# Opportunity Costs: Irrigation vs. Hydropower

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## Abstract

An analysis is done of the costs imposed on participants in the electricity market arising from irrigation diversions from the Columbia River. The hypotheses analyzed are: a) that electricity consumers' welfare is not affected by irrigation diversions, b) that hydropower loss estimates derived using time and location specific data do not differ from those derived using average data, c) that water year does not affect welfare losses, d) that demand elasticity does not affect welfare losses, e) that farmer repayments do not affect welfare losses, and f) that interruption of water in critical flow years does not affect welfare losses. Electricity consumers are found to lose welfare when diversions are increased. Considering a potential diversion in central Washington, the annual loss to electricity consumers is in excess of $100 per acre developed. When the government delivers water to farmers' fields, this loss exceeds $200 per acre. In addition, the welfare loss estimates are found to be sensitive to the amount diverters pay of pumping costs and the potential interruption of diversions. The results under the diversion interruption simulation show potential for reducing the tradeoffs between irrigation development and hydroelectric power generation.

## Foreword

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# Introduction

The Columbia River and its tributaries have been valuable resources in the development of the Pacific Northwest. As population and economic growth continue, tradeoffs in the usages of Columbia River resources are becoming necessary. Water is no longer a surplus commodity; rather, for the most part, it is fully allocated among usages. At the present time, major uses of river water include hydroelectric generation, irrigation, transportation, fisheries support, and recreation. Additionally, the dam system is used to control flooding. Cases exist where future increases in one use will diminish the activity under other uses. For example, increasing water in fish ladders reduces the amount of hydroelectric power that can be generated.

In recent years, situations have arisen which have important implications for the allocation of Columbia River water. The proposed irrigation developments in Eastern Washington, Eastern Oregon, and Idaho are an example. Another is the continuing escalation in electricity costs arising as thermal plants are constructed. A clear example of tradeoffs involves future irrigation development as it competes with hydroelectric power generation. Removal of water to develop irrigation projects results in lost hydroelectric power and a consequent increase in the need for thermal power (Whittlesey and Gibbs; Whittlesey _et al._).

The essential question is: How can water be allocated to best serve society given the options available and current legal setting? This study focuses on one dimension of this question, namely the tradeoff between water allocated to irrigation versus water remaining instream providing hydroelectric generation. The question is addressed in terms of the resultant welfare of society.

Overall perspectives on both the agricultural and electricity portions of the problem have been provided by Martin and Whittlesey _et al._, respectively. This study focuses on the electricity side only. Previous authors have focused on both the specific problem addressed here (Whittlesey and Gibbs, Whittlesey _et al._) and on the problem in other settings (e.g., Gisser _et al._). This particular study differs from the previous Whittlesey and associates studies in five methodological aspects:

1) The previous studies have based their analyses on critical flow years. This study considers the probability distribution of flows using data on 40 water years (1929-1968).

2) The previous studies have assumed that consumers do not alter electricity consumption regardless of price changes. This study considers both constant consumption and alternative degrees of price responsiveness (demand elasticity).

3) Previous studies have utilized data on power lost due to water diversion which did not depend on dams, water year or time of diversion. This study uses estimates which depend on all these factors.

4) This study examines alternative assumptions regarding irrigator repayment for power used in diverting (pumping) water.

5) Whittlesey *et al*. maintained the irrigation diversion at the same level in all years. This study investigates a situation where irrigation diversions may be interrupted in low river water years.

Thus, this study investigates the consequences of irrigation diversions for the electricity consumers, paralleling the studies of Whittlesey and associates while using different assumptions.

## Hypotheses

The fundamental null hypothesis is that there is no economic loss to electricity consumers and those paying for pumping when irrigation diversions increase. Whittlesey *et al*. have already analyzed this hypothesis and shown it to be false; however, we restate and test it for completeness of analysis.

Several secondary hypotheses are also examined. The secondary null hypotheses are (a) that the power lost estimates do not differ between this and the Whittlesey _et al_. study; equivalently, that use of the average figure for power lost (0.87 kwh/acre-ft/ft) does not yield results any different from the dam, month and water year specific data; (b) that society's loss is not affected by choice of water year, (c) that society's loss is not affected by demand elasticity, (d) that society's loss is not affected by the share of pumping energy that diverters pay for, and (e) that society's loss is not affected by the interruptible water rights simulation.

## Background

This section delves into each of the above hypotheses providing background on the secondary hypotheses. Background is also given on the electricity pricing assumptions adopted.

### Estimates of Power Lost

Whittlesey _et al_. develop hydropower loss estimates using an assumption that 0.87 kilowatt hours are generated when an acre foot of water falls one foot. Their estimate of total power lost involved multiplying the acre feet of water diverted, adjusted for return flows by 0.87. Data obtained from the Bonneville Power Administration Hydroelectric Power Planning Program (the BPA hydro regulation model or hydro) indicate that 0.87, while in the range of the data, is not necessarily representative of diversion conditions. The kilowatt hours per acre foot per foot of fall (kwh/acre-ft/ft) depends upon dam, month, and water year of diversion. For example, (a) the average generation figures per kwh vary from 1.1 to 0.75 kwh/acre-ft/ft across the main stem Columbia dams; (b) during certain peak flow months, the marginal electricity generated by the hydroelectric system is zero, as there is more water (spill) than generating capacity; (c) analyzing the Grand Coulee Dam (GCD) data, one finds a 40-year average generation of 0.795 kwh/acre-ft/ft with a coefficient of variation of 11.1 percent; (d) analyzing the water year induced fluctuations in the GCD data, kwh/acre-ft/ft varies from as small as 0.69 to as large as 0.85; simultaneously, the coefficient of variation ranges from as small as 4.8 percent to as large as 42.6 percent (depending upon the amount of spill); (e) analyzing monthly GCD data, average generation varies from a low of 0.63 kwh/acre-ft/ft in May to a high of 0.87 kwh/acre-ft/ft in September, and also exhibits large changes in the coefficient of variation (May being 31 percent, September being 0.2 percent). Thus, it would appear advantageous to use data accounting for dam, month and water year.

Water Year Choice - Flow Uncertainty

Columbia River streamflow variation has been quite substantial (see Figure 1). Over the thirty-year period from 1929 to 1958, the yearly discharge at the lowest dam on the river (Bonneville Dam) averaged 177,421 cubic feet per second (Pacific Northwest River Basins Commission, 1970). The distribution of flows is fairly wide, exhibiting a coefficient of variation of 0.19. The implications for electricity production of this variation can be significant. Figure 2 shows the fluctuation in hydroelectric generation resulting from the Bonneville Power Administration (BPA) hydro model results used as a source of data within this study.[1/] Probabilities of selected hydroelectric generation levels computed from the BPA hydro model results are given in Table 1.

Variation in water flows alter the regional cost of electricity production. When water levels vary, the electricity generation varies between hydroelectric and thermal sources. This has substantial cost implications, since hydropower costs are approximately 10 percent of thermal power costs (Northwest Power Planning Council - NPPC). Water diversions in low flow years can reduce total generating capacity below demand levels. Consequently, new thermal generating plants may need to be constructed, increasing electricity rates. Consequently, the often made assumption is that only critical flow years should be

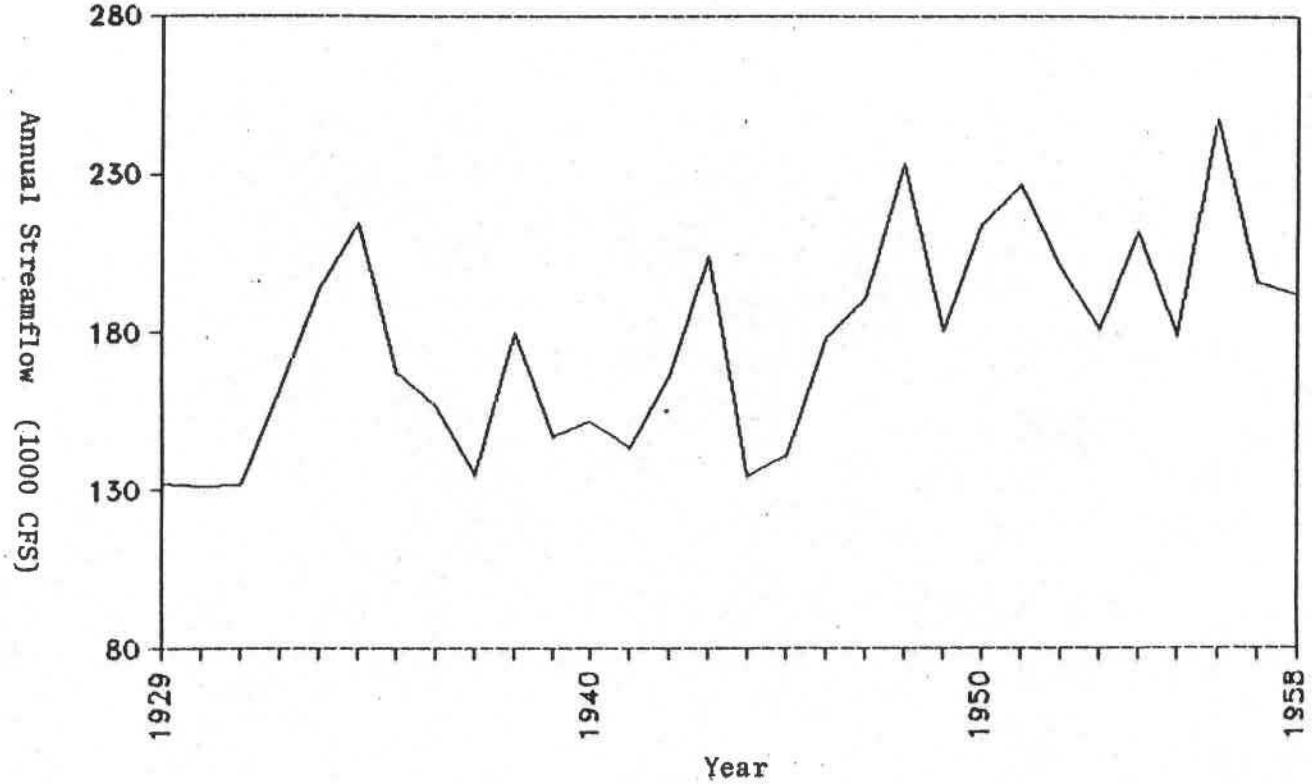



Figure 1. Annual streamflow – Bonneville Dam.

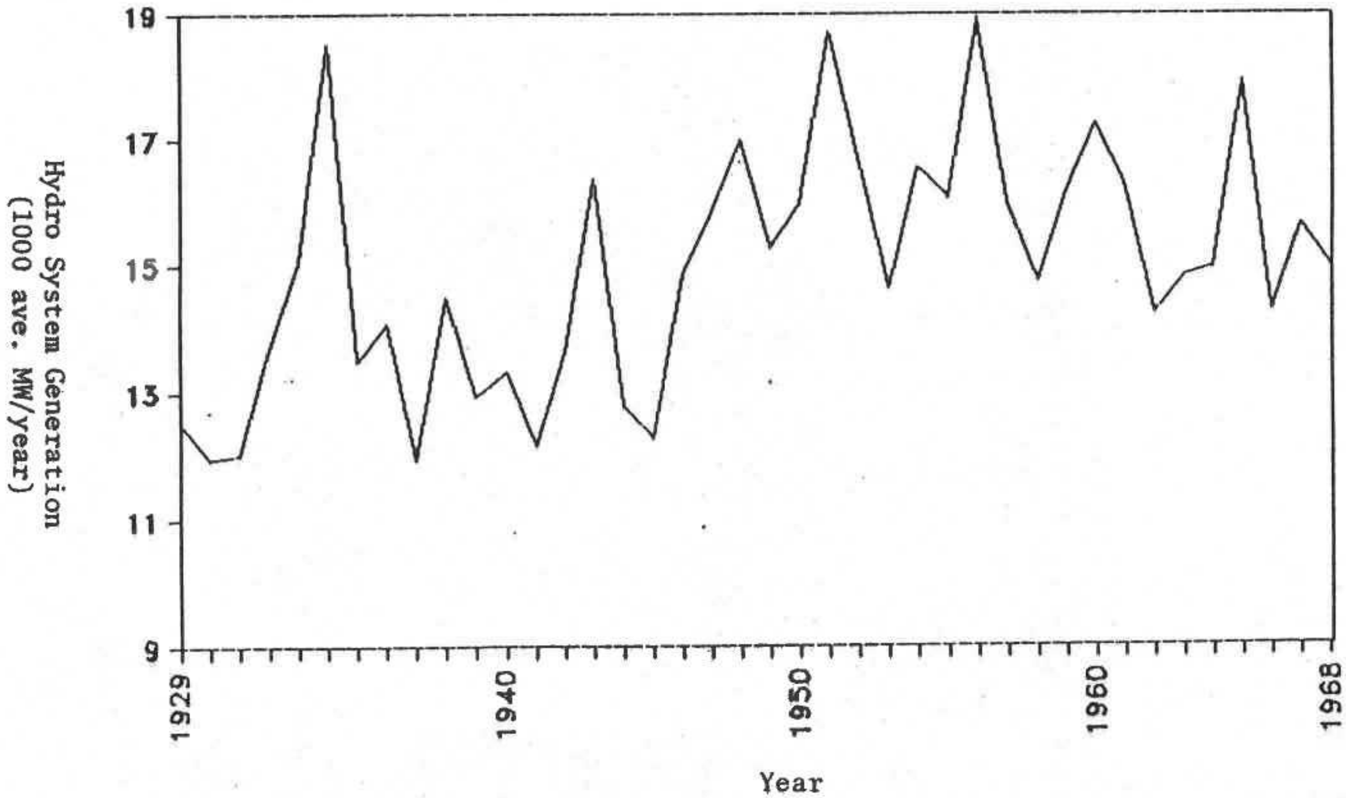



Figure 2. Hydro system generation.

Table 1. Hydropower Generation Probabilities[a]

| Midpoint Hydro Power Generation Level (1000 MWh) b/ | Probability (%) |
|---|---|
| 105,120 | 15 |
| 113,880 | 10 |
| 122,640 | 13 |
| 131,400 | 23 |
| 140,600 | 20 |
| 148,920 | 10 |
| 157,680 | 3 |
| 166,440 | 8 |

a/ The hydropower generation figures arise from a BPA simulation using present dam system under 1983 withdrawal levels. The simulation is based on water years that occurred from 1929 to 1968. A more detailed distribution is provided in Table 3.

b/ The units of this column are thousand megawatt hours.

examined. However, it is possible that substantially lower costs are encountered in other years. Thus, we examine the welfare consequences of diversions arising under the full observed distribution of water years.

Price Responsiveness of Demand - Demand Elasticity

Until recently, Pacific Northwest electricity demand projections have utilized a base plus growth rate methodology. However, with the recent rate increases stimulated by increasing new facility costs (particularly those associated with the Washington Public Power Supply System power plants), electricity consumption growth rates have fallen considerably. This demonstrates that consumer demand is responsive to price. Whittlesey et al.'s estimates are based on an assumption that demand is not responsive to price. Rather, Whittlesey et al. assume that all potential hydroelectric power diverted by agriculture plus pumping energy use must be fully replaced by thermal generation. However, consumers might well reduce quantities of electricity consumed when diversions cause electricity rate increases. The quantity of reduced consumption would depend on the degree of demand responsiveness and the price, quantity supply relationship. Several different estimates of demand responsiveness have been developed. Charles River Associates have estimated the regional elasticity (percentage change in quantity per percentage change in price) of demand for electricity at -0 .1, the Department of Energy has estimated -0.54, and the Electric Power Research Institute and BPA (1983) have suggested elasticities of -1.0. Demand functions with these elasticities would lead to different welfare loss estimates than would an assumption of no demand response. However, one should note that the amount of power being diverted by the proposed irrigation developments is relatively small with respect to total consumption. Thus, the price effect could be small. This empirical issue is examined below.

Diverter Pumping Payment

A major issue in developing welfare impacts of irrigation diversions involves the amount of pumping electricity paid for by irrigation diverters. Many irrigation projects involve government delivery of water to canals on the project. This implies that the government pays for pumping the water from the river to the base elevation of the farming activities. Government funds transfers from, say, the Bureau of Reclamation to BPA paying for this energy generally occur at a lower electricity rate than other sales. Further, the projects do not generally include a provision for the government to fully recover pumping energy expenditures requiring general tax funds to be used. Thus, a portion of the pumping cost is borne by society as a whole and/or electricity consumers. On the other hand, a number of irrigation developments have been established in which irrigators pay the entire price at full electricity rates, including the lift cost from the river and the delivery cost onto their land. The particular arrangement relevant to any project depends upon the agencies and institutional arrangements involved. Project specific pumping payment arrangements are not studied at length here. Rather, three simplifying assumptions were used: 1) the water diverters pay none of the pumping cost, which approximates a project where the water is delivered to the farmers' fields and used in flood irrigation, with electricity consumers and/or some government agency paying the pumping bill; 2) irrigators pay for 100 feet of the lift, which approximates the cases where farmers pay the pressurization requirements to run the water through sprinklers, paying nothing for delivery to their farm and/or payment at a subsidized rate; and 3) irrigators paying all pumping costs.

Interruptible Power

Fluctuating hydroelectric potential has led to an interruptible electricity delivery policy in the nonagricultural parts of the economy (Norwood, p. 1361). For example, aluminum plants along the Columbia River receive some interruptible power. Under current law (BPA, 1980), consumptive uses of the river system, such as irrigation, have priority over instream uses such as electricity generation. Thus, hydropower generation may be preempted by irrigation diversions. Consequently, increased thermal generation could be required, with the increased costs borne by electricity consumers when irrigation diversions increase. Electricity consumers may be willing to pay diverters in order to have the water available for electricity production, particularly in low water years. A case is considered below where there are interruptible water diversions. Under this case, irrigation water is only diverted when water use does not require additional thermal generation facilities. Water is not used in years when the converse is true. The peak load pricing literature (i.e., Joskow) suggests that under such a situation, pricing should be based on the marginal (operating) cost of generating power as opposed to operating cost plus amortized facility construction costs. The welfare implications of this type of interruptible water regime are studied.

## Electricity Pricing

Virtually all electricity utilities base their pricing on average costs. The assumption of average cost pricing is adopted in this study. Thus, the price paid by consumers equals the summed fixed costs plus hydroelectric operating costs plus thermal operating costs divided by the sum of electric consumption by consumers plus the proportion of pumping energy paid for by diverters times the quantity of pumping energy (see equation 2, in the economic submodel section below). Two pricing models are utilized, each containing different assumptions on the fixed costs of new construction. The first model assumes that the thermal marginal cost equals amortized capacity costs plus operating costs (Pricing Model 1). The second model incorporates the maximum amount of thermal power constructed as a fixed cost, then sets the thermal marginal cost at the thermal operating cost (Pricing Model 2) in accordance with the peak load pricing literature (Joskow). Model 2 is more accurate than model 1, since model 1 allows a different amount of installed capacity to be paid for in each flow year. Model 2 holds the installed capacity cost constant across all flow years. However, model 2 is more difficult to implement, especially when the quantity of electricity consumed depends on the rate. Models 1 and 2 appear to upper and lower bound the pricing options. The sensitivity of the results to these models will be examined.

## Model Development

The analysis of these hypotheses involves the development of two submodels. The first submodel predicts the physical consequences of irrigation development. The second submodel derives estimates of the economic consequences of irrigation diversions given the physical results.

Physical Submodel

Increased irrigation diversions would likely lead to a change in operating policies on the river system. The so-called "RULE" curves (Miller and Halter) utilized to operate dams would likely be adjusted to supply water for the additional irrigation. Bonneville Power Administration uses a simulation model to study and generate such issues (e.g., see the Pacific Northwest Utilities Conference Committee reference). When this study was first conceived, the authors approached BPA hoping to run the simulation model under different irrigation diversions. It turned out that the model could not be obtained, and if BPA did the runs, including rule curve tuning to account for irrigation diversions, then each project analysis would take more than three person weeks of BPA staff time. Thus, for practical purposes use of the model was judged impossible. In addition, it was pointed out that the diversions to be studied were quite small relative to the total simulated flow. However, we were informed that the simulation model output contained what are known as H/K factors, which give the marginal generation of hydropower per unit of water by dam, water year and month. Given the relatively small change in water flow, it was suggested that we use these factors to develop estimates of potential hydroelectricity loss.[2/]

H/K factors were obtained for water years 1929-1968 for 14 subperiods within each year, for each main stem Columbia and Snake River Dam. These H/K's are based on an assumption of 1983 status of the river - withdrawals, dams, navigation use, etc. Consequently, the basic equation for the amount of electricity lost due to diverted water involves the H/K factor times the change in flow caused by the irrigation diversion. The change in flow arises from the physical water use involved with a particular irrigation project as estimated in a particular month. All downstream dams were assumed to lose this water. Return flow adjustments were also applied. Thus, the hydropower generating loss model is given by:

$$(1) \quad GENLOS_y = \sum_{m}\sum_{d}(HK_{myd})\,(MOPROP_m)\,[(D_{1d})\,(DIVER) - \sum_{q}(D_{2dq})\,(RETURN_q)] * 8760$$

where:

$GENLOS_y$ = generating loss at the streamflow associated with water year y [megawatt hours (mwh) per year] (y = 1929...1968),

$HK_{myd}$ = H/K for dam d and water year y in month m [mwh per cubic foot-second (mwh/cfs)] (d = 1...19, y = 1929...1968, m = 1...14),

$MOPROP_m$ = the proportion of the yearly withdrawal in month m (m = 1...14) assumed also to be monthly distribution of return flows,

$D_{1d}$ = One if dam d is downstream from point of withdrawal, zero otherwise,

DIVER = amount of withdrawal by the diversion (d = 1...19) [cfs],

$D_{2dq}$ = One if dam d is downstream from dam q, zero otherwise,

$RETURN_q$ = return flow from diversion initially entering dam q (d = 1...19) [cfs],

8760 = number of hours in a year.

The Economic Submodel

Hydroelectric power is a cheaper source of power than thermal power. Thus, it is assumed that hydroelectric power would be utilized first and thermal power second. Consequently, our economic model assumes that as much hydropower be used as needed and/or available. Thermal power is then added on until demand is met. The resultant average cost pricing model is:

$$(2)\quad PI_y = \frac{(FC + CH\ H_y + CN\ NI_y)}{QF + d\ PUMP}$$

where:

$PI_y$ = Average price of electricity in water year y/[mills/mwh],

FC = system fixed costs [mills]. The fixed costs differ depending on the pricing model assumed,

CH = cost of hydroelectric generation [mills/mwh],

$H_y$ = net amount of hydropower produced in water year y given streamflow and withdrawals which equals the minimum of QF + PUMP and the hydro power generating capacity adjusted for generating loss [$GENLOS_y$] in [mwh],

$GENLOS_y$ = generating loss in water year y [mwh],

CN = average amortized cost of nonhydro resources [mills/mwh]. This differs depending on the pricing model assumed,

$NI_y$ = net amount of nonhydropower produced in year y which equals the minimum of 0 and QF + PUMP - $H_y$ [mwh],

QF = electricity demand in water year y [mwh] which is either fixed or a linear function of price ($QF_y = a + b\ P_y$),

d = the proportion of pumping energy paid for by diverters,

PUMP = the pumping energy used by farmers in diverting water to cropland [mwh].

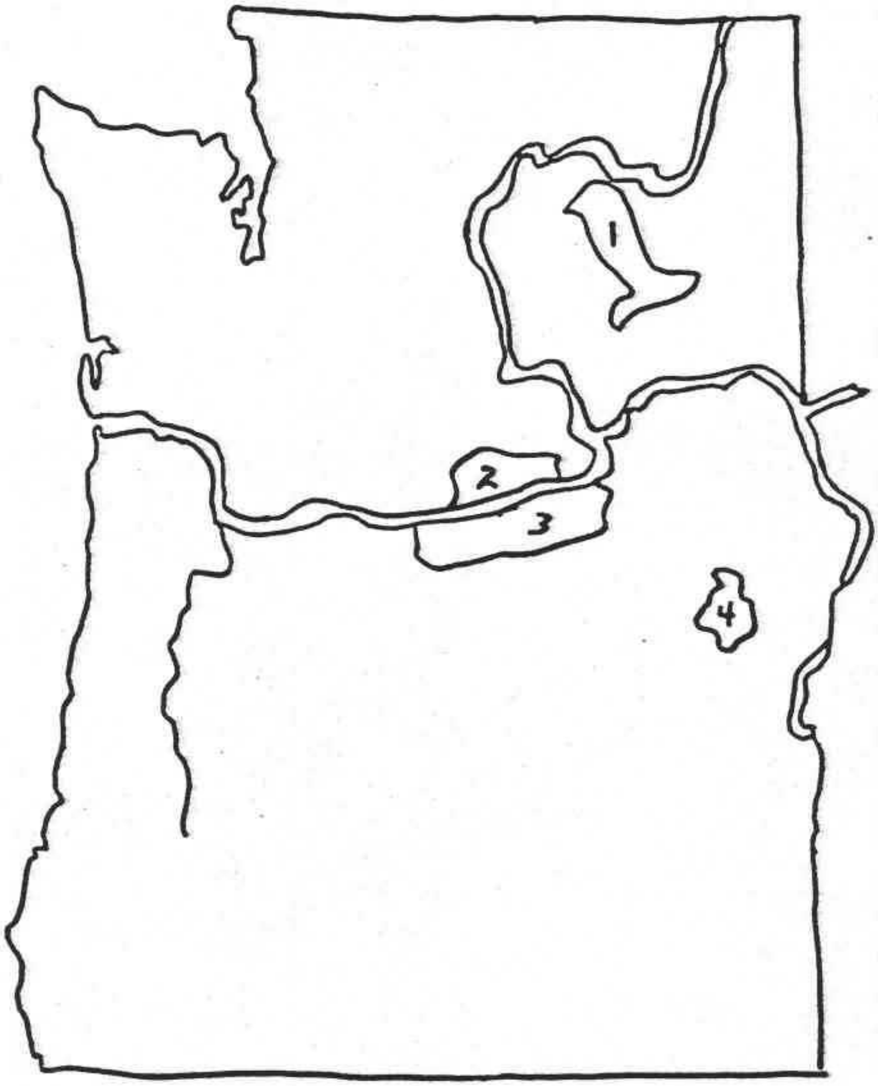
This formula is used to generate price changes. When demand is assumed to be price responsive, then this formula is simultaneously solved with a linear demand curve (P = a + bQ) to determine QF. The linear demand curve passes through the point described by the 1983 price (P) and quantity (Q) of electricity consumed, exhibiting whichever of the elasticity (E) estimates given above is assumed at that point [b = EP/Q; a= P(1-E)]. In the no demand response/inelastic case, the price is simply calculated given the quantity demanded.

The economic submodel is run with and without diversions. In turn, electricity consumers' surplus is calculated for each water year using the Hicks formula (as explained in Brokken et al.). Thus, the loss estimate is the change in price times the average quantity demanded (not including pumping electricity use for the new diversions).

This surplus is electricity consumers' surplus only if all residual pumping costs not paid by farmers are passed on to electricity consumers. If transfer payments go on in the government, then the welfare loss is borne both by electricity consumers' and by those paying for pumping. In this case, the loss estimate is only strictly accurate for the inelastic case, since the pricing model does not consider a government transfer payment.

## Design of Case Analysis -Data Development

There are many possible sites for irrigation development in the Pacific Northwest. Whittlesey _et al_. identified forty-four. This study examines four of the Whittlesey _et al_. sites: East High, Horse Heaven Hills I (HHH), Umatilla II, and Grande Ronde (see Figure 3 for locations). They were chosen based on size of development area, cumulative head of elevation from sea level of the dam diverted from, and pumping total dynamic head (TDH). The larger the development area, the greater the amount of water required and the larger the potential energy loss. The higher (with respect to cumulative head) the dam withdrawn from, the greater hydropower loss per unit of water diverted. Pumping TDH relates to the pump energy required to deliver river water to cropland. The greater the TDH, the more electricity used in pumping. Summary characteristics of the projects are given in Table 2.




LEGEND:

1 - EAST HIGH
2 - HORSE HEAVEN HILLS
3 - UMATILLA
4 - GRANDE RONDE

Figure 3. Development Areas.

(After Whittlesey et al, 1981)

Table 2. Characteristics of Development Areas.

| Area | State(s) | Acres | Pump Lift (ft.) | Diversions a/ | Return Flows a/ | Net Depletion a/ | Dam of Diversion | Dam(s) of Return Flow | Pumping Loss b/ |
|---|---|---|---|---|---|---|---|---|---|
| East High | Washington | 310,000 | 690 | 1,242,067 | 447,175 | 794,892 | Grand Coulee (1167) c/ | McNary (50%) Priest Rapids (50%) | 866 |
| Horse Heaven Hills | Washington | 70,000 | 865 | 218,167 | 21,817 | 196,350 | McNary (316) | John Day | 226 |
| Umatilla II | Oregon | 40,000 | 900 | 109,300 | 10,933 | 98,367 | John Day (242) | John Day | 118 |
| Grande Ronde | Oregon | 38,000 | 380 | 74,068 | 7,410 | 66,658 | Lower Granite (98) | Lower Granite | 43 |
| Combined Areas | Washington, Oregon | 458,000 | --- | 1,643,602 | 487,335 | 1,156,267 | --- | --- | 1253 |

a/ Acre - feet per year.

b/ 1000 megawatt hours per year. This figure is the amount of electricity required to pump the indicated diversion.

c/ The figure in parentheses is the cumulative feet of fall to the river mouth.

Source: Whittlesey <u>et al</u>., 1981.

The data for the model are drawn from a number of sources. Whittlesey *et al*. give the data utilized for diversions, return flows, sizes of irrigation developments, and pumping energy. The BPA simulation model results give the H/K factors. A Soil Conservation Service report provides the monthly proportions of water diversion. Fixed costs estimates came from BPA (1983). Northwest Power Planning Council (NPPC) reports provide data on hydroelectric generation cost, along with the base price of electricity. The base quantity of electricity came from a Pacific Northwest Utilities Conference Committee Report. The cost of non-hydro was calculated using BPA (1983) and NPPC data.

## Results

### Physical Submodel Results

The physical submodel results for hydroelectric generation lost under the irrigation diversions are given in Table 3. The quantities of power lost are a relatively small portion of total generating capacity, amounting to as much as 0.8 percent of average hydropower generation when all projects operate simultaneously to as little as 0.014 percent when just the Umatilla project operates. These losses are yet smaller when compared with the projected regional electricity demand level which is 163,566 thousand megawatt hours. Nevertheless, the numbers are not inconsequential; they should perhaps be compared with the

Table 3. Physical Results.

| Water Year | Potential Hydro | East High | Grande Ronde | Umatilla | Horse Heaven Hills | All Areas |
|---|---|---|---|---|---|---|
| | | -------Power Lost Under Diversions------ | | | | |
| | ------------------1000 megawatt hours------------------ | | | | | |
| 1930 | 104559 | 1121 | 41 | 21 | 45 | 1228 |
| 1937 | 104647 | 1113 | 42 | 21 | 45 | 1220 |
| 1931 | 105260 | 1121 | 42 | 21 | 45 | 1229 |
| 1941 | 106548 | 1121 | 42 | 21 | 45 | 1229 |
| 1945 | 107564 | 1104 | 39 | 20 | 44 | 1207 |
| 1929 | 109342 | 1104 | 44 | 20 | 44 | 1212 |
| 1944 | 111891 | 1095 | 44 | 20 | 44 | 1203 |
| 1939 | 113346 | 1086 | 41 | 20 | 45 | 1192 |
| 1940 | 116718 | 1113 | 41 | 20 | 44 | 1218 |
| 1935 | 118111 | 1077 | 43 | 20 | 44 | 1184 |
| 1942 | 119521 | 1095 | 42 | 20 | 44 | 1201 |
| 1932 | 120135 | 1042 | 41 | 19 | 42 | 1145 |
| 1936 | 123402 | 1034 | 39 | 20 | 42 | 1134 |
| 1962 | 124839 | 1086 | 39 | 20 | 44 | 1190 |
| 1966 | 125242 | 1077 | 42 | 20 | 44 | 1183 |
| 1938 | 127073 | 1042 | 37 | 19 | 42 | 1141 |
| 1953 | 128395 | 1016 | 35 | 19 | 40 | 1111 |
| 1958 | 129324 | 990 | 35 | 18 | 38 | 1080 |
| 1963 | 129753 | 1104 | 39 | 20 | 44 | 1207 |
| 1946 | 130559 | 955 | 39 | 18 | 37 | 1048 |
| 1964 | 131032 | 964 | 32 | 16 | 34 | 1045 |
| 1968 | 131260 | 1069 | 39 | 20 | 43 | 1171 |
| 1933 | 131934 | 981 | 35 | 18 | 38 | 1071 |
| 1949 | 133958 | 972 | 37 | 18 | 37 | 1063 |
| 1967 | 137068 | 876 | 32 | 16 | 34 | 957 |
| 1947 | 138837 | 964 | 38 | 18 | 38 | 1056 |
| 1957 | 139871 | 902 | 33 | 17 | 36 | 988 |
| 1950 | 140002 | 894 | 34 | 16 | 34 | 978 |
| 1955 | 140756 | 914 | 39 | 19 | 41 | 1014 |
| 1959 | 141728 | 990 | 37 | 19 | 40 | 1086 |
| 1961 | 142587 | 902 | 37 | 18 | 39 | 997 |
| 1943 | 143533 | 999 | 35 | 19 | 39 | 1092 |
| 1954 | 144969 | 916 | 37 | 18 | 40 | 1012 |
| 1952 | 146222 | 955 | 33 | 17 | 36 | 1041 |
| 1948 | 148902 | 710 | 28 | 13 | 29 | 780 |
| 1960 | 151049 | 1016 | 39 | 19 | 41 | 1115 |
| 1965 | 157154 | 990 | 32 | 18 | 39 | 1079 |
| 1934 | 162253 | 990 | 40 | 19 | 40 | 1090 |
| 1951 | 163970 | 867 | 33 | 17 | 33 | 950 |
| 1956 | 165801 | 745 | 29 | 12 | 26 | 812 |
| Mean | 131228 | 1003 | 38 | 19 | 40 | 1099 |
| Std dev | 16583 | 99 | 4 | 2 | 4 | 109 |
| Coefficient of variation | 0.126 | 0.099 | 0.107 | 0.110 | 0.112 | 0.099 |
| Whittlesey et al. report | - | 1123 | 41 | 21 | 59 | -- |

size of an average thermal generating facility which would generate between three and eight million megawatt hours. Thus, the loss due to all the projects essentially means that one would need the generating power of between 1/3 and 1/8 the capacity of a new thermal generating facility. The cost of replacing this power is not insubstantial.

Addressing the hypothesis regarding sensitivity of power lost to kwh/acre-ft/ft estimates, we compare our results with those of Whittlesey et al. Whittlesey et al.'s results are included as the last row in Table 3. Whittlesey et al.'s estimates are approximately 10 percent higher than our average results basically equaling our critical flow results for the East High, Grande Ronde and Umatilla projects. They are approximately 50 percent higher than our mean results for Horse Heaven Hills while exceeding the critical flow results by 31 percent. Thus, there were some benefits to the month and year specific H/K's. The null hypothesis of no difference is rejected at any reasonable confidence level for Horse Heaven Hills. However, although there is a qualitative difference, the Whittlesey et al.'s results are not significantly different for the first three irrigation districts.

The final notable physical result involves comparison of the standard error on hydropower generation vis-a-vis the irrigation effects. Note that the irrigation effects are small relative to the fluctuations in power caused by water flows. This is dramatically illustrated by referring to the potential hydro column in which the standard error is 16,583 megawatt hours, approximately 13.5 times the largest diversion effect.

## Economic Results

Economic results pertinent to the general hypothesis are given in Table 4. These results show a significant welfare loss on behalf of electricity consumers and those paying for pumping arising due to irrigation diversion. For example, when a zero pumping cost assumption is adopted, then implementation of the East High project results in an annual welfare loss of between 67 and 72 million dollars. This amounts to an annual loss of between $217 and $232 per acre developed or a loss of between $85 and $91 per acre of foot of water diverted.[3/] Thus, society in the form of consumers and those paying for the pumping would suffer an equivalent income loss to that arising from an annual payment of $217 for each acre of the East High project developed. Furthermore, even if irrigators pay the entire cost of pumping at unsubsidized electricity rates, there would be between a 38 and 39 million dollar loss to electricity consumers. This is equivalent to a loss of between $123 and $126 per acre developed or between $48 and $49 per acre foot diverted. These results are all statistically different from zero at $\alpha = 0.001$. Thus,

Table 4. Consumers' Surplus Losses Under Diversions

| | Pumping Cost Paid[a] | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | None | | | 100'[b] | | | all | | |
| Diversion | Total | Per acre | Per acre-ft | Total | Per acre | Per acre-ft | Total | Per acre | Per acre-ft |
| | $1000 | ------($)------ | | $1000 | ------($)------ | | $1000 | ------($)------ | |
| | | | | Pricing Model 1 | | | | | |
| East High | 67395 | 217 | 85 | 63144 | 204 | 79 | 38213 | 123 | 48 |
| Grande Ronde | 2876 | 76 | 43 | 2577 | 68 | 39 | 1438 | 38 | 22 |
| Umatilla | 5054 | 126 | 51 | 4614 | 115 | 47 | 1092 | 27 | 11 |
| Horse Heaven Hills | 9807 | 140 | 50 | 8927 | 128 | 46 | 2236 | 32 | 32 |
| All areas | 85546 | 187 | 74 | 79630 | 174 | 69 | 43269 | 94 | 37 |
| | | | | Pricing model 2 | | | | | |
| East High | 72007 | 232 | 91 | 67202 | 217 | 84 | 39014 | 126 | 49 |
| Grande Ronde | 3165 | 83 | 47 | 2827 | 74 | 42 | 1539 | 41 | 23 |
| Umatilla | 5322 | 133 | 54 | 4824 | 121 | 49 | 841 | 21 | 9 |
| Horse Heaven Hills | 10305 | 147 | 52 | 9310 | 133 | 47 | 1740 | 25 | 9 |
| All areas | 91842 | 201 | 79 | 85155 | 186 | 74 | 44049 | 96 | 38 |

Note: Figures at average of losses assuming inelastic demand.

[a] The "pumping paid for" columns refer to the amount of pumping energy paid for by the diverter at full energy price. The columns represent no payments (none), payments for 100'of lift, and payment for all pumping energy.

[b] The 100' lift assumption translates to irrigators paying 14.5% of the power cost at East High, 11.1 % at Horse Heaven Hills, and 13.9 when all diversions are implemented.

electricity consumers and those paying for pumping incur substantial losses when Columbia River irrigation projects are developed. However, this loss would be counterbalanced by the consumers' and producers' surplus gains stimulated by the agricultural production increase. Our results exhibit the same qualitative findings as Whittlesey et al.[4/] Whittlesey et al.'s consumers' surplus losses are $219 per acre for East High, $72 for Grande Ronde, $145 for Umatilla, and $109 for Horse Heaven Hills. Whittlesey et al. show that losses of this magnitude generally led to benefit cost estimates of less than one considering producers' surplus effects (not counting any consumers' surplus gains) versus development costs and hydropower loss estimates. We did not address this question. We conclude that Columbia River irrigation developments will impose significant welfare losses on electricity consumers and those paying for subsidizing pumping. For the practical case, one would expect farmer payments to be somewhere between the 100 foot case and the all case. The null hypothesis of no loss is rejected.

Turning attention to the water-year hypothesis, pertinent data are presented in Table 5. Here, using pricing model 2 and inelastic demand, the loss results were tabulated for the average of the 40 water years, the 25th percentile water year, the 10th percentile water year, and the smallest flow water year - the lowest recorded in the

Table 5. Consumers' Surplus Losses for Alternative Flow Levels.

| | | Pumping Cost Paid | | | | | |
|---|---|---|---|---|---|---|---|
| | | None | | 100' | | All | |
| | Flow Assumption | Total | Per Acre | Total | Per Acre | Total | Per Acre |
| | | $1000 | —($)— | $1000 | —($)— | $1000 | —($)— |
| East High | Average | 72007 | 232 | 67202 | 217 | 39014 | 126 |
| | 75% | 73024 | 236 | 68136 | 220 | 39466 | 127 |
| | 90% | 73381 | 237 | 68420 | 221 | 39326 | 127 |
| | Critical | 73381 | 237 | 68408 | 221 | 39241 | 127 |
| | Maximum | 73381 | 237 | 68420 | 221 | 40647 | 131 |
| | Minimum | 57227 | 185 | 52635 | 170 | 25699 | 83 |
| Grande Ronde | Average | 3165 | 83 | 2827 | 74 | 1539 | 41 |
| | 75% | 3238 | 85 | 2894 | 76 | 1584 | 42 |
| | 90% | 3232 | 85 | 2882 | 76 | 1553 | 41 |
| | Critical | 3224 | 85 | 2875 | 76 | 1541 | 41 |
| | Maximum | 3246 | 85 | 2899 | 76 | 1657 | 44 |
| | Minimum | 2540 | 67 | 2216 | 58 | 983 | 26 |
| Umatilla | Average | 5322 | 133 | 4824 | 121 | 841 | 21 |
| | 75% | 5387 | 135 | 4881 | 122 | 830 | 21 |
| | 90% | 5395 | 135 | 4881 | 122 | 770 | 19 |
| | Critical | 5395 | 135 | 4880 | 122 | 758 | 19 |
| | Maximum | 5395 | 135 | 4896 | 122 | 1082 | 27 |
| | Minimum | 4263 | 107 | 3786 | 95 | -27 | -1 |
| Horse Heaven Hills | Average | 10305 | 147 | 9310 | 133 | 1740 | 25 |
| | 75% | 10440 | 149 | 9428 | 135 | 1728 | 25 |
| | 90% | 10447 | 149 | 9421 | 135 | 1607 | 23 |
| | Critical | 10448 | 149 | 9419 | 135 | 1585 | 23 |
| | Maximum | 10448 | 149 | 9457 | 135 | 2196 | 31 |
| | Minimum | 8247 | 118 | 7294 | 104 | 49 | 0 |
| All areas | Average | 91842 | 201 | 85155 | 186 | 44049 | 96 |
| | 75% | 93038 | 203 | 86236 | 188 | 44429 | 97 |
| | 90% | 93401 | 204 | 86500 | 189 | 44075 | 96 |
| | Critical | 93393 | 204 | 86474 | 189 | 43945 | 96 |
| | Maximum | 93393 | 204 | 86522 | 189 | 46393 | 101 |
| | Minimum | 73224 | 160 | 66837 | 146 | 27575 | 60 |

Note: Figured assuming inelastic demand under Pricing Model 2.

40-year period. Maximum and minimum consumers' loss estimates are also recorded. Several things can be noted about these results. First, limited sensitivity to assumptions between average and critical is exhibited. Less than one standard error separates these results. This is a consequence of limited variability of the physical results over this range (Table 3). One interesting result is that the loss estimates are not perfectly correlated with overall flow level. This is, again, a consequence of the physical results. Referencing Table 3, the hydroelectricity lost with all projects implemented is 1228 1000 MWH in the 1930 water-year, but the results for a year with 50 percent higher flows (1960) are less than 10 percent lower, but in another virtually equivalent high flow year (1948) they are almost 50 percent lower. Further, considering the Grande Ronde project, the results between the lowest (1930) and an almost highest flow year (1934) differ by only 2.5 percent. Welfare losses are not necessarily greatest in the critical flow years. Rather, the timing of diversion and the marginal power generation (H/K at the time of the diversion) are more influential. Nevertheless, there is not a significant difference (at the 5 percent level) between the results based on mean and the critical flow assumptions. Therefore, we accept the null hypothesis that the flow year assumption over the critical to mean range does not alter the welfare loss results. One additional interesting result regarding the flow year, when diverters pay all of the cost of pumping then the lower the flow - the more non-hydro power generated - the less the societal impact. This occurs because irrigation diverters are sharing in the increased generation rate increase. Irrigation diverters should pay all pumping charges if the losses to the electricity consumers and those paying for pumping are to be minimized.

Results pertinent to the hypothesis regarding the sensitivity of loss estimates to the quantity response to rate changes are given in Table 6.[5/] The alternative elasticity assumptions do not exert a great deal of influence on the loss results, being different generally by no more than two standard errors.[6/] This arises because of the small marginal changes in power generation arising under the irrigation diversions (the East High diversion is on the order of 6/10 of a percent of the total regional electricity consumed). Thus, the null hypothesis is accepted that the quantity response to price/demand elasticity does not influence the magnitude of losses.

Let us now address the influence of diverter pumping payments on welfare loss estimates. Alternative payment levels lead to statistically different results in all tables (between none and all). Electricity consumers and those who pay for pumping incur the smallest losses when irrigators pay the full costs of pumping water. Obviously, this loss is mitigated by the marginal benefits of increased

Table 6. Consumers' Surplus Losses Under Alternative Elasticities

| | | Pumping Cost Paid | | | | | |
|---|---|---|---|---|---|---|---|
| | | None | | 100' | | all | |
| Diversion | Elasticity Assumption | Total $1000 | Per acre —($)— | Total $1000 | Per acre —($)— | Total $1000 | Per acre —($)— |
| East High | Inelastic | 67395 | 217 | 63144 | 204 | 38213 | 123 |
| | -0.10 | 68026 | 219 | 63836 | 206 | 39293 | 127 |
| | -0.54 | 63520 | 205 | 59593 | 192 | 36592 | 118 |
| | -1.00 | 59419 | 192 | 55732 | 180 | 34165 | 110 |
| Grande Ronde | Inelastic | 2876 | 76 | 2577 | 68 | 1438 | 38 |
| | -0.10 | 2956 | 78 | 2659 | 70 | 1541 | 41 |
| | -0.54 | 2752 | 72 | 2477 | 65 | 1431 | 38 |
| | -1.00 | 2567 | 68 | 2311 | 61 | 1334 | 35 |
| Umatilla | Inelastic | 5054 | 126 | 4614 | 115 | 1093 | 27 |
| | -0.10 | 5193 | 130 | 4761 | 119 | 1300 | 33 |
| | -0.54 | 4834 | 121 | 4430 | 111 | 1197 | 30 |
| | -1.00 | 4508 | 113 | 4130 | 103 | 1110 | 28 |
| Horse Heaven Hills | Inelastic | 9807 | 140 | 8927 | 128 | 2236 | 32 |
| | -0.10 | 10076 | 144 | 9212 | 132 | 2632 | 38 |
| | -0.54 | 9380 | 134 | 8572 | 122 | 2425 | 35 |
| | -1.00 | 8749 | 125 | 7994 | 114 | 2250 | 32 |
| All Areas | Inelastic | 85546 | 187 | 79630 | 174 | 43269 | 94 |
| | -0.10 | 86276 | 188 | 80450 | 176 | 44643 | 97 |
| | -0.54 | 80602 | 176 | 75129 | 164 | 41549 | 90 |
| | -1.00 | 75439 | 165 | 70293 | 153 | 38780 | 85 |

Note: Figured at average of losses under Pricing Model 1.

agricultural production; however, an analysis including the nonagricultural effects would be needed to weigh these results one against another. Furthermore, a significant societal subsidy is in effect when government agencies pay for pumping and/or subsidize pumping electricity rates. For East High, this would be on the order of $30 million per year, or $81 an acre. Thus, diverters' payments are a significant argument in the loss estimates.

Results on the interruptible water hypothesis are given in Table 7. Under the interruptible analysis, diversions occur only when their impact on generation facilities does not cause need for more thermal generating capacity to meet inelastic demand. Such interruptions are infrequent. Considering the East High case example, diversions are interrupted 3 years out of 40.[7/] No water is assumed to be used in those years. In the other 37 years full diversion occurs. The assumed cost of replacement power is the thermal operating cost. The interruptible results show a considerably smaller change in welfare. The annual savings between the interruptible and noninterruptible amount to between $52 and $55 million. When diverters both pay all pumping costs and are interruptible, the results show a welfare gain from irrigation as the irrigation use reduces average power costs to electricity consumers. The interruptible results also may be interpreted as the maximum amount electricity consumers and those paying for pumping

Table 7. Consumers' Surplus Under Noninterruptible and Interruptible Water.

| Diversion | | Pumping Cost Paid: None — Total $1000 | None — Per acre ($) | None — Per acre-ft ($) | 100' — Total $1000 | 100' — Per acre ($) | 100' — Per acre-ft ($) | All — Total $1000 | All — Per acre ($) | All — Per acre-ft ($) |
|---|---|---|---|---|---|---|---|---|---|---|
| East High | Average[a] | 72007 | 232 | 91 | 67202 | 217 | 84 | 39014 | 126 | 49 |
| | Interrupted[b] | 16772 | 54 | 21 | 12378 | 40 | 16 | -13400 | -43 | -17 |
| | Difference[c] | 55235 | 178 | 70 | 54824 | 177 | 68 | 52414 | 169 | 66 |
| | Inter %[d] | 7.5% | 7.5% | 7.5% | 7.5% | 7.5% | 7.5% | 7.5% | 7.5% | 7.5% |
| | Inter Payment[e] | 736467 | 2373 | 933 | 730987 | 2360 | 907 | 698853 | 2253 | 880 |
| Grande Ronde | Average | 3165 | 83 | 47 | 2827 | 74 | 42 | 1539 | 41 | 23 |
| | Interrupted | 775 | 20 | 12 | 446 | 12 | 7 | -808 | -21 | -12 |
| | Difference | 2390 | 63 | 35 | 2381 | 62 | 35 | 2347 | 62 | 35 |
| | Inter % | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% |
| | Inter Payment | 95600 | 2520 | 1400 | 95240 | 2480 | 1400 | 93880 | 2480 | 1400 |
| Umatilla | Average | 5322 | 133 | 54 | 4824 | 121 | 49 | 841 | 21 | 9 |
| | Interrupted | 1452 | 36 | 15 | 980 | 24 | 10 | -2795 | -70 | -28 |
| | Difference | 3870 | 97 | 39 | 3844 | 97 | 39 | 3636 | 91 | 37 |
| | Inter % | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| | Inter Payment | 77400 | 1940 | 780 | 76880 | 1940 | 780 | 72720 | 1820 | 740 |
| Horse Heaven Hills | Average | 10305 | 147 | 52 | 9310 | 133 | 47 | 1740 | 25 | 9 |
| | Interrupted | 2807 | 40 | 14 | 1865 | 27 | 10 | -5305 | -76 | -27 |
| | Difference | 7498 | 107 | 38 | 7445 | 106 | 37 | 7045 | 101 | 36 |
| | Inter % | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| | Inter Payment | 149960 | 2140 | 760 | 148900 | 2120 | 740 | 140900 | 2020 | 720 |
| All Areas | Average | 91842 | 201 | 79 | 85155 | 186 | 74 | 44049 | 96 | 74 |
| | Interrupted | 21112 | 46 | 18 | 15181 | 33 | 13 | -21274 | -46 | -18 |
| | Difference | 70730 | 155 | 61 | 69974 | 153 | 61 | 65323 | 142 | 92 |
| | Inter % | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% | 10.0% |
| | Inter Payment | 707300 | 1550 | 610 | 699740 | 1530 | 610 | 653230 | 1420 | 92 |

Note: Figured using average of losses assuming inelastic demand under Pricing Model 2.

[a] Average results under a policy of constant diversion.

[b] Average results under an interruptible policy.

[c] Difference between two policies.

[d] Percentage of time that interruptions occur.

[e] Difference divided by percent of time interruptions occur.

would be willing to bribe (in a Scitovsky sense) diverters to not divert water in critical flow years. This amount is calculated by taking the annual difference divided by the percentage of interruption. In the zero pumping cost paid case for East High this amounts to $2373 an acre. This amount could be paid to diverters each year that the interruption occurred, leaving electricity consumers and those paying for pumping indifferent in terms of welfare. This indicates potential for compromise between diverters and the rest of society. Diverters' water could be purchased in critical years at some lower price, possibly leaving both parties better off.

## Concluding Comments

This study verifies the results of Whittlesey and associates showing that electricity consumers and those paying for pumping implicitly incur substantial welfare losses when irrigation projects are permitted to divert Columbia River water. Water in the river is not a valueless commodity. Even when producers pay for all pumping, the loss due to hydropower diverted for the potential East High project is as high as $49 per acre foot or $126 per acre developed. An appraisal of whether this cost renders projects unattractive would also involve consideration of the consumers' and producers' surplus gains from agricultural production. Local profitability might also be involved (as in Findeis and Whittlesey). However, we did not investigate this question.

Several conclusions may be drawn beyond those in Whittlesey and associates. First, although the Umatilla project exhibits almost one-third more pump lift than the East High project, the per acre costs of the irrigation development are considerably lower. This is due to the lower potential hydropower loss per unit of water diverted. The Umatilla project is considerably further down river diverting from a dam with a much lower cumulative head. The losses per acre foot diverted for the lower three projects are roughly one-half of the East High project. This indicates that society should, if it deems Columbia River irrigation projects socially worthwhile, develop those closer to the river mouth before the ones further upstream, all other things being constant.

Second, an important element in social losses involves the proportion diverters pay of the cost of pumping water. Society would probably prefer diverters to pay full cost. However, from a strict sense, this depends on the tradeoff between hydropower-based losses and the marginal benefits to agricultural production from diverters paying full cost versus paying reduced costs. An answer to this question would involve a more detailed study of the consumers' and producers' surplus stimulated by the marginal changes in agricultural production.

Third, it appears that assumptions involving elasticity of demand, water year and whether or not spilled water is present are not terribly significant in terms of determining the social costs of irrigation.

Fourth, it appears that an interruptible policy would be socially favorable to electricity consumers and those paying for pumping. Such a policy could be implemented in several ways. Water rights could be granted to hydroelectric generation by dam, making future irrigation developments junior to the dams, with these water rights set at a figure establishing a flow level reflecting 90 percent confidence. Alternatively, utilities or agencies could offer a land retirement type payment where a certain amount of money was offered to temporarily purchase water diversion rights in critical flow years. This could be financed by a fund generated by rate payers.

Finally, some sort of forced curtailment could be attempted. Some form of interruptible policy appears feasible for most annual cropping situations. Some perennial cropping situations could also be handled.

## FOOTNOTES

1 The hydro regulation simulation model (Hydro) provides the basis for BPA's hydroelectricity supply projections as given in the referenced PNUCC report. The particular model the results come from is the one used in the 1982 Northwest Regional Forecast Run for 1983 Levels. Thanks to Art Evans and John Dillard at BPA for making its output available.

2 The authors are indebted to Art Evans and John Dillard at BPA for their cooperation and suggestions.

3 Under inelastic demand this and the other estimates below equal the net loss to electricity consumers plus the net loss of pumping energy above diverter payments to whomever it falls (taxpayers through the Bureau of Reclamation, rate payers through BPA, etc.).

4 Whittlesey *et al.*'s results are adjusted for diverter payments at a rate which would be equivalent to two mills in East High, 4.3 mills elsewhere. These correspond to a diverter payment factor (d) equaling 0.061 for East High and d = 0.130 elsewhere and would, therefore, fall in a case between zero and 100'results.

5 These results are derived using Pricing Model 1. This model was used because of the difficulty of balancing nonhydroelectric capacity under Pricing Model 2. A different capacity would be required for each analysis. Pricing Model 1 permits different amounts of installed capacity paid for in each year. However, we do not anticipate these results will greatly differ from those under Pricing Model 2, as evidenced by the comparative results from the two pricing models (Table 4).

6 The slightly higher results under the elasticity -0.1 relative to inelastic demand occurs since slightly more electricity was consumed than in the inelastic case. The demand equations were not balanced so that the average demand was less than that used in the inelastic case.

7 If diverters were interrupted in the historical three lowest flow years then three interruptions would have occurred between 1929 and 1937 (Table 3). Subsequently, there would have been no interruptions through 1968.

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