Discussion Paper on Storage Hydro PPA Pricing

This report has been prepared for the Electricity Regulatory Commission by:

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Abbreviations and acronyms

BESS	Battery Energy Storage System
CAPM	Capital Asset Pricing Model
CERC	Central Electricity Regulatory Commission (India)
CfD	Contract for Difference
DAC	Day Ahead Contingency
DAM	Day Ahead Market
DKSHEP	Dudhkoshi Storage Hydroelectric Project
DoED	Department of Electricity Development
DSCR	Debt Service Coverage Ratio
ECA	Economic Consulting Associates
ERC	Electricity Regulatory Commission
FO&M	Fixed Operations and Maintenance
GBHF	Government-Backed Hedging Facility
GWh	Gigawatt-Hour
HEP	Hydro-Electric Project
HP-DAM	High Price Day-Ahead Market
IDA	Intra Day
IDC	Interest During Construction
IEX	Indian Energy Exchange
INR	Indian Rupee
IPP	Independent Power Producer
IRR	Internal Rate of Return
JICA	Japan International Cooperation Agency
kW	Kilowatt
kWh	Kilowatt-Hour
Lao PDR	Lao People’s Democratic Republic
LCOE	Levelised Cost of Electricity
LLCR	Loan Life Coverage Ratio
MoEWRI	Ministry of Energy, Water Resources and Irrigation
MW	Megawatt
MWh	Megawatt-Hour
NEA	Nepal Electricity Authority
NPR	Nepalese Rupee
NPV	Net Present Value
NREL	National Renewable Energy Lab
NREP	Nepal Renewable Energy Programme

NT2	Nam Theun 2 (Lao PDR)
Nu	Bhutanese ngultrum
PPA	Power Purchase Agreement
PROR	Peaking Run-Of-River
ROE	Return On Equity
ROR	Run-Of-River
RTM	Real-Time Market
SHEP	Storage Hydroelectric Project
SO	System Operator
SRAS	Secondary Reserve Ancillary Service
TAM	Term Ahead Market
TRAS	Tertiary Reserve Ancillary Service
US¢	United States Dollar Cent
USD	United States Dollar
VOLL	Value of Lost Load
VO&M	Variable Operating and Maintenance costs
WECS	Water and Energy Commission Secretariat

Exchange rate assumptions:

USD 1.0 = NPR 133.5

INR 1.0 = NPR 1.60

MAIN REPORT

1 Introduction

This report has been prepared by Economic Consulting Associates (ECA) for the Electricity Regulatory Commission (ERC). The purpose of this report is to develop a proposal for the pricing arrangements for power purchase agreements (PPAs) for reservoir hydropower plants, entered into between the Nepal Electricity Authority (NEA) and independent power producers (IPPs), which are subject to approval by ERC.

Three key questions need to be addressed in identifying the appropriate PPA pricing option for storage hydroelectric power projects (SHEPs) in Nepal. These are:

1. How are the **eligible costs** to be recovered through tariffs determined?

2. What is the appropriate **charging structure** to recover these costs?

3. How is the **tariff calculated** to recover these costs?

In our analysis and proposals for addressing these questions, we have made a number of key assumptions:

- The objective is to **deliver investment in reservoir hydro at an acceptable cost**. This presupposes that the project has previously been determined to be the least-cost approach to meeting demand.

- The inherent risks in large hydropower projects, the political and wider macro-economic uncertainties of Nepal, and Nepal's reliance on international capital, mean that **'derisking' to make reservoir hydro projects attractive to international investors is an important part of the pricing design**.

- While ERC will issue guidelines and approve the final tariff, there is scope for negotiation between the project owner and the licensee purchasing power from the project. Therefore, **the guidelines can be considered to set an upper limit on the tariff, but negotiations can reduce the tariff below this limit**.

This discussion paper has been developed in collaboration with the ERC and has incorporated multiple rounds of stakeholder consultation. This has comprised of preparing a draft discussion paper which was circulated to stakeholders, undertaking a mission to Kathmandu in November 2024 to conduct a stakeholder workshop and meet with the Ministry of Energy, Water Resources, and Irrigation (MOEWRI), and responding to multiple comments from the ERC and other stakeholders on the draft discussion paper and feedback from the stakeholder workshop.

The remainder of this report is organised as follows:

- Section 2 provides a brief overview of the Nepali electricity sector to provide context for the proposals. This is supplemented by Annex A1, which contains tables of existing and planned power plants in Nepal.

- Sections 3 to 5 discuss alternative approaches to setting hydropower tariff, considering in turn questions of eligible costs, charging structures, and calculation of the tariff, and provide our proposals. These are supplemented by Annex A2, which reviews recent pricing in Indian electricity markets as a potential benchmark for the value of hydropower in Nepal, and by Annex A3, which contains analysis of options for setting a dry-wet season tariff ratio.

- Section 6 provides a summary of the sensitivity of hydropower tariffs under our proposals to changes in key variables, to provide an indication of which components of the approach are most critical to the final tariff. This is supplemented by Annex A4, which contains illustrative tariff calculations using hypothetical parameters for a reservoir hydro project with a number of sensitivities. The MS Excel file used for these calculations is provided alongside this report.

- Section 7 summarises.

An earlier draft of this report was consulted on with key stakeholders. This final version reflects the comments received during the consultation process.

2 Setting the context

2.1 Electricity supply and demand

2.1.1 Supply

Electricity generation in Nepal is dominated by hydropower. The NEA, in its Annual Report for 2023-24, lists 161 IPP hydro projects and 57 NEA projects (whether directly owned or owned through a subsidiary), with a combined capacity of 2,991 MW (95% of total generation capacity). Hydro capacity is predominantly run-of-river (ROR) plants with a small number of peaking run-of-river (PROR) plants with reservoirs with a few hours of storage capacity. Kulekhani I (60 MW[1]) is currently Nepal's only reservoir hydropower plant. In terms of dispatchable generators, there are two sizeable thermal plants, the 39 MW Duhabi Multi-Fuel and the 14 MW Hetauda Diesel Powerhouse, plus a 6 MW bagasse-fired IPP. However, both the diesel-fired plants are aging and are little used today. Duhabi's first unit was commissioned in 1990-91 and Hetauda's commissioning dates back to 1963-80.[2]

A further 3,741 MW of hydropower plant capacity is under construction or at the planning / proposal stage. Of this, 1,678 MW represents reservoir hydropower capacity and a further 150 MW comprises the Begnas Rupa pumped storage project. A listing of existing, under construction, and planned power plants is provided in Annex A1.

Nepal has pronounced wet and dry seasons. The dry season is approximately December to May and the wet season is approximately June to November.[3] Combined with the reliance on ROR hydropower generating capacity, this leads to very different patterns of generation between the seasons. This is illustrated below (Figure 1). In the dry season, Nepal imported over 1,800 GWh from India, to which it is interconnected, but still sees some curtailments due to limited generating capacity and reduced imports at the evening peak, as illustrated by the generation mix during the maximum system demand day in 2022-23. Meanwhile, Nepal exported over 1,900 GWh to India in its wet season.

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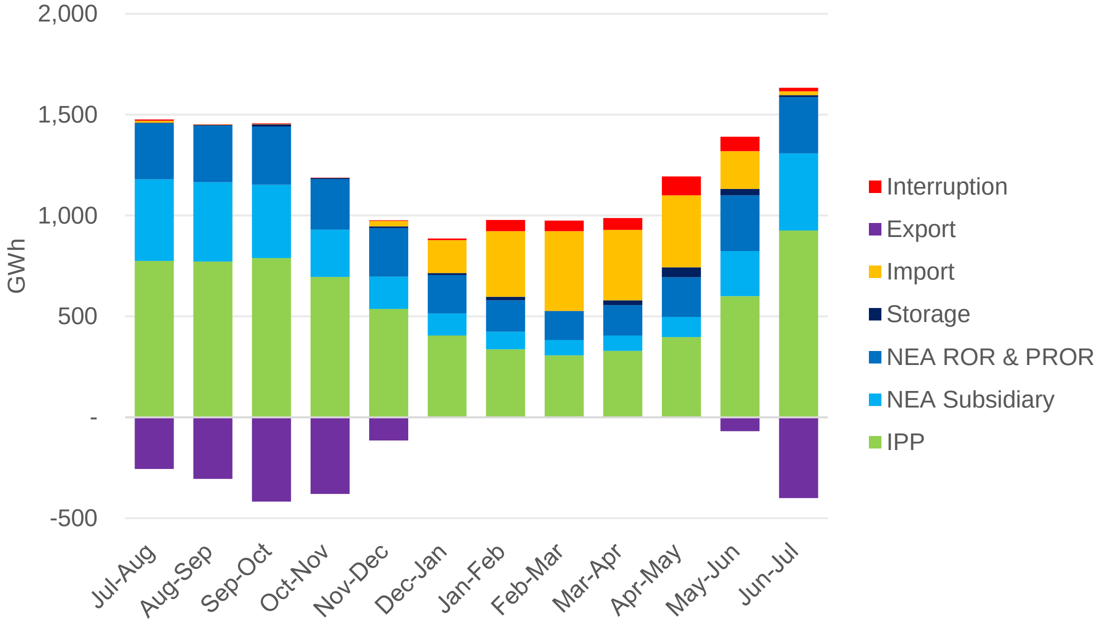
1 Kulekhani II (32 MW) and Kulekhani III (14 MW) are cascades of the Kulekhani I reservoir.

2 NEA. 2024. Annual Report 2023-24 (pp28)

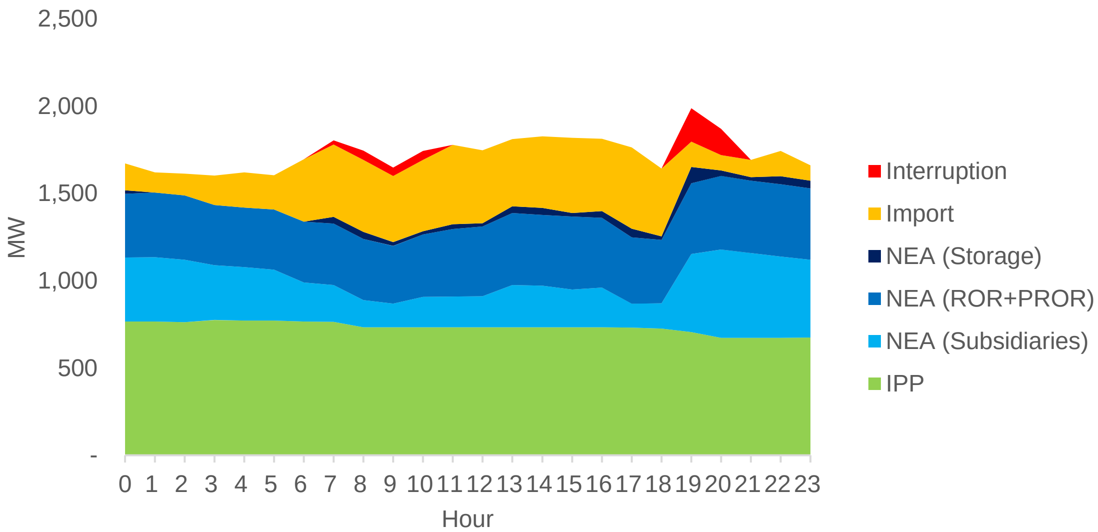
3 According to the Nepali lunisolar calendar, the wet season is defined as 16 Jestha to 15 Mangsir and the dry season is defined as 16 Mangsir to 15 Jestha.

Figure 1 Generation mix

Monthly energy balance, 2023-24



Generation mix during maximum system demand day, 2022-23 (1 June 2023)



Source: NEA. 2024. Annual Report 2023-24 (pp179) and NEA. 2023. Annual Report 2022-23 (pp149)

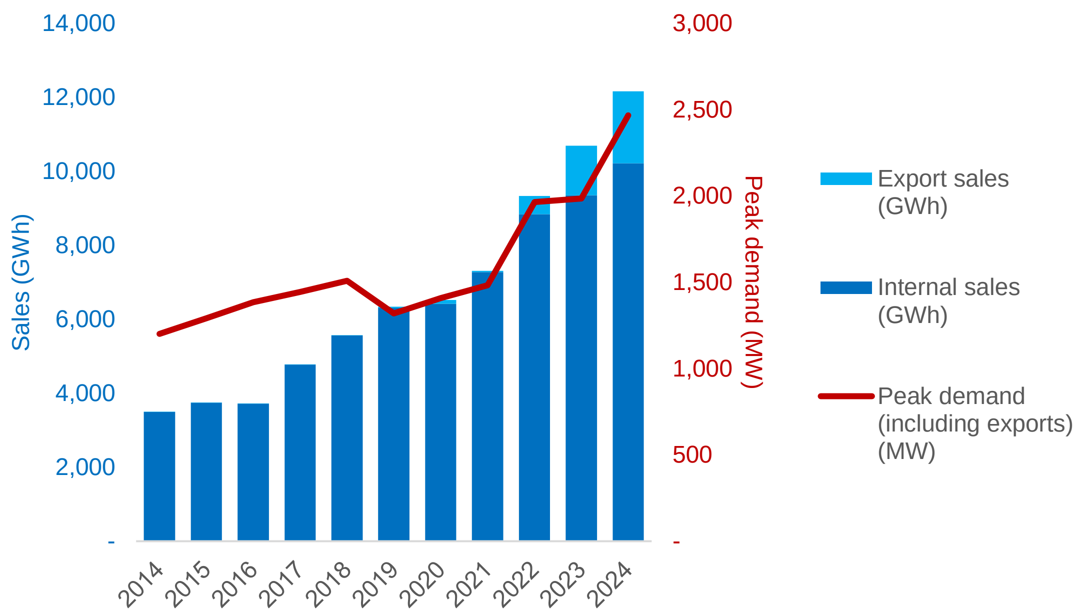
2.1.2 Demand

Electricity demand in Nepal has grown rapidly in recent years, averaging 13.6% electricity consumption growth annually and 7.3% consumer numbers growth annually during 2015-24 (Figure 2).[4] This has been accompanied by the start of significant exports to India. NEA

4 NEA. 2024. Annual Report 2023-24 (pp171-173)

forecasts consumption to reach 31.1 TWh by 2030 (a near-tripling of current levels), 50.9 TWh by 2035, and 82.6 TWh by 2040, requiring 6.9 GW of installed capacity, 11.2 GW, and 18.1 GW, respectively.[5]

Figure 2 Historical electricity sales and peak demand



Source: NEA. 2024. Annual Report 2023-24 (pp171-172)

2.1.3 Exports and imports

Exports to and imports from India are an increasingly important factor in the Nepalese power sector. Nepal began participating in the Indian Energy Exchange (IEX) in April 2021. NEA can now export up to 690.5 MW to India via a combination of IEX spot trades and bilateral agreements, and this is expected to continue to grow. A recent political agreement announced an intention to increase export capacity to up to 10,000 MW by 2034.[6]

Nepal exported 1,946 GWh to India in 2023-24, a 45% increase from 1,346 GWh in 2022-23 and almost four times as high as 493 GWh in 2021-22. Nepal imported 1,895 GWh from India in 2023-24, a slight decrease from 1,833 GWh in 2022-23, making it a net exporter (+51 GWh) for the first time.[7] Exports to India have now grown to 14.6% of NEA's gross electricity sales revenue in 2023-24, compared to minimal exports pre-2019 and exports making up only ~1% of

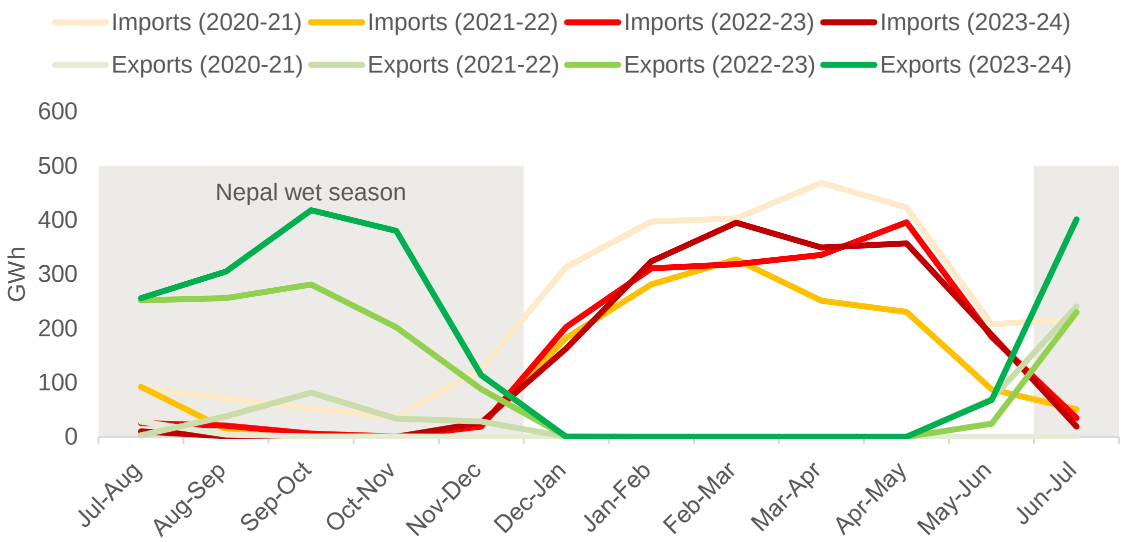
5 A report for the Nepal Renewable Energy Programme (NREP) notes that this forecast may be excessive, highlighting a number of concerns with the forecasts produced by the NEA and Water and Energy Commission Secretariat (WECS). The NEA/WECS forecast for 2025 electricity consumption of 14.9-18.6 TWh implies a 50+% increase from 2023 levels, which appears unlikely. The report's alternative forecast is for electricity consumption to reach 22.1 TWh by 2040, requiring installed capacity to rise to 3.6 GW by 2030, 4.7 GW by 2035, and 5.9 GW by 2040. [VRock. 2021. Projection of Emissions Associated with Electricity Trading as part of Nepal's Long-Term Strategy to Achieve Net-Zero Emissions Status by 2050. Report for Nepal Renewable Energy Programme]

6 Anil Giri. 5 January 2024. "Nepal and India review relations, sign 10,000MW power export deal". The Kathmandu Post

7 NEA. 2024. Annual Report 2023-24 (pp3) and NEA. 2023. Annual Report 2022-23 (pp14)

gross electricity sales before starting to rise in 2022.[8] These exports and imports are highly seasonal in nature (Figure 3): Nepal exports during the wet season, while imports from India are concentrated in the dry season.

Figure 3 Nepal-India exports and imports (2020-21 to 2023-24)

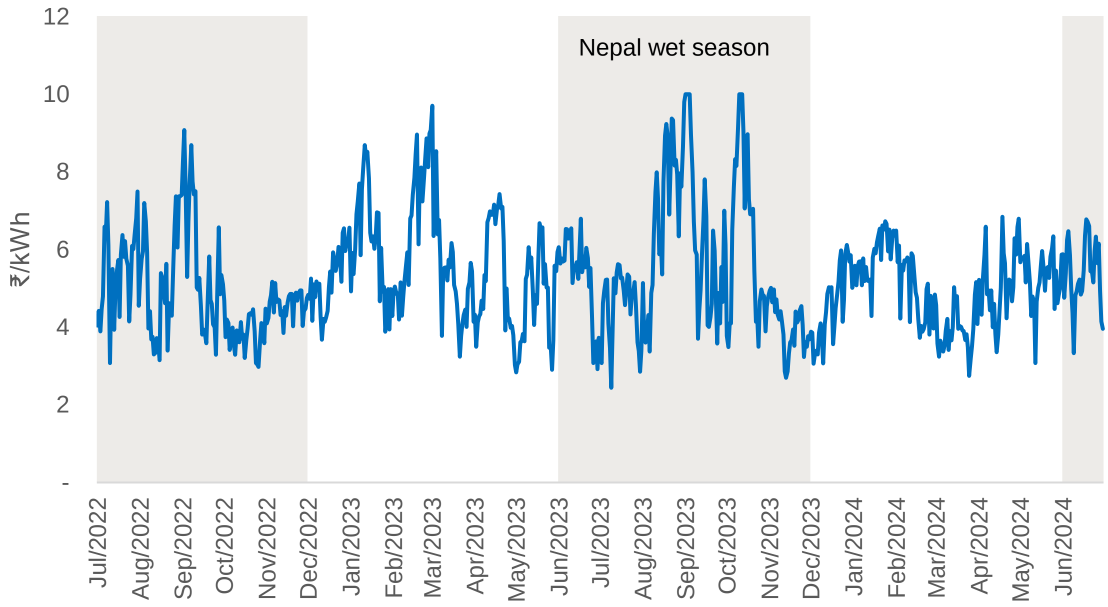


Source: NEA. 2023. Annual Report 2022-23 (pp152-153) and NEA. 2024. Annual Report 2023-24 (pp180-181). Displaying dry season of December - May (16 Mangsir – 15 Jestha) and wet season of June - November (16 Jestha – 15 Mangsir).

Recent patterns in IEX prices do not clearly correspond with Nepal's wet and dry seasons (Figure 4). Between July 2022 and June 2024, average IEX DAM prices were only nominally higher during Nepal's dry seasons at INR 5.30/kWh (US¢ 6.3/kWh or NPR 8.5/kWh) versus INR 5.22/kWh (US¢ 6.2/kWh or NPR 8.4/kWh) during Nepal's wet seasons.

8 NEA. 2024. Annual Report 2023-24 (pp174)

Figure 4 IEX DAM prices (July 2022 to June 2024)



Source: CEA. Monthly Reports Archive

Prices shown are volume-weighted daily average market-clearing prices for the IEX's day-ahead market (DAM). Displaying dry season of December - May (16 Mangsir – 15 Jestha) and wet season of June - November (16 Jestha – 15 Mangsir).

There have been episodes of IEX DAM price volatility, such as a price spike in the middle of Nepal's wet season in August-September 2023,[9] but this was due to unusually hot weather in India, which corresponded with reduced hydropower generation. Prices appear to have been less volatile in recent months.

2.2 Existing hydropower PPA tariffs

Standard tariffs for purchases by NEA from ROR, PROR, and reservoir hydropower projects were issued by the NEA Board on 27 April 2017 (Table 1). We understand from the ERC that those for reservoir hydropower projects were specifically intended for Nepal's only existing reservoir project, Kulekhani I, and have subsequently been withdrawn. Nevertheless, we include them here for completeness.

Specific conditions relating to reservoir hydropower PPA tariffs were:

- A 3% annual escalator was applied for 8 years.
- The 'base rate' is lowered for projects if their actual return on equity (ROE) exceeds 17%.

[9] As noted in Annex A2, this period also saw the highest volume of trading in the IEX's 'high-price' DAM (HP-DAM) as DAM prices consistently reached its price cap of 10 INR/kWh (NPR 16/kWh or US¢ 11.9/kWh). Trading on the HP-DAM has otherwise been minimal.

- If the dry season energy generated falls below 35% of annual energy generated, the PPA rates revert to that of a PROR project.
- Active storage volume should not fall below 15 days of design discharge levels.
- Dead storage volume should be designed to not be filled by sediment for at least 50 years.

Table 1 Nepal hydropower PPA tariffs (effective 27 April 2017)

Reservoir hydropower projects (subsequently withdrawn)

Season	Rate (NPR/kWh)	Minimum dry season energy %
Dry season	12.4	35%
Wet season	7.1	

ROR hydropower projects

Option	Season	Rate (NPR/kWh)	Dry / wet season energy (%)
1: 6 months dry season, 6 months wet season	Dry season	8.4	Wet season maximum 70%
	Wet season	4.8	
2: 4 months dry season, 8 months wet season	Dry season	8.4	If energy over 6-month dry season is less than 30%
	Wet season	4.8	

PROR hydropower projects

Season	Time of Day	Daily hours at rated capacity	Rate (NPR/kWh)	Minimum dry season energy (%)
Dry season	Peak	1-2	8.5	30%
		2-3	8.8	
		3-4	9.4	
		4-6	10.55	
	Non-peak		4.8	
Wet season	All hours		4.8	15%

Source: NEA Board Decisions on the Power Purchase Rates and Associated Rules for PPA of ROR/PROR/Storage Projects Effective from 2074/01/14 (April 27, 2017)

Wet season is 16 Jestha to 15 Mangsir (June-November) and dry season is 16 Mangsir to 15 Jestha (December-May).

A summary comparison of these hydropower PPA default tariffs is provided below (Table 2). The standard ratio between dry and wet tariffs is 1.75 times, increasing for PROR with greater storage. The levelised tariff for reservoir hydropower projects is NPR 8.96/kWh (US¢ 6.7/kWh), and for ROR and PROR hydropower projects is ~NPR 5-6/kWh (US¢ 3.7-4.5/kWh).

Table 2 Nepal hydropower PPA tariffs compared

Project type		Dry : Wet tariff ratio	Levelised tariff [a] (NPR/kWh)
Reservoir (now withdrawn)		1.75	8.96 (US¢ 6.7/kWh)
ROR	**1**: 6 months dry season, 6 months wet season	1.75	5.88 (US¢ 4.4/kWh)
	2: 4 months dry season, 8 months wet season	1.75	5.34 (US¢ 4.0/kWh)
PROR	1-2 peak hours at rate capacity	1.77	4.95 (US¢ 3.7/kWh)
	2-3 peak hours at rate capacity	1.83	5.05 (US¢ 3.8/kWh)
	3-4 peak hours at rate capacity	1.96	5.18 (US¢ 3.9/kWh)
	4-6 peak hours at rate capacity	2.20	5.52 (US¢ 4.1/kWh)

Source: ECA calculations

a Levelised tariff is calculated assuming dry season generation is equal to the required minimum

3 Eligible costs

This section considers what should be the basis for setting the price or allowed cost for a SHEP. The subsequent sections then consider the appropriate structure of the tariffs used to recover the approved price.

Within this section, the first subsection considers the overall approach to be adopted and proposes the use of an "open book" methodology where the price is based on the actual costs incurred. The second subsection then consider which costs should be eligible for recovery. The third subsection discusses a number of associated considerations which have been raised in the consultation process.

3.1 Selecting the approach

Options for determining the costs of a hydropower (and other) generators and so the price to be paid can be divided into:

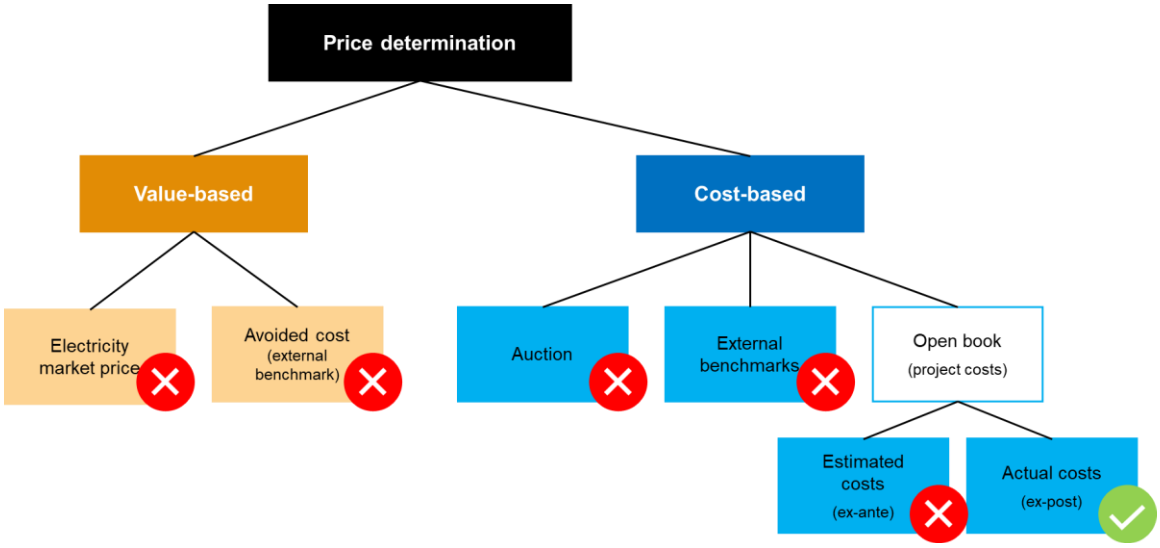
- **Value-based approaches**, where the price is linked to the cost of the alternative supply option (the "avoided cost"). This says that the owner is being paid the value of their supply to customers (what customers would otherwise have to pay).
- **Cost-based approaches**, where the price is linked to the actual cost of the plant. This says that the owner is being paid the cost of their supply, whether this is lower or higher than the cost of the alternative supply option.

Within each approach, there are various options as to how to determine value or cost.

The choice between the two approaches reflects a combination of practicality (which approaches can be applied) and the desired allocation of risks. A value-based approach places the risk on project owners that the value of the project to customers is more or less than the cost to build it. A cost-based approach places the risk on customers that they are paying more or less than the value they place on the supply from the project. In the Nepali context, we have assumed that, as set out in the introduction, derisking investments is important to attract finance, and our proposals reflect this.

Below, we show these basic options and the various approaches that can be taken to setting the price under each (Figure 5). The remainder of this section discusses the application of these approaches to hydropower in Nepal.

Figure 5 Options for determining eligible prices / costs



Source: ECA

3.2 Value-based approaches

Value-based approaches assume that the appropriate price to pay for hydropower is what is its value to the customer. This can be higher or lower than the cost of the plant to the owner.

The value to the customer is the price of the alternative supply option (the "avoided cost"). This can be set in an electricity market, where one exists, or be estimated from an external benchmark. In the case of Nepal, there is no established electricity market and, therefore, this is currently not a feasible option for determining prices for reservoir hydropower. Instead, we refer to external benchmarks. For this purpose, we consider two such benchmarks:

- Indian power market prices given that, in the dry season, the alternative marginal supply source for Nepal is imports from India and, therefore, this is what Nepalese customers would otherwise expect to pay for supplies.[10]

- Estimates of the cost of alternative power plants located in Nepal, for example, new oil-fired generation.

3.2.1 Avoided cost of imports

The first benchmark we consider is the avoided cost of importing energy from India. For the avoidance of doubt, in doing so we are estimating the value of a hydropower plant to Nepalese customers as the avoided cost of otherwise having to import power from India. This is a different question as to whether it is viable to develop a hydropower plant in Nepal for export to India, which depends on a comparison of the cost of that plant and the prices that may be received by its owners. It is also a different question as to whether a hydropower plant can both sell to

[10] In the context of setting a dry-wet season tariff ratio (see Section 4.4), we review potential external benchmarks in Annex A2.

customers in Nepal and export to India, and how, if doing so, the export revenues should be treated (a question discussed later in this section).

From discussions with ERC, we understand that imports from India are currently sourced through a combination of bilateral contracts priced at NPR 11-12/kWh (INR 6.9-7.5/kWh or US¢ 8.2-8.9/kWh) and spot trading on the IEX DAM. Day-ahead market prices on the IEX have averaged INR ~5.3/kWh (NPR 8.5/kWh or US¢ 6.3/kWh) across 2022-24 (see Figure 4). The IEX's Real-Time Market (RTM) had a weighted average price of INR 4.99/kWh (NPR 8.0/kWh or US¢ 6.0/kWh) for 2023-24.[11]

We do not know the balance between bilateral and spot trades and, therefore, the average price of electricity imports to Nepal. Indicatively, assuming a split of two-thirds of imports being made under contracts and one-third under spot trades, the weighted average price, and so the avoided cost to Nepal, would be NPR ~9.5/kWh (US¢ ~7/kWh). This is approximately equal to our estimates of the cost of a generic SHEP in Nepal (see Annex A4), which would imply a value-based approach to pricing would make such a project financially viable.

Despite this, we do not propose the use of a value-based pricing approach based on the avoided cost of imports due to the risks this creates for project owners, which are likely to deter investment:

- By their nature, Indian electricity market prices will be driven by supply and demand in India itself. This creates very significant price risk for investors in reservoir hydro projects in Nepal as their returns would be linked to prices in a market over which they have no control or influence.

- Nepal has ambitious plans to expand its own generating capacity. Potentially, in future, this could lead to a situation where Nepal is no longer reliant on power imports from India, in which case using the avoided cost of Indian electricity market prices as the basis for paying Nepalese generators would seem inappropriate.

- Indian electricity market prices, represented by day-ahead prices in IEX, are currently capped at INR 10/kWh (NPR 16/kWh or US¢ 12.0/kWh). Whether this cap will be maintained for the full-life of any reservoir hydro project, will be increased, or will be reduced (it was reduced from INR 12/kWh in April 2023[12]), is uncertain and so introduces further price risk for its investors.

3.2.2 Avoided costs of alternative power plants

As an alternative to using imports as the avoided cost, and so value to customers, the PPA price could instead be set equal to the cost of an alternative power plant located in Nepal. This would represent the alternative investment that would be needed to meet demand.

The obvious question raised by such an approach is what is the alternative plant? This needs to be capable of delivering a similar magnitude of energy and, crucially, to do so in a 'firm' or dispatchable manner across the year. This implies the appropriate alternative would likely be a new thermal power plant (probably oil-fired) if built in Nepal given the challenges involved in

[11] CERC. 2024. Report on Short-term Power Market in India: 2023-24 Tables 15(b) and 17(b).

[12] Sweta Goswami, 14 April 2023, Govt lowers price cap at power exchanges to Rs 10 per unit, *Money Control*.

developing non-hydro firm renewable energy supply, the lack of natural gas supply, and the expense involved and environmental concerns around using imported coal.

As with relying on the use of import prices as a benchmark of value to customers, the use of an alternative power plants places significant risk on investors and, therefore, is not proposed:

- Ideally, the alternative power plant would be identified using a comprehensive least-cost planning study. However, no such recent study appears to be available for Nepal, which implies considerable judgement and, therefore, uncertainty, is required in identifying the alternative plant.

- Thermal power plant costs are driven by fuel prices, which can change significantly over time. This makes the value of SHEP difficult to determine and, therefore, to agree the contract price.

3.3 Cost-based approaches

The alternative approach to setting prices is to base these on the cost of the project, rather than to use its value to customers. The inevitable challenge this poses is how to be confident that such costs are efficient and are not inflated.

There main approaches can be taken to responding to this challenge:

- Creating competition for the project, through auctions, with the expectation being that competitive pressures will force developers to offer an efficient cost.

- Setting allowed costs based on external benchmarks, which cannot be manipulated by the project developers.

- Assessing and negotiating eligible costs on an “open book” basis, whereby the contracting party is able to examine the costs incurred and to challenge those it considers excessive and/or unjustified.

Each of these is discussed below.

3.3.1 Auctions

Auctions can be an effective means of using competition to push developers to minimise costs and prices. However, to be effective, they generally require that competition takes place between equivalent options. For example, an auction might be held to procure new solar power capacity with the bidders selecting sites, given that this is a generic technology. Alternatively, an auction might be held to select the developer of a new thermal power plant at a site designated by the buyer, so that all bidders are competing on equal terms.

Relying on auctions to determine the price of new, large, hydropower projects is particularly difficult. The cost of such projects is very dependent on size and sites. There are relatively few sites suitable for such projects. And there may be few firms able to actually implement such projects.

Internationally, only Brazil has attempted to produce large-scale hydro capacity through auctions selecting between different project locations and designs. Under the Brazil model, the government takes responsibility for identifying suitable sites, conducting environmental and social assessments, and managing the permitting process (including allocation of water rights).[13] It then auctions these sites, either in individual tenders for the largest projects or as options within procurements for a specified quantity of capacity or energy. Brazil also runs auctions for procuring renewable energy, including small hydropower, without specifying sites and auctions for concession rights to existing large hydropower projects. Between 2005 and 2017, 29 large hydropower projects (>100 MW) were procured in auctions, out of 1,068 total projects procured[14]. Large hydropower installed capacity procured totalled 28.7 GW out of total procured capacity of 79.4 GW, although 11.2 GW of this was a single project (the Belo Monte hydropower project), which was individually tendered, as Brazil has struggled to identify enough eligible sites to run large hydro-specific auctions.

We consider it unlikely that a similar approach could be adopted in Nepal. Only a small number of suitable sites for large hydropower projects have been identified meaning little potential for competition between sites (Table 10 in Annex A1). As projects are likely to require concessional financing, it may also be difficult to attract a sufficiently large number of bidders given that access to such financing generally requires projects are owned by a public entity (ie, NEA, either directly or through subsidiaries).

3.3.2 External benchmark

Relying entirely on benchmark costs is also considered infeasible. To use benchmarks alone, it is necessary to have an extensive database of relevant costs to be confident that the benchmarks adopted will reasonably reflect costs for the specific country and project. This is particularly so for reservoir hydro projects whose costs are very much driven by site selection and unpredictable geological factors. Such a database is lacking in Nepal given the minimal number of large reservoir hydropower projects developed to date.

This does not rule out the use of benchmarks for reviewing individual cost elements, but does mean that relying entirely on benchmarks is unlikely to be realistic. We further consider the role of benchmarking and contingencies in Section 3.5.1.

3.3.3 Open book model

Given the impracticality of both the auction and benchmarking cost-based approaches, as well as the value-based approaches (Section 3.2), **we therefore propose to focus on approaches based around the use of the project's own costs, under an open book model.** This can be considered equivalent to a 'cost-plus' model. We discuss various options for the treatment of 'eligible costs' within this model in the following sub-section.

[13] Tolmasquim, M.T, et al, 2021, Electricity market design and renewable energy auctions: The case of Brazil, *Energy Policy 158*, 112558.

[14] Diniz B. 2022. Delays in the Construction of Power Plants from Electricity Auctions in Brazil. Mendeley Data

3.4 Eligible costs (open book method)

3.4.1 Construction costs

The first question using an open book model raises is whether to rely on estimated (*ex ante*) construction costs, for example, those approved at design stage, or actual (*ex post*) costs once these are known post-commissioning.

Differences between these costs can be large in the case of hydropower projects, much more so than for thermal power projects and wind and solar projects, given the inherent uncertainties over site conditions. Recent international studies, for example, have estimated cost overruns on large hydropower projects as averaging 33% for post-2000 projects, as averaging 20% for a sample of World Bank-supported hydropower projects, and as averaging as much as 98% for hydropower mega-projects in Brazil.[15]

Nepal's recent experience with the construction of its largest hydro plant, the 456 MW Upper Tamakoshi Hydropower Project, is emblematic of this risk. Cost overruns, including significantly higher interest during construction (IDC) due to delays, have seen the total project cost rise from an initial estimate of NPR 49 billion to NPR ~85 billion once finally commissioned in 2021, a 73% cost overrun (including interest).[16] Some of the cost overruns could be attributed to unexpected 'force majeure' events (the 2015 earthquake and the Covid-19 pandemic), but these are exactly the type of cost risks that a project owner is highly unwilling to bear for HEPs (without imposing prohibitively expensive financing costs).

Given the importance attached to attracting investment in large hydropower projects, we consider it unrealistic to expect investors to bear such large cost risks. Therefore, we propose the use of **actual construction costs** as the basis for the tariff, as follows:

- A preliminary tariff is set based on estimated costs at the time of PPA signature. This initial estimate would inevitably be highly uncertain.[17]
- This preliminary tariff is updated as a final tariff which reflects the actual construction costs of the project, including financing and other charges, following the start of commercial operations.
    - Cost estimates for both the preliminary and final tariffs would be subject to independent verification by a third party auditor. We discuss the importance and potential purveyor of this role in Section 3.5.5.

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15 Plummer-Braeckman J, T Disselhoff, J Kirchherr. 2019. "Cost and schedule overruns in large hydropower dams: an assessment of projects completed since 2000". International Journal of Water Resources Development. Volume 36:5, pp839-854 | Baurzhan S, G Jenkins, G Olasehinde-Williams. 2021. The Economic Performance of Hydropower Dams Supported by the World Bank Group, 1975-2015. Queen's Economics Department Working Paper No. 1463 | Callegari C, A. Szklo, R. Schaeffer. 2018. "Cost overruns and delays in energy megaprojects: How big is big enough?". Energy Policy. Volume 114, pp211-220.

16 Sangam Prasain and Prithvi Man Shrestha, 6 July 2021, Nepal starts operating its largest hydropower station, *The Kathmandu Post*.

17 Guidance from the Association for the Advancement of Cost Engineering (AACE) suggests that any cost estimate for hydropower projects at the 'study' or 'feasibility' phase ('Class 4') would typically have an 'expected accuracy range' of -30%-+50%, with a 50% level of confidence: AACE, 2013, Cost Estimate Classification System – as applied in Engineering, Procurement, and Construction for the Hydropower Industry, AACE International Recommended Practice No. 69R-12.

- An interim tariff update may also be required between financial close and construction start. In any case, actual construction costs are what are relevant for the final tariff.

While this, inevitably, reduces incentives to control costs during construction, we assess the balance of risks in the case of reservoir hydro projects in Nepal as favouring limiting the risk to investors of cost overruns rather than incentives to avoid such overruns. We consider the case for applying benchmarks and / or contingencies to construction costs in Section 3.5.1.

Where major maintenance works are expected to be required during the lifetime of the project, which will be capitalised, we propose to **capitalise these works into the tariff calculation at their estimated cost** and in the planned year. While there will be inherent uncertainty over the timing and cost of these works:

- Such costs are small and relatively predictable compared to initial construction costs,
- These costs may be less relevant / material for shorter PPAs,
- Capitalising these costs *ex ante* reduces the regulatory burden on the ERC in not having to readjust the tariff in response to, and assess the prudency of, every major maintenance capex (including answering the question as to what qualifies as 'major'), and
- We consider that transferring *some* risk to the project owners is acceptable, particularly with project investors being insulated from construction cost risk.

3.4.2 Operating and maintenance costs

The distinction between estimated and actual costs is less of a concern for operating and maintenance costs, which are generally easier to estimate, and which are less significant. To avoid frequent resets of prices and to encourage the project owner to seek operating efficiencies (and transfer some cost risk to project owners), we propose that **operating costs, therefore, are fixed using a forecast** of these (including escalation factors).

3.4.3 Depreciation and debt service costs

The third question addressed under the proposed open book approach is whether the costs of servicing debts (repayment of principal) are passed-through or whether these are funded from depreciation charges. The former provides greater certainty for lenders but also raises the question of how equity investors recover their capital (which would normally come through the depreciation charge). On balance, we propose to **apply a depreciation charge** with protection to lenders coming through arrangements such as covenanted minimum Debt Service Coverage Ratios (DSCR) and / or Loan Life Coverage Ratios (LLCR).

A question does arise as to whether the depreciation schedule should be adjusted to allow for higher depreciation charges in earlier years, when debt service obligations are at their greatest. For example, the Central Electricity Regulatory Commission (CERC) in India, in its tariff regulations, allows hydropower plants to recover 57% of their capital costs through depreciation charges in their first 12 years of operation, with the balance being spread over the remaining useful life of the assets.[18]

A typical reservoir hydro project may be financed by a mix of commercial debt, which may have a shorter tenor (10-20 years), and concessional / sovereign debt that may have a longer tenor (25+ years). Therefore, the average tenor of all debt, weighted by loan size, could be in the range of 20-30 years. Depreciating a reservoir hydro project's cost over the useful lifetime of the assets, which could be 50+ years, therefore, is likely to mean insufficient cash being received in earlier years to cover debt service costs. This is particularly so if future hydropower projects are not able to attract debt under concessional terms and so face shorter tenors.

To address this, we propose to **allow accelerated depreciation in earlier years**, following the CERC model. Under this approach, a percentage of the asset value, excluding salvage value, would be depreciated over the initial subset of the project lifetime, with the remaining value, excluding salvage value, being depreciated over the remaining lifetime. This assumes that the PPA tariff can be determined using a depreciation schedule which may differ from that in the project owner's financial statements.

The percentage of asset value for which accelerated depreciation applies, and over how many years, would depend on a project's costs and financing specifics. For example, for a project with 80% debt and 20% equity financing, accelerated depreciation could be applied to 50% of the asset value, excluding salvage value, over the first 15 years of the project, which would broadly match expectations on debt servicing. Other considerations could be whether other costs are higher or lower during a project's earlier years, eg, if differing royalty rates or tax holidays apply.

For the purposes of calculating depreciation, we recommend the default follows the CERC approach which assumes that 10% of the asset value is salvageable. This would also apply for major maintenance works. This would be subject to negotiation between the project owner and power purchaser and to regulatory approval of a lower value.

The tariff will also be subject to a test that it allows sufficient cash flows to meet minimum DSCR / LLCR requirements, with further profiling being allowed on a case-by-case basis if needed. This profiling can be achieved by increasing the share of asset values recovered during the accelerated depreciation period.

Interest is included at its calculated value in each year, given the contracted interest rate and the forecast loan balance to which this is applied.

Table 3 Options for depreciation and debt service costs

Approach	Discussion
Debt service costs	
Pass-through	• Provides better certainty to lenders (lowering cost of debt) • Raises questions as to how equity investors recover their capital
Depreciation charge	• Gives equity investors better assurance of capital recovery (lowering cost of equity) • Can protect lenders via minimum DSCR / LLCR covenants

[18] The regulations apply an annual depreciation charge of 5.28% for the first 12 years of the assets' life. The asset value is calculated as 90% of the construction cost, allowing for a 10% salvage value. [Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024]

Approach	Discussion
Depreciation charge schedule	
Align depreciation charge with asset lifetime	• Aligns depreciation charges with project owner's financial statements • Lowers early years tariff (or eliminates need for two-period tariff schedule) • May lead to insufficient debt service coverage in earlier years (HEP have 50+ year lifetimes)
Accelerated depreciation	• Can better match project revenues with debt repayment costs, improving financial viability • Choose years of acceleration and percentage of asset value accelerated – align with underlying financing mix, other cost factors, eg, tax holiday periods • Implies need for two-period tariff schedule – need to monitor extent that early years tariff is higher
Asset salvage value	• CERC assumes default of 10% - recommend adopting this default value but subject to negotiation with project owner

Source: ECA analysis

3.4.4 Return on equity

We assume that the allowed return on equity (ROE) will be an input to the tariff calculation. This raises the obvious question of how to avoid an excessive rate being claimed?

Our proposed approach is to **set a cap on the allowed ROE to be included in the tariff**. Project owners and power purchasers will, of course, be able to negotiate a lower return than this and we expect there will be an element of iteration where the impacts of lower returns on the tariff, and so affordability of the project, relative to the impacts on the ability to raise finance, are considered.

As regards the appropriate cap, further analysis is required. For the present, we refer to the CERC regulations, as referenced above, which apply a limit of 17.0% for reservoir hydropower projects on a post-tax basis, INR-denominated[19]. As a comparison, the USAID Urja Nepal programme estimates an ROE for hydropower projects in Nepal of 11.3%, on a post-tax basis[20]. However, this may be unrealistically low given that international commercial loans, denominated in USD, are currently assumed to bear an interest rate of 11.0% despite having much lower risk than equity,[21] and we believe there may have been an error in its calculation. An appropriate cap value, which seeks to balance encouraging sufficient investment to meet hydro development goals while not overburdening customer bills, will ultimately need to be determined

19 This rate applies to new reservoir hydropower projects with a commercial operations date on or after 1 April 2024. Older projects are permitted a ROE of 16.5%.

20 USAID Urja Nepal Program. 20 September 2022. Discussion Paper on Return on Equity (ROE) for Generation Projects. The value shown is that calculated by applying the Capital Asset Pricing Model (CAPM) and assumes a tax rate of 20%. Note that the reported ROE in the paper (slide 9) appears to mistakenly apply an unlevered beta to calculate the cost of equity which will understate the value. It also uses a debt:equity ratio of 70:30. A higher debt:equity ratio, such as a 80:20 financing ratio, would, under CAPM, translate into a higher levered beta and so ROE.

21 According to indicative cost and financing assumptions provided by ADB for the Dudkhoshi Storage Hydroelectric Project (DKSHEP), and other assumptions from USAID Urja Nepal Program. 12 September 2023. Dudhkoshi Storage Hydroelectric Project: Financial Analysis Summary.

by Nepalese stakeholders. Project owners will also likely be concerned about the solvency of the NEA, the offtaker, and will want assurance that the Government will backstop the PPA in case of default, or an appropriate termination payment.

If timely completion is a concern, then incentives could be provided through the allowed ROE. For example, a bonus could be applied for early completion and a penalty for delayed completion. However, this does create its own risk of perverse incentives—for example, increased costs due to accelerated development which may then be passed-through into the allowed tariff.

There is also a question of how to include tax paid on profits. These can either be included directly or added to ROE by adjusting this upwards for tax (the approach taken in India)[22]. Furthermore, we understand that reservoir hydropower projects in Nepal could benefit from tax holidays. Therefore, **we propose to use calculated taxes** rather than adjust the ROE, as this will allow the benefits of tax holidays to be passed through to customers in the form of a lower required tariff.

A number of further mechanisms should be put in place to protect the ultimate customers from excessive returns. These include:

- Setting guidance for a **minimum share of debt financing**, perhaps 50%, to avoid developers placing excessive reliance on more costly equity financing.

- Incorporating a mechanism for **sharing returns above the cap with customers** (eg, through automatic downward tariff adjustments where actual returns exceed the cap by more than a given amount). This would be one-sided in that shareholders would not be compensated for actual returns below the cap (as the higher return to equity is justified by the risk that actual returns will be below expectations).

3.4.5 Managing forex risks

A key risk for investors is the allocation and mitigation of foreign exchange risks. Options that could be adopted include:

1. Apply an NPR-denominated tariff, with indexation to the USD-to-NPR exchange rate to compensate for cost increases resulting from depreciation of the NPR relative to the USD.

2. Apply an NPR-denominated tariff with a requirement on the project owner to hedge their exposure to foreign exchange movements on their debt service and other costs, with the costs of hedging being passed-through to the tariff.

3. Apply an NPR-denominated tariff with an inbuilt escalation factor allowing for forecast depreciation of the NPR against the USD.

4. Apply both NPR-denominated and USD-denominated tariffs, with costs split between these based on the currency in which they are incurred.

[22] The formula used is *pre-tax ROE – post-tax ROE / (1 – tax rate)*. For example, applying a 20% tax rate, the 17.0% post-tax ROE cap would convert to 21.25%.

The second option may appear attractive in providing cost certainty, but it assumes it is (financially and technically) feasible to enter into long-term hedges of the NPR against the USD. In India, private hedging is estimated to add 7+ pp to loan costs, eliminating any potential advantage of USD-denominated debt. However, a government-backed hedging facility (GBHF) is estimated to reduce that cost by 3.5 pp (with the cost of hedging treated as a pass-through cost in PPAs).[23]. For an NPR-denominated PPA where the project owner has borrowed in USD, this could entail the GBHF entering into a Contract for Difference (CfD) with the project owner at a fixed exchange rate. When debt payments are due, if the exchange rate is higher, the GBHF makes a net payment to the project owner; if the exchange rate is lower, the project owner makes a net payment to the GBHF. The GBHF would need to forecast the cost of these differences and fund a capital buffer for handling extreme forex movements. This may not be a realistic option for Nepal given it would require significant fiscal support (the Indian case estimates a capital buffer requirement of 30% of the loan value[24]) and the relative illiquidity of the NPR-USD hedging market would likely add a significant premium.

The third option, which relies on the accuracy of the NPR-USD forecast, imposes what are likely to be considered excessive risks on the project owner.

Of these, we suggest either the first or fourth option is most appropriate, depending on the willingness and ability of NEA, as the power purchaser, to pay in USD, the extent of a project's NPR- versus USD-denominated costs, and how readily a project's costs can be disaggregated between NPR- and USD-denominated costs.

3.5 Other considerations

Discussions with key stakeholders raised a number of other questions regarding eligible costs to be included in tariffs. We discuss these below.

3.5.1 Benchmarking and contingencies

Applying benchmarking to eligible constructions costs may be desirable to try and apply some level of cost control and efficiencies given an open book model inherently lacks such incentives. While there may be some elements of construction costs that are benchmarkable – a disaggregation of what construction costs can be effectively benchmarked or not against standard international reservoir cost estimates would require a techno-engineering view – project investors will likely insist that the vast majority of costs cannot be readily benchmarked given large-scale reservoir hydro costs are overwhelmingly driven by site selection. The most significant cost overrun risk comes from construction delays due to unpredictable geological factors rather than the cost of standard HEP parts and equipment. Applying greater scrutiny to cost sub-components would also need to be balanced against project investors likely demanding higher costs of debt or equity in compensation for taking on any construction cost risk.

Setting caps on construction cost contingencies may also be desirable, if not easily implemented in practice. When a preliminary tariff is set at financial close, a cap could be set on cost

23 A. Farooquee and G. Shrimali, 2016, Making renewable energy competitive in India: Reducing financing costs via a government-sponsored hedging facility, *Energy Policy 95*, 518-528

24 The Indian Government estimated that a supporting currency 'hedge fund' for its solar auctions would require USD 1 billion of capital, which would cover 3% of INR-USD depreciation for 25-year contracts, but that fund would only last 15 years if the INR depreciated 5%: IRENA, 2015, Renewable Energy Auctions: A Guide to Design, Box 6.5

contingencies. From the perspective of project owners, this effectively sets a cap on eligible construction costs. Unless the cap is generously high, this greatly adds to financing risk given the inherent cost uncertainties of large-scale hydro projects. Even if project owners accept the premise of contingencies cap, it would likely become a contentious negotiating point, with a trade-off between capping construction costs and accepting potentially significantly higher debt and equity costs. Once set, a cap may inevitably become the project's *target* cost rather than a *cap* when negotiating the final tariff, dampening the efficiency incentive.

The scope of eligible costs can be considered in negotiations, and would be reviewed at the preliminary and final PPA tariff stages by the technical auditor (Section 3.5.5), but applying an unconditional *ex ante* cap on eligible costs is unlikely to be practical when trying to attract investors considering the inherent cost risks.

3.5.2 Accounting for wider socio-economic benefits

Reservoir hydro projects potentially have benefits that go beyond electricity generation, notably for flood control, irrigation, fisheries, and regional development. These benefits are typically not paid for directly.[25] Therefore, they can justify setting a tariff for electricity supply below full cost-recovery levels to reflect that the project delivers benefits other than those for electricity customers, and electricity customers should not be paying for these benefits.

Our view is that the appropriate mechanism for capturing such additional benefits is through the provision of concessional financing, whether as concessional loans from international institutions or as equity, grants, or concessional loans from government (for example, as 'viability gap funding'). Such concessional funding lowers the cost of the project and, therefore, the price for electricity supplied by the project.

3.5.3 Splitting the reservoir and powerhouse

Drawing on a model proposed by the Japan International Cooperation Agency (JICA),[26] MoEWRI has expressed interest in splitting reservoir hydro projects between the reservoir and the powerhouse. Our understanding is that the intent of the model is to allow the reservoir, which may have wider socio-economic benefits, to be publicly-owned and so eligible for funding from concessional sources. Meanwhile, the powerhouse would be privately-owned and rely on commercial funding. The powerhouse owner would pay a 'dam lease fee' that finances the reservoir's debt repayments.

In principle, while this may introduce some contractual complexity, we do not see an inherent issue with this approach, nor does it conflict with an open book model. For the final electricity tariff, the key question is the total cost of the reservoir and powerhouse combined. If splitting these is necessary to enable access to concessionary financing, with the costs of servicing this finance being reflected in the dam lease fee, then the electricity tariff becomes the sum of the direct cost of the powerhouse and this dam lease fee. However, we would still expect that the regulator (ERC) would wish to confirm the reasonableness of the reservoir costs making up the

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25 In cases where these benefits, and their beneficiaries, can be clearly identified and costed, user fees could be applied, with this revenue used to offset some of the cost of the HEP in the PPA tariff charged to final electricity customers. The practicality of this would need to be considered on a case-by-case basis, likely in consultation with the Department of Water Resources and Irrigation.

26 JICA, NEWJEC Inc, The Kansai Electric Power Co., Inc., 2020, Data Collection Survey on the PPP Modality in Hydropower Project in Nepal.

lease fee, meaning the outcome as regards the need for review of costs is equivalent to a model where the same entity is responsible for both the reservoir and powerhouse.

3.5.4 Export revenues

Nepal has high expectations for hydropower exports to India and Bangladesh. This raises the question as to how to set prices for Nepalese customers from projects that both supply Nepal and export.

Currently, India's CERC reports that the 2023-24 average weighted price of Nepalese imports from India through IEX was INR 4.43/kWh (NPR 7.1/kWh or US¢ 5.3/kWh), down from INR 5.95 (NPR 9.5/kWh or US¢ 7.1/kWh) in 2022-23.[27] From discussions with ERC, we understand that current bilateral export contracts with India have prices of INR 5.45/kWh (NPR 8.7/kWh or US¢ 6.5/kWh) and with Bangladesh (wheeling through India on a trial basis) of US¢ 6.4/kWh (NPR 8.5/kWh or INR 5.3/kWh). Such prices are slightly lower than our estimates of the costs of a hypothetical SHEP, but there is reason to believe that higher prices could be realised through India's new short-term and ancillary service markets (see Annex A2).

The treatment of export revenues in determining prices charged to Nepali customers should, in our view, depend on the nature of these exports:

- If a specific share of the project is allocated to exports, then the project's costs should be split proportionally. The tariff charged to Nepali customers would, then, reflect the share of cost, capacity, and energy allocated to domestic supply. One point for consideration is whether concessional funding should be entirely attributed to domestic customers (ie, debt service costs are differentiated between domestic customers and export customers).

- If, instead, the project exports surplus energy then the project's costs should be allocated entirely to Nepali customers and the tariff calculated on this basis. However, revenues from exports should be offset against these costs and tariffs adjusted as necessary. A question for consideration is whether to allow the project owner to retain a share of such export revenues to provide an incentive to maximise them (eg, 90% of export revenues is offset against tariffs for Nepali customers and 10% is retained by the owner as increased profits). In any case, in practice, project investors will likely prefer revenue certainty when determining their expected return on equity.

3.5.5 Technical auditor roles

Under an open book pricing model, third-party verification and auditing of costs, maintenance, and technical specifications is an important task. The Government and public stakeholders will need assurance that the costs embedded in the PPA are properly audited and justly incurred. While most unexpected costs need to be accounted for in the PPA price under an open book model, assurance will be needed that all claimed costs are audited and can be properly attributed to the construction. For example, the technical auditor would rule whether project delays, and associated cost overruns, are the fault of the project developer – and thus should not be included in eligible costs – or are due to (unpredictable) geological risks.

[27] CERC. 2024. Report on Short-term Power Market in India: 2023-24. (Table 36)

A technical auditor will also be needed to confirm that the technical specifications agreed upon for the preliminary tariff match those of the completed project, which is particularly important if applying capacity-based fixed charges (see Section 4.3). Such payments would be based on a HEP's declared / nominated capacity, which is not as immediately verifiable as energy-only based PPAs where payment is based on metered electricity generation. A technical auditor must therefore confirm through testing that the completed project's capacity matches its planned capacity.

The audit itself would generally be carried out by an independent engineer with the resources and technical knowledge necessary for this role. However, legal responsibility for auditing will rest with a public agency, which will need the capabilities to procure, monitor, and approve the audit report and to lead negotiations if required on allowable costs with the project owner.

For **cost auditing**, we suggest that the ERC could undertake the hiring of the third-party technical auditors responsible for approving and, if required, negotiating the cost of both the preliminary and final tariff. Alternatively, this role could be undertaken by an independent 'panel of experts'.

For **technical auditing** of both the technical specifications of the completed project and ongoing maintenance and asset health inspections, the Department of Electricity Development (DoED), which is responsible for issuing generation licenses, could take on this role. The DoED should at least have some technical familiarity with hydro projects, from which a deeper understanding of reservoir hydro projects can be built. The DoED will also have an interest in the asset health of HEPs as their ownership is transferred to the Government at the end of their license. The DoED can thus pair verifying a plant's available capacity with annual inspections of maintenance standards and asset health.

4 Charging structure

4.1 Selecting the approach

Costs of hydropower projects are almost entirely fixed. Despite this, it is standard practice to split cost recovery between fixed- or capacity-based charges and variable- or energy-based charged and, thereby, allocating a share of volume risks to project owners. Two-part tariffs that combine capacity and energy charges are now applicable under the ERC Act.[28]

Doing so has the advantages of:

- **Sharing volume risk between project owners and power purchasers in a way that is seen as equitable**. In a hydrologically dry year, for example, when water flows are below average levels, the payments made to the project are reduced. This can be seen as 'fair' by customers whereas, if the project continues to earn the same amount while generating much less than normal, there is likely to be high political concern.

- **Creating incentives for efficient project design and construction**. Linking revenues, in part, to generation provides incentives for project owners to look to maximise output during the design and construction phase.[29]

- **Creating incentives for efficient project operation and reservoir management**. While project owners cannot control water flows and do not determine dispatch of their project, they can still increase generation when a project is operating by decisions such as when to maintain equipment and managing leakages.

This raises three design questions, which we summarise below:

- What is the appropriate split between fixed and variable charges for cost-recovery?

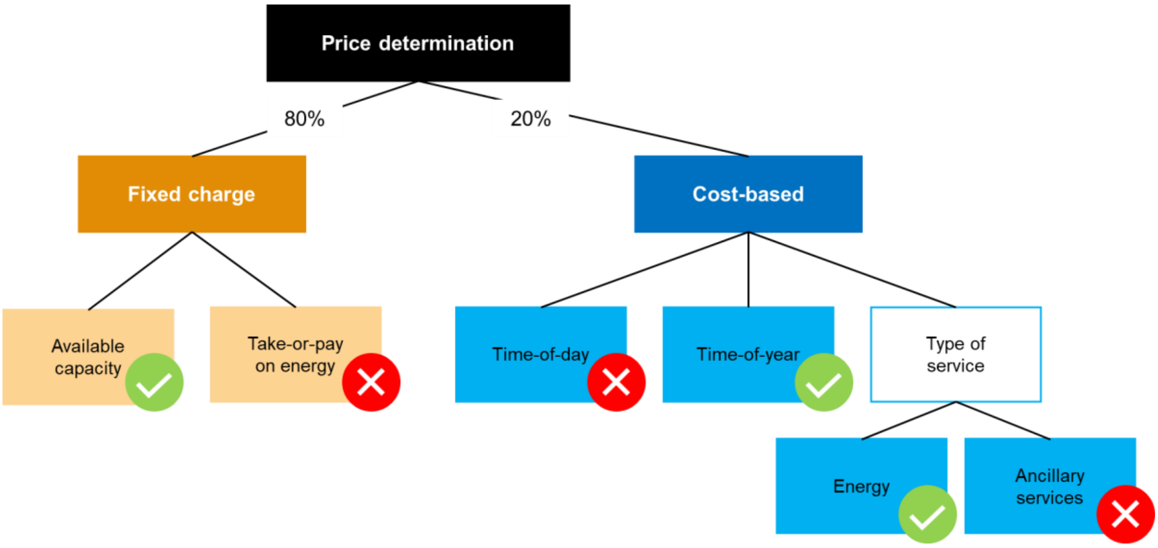
- What is the basis for fixed charge recovery?

- What is the appropriate structure of variable charges?

28 Electricity Regulatory Commission (ERC) Act 2018, Chapter 4: Tariff and Charges, 10. (2).

29 As per Chapter 4: 10. (3)-(4) of the ERC Act 2018, capacity charges can be set to incentivise producers to maximise capacity availability, with the applicable capacity charge varying according to how much capacity is actually available.

Figure 6 Options for charging structure



Source: ECA. 80% / 20% split is based on an illustrative example of a project with 80% debt and 20% equity financing, with fixed charges linked to debt costs and variable costs linked to equity costs.

4.2 Split between fixed and variable charges

Given that the costs of a hydropower project are almost entirely fixed, the split between fixed and variable charges is, inevitably, somewhat arbitrary. The CERC tariff regulations for India, for example, apply a 50:50 split of costs between the two charging types.[30] In contrast, the take-or-pay element of the Nam Theun 2 (NT2) hydropower project in the Lao People's Democratic Republic (Lao PDR) effectively has a fixed cost share of 95%.[31]

We consider it appropriate to **allocate a percentage of costs to the fixed charge component in accordance with the gearing of the project**. For example, a project with 80% debt financing would have 80% of its costs allocated to the fixed charge component.

This proposal is based on the following:

- This approximately matches the share of debt in project costs and, therefore, provides comfort to lenders that their repayments are not at risk.
- This avoids having a very high energy charge which, in turn, might induce inefficiencies in scheduling and dispatching decisions. For example, a high energy charge may lead to the system operator (SO) preferring to use thermal generation or imports where these have a lower *financial* cost, despite the *economic* cost (the cost of water) of using reservoir hydro being zero.

We recognise that allowing a project to recover much of its costs even if not generating, as would be implied by this structure, can be controversial and politically contentious. However, it

30 CERC, Notification, NO.L-1/268/2022/CERC, Regulation 65.

31 Nam Theun 2 Hydroelectric Project: The EGAT Power Purchase Agreement: Summary for Public Disclosure.

is also consistent with our understanding of the core objectives of the pricing mechanisms, notably that of derisking investments to encourage external financing at an acceptable cost, and recognises the wider grid services (as readily dispatchable capacity) provided by SHEPs.

4.3 Basis for fixed charge recovery

Fixed charges are generally linked to availability of hydropower projects, so that project owners have an incentive to ensure they are available even if not dispatched. Such linkage can be through two mechanisms:

- Payment based on available capacity (an NPR/kW capacity charge). Where actual availability falls below the target value set in the PPA, the revenues received by the project owner will also fall. Alternatively, the payment could be based on nameplate capacity to better ensure debt servicing, effectively becoming a fixed annual fee as long as nameplate capacity remains unchanged, but this would reduce the operational incentive to maintain capacity availability, and could lead to political opposition if plant availability under-performs yet capacity payments remain unchanged.

- Energy payments with a take-or-pay requirement (an NPR/kWh charge but with an obligation on the power purchaser to 'take' a given energy quantity whether this is consumed or not). This operates in effect as an availability payment as, provided that the capacity is available, the project owner is paid for the energy that capacity is able to generate whether or not this is dispatched.

Our proposal is to adopt a capacity charge, linked to available capacity in each charging period. We consider this to be more transparent than a take-or-pay obligation, and less likely to distort dispatching decisions (eg, where the SO dispatches a hydropower plant because it is at risk of falling below take-or-pay quantities even if not least-cost). It may also raise less political opposition as it is generally easier to explain to stakeholders why the power purchaser is paying for capacity that it may choose to use (paying for the "option" to use capacity), as opposed to why it is paying for "deemed" energy that it is not using.

Inspections by the technical auditor (Section 3.5.5) can also serve to monitor and verify the HEP's nominated / available capacity, with such inspections taking place at least annually. Given the relative infrequency of on-site inspections, a more immediate and practical form of capacity availability verification could be applied via SO dispatch instruction: The SO periodically instructs a HEP to generate at a certain level, perhaps even at its maximum nameplate capacity. If the generator is unable to follow the SO's instructions, its credited available capacity (and capacity payment) is reduced accordingly.

Table 4 Options for fixed charges

Option	Discussion
Per kW payment based on *available* capacity	• Incentivises maintaining available capacity. • Unlikely to distort dispatching decisions. Less likely to have political opposition. • May need to review terms if actual availability falls below target and debt payment risks arise.

Option	Discussion
Per kW payment based on *nameplate* capacity	• Essentially a fixed annual fee, which may best ensure debt servicing. • Reduces operational incentive to maintain capacity availability. • Unlikely to distort dispatching decisions. • Could lead to political opposition if actual capacity availability underperforms but payments are unchanged.
Energy payments with take-or-pay requirement	• Effectively works as an availability payment. • May distort dispatching decisions as the SO dispatches hydro to avoid falling below take-or-pay level even if not least cost. • Potential political opposition if the power purchaser needs to explain to the public why it is paying for energy that it is not using. • Take-or-pay element could conflict with need for 'must take' in cases of hydrology management / irrigation use.

Source: ECA analysis

4.4 Structure of variable charges

The variable or energy charge can vary by any, all, or none of:

- Time-of-day (peak and off-peak).
- Time-of-year (dry and wet seasons).
- Type of service (energy or ancillary services).

If the project owner is not responsible for scheduling or dispatching of a reservoir hydro project, we do not consider it necessary to have energy tariffs that vary by time-of-day. The SO will schedule generation to minimise the costs of meeting peak demand. As reservoir hydro's costs do not vary by time-of-day, there is no obvious advantage to having a time-of-day based tariff. Therefore, **we propose a flat tariff across the day**.

However, **we do propose to adopt differentiated dry and wet season tariffs**. This follows current practice in Nepal and does create incentives for project owners to focus on maximising generation in dry seasons. **Our draft guidance retains NEA's existing default ratio of a dry season tariff that is 1.75 times the wet season tariff**, on the basis that this should reflect NEA's own assessment of cost differentials (see Table 2). While we consider some alternative benchmarks for setting the dry-wet tariff ratio in Annex A3, we conclude that 1.75 times appears to be reasonable for the scenarios and sensitivities considered in Annex A4. However, we would recommend deferring to the most recent NEA least-cost planning study, if available, which should have the best perspective as to the relative value of dry versus wet season energy dispatch.

We also do not propose separate tariffs for the provision of ancillary services, such as spinning reserve or its equivalent, as we understand that, under Nepal's Grid Code, these are mandatory services which are scheduled in merit (least-cost) order. For a reservoir hydro plant, this means it would only be scheduled for spinning reserve if its energy tariff is higher than that of the marginal plant scheduled to meet forecast demand. The reservoir hydro plant would still receive its capacity charge, which is based on its availability, and would be paid its energy charge if dispatched because of a failure of another, scheduled, unit. The implication is that there is no need for a separate ancillary services charge.

Table 5 Options for variable charges design

Option	Discussion
Time-of-day (peak and off-peak tariffs)	• Unnecessary to apply if project owner is not responsible for scheduling / dispatch of hydro. Can rely on SO to schedule generation to minimise costs. • Reservoir hydro costs do not vary by time-of-day.
Seasonal (wet and dry season tariffs)	• Creates incentive for project owner to focus project design on maximising dry season generation, which is particularly relevant to Nepal’s wet-dry season supply imbalance. • Number of options for setting dry-wet season ratio – see Annex A2. Prevailing ratio of 1.75 appears to be reasonable but this ratio can be determined by NEA least-cost planning studies (if available).

Source: ECA analysis

5 Tariff calculation

The third question addressed is how the tariff is calculated. The key questions are whether:

- The tariff is levelised or calculated on a year-by-year basis. Under a levelised tariff, the tariff is calculated so that the net present value (NPV) of cashflows to shareholders, discounted at the allowed ROE, is equal to zero, which is equivalent to the internal rate of return (IRR) to equity being equal to ROE. This can lead to revenues exceeding costs in some years and being below in others. By contrast, setting the tariff on year-by-year basis means setting revenues equal to costs (including a return on equity) in each year.

- If a levelised tariff is applied:

  - Whether this is flat throughout the period or is indexed to inflation and exchange rate movements.

  - Whether this is the same in all years or whether the tariff differs between an initial period when debt service costs are being paid and cashflows may need to be higher to comply with minimum DSCR / LLCR covenants, and a later period.

Our proposal is to apply a levelised tariff that is indexed to inflation and foreign exchange movements, and that is split between an initial 15-year period and later periods (matching the period of accelerated depreciation to recover debt service; periods of tax holidays and reduced royalty rates would also be a factor). This provides greater certainty over the future tariff, by using a levelised calculation, while also reducing the up-front tariff by allowing it to rise with inflation. And applying a split period approach makes it easier to comply with DSCR / LLCR requirements in earlier years.

The indexation mechanism will differ depending on the shares of NPR- and USD-denominated costs. For example, if a hydro reservoir project has all or close to all of its debt USD-denominated, we would propose to index the capacity charge component (80%, as proposed in Section 4.2 in the case of a project with 80% debt financing), which is broadly intended to recover debt costs, to US inflation and the USD:NPR exchange rate, and the variable energy charge component (20%) to Nepalese inflation. These ratios can be set in accordance with a specific project's financing and cost mix.

6 Prices and sensitivities

We set out illustrative tariff calculations in Annex A4 for a hypothetical SHEP based on a reasonable set of (simplified) costs / parameters. We stress that these calculations are purely illustrative for exploring the impact of relative *sensitivities*, and are not meant to be interpreted as a suggestive benchmark for future hydro project tariffs, nor indicative of any views or regulatory precedence from the ERC.

For our 'base case' parameters in Annex A4.1, we calculate (before indexation):

- For an energy-only tariff, Phase 1 (years 1-15) tariffs of 5.69 NPR/kWh in the wet season and 9.95 NPR/kWh in the dry season and Phase 2 (years 16-50) tariffs of 4.83 NPR/kWh in the wet season and 8.46 NPR/kWh in the dry season.
    - For a single-phase energy-only tariff that applies for years 1-50 (before indexation), the wet season tariff is 5.45 NPR/kWh and the dry season tariff is 9.54 NPR/kWh.
- If applying a 20/80 cost allocation split between energy and capacity tariffs, the resulting tariffs for Phase 1 are a wet season energy tariff of 1.14 NPR/kWh, a dry season energy tariff of 1.99 NPR/kWh, and a capacity tariff of 2.141 NPR/kW/month. For Phase 2, the wet season energy tariff is 0.97 NPR/kWh, the dry season energy tariff is 1.69 NPR/kWh, and the capacity tariff is 1,464 NPR/kW/month.

We discuss a set of sensitivities in Annex A4.2. The findings of these sensitivities are summarised in Table 6. The sensitivities highlight that:

- The linkage of the weighted average debt tenor and application of accelerated depreciation can materially impact the levels and lengths of the two-period final tariff.
- The impact of extending / reducing tax holidays and reduced royalty periods is relatively muted.
- Capex increases cause a nearly one-to-one increase in the tariff, highlighting that it is the most material cost component for final tariffs. The impact of fixed O&M increases is much more muted.
- Raising the cost of debt or the cost of equity both have substantial impacts on the final tariff, emphasising the importance of trying to minimise these rates while still attracting sufficient project investment.
- Increasing debt's share of the project financing can help reduce final tariffs, but, if pushed to the limit, an overly levered project requires further design tweaking, eg, extending the higher Phase 1 tariff period, in order to maintain healthy debt financing metrics.

Table 6 Illustrative tariff sensitivities

Sensitivity	Impact
Debt tenor and length of Phase 1 tariff	• This sensitivity is based on the linkage between the weighted average debt tenor and how accelerated depreciation is applied in a Phase 1 tariff • Reducing the weighted average debt tenor from 27 to 20 years and reducing the accelerated depreciation period to 10 years increases the tariff by 8.4% • Increasing the weighted average debt tenor from 27 to 30 years and increasing the accelerated depreciation period to 20 years reduces the tariff by 2.9%
Tax holidays and royalty rates	• Reducing the tax holiday and reduced royalty period from 15 years to 10 years increases the tariff by 2.3% • Extending the tax holiday and reduced royalty period from 15 years to 20 years reduces the tariff by 1.4%
Fixed versus variable tariff cost recovery share	• This sensitivity illustrates the impact of the cost allocation between the energy and capacity tariff • Focusing on the Phase 1 wet season energy tariff, increasing the energy tariff's share of cost recovery from 20% to 50% to 80% increases the rate from 1.14 NPR/kWh to 2.84 NPR/kWh to 4.55 NPR/kWh, respectively. • Conversely, the Phase 1 capacity tariff reduces from 2,141 NPR/kW/month to 1,338 NPR/kW/month to 535 NPR/kW/month, respectively.
Capex and fixed O&M	• Increasing the capex estimate by 30% raises the tariff by 29.6% • Increasing the FO&M estimate by 30% raises the tariff by 2.3%
Cost of debt	• Raising each loan's interest rate by 30% (from a weighted average rate of 3.9% to 5.1%) raises the tariff by 7.6%
Cost of equity	• Raising the cost of equity from a nominal ROE of 13.8% to the cap of 17.0% raises the tariff by 12.1%
Financing mix	• Increasing the debt:equity share from 82:18 to 90:10 lowers the headline tariff by 8.2% in Phase 1 and 35.2% in Phase 2, but this is largely due to having to lengthen the Phase 1 period and lower the Phase 2 : Phase 1 ratio in order to maintain minimum debt covenants • Lowering the debt:equity share from 82:18 to 70:30 raises the tariff by 12.1%

Source: ECA analysis

7 Summary

Table 7 summarises our assessment of the value- and cost-based approaches, with our recommendation, following an open book model, in **bold**.

Table 7 Value- versus Cost-based approaches

Approach	Options	Discussion
Value-based	Electricity market prices	• Nepal lacks an established electricity market. • Even if one emerges, it is unlikely that large, capital-intensive hydro-electric projects (HEPs) would risk purely relying on wholesale market prices.
	Avoided cost (external benchmark)	• Imports from India's power market is the NEA's main alternative offtake option (and a useful comparison point) but: – Prices are ultimately driven by supply-demand in India, not Nepal. – IEX markets are subject to price caps, adding uncertainty that investors cannot influence. – Ambitious hydro plans could lead to Nepal no longer relying on Indian imports, making it a less relevant avoided cost benchmark. – Recent DAM prices are likely too low to make a reservoir hydro project viable. – New 'high price' and ancillary service markets have higher price caps and potentially higher prices. However, these markets have been thinly traded. It is also important not to confuse the potential export value for a hydro project with the value to the NEA in terms of avoided import costs. Subject to such opportunities being available and domestic obligations, we do not see an issue with a hydro project using exports to effectively cross-subsidise domestic offtake. • Cost of avoided generator (diesel) unlikely to be relevant to Nepal's hydro-dominated system. Marginal cost of alternative supply, as estimated by an NEA least-cost planning study (if available), may be considered.
Cost-based	Auction	• Setup requires large upfront costs for the NEA / government, plus sufficient institutional capacity • Effective competition requires steady stream of offering projects, which is questionable for large-scale hydro
	External benchmark	• Infeasible as requires having extensive database of relevant costs, which does not yet exist for Nepal, and international benchmarks are unlikely to be reflective of Nepali conditions
	Open book	• **Apply estimated (*ex ante*) and / or actual (*ex post*) costs**

Source: ECA analysis

We summarise our baseline proposals below in Table 8.

Table 8 Summary of proposed baseline PPA tariff approach for reservoir hydro projects

Element	Proposal and reasoning
Eligible costs	
Construction costs	• Preliminary tariff calculated using cost estimates at PPA signature • Final tariff calculated within one year of commercial operations date, using actual costs (verified by independent third-party auditor) • Project investors unlikely to accept the high cost overrun risk for SHEPs if tried to apply estimated cost (with capped contingencies) • Value-based approaches do not appear to be appropriate for Nepal
Major repairs costs (capitalised maintenance)	• Estimated costs and timings included in tariff calculation • Passes *some* less material cost risk on to project owners
Operating and maintenance costs	• A fixed cost estimate, which may include an escalation factor (which can be split between US- or NPR-inflation-linked costs), is included in tariff calculation • Passes some cost risk on to project owners, while also incentivising operational efficiencies
Depreciation	• Apply a depreciation charge, with an allowance for accelerated depreciation, with a higher Phase 1 tariff, to better align tariff revenue with debt servicing costs • Can apply accelerated depreciation to 50% of asset value less salvage value depreciated on straight-line basis in first 15 years (accelerated depreciation). Exact parameters will depend on project-specific debt-equity financing mix and weighted average loan tenor. • Remaining asset value less salvage value depreciated on straight-line basis over remaining useful life of assets • Default salvage value set at 10% of asset value
Interest costs	• Estimated interest costs using contracted loan terms included in tariff calculation
Debt-equity financing mix	• Will ultimately depend on what financing is available, and at what terms, but guidance could be set for a minimum share of debt financing, eg, 50%, to avoid developers excessively relying on costlier equity financing • Open book model is indifferent to splitting the reservoir and powerhouse into separate projects in order to secure more concessionary debt or equity financing
DSCR / LLCR compliance	• Provide assurance to lenders on repayment risk by covenanting minimum a Debt Service Coverage Ratio (DSCR) and / or Loan Life Coverage Ratio (LLCR), with the latter potentially more appropriate for long-life SHEPs • Increase share of asset value depreciated over first 15 years, if required to meet minimum DSCR / LLCR covenants, *and/or* adjust ratio of first and second phase tariffs
Return on equity	• Return on equity capped at 17.0% pre-tax[32], and can be negotiated lower

[32] Value to be confirmed by Nepalese stakeholders.

Element	Proposal and reasoning
	• Incorporate a (one-sided) mechanism for sharing returns above the cap with customers, eg, through automatic downward tariff adjustments
Taxes	• Estimated taxes included in tariff calculation • Allows for directly sharing benefit of tax holidays with customers through a lower required tariff, rather than upwardly adjusting the ROE
Forex risks	• Can apply an NPR-denominated tariff that is indexed to the USD-NPR exchange rate or, if practical, split into NPR- and USD-denominated tariffs according to NPR- and USD-linked costs • An inbuilt escalation factor based on a USD-NPR forecast likely places too much risk on project investors • Hedging forex risk via a government-backed hedging facility, and treating the associated costs as pass-through, is unlikely to be applicable to Nepal
Charging structure	
Fixed charge / energy charge split	• Set in accordance to debt:equity ratio, which should approximately match the share of debt in project costs, providing comfort to lenders about repayment risk, and avoids a very high energy charge, which could distort dispatching decisions • For example, 80% of costs to fixed charge, 20% to energy charge for a project with 80% debt financing and 20% equity financing
Fixed charge basis	• Paid on available capacity (NPR/kW) • Recognises dispatchable capacity grid service provided by SHEPs, rather than simple energy-only tariffs • An available capacity charge is more transparent than a take-or-pay obligation and can arguably raise less political opposition • A nameplate capacity charge effectively becomes a fixed annual fee, which may best ensure debt servicing, but reduces operational incentives and could lead to political opposition if capacity availability underperforms • Capacity charges now applicable to PPAs under the ERC Act 2018
Energy charge basis	• Paid on energy generated (NPR/kWh) • Maintaining a variable energy charge shares some volume risk with project owners • Dry season tariff set at 1.75 times wet season tariff (subject to value indicated by latest NEA least-cost planning study, if available)
Tariff calculation	
Basis for calculation	• Levelised tariff calculation (equity IRR equals ROE) • Different tariffs apply for first 15-year period and other years
Treatment of inflation	• Indexation to actual inflation • Indexation mechanism will differ according to relative shares of NPR- and USD-denominated costs (and the applicable inflation rate)

Source: ECA

ANNEXES

Table 9 Existing power plants

	Type	Capacity (MW)
NEA (including subsidiaries) hydro power plants		
Upper Tamakoshi Hydropower Ltd	PROR	456
Kali Gandaki A	PROR	144
Middle Marsyandi	PROR	70
Marsyangdi	PROR	69
Upper Trishuli 3A HEP	ROR	60
Kulekhani I	Reservoir	60
Medium hydro (3.3-45 MW)	ROR	198
Small hydro (<3.3 MW)*	ROR	19
NEA hydro subtotal		**1,076**
IPP hydro power plants		
Solukhola Dudhkoshi	ROR	86
Likhu-1	ROR	77
Middle Tamor	ROR	73
Nilgiri Kola-2 Cascade	ROR	71
Khimti	ROR	60
Super Dordi ‘Kha’	ROR	54
Likhu-2	ROR	52
Likhu-IV	ROR	52
Upper Marsyangdi A	ROR	50
Bhote Koshi	ROR	45
Small-medium hydro IPPs (<45 MW)	ROR	1,194
IPP hydro subtotal		**1,915**
Other power plants		
Duhabi Multi-Fuel	Diesel	39
Hetauda Diesel Powerhouse	Diesel	14
Solar projects (NEA)	Solar	107
Bagasse (IPP)	Bagasse	6
Other subtotal		**166**
Total capacity		**3,157**

Source: NEA. 2024.

ROR = Run-Of-River | PROR = Peaking Run-Of-River

*   Includes grid-connected and isolated small hydro

Capacities rounded to nearest integer. Some ROR hydropower plants are cascades. Some small hydro has been leased to the private sector or are not in regular operation

Table 10 Under construction, planned, and / or proposed hydro power plants

	Type	Capacity (MW)
Under construction		
Tanahu	Reservoir	140
Rasuwagadi	ROR	111
Madhya Bhotekoshi	ROR	102
Sanjen	ROR	43
Rahuganga	PROR	40
Upper Trishuli 3B	ROR	37
Upper Sanjen	ROR	15
Tamakoshi-V	ROR	95
Upper Modi ‘A’	ROR	42
Upper Modi	ROR	18
Under construction subtotal		**642**
Planned and proposed		
Upper Arun	PROR	1,061
Uttar Ganga Storage	Reservoir	828
Dudhkoshi Storage (DKSHEP)	Reservoir	670
Chainpur Seti	PROR	210
Aadhikhola Storage	Reservoir	180
Begnas Rupa Pump Storage	Pumped storage	150
Planned and proposed subtotal		**3,099**
Total capacity		**3,741**

Source: NEA. 2024. Annual Report 2023-24

ROR = Run-Of-River | PROR = Peaking Run-Of-River

Capacities rounded to nearest integer. Some ROR hydropower plants are cascades

A2 Indian exchange price benchmarks

Compared to India's DAM, higher price caps, and potentially higher prices, are present on two sets of recently launched Indian electricity markets:

- The IEX has launched 'High Price' (HP) versions of the Day Ahead (HP-DAM), Intra Day (HP-ITD), Day Ahead Contingency (HP-DAC), and Term Ahead (HP-TAM) markets.
- New ancillary services markets: Primary (PRAS), Secondary (SRAS), and Tertiary (TRAS) Reserve Ancillary Services, which have superseded the Reserve Regulated Ancillary Services (RRAS).
  - PRAS is designed for instantaneous frequency response, which reservoir hydro may not be technically capable of providing, SRAS and TRAS require response times of 30 seconds and 15 minutes, respectively, which reservoir hydro should be capable of providing.

A2.1 'High Price' IEX markets

The HP-DAM was launched in March 2023 in response to major price spikes in international coal and gas markets in 2022. Eligible generators for this market included LNG-fuelled gas plants, imported coal-fuelled plants, and battery energy storage systems (BESS). The HP-DAM's price cap was initially set at INR 50/kWh (NPR 80/kWh or US¢ 59.7/kWh),[33] but it was subsequently reduced to INR 20/kWh (NPR 32/kWh or US¢ 23.9/kWh).[34]

When reducing the price cap, CERC cited the minimal amount of actual trading in the HP-DAM since its launch, contemplating whether the demarcation of the DAM and HP-DAM should remain given the decline in global gas prices.[35] The market remains active, if only thinly and sporadically traded.[36] Stakeholders have reported that some distribution companies prefer to load shed rather than purchase on the HP-DAM, indicating that the maximum price for some Indian offtakers may be well below the price cap.[37]

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33 In its petition, the IEX cited that the operating cost of an open-cycle gas turbine (OCGT) reached INR 58.48/kWh (NPR 93.6/kWh or US¢ 70.1/kWh) in 2022, which was well above that period's DAM price cap of INR 12/kWh (NPR 19.2/kWh or US¢ 14.3/kWh): https://cercind.gov.in/2023/orders/359-MP-2022.pdf

34 CERC, 31 March 2023, Petition No. 04/SM/2023

35 CERC, 31 March 2023, Petition No. 04/SM/2023 pp3-4.

36 There has been 43.2 GWh of HP-DAM volumes between its launch in March 2023 and August 2024, averaging 2.4 GWh per month, with a weighted-average price of INR 16.7/kWh (NPR 26.7/kWh or US¢ 19.9/kWh). This represents only 0.01% of bilateral or exchange-based trades, or 0.002% of total generation, during that time period.

Furthermore, 38.6 GWh (89%) of HP-DAM trade to date has occurred within the window of August-October 2023 (likely linked to a period of unusually hot weather and reduced hydro generation in India; see Figure 4), with only 3.3 GWh of trades since, and many months exhibiting zero HP-DAM volumes.

Source: https://www.cercind.gov.in/report_MM.html

37 B. Bertagnini et al, 2023, Powering Progress: Batteries for Discoms, RMI and GEAPP, pp90.

IEX also introduced ‘high price’ versions of its ITD, DAC, and TAM markets in late 2023, partly in response to the HP-DAM’s low liquidity.[38] Like the HP-DAM, eligibility for the HP- markets is periodically determined by the CEC. These markets also have a price cap of INR 20/kWh. However, actual trading volumes for these markets have also been thin and sporadic.[39]

A2.2 Ancillary service markets

For its newly designed ancillary service markets, market-based procurement for TRAS was launched in June 2023, while PRAS and SRAS are still procured out-of-market.

TRAS UP prices are capped at INR 20/kWh for HP-DAM eligible generators; otherwise, a price cap of INR 10/kWh applies. The CERC has aligned the price caps to reduce the potential for between market energy arbitrage. Up to March 2024, there has been 47.1 GWh of energy scheduled through TRAS UP,[40] but price results to date have been described as ‘opaque’ and lacking ‘market price clarity’,[41] so there is little indication at this stage as to whether Nepalese reservoir hydro would readily have the opportunity to export ancillary services to the Indian grid nor what the cost competition would be like in these markets.

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38 CERC, 16 October 2023, Petition No. 259/MP/2023

39 According to market data on the IEX website, trades in these markets have cleared at an average price of INR 15/kWh (NPR 24.0/kWh or US¢ 17.9/kWh),

The CERC reports a HP-TAM price range of INR 11.99-15.60 (NPR 19.2-25.0/kWh or US¢ 14.3-18.6/kWh): CERC, Report on Short-term Power Market in India: 2023-24, Table 17(b).

In any case, actual trading volumes for 2024 have been minimal:

For the HP-ITD market: 1 GWh in April, 1.3 GWh in June, 1.1 GWh in July, and 7 GWh in August, with zero volumes in other months.

For the HP-DAC market: 0.8 GWh in June and 1.1 GWh in July, with zero volumes in other months.

40 CERC, Report on Short-term Power Market in India: 2023-24, Table 34(a). TRAS volumes have been higher for TRAS UP shortfall / emergency, which applies to generators with regulated tariffs and unused capacity.

41 B. Bertagnini et al, 2023, Powering Progress: Batteries for Discoms, RMI and GEAPP, pp33 and J. Cohen et al, October 2024, Growing Markets for Grid-Connected Battery Storage in India, RMI.

A3 Benchmarks for dry-wet season tariff ratio

We consider a few alternatives methods and data sources for setting the ratio of dry and wet season PPA tariffs:

- Recent average hourly prices on the IEX;
- The average cost of Nepal's IEX imports from India, as reported by India's CERC;
- The per kWh financial cost of purchases from India, as per NEA's financials; and
- The levelised cost of electricity of new build diesel-fired power plants.

We contrast each benchmark to the prevailing dry and wet season PPA tariff rate for Nepal's hydro power plants: NPR 4.8/kWh, or US¢ 3.6/kWh, and NPR 8.4/kWh, or US¢ 6.3/kWh, respectively, in Table 11.

Table 11 Comparison of benchmarks for setting dry-wet season tariff ratio

Approach	Implied dry season rate (NPR/kWh)	Dry : wet season ratio
Prevailing dry-wet season PPA tariffs in Nepal	**8.40 (US¢ 6.28/kWh)**	**1.75**
Average IEX price during Nepal dry season (June 2022-July 2024)	8.45 (US¢ 6.32/kWh)	1.76
Reported average cost of Nepal imports from India via IEX (June 2022-December 2023 weighted average)	7.67 (US¢ 5.73/kWh)	1.60
NEA financial cost of imports from India (2022-24 weighted average)	9.88 (US¢ 7.39/kWh)	2.06
Cost of new build diesel	45-49 (US¢ 33.5-36.9/kWh)	9.33-10.28
Cost of new build solar PV + BESS	10.4-13.6 (US¢ 7.8-10.2/kWh)	2.16-2.83

Source: ECA calculations; NREL.

Excluding the diesel and solar PV + BESS LCOEs, the benchmarks suggest a range of 1.60 to 2.06, and averaging 1.81. Given there are some uncertainties about each measurement, the prevailing ratio of 1.75 is well within the estimates' range, and 1.75 times should reflect NEA's own assessment of cost differentials, we conclude that the prevailing ratio is still a reasonable basis for setting a forward-looking dry-wet season tariff ratio for reservoir hydro PPAs, and is used for this document's illustrative calculations. However, in practice, we would still recommend deferring to the most recent NEA least-cost planning study, which should have the best perspective as to the relative value of dry versus wet season energy dispatch.

Each approach is further discussed in the following subsections.

Hourly IEX prices

Increased interconnection and trade with India will gradually increase Nepal's exposure to hourly prices on India's electricity exchange, the IEX (Figure 4). This provides a potential market-based benchmark for the value of generation during the dry season compared to the wet season.

As reported in Section 2.1.3, average IEX DAM prices for June 2022 to July 2024 were only nominally higher during Nepal's dry seasons at INR 5.30/kWh (US¢ 6.3/kWh or NPR 8.5/kWh) versus INR 5.22/kWh (US¢ 6.2/kWh or NPR 8.4/kWh) during Nepal's wet seasons.

While we concluded in Section 3.1 that these prices would likely be insufficient for recovering the costs of a hydro reservoir project, nor would investors in Nepalese hydro plants likely accept the risk of significant exposure to IEX spot prices (not ruling out longer-term bilateral export contracts, if available), IEX prices should reasonably reflect the 'avoided cost' of additional Indian imports compared to hydro reservoir dispatch during the dry season.

The IEX DAM's average price during Nepal's dry season of NPR 8.5/kWh (US¢ 6.3/kWh) for June 2022-July 2024 gives a ratio of 1.76 compared to Nepal's current wet season tariff, which is almost exactly equal to the dry-wet season ratio in Nepal's prevailing hydro PPA tariff rates of 1.75.

Average cost of imports from India via the IEX

India's CERC publishes monthly monitoring reports on short-term electricity transactions,[42] which includes reporting the volume and volume-weighted price of export-imports between India and Nepal via the IEX. This will not represent all imports from India as there are also some bilateral arrangements, but the majority of India-Nepal power exchange is now linked to the IEX.[43]

While the average IEX prices reported in the above subsection may reflect the typical cost of imports across Nepal's dry season and utilises every hour of data, the CERC figures may better reflect the cost of imports when considering the operational realities of the Nepalese grid, eg, Nepal's highest periods of system stress and imports may not directly correlate with the highest periods of system stress and prices in India.

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42 https://www.cercind.gov.in/report_MM.html

The CERC also reports the volume and average price of exports to Bhutan, which primarily exports excess hydro to India. The CERC reports only two months where Bhutan imported from India: 26 GWh in October 2023 at an average price of INR 6.7/kWh (US¢ 8.0/kWh) and 14 GWh in November 2023 at an average price of INR 4.1/kWh (US¢ 4.9/kWh).

We also note a couple reports suggesting Bhutan's average import prices were 3.33 Nu/kWh (US¢ 4.0/kWh) in Winter 2022 and 4.72 Nu/kWh (US¢ 5.7/kWh) in Winter 2023 (Kuensel. 9 March 2023. "Nu 8.35 per unit for imported electricity". | USAID. 2023. Deepening Cross Border Electricity Trade and Regional Electricity Market Development for Sustainable Energy in the South Asia Region: South Asia Forum for Infrastructure Regulation (SAFIR) and South Asia Regional Energy Partnership (SAREP), Conference Proceedings, 2-3 March 2023)

While notable, these are minimal data points and the cost of Indian exports to Bhutan is less relevant than the reported price for Indian exports to Nepal.

43 NEA. 2024. Annual Report 2023-24 (p121).

The volume-weighted average of reported exports to Nepal between May 2022 and April 2024 is INR 4.81/kWh (US¢ 5.7/kWh or NPR 7.7/kWh), which gives a ratio of 1.60 compared to Nepal's current wet season tariff.

Financial cost to the NEA of imports from India

The NEA's financial reports separately report the cost of sales of power purchases from India. Dividing this value by the amount of purchased energy gives an approximate estimate of the actual per kWh cost of imports from India. This is a relatively crude measure, but it may reflect some additional costs that are not accounted for when simply taking averages of hourly IEX prices, eg, transmission charges, transaction fees, trader margins, etc.

For 2021-22 to 2023-24, the implied volume-weighted average cost of Indian imports from this method is NPR 9.88/kWh (US¢ 7.4/kWh), which gives a ratio of 2.06 compared to Nepal's current wet season tariff.

Cost of new build diesel or solar PV + BESS

One option would be to base the value of dry season dispatch on the levelised cost of electricity (LCOE) of the firm supply provided by a new build diesel-fired power plant. This approach would value dry season dispatch according to the 'avoided cost' of commissioning new diesel-fired capacity.[44]

We use techno-economic estimates for the cost of diesel-fired generation capacity sourced from a couple recent power generation technology cost studies in Indonesia and Vietnam.[45]

Key assumptions are:

- A capex cost of USD 625-915/kW, a project IRR of 15%, and a project lifetime of 25 years.
- A relatively low plant capacity factor of 15%, reflecting that the plant would only be intended to serve as backup / 'peaker' capacity.
    - This assumption can vary, but variable fuel costs dominate the calculation in any case.
- Fixed and variable O&M of USD 9.1-10.0/kW-yr and USD 6.5-7.3/MWh, respectively.
- Average operating fuel efficiency of 45%.

[44] Nepal has a couple existing diesel power plants (39 MW Duhabi Multi-Fuel and the 14 MW Hetauda Diesel Powerhouse), which likely have fully depreciated capital costs, but they are essentially mothballed.

[45] EREA and DEA. 2023. Viet Nam Technology Catalogue for Power Generation 2023. | MEMR and DEA. 2024. Technology Data for the Indonesian Power Sector 2024: Catalogue for Generation and Storage of Electricity.

- A diesel fuel cost of NPR 149/litre (USD 1.11/litre), which is the most recent reported diesel retail price set by the Nepal Oil Corporation, as determined by prices set by the Indian Oil Corporation.[46]

These assumptions produce a LCOE range of USD 335-369/MWh, or NPR 45-49/kWh. This would suggest a ratio of 9.33-10.28 compared to the prevailing wet season hydro PPA tariff rate.

While this calculation may indicate how much a grid or private business may be theoretically willing to pay to avoid load interruptions – such calculations can be used as a proxy for the Value of Loss Load (VOLL) – it is multiples higher than existing tariff rates and does not align with system planning that is focused on developing new hydro rather than considering any new backup thermal generation. In reality, Nepal would likely seek to expand the volume and capacity of cheaper imports from India, as discussed above, as well as investing in within-country transmission capacity[47], to reduce load interruptions rather than build a new fleet of diesel-fired capacity, especially with Nepal dependent on imports from India for fuel oil.

Solar PV plus BESS is likely to get increased attention as a potential future marginal supply source, but this would depend on its consideration within the NEA's least-cost planning, if / when it can be deployed at scale in Nepal, and at what cost. For a benchmark reference, the National Renewable Energy Laboratory (NREL) in the US estimates that a Class 5[48] solar PV plus a four-hour Li-ion BESS has a LCOE range of USD 78-102/MWh (NPR 10.4-13.6/kWh) for 2025.[49] This would suggest a ratio of 2.16-2.83 compared to the prevailing wet season hydro PPA tariff rate, but this is an international benchmark figure that would need to be cross-checked with a Nepal-specific cost estimate.

[46] The Himalayan Times. 15 September 2024. "NOC reduces fuel prices" and https://www.globalpetrolprices.com/Nepal/gasoline_prices/

[47] We understand that a significant share of current load interruptions are due to insufficient east-to-west transmission capacity rather than insufficient generation capacity.

[48] A Global Horizonal Irradiance (GHI) ranging from 4.5-4.75.

One estimate puts Nepal's average solar irradiance at 4.7 kWh/m^2/day: Poudyal, K.N. et al, 2013, Estimation of the daily global solar radiation; Nepal experience, Measurement, Volume 46, Issue 6, pp1807-1817.

[49] NREL, Annual Technology Baseline 2024, Utility-Scale PV-Plus-Battery, Data updated 19 July 2024.

It is of course arguable whether a four-hour BESS is sufficiently sized to be considered like-for-like with reservoir hydro capacity, with longer duration Li-ion BESS yet to be deployed at scale. Other electro-chemical BESS or storage technologies may be considered more appropriate for Nepal. Hence why the appropriate comparison depends on the needs identified in the NEA's least-cost planning.

A4 SHEP cost estimates and sensitivities

To provide illustrate the impact of different tariff design options and parameters, this annex compares 'base case' tariffs to a selection of design and parameter sensitivities.

A4.1 Base case tariff

The calculated tariffs for our base case, based on a reasonable (if simplified) set of design and cost / parameter assumptions, are presented in Table 12. We consider the impact of both design options and parameter sensitivities relative to this 'base case' in the following subsections. We only compare energy-only tariffs for brevity, except for the 50:50 capacity:energy sensitivity.

It is important to stress that the costs and parameters in Table 12 are purely hypothetical and should not be considered indicative of regulatory precedent and / or the views of the ERC.

As per Table 11 in Section 6, we calculate (before indexation):

- For an energy-only tariff, Phase 1 (years 1-15) tariffs of 5.69 NPR/kWh in the wet season and 9.95 NPR/kWh in the dry season and Phase 2 (years 16-50) tariffs of 4.83 NPR/kWh in the wet season and 8.46 NPR/kWh in the dry season.
  - For a single-phase energy-only tariff that applies for years 1-50 (before indexation), the wet season tariff is 5.45 NPR/kWh and the dry season tariff is 9.54 NPR/kWh.
- If applying a 20/80 split between energy and capacity tariffs, the resulting tariffs for Phase 1 are a wet season energy tariff of 1.14 NPR/kWh, a dry season energy tariff of 1.99 NPR/kWh, and a capacity tariff of 2.141 NPR/kW/month. For Phase 2, the wet season energy tariff is 0.97 NPR/kWh, the dry season energy tariff is 1.69 NPR/kWh, and the capacity tariff is 1,464 NPR/kW/month.

Table 12 Illustrative hydro project key financial parameters

Parameter	Value	Notes
Costs		
Capital cost	USD 2,550m	USD 3,400/kW for 750 MW capacity plant Cost on completion, i.e., inclusive of IDC.
Operations & Maintenance (O&M)	USD 10.2m pa (NPR 1,362m pa)	0.4% of capex 3.0% escalation (in USD nominal terms)
Maintenance capex	Year 15: USD 26.3m for runner replacement Year 25: USD 52.5m for equipment replacement	USD 35/kW for runner replacement and USD 70/kW for equipment replacement.
Financing		
Equity		

Parameter	Value	Notes
NEA	USD 285m (12%)	Equity IRR: 12.47%
Public	USD 115m (5%)	Equity IRR: 17.5% (subject to 17.0% cap)
Equity subtotal	**USD 400m (17%)**	
Debt		
International Development Association (IDA)-equivalent	USD 600m (26%)	1.5% interest, 32-year tenor
Sovereign Concessional Loans	USD 1,200m (52%)	4.5% interest, 25-year tenor
Domestic Commercial Loans	USD 100m (4%)	11.0% interest, 20-year tenor
Debt subtotal	**USD 1,900m (83%)**	Weighted average tenor of 27 years
Total financing	**USD 2,300m**	
Other assumptions		
Concession period	50 years	The length of hydro storage PPAs is a matter for consultation. Long PPAs may be reasonable for reservoir hydro projects given their scale and long-life. It is notable that ICRA Nepal cited the limited project life (25 years) of the Upper Tamakoshi hydro project, as capped by the energy generation license, as a risk factor.[50]
Construction period	7 years	
Tax rate	20%	15-year 'full holiday' and 6-year 'half holiday'
USD:NPR appreciation	3.2% p.a.	Based on relative long-term inflation forecasts of 2.1% for the USA and 5.4% for Nepal.[51]
Profit sharing with employees	2% of earnings (before tax)	
Royalties to Government		
Capacity royalties	Up to 15 years: NPR 100/kW After 15 years: NPR 1,000/kW	
Energy royalties	Up to 15 years: 2% of revenue After 15 years: 10% of revenue	
Design options		
Tariff periods	Phase 1: Years 1-15 Phase 2: Years 16-50	Linked to accelerated depreciation and tax holiday and royalties assumptions.
Accelerated depreciation	15 years 50% of asset value	Linked to debt financing mix, tax / royalty holidays, plus CERC regulatory precedent.
Ratio of Phase 1 and Phase 2 tariff	0.85	Can be adjusted according to forecast DSCR / LLCR and

50 ICRA Nepal, 23 November 2022, Upper Tamakoshi Hydropower Limited: [ICRANP-IR] BB assigned.

51 IMF, World Economic Outlook (October 2024), Inflation rate, average consumer prices.

Parameter	Value	Notes
		resulting Phase 1 and Phase 2 tariffs
Dry-wet season tariff ratio	1.75	Set according to prevailing dry-wet season hydro tariffs in Nepal, informed by relevant NEA least-cost planning study (if available). Analysis in Annex A2 suggests this is a reasonable ratio.
Tariff escalation	Escalation weights: US CPI: 80% Nepal CPI: 20% Forex: 80%	Numerous options for weighting and timing of escalator. One option could be to reduce or halt the escalator once debt payments have been completed in the later years of the PPA but the impact on the NPV tariff is heavily muted (~1%) due to discounting.
Calculated tariffs	**Phase 1 (Years 1-15)**	**Phase 2 (Years 16-50)**
Energy-only tariff (before indexation)		
Energy tariff	Wet season: 5.69 NPR/kWh (4.26 US¢/kWh) Dry season: 9.95 NPR/kWh (7.46 US¢/kWh)	Wet season: 4.83 NPR/kWh (3.62 US¢/kWh) Dry season: 8.46 NPR/kWh (6.34 US¢/kWh)
Energy and capacity tariff (before indexation): 20% energy, 80% capacity		
Energy tariff	Wet season: 1.14 NPR/kWh (0.85 US¢/kWh) Dry season: 1.99 NPR/kWh (1.49 US¢/kWh)	Wet season: 0.97 NPR/kWh (0.72 US¢/kWh) Dry season: 1.69 NPR/kWh (1.27 US¢/kWh)
Capacity tariff	2,141 NPR/kW/month (16.0 US$/kW/month)	1,464 NPR/kW/month (11.0 US$/kW/month)

Source: ECA assumptions and analysis, guided by consultation with and indicative values provided by the ADB and ERC and assumptions from USAID Urja Nepal Program. 12 September 2023. Dudhkoshi Storage Hydroelectric Project: Financial Analysis Summary.

A4.2 Sensitivities

The following sensitivities are reported in the subsections below:

- **A4.2.1**: Debt tenor and length of Phase 1 tariff period
- **A4.2.2**: Tax holidays and reduced royalty rates
- **A4.2.3**: Fixed versus variable tariff cost recovery share
- **A4.2.4**: Capex and fixed O&M
- **A4.2.5**: Cost of debt
- **A4.2.6**: Cost of equity

- **A4.2.7**: Financing mix

A4.2.1 Debt tenor and length of Phase 1 tariff period

The length of the Phase 1 and Phase 2 tariff periods is essentially linked to the weighted average tenor of debt. A higher Phase 1 tariff is intended to ensure debt servicing, which will be frontloaded for long-lived assets like reservoir hydro projects. This also influences the application of accelerated depreciation.

We consider two scenarios in Table 13 with differing debt tenors:

- **Scenario 1 – Phase 1 reduced to 10 years**: Weighted average tenor of debt decreased to 20 years[52]. Reduce accelerated depreciation period to 10 years.
  - Decreasing the debt tenor leads to an overall increase in the required tariffs, albeit with the higher rate Phase 1 being shorter given a shorter period of debt servicing.
- **Scenario 2 – Phase 1 increased to 20 years**: Weighted average tenor of debt increased to 30 years[53]. Reduce accelerated depreciation period to 10 years.
  - Increasing the debt tenor leads to an overall decline in the required tariffs, albeit with a longer Phase 1 tariff in order to ensure debt servicing.

Table 13 Sensitivity: debt tenor and length of Phase 1 tariff period

Scenario	Phase 1	Phase 2
Base case – 15-year Phase 1: Weighted average debt tenor of 27 years, 15-year accelerated depreciation		
Energy tariff	Years: 1-15 Wet season: 5.69 NPR/kWh (4.26 US¢/kWh) Dry season: 9.95 NPR/kWh (7.46 US¢/kWh)	Years: 16-50 Wet season: 4.83 NPR/kWh (3.62 US¢/kWh) Dry season: 8.46 NPR/kWh (6.34 US¢/kWh)
Scenario 1 – 10-year Phase 1: Weighted average debt tenor of 20 years, 10-year accelerated depreciation		
Energy tariff **(+8.4% relative to base case)**	Years: 1-10 Wet season: 6.17 NPR/kWh (4.62 US¢/kWh) Dry season: 10.79 NPR/kWh (8.08 US¢/kWh)	Years: 11-50 Wet season: 5.24 NPR/kWh (3.93 US¢/kWh) Dry season: 9.17 NPR/kWh (6.87 US¢/kWh)
Scenario 2 – 20-year Phase 1: Weighted average debt tenor of 30 years, 20-year accelerated depreciation		
Energy tariff **(-2.9% relative to base case)**	Years: 1-20 Wet season: 5.52 NPR/kWh	Years: 21-50 Wet season: 4.69 NPR/kWh

[52] Decrease IDA-equivalent loan from 32 to 25 years, sovereign concessional loans from 25 to 18 years, and domestic commercial loans from 20 to 10 years.

[53] Increase IDA-equivalent loan from 32 to 34 years, sovereign concessional loans from 25 to 28 years, and domestic commercial loans from 20 to 22 years.

Scenario	Phase 1	Phase 2
	(4.14 US¢/kWh) Dry season: 9.66 NPR/kWh (7.24 US¢/kWh)	(3.52 US¢/kWh) Dry season: 8.21 NPR/kWh (6.15 US¢/kWh)

Source: ECA analysis.

A4.2.2 Tax holidays and reduced royalty rates

The length of any tax holidays or reduced royalty rates will also influence the required length of the Phase 1 and Phase 2 tariffs. These factors can cause step-changes in year-to-year cashflows, which can pose a challenge for 'smoothing' DSCRs across the full period of operation. This is less of a challenge for LLCRs, which evaluate debt servicing over the course of the project's loans rather than annual metric like DSCRs.

Any tax holidays or reduced royalties will likely have political considerations, but we consider the impact of reducing or extending their length in Table 13. Naturally, reducing the tax holidays or period of reduced royalties results in a higher required tariff.

- **Scenario 1 – reduce length of tax holiday and reduced royalties**: Reduce tax holiday from 15 to 10 years, the half tax holiday from 6 to 3 years, and reduced royalties from 15 to 10 years.
- **Scenario 2 – increase length of tax holiday and reduced royalties**: Increase tax holiday from 15 to 20 years, the half tax holiday from 6 to 9 years, and reduced royalties from 15 to 20 years.

Table 14 Sensitivity: tax holidays and reduced royalty rates

Scenario	Phase 1 (Years 1-15)	Phase 2 (Years 16-50)
Base case – 15-year tax holiday, 6-year half tax holiday, 15-year reduced royalties		
Energy tariff	Wet season: 5.69 NPR/kWh (4.26 US¢/kWh) Dry season: 9.95 NPR/kWh (7.46 US¢/kWh)	Wet season: 4.83 NPR/kWh (3.62 US¢/kWh) Dry season: 8.46 NPR/kWh (6.34 US¢/kWh)
Scenario 1 – 10-year tax holiday, 6-year half tax holiday, 10-year reduced royalties		
Energy tariff **(+2.3% relative to base case)**	Wet season: 5.82 NPR/kWh (4.36 US¢/kWh) Dry season: 10.19 NPR/kWh (7.63 US¢/kWh)	Wet season: 4.95 NPR/kWh (3.71 US¢/kWh) Dry season: 8.66 NPR/kWh (6.49 US¢/kWh)
Scenario 2 – 20-year tax holiday, 9-year half tax holiday, 20-year reduced royalties		
Energy tariff **(-1.4% relative to base case)**	Wet season: 5.61 NPR/kWh (4.20 US¢/kWh) Dry season: 9.81 NPR/kWh (7.35 US¢/kWh)	Wet season: 4.77 NPR/kWh (3.57 US¢/kWh) Dry season: 8.34 NPR/kWh (6.25 US¢/kWh)

Source: ECA analysis.

A4.2.3 Fixed versus variable tariff cost recovery share

If split into energy and capacity tariffs, the base case assumes that 80% of costs are recovered via capacity tariffs, the fixed component, which broadly aligns with 80% debt financing and, by lowering calculated energy tariff, reduces any risk of distorting the SO's dispatch decisions.

However, for illustration, we report the resulting tariffs if a 50:50 split between the variable and fixed components were applied, which aligns with CERC regulations, or a 20:80 energy:capacity split.

Table 15 Sensitivity: fixed versus variable tariff cost recovery share

Scenario	Phase 1 (Years 1-15)	Phase 2 (Years 16-50)
Base case – 20% energy, 80% capacity		
Energy tariff	Wet season: 1.14 NPR/kWh (0.85 US¢/kWh) Dry season: 1.99 NPR/kWh (1.49 US¢/kWh)	Wet season: 0.97 NPR/kWh (0.72 US¢/kWh) Dry season: 1.69 NPR/kWh (1.27 US¢/kWh)
Capacity tariff	2,141 NPR/kW/month 16.0 US$/kW/month	1,464 NPR/kW/month 11.0 US$/kW/month
Scenario – 50% energy, 50% capacity		
Energy tariff **(2.5x relative to base case)**	Wet season: 2.84 NPR/kWh (2.13 US¢/kWh) Dry season: 4.98 NPR/kWh (3.73 US¢/kWh)	Wet season: 2.42 NPR/kWh (1.81 US¢/kWh) Dry season: 4.23 NPR/kWh (3.17 US¢/kWh)
Capacity tariff **(0.6x relative to base case)**	1,338 NPR/kW/month 10.0 US$/kW/month	915 NPR/kW/month 6.9 US$/kW/month
Scenario – 80% energy, 20% capacity		
Energy tariff **(4.0x relative to base case)**	Wet season: 4.55 NPR/kWh (3.41 US¢/kWh) Dry season: 7.96 NPR/kWh (5.96 US¢/kWh)	Wet season: 3.87 NPR/kWh (2.90 US¢/kWh) Dry season: 6.77 NPR/kWh (5.09 US¢/kWh)
Capacity tariff **(0.25x relative to base case)**	535 NPR/kW/month 4.0 US$/kW/month	366 NPR/kW/month 2.7 US$/kW/month

Source: ECA analysis.

A4.2.4 Capex and fixed O&M

This sensitivity considers scenarios where either capex or fixed O&M are 30% higher than the base case estimates in Table 12. In the capex scenario, we also assume that all debt and equity need to rise by 30% (at the same terms).

Reviewing the results in Table 16, this leads to a nearly one-for-one increase in required tariffs. The increase in fixed O&M is less consequential, although not insignificant given the escalators applied to fixed O&M, plus USD:NPR forex.

Table 16 Sensitivity: capex and fixed O&M

Scenario	Phase 1 (Years 1-15)	Phase 2 (Years 16-50)
Base case		
Energy tariff	Wet season: 5.69 NPR/kWh (4.26 US¢/kWh) Dry season: 9.95 NPR/kWh (7.46 US¢/kWh)	Wet season: 4.83 NPR/kWh (3.62 US¢/kWh) Dry season: 8.46 NPR/kWh (6.34 US¢/kWh)
Scenario 1 – capex +30%		
Energy tariff **(+29.6% relative to base case)**	Wet season: 7.37 NPR/kWh (5.52 US¢/kWh) Dry season: 12.90 NPR/kWh (9.67 US¢/kWh)	Wet season: 6.27 NPR/kWh (4.69 US¢/kWh) Dry season: 10.97 NPR/kWh (8.22 US¢/kWh)
Scenario 2 – fixed O&M +30%		
Energy tariff **(+2.3% relative to base case)**	Wet season: 5.82 NPR/kWh (4.36 US¢/kWh) Dry season: 10.18 NPR/kWh (7.62 US¢/kWh)	Wet season: 4.94 NPR/kWh (3.70 US¢/kWh) Dry season: 8.65 NPR/kWh (6.48 US¢/kWh)

Source: ECA analysis.

A4.2.5 Cost of debt

The base case assumes the following debt financing characteristics:

- IDA-equivalent: USD 600m at an interest rate of 1.5% and a tenor of 32 years.
- Sovereign concessional loans: USD 1,275m at an interest rate of 4.5% and a tenor of 25 years.
- Domestic commercial loans: USD 100m at an interest rate of 11.0% and a tenor of 20 years.

In Table 17, we consider a scenario where the interest rate on each of these loans is 30% higher than the base case: 1.8% for the IDA-equivalent loan, 5.9% for the sovereign concessional loans, and 14.3% for the domestic commercial loans. This causes required tariffs to increase by 7.6%.

Table 17 Sensitivity: cost of debt

Scenario	Phase 1 (Years 1-15)	Phase 2 (Years 16-50)
Base case		
Energy tariff	Wet season: 5.69 NPR/kWh (4.26 US¢/kWh) Dry season: 9.95 NPR/kWh (7.46 US¢/kWh)	Wet season: 4.83 NPR/kWh (3.62 US¢/kWh) Dry season: 8.46 NPR/kWh (6.34 US¢/kWh)
Scenario – 30% higher interest rates		
Energy tariff	Wet season: 6.12 NPR/kWh	Wet season: 5.20 NPR/kWh

Scenario	Phase 1 (Years 1-15)	Phase 2 (Years 16-50)
(+7.6% relative to base case)	(4.58 US¢/kWh) Dry season: 10.71 NPR/kWh (8.02 US¢/kWh)	(3.90 US¢/kWh) Dry season: 9.10 NPR/kWh (6.82 US¢/kWh)

Source: ECA analysis.

A4.2.6 Cost of equity

The base case assumes the NEA's (nominal) ROE is 12.5% and the public's (nominal) ROE is 17.5%, albeit the latter is capped at 17.0%. In the base case, with USD 285m of NEA equity funding and USD 115m of public funding, the weighted ROE is 13.8%.

Table 17 considers a sensitivity where both equity holders have a (nominal) ROE of 17.0%, ie, up to the cap proposed in Section 3.4.4. This raises the required tariff by 12.1% relative to the base case

Table 18 Sensitivity: cost of equity

Scenario	Phase 1 (Years 1-15)	Phase 2 (Years 16-50)
Base case – (weighted) return on equity of 13.8%		
Energy tariff	Wet season: 5.69 NPR/kWh (4.26 US¢/kWh) Dry season: 9.95 NPR/kWh (7.46 US¢/kWh)	Wet season: 4.83 NPR/kWh (3.62 US¢/kWh) Dry season: 8.46 NPR/kWh (6.34 US¢/kWh)
Scenario – return on equity of 17.0%		
Energy tariff **(+12.1% relative to base case)**	Wet season: 6.37 NPR/kWh (4.77 US¢/kWh) Dry season: 11.15 NPR/kWh (8.35 US¢/kWh)	Wet season: 5.42 NPR/kWh (4.06 US¢/kWh) Dry season: 9.48 NPR/kWh (7.10 US¢/kWh)

Source: ECA analysis.

A4.2.7 Financing mix

The base case, using rounded debt/equity funding assumptions, has a debt:equity ratio of 82:18. We consider two scenarios that vary this ratio in Table 19:

- Increasing the debt share to 90%
  - We increase the debt funding by USD 170m (adding USD 75m of IDA-equivalent loans, USD 75m of sovereign concessional loans, and USD 20m of domestic commercial loans) and commensurately reducing equity (reducing NEA equity by USD 120m and public equity by USD 50m)
  - While this approach lowers the required tariff, it also materially lowers the DSCR, which averages only 1.23 across the first 25 years of operations. We alleviate this by increasing the Phase 1 tariff length to 25 years, increasing the length of accelerated depreciation to 20 years, and lowering the Phase 2

: Phase 1 ratio to 0.60, ie, further frontloading the tariff. This highlights the potential limits on debt-based financing, even if nominally cheaper.[54]

- Lowering the debt share to 70%
  - We increase the equity funding by USD 290m (adding USD 200m of NEA equity and USD 90m of public equity) and commensurately reduce debt (reducing IDA-equivalent loans by USD 100m, sovereign concession loans by USD 170m, and domestic commercial loans by USD 20m).
  - While tariffs are higher in this scenario, it is notable that the 25-year average DSCR is healthy at 1.96, suggesting further scope for raising (cheaper) debt financing.
- Together, these two scenarios suggest that, under these hypothetical project parameters, an 80:20 debt:equity split could be the 'sweet spot' for balancing lower tariffs and healthy DSCRs.

Table 19 Sensitivity: financing mix

Scenario	Phase 1	Phase 2
Base case – 82:18 debt:equity		
Energy tariff	Years: 1-15 Wet season: 5.69 NPR/kWh (4.26 US¢/kWh) Dry season: 9.95 NPR/kWh (7.46 US¢/kWh)	Years: 16-50 Wet season: 4.83 NPR/kWh (3.62 US¢/kWh) Dry season: 8.46 NPR/kWh (6.34 US¢/kWh)
Scenario – 90:10 debt:equity		
Energy tariff Phase 2 : Phase 1 ratio: reduced from 0.85 to 0.60 **(Phase 1: -8.2%, Phase 2: -35.2% relative to base case)**	Years: 1-25 Wet season: 5.22 NPR/kWh (3.91 US¢/kWh) Dry season: 9.13 NPR/kWh (6.84 US¢/kWh)	Years: 26-50 Wet season: 3.13 NPR/kWh (2.35 US¢/kWh) Dry season: 5.48 NPR/kWh (4.10 US¢/kWh)
Scenario – 70:30 debt:equity		
Energy tariff **(+12.1% relative to base case)**	Years: 1-15 Wet season: 6.47 NPR/kWh (4.84 US¢/kWh) Dry season: 11.32 NPR/kWh (8.48 US¢/kWh)	Years: 16-50 Wet season: 5.50 NPR/kWh (4.12 US¢/kWh) Dry season: 9.62 NPR/kWh (7.20 US¢/kWh)

Source: ECA analysis.

[54] We note that ICRA Nepal cited the Upper Tamakoshi hydro project's relatively high gearing ratio of 88:12 as a risk factor: ICRA Nepal, 23 November 2022,
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