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UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

RESOURCES, COMMUNITY, AND ECONOMIC DEVELOPMENT DIVISION

September 16, 1985

B-220261

The Honorable Edward J. Markey
Chairman, Subcommittee on Energy
Conservation and Power
Committee on Energy and Commerce
House of Representatives

Dear Mr. Chairman:

Subject: Evaluation of Cost Estimates Related to the Relicensing of Hydroelectric Projects (GAO/RCED-85-169)

Your letter of July 11, 1985, requested that we review widely varying cost estimates associated with relicensing hydroelectric projects. These cost estimates were presented to your Subcommittee during its consideration of legislation to reform the process used by the Federal Energy Regulatory Commission to relicense hydroelectric projects. After providing your staff with a briefing on our work on August 20, 1985, they asked us to summarize the results in a report to you by September 16, 1985.

The enclosed report evaluates the cost estimates for transferring (1) the licenses of three projects in California from a private utility to municipalities and (2) all investor-owned hydroelectric projects nationwide. For the California projects we discuss the methodology, data, and assumptions used in the studies, and recalculate the estimates to reflect other assumptions which we believe may be at least as valid and could have a substantial effect on the costs. We did not recalculate the estimates for the nationwide cost of transferring all licenses because we believe that numerous uncertainties preclude an accurate estimate of the nationwide cost impact at the present time. We do, however, discuss the methodologies, data, and assumptions of the estimates that were presented to the Subcommittee.

(007062)

As arranged with your office, we are sending copies of this report to appropriate House and Senate committees and other interested parties on the date it is issued. We will also make copies available to others upon request.

Sincerely yours,

Ralph V. Carlone for

J. Dexter Peach
Director

Enclosure

EVALUATION OF

COST ESTIMATES RELATED TO

THE RELICENSING OF HYDROELECTRIC PROJECTS

INTRODUCTION

The Federal Energy Regulatory Commission (Commission) is authorized to issue licenses to nonfederal entities for building and operating hydroelectric facilities for the development of the nation's water resources. The licenses are issued for a period up to 50 years. The Commission is required by the Federal Power Act (16 USC 800a, as amended) to give preference to states and municipalities (municipality), over a privately owned utility (utility), whenever the two entities file equally well adapted development plans for the same project.

Upon the expiration of a license, the Commission is authorized to grant a new license. A new license is not automatic and is subject to competition. Many of the licenses originally issued to utilities have expired, and the utilities have applied for relicensing. In some instances municipalities have filed competing applications for the license.

The doctrine of preference for municipal applicants at the time of relicensing has been contested. In a 1980 case the Commission ruled that the doctrine of preference applied at the time of license renewal as well as the time of original licensing and awarded the license in question to the city of Bountiful, Utah. That ruling was upheld in federal appeals court. However, in 1983 the Commission changed its position and ruled that the doctrine of municipal preference applied only to the new licensing of a hydroelectric project and not for an application for relicensing by the current license holder. That ruling is currently under review by a federal appeals court. In the interim, several bills have been introduced in the Congress (H.R. 44, H.R. 1815, H.R. 1959, and S. 426) to clarify or modify certain provisions of the Federal Power Act relating to hydroelectric project licensing, including the doctrine of municipal preference.

As part of congressional hearings on these bills, various cost estimates of the impact of transferring hydroelectric projects from the original licensee to a new licensee (presumably a municipality under the doctrine of preference) have been submitted in reports and testimony. However, these estimates vary greatly. For example, two studies estimate the cost of transferring three Pacific Gas and Electric Company (PG&E) projects to competing municipalities as either $18.3 million or $147.5 million per year. On a nationwide basis two other studies have presented the cost of transferring all investor-owned hydroelectric licenses to municipalities as between $200 million and $4.5 billion per year.

Objectives, Scope, and Methodology

The Chairman, Subcommittee on Energy Conservation and Power, House Committee on Energy and Commerce, by letter dated July 11, 1985, requested that we review the cost estimates presented to the Subcommittee on the impacts of transferring the licenses of the three PG&E projects and all investor-owned utility projects nationwide. We were asked to determine the basis for the estimates and the reasons for the differences. In subsequent discussions with the subcommittee staff, we were asked to analyze the methodology, assumptions, and data in the two PG&E studies and to reflect the effect on the cost estimates of changes which we believe would be valid.

In order to provide a response by September 16, 1985, and as agreed with the Subcommittee staff, we did not do an exhaustive analysis of the studies nor develop an independent GAO estimate of the costs but merely recalculated estimates for the PG&E projects with the changes in assumptions that we believe may be at least equally valid and result in a substantial difference in the cost estimates. We did not recalculate the nationwide cost estimates, but discussed the similarities, differences, and reliability of these estimates to provide a perspective for interpreting them. To determine the basis for the existing cost estimates we

--interviewed the authors of the studies about preparation of the cost estimates;

--reviewed the studies to identify key methodologies, assumptions, and data differences;

--interviewed Commission officials familiar with hydroelectric licensing and electric rate making; and

--reviewed Commission files to verify selected data used in preparing the cost estimates.

As you requested we did not obtain agency comments. Our work was conducted in Washington, D.C., during July and August 1985.

BACKGROUND

Various studies have used two different cost components in calculating the costs associated with transferring hydroelectric licenses from the original licensee to a new licensee. These components are (1) the increase in the average cost to the remaining customers of the original licensee, due to the necessity of allocating fixed charges for fossil and nuclear fuel and other operating expenses to a smaller number of customers[1] and (2) additional costs incurred by the utility to purchase or generate power to replace the output from the transferred project.

The increase in average cost to the remaining customers results from a reallocation of both the fuel and plant costs (costs used in determining the base rate) associated with generating power to a smaller customer base. For example, if an existing wholesale customer takes over a project license, then that customer does not need to purchase its power from the original license holder. As a result, sales of the original license holder are reduced but many costs remain fixed such as the cost of fuel to run the utility's coal- and oil-fired generating units. These fixed costs must now be reallocated to a smaller customer sales base which results in an increase in the average cost of power to the remaining customers.

Replacement power costs are costs incurred by the utility to replace the output of power lost to the utility when a project license is transferred. The utility can either generate the additional power from existing plants or purchase the additional power from other sources. Replacement power costs can also include the cost of building or purchasing a new power plant and the fuel to generate the electricity lost by the transfer of the hydroelectric license.

One additional factor considered in determining the cost of transferring the hydroelectric licenses is the benefit gained from reduced ownership and operating expenses associated with the licensed project. For example, expenditures for property taxes, depreciation, maintenance, and similar items directly applicable to the transferred project will be eliminated after the transfer. The benefit from these reduced expenditures is offset against the increased costs to estimate the net costs of the transfer.

COST ESTIMATES FOR TRANSFERRING THE LICENSES OF PG&E PROJECTS

Two estimates were presented to the Subcommittee on the cost of transferring the licenses of three PG&E hydroelectric projects to competing municipalities. A study prepared by PG&E estimated the cost at $147.5 million per year in increased costs to individual customers and for replacement power. Another study, prepared by R.W. Beck and Associates for the competing

[1]Not all analysts agree with the concept of treating the increase in average costs to remaining customers as a legitimate cost increase. These analysts argue that in theory a different group of customers, essentially those of the new owner, receive a corresponding decrease in their costs. In effect, the analysts argue that the net cost to the economy is zero.

municipalities,[2] estimated that PG&E would incur $18.3 million per year in additional costs.

Table 1.1 summarizes the major differences in the estimates.

Table 1.1

Cost Component	PG&E Estimate	R.W. Beck Estimate	Variance
Increased Average Cost Allocated to Remaining Customers			
Fuel Costs	$46,243,000[a]	Not estimated	$46,243,000
Base Rate Costs	25,865,000	Not estimated	25,865,000
Subtotal	$72,108,000	Not estimated	$72,108,000
Replacement Power Costs	$109,443,000[b]	$40,338,229[c]	$69,104,771
Total Cost	$181,551,000	$40,338,229	$141,212,771
Reduced Ownership and Operating Costs	-34,038,000	-22,023,458	-12,014,542
Net Total Cost	$147,513,000	$18,314,771	$129,198,229

[a]Calculated for 100 percent of the output from Mokelumne and 7.13 percent from the Rock Creek-Cresta and Haas-Kings River projects.

[b]Calculated at 6.9 cents per kilowatt hour for 92.87 percent of the output from Rock Creek-Cresta and Haas-Kings River projects.

[c]Calculated at 6.6 cents per kilowatt hour for 35.39 percent of the output from Rock Creek-Cresta and Haas-Kings River projects.

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[2]Several groups are competing for three PG&E projects. The city of Santa Clara, California, is competing for the Mokelumne project license. A consortium made up of the Southern California cities of Anaheim, Azusa, Banning, Colton, and Riverside, the Sacramento Municipal Utility District (SMUD), and the Northern California Power Authority (NCPA) made up of the cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompac, Palo Alto, Redding, Roseville, Santa Clara, Ukiah, and the Plumas-Sierra Cooperative are competing for the Rock Creek-Cresta and Haas-Kings River project licenses. The cities of Lodi, Redding, Santa Clara, and Ukiah are not participating in the competition for the Rock Creek-Cresta project.

The following sections discuss the differences in the methodologies, assumptions, and data used to develop the above cost estimates.

Methodology

While the methodologies for calculating these costs are straightforward from a mathematical sense, the practical use of the methodologies depends on which of the following questions the analyst is attempting to address.

--What additional costs will the utility's customers incur from the license transfer?

--What additional costs will the utility incur from the license transfer?

The PG&E study was undertaken to answer both questions according to its author. As such, it includes both the increase in average cost and the replacement power cost components. On the other hand, the R.W. Beck study was designed, according to the official responsible for the study, to address the second question. As a result, the study includes an analysis of only the replacement power cost component. This difference accounts for about $72 million of the total variation in the PG&E and R.W. Beck cost estimates. Both studies also analyzed the benefit from reduced operating and ownership expenses.

Assumptions

In calculating the costs of transferring the project licenses, both studies made certain assumptions related to the need to replace power, the source of that replacement power, and its cost. The key assumption that accounted for most of the difference in the study estimates of replacement power costs was the assumption on the amount of power needing to be replaced. The PG&E study assumed that 92.87 percent of the output from two projects (Rock Creek-Cresta and the Haas-Kings River) needed to be replaced and that none of the power from the third project (Mokelumne) needed to be replaced. While the R.W. Beck study agreed on the Mokelumne project, it assumed that only 35.39 percent of the power from other two projects needed to be replaced.

The PG&E study assumed that the output of power from all lost projects must be replaced unless there is a corresponding decrease in the demand for power. For example, in the case of the Mokelumne project, the city of Santa Clara, which normally buys power from PG&E, is competing for the project license. Santa Clara buys approximately the same amount of power from PG&E that is generated by the Mokelumne project and will presumably not need that power if it wins the project license. As such, the loss of power will be offset by a reduced demand for power from Santa Clara which means that, in this case, PG&E will not have to purchase or generate any replacement power. The R.W. Beck study concurs in this treatment of the need for replacement power from the Mokelumne project.

The studies do not agree, however, on the need for replacing the output from the Rock Creek-Cresta and Haas-Kings River projects. The PG&E study, using the same assumption discussed above, concludes that there will only be about a seven percent reduction in demand to offset the lost output since most of the cities competing for the license do not buy any power from PG&E. As a result, PG&E concludes that about 93 percent of the power needs to be replaced to meet its customers' needs. In comparison, the R.W. Beck study uses different assumptions to estimate the need for replacement power at about 35 percent. The R.W. Beck study assumed that only the output from the projects that would go to municipalities that do not normally purchase their power from PG&E and are not in the PG&E service area needed to be replaced. The Beck study assumed that there would be a large scale (about 2 billion kilowatt hours) shuffling of wholesale customers and suppliers within the service area. This difference accounts for most of the $69 million of the variation in the PG&E and R.W. Beck cost estimates for the three projects.

Another assumption made in both studies was that the cost of replacement power would be calculated at the marginal cost rate. This is generally the highest rate at which a utility generates or purchases power because it represents the addition of a new plant and new fuel costs to generate the next unit of power. This assumes that the utility's present plants are all producing at full power or needed as emergency reserves. As a result, the utility must either build a new plant or, alternatively, purchase the power at an equivalent rate from another source with excess capacity.

Data

The two studies used different data to calculate some costs related to the transfer of the PG&E project licenses. For example, the PG&E study used a figure of 2,796 million kilowatt hours as the power generated by the three projects and 6.9 cents per kilowatt hour as the cost of replacement power. The corresponding figures for the R.W. Beck study were 2,673 million kilowatt hours and 6.6 cents. These data differences account for some variation in the cost estimates between the two studies. However, the differences were minor when compared to those caused by the differences in methodology and assumptions and are included in the estimates discussed above.

Finally, there was a difference in the data used to calculate the benefits from reduced ownership and operating expenses. The PG&E study, using actual company data from the projects, calculated the benefit as being about $12 million greater than the R.W. Beck study, which extrapolated from published summary data.

Recalculation of the Cost Estimates

Within the timeframe allocated for this project, we were not able to construct an independent estimate of the costs. We were, however, able to evaluate certain assumptions and data used in the studies. As a result of this evaluation, we believe two key assumptions regarding the amount of power needing to be replaced and the cost of such power could be viewed somewhat differently than is done in either of the studies. We, therefore, recalculated the estimates using the different assumptions but employing the same methodology.

Regarding the amount of replacement power needed, PG&E estimated that about 93 percent of the power would have to be replaced and R.W. Beck estimated only about 35 percent would have to be replaced. The bases for these estimates are discussed above.

There are many factors that make it difficult to determine whether the PG&E or R.W. Beck study assumptions are more accurate. For example, the power output lost by PG&E, if the project licenses are transferred, will not be lost from the California power supply, rather only the ownership will change. The power would still be available for sale by the new owner, perhaps even to the original customers. From that point of view, the R.W. Beck assumption that there will be a shuffling of wholesale supply and demand appears to have merit. On the other hand, to assume, as in the R.W. Beck study, that there will be a large shuffling of wholesale supply and demand overlooks a number of complicating factors. There are potential problems associated with long-term contracts between PG&E and its wholesale customers, wholesale customers' location relative to the projects, transmission line availability, and also the availability and price of the power.

Because of these difficulties, we modified the R.W. Beck study assumption. We assumed that PG&E would continue serving its wholesale customers, except for those customers which already have a relationship with the consortium of municipalities competing for the projects. We believe that where such a relationship already exists, there is a legitimate rationale for assuming that a shuffling of wholesale purchasers and suppliers could take place. For example, the city of Lodi is a member of NCPA, but is not participating in NCPA's competition for the project licenses. As such, PG&E counts Lodi as a continuing customer and counts power sales to Lodi as needing to be replaced by purchases of new power. On the other hand, we assumed that since Lodi is a member of NCPA and receives its power from PG&E indirectly through NCPA, that Lodi would switch its purchases to NCPA once NCPA has its own power source. Such a switch would reduce PG&E's need to replace power by an equivalent amount. We made similar reductions for direct sales to NCPA, to the city of Lompac, and to SMUD which receives power under an integration agreement with PG&E. We calculated that these changes would result in the need for replacement power at about 75.28 percent of the output of the Rock Creek-Cresta and Haas-Kings River projects.

Regarding the cost of replacement power, both the PG&E and R.W. Beck studies assumed that replacement power would be purchased at the marginal cost rate of power. This assumes that all existing plants are operating at full capacity or are needed as emergency reserves. Therefore, to generate additional units of power the company needs to build or buy new plant capacity and then burn additional fuel to generate power. This is a generally conservative approach to estimating the cost of replacement power because it assumes the worst case scenario and predicts the highest possible cost consequences.

Using Commission records (FERC Form-1), we determined that PG&E's reserve capacity for the 1985-88 time frame is about 32 percent of its total generating capacity. This figure is significantly higher than the 15-20 percent reserve margin generally considered sufficient by industry standards for a utility with multiple power plants and types (oil, gas, hydro, and nuclear) of generating capacity. Further, PG&E predicts reserve capacity to remain at about the same level over the next 10 years even after considering future growth in demand. As such, we believe that the most likely source of replacement power would be from PG&E's internal reserve capacity, not from building or purchasing new capacity at the marginal cost rate. By using internal reserve capacity, we estimate the cost of replacement power costs at 4.3 cents per kilowatt hour, rather than the 6.9 cents used by PG&E.

We did not calculate a separate amount for the benefit gained from reduced ownership and for operating expenses resulting from the licenses' transfer. Instead, we used PG&E's calculation since it was based on actual company data. Use of PG&E's estimate has the effect of reducing the cost of the transfer to PG&E customers.

Such changes in assumptions result in a revised cost estimate, including increased average costs of $105.1 million. Table 1.2 shows the major cost components of the revised cost estimate.

Table 1.2

Cost Component	Revised Estimate
Increased average cost Allocated to Remaining Customers	
Fuel costs	$57,731,000[a]
Base rate costs	25,865,000
Subtotal	83,596,000
Replacement power costs	$55,542,000[b]
Total	139,138,000
Reduced ownership & operating costs	-34,038,000
Net total Cost	$105,100,000

[a]Calculated for 100 percent of the output from Mokelumne and 24.72 percent from the Rock Creek-Cresta and Haas-Kings River projects.

[b]Calculated at 4.3 cents per kilowatt hour for 75.28 percent of the output from Rock Creek-Cresta and Haas-Kings River projects.

NATIONWIDE COST ESTIMATES FOR TRANSFERRING PROJECT LICENSES

Two separate estimates were presented to the Congress on the nationwide impacts of transferring hydroelectric project licenses. The Edison Electric Institute (EEI) prepared a study of all investor-owned hydroelectric projects that calculated the fuel cost savings to customers from those projects as $1.5 billion to $4.5 billion per year.[3] The $1.5 billion represents the cost of replacing all the power generated by the 366 projects with coal-fired generation; the $4.5 billion is the corresponding amount for oil-fired generation. Although the EEI study did not

[3]In 1984, EEI calculated the fuel cost savings as $1 to $3.5 billion per year. In 1985, EEI published the revised fuel cost savings as discussed above.

attempt to directly quantify the costs of transferring project licenses, its estimated fuel cost savings have been used as one measure of the impact on utility customers.

The Consumer Energy Council of American (CECA) Research Foundation estimated the costs of transferring all 366 investor-owned hydroelectric utility licenses at $200-300 million per year. The CECA estimate represented the increase in average costs allocated to the remaining customers.

Methodologies, Assumptions, and Data of Nationwide Studies

The two studies of the nationwide impact of transferring hydroelectric licenses used different methodologies. The EEI study did not calculate the cost of transferring the licenses, but it estimated the savings to utility customers from using hydropower versus coal or oil to generate an equivalent amount of electric power. The EEI study did not account for either the increase in average costs as a result of the transfer or the benefits from reduced operating and ownership costs. The CECA study, by comparison, calculated the increase in average fuel and base rate costs to utility customers. Although performed on an aggregate basis, the CECA study used methodology similar to that used by PG&E in calculating the company-specific costs for transferring PG&E project licenses. The CECA study did not calculate replacement power costs but did calculate the benefit from reduced operating and ownership costs as part of its calculation of the average cost increase.

The studies used different assumptions in calculating the nationwide impact of transferring hydroelectric licenses. The EEI study calculates the current fuel savings for all investor-owned hydroelectric projects. When this fuel savings estimate is used to represent the cost to utility customers of transferring project licenses, it requires the user to assume that all licenses will be transferred and that all project output needs to be replaced. Conversely, the CECA study assumes that none of the power needs to be replaced. Instead, the CECA study assumes that there will be a shuffling of wholesale suppliers and customers. Therefore, the CECA study assumes that the only impact on customers is the increase in the average fuel and base rate costs.

The two studies also used different data to calculate the impact of transferring project licenses. However, since the studies were not attempting to determine the same impact, the use of different data was not relevant to the variation in the studies' outcomes.

Uncertainties in Nationwide Cost Estimate

Both the EEI and CECA studies on the impact of transferring hydroelectric project licenses are based on assumptions that are difficult to support under current circumstances. For example, both assume that all licenses will be transferred, although the CECA study is highly critical of this assumption and uses it solely for comparison purposes. Another assumption is that either all or none of the power from all projects needs to be replaced.

Whether or not a license is transferred depends to some extent on individual project circumstances, such as the project's size and location and the interest of a competing group. For example, only about 10 of the 125 projects relicensed since 1970 have been challenged. However, this probably does not indicate adequately the level of interest in competing for project licenses, since the issue of preference for municipalities was and is not clear. Until the preference issue is clarified in the current court case or through congressional action, and until individual licenses come up for renewal, no means exist to determine the interest of competing municipalities. As such, neither the number of licenses that will be competed for nor the number that might be transferred can be determined with any accuracy.

In addition, the amount of power that might need to be replaced is subject not only to the unpredictability of competition for a project but also to individual project circumstances, as discussed in the case of the PG&E projects. Therefore, at the present time, the cumulative nationwide impact cannot be accurately predicted.

The combination of these two factors makes estimating the nationwide impact a highly speculative effort. Because of the difficulty in predicting the number of licenses that might be competed for, the number subsequently transferred, and the need to replace power from these licenses, no reliable means exist at this time to estimate the nationwide impact on customers.