Evaluation of the Economic Performance of Hydropower Developments Supported by the World Bank Group 1975 to 2015

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ABSTRACT

One solution to the global energy challenge is the intensification of investment in hydropower projects that provide clean, reliable and affordable energy (IEA, 2012). Advocates of hydropower projects site their numerous benefits such as reduction in fossil fuel consumption, provision for water for irrigation and other uses, flood control and inland water transport. However, a common challenge often faced by hydropower projects is the issue of cost and time overruns.

This study builds on the earlier work of Awojobi and Jenkins (2015) which examined the net economic benefits of 58 WBG financed hydropower projects between 1975 and 2005. It is thus important to evaluate the net benefits attached to hydropower projects constructed post-2005. This study extends the sample size by 10 more to cover 68 WBG financed hydropower projects and re-computes the results for the previous 58 hydro dams using a consistent set of data and assumptions. This extended sample will enable one to evaluate changes that might have taken place in project design and appraisal over time.

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Keywords: hydropower, electricity, cost overrun, time overview, economic benefits

Jel Classification: D61, L94, O22, Q4

Introduction

One solution to the global energy challenge is the intensification of investment in hydropower projects that provide clean, reliable and affordable energy (IEA, 2012). Advocates of hydropower projects site their numerous benefits such as reduction in fossil fuel consumption, provision for water for irrigation and other uses, flood control and inland water transport. However, a common challenge often faced by hydropower projects is the issue of cost and time overruns. A review of previous research on this subject provides clear evidence that a significant number of hydropower projects suffer from cost and time overruns (see Merrow, Shangraw & Kleinberg, 1990; Bacon & Besant-Jones, 1998; Ansar, Flyvbjerg, Budzier & Lunn, 2014; Sovacool, Nugent & Gilbert, 2014; Awojobi & Jenkins, 2015).

Accurate projections of construction schedules and costs are crucial to the development of hydropower projects. These projections of construction times and cost projections are central elements in preparation of construction and operation timetables and the financial arrangements associated with such projects (Bacon & Besant-Jones, 1998). Construction cost and time overruns therefore increase the probability of a loss of economic justification for executing hydropower projects. Cost and time overruns may also significantly affect the financing capacity of the project owners and the electricity pricing policies where the project is situated. Detailed investigation of the issues surrounding cost and time overruns can provide vital insight as regards inefficiencies associated with different stages in the evaluation and construction phases of hydropower projects. We thus seek to determine how cost and time overruns affect the net economic benefits of a portfolio of 68 hydropower projects financed by the World Bank Group (WBG) between 1975 and 2015.

This study builds on the earlier work of Awojobi and Jenkins (2015) which examined the net economic benefits of 58 WBG financed hydropower projects between 1975 and 2005. It is thus important to evaluate the net benefits attached to hydropower projects constructed post-2005. This study extends the sample size by 10 more to cover 68 WBG financed hydropower projects and re-computes the results for the previous 58 hydro dams using a consistent set of data and assumptions. This extended sample will enable one to evaluate changes that might have taken place in project design and appraisal over time. The larger sample size limits the margin of error in the results and gives greater power to detect differences on the basis of dam size, region and construction period. Finally, this study explicitly quantifies the benefits from lower carbon emissions due to reduction in fossil fuel consumption caused by hydropower projects.

Overall, the focus of this study is four-fold. The first focus is to estimate the net economic benefits of a portfolio of 68 WBG financed hydropower projects to the societies where they are situated. The second focus is to re-examine how construction risks (cost and time overruns) affect the net benefit of these projects across size, region and time. The third focus is on the causes of the cost and time overruns and if there is a trend in outcomes for project completed in recent years as compared to earlier completions. The fourth focus is to estimate the beneficial impact of hydropower projects as a source of renewable energy on the global environment in terms of carbon emissions reduction.

Methodology

For the analysis of cost overruns, four concepts are used: estimated nominal cost, estimated real cost (base year price), actual nominal cost, and actual real cost. The estimated nominal cost used is the sum of base cost (using constant prices), plus an amount to reflect the provisions for physical and price contingencies. According to the World Bank appraisal methodology that has been used since 1976, cost estimates for projects should include a price contingency to account for expected changes in the price level of both imported and locally purchased inputs. In addition, an amount is set aside for physical contingencies. This contingency accounts for expected errors in forecasting of base cost estimates that affect the quantities of inputs required to complete the project (Bacon et al., 1996). Therefore, the estimated real cost at appraisal is derived by simply deducting the price contingency from the estimated nominal project cost, but including physical contingencies. Projects completed before 1976[1] are excluded to maintain a consistent methodology for evaluating the cost performance of the selected projects.

The change in the real cost schedule of a large project can be the result of two factors. First, real cost changes can occur because of changes in input quantities and real price adjustment; second, change orders will alter the real cost as a project is redesigned. The change in real cost reported here is the difference in cost between the real estimate of cost (which includes physical contingencies) at the time of appraisal – the point of decision making – and the actual real completion cost. Real cost overruns as measured in this study excludes cost changes owing to change orders.

The actual nominal cost (in current prices) is the completion cost of the project as reported in the World Bank’s Implementation and Completion Reports (ICRs), while the actual real cost is the deflated values of the actual nominal costs. The impact of general inflation on

[1] There is only one project completed in 1975.

the cost of a project will usually be transferred eventually to consumers of the project's output through adjustment of electricity tariffs to reflect movements in the general level of prices. Hence, a budget overrun caused by general inflation should not be counted as a real cost overrun.

For a balanced view of the true value of dams, we propose an analytical framework that incorporates the uncertainties underlying both the costs and benefits of hydropower dams. The uncertainty underlying the benefit side is the volatile price of fuel that is avoided by undertaking the hydropower investment. The downside uncertainty in the cost of hydro is the risk of capital cost and time overruns. To find the effect of these risks and uncertainties on the outcome of our analysis, we collect data for completed dams and parameters for evaluating the alternative plant based on actual statistics from historical records, project evaluation documents (PADs), post evaluation reports such as the ICRs, and other sources. Data on the capital and variable costs of open-cycle, diesel, combined-cycle and coal plants are collected to estimate the fixed capital and variable costs of the alternative plants avoided by constructing the hydropower dam.

Data and measurements

Information was collected from the World Bank PADs and ICRs for each of the 68 WBG hydropower projects. These projects together account for over 36 gigawatts (GW) of installed power-generation capacity (Table 1, column 2).

Due to the complexity of quantifying and measuring the benefits of the multipurpose dams and pumped storage dams, we have divided 68 WBG hydropower projects into three groups as power only dams, pumped storage dams and multipurpose dams, and concentrated on power only dams. There are 49 WBG projects that are power only dams with total installed capacity of 24.4 GW, 3 projects that are pumped storage dams with total installed capacity of

3.3 GW, and 16 projects that are multipurpose dams with total installed capacity of 8.7 GW (Table 1, column 2). Detailed information on 68 projects is provided in Appendix A (Appendix A Table 1).

Table 1. Summary of projects by type

Type of the project	Number of Projects [1]	Capacity (MW) [2]	Average real cost (US$ million, 2010): Real Capital Cost, Estimated [3]	Real Capital Cost, Actual [4]	Estimated Cost/MW [5]	Actual Cost/MW [6]
Power only dams	49	24,406	33,305	42,970	1.365	1.761
Pumped storage dams	3	3,300	1,839	1,686	0.557	0.511
Multipurpose dams	16	8,692	13,537	19,790	1.557	2.277
Aggregate	**68**	**36,398**	**48,681**	**64,446**	**1.337**	**1.771**

Note: Columns 3 and 4 present the undiscounted but deflated sum of the actual costs incurred for all projects within each group. Figures in column 5 and 6 are weighted averages of cost per MW for various groups.

Table 1 shows the composition of data used for this analysis. The cost per megawatt (MW) of an installed power station is presented in 2010 constant US dollar (US$) prices. The average cost per MW of capacity of projects when fully implemented is significantly lower for pumped storage dams (US$ 0.51 million/MW) than that of multipurpose dams (US$ 2.28 million/MW), or power only dams (US$ 1.76 million/MW (Table 1, column 6).

Four of the 49 projects that are power only dams consist of combination of multiple dams making the total number of power only dams equal to 57. As shown in Table 2, the 57 power only dams are concentrated in East Asia and Pacific islands (16), Latin America and the Caribbean islands (16), Sub-Saharan Africa (12), Europe and Central Asia (8), and in South Asia (5). The average size (in MW) of the projects is much smaller in Sub-Saharan than in Latin America, Asia, Europe, and Caribbean and Pacific islands. The average cost per MW of capacity of projects when fully implemented is significantly lower in East Asia and Pacific islands (US$ 1.13 million/MW) than in Sub-Saharan Africa (US$ 2.81 million/MW), Latin America and Caribbean islands (US$ 2.05 million/MW), South Asia (US$ 1.93 million/MW), and in Europe and Central Asia (US$ 1.59 million/MW) (Table 2, column 6).

Table 2. Summary of data by region

Geographical Location	Number of Dams [1]	Capacity (MW) [2]	Average real cost (US$ million, 2010) Real Capital Cost, Estimated [3]	Real Capital Cost, Actual [4]	Estimated Cost/MW [5]	Actual Cost/MW [6]
East Asia and Pacific	16	7,139	6,983	8,099	0.978	1.134
Europe and Central Asia	8	3,106	4,813	4,947	1.549	1.593
Latin American and the Caribbean	16	10,283	13,428	21,032	1.306	2.045
South Asia	5	2,303	3,998	4,448	1.736	1.931
Sub-Saharan Africa	12	1,575	4,066	4,430	2.582	2.813
Aggregate	**57**	**24,405**	**33,289**	**42,956**	**1.364**	**1.760**

Note: Columns 3 and 4 present the undiscounted but deflated sum of the actual costs incurred for all projects within each regional category. Figures in column 5 and 6 are weighted averages of cost per MW for various regions.

Cost overrun computation

The World Bank projects ICRs give the cost of a project along with the percentages of the total that are foreign and local costs[2]. The actual project cost, however, is expressed in nominal dollar terms. To compute the actual real cost, it is necessary to spread the actual nominal cost over the entire project construction period. The distribution of capital expenditure over the construction period follows the mathematical formulation by Drummond (2012), which is similar to that used by Bacon et al. (1996)[3].

The annual nominal costs are split into foreign and local components, and then deflated to the prices of the starting year. The domestic costs are first converted from nominal US$ to nominal domestic currency units using the market exchange rate for each period. These nominal amounts of domestic costs are deflated by the domestic price index, and then converted back into US$ of the starting year of the project using the market exchange rate for that year.

[2] Information on decomposition of total costs into foreign and local components was missing only for four projects out of sixty eight. Average number for other hydro projects taken place in the same country was used as a proxy.
[3]The spreading of the construction costs was carried out using the function:

$$Y_i = \frac{1}{2+p}\left[(s+1)\left(\frac{i}{I}\right)^s\left(p + \pi sin\left(\pi\left(\frac{i}{I}\right)^{s+1}\right)\right)\right]$$

where Y_i is the share of total capital expenditures allocated to period *i* of the entire construction span that is *I* years; *S* represents the skewness of the cost lay-out curve assumed to be 0.2 for a positively skewed curve over the construction cycle; *p* is the flatness of the curve, and it varies according to the length of construction cycle.

The foreign costs are deflated with the GDP deflator index for the USA. Adding up these two components gives the actual real cost of the project, expressed in dollar terms[4].

This procedure is used to estimate the actual real costs of constructing the dams (Table 2 and Table 1, column 4). The real cost overrun is then computed as the deviation of the actual real cost from the estimated real cost, taken as a percentage of the estimated real cost. We estimate the nominal cost overrun as the percentage deviation of the actual completion cost over the estimated real cost of constructing the dam. This includes both the changes resulting from price escalation and the real cost growth in excess of physical contingencies set aside during appraisal.

Cost of time overrun

Delays often occur during the implementation of a hydro dam project that extend the construction period beyond its original schedule. More than 77 percent of the projects in our sample experience a time overrun of more than 10 percent of the initial time estimated for completion. In planning for power project investments with alternative forms of energy generation, it is important to consider that there are both economic costs and benefits from delaying the construction of these projects. When there is time overrun, there are benefits in PV terms from cost savings from postponing the real capital expenditure outlays[5]. The actual

4 Actual real cost (US$) is:

$$\sum_{i=0}^{T}\frac{C_i^{n\$} * FCX}{I_{o,i}^{F}} + \frac{1}{E_0^m}\sum_{i=0}^{T}\frac{C_i^{n\$} * (1 - FCX) * E_i^m}{I_{0,i}^{D}}$$

where $Cn\$$ denotes the actual nominal cost, FCX is the share of imported components of the total cost; IF and ID are the foreign and domestic price indices, respectively.

5

project cost will be subjected to a longer period of discounting. These benefits, however, may not be significant enough to offset the cost of supplying power by alternative means during the delay period[6].

Although cost overrun and time overrun are not completely separable concepts in project appraisal, the cost implication of the latter is best explained by a marginal evaluation of the societal resource flows that may ultimately be beneficial to the society.

The cost of power generation through the best available alternative is our estimate of the economic value of the lost benefits of electricity generation that are the result of the delay in construction of the hydropower facility. The most likely scenario is that with the delay in the dispatch of the hydro plant, during the peak and off-peak periods other thermal plants will operate for more hours. These will be the plants with the highest marginal running costs (MRC) in the system, which would have been partially or fully retired as a result of the introduction of the hydro dam. The additional costs will include the fuel and variable operating and maintenance (VOM) costs incurred in keeping these marginal plants operating.

In Table 3 the cost data are reported for different alternative thermal plants that we have used in our analysis. Carbon factors for different types of fossil fuel, namely HFO, natural gas, diesel and coal, are also provided in Table 3.

$$\text{Cost savings} \quad = \sum_{i=1}^{T}[C_i^{r\$} * (1+r)^{-i}] - \sum_{j=1}^{Z}[C_j^{r\$} * (1+r)^{-j}]$$

where *i* is the construction year within the scheduled period *T*; *j* is the construction year up to the actual completion period *Z*; $C^{r\$}$ is the real capital expenditure on the hydro project during construction years.

6 If the energy demanded goes unsupplied, the actual cost to the economy may be higher than the hypothetical marginal thermal supply cost that is used in the estimation of the cost of delays.

Table 3. Cost assumptions on alternative thermal plants.

	Type of power plant			
	OCGT	CCGT	Diesel	Coal
Capital cost (US$/kW)	900	1,260	650	3,636
Variable O&M cost (US$/MWh)	3.5	3.5	15.0	4.6
Efficiency rating (%)	34.1%	51.7%	34.5%	38.8%
Fuel requirement, HFO (litre/kWh)	0.252	0.167	0.250	-
Fuel requirement, NG (ft3/kWh)	9.747	6.433	9.649	-
Fuel requirement, diesel (litre/kWh)	0.259	0.171	0.257	-
Fuel requirement, coal (kg/kWh)	-	-	-	0.405
	HFO	NG	Diesel	Coal
CO2 factor (CO2kg/kWh)	0.256	0.181	0.256	0.326

Source: EIA (2016), EPA (2015), Lazard (2015), and World Bank database of implemented projects (SARs and ICRs).

This opportunity cost varies with oil price fluctuations. For countries with a low cost of generating electricity with hydropower, a delay will be more costly because of the relatively unfavorable cost of generating power from alternative sources. The net social cost of delay is then measured as the difference between the marginal running cost of the alternative power generation and the cost savings from the postponed real investment in the dams.

A real discount rate of 10 percent is used to adjust both benefits and costs to bring them to a common point in time.

Measuring the benefits of dams

The benefits of a hydropower dam can be quantified as the value of the avoided generation cost of the fossil-fuel-powered plants that would be required to be built and operated to supply the same volume of electricity as would be supplied by the hydro dam (Zuker and Jenkins, 1984). While the avoided cost of thermal generation does not capture all the economic benefits, or externalities, associated with a hydro dam, these cost savings are a good proxy for a major part of the benefits of hydroelectricity generation when there is a commitment to supply the quantity demanded by one means or another.

An important positive characteristic of hydropower dams is that they allow for less carbon emissions (CO2e) by the alternative thermal plants than would otherwise be the case. This positive externality is a global benefit and it is valued here as the economic cost of carbon damage avoided. A third, but negative, externality that is characteristic of hydro dam developments is the costs associated with community relocation and the loss of agricultural land through flooding. As the World Bank is quite vigilant with the study of environmental impacts and estimation of compensation for affected communities, the capital costs reported for these projects have in many instances already included compensation payments for these costs. Hence, we make no further adjustments in our economic analysis for these social-environmental costs.

Likewise, in the estimation of the economic net present value (NPV) or economic internal rate of return (EIRR) of the projects, we exclude the other benefits often associated with dams, such as providing potable water, irrigation, flood control services, and protection of existing dams situated in a cascade downstream to control extreme flooding and impact on dam safety[7]. Thus, assuming that the next best alternative energy can be generated from a standard thermal plant, the benefits of the hydro dams are measured in three parts: i) cost savings on the fixed annual capital cost of the alternative electricity-generation plant; ii) marginal running cost of the alternative plant; and iii) externality to society and the global environment from the avoided impacts of carbon emissions (CO2e)[8]. The social benefits from

7 In some instances, these externalities are quite substantial (World Bank OED, 1996).

8 The benefit of the hydropower dam is measured as:

$$\sum_{t=0}^{Z+40}\left\{\left[K\frac{r(1+r)^N}{(1+r)^N-1}IC\right]+VOM+(f_t p_t)G_t+SCC\right\}(1+r)^{-t}$$

where K represents the capital cost and N is the economic life of the alternative plant. IC denotes the installed capacity in MW, and G the equivalent electricity output expected to be generated from the hydropower facility in making electricity available to facilitate economic activities are not included, since such benefits would have occurred with the alternative thermal system.

Data on the capital cost of single-cycle, combined-cycle, diesel and coal fired power-generation plants are summarized in Table 3[9]. The annuity formula is used to estimate the annual capital cost per kW, which includes both the depreciation and economic opportunity cost of capital investment, where the economic life (N) of the alternative plant is assumed to be 25 years. The calculated annual capital cost per kW is then multiplied by the installed capacity size of the hydro to obtain the total fixed annual capital cost.

The marginal running cost (MRC) is taken as the value of the fuel and the VOM expense that would be necessary to operate the alternative plants if the hydro dams had not been implemented. This value of fuel is a function of the price (p_t) of fuel and the amount of fuel required per unit of electricity to be generated (f_t). Given that the market price of fuel varies substantially by fuel type, four common types of fuel are considered for the estimation of benefits – heavy fuel oil (HFO), natural gas, diesel, and coal. The type of the thermal alternative plant assumed at the project appraisal stage by the project analysts, together with the type of fuel, are collected from the World Bank PADs for each of the 68 projects. The same thermal alternatives are assumed in our analysis. The actual fuel prices for the period of 1970-2015 from the U.S. Energy Information Administration (EIA) database are used in the calculation of benefits of hydro dams. The fuel prices after 2015 are assumed to be constant at 2015's prices. The fuel prices are adjusted upward by 20 percent when calculating the fuel cost for all regions. This margin/markup on price is to cover port charges, transportation cost, insurance, and distribution cost (IEA, 2014).

period t; f stands for fuel requirement in liter/kWh, and p for price of fuel at period t. *SCC* denotes the social cost of carbon emission. Fixed operating and maintenance costs have been estimated to be similar for both the hydropower facility and the thermal plant (EIA, 2013). Hence, we do not include fixed operating and maintenance in the formula for estimating the hydro benefit.

[9] Data on the capital cost of single-cycle and combined-cycle power generation plants are from the World Bank database of implemented projects (SARs and ICRs).

Fuel requirements per kWh for single-cycle, combined-cycle, diesel and coal fired power-generation plants are summarized in Table 3 where the heating values for those plants are assumed to be 10,000 Btu/kWh, 6,600 Btu/kWh, 9,900 Btu/kWh and 8,800 Btu/kWh respectively (EIA, 2016). Data for net electricity generation of hydro dams are available from the World Bank PAD and ICRs for various projects. When there is only one alternative thermal plant assumed at the appraisal stage, the quantity of electricity projected is attributed solely to that thermal power plant. However, if the thermal alternatives are different for the peak and off-peak periods, and the amounts of electricity are not explicitly distributed among those periods in the PADs, then we assume electricity generation during peak period as 4 hours a day for 260 days and the rest goes to the off-peak period. The VOM cost for the single-cycle, combined-cycle, diesel and coal fired power-generation plants are set at US$ 3.5 per MWh, US$ 3.5 per MWh, US$ 15.0 per MWh, and US$ 4.6 per MWh respectively (EIA, 2016).

The social cost of carbon emission is taken from the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG, 2016) estimates. IWG estimates are used as a guide on estimating the social cost of carbon emissions by WB.

Since this type of project produces benefits over long periods, the results are expected to be sensitive to the choice of discount rate. Therefore, a range of discount rates are considered in a sensitivity analysis to test the robustness of the results of the analysis.

Once the benefits of the hydropower projects are estimated, the net benefits of the dams are derived by subtracting the actual cost of the dam projects from their estimated benefits, and then expressed as the stream of net benefits over time in real PV terms, using 2016 as the base year. The value of electricity that is estimated in this study includes all generation costs, but does not include any differentiated transmission and distribution costs if these were not included in the project reports.

Results and discussion of findings

Findings on cost overruns

The distribution of real cost overruns by dam for our sample of 57 power only dams is shown in Figure 1. These estimates are not weighted by size of dam. The distribution has a mean of 24 percent and standard deviation of 42 percent. Real cost overruns range from -41.8 percent to 176.7 percent of the estimated real costs. Over 70 percent of the projects experienced overruns, half of the overruns were within the 0 percent to 25 percent range. The distribution of real cost overruns is positively skewed; the coefficient of skewness is 1.53.

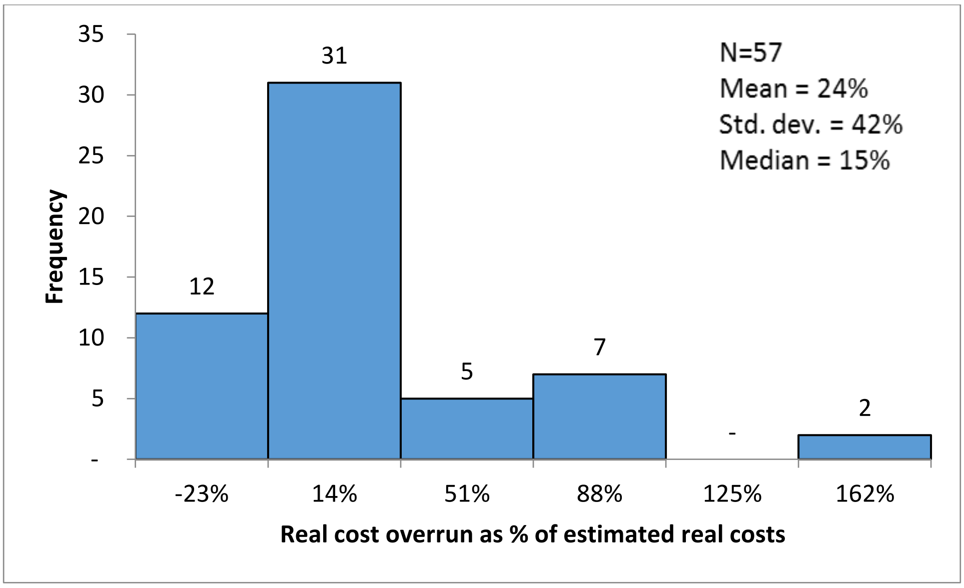

Figure 1. Distribution of real cost overruns

Both the impacts of inflation and the real cost overruns are reported in Table 4. In this case the averages are now weighted averages of the various dams, where the weights are the proportions of the MWs of capacity represented by each dam in the total sample.

As shown in column 2, the cumulative movements in prices have, on average, increased the nominal cost of these dams by 52.6 percent of the estimated real base cost. The estimated real base cost includes the non-price contingencies that are usually included at the time of appraisal, but excludes the price contingencies. The range of total nominal escalation of costs ranges from 87.4 percent of base cost estimates in Latin American and Caribbean region to 13 percent in Europe and Central Asia. In East Asia and Pacific, Sub-Saharan Africa, South Asia the rates of nominal cost escalation are 35.5, 31.0, and 18.4 percent, respectively. The dams implemented in Latin America and Caribbean islands have suffered more from inflation than those in other regions.

The values of the real cost overruns are measured as the excess of the change in actual real costs over the estimated physical contingencies, expressed as a percentage of estimated real cost.

Table 4. Estimated average cost overruns across regions.

Region	Number of Dams [1]	Nominal Cost Overrun as Percentage of Estimated Real Cost (%) [2]	Estimated Price Contingency as percentage of Estimated Real Cost (%) [3]	Actual Price Escalation as Percentage of Estimated Real Cost (%) [4]	Real Cost Overrun as Percentage of Estimated Real Cost (%) [5]
East Asia and Pacific	16	35.57%	22.22%	15.36%	20.22%
Europe and Central Asia	8	12.99%	12.07%	10.29%	2.70%
Latin American and the Caribbean	16	87.37%	18.02%	32.17%	55.20%
South Asia	5	18.44%	16.59%	5.26%	13.18%
Sub-Saharan Africa	12	30.96%	17.60%	21.14%	9.82%
Weighted average	***57***	***52.61%***	***18.33%***	***21.22%***	***31.39%***
Weighted average*	51	44.93%	17.24%	21.30%	23.64%
East Asia and Pacific*	15	35.50%	22.22%	15.36%	20.15%
Latin American and the Caribbean*	12	75.07%	16.12%	34.48%	40.60%
South Asia*	4	7.25%	12.50%	2.17%	5.08%

* Excluding 3 outliers in Latin America and the Caribbean, 1 outlier in East Asia and Pacific, and 1 outlier in South Asia (based on the analysis of the distribution of real cost overrun)

Weighted average real cost overrun is calculated as 31.4 percent of the estimated real cost for the sample of 57 power only dams. This number drops down to 23.6 percent of estimated real cost if we exclude 5 outliers in our sample of 57 dams. The analysis of the distribution of the real cost overruns show that there are 5 outliers in the data set and the highest amount of outliers is in Latin American and Caribbean region: 3 out of 5 outliers. Remaining two outliers are in East Asia and Pacific region, and in South Asia.

By region, the lowest real cost overruns are found for the 8 dams built in Europe and Central Asia, averaging only 2.7 percent over those projected. The experience of Europe and Central Asia contrasts with that of Latin American and the Caribbean region, where real costs are on average 55.2 percent greater than initial estimates, with a cost overrun more than twentyfold that estimated for Europe and Central Asia. Even after removing the outliers, the estimated real cost overrun in Latin America and the Caribbean stands as 40.7 percent of the estimated real cost; this is still much higher than the weighted average of the whole sample. Every country in Latin America and Caribbean has witnessed very high real cost overruns[10].

The average real cost overrun is also low in Sub-Saharan Africa, 9.8 percent of the estimated real costs. This is followed by South Asia; the average real cost overrun is 13.2 percent of the estimated real costs. This value goes down further to 5.1 percent if we remove the outlier from the calculation.

The average real cost overrun for dams in East Asia and Pacific is 20.2 percent of the estimated cost. After removing the outlier, the weighted average real cost overrun is still almost the same as without removing the outlier due to the fact that the outlier dam's capacity is very small making no much of difference when we remove it.

To look deeper behind the reasons for the cost overruns, each of the ICRs were reviewed to find the reasons stated that lead to the cost overrun. These reasons are summarized in Table 5.

Table 5. Causes of cost overruns (summary)

#	Most recurring causes of cost overrun	Frequency of reason given
1	Changes in work volume	13
2	Geological problems	10
3	Inflation/Currency fluctuation	8
4	Unrealistic appraisal estimates	8
5	Real price escalation	5
6	Management challenges	4
7	Time overrun	3
8	Adverse weather condition and natural calamities	3

[10] Pehuenche dam in Chile and Aguamilpa dam in Mexico have witnessed the real cost overruns of -42.8 and -6.2 percent of the estimated real costs respectively. Yet, these are the only cases where the real cost overruns are low in Latin American and Caribbean region. In the same countries other dams have had high real cost overruns like La Huguera dam in Chile and Zimapan dam in Mexico: 80.9 percent and 77.9 percent of the estimated real costs respectively.

9	Unsatisfactory contractor/implementing agency performance	3
10	Resettlement cost	3
12	Challenges with government procedures & policies	3
11	Transportation challenges	2
13	Construction challenges	2
14	Conflict among stakeholders	1
	Total number of stated reasons	68

Of the 68 reasons given for the cost overruns (for some projects more than one reason was given), a total of 13 times a change in work volume was identified as a cause. Geological problems were identified 10 times, while inflation/currency fluctuations and unrealistic appraisal estimated were identified 8 times each. Real price escalation was identified 5 times. These five reasons account for 64.7 percent of the total reasons given for the cost overruns.

It is interesting to note that resettlement costs are only identified in three cases as being a significant cause of cost overruns. It appears that the World Bank has done quite a good job of dealing with these issues prior to the start of the project. However, other implementation issues such as unsatisfactory contractor/implementing agency performance, management challenges, transportation challenges, challenges with government procedures and policies and construction challenges have accounted for a total of 14 of the reasons given for the cost overruns. The “force majeure” type challenges of geology and adverse weather conditions account for 13 reasons which are similar to the above accumulation of the implementation problems faced by the project, and the incidence of changes in work volumes. Details are found in Appendix B of the report.

Clearly, the project managers and consultants who planned these projects underestimated both the average magnitude and the range of physical contingencies required by these dam projects. The uncertainty in the estimation of costs and implementation challenges has led to a very significant downward bias in the estimated costs as compared to actual experience.

Table 6. Incidence of cost overrun by size of installed capacity

Size: installed capacity (MW)		Number of Dams [1]	Actual Real Cost Growth as Percentage of Estimated Real Cost (%) [2]	Estimated Physical Contingencies as percentage of Estimated Real Cost (%) [3]	Real Cost Overrun as Percentage of Estimated Real Cost (%) [4]	Nominal Cost Overrun as Percentage of Estimated Real Cost (%) [5]
0	**- 99**	**19**	**18.71%**	**8.77%**	**9.93%**	**24.54%**
	WS	9	23.64%	9.18%	14.46%	31.03%
	WOS	10	15.17%	8.48%	6.69%	19.89%
100	**- 299**	**18**	**40.03%**	**8.89%**	**31.13%**	**47.60%**
	WS	10	31.93%	10.01%	21.92%	38.47%
	WOS	8	50.16%	7.50%	42.66%	59.04%
300	**- 699**	**10**	**22.20%**	**9.30%**	**12.90%**	**28.90%**
	WS	9	22.06%	9.42%	12.64%	28.82%
	WOS	1	23.51%	8.27%	15.24%	29.68%
700	**- 1499**	**6**	**54.22%**	**11.32%**	**42.90%**	**50.29%**
	WS	5	67.75%	11.69%	56.06%	66.07%
	WOS	1	7.59%	10.07%	-2.49%	-4.12%
1,500	**and above**	**4**	**44.23%**	**10.42%**	**33.81%**	**68.75%**
	WS	4	44.23%	10.42%	33.81%	68.75%
	WOS	0	0.00%	0.00%	0.00%	0.00%
Weighted average		***57***	***41.59%***	***10.20%***	***31.39%***	***52.61%***

Table 6 shows the results of the data analysis for the incidence of cost overrun by size of hydro power generation capacity installed (MW) which is further filtered by the type of the dam whether it has storage or not. There is no simple linear relationship between the degree of cost overrun and a dam’s capacity, or cost overrun and type of a dam. However, dams of larger size, with installed capacity above 700 MW, have performed much poorer in terms of cost planning. Table 6, column 4, shows that on average, dams with capacity between 700 MW to 1499 MW had, by the time of completion, cost overruns of 42.9 percent of real cost estimates at appraisal. Furthermore, projects above 1500 MW capacity had average real cost overruns of 33.8 percent.

Very small sized dams (0–99 MW) seem to have much better estimates at appraisal, with relatively lower real cost overruns of 9.9 percent on average of the real cost estimates during planning. This has been followed by projects with medium-sized installed capacity (300–699 MW) and small projects (100–299 MW), with real cost overruns of 12.9 and 31.1 percent on average of the real cost estimates during planning respectively.

Physical contingency estimates do not differ much for the various size categories: physical contingency estimate is about 9–11 percent of real cost estimates (Table 6, column 3). This shows evidence of a common methodology used by the World Bank in estimating physical contingencies.

Table 7. Comparison of cost overruns for different periods

Projects completed (between)		Number of Dams [1]	Estimated Physical Contingencies as percentage of Estimated Real Cost (%) [2]	Real Cost Overrun as Percentage of Estimated Real Cost (%) [3]	Estimated Price Contingency as percentage of Estimated Real Cost (%) [4]	Actual Price Escalation as Percentage of Estimated Real Cost (%) [5]	Nominal Cost Overrun as Percentage of Estimated Real Cost (%) [6]
1975	1987	21	10.46%	47.37%	19.04%	36.07%	83.44%
1988	1997	20	10.58%	30.54%	21.75%	9.18%	39.71%
1998	2015	16	9.40%	10.53%	13.28%	15.25%	25.78%
Weighted average		***57***	***10.20%***	***31.39%***	***18.33%***	***21.22%***	***52.61%***

At the appraisal stage, an average of 18.3 percent change in price level is projected for the 57 dams in this study (Table 7, column 4). The actual results show that there was a 21.2 percent change in nominal costs owing to price escalation (Table 7, column 5). Taking into account the error between the estimated price contingency and the actual price escalation, expressed as a percentage of estimated real cost, the average error due to the inflation forecast is only 2.9 percentage points. This reveals that on average the inflation forecasts for cost projections in the World Bank projects have not been systematically biased over the entire period for this portfolio of projects. Errors in the forecasting of prices from project to project, however, may be a significant source of risk when planning the financing arrangements of projects.

There is an evidence here of substantial learning since 1998 in price level projections by World Bank project appraisers. The results for the 16 dams completed between 1998 and 2015 were on average the most accurate predictions. The weighted average price contingency proposed by the World Bank analysts was 13.3 percent while the actual weighted average price increase experienced was 15.3 percent. The average error due to the inflation forecast is only two percentage points.

This was not the case for the dams completed in earlier periods. The price levels were either underestimated or overestimated well below/above the actual price levels. The weighted average price contingency proposed by the World Bank analysts for 21 dams completed between 1975 and 1987 was 19 percent while the actual weighted average price increase experienced was 36.1 percent. The average error due to the inflation forecast was underestimated by more than 17 percentage points. The reverse is true for the period between 1988 and 1997. The weighted average price contingency proposed by the World Bank analysts for 20 dams completed between 1988 and 1997 was 21.8 percent while the actual weighted average price increase experienced was only 9.2 percent. The average error due to the inflation forecast was overestimated by 12.6 percentage points.

In Table 7, a comparison is made of the cost overrun estimations for the 21 hydropower dams included in the dataset used by Bacon et al. (1996) and completed prior to 1987 with the measured cost overrun of dams completed between 1988 and 2015. There is an evidence here of substantial learning since 1998. The level of real cost overrun in the period of 1988 to 1997 fell from prior 1987 period by more than 16.8 percent from 47.4 percent to 30.5 percent of the estimated real cost. Furthermore, in the period following 1998 the real cost overrun continues falling and reduced dramatically to 10.5 percent, almost fivefold reduction in real cost overrun in comparison to the period before 1987 (Table 7, column 3).

Then, next our step was to try to understand and find the possible reasons if there any that could explain the substantial reduction in the real cost overrun over the time. Therefore, we have investigated whether there is any relationship between sizes of the dams and year when those dams are completed, or between type of the dam whether it has storage or not with the time when it has been completed. Table 8 is a cross tabulation where one can see what type of dams and how many of them where build in each time period, what were the sizes of those dams.

Table 8. Type and size of the dams for different periods

Dams completed (between)		Number of Dams	
		WS	**WOS**
1975	**1987**	14	7
Average capacity	**447 MW**	618 MW	105 MW
Average capacity excluding outliers*	**171 MW**	217 MW	105 MW
1988	**1997**	17	3
Average capacity	**409 MW**	464 MW	93 MW
Average capacity excluding outliers*	**336 MW**	381 MW	93 MW
1998	**2015**	6	10
Average capacity	**428 MW**	666 MW	285 MW
Average capacity excluding outliers*	**150 MW**	140 MW	156 MW

*Average capacity for this time period excluding the outliers (based on the distribution analysis of dam capacities for each time period).

In Table 8 one thing that that catches the attention is that over the time the type of the dams that WBG has financed has shifted from with storage type of dams to more into without storage type of dams and the average size of the dams has been reduced. This could be one possible explanation why the real cost overrun has reduced dramatically over the time.

Findings on time overruns

Of the dams in this study, the majority experienced time overruns, with an average time overrun of 13.8 months, or 20.2 percent of the scheduled completion time for the project[11]. The overall net cost of the time overrun was 11.1 percent of the estimated real construction cost (Table 9, column 7). This cost could have been avoided if there had been no delays in construction. In South Asia, all 5 projects experienced significant time overrun. The average time overrun was 33.1 percent of the estimated construction schedule at appraisal stage, and the cost of time overrun to the society averaged 28.7 percent of the estimated real cost of the project.

In Europe and Central Asia, time overruns occurred in all 8 projects implemented in this analysis. The average time slippage was 17.1 months, or 22 percent of the estimated construction schedule, at a cost of 18.2 percent of the estimated real cost of the projects. In

[11] This is the weight-adjusted average of installed capacity for each project to the total installed capacity for all the projects in this sample.

Sub-Saharan Africa, time overruns occurred in 9 out of 12 projects in this analysis. The average time slippage was 11.1 months, or 21.3 percent of the estimated construction schedule, at a cost of 9.3 percent of the estimated real cost of the projects. In Latin America and Caribbean islands, time overruns occurred in 14 out of 16 projects in this analysis. The average time slippage was 18.5 months, or 26.9 percent of the estimated construction schedule, at a cost of 10.4 percent of the estimated real cost of the projects.

Table 9. Incidence and cost of time overruns across various regions

Region	Number of Dams [1]	Number of dams with time overrun [2]	Average capacity (MW) [3]	Scheduled (months) [4]	Slippage (months) [5]	Average time overrun (%) [6]	Cost of time overrun as percentage of estimated real costs (%) [7]
East Asia and Pacific	16	13	446	90.7	3.2	5.27%	3.62%
Europe and Central Asia	8	8	388	81.0	17.1	22.04%	18.15%
Latin American and the Caribbean	16	14	643	75.8	18.5	26.94%	10.42%
South Asia	5	5	461	73.9	23.6	33.14%	28.68%
Sub-Saharan Africa	12	9	131	53.0	11.1	21.25%	9.26%
Weighted average	***57***	***49***	***428***	***79.2***	***13.8***	***20.20%***	***11.06%***

The cost of time overrun is measured for projects that had actual time of construction exceed their schedule by more than six months. We assumed that there is no cost of time overrun for this set of projects.

Projects in East Asia and Pacific islands showed better implementation performance than those in other regions. The construction schedule estimates at appraisal were more realistic. With an average construction schedule of 90.7 months, the average delay in completion was only 3.2 months, and the associated cost to society of this overrun averaged 3.6 percent of estimated real cost.

The underlying causes of the time overruns as reported in Table 10 are quite varied. The 5 most frequent reasons given are geological problems (15), conflict among stakeholders (12), adverse weather and national calamities (11), financing (11) and delay in equipment delivery (9). The next five most important identified causes are challenges from government procedures and policies (7), changes in work volumes (7), management challenges (7), delay in bidding/award process (6), and construction challenges (6). It is interesting to note that among the top 10 factors causing time overruns only two, geological problems and changes in work volumes, rank in the top 5 causes of real cost overruns. The detailed analysis of causes of time overruns by project is reported in Appendix C.

Table 10. Causes of time overruns (summary)

#	Most recurring causes of cost overrun	Frequency of reason given
1	Geological problems	15
2	Conflict among stakeholders	12
3	Adverse weather condition and natural calamities	11
4	Financing	11
5	Delay in equipment delivery	9
6	Challenges with government procedures & policies	7
7	Changes in work volume	7
8	Management challenges	7
9	Delay in bidding/award process	6
10	Construction challenges	6
11	Unsatisfactory contractor/implementing agency performance	5
12	Unrealistic appraisal estimates	4
13	Delay of civil works	3
14	Damages	3
15	Delay in project design	2
16	Quality problems	1
17	Transmission challenges	1
18	Corruption/Lack of financial disclosure	1
	Total number of stated reasons	111

In addition to our findings on the severity of time overrun across regions, an investigation was conducted to determine whether the bias in the estimated time for constructing these dams varied by size of dam and by the type of the dam whether it has storage or not. Table 11 gives a summary of the variations between the scheduled length of construction and the actual completion period of dams, distributed according to size of the dam and the type of the dam.

Table 11, column 4, shows the time overrun across the various sizes of hydropower projects. While the average time overrun for all 57 dams was 20.2 percent of the scheduled time, there was a large difference between the time overrun of the 4 large dams (> 1,500 MW capacity), at only 8.5 percent, and that of the remaining 53 dams, at an average of 29.4 percent of the initial scheduled time for completion.

Table 11. Distribution of the cost of time overrun by size

Size: installed capacity (MW)		Number of Dams	Scheduled (months)	Slippage (months)	Average time overrun (%)	Cost of time overrun as percentage of estimated real costs (%)
		[1]	[2]	[3]	[4]	[5]
0	***- 99***	***19***	***58.3***	***20.2***	***37.90%***	***34.23%***
	WS	9	64.0	17.9	29.90%	42.49%
	WOS	10	54.2	21.9	43.63%	28.32%
100	***- 299***	***18***	***57.0***	***14.2***	***28.48%***	***6.42%***
	WS	10	62.4	10.6	18.07%	3.62%
	WOS	8	50.2	18.7	41.51%	9.91%
300	***- 699***	***10***	***64.2***	***12.9***	***20.39%***	***8.25%***
	WS	9	64.7	12.0	18.69%	8.40%
	WOS	1	59.0	21.0	35.59%	6.94%
700	***- 1499***	***6***	***76.2***	***22.6***	***30.82%***	***13.99%***
	WS	5	73.9	22.2	31.47%	6.49%
	WOS	1	84.0	24.0	28.57%	39.88%
1,500	***and above***	***4***	***97.1***	***7.6***	***8.45%***	***9.53%***
	WS	4	97.1	7.6	8.45%	9.53%
	WOS	0	0.0	0.0	0.00%	0.00%
Weighted average		***57***	***79.2***	***13.8***	***20.20%***	***11.06%***

In terms of the costs of the time overruns, the highest costs incurred by smallest dams (0 – 99 MW) at an average of 34.2 percent of the estimated real costs (Table 11, column 5). This is followed by large dams (700–1499 MW), very large dams (above 1500 MW) and medium sized installed capacity (300-699 MW); they have had an average of 14 percent, 9.5 percent and 8.3 percent of cost of time overrun as percentage of estimated real costs respectively. Smaller dams (100 – 299 MW) have had relatively smaller amount of cost of time overrun, 6.4 percent of the estimated costs. It is clear that the very large sized dams were the more efficient as electricity generators as compared to the smaller dams because the cost of time overruns associate with a smaller slippage in schedule was proportionally much larger than the case of the smaller dams where the slippage in time was much larger but the cost of the time overruns was proportionally smaller.

Table 12. Comparison of cost of time overruns for different periods

Projects completed (between)		Number of Dams	Average capacity (MW)	Schedule d (months)	Slippage (months)	Average time overrun (%)	Cost of time overrun as percentage of estimated real costs (%)
		[1]	[2]	[3]	[4]	[5]	[6]
1975	1987	21	447	78.1	10.2	12.99%	9.57%
1988	1997	20	409	73.5	21.3	30.44%	8.29%
1998	2015	16	428	87.4	9.9	17.84%	16.42%
Weighted average		***57***	***428***	***79.2***	***13.8***	***20.20%***	***11.06%***

Bacon et al. (1996) found that the average slippage in the actual construction length of hydropower projects was 28 percent of the time scheduled. In Table 12, a comparison is made between the 21 dams completed prior to 1987 and those completed after 1987. Although the slippage time has reduced to 9.9 months for the projects completed after 1998 compared to the ones completed before 1998, but at a higher cost. This arises because the hydro dams built since 1998 have been lower cost generators of electricity as compared to the thermal alternative that was the case for dams build before 1998. The average time overrun as the percentage of the initial scheduled time for the projects completed after 1998 has been reduced to 17.8 percent from the average value of 30.4 percent for the period 1988 to 1997. The cost of time overrun as the percentage of the estimated real costs has increased to 16.4 percent in the period after 1998, 72 percent larger than that of period 1975 to 1987 and almost two times that of period 1988 to 1997. It is clear that as the cost of thermal generated electricity has increased with increases in fuel prices, then the loss to the country increases from the delay in the supply of lower cost hydro generated electricity.

The estimated cost of time overruns in these results is smaller as compared to the magnitude of the real cost overruns. While the extension to the implementation schedules for the completion of the dams may be significant in terms of calendar months, the real costs imposed by these delays are 11.1 percent of the initial real cost estimate for the projects. These estimates include the impact of the delay on both the PV of construction costs and the PV of the increased running costs of the electricity system as it tries to make up for the loss in electricity generated by the dams as a result of the delay.

However, we need to consider that the loss from time costs as measured here is a loss to the economy due to the loss of a low cost service. This is usually neglected with considering the cost of time delays. This cost is over and above the additional costs incurred to complete construction of a facility that a time delay might impose.

Findings on net benefits of hydropower dams

The discrepancy between the appraisal and the actual rates of return of dams in this study is analyzed based on the 'avoided cost' methodology for electricity generation. Here, the economic benefits of the hydro dams are measured as the cost savings that would be incurred to generate an equivalent amount of electricity with a similar load factor with a configuration of alternative thermal technologies. The rates of return of this portfolio of dams are estimated twice. First, we estimate the ex-ante rates of return, which are based on the estimated construction costs of the dams at the time of appraisal. Second, the rates of return are calculated based on the actual construction costs of the dams. The results are presented in Table 13 by region.

In this study, the internal rates of return are the discount rates at which the estimated benefits associated with the avoided costs of the dams over the operating life of the projects are equal to the actual costs of the dams. This analysis is carried out both excluding the SCC at US$ 39, and including this positive global externality of hydro dams.

The differences between the estimated ex-ante and ex-post rates of return are directly associated with the magnitude of the cost overruns included in the estimated ex-post rates of return. Intuitively, the systematic pattern of errors in cost projections identified in the study suggests that the ex-post rates of returns are more likely to be somewhat below their estimated ex-ante values.

The quantities and load factor of the electricity generated by each hydro dam are those projected at the appraisal stage. Any loss of output due to delays in the dam completion is accounted for in the analysis. When the dam is delayed, the benefit projected profile is shifted to the period when the dam actually starts operation. Hence, the benefits of the dam will have a lower PV. To better understand the impact of possible shortfalls in actual power generation on the outcome of our analysis, we perform a sensitivity analysis for the level of energy output. The benefits of the individual dams – that is, the cost savings from not employing the replacement plant – are estimated using actual data for HFO, natural gas, diesel and coal prices corresponding to each of the years the hydro power plants have operated to date. For periods beyond 2015 to the end of the hydro dams' life cycle (40 years), the HFO, natural gas, diesel and coal prices are assumed to be fixed in real terms at US$ 356.5 per ton, US$ 5.6 per thousand cubic feet, US$ 737.1 per ton, and US$ 93.2 per ton, respectively.

For the range of 57 dams in this study, the average ex-ante rate of return, excluding the benefits of avoided carbon emissions avoided by these hydro dams, estimated at the time of appraisal for the whole portfolio is 17.4 percent, while the ex-post average rate of return is 15.4 percent. The PV of the net benefits evaluated as of 2016 (expressed in terms of the 2016 price level) amounts to US$ 529 billion (Table 13).

Table 13 shows the distribution of the results by region in terms of rates of return and PVs expressed in 2016 dollar prices. The highest rates of return are realized in South Asia and East Asia and Pacific regions. The 5 dams constructed in South Asia, representing about 2.3 GW of installed capacity, have produced an economic net benefit of about US$ 50 billion for the region. The ex-post EIRR for the region is 21 percent, falling slightly below the rate of return at the time of the appraisal, which was estimated to be 21.7 percent. The 16 dams constructed in East Asia and Pacific, representing about 7.1 GW of installed capacity, have produced an economic net benefit of about US$ 100 billion for the region. The ex-ante EIRR for the region is 18.5 percent, and ex-post EIRR is 17.0 percent.

Table 13. Estimated vs. Actual Economic Internal Rate of Return (EIRR) according to region

Region	Number of Dams	Total capacity installed (MW)	PV of estimated costs @ 10% (US$ million, 2016)	PV of actual costs @ 10% (US$ million, 2016)	PV of benefits @ 10% (US$ million, 2016)	Net PV of hydro @ 10% (US$ million, 2016)	Ex-ante EIRR (%)	Ex-post EIRR (%)	Number of dams with projected negative NPV	Number of dams with actual negative NPV
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
East Asia and Pacific	16	7,139	116,132	137,123	237,341	100,218	18.5%	17.0%	1	2
Europe and Central Asia	8	3,106	108,461	113,472	170,921	57,449	13.7%	13.5%	1	1
Latin American and the Caribbean	16	10,283	348,008	553,300	785,442	232,142	17.0%	13.7%	1	8
South Asia	5	2,303	29,381	32,168	82,145	49,977	21.7%	21.0%	1	2
Sub-Saharan Africa	12	1,575	104,344	116,055	205,669	89,614	16.1%	15.1%	3	2
Total	***57***	***24,405***	***706,327***	***952,118***	***1,481,519***	***529,401***	***17.4%***	***15.4%***	***7***	***15***

The 16 dams built in Latin American and Caribbean represent about 10.3 GW of installed capacity. The 17 percent ex-ante EIRR estimated for the region turned out to be 13.7 percent ex-post. The deviation between the ex-ante and ex-post EIRR for the region is explained by the high magnitude of real cost overruns. Notwithstanding the high level of overruns, overall, the dam investments have contributed a net economic gain of US$ 232 billion to the region.

A total of US$ 89 billion worth of net gains are expected to be realized in the Sub-Saharan Africa by the end of the operating life cycle of the 12 dams built in the region. For this sub-sample, the ex-ante EIRR was estimated at 16.1 percent, and ex-post EIRR is 15.1 percent.

The lowest rates of return are realized in Europe and Central Asia region. 8 dams built in the region represent about 3.1 GW of installed capacity and have produced an economic net benefit of about US$ 57 billion for the region. For this region, the ex-ante EIRR was estimated at 13.7 percent, but the ex-post results show that the actual EIRR generated by the projects is 13.5 percent on average.

Table 13 columns 9 and 10 show how many dams in each region had estimated and actual negative NPVs. The highest amount of negative NPV dams is in Latin American and the Caribbean region where half of the dams had negative NPVs, although at the appraisal stage only one out 16 dams had an estimated negative NPV. This could be explained by the high magnitude of real cost overruns in the region. This is followed by South Asia and Sub-Saharan Africa where 40 percent and 16.7 percent of the dams had negative NPVs respectively (Table 13, column 10). In Europe and Central Asia and in East Asia and Pacific regions 12.5 percent of the dams had negative NPVs.

The PVs of the net benefits are reported in Table 14, column 6, according to the size of the installed capacity of the dams and the type of the dams whether they have storage or not. The results show that the internal rates of return of the dams (columns 7 and 8) increase by the size of generating capacity of the dam. Larger dams produce the bulk of the benefits and have relatively higher rates of return on their investment outlays. Smaller dams have the lower rates of return and the highest amount of negative NPV projects are among these smaller dams. 36.8 percent of smallest dams in range of 0 to 99 MW of installed capacity, 30 percent of medium size dams in range of 300 to 699 MW of installed capacity, and 22.2 percent of dams in range of 100 to 299 MW of installed capacity have actual negative NPVs. That is not the story with the large scale dams, only one out of 10 large dams has an actual negative NPV.

When it comes to the type of the dam, there seems no significant difference on rates of return whether a dam has storage or not. There is a considerable difference in rates of return in large dams of 700 to 1499 MW of installed capacity. Yet, the number of with storage and without storage dams in this installed capacity range is not comparable. Therefore, we would ignore this case.

Table 14. Estimated vs. actual EIRR according to size of installed capacity (MW)

Size: installed capacity (MW)		Number of Dams	Total capacity installed (MW)	PV of estimated costs @ 10% (US$ million, 2016)	PV of actual costs @ 10% (US$ million, 2016)	PV of benefits @ 10% (US$ million, 2016)	Net PV of hydro @ 10% (US$ million, 2016)	Ex-ante EIRR (%)	Ex-post EIRR (%)	Number of dams with projected negative NPV	Number of dams with actual negative NPV
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
0	***- 99***	***19***	***969***	***64,532***	***76,498***	***83,008***	***6,510***	***14.0%***	***13.4%***	***6***	***7***
	WS	9	404	28,923	34,253	31,769	-2,484	14.0%	12.9%	4	5
	WOS	10	565	35,609	42,245	51,239	8,994	14.0%	13.8%	2	2
100	***- 299***	***18***	***3,239***	***134,990***	***158,825***	***253,075***	***94,250***	***15.4%***	***13.1%***	***1***	***4***
	WS	10	1,801	89,223	103,051	167,329	64,279	15.6%	14.0%	0	1
	WOS	8	1,438	45,768	55,774	85,745	29,971	15.1%	12.0%	1	3
300	***- 699***	***10***	***4,106***	***151,031***	***192,028***	***258,832***	***66,803***	***15.5%***	***15.5%***	***0***	***3***
	WS	9	3,694	150,070	190,921	256,964	66,043	15.4%	15.6%	0	3
	WOS	1	412	961	1,107	1,868	760	16.2%	14.7%	0	0
700	***- 1499***	***6***	***6,450***	***116,257***	***180,786***	***284,964***	***104,177***	***19.5%***	***17.0%***	***0***	***1***
	WS	5	5,000	103,519	168,365	220,096	51,731	17.5%	14.1%	0	1
	WOS	1	1,450	12,738	12,421	64,867	52,446	26.4%	26.7%	0	0
1,500	***and above***	***4***	***9,642***	***239,516***	***343,980***	***601,641***	***257,661***	***17.8%***	***15.3%***	***0***	***0***
	WS	4	9,642	239,516	343,980	601,641	257,661	17.8%	15.3%	0	0
	WOS	0	0	0	0	0	0	0.0%	0.0%	0	0
	Total	***57***	***24,405***	***706,327***	***952,118***	***1,481,519***	***529,401***	***17.4%***	***15.4%***	***7***	***15***

Considering the relevance of hydropower in the renewable/green energy policy campaign, the social cost of carbon emission (CO2e) that is avoided is an important component of this analysis. Adding this global benefit to the results increases the ex-ante EIRR for host countries in the portfolio from 17.4 percent to 19.5 percent, and ex-post EIRR from 15.4 percent to 17.3 percent (Table 15).

For sample of 57 dams there is on average 2.1 percent difference between ex-ante EIRRs calculated including and excluding the benefit of avoided social cost of carbon emission (Table 15). There is on average 1.9 percent difference between ex-post EIRRs calculated including and excluding the benefit of avoided social cost of carbon emission. The PV of the net benefits evaluated as of 2016 (expressed in terms of the 2016 price level) increases from US$ 529 billion by additional US$ 342 billion of benefits of avoided carbon emissions making the PV of net benefits equal to US$ 871 billion (Table 15, columns 6-8). This value of net benefits represents a very substantial contribution both to the wellbeing of the countries in which these dams are located (US$529 billion) and to the rest of the world through their role in reducing carbon emissions (US$ 342 billion).

Table 15 shows that 16 dams in Latin America and Caribbean avoid 386 million tons of carbon dioxide emissions throughout their project lives in the region. 16 dams in East Asia and Pacific avoid 367 million tons of carbon dioxide emissions throughout their project lives in the region. 8 dams in Europe and Central Asia, 5 dams in South Asia, and 12 dams in Sub-Saharan Africa avoid 136 million tons of carbon dioxide, 105 million tons of carbon dioxide, and 75 million tons of carbon dioxide emissions throughout their project lives in their regions respectively.

Table 15. Estimated vs. actual Economic Rate of Return (EIRR) according to region with and without SCC

Region	Number of dams [1]	Total capacity installed (MW) [2]	Avoided CO2 avoided (thousand tonnes) [3]	PV of actual costs @ 10% (US$ million, 2016) [4]	PV of benefits @ 10% with avoided CO2 (US$ million, 2016) [5]	Net PV of hydro @ 10% (US$ million, 2016) [6]	Net PV of avoided CO2 @ 10% (US$ million, 2016) [7]	Net PV of hydro @ 10% with avoided CO2 (US$ million, 2016) [8]	Ex-ante EIRR with avoided CO2(%) [9]	Ex-post EIRR with avoided CO2(%) [10]	Difference in ex-ante EIRR (%) [11]	Difference in ex-ante EIRR (%) [12]
East Asia and Pacific	16	7,139	367,372	137,123	292,544	100,218	55,203	155,422	20.9%	19.3%	2.5%	2.3%
Europe and Central Asia	8	3,106	136,021	113,472	219,816	57,449	48,895	106,344	15.9%	15.6%	2.2%	2.2%
Latin American and the Caribbean	16	10,283	386,464	553,300	971,084	232,142	185,642	417,785	19.1%	15.5%	2.1%	1.8%
South Asia	5	2,303	104,546	32,168	87,736	49,977	5,591	55,568	22.6%	21.8%	0.8%	0.8%
Sub-Saharan Africa	12	1,575	74,679	116,055	252,551	89,614	46,882	136,496	18.3%	17.1%	2.1%	2.1%
Total	***57***	***24,405***	***1,069,082***	***952,118***	***1,823,732***	***529,401***	***342,213***	***871,615***	***19.5%***	***17.3%***	***2.1%***	***1.9%***

Table **16** summarizes the number of dams in various regions with cost and time overruns.

Table 16. Projects with cost and time overruns across various regions

Region	Total number of dams	Dams with real cost overrun: Number of dams	Number of dams with estimated negative NPV	Number of dams with actual negative NPV	Dams with time overrun: Number of dams	Number of dams with estimated negative NPV	Number of dams with actual negative NPV
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
East Asia and Pacific	16	10	1	2	13	1	2
Europe and Central Asia	8	7	1	1	8	1	1
Latin American and the Caribbean	16	14	1	8	14	1	7
South Asia	5	3	1	2	5	1	2
Sub-Saharan Africa	12	6	1	1	9	3	2
Total	***57***	***40***	***5***	***14***	***49***	***7***	***14***

Another point of interest was to look at the difference between the rates of return estimated by the WB project appraisal analysts and the Independent Evaluation Group (IEG). Table 17 shows both WB and IEG's estimates of ex-ante and ex-post EIRRs for 57 dams in our sample for different regions.

Table 17. Estimated vs. actual Economic Rate of Return (EIRR) according to WB and IEG estimations

Region	Total number of dams	Number of dams with EIRR estimations available (WB)	Ex-ante EIRR (WB) (%)	Ex-ante EIRR (IEG) (%)	Number of WB dams with ex-ante EIRR higher than IEG evaluations	Ex-post EIRR (WB) (%)	Ex-post EIRR (IEG) (%)	Number of WB dams with ex-post EIRR higher than IEG evaluations
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
East Asia and Pacific	16	15	12.99%	18.48%	4	10.79%	16.98%	3
Europe and Central Asia	8	7	11.70%	13.71%	4	9.74%	13.46%	2
Latin American and the Caribbean	16	14	16.04%	17.02%	7	10.01%	13.65%	5
South Asia	5	5	18.52%	21.73%	3	18.49%	21.01%	2
Sub-Saharan Africa	12	9	9.61%	16.14%	6	6.81%	15.06%	3
Total	***57***	***50***	***14.41%***	***17.41%***	***24***	***10.79%***	***15.38%***	***15***

The average ex-ante rate of return by WB project analysts are on average 3 percent lower than that of IEG's, the ex-post rate of return by 4.6 percent. On a regional base, the ex-ante EIRRs estimated by both WB and IEG are pretty close to each other for the dams in Latin America and Caribbean and Europe and Central Asia regions. WB project analysts have underestimated the rates of return in Sab-Saharan Africa, East Asia and Pacific, and in South Asia by 6.5 percent, 5.5 percent, and 3.2 percent respectively compared to the IEG's estimates.

Out of 50 projects for which ex-ante EIRR data is available from WB PADs, in 24 of them WB estimate of rate of return was higher than that of IEG's, and in 26 of them lower.

Sensitivity of net benefits of the dams to choice of discount rates

Given that hydro dams are capital intensive, with most of their costs coming as up-front capital outlays, while the benefits are to be realized in later periods of the project's life cycle, the net benefits are quite sensitive to choice of discount rate. Table 18 shows that the cumulated net benefits of the dams in this study increase when the rate of discount is increases up till 10 percent, and are reduced when the discount rate increases further afterwards. Even at the 12 percent rate of discount, a value of US$ 480 billion accruing directly to the counties hosting these hydro powe dams still a substantial net economic gain from this portfolio of dams.

Table 18. Sensitivity of net benefits to choice of discount rates (US$ million, 2016)

Discount rate	*PV of estimated costs @ discount rate (US$ million, 2016)* [1]	*PV of actual costs @ discount rate (US$ million, 2016)* [2]	*PV of benefits @ discount rate (US$ million, 2016)* [3]	*Net PV of hydro @ discount rate (US$ million, 2016)* [4]
8%	385,191	515,810	1,023,470	507,660
9%	521,424	700,643	1,223,964	523,321
10%*	706,327	952,118	1,481,519	529,401
11%	957,209	1,294,087	1,812,540	518,454
12%	1,297,465	1,758,825	2,238,333	479,508

*base rate.

Conclusions and policy implications

While there is much evidence to show that the construction costs and time schedules for the completion of dam projects are commonly underestimated at the time of appraisal, the results of this study support the view that this portfolio of dam investments is, on the whole, economically worthwhile. This study finds that about 70 percent of the dams incurred construction costs above their initial estimates. Weighted according to the capacity of the project (MW), the real cost overruns for these dams are estimated to be 31.4 percent.

This study also provides some evidence that the World Bank's track record in this regard has significantly improved since 1998 as compared to the period 1975 to 1998, dropping from an average of 47.4 percent the earlier period to 10.5 percent for the 16 projects financed since 1998. Given the high standard deviation of the rates of real cost overruns across the dams, it would appear that there are many unknown elements of cost at the time of appraisal which might require considerable expenditures to be incurred in order to obtain more accurate information. While contingencies for real cost escalation are made by World Bank project appraisers, there seems to be insufficient information available at the time of appraisal to closely link the value of the contingencies to the likely incidence of real cost overruns. The distribution of cost overruns derived by this study can be useful in arriving at such a decision on what amount of contingency budget will be appropriate, or what ex-ante benefit–cost ratio should be considered before reaching a decision to build the dam after taking into account the risk of overruns. This is of course contingent on the level of risk tolerance of the decision makers.

In this study the cost of time overruns is estimated in terms of the alternative generation costs of the electricity not supplied by the project owing to the delay in completion of the dams. Although these costs are positive, at 11.1 percent of the initial real estimated cost of the dams, they are not as high as the underestimation of the real costs of construction.

Nevertheless, the magnitude of failure in cost projections has not prevented most of these dams from being economically beneficial investments. Aggregated over the portfolio of 57 dams, the economic NPV of the set is at least US$ 529 billion.

This key finding from this study provides a strong empirical case for dam investments. If the dams had not been constructed, the economic cost of generating and supplying an equivalent amount of electricity to these societies would have been much greater than the actual cost of the hydropower dam projects. Thus, the notion that hydro dams should not be built because they suffer from cost overruns (Ansar et al., 2014; Sovacool et al., 2014) does not necessarily hold when the benefits of the dams are also brought into the assessment.

Policy implications

The high degree of variability and uncertainty of costs in dam construction raises the question of what improvements in the appraisal and project selection methodology would contribute to better investment decision making. The probabilities and magnitude of the cost overruns that are likely to arise with dams of specific types in particular countries should become a central part of modern project appraisal for such investments.

Because the benefits and the costs of every dam differ, and many dams are far from being marginal investments, the analysts and decision makers should also consider the risks, on the side of both benefits and costs, before coming to a decision on whether a particular dam is an investment that should be supported. One obvious recourse is to carry out a rigorous and impartial sensitivity analysis that recognizes the uncertainty in estimating the major evaluation variables (project cost and time, power demand forecast, fuel price, hydrology, etc.), and to use this analysis to stress test the robustness of the project's economic justification (such as by assessing the probability that the project NPV is less than zero). Under this approach, uncertainty about cost and time estimates is treated in a larger framework than when it is treated alone.

The policy recommendation to be drawn from this analysis is that one should not view all hydro dams as being too risky to undertake. A critical variable is the value of the benefits they will produce, and at what range of costs. If the benefits are large enough relative to the expected costs, such investments can very well be worth the risk. In the case of hydro dams, there is the very real technical uncertainty associated with the geophysical nature of the sites and also the implementation challenges of a management and bureaucratic nature that arise in the process of building the facility. Hence, a realistic assessment of the future benefits of a project is critical in order to assess the magnitude of construction cost risks that can be accommodated.

Appendices

Appendix A: Project information

Appendix A Table 1. Detailed information on projects

#	Project ID	Type	Start	Complete	Capacity (MW)	Energy generation (GWh)	Load factor (%)	Estimated capital cost (US$ million)	Actual capital cost (US$ million)	Estimated physical contingency (US$ million)	Estimated price contingency (US$ million)	Construction months, estimated	Construction months, actual
	Power only dams												
1	Gitaru HPP, Kenya	WS	1974	1978	145	750	59%	123.6	112.1	12.5	12.5	51	51
2	Kapichira Hydroelectric, Malawi	WOS	1992	2000	64	135	24%	231.3	139.9	20.6	55.6	72	96
3	Ruzizi Hydroelectric, Burundi-Rwanda-CDR	WOS	1983	1990	30	140	53%	84.9	79.9	7.8	12.2	82	98
4	Kiambere Hydroelectric, Kenya	WS	1984	1988	150	790	60%	311.8	269.1	33.6	55.1	44	44
5	Andekaleka Power, Madagascar	WS	1979	1982	56	278	57%	116.3	142.1	11.2	22.7	37	39
6	Nkula II Project, Malawi	WOS	1977	1981	56	315	64%	66.4	82.5	6.8	9.8	44	60
7	Mtera Hydroelectric, Tanzania	WS	1984	1991	80	340	49%	197.1	161.0	16.6	45.8	66	92
8	Kidatu Hydropower Plant, Tanzania	WS	1971	1975	200	523	30%	59.0	66.6	6.3	9.1	51	49
9	Volta River Hydroelectric Project, Ghana	WS	1977	1982	324	1,400	49%	190.0	265.0	8.7	25.0	60	76
10	Kpong Hydroelectric, VRA, Ghana	WOS	1977	1982	160	940	67%	236.0	296.0	14.8	45.7	60	72
11	San Carlos, Colombia	WS	1980	1987	1,240	5,144	47%	523.0	601.0	36.6	96.8	79	92
12	Fourth Guadalupe, Colombia	WOS	1981	1986	213	1,077	58%	228.3	211.7	18.9	68.3	51	63
13	Playas Hydropower, Colombia	WS	1983	1988	200	1,450	83%	311.4	235.1	28.1	82.0	48	75
14	Itumbiara Dam, Brazil	WS	1974	1981	2,080	6,430	35%	593.0	1051.0	67.5	56.3	87	84
15	Pehuenche Hydroelectric Dam, Chile	WS	1988	1993	500	2,765	63%	680.5	353.2	48.5	110.3	58	70
16	Nispero Power Project, Honduras	WOS	1979	1984	23	70	36%	53.0	65.0	4.9	2.8	42	63
17	Guavio Hydro Power Project, Colombia	WS	1983	1993	1,000	5,200	59%	1303.0	2545.0	100.5	270.9	72	132
18	Paulo Afonso IV Complex, Brazil	WS	1974	1984	2,462	6,200	29%	692.6	1414.0	60.5	80.5	96	120

19	Aguacapa Power Project, Guatemala	WOS	1978	1981	90	392	50%	100.0	183.0	5.1	14.3	34	44
20	La Fortuna, Panama	WS	1978	1984	300	1,320	50%	222.1	522.0	22.6	71.5	67	84
21	Chixoy Hydro-power, Guatemala	WS	1978	1982	300	1,470	56%	373.0	519.0	42.5	36.5	48	60
22	El Cajon Hydropower Dam, Honduras	WS	1981	1985	300	1,228	47%	493.2	543.4	39.0	142.4	60	58
23	Aguamilpa Hydroelectric project, Mexico	WS	1989	1995	960	2,131	25%	858.0	850.3	120.4	109.7	60	84
24	Zimapan Hydroelectric project, Mexico	WS	1989	1995	292	1,291	50%	418.0	829.2	36.6	33.4	60	84
25	GaziBarotha Hydropower, Pakistan	WOS	1995	2003	1,450	6,600	52%	1864.0	1616.0	169.8	178.5	84	108
26	Cirata Hydroelectric Site, Indonesia	WS	1994	1999	500	1,424	33%	313.0	193.2	30.9	24.7	58	68
27	Saguling Dam, Indonesia	WS	1981	1986	700	2,156	35%	726.7	663.0	55.7	206.8	66	72
28	Bersia Hydroelectric project	WOS	1980	1986	72	238	38%	87.3	69.6	5.3	13.1	72	84
29	Kenering Hydroelectric project	WOS	1980	1986	120	456	43%	145.6	116.1	8.8	21.9	72	84
30	Ban Chao HPP, Thailand	WS	1974	1979	360	1,230	39%	158.7	210.2	12.3	15.5	78	78
31	Yantan Hydroelectric Project, China	WS	1987	1994	1,100	5,040	52%	542.0	661.0	47.4	196.7	87	94
32	Kerala Power Project, India	WOS	1986	1992	180	604	38%	333.3	420.0	16.8	60.6	64	84
33	Marsyangdi Hydroelectric, Nepal	WOS	1986	1989	69	349	58%	323.3	252.0	33.6	44.0	44	49
34	Lubuge Hydroelectric, China	WS	1985	1991	600	2,393	46%	615.0	566.6	35.8	66.5	74	85
35	Ertan I, Sichuan, China	WS	1992	2000	3,300	17,000	59%	1885.0	2282.0	164.0	228.7	111	108
36	Karakaya Hydropower, Turkey	WS	1980	1988	1,800	7,353	47%	1160.4	1135.6	99.8	119.6	85	102
37	Grabovica hydroelectric power plant, Yugoslavia	WS	1980	1989	116	346	34%	104.8	116.3	5.2	11.2	105	116
38	Salakovac Hydroelectric power plant, Yugoslavia	WS	1980	1989	206	580	32%	185.6	206.0	9.1	19.8	105	116
39	Mostar Hydroelectric power plant, Yugoslavia	WS	1980	1989	65	293	52%	154.3	167.1	8.0	24.5	105	116
40	Sir Hydropower Project, Turkey	WS	1986	1991	282	710	29%	241.0	286.9	21.8	38.0	50	61
41	Sigalda HPP, Iceland	WS	1973	1977	100	650	74%	64.3	88.0	3.8	6.4	61	66
42	Berke Hydropower, Turkey	WS	1985	1992	510	1,672	37%	592.1	502.6	50.9	55.7	72	98
43	Yonki Dam, Papua New Guinea	WS	1987	1991	30	165	63%	99.6	124.0	9.2	16.2	52	66

44	Afulilo Hydropower project, Western Samoa	WS	1987	1992	6	24	43%	17.2	33.0	1.7	1.8	42	73
45	Wailoa Hydroelectric, Fiji	WS	1977	1981	80	200	29%	77.1	89.0	6.5	12.5	60	63
46	Rampur Hydropower project, India	WOS	2008	2014	412	1,835	51%	595.0	674.3	43.0	75.0	59	80
47	Dongping hydroelectric power plant, China	WS	2003	2008	110	324	34%	86.6	91.5	7.8	4.9	65	65
48	Najitan hydroelectric power plant, China	WOS	2003	2011	51	151	34%	42.3	43.9	3.6	2.3	65	101
49	Songshuling hydroelectric power plant, China	WOS	2003	2011	50	154	35%	42.1	39.0	3.5	2.2	65	101
50	Xiakou hydroelectric power plant, China	WS	2003	2011	32	80	29%	31.6	31.1	2.2	1.4	65	101
51	Guangrun hydroelectric power plant, China	WS	2003	2011	28	93	38%	35.8	50.9	2.0	1.2	65	101
52	Felou hydroelectric project, Mali, Mauritania, Senegal	WOS	2007	2014	60	330	63%	222.2	183.5	1.3	23.2	38	92
53	Bujagali, Uganda	WOS	2007	2012	250	1,438	66%	735.0	902.0	18.0	23.0	44	54
54	La Higuera, Chile	WOS	2005	2010	155	840	62%	191.6	347.6	20.0	17.8	30	60
55	Cheves Hydro, Peru	WOS	2010	2015	168	840	57%	415.0	633.0	21.5	29.8	38	58
56	Allain Duhangan II, India	WOS	2005	2012	192	810	48%	365.5	546.4	20.1	139.3	50	86
57	Pamir Private Power Project, Tajikistan	WS	2003	2010	28	236	96%	24.4	29.4	1.4	0.7	45	93
	Pumped storage dams												
1	Lam Takhong Hydroelectric, Thailand	PS	1994	2001	500	668	15%	475.4	278.0	34.7	44.5	82	96
2	Yixing Pumped Storage, China	PS	2002	2009	1,000	1,498	17%	490.5	434.6	37.1	28.7	82	98
3	Tianhuangping Hydroelectric Project, China	PS	1993	1998	1,800	2,527	16%	547.0	610.0	32.2	48.7	55	66
	Multipurpose dams												
1	Nangbeto Hydroelectric, Togo	WS	1985	1992	63	148	27%	127.0	117.0	7.5	23.2	73	87
2	Sidi Chero-Al Massira Hydro Project, Morocco	WS	1976	1981	120	310	29%	130.0	152.0	15.9	20.1	61	61
3	Lupohlo 3rd Power Project, Swaziland	WS	1981	1986	20	54	31%	52.5	55.8	5.2	8.6	60	71
4	Rio Grande, Colombia	WS	1983	1990	3,100	17,080	63%	2637.0	5556.0	216.7	492.8	84	90
5	Yacyreta Dam, Argentina/Paraguay	WS	1994	2000	1,800	5,340	34%	2248.0	2251.0	167.5	246.6	86	79

6	Second Xiaolangdi Multipurpose Dam, China	WS	1976	1981	60	165	31%	68.0	118.0	3.5	21.7	60	71
7	Kulekhani HPP, Nepal	WS	1979	1985	400	765	22%	510.0	622.0	32.9	88.5	72	84
8	Chungju Multipurpose Dam, Korea	WS	1977	1981	72	229	36%	144.6	134.0	6.6	23.6	54	60
9	Pattani Hydroelectric Project, Thailand	WS	1980	1985	241	765	36%	361.9	376.0	34.2	58.3	65	72
10	Khao Laem HPP, Thailand	WS	1987	1997	1,400	4,763	39%	779.0	1020.0	50.8	25.3	120	127
11	Shuikou I&II Hydroelectric Project, China	WS	1992	2000	240	520	25%	193.0	276.0	13.4	13.7	58	97
12	Daguangba Multipurpose Project, China	WS	1981	1991	56	165	34%	235.0	270.0	16.0	29.2	67	124
13	Nyaunggyat Dam, Myanmar	WS	1983	1992	600	1,962	37%	506.0	551.0	44.2	121.1	81	112
14	Upper Indravati Hydro Project, India	WS	1980	1989	387	1,219	36%	444.7	489.4	22.3	55.4	105	116
15	4th Inland Waterways Project, China	WS	2005	2011	76	273	41%	249.6	218.5	17.8	8.9	60	77
16	Jiangxi Shihutang Navigation and Hydropower complex project, China	WS	2009	2014	120	472	45%	303.6	330.2	13.0	29.1	65	65

Source: WB project ICR and PADs.

Appendix B: Cost overrun tables

Appendix B Table 1: Projects affected by changes in Work Volume (25.5% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Aguacapa Power Project, Guatemala	1,978	1,981	90	49.72%
2	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%
3	Ban Chao HPP, Thailand	1,974	1,979	360	39.00%
4	Itumbiara Dam, Brazil	1,974	1,981	2,080	35.29%
5	Kpong Hydroelectric, VRA, Ghana	1,977	1,982	160	67.07%
6	Nispero Power Project, Honduras	1,979	1,984	23	35.51%
7	La Fortuna, Panama	1,978	1,984	300	50.23%
8	San Carlos I&II, Colombia	1,980	1,987	1,240	47.36%
9	Volta River Hydroelectric Project, Ghana	1,977	1,982	324	49.33%
10	Yonki Dam, Papua New Guinea	1,987	1,991	30	62.79%
11	Zimapan power dam, Mexico	1,989	1,995	292	50.47%
12	Nkula II project, Malawi	1,977	1,981	56	64.21%
13	El Cajon Hydropower Dam, Honduras	1,981	1,985	300	46.73%

Appendix B Table 2: Projects affected by Inflation/Currency fluctuation (15.7% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Allain Duhangan II, India	2,005	2,012	192	48.16%
2	Ban Chao HPP, Thailand	1,974	1,979	360	39.00%
3	Kidatu Hydropower Plant, Tanzania	1,971	1,975	200	29.85%
4	Kpong Hydroelectric, VRA, Ghana	1,977	1,982	160	67.07%
5	Sigalda HPP, Iceland	1,973	1,977	100	74.20%
6	Turkey - Sir Hydropower Project	1,986	1,991	282	28.74%
7	Yantan Hydroelectric Project, China	1,987	1,994	1,100	52.30%
8	El Cajon Hydropower Dam, Honduras	1,981	1,985	300	46.73%

Appendix B Table 3: Projects affected by Geological problems (19.6% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Allain Duhangan II, India	2,005	2,012	192	48.16%
2	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%
3	Cheves Hydro, Peru	2,010	2,015	168	57.08%
4	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
5	Guangrun hydroelectric power plant, China	2,003	2,011	28	37.79%
6	Kidatu Hydropower Plant, Tanzania	1,971	1,975	200	29.85%
7	Nispero Power Project, Honduras	1,979	1,984	23	35.51%
8	Sigalda HPP, Iceland	1,973	1,977	100	74.20%
9	Zimapan power dam, Mexico	1,989	1,995	292	50.47%
10	Wailoa Hydroelectric, Fiji	1,977	1,981	80	28.54%

Appendix B Table 4: Projects affected by Unrealistic appraisal estimates (15.7% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Afulilo Hydropower project, Western Samoa	1,987	1,992	6	43.49%
2	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%

3	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
4	Itumbiara Dam, Brazil	1,974	1,981	2,080	35.29%
5	Kerala Power Project, India	1,986	1,992	180	38.31%
6	Paulo Afonso IV Complex, Brazil	1,974	1,984	2,462	28.75%
7	Bujagali, Uganda	2,007	2,012	250	65.66%
8	Chixoy Hydro-power, Guatemala	1,978	1,982	300	55.94%

Appendix B Table 5: Projects affected by Real price escalation (9.8% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Itumbiara Dam, Brazil	1,974	1,981	2,080	35.29%
2	Guangrun hydroelectric power plant, China	2,003	2,011	28	37.79%
3	Nkula II project, Malawi	1,977	1,981	56	64.21%
4	Bujagali, Uganda	2,007	2,012	250	65.66%
5	Paulo Afonso IV Complex, Brazil	1,974	1,984	2,462	28.75%

Appendix B Table 6: Projects affected by Time overrun (5.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
2	San Carlos I&II, Colombia	1,980	1,987	1,240	47.36%
3	La Fortuna, Panama	1,978	1,984	300	50.23%

Appendix B Table 7: Projects affected by Adverse weather and natural calamities (5.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Afulilo Hydropower project, Western Samoa	1,987	1,992	6	43.49%
2	Aguacapa Power Project, Guatemala	1,978	1,981	90	49.72%
3	Pamir Private Power Project, Tajikistan	2,003	2,010	28	96.07%

Appendix B Table 8: Projects affected by Unsatisfactory contractor/implementing agency performance (5.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%
2	Kerala Power Project, India	1,986	1,992	180	38.31%
3	La Higuera, Chile	2,005	2,010	155	61.86%

Appendix B Table 9: Projects affected by Management challenges (7.8% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%
2	Cheves Hydro, Peru	2,010	2,015	168	57.08%
3	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
4	Wailoa Hydroelectric, Fiji	1,977	1,981	80	28.54%

Appendix B Table 10: Projects affected by Resettlement costs (5.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Ertan I, Sichuan, China	1,992	2,000	3,300	58.81%

2	Bujagali, Uganda	2,007	2,012	250	65.66%
3	Guangrun hydroelectric power plant, China	2,003	2,011	28	37.79%

Appendix B Table 11: Projects affected by Transport challenges (3.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%
2	Nkula II project, Malawi	1,977	1,981	56	64.21%

Appendix B Table 12: Projects affected by Government procedures/policies (5.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Allain Duhangan II, India	2,005	2,012	192	48.16%
2	Itumbiara Dam, Brazil	1,974	1,981	2,080	35.29%
3	Zimapan power dam, Mexico	1,989	1,995	292	50.47%

Appendix B Table 13: Projects affected by Construction challenges (3.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Aguacapa Power Project, Guatemala	1,978	1,981	90	49.72%
2	Cheves Hydro, Peru	2,010	2,015	168	57.08%

Appendix B Table 14: Project affected by Conflict among stakeholders (1.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%

Appendix B Table 15: Projects with no cost overrun (41.2% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Berke Hydropower, Turkey	1,985	1,992	510	37.43%
2	Cirata Hydroelectric Site, Indonesia	1,994	1,999	500	32.51%
3	Felou hydroelectric project, Mali, Mauritania, Senegal	2,007	2,014	60	62.79%
4	Fourth Guadalupe, Colombia	1,981	1,986	213	57.72%
5	Gitaru HPP, Kenya	1,974	1,978	145	59.05%
6	Karakaya Hydropower, Turkey	1,980	1,988	1,800	46.63%
7	Kiambere Hydroelectric, Kenya	1,984	1,988	150	60.12%
8	Lubuge Hydroelectric, China	1,985	1,991	600	45.53%
9	Marsyangdi Hydroelectric, Nepal	1,986	1,989	69	57.74%
10	Mtera Hydroelectric, Tanzania	1,984	1,991	80	48.52%
11	Pehuenche Hydroelectric Dam, Chile	1,988	1,993	500	63.13%
12	Playas Hydropower Project, Colombia	1,983	1,988	200	82.76%
13	Ruzizi Hydroelectric, Burundi-Rwanda-CDR	1,983	1,990	30	53.27%
14	Saguling Dam Indonesia	1,981	1,986	700	35.16%
15	Kapichira Hydroelectric, Malawi	1,992	2,000	64	24.08%
16	Ghazi-Barotha hydropower project, Pakistan	1,995	2,003	1,450	51.96%
17	Bersia Hydroelectric project	1,980	1,986	72	37.73%
18	Kenering Hydroelectric project	1,980	1,986	120	43.38%
19	Aguamilpa Hydroelectric project, Mexico	1,989	1,995	960	25.34%

20	Songshuling hydroelectric power plant, China	2,003	2,011	50	35.16%
21	Xiakou hydroelectric power plant, China	2,003	2,011	32	28.90%

Appendix B Table 16: Projects with no information on causes of cost overrun

#	Name	Started	Completed	Capacity	Load Factor
1	Grabovica hydroelectric power plant, Yugoslavia	1,980	1,989	116	34.05%
2	Salakovac Hydroelectric power plant, Yugoslavia	1,980	1,989	206	32.22%
3	Mostar Hydroelectric power plant, Yugoslavia	1,980	1,989	65	51.86%
4	Dongping hydroelectric power plant, China	2,003	2,008	110	33.62%
5	Najitan hydroelectric power plant, China	2,003	2,011	51	33.80%
6	Rampur Hydropower project, India	2,008	2,014	412	50.84%

Appendix C: Time overrun tables

Appendix C Table 1: Projects affected by Geological problems (26.8% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Fourth Guadalupe, Colombia	1,981	1,986	213	57.72%
2	Cheves Hydro, Peru	2,010	2,015	168	57.08%
3	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
4	Chixoy Hydro-power, Guatemala	1,978	1,982	300	55.94%
5	Guangrun hydroelectric power plant, China	2,003	2,011	28	37.79%
6	Nispero Power Project, Honduras	1,979	1,984	23	35.51%
7	La Fortuna, Panama	1,978	1,984	300	50.23%
8	Grabovica hydroelectric power plant, Yugoslavia	1,980	1,989	116	34.05%
9	Salakovac Hydroelectric power plant, Yugoslavia	1,980	1,989	206	32.22%
10	Mostar Hydroelectric power plant, Yugoslavia	1,980	1,989	65	51.86%
11	Rampur Hydropower project, India	2,008	2,014	412	50.84%
12	Ruzizi Hydroelectric, Burundi-Rwanda-CDR	1,983	1,990	30	53.27%
13	San Carlos I&II, Colombia	1,980	1,987	1,240	47.36%
14	Wailoa Hydroelectric, Fiji	1,977	1,981	80	28.54%
15	Allain Duhangan II, India	2,005	2,012	192	48.16%

Appendix C Table 2: Projects affected by Adverse weather and natural calamities (19.6% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Afulilo Hydropower project, Western Samoa	1,987	1,992	6	43.49%
2	Aguacapa Power Project, Guatemala	1,978	1,981	90	49.72%
3	Karakaya Hydropower, Turkey	1,980	1,988	1,800	46.63%
4	Grabovica hydroelectric power plant, Yugoslavia	1,980	1,989	116	34.05%
5	Salakovac Hydroelectric power plant, Yugoslavia	1,980	1,989	206	32.22%
6	Mostar Hydroelectric power plant, Yugoslavia	1,980	1,989	65	51.86%
7	Nispero Power Project, Honduras	1,979	1,984	23	35.51%
8	Pamir Private Power Project, Tajikistan	2,003	2,010	28	96.07%
9	Rampur Hydropower project, India	2,008	2,014	412	50.84%
10	Kapichira Hydroelectric, Malawi	1,992	2,000	64	24.08%
11	Pehuenche Hydroelectric Dam, Chile	1,988	1,993	500	63.13%

Appendix C Table 3: Projects affected by Conflict among stakeholders (21.4% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Berke Hydropower, Turkey	1,985	1,992	510	37.43%
2	Cheves Hydro, Peru	2,010	2,015	168	57.08%
3	Karakaya Hydropower, Turkey	1,980	1,988	1,800	46.63%
4	Kerala Power Project, India	1,986	1,992	180	38.31%
5	Kapichira Hydroelectric, Malawi	1,992	2,000	64	24.08%
6	Mtera Hydroelectric, Tanzania	1,984	1,991	80	48.52%
7	Ruzizi Hydroelectric, Burundi-Rwanda-CDR	1,983	1,990	30	53.27%
8	Sigalda HPP, Iceland	1,973	1,977	100	74.20%
9	Nkula II project, Malawi	1,977	1,981	56	64.21%
10	Bersia Hydroelectric project	1,980	1,986	72	37.73%

11	Kenering Hydroelectric project	1,980	1,986	120	43.38%
12	Allain Duhangan II, India	2,005	2,012	192	48.16%

Appendix C Table 4: Projects affected by Financing challenges (19.6% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
2	Karakaya Hydropower, Turkey	1,980	1,988	1,800	46.63%
3	Xiakou hydroelectric power plant, China	2,003	2,011	32	28.90%
4	Guangrun hydroelectric power plant, China	2,003	2,011	28	37.79%
5	Marsyangdi Hydroelectric, Nepal	1,986	1,989	69	57.74%
6	Grabovica hydroelectric power plant, Yugoslavia	1,980	1,989	116	34.05%
7	Salakovac Hydroelectric power plant, Yugoslavia	1,980	1,989	206	32.22%
8	Mostar Hydroelectric power plant, Yugoslavia	1,980	1,989	65	51.86%
9	San Carlos I&II, Colombia	1,980	1,987	1,240	47.36%
10	Sigalda HPP, Iceland	1,973	1,977	100	74.20%
11	Felou hydroelectric project, Mali, Mauritania, Senegal	2,007	2,014	60	62.79%

Appendix C Table 5: Projects affected by Government procedures/policies (12.5% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Kerala Power Project, India	1,986	1,992	180	38.31%
2	Kpong Hydroelectric, VRA, Ghana	1,977	1,982	160	67.07%
3	Marsyangdi Hydroelectric, Nepal	1,986	1,989	69	57.74%
4	Volta River Hydroelectric Project, Ghana	1,977	1,982	324	49.33%
5	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
6	Aguamilpa Hydroelectric project, Mexico	1,989	1,995	960	25.34%
7	Zimapan Hydroelectric project, Mexico	1,989	1,995	292	50.47%

Appendix C Table 6: Projects affected by Delayed bidding/award process (10.7% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Aguacapa Power Project, Guatemala	1,978	1,981	90	49.72%
2	Kpong Hydroelectric, VRA, Ghana	1,977	1,982	160	67.07%
3	Mtera Hydroelectric, Tanzania	1,984	1,991	80	48.52%
4	Saguling Dam Indonesia	1,981	1,986	700	35.16%
5	Kapichira Hydroelectric, Malawi	1,992	2,000	64	24.08%
6	Felou hydroelectric project, Mali, Mauritania, Senegal	2,007	2,014	60	62.79%

Appendix C Table 7: Projects affected by Changes in work volume (12.5% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Aguacapa Power Project, Guatemala	1,978	1,981	90	49.72%
2	Fourth Guadalupe, Colombia	1,981	1,986	213	57.72%
3	Yonki Dam, Papua New Guinea	1,987	1,991	30	62.79%
4	Nispero Power Project, Honduras	1,979	1,984	23	35.51%
5	Lubuge Hydroelectric, China	1985	1991	600	46%
6	Paulo Afonso IV Complex, Brazil	1974	1984	2462.4	29%
7	San Carlos I&II, Colombia	1,980	1,987	1,240	47.36%

Appendix C Table 8: Projects affected by Construction challenges (10.7% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Aguacapa Power Project, Guatemala	1,978	1,981	90	49.72%
2	Cheves Hydro, Peru	2,010	2,015	168	57.08%
3	Karakaya Hydropower, Turkey	1,980	1,988	1,800	46.63%
4	Playas Hydropower Project, Colombia	1,983	1,988	200	82.76%
5	Sigalda HPP, Iceland	1,973	1,977	100	74.20%
6	Yantan Hydroelectric Project, China	1,987	1,994	1,100	52.30%

Appendix C Table 9: Projects affected by Management challenges (12.5% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Afulilo Hydropower project, Western Samoa	1,987	1,992	6	43.49%
2	Cheves Hydro, Peru	2,010	2,015	168	57.08%
3	Guangrun hydroelectric power plant, China	2,003	2,011	28	37.79%
4	Kerala Power Project, India	1,986	1,992	180	38.31%
5	Nispero Power Project, Honduras	1,979	1,984	23	35.51%
6	Sigalda HPP, Iceland	1,973	1,977	100	74.20%
7	Turkey - Sir Hydropower Project	1,986	1,991	282	28.74%

Appendix C Table 10: Projects affected by Unsatisfactory contractor/implementing agency performance (8.9% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Fourth Guadalupe, Colombia	1,981	1,986	213	57.72%
2	Kerala Power Project, India	1,986	1,992	180	38.31%
3	Paulo Afonso IV Complex, Brazil	1974	1984	2462.4	29%
4	Yantan Hydroelectric Project, China	1,987	1,994	1,100	52.30%
5	La Higuera, Chile	2,005	2,010	155	61.86%

Appendix C Table 11: Projects affected by Delayed equipment delivery (16.1% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Najitan hydroelectric power plant, China	2,003	2,011	51	33.80%
2	Songshuling hydroelectric power plant, China	2,003	2,011	50	35.16%
3	Xiakou hydroelectric power plant, China	2,003	2,011	32	28.90%
4	Guangrun hydroelectric power plant, China	2,003	2,011	28	37.79%
5	Lubuge Hydroelectric, China	1985	1991	600	46%
6	Yantan Hydroelectric Project, China	1,987	1,994	1,100	52.30%
7	Kapichira Hydroelectric, Malawi	1,992	2,000	64	24.08%
8	Nkula II project, Malawi	1,977	1,981	56	64.21%
9	Pehuenche Hydroelectric Dam, Chile	1,988	1,993	500	63.13%

Appendix C Table 12: Projects affected by Unrealistic appraisal estimates (7.1% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Afulilo Hydropower project, Western Samoa	1,987	1,992	6	43.49%
2	Grabovica hydroelectric power plant, Yugoslavia	1,980	1,989	116	34.05%
3	Salakovac Hydroelectric power plant, Yugoslavia	1,980	1,989	206	32.22%
4	Mostar Hydroelectric power plant, Yugoslavia	1,980	1,989	65	51.86%

Appendix C Table 13: Projects affected by Poor quality of inputs (1.8% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Lubuge Hydroelectric, China	1985	1991	600	46%

Appendix C Table 14: Projects affected by Delay in civil works (5.4% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Guavio Hydro Power Project, Colombia	1,983	1,993	1,000	59.36%
2	Lubuge Hydroelectric, China	1985	1991	600	46%
3	Ghazi-Barotha hydropower project, Pakistan	1,995	2,003	1,450	51.96%

Appendix C Table 15: Projects affected by Damages (5.4% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Pamir Private Power Project, Tajikistan	2,003	2,010	28	96.07%
2	Rampur Hydropower project, India	2,008	2,014	412	50.84%
3	San Carlos I&II, Colombia	1,980	1,987	1,240	47.36%

Appendix C Table 16: Projects affected by Delayed project design (3.6% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Kapichira Hydroelectric, Malawi	1,992	2,000	64	24.08%
2	Playas Hydropower Project, Colombia	1,983	1,988	200	82.76%

Appendix C Table 17: Project affected by Transmission challenges (1.8% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Rampur Hydropower project, India	2,008	2,014	412	50.84%

Appendix C Table 18: Project affected by Corruption/lack of financial disclosure

#	Name	Started	Completed	Capacity	Load Factor
1	Bujagali, Uganda	2,007	2,012	250	65.66%

Appendix C Table 19: Projects with no time overrun (16.1% of total projects considered)

#	Name	Started	Completed	Capacity	Load Factor
1	Andekaleka hydroelectric Project, Madagascar	1,979	1,982	56	56.67%
2	Ban Chao HPP, Thailand	1,974	1,979	360	39.00%
3	El Cajon Hydropower Dam, Honduras	1,981	1,985	300	46.73%
4	Ertan I, Sichuan, China	1,992	2,000	3,300	58.81%
5	Gitaru HPP, Kenya	1,974	1,978	145	59.05%
6	Itumbiara Dam, Brazil	1,974	1,981	2,080	35.29%
7	Kiambere Hydroelectric, Kenya	1,984	1,988	150	60.12%
8	Kidatu Hydropower Plant, Tanzania	1,971	1,975	200	29.85%
9	Dongping hydroelectric power plant, China	2,003	2,008	110	33.62%

Appendix C Table 20: Project with no information on causes of time overrun

#	Name	Started	Completed	Capacity	Load Factor
1	Cirata Hydroelectric Site, Indonesia	1994	1999	500	33%

Appendix D: Benefits in Addition to Electricity

In addition to providing renewable energy, 16 of the 68 projects analyzed produce a number of additional benefits such as flood control, water supply, irrigation and navigation. When these additional benefits are taken into consideration, the projects become even more valuable. A comparison of the economic internal rate of returns (EIRRs) from our analyses and those recorded in the project appraisal documents as reported in the table below shows that; ex-ante, the average EIRR from the project appraisal documents for this set of projects is 3.1% higher than the average from our computations, and ex-post, it is 2.6% higher than our calculations.

#	Project name	Additional Benefits	Ex-ante EIRR		Ex-post EIRR	
			(WB)	(IEG)	(WB)	(IEG)
1	Nangbeto Hydroelectric, Togo	Irrigation	10.0%	11.2%	10.0%	11.1%
2	Sidi Chero-Al Massira Hydro Project, Morocco	Irrigation	9.6%	9.5%	11.1%	8.7%
3	Lupohlo 3rd Power Project, Swaziland	Irrigation	9.4%	5.3%	6.8%	4.2%
4	Rio Grande, Colombia	Potable water supply	18.0%	12.7%	9.0%	12.7%
5	Yacyreta Dam, Argentina/Paraguay	Navigation & irrigation	14.0%	17.4%	5.5%	11.0%
6	Second Xiaolangdi Multipurpose Dam, China	Flood control & irrigation	20.8%	12.5%	13.2%	12.6%
7	Kulekhani HPP, Nepal	Irrigation, fisheries & recreation	6.0%	11.0%	3.3%	5.4%
8	Chungju Multipurpose Dam, Korea	Municipal, industrial & irrigation water	12.0%	8.1%	13.9%	6.5%
9	Pattani Hydroelectric Project, Thailand	Flood control & irrigation	11.0%	6.4%	12.0%	6.6%
10	Khao Laem HPP, Thailand	Flood & pollution control, & irrigation	16.0%	8.9%	16.0%	8.1%
11	Shuikou I&II Hydroelectric Project, China	Navigation	15.0%	17.8%	21.5%	15.8%
12	Daguangba Multipurpose Project, China	Irrigation	15.0%	14.9%	16.1%	12.1%
13	Nyaunggyat Dam, Myanmar	Irrigation	21.3%	3.3%	14.1%	3.1%
14	Upper Indravati Hydro Project, India	Irrigation	12.0%	13.2%	n.a.	11.2%
15	4th Inland Waterways Project, China	Navigation	n.a.	8.0%	n.a.	9.9%
16	Jiangxi Shihutang Navigation and Hydropower complex project, China	Navigation	14.9%	9.5%	12.9%	9.0%
		Average	13.7%	10.6%	11.8%	9.2%

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