter Reading Report (1999)[18] 46 of 100 utilities interviewed installed some automated meter reading, though generally not on a system-wide basis. Thirty-three cited cost savings and 25 cited customer service considerations as reasons for these installations.

Table 3 from the Cambridge Energy Research Association includes potential benefits referenced by utilities. The 1999 report estimated that benefits from residential installations could total $7-9 per meter/month. This estimate includes meter reading savings, but does not include time-related rate-induced electricity shifts. A preliminary City Light study confirmed some CERA data points; however, some City Light savings were lower, and others were not thoroughly studied. Ongoing transmission and distribution system management benefits, in particular, may offer the greatest potential for benefits, and should be further analyzed.

[18] Chartwell is an independent energy and utility information consulting service based in Atlanta, Ga.

Table 3--Potential Automated Metering Benefits
(2002 Dollars per Meter per Month)

Reduce Meter Reading Cost $0.90+	Reduce uncollectibles $0.08
Reduce Probl./Special Reads$0.08	Improve accounting $0.04
Improve Meter Accuracy $0.50	Call Ctr. Cost Reductions $0.24
Reduce Meter Testing $0.07	Improve Distrib. Mgmt. $0.70
Elimination of Locks $0.07	Demand-side Mgmt. $0.71
Reduce on-site connects/disconnects, primarily high churn $0.04-$0.08	Reduce Outage Report Time $0.02
Reduce estimated bills $0.04+	Improve Outage Mgmt. $0.31
Reduce electricity theft $0.10-$3.33	Reduce Revenue-Lost Outages $0.08
Improve read-to-bill time $0.10	Reduce employee injuries --
Improve bill-to-pay time $0.45	TOTAL=$7-9/meter/month (est.)

If such benefit estimates are applicable to City Light, then the cost of a residential interval meter could be justified in a relatively short 2-3 years, especially if these benefits are combined with the value of shifted energy that might be achieved. However, the infrastructure costs would have to be factored into a cost study and would certainly change the analysis.

Summary

Time-based rates will be examined in the normal rate review process; however, their application to other than the largest commercial/industrial customers is unlikely given the infrastructure costs. An analysis must include power systems management, and energy marketing issues related to time-based pricing opportunities; field service and T&D system operations, customer service, and back-office and administrative solutions. Unless designed, communicated and billed properly, time-based rates can engender customer confusion and complaints. The relatively low $7-9/Mwh cost differential between peak and off-peak periods makes it difficult to realize reasonable infrastructure payback periods. Other strategies, particularly conservation and customer education campaigns, combined with contractual arrangements and public appeals to shed load during emergencies or during high-priced electricity markets, may be more effective, and less costly solutions to the region's energy independence and security.

Appendix 4: Boundary Relicensing

Background

The Boundary Hydroelectric Project is Seattle City Light's largest generation resource. The Project was completed in 1967, expanded in 1986, and meets 30 to 45 percent of Seattle's annual needs for electricity. Because Boundary is Seattle City Light's most economical generation resource, successful relicensing of the Project will help maintain City Light's overall low cost power supply. Boundary is also a reliable, renewable resource.

Status

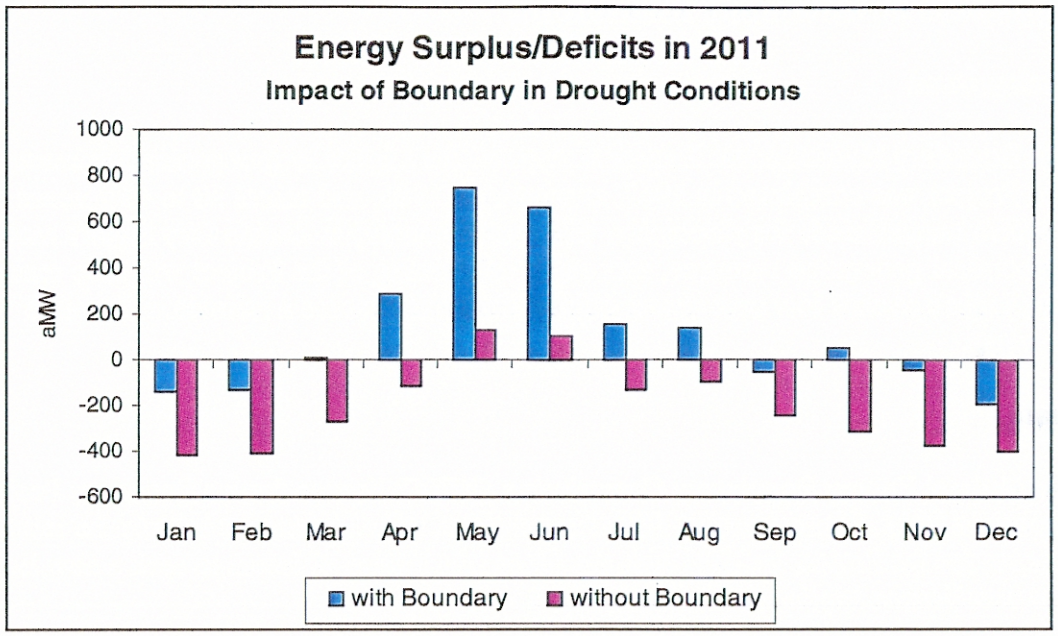
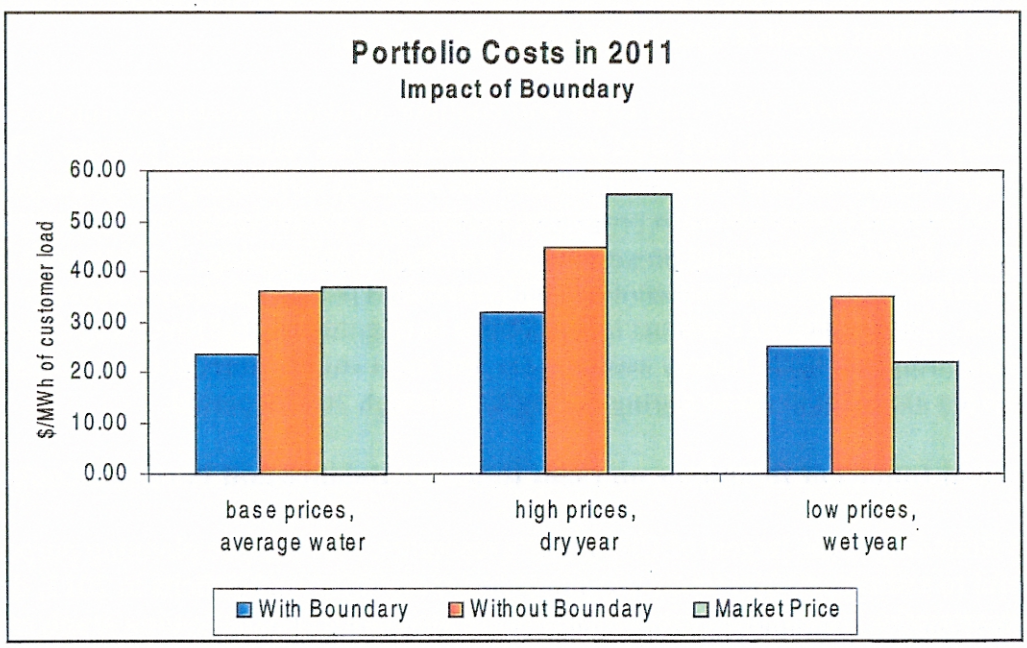
The Federal Energy Regulatory Commission (FERC) license for the Boundary Project expires in 2011. Under current FERC regulations, City Light must initiate the relicensing process for the Project in 2006 with the filing of a Notice of Intent to seek a new license. The new license application is due in 2009.

City Light has formed an Oversight Committee comprised of the deputy superintendents from Generation and Finance, the Director of Strategic Planning, Environment and Safety and staff from these divisions, and a representative from the City Attorney's office. A cross-division Relicensing Team with staff from Strategic Planning, Generation and Power Management Branches, and Environment & Safety has also been created. This Team will focus on internal organization, strategic planning, and relationship building with the pertinent resource agencies and key stakeholders.

During the years 2002-2004, City Light will continue to identify and track important regulatory, environmental, and legal issues important to the relicensing process. The Oversight Committee and Relicensing Team will focus on developing and maintaining effective internal communication programs; monitoring federal legislative and regulatory changes to FERC's relicensing process; team training on relicensing; meeting with FERC; and participation with local stakeholders and watershed planning/salmon recovery activities. City Light will continue to participate in ongoing studies involving dissolved gas monitoring and basic fishery assessments, but most study efforts in the relicensing process are expected to occur during the 2004/5 through 2007/8 period.

Estimated Impact of Boundary on Load Resource Balance and Portfolio Costs

Since Boundary is the largest of City Light's resources, for resource planning purposes it is useful to estimate its impact on potential energy surpluses and deficits in 2011, despite the uncertainties surrounding projections for the long term. The following graph assumes the base forecast of load and drought conditions. As the graph indicates, without the generation from Boundary City Light would have large monthly energy deficits in all months except late spring and early summer.



The impacts on portfolio costs would be significant, as illustrated in the following graph, which shows projected 2011 portfolio costs per MWh of customer load under average water conditions and base market prices, wet conditions and low prices (34% below base projections) and drought and high prices (50% above base projections).