Federal Democratic Republic of Nepal
Ministry of Energy, Water Resources and Irrigation

DATA COLLECTION SURVEY ON THE PPP MODALITY IN HYDROPOWER PROJECT IN NEPAL

FINAL REPORT

May 2020

Japan International Cooperation Agency

NEWJEC Inc.
The Kansai Electric Power Co., Inc.

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Data Collection Survey on the PPP Modality in Hydropower Project in Nepal

Final Report

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Abbreviations

ADB	Asian Development Bank
B/S	Balance Sheet
BOO	Build, Operate and Own
BOOT	Build, Own, Operate and Transfer
BOT	Build ,Operate and Transfer
BT	Build and Transfer
CA	Concession Agreement
COD	Commercial Operation Date
DSCR	Debt Service Coverage Ratio
DC	Direct Current
DoED	Department of Electricity Development
DoI	Department of Industry
EDL	Electricité Du Laos in Lao P.D.R.
EGAT	Electricity Generating Authority of Thailand
EIA	Environmental Impact Assessment
EIRR	Equity Internal Rate of Return
EPCF	Engineering, Procurement, Construction and Financing
ERC Act	Electricity Regulation Commission Act, 2074
ERC Bylaws	Bylaws Relating to Purchase/Sale of Electricity and Conditions to be fulfilled by the Licensees, 2076
ERC Rules	Electricity Regulatory Commission Rules, 2018
ESIA	Environmental and Social Impact Assessment
F/S	Feasibility Study
FITTA	Foreign Investment and Technology Transfer Act 2019
FSL	Full Spillway Level
GLOF	Glacial Lake Outburst Flood
GON	Government of Nepal
IAEA	International Atomic Energy Agency
IBN	Investment Board of Nepal
IDA	International Development Association
IEE	Initial Environmental Examination
IIPB	Industry and Investment Promotion Board
IPP	Independent Power Producer
IRR	Internal Rate of Return
IUCN	International Union for Conservation of Nature
JICA	Japan International Cooperation Agency
JVA	Joint Venture Agreement
LARAP	Land Acquisition and Resettlement Action Plan
LD	Liquidated Damages

LED	Light Emitting Diode
LOL	Lowest Operation Level
MAED	Model for Analysis of Energy Demand
MOA	Memorandum of Agreement
MoEWRI	Ministry of Energy, Water Resources and Irrigation
MoF	Ministry of Finance
MOU	Memorandum of Understanding
NEA	Nepal Electricity Authority
NERC	Nepal Electricity Regulatory Commission
NPC	National Power Corporation in the Philippines
NRB	Nepal Rastra Bank
NTP	Notice to Proceed
OCR	Office of Company Register
P/L	Profit and Loss Statement
PDA	Project Development Agreement
PPA	Power Purchase Agreement
PPP	Public Private Partnership
PROR	Peaking Run of River
RIPDP	Resettlement and Indigenous People Development Plan
PLN	*Perusahaan Listrik Nagara*: National Electricity Company in Indonesia
ROE	Return on Equity
ROR	Run of River
ROW	Right-of-way
RPGCL	Rasttriya Prasaran Grid Company Limited; National Transmission and Grid Company
RUPTL	Long Term Business Plan of PLN
SDR	Special Drawing Rights
SPC	Special Purpose Company
SVC	Static Var Compensator
UNDP	United Nations Development Programme
USAID	United States Agency for International Development
VAT	Value Added Tax
VSPPPM	Vertical Separation PPP Modality
WASP	Wien Automatic System Planning
WB	World Bank
WECS	Water and Energy Commission Secretariat

Unit

cm	centimeter
GW	Gigawatt (=1,000 MW = 1,000,000 kW)
GWh	Gigawatt – hour (=1,000 MWh = 1,000,000 kWh)
INR	India Rupee
km	Kilometer
km^2	square kilometer
kV	Kilo Volt
kW	kilowatt
kWh	Kilowatt - hour
m	meter
m/s	meter per second
m^3	cubic meter
m^3/s	Cubic meter per second
mm	millimeter
MNPR	Million Nepalese Rupee
MUSD	Million United States Dollar
MW	Megawatt (= 1,000 kW)
MWh	Megawatt – hour (= 1,000 kWh)
NPR	Nepalese Rupee
USD	United States Dollar
t	ton
THB	Thai Bhat

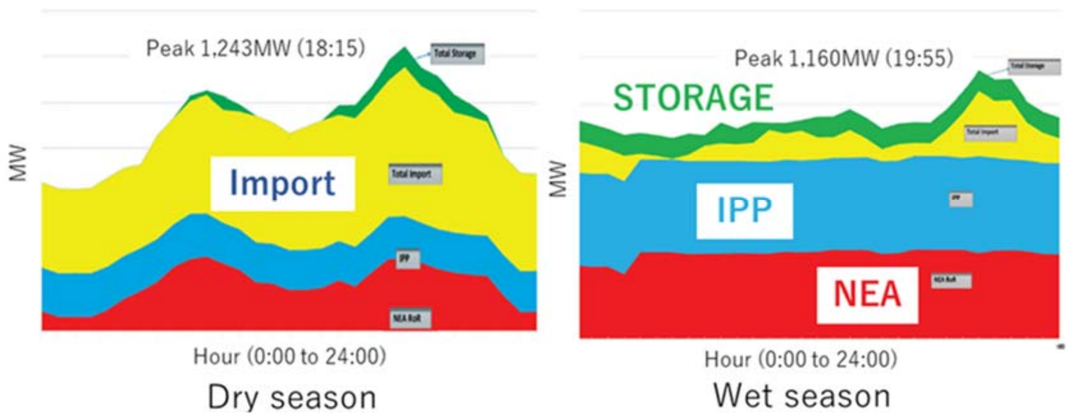
SUMMARY

1. Background and Power Sector in Nepal

Nepal is enriched with water resources. Theoretical hydropower generation potential is estimated 83MW in which commercially viable potential is 42 MW, while only 1.2MW capacity has been developed as of July 2019. Since almost operational plants are run-of-river (**ROR**) type except storage type Kulekhani I and II (combined capacity is 92MW), electricity supply capacity is drastically reduced at dry season when river discharge reduces to around 10% of wet season.

Peak demand of 1,320MW in 2018/19 exceed supply capacity and supply-demand gap is fulfilled by importing electricity from India. Imported energy in 2018/19 reaches 2,813GWh occupying 59% of domestic supply. Electricity import increases during dry season when supply capacity of domestic power plants reduces.

Government of Nepal (**GON**) set the policies for power sector development, i) Hydropower Development Policy of 2001, ii) Action Plan on National Energy Crisis Mitigation and Electricity Development Decade of 2016 and iii) Energy, Water Resources and Irrigation's Sector's Status and Roadmap for the Future of 2018 (usually called "White Paper"), all of which encourage development of storage type hydropower plants for meeting the domestic demand growth as well as energy security. The White Paper also encourages foreign private investment to power sector.



Daily Demand Curve in NEA Annual Report 2018/19

GON encourages private investment in power sector since Hydropower Policy 1992. Generation capacity of independent power producers (**IPPs**) reached around 50% of total supply capacity as of 2019. Foreign investment IPP projects, however, have been completed only four (4) ROR type projects with total capacity of 180MW.

In order to enhance foreign private investment, Nepal Electricity Authority (**NEA**) standardized maximum purchase tariff for IPP projects[1] for each type of hydropower projects and announced a Foreign Currency Denominated Power Purchase Agreement Template (**PPA Template**) in 2017. The PPA Template indicates standard terms and conditions for ROR project with over 100MW capacity.

1 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)

On the other hand, GON laid down the policy of unbundling of power sector. Nepal Electricity Regulatory Committee (**NERC**) has been established in 2017 by enacting Electricity Regulatory Act (**ERC Act**), which also indicates unbundling of NEA and establishment of a wholesale electricity market with participation of power generation companies and distribution companies. NERC promulgated a Bylaw of ERC Act in October 2019 (**ERC Bylaw**). Maximum tariff for each type of hydropower regulated by NEA in 2017 is maintained but only applied to hydropower plant equal to or below 100MW (**Standard Tariff**)[2]. Determination criteria of power purchase tariff for over 100MW plants has been revised from Standard Tariff to cost based tariff subject to the Return on Equity (**ROE**) of the generation company being below 17% (NPR base).

It should be noted that the GON's policy on covering foreign currency exchange variation risk is still under discussion as of December 2019. In the PPA Template, a portion of NEA's payment for purchasing electricity is made by foreign currency (e.g., USD) for 10 years after commercial operation date (**COD**) and a "Hedge Fund" (to be established) cover the exchange risk of NEA. Cost of hedging is shared by GON, NEA and generation company. After the enactment of ERC Bylaw, though, this foreign currency payment system was abandoned and payment from NEA is only made by local currency (i.e., Nepalese Rupee; NPR) according to NERC and NEA. Though GON promulgated a Hedging Regulation in 2019 for covering exchange rate variation risk for infrastructure projects including power sector (generation and transmission line above certain capacities), detailed procedure is not determined.

2. Proposal of Vertical Separation PPP Modality

Huge initial investment is required for developing storage type hydropower plant and only single entity or financier cannot develop those plants because of its magnitude. Japan International Cooperation Agency (**JICA**) proposes a Vertical Separation PPP Modality (**VSPPPM**) to support private investment in developing such large-scale projects. JICA nominated a joint venture of the NEWJEC Inc. and the Kansai Electric Power Co. Inc. (**Survey Team**) for studying the application and proposing the detail of the VSPPPM.

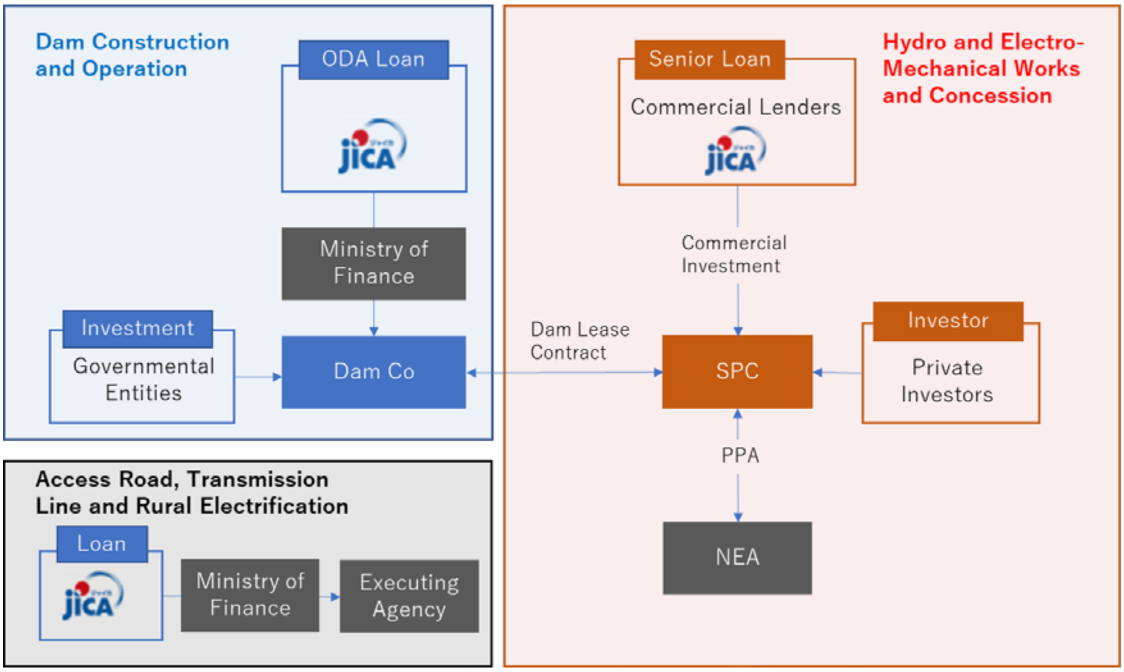
In the VSPPPM, construction and operation of the dam is separated from private entity and another entity (Dam Company or **Dam Co**) undertakes it by utilizing an Official Development Assistance (**ODA**) Loan. Dam Co may be a governmental entity with participation of domestic private investors. A Special Purpose Company (**SPC**) or Generation Company (**Gen Co**) established by private investment constructs and operates the power related facilities under the Built, Operate and Transfer (**BOT**) based concession. Gen Co utilizes impounded water behind the dam and generates electricity and sell to NEA (off-taker) under PPA and pay a dam lease fee to the Dam Co for utilization of water.

By separating the dam construction from IPP and utilize the ODA Loan, initial investment of the Gen Co significantly reduced. The longer tenor of the ODA Loan also reduce annual cost incurred to the Gen Co.

Since the VSPPPM involves an independent company (even it is a governmental entity) to be responsible for construction and operation of the dam, responsibility sharing mechanism should be clearly defined in the contractual framework. The Project Development Agreement (**PDA**) should be concluded among GON, Dam Co and Gen Co. Details of responsibility sharing for land

2 The tariffs stipulated in "Bylaw Relating to Purchase/Sale of Electricity and Conditions to be Fulfilled by the Licensees, 2076" are same values shown in "NEA Board Decision on the Power Purchase Rates and Associated Rules for PPA pf ROR/PROR/STORAGE Projects Effective From 2074/01/14 (April 27,2017)

acquisition, permits, environmental protection, design, financing arrangement, construction, commissioning and operation between dam and power facilities should be agreed in the Dam Lease Contract between Dam Co and Gen Co. Though the PPA is concluded between NEA and Gen Co, NEA should recognize that the power generation requires the dam and reservoir for which Dam Co is responsible.



VSPPP Modality Concept

3. Validity of VSPPPM

Effectiveness of the VSPPPM is validated by applying VSPPPM to a Model Project. The Model Project is selected from candidate storage type projects listed up at the Nationwide Master Plan Study on Storage-type Hydroelectric Power Development in Nepal in 2014. A feasibility study of the Model Project was carried out by NEA and updated in June 2019 (**Updated F/S**) with site investigations, design analysis, cost and schedule estimate. A Draft Environmental Impact Assessment (**EIA**) is also publicized in August 2019.

A preliminary cash flow model for the Model Project is developed to validate the effectiveness of the VSPPPM.

Total project cost is divided into two (2), i.e., cost for dam and related facilities (project cost for Dam Co) and cost for power facilities (project cost for Gen Co). It is assumed that the ODA loan is borrowed by the Dam Co through Ministry of Finance with loan condition of the Yen Loan. Gen Co arrange private loan from commercial lenders on project finance basis.

Separation of Construction Cost for VSPPPM

Unit: MUSD

Item		Conventional IPP	VSPPPM		
		Gen Co	Total	Dam Co	Gen Co
1	Preliminary Works and Access Roads	126	126	83	42
2	Civil Works	487	487	389	97
3	Hydro-mechanical	57	57	16	41
4	Electro-mechanical	116	116	0	116
5	Transmission Line and Substation	3	3	0	3
6	Allowance	79	79	49	30
7	Markups	105	105	65	40
8	Project Administration & Management	172	172	107	66
9	Advisory Fee for Legal and Financing on Project Finance (2% of the total items 1 to 8)	23	9	0	9
	Total	**1,167**	**1,153**	**709**	**444**

Conditions of the ODA Loan is referred to the Yen Loan, which is 40 years tenor, 0.01% interest rate per annum with 10 years grace period. Interest borne to Dam Co is assumed to be 3.01% considering additional interest by Ministry of Financing. Condition of the commercial loan is that repayment period is 10 to 14 years after COD, interest rate is 7% per annum. No financing related cost is considered. Debt equity ratio is assumed to be 70:30 for both Dam Co and Gen Co. Equity of the Dam Co is supposed to be injected from governmental entities and domestic private companies. Project cost including escalation and interest during construction is summarized in the following table.

Project cost under Conventional IPP Scheme and VSPPPM

Item		Cost (MUSD)			
		Conventional IPP	VSPPPM		
		SPC	Total	Dam CO	Gen.CO
1	Construction Cost	1,167	1,153	709	444
2	Interest During Construction	231	145	59	86
3	Escalation	35	35	29	6
Project Cost		**1,434**	**1,332**	**796**	**536**
Debt (70% of Project Cost)		1,004	934	559	375
Equity (30% of Project Cost)		430	398	237	161

Other conditions applied to the cash flow model is tabulated in the following table.

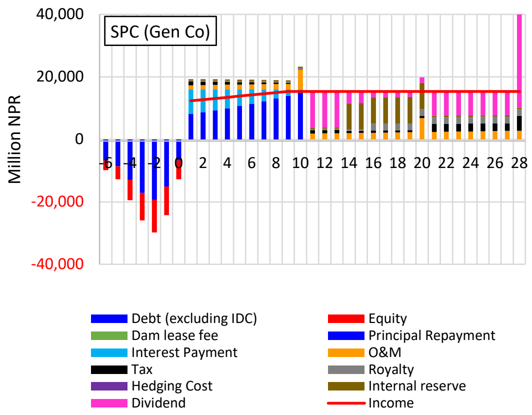
Prerequisites applied to Cash Flow Model

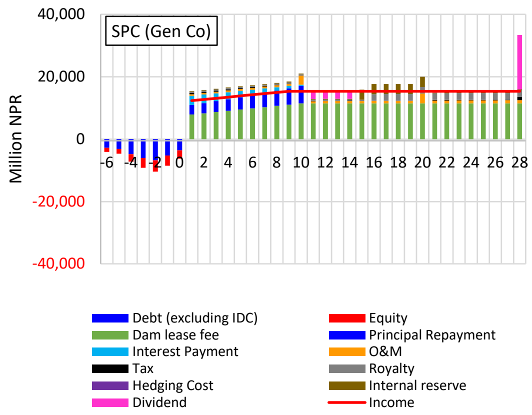
Item	Conditions
Capacity	417 MW
Annual energy production	682.5 GWh (Dry season), 549.5 GWh (Wet season)
O&M expense	1% of total cost excluding Item 9 in Table 6.2-1 With 6.5%/year of simple escalation
Depreciation rate, period	Straight-line depreciation at an annual rate of 5%, which corresponds to the depreciation period of 20 years. (accounting regulation in Nepal)
Internal Reserve for Repair	Assumed large-scale repair every 10 years 2 MUSD is reserved for each of dam and generation facilities annually
Tax	
Corporate tax	For 10 years from COD 0% From 11th to 15th year 10% After 16th year 20%
Tax on interest	15%
Tax on Dividend	5%
Royalty	For 15 years from COD Capacity kW × 200NPR/kW + Income × 2% After the 16th year of COD Capacity kW × 1,500NPR/kW + Income × 10%

Cash flow analysis is made for i) fixed tariff case and ii) variable tariff case. Note that since governmental policy for hedging the foreign currency exchange variation is not determined, impact of local currency depreciation against USD nor hedging cost is not considered in the cash flow model. Those impacts on feasibility are estimated as reference, with rough assumptions in the cash flow model.

Fixed Tariff Case

Standard Tariff is applied to the cash flow model. The tariff rates in the Standard Tariff for storage type project are fixed as 12.4 NPR/kWh in dry season and 7.1 NPR/kWh in wet season. Simple escalation with 3% for first 8 years is applied to the tariff. For a comparison purpose, conventional IPP case (SPC construct and operate both dam and power facilities) is also analyzed. In each case, it is found that the expenditure during the loan repayment period exceeds the income. It should be noted, though, expenditure during repayment period for VSPPPM case reduced significantly comparing with conventional IPP case. Focusing on the Debt Service Coverage Ratio (**DSCR**) which is an index for bankability, the average DSCR is 0.7 for the conventional scheme and 0.5 for the VSPPPM. Although effectiveness of VSPPPM is clarified, these values indicates that the project is not bankable for both cases.





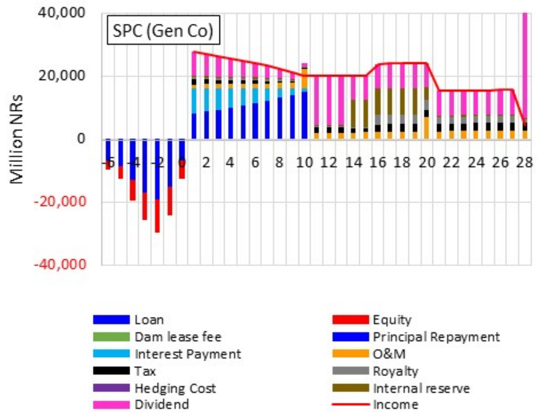
Conventional IPP Scheme *VSPPPM*

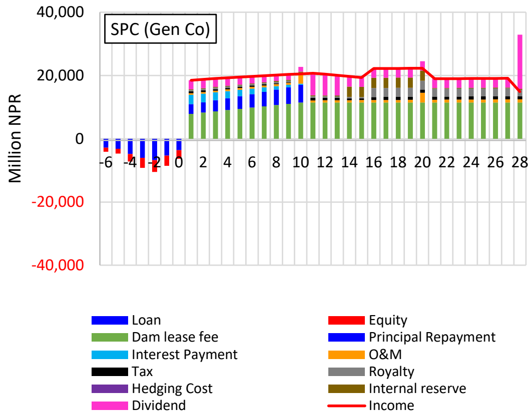
Gen Co's Cash Flow with Fixed Tariff

Variable Tariff Case

The ERC Bylaw stipulate that the purchase tariff for hydropower projects over 100MW is determined "cost plus modality" base subject to the ROE of the generation company being less than 17%. This tariff determination scheme may have a possibility that purchase tariff could be more than the Standard Tariff at certain year(s). In this variable tariff case, purchase tariff of each year is set so as to keep ROE 17%.

The result is compared by the DSCR, Equity Internal Rate of Return (**EIRR**) of the investors for Gen Co, Equity Recovery Period and Levelized Tariff (discounted tariff through operation years by 10% discount rate). It is found that the VSPPPM contribute to reduce necessary purchase tariff to keep Gen Co's ROE at 17% comparing with conventional IPP case, but the Levelized Tariff of 5.2 NPR/kWh is still around 40% more than that of the Standard Tariff case, which is 3.8 NPR/kWh.





Conventional IPP Scheme *VSPPPM*

Gen Co's Cash Flow with Variable Tariff to Keep ROE 17%

Result of Cash Flow Analysis (Variable Tariff Case)

Case	Case 00	Case 01	Standard Tariff (Reference)
Scheme	Conventional IPP	VSPPPM	—
Minimum DSCR Average DSCR	1.1 1.3	1.1 1.3	—
EIRR (NPR base) EIRR (USD base)	10.7% 10.7%	10.9% 10.9%	—
Equity Recovery Period	11 years	11 years	—
Initial Tariff Levelized Tariff Maximum Tariff	22.5 NPR/kWh 6.2 NPR/kWh 22.5 NPR/kWh	15.0 NPR/kWh 5.2 NPR/kWh 18.0 NPR/kWh	10.0 NPR/kWh 3.8 NPR/kWh 12.4 NPR/kW

Sensitivity analysis then is carried out. Parameters are i) private loan repayment period, ii) depreciation period of dam facilities, iii) expected equity return of Dam Co's investors. Sensitivity of depreciation period and expected EIRR for Dam Co's investors are intended to evaluate the impact of the dam lease fee.

It was found that by changing loan repayment period of Gen Co from 10 years to 14 years, depreciation period of the dam from 20 years (accounting regulation in Nepal) to 50 years and expected equity return from 8% to 3%, the levelized tariff becomes 4.3 NPR/kWh, which is around 10% increase compared with that of Standard Tariff case.

This required tariff level, together with EIRR 11.8% and minimum DSCR 1.3, may be accepted by GON for enhancing storage type hydropower development for energy security and may attract private investors and lenders.

Sensitivities of Cash Flow Analysis

Case	Case 01	Case 02	Case 03	Case 04
Repayment Period	10 years	**<u>14 years</u>**	14 years	14 years
Depreciation Period on Dam Facility	20 years	20 years	**<u>50 years</u>**	50 years
EIRR of Dam Co	8%	8%	8%	**<u>3%</u>**
Minimum DSCR Average DSCR	1.1 1.3	1.3 1.6	1.3 1.6	1.3 1.6
EIRR (NPR base) EIRR (USD base)	10.9% 10.9%	11.8% 11.8%	11.8% 11.8%	11.8% 11.8%
Equity Recovery Period	11 years	7 years	7 years	7 years
Initial Tariff Levelized Tariff Maximum Tariff	15.0 NPR/kWh 5.2 NPR/kWh 18.0 NPR/kWh	15.0 NPR/kWh 5.3 NPR/kWh 18.1 NPR/kWh	13.6 NPR/kWh 4.7 NPR/kWh 15.8 NPR/kWh	12.6 NPR/kWh 4.3 NPR/kWh 14.2 NPR/kW

As mentioned previously, cash flow analysis considering currency exchange variation are tested by applying rough assumptions to Case 02 as supplementary case. The result shows equity return in USD base and DSCR falls down to the level which may not attract foreign investors nor foreign lenders. For example, if depreciation of NPR against USD is estimated 4.4 NPR/USD (corresponds to 4.7% per year) and hedging cost is assumed to be 5.35% incurred to Gen Co, the equity return is 2.2% in USD basis and minimum DSCR is 0.9. From this examination, it should be noted that a governmental policy for hedging currency exchange variation risk is essential for attracting foreign investment in Nepalese power sector.

4. Conclusion and Recommendation Summary

Model Project was initially studied in the feasibility study carried out by NEA and updated in June 2019 (Updated F/S) through site investigations and updated design. Updated F/S revised project cost and annual generation. In this Survey, cash flow analyses are carried out for the result of Updated F/S and validate effectiveness of the VSPPPM. Followings are summary of the analyses. As discussed in later parts, impact by foreign currency exchange rate variation is not considered since the exchange rate variation hedging policy is still under discussion among governmental agencies in base case scenario, but such impact is evaluated roughly by the cash flow analysis.

By applying VSPPPM, necessary electricity purchase tariff for making project bankable can be reduced by about 30%, which is a significant improvement. However, necessary tariff for the model project is still 40% higher than the Standard Tariff level introduced by NEA (2017) and by NERC (2019). By revising assumed conditions, i.e., i) loan repayment period from 10 years to 14 years, ii) depreciation period for dam facilities from 20 years (regulation) to 50 years and iii) expected EIRR for investors to Dam Co from 8% to 3%, necessary tariff can be reduced to 10% higher level than the Standard Tariff.

Nepal government established NERC and power sector reform is underway. As the ERC Bylaw announced in October 2019 stipulates a new tariff determination policy based on generation cost subject to the ROE of the generation company being less than 17% (NPR base) and governmental policies are expected to be taken into account to determine the tariff flexibly. In such circumstance, there is a possibility that higher tariff than the Standard Tariff can be accepted by the government.

On the other hand, foreign currency exchange policy of the government has a big impact to foreign investment in, not only storage type hydropower, but also foreign investment decision for all power sector business. As of December 2019, the NERC and NEA representative stated that neither government nor NEA take currency exchange risk but assist developers to hedge principal portion of the loan through currency exchange market. The details of the hedging mechanism, however, are not determined, e.g., hedging cost sharing mechanism. Since foreign investors or lenders has to fix the risks at PPA signing or financial closure, it is recommended that the government clearly announce a policy to take currency exchange risk. As a result of the referenced estimate, it is found that cash flow analysis considering currency exchange variation results in the EIRR for foreign investors being single digit, which is not enough for investment.

In order to apply VSPPPM, roles and responsibilities of the government, dam company (Dam Co), generation company (Gen Co or SPC) and NEA should be clarified in the Project Development Agreement (PDA), Power Purchase Agreement (PPA) and Dam Lease Contract. The Survey Team recommends PDA be concluded among GON, Dam Co and Gen Co, and propose basic structure of each contract and outline of the Dam Lease Contract between Dam Co and Gen Co.

Operational procedure for storage type hydropower is also recommended. In order to maximize benefit of storage type hydropower, reservoir operation for generation purpose should be fully controlled by NEA as a system operator, who determine generation plan taking supply-demand balance into account and instruct electricity dispatch to Gen Co. As all generated energy should be instructed and purchased by NEA, tariff structure is recommended to have two (2) component, i.e., Capacity Payment (per kW) and Energy Payment (per kWh). Capacity Payment system stabilize Gen Co's financial status as well as Dam Co's as the source of the repayment of ODA loan is only a dam lease fee paid by Gen Co. Capacity Payment structure also corresponds to payment for a specific function of the storage type hydropower, which is capability to supply ancillary services. The Survey Team recommends revision of purchase tariff structure in PPA for storage type hydropower considering those factors.

Another consideration for storage type hydropower should be made on emergency operation of the dam. As storage type hydropower requires high dam, environmental and social impact in case of failure of dam gates operation and/or breach of the dam is significant and should be avoided as the first priority. A system should be established to keep Dam Safety and prevent any hazard to downstream of the dam. Such system involves GON, local government unit located downstream of the dam, local residences, Dam Co, Gen Co and NEA. PDA, PPA, Dam Lease Contract should be structures so as to keep Dam Safety.

SECTION 1 BACKGROUND, OBJECTIVES AND AREA

1.1 BACKGROUND

Electricity generation capacity in the Federal Democratic Republic of Nepal (hereinafter referred to as "**Nepal**") is 1,182 MW at peak and 4,738 GWh per year in July 2019 while peak demand is 1,320 MW and electricity demand is 7,584 GWh (including transmission and distribution loss), both of which much higher exceed the supply capacity. The deficit is dependent on import from neighboring India, and the import volume of 2,813 GWh in 2018/19 corresponds to 59% of the domestic supply.

The power supply-demand gap becomes a particularly serious problem during the dry season. Nepal has abundant water resources and it is estimated that the theoretical hydropower potential is 83 GW, in which the commercially viable potential capacity is 42 GW. Hydropower generation accounts for more than 90% of the current capacity and generated electricity. Since most of the existing hydropower plants are run of river (**ROR**) type, the generation ability drops significantly in the dry season when the flow rate decreases to less than 10% of the wet season, and the problem of the supply and demand gap becomes obvious. The storage type hydropower plant that can supply stable electricity even in the dry season is only the Kulekhani I hydropower plant (1976-78 Yen Loan acceptance, 60 MW) and the Kulekhani II hydropower plant (1982-83 Yen Loan acceptance, 32 MW), both developed with Japan's assistance.

In view of such situation, the government of Nepal (**GON**) positions the promotion of storage-type hydropower development as an utmost urgent matter. Responding the GON policy, JICA implemented the "Nationwide Master Plan Study on Storage-type Hydroelectric Power Development in Nepal" in 2014. In this masterplan, 10 priority projects were selected from the viewpoints of technology, economy, environmental and social consideration, etc. from the long-list of storage type hydropower potentials provided by Nepal Electric Authority (**NEA**). Based on the results of this survey, some development activities are being made such as detailed design of the Dudh Koshi project funded by the Asian Development Bank (**ADB**) and detailed design of the Nalsyau Gad project by GON. In addition, GON listed storage type projects such as Tamor and Utter Ganga as promising project candidates. It is anticipated, however, since the project cost will exceed the scale of 1 Billion USD in any projects, it would be difficult to develop those projects by only public funds such as ODA or foreign direct investment considering the Nepalese national development budget .

Contemplating the situation, GON expects application of the Public Private Partnership (**PPP**), especially a methodology of cooperative development in which public funds are utilized to dam portion while private sector invests power plants from the intake structure. In this report, this type of PPP development is called as a Vertical Separation PPP Modality (**VSPPPM**).

Under these circumstances, JICA implemented the Data Collection Survey on the PPP Modality in Hydropower Project in Nepal (**Survey**) to support development of storage type hydropower plants by proposing a "Vertical Separation PPP" scheme and Japan's ODA, and appointed a joint venture of NEWJEC Inc. and Kansai Electric Power Co. Inc. (**Survey Team**) to render the Survey.

1.2 OBJECTIVES AND AREA OF SURVEY

The objectives of this Survey are to examine a specific system for implementing and promoting PPP investment to hydropower generation sector in Nepal by applying the VSPPPM. The Vertical Separation PPP[3] system is generally applied to railway sector where the infrastructure of railway is constructed by public sector and private companies operate the railway by acquiring the concession right then operational revenue covers concession fee and capital recovery. In this Survey, the Vertical Separation PPP means the scheme in which public sector construct and operate a dam and reservoir, and private investors construct and operate power facilities by utilizing reservoir then electricity sales revenue covers dam lease fee and capital recovery.

Survey items and procedures are presented below:

(1) Review of existing documents including discussion results between JICA and GON,

(2) Sample data collection and analysis for the VSPPPM,

(3) Review of private investment conditions of hydropower sector in Nepal. Special attention is paid to investment environment and issues in legal and commercial aspect by referring to case study of the Project Development Agreement (**PDA**) and Power Purchase Agreement (**PPA**). A proposal of contractual terms necessary for the VSPPPM, for example, an agreement between dam owner and power plant owner (hereinafter called as the **Dam Lease Contract**). Selection of a project for examining applicability of the VSPPPM can be justified (**Model Project**),

(4) Development of an Interim Report followed by discussions with related GON governmental agencies and JICA,

(5) Site survey of the Model Project and review of previous investigation/study in terms of technical appropriateness,

(6) Development of a financial model in case of applying the VSPPPM to the Model Project,

(7) Identification of issues and a proposal of improvement for PDA and PPA based on the financial model followed by consultation with GON. Identification of contractual framework of the Dam Lease Contract, risk-sharing proposal and other necessary arrangement and consultation with GON,

(8) Analyzing issues to be considered in case Japanese private sector investing hydropower development from the result of the Model Project study,

(9) Development of an Interim Report covering items above and consultation with JICA. Development of a Draft Final Report and consultation with JICA and GON then finalization of the Final Report,

(10) Holding a seminar in Nepal with the relevant agencies of GON, private sectors and other stakeholders. Collection of opinions from participants,

(11) Invitation of representatives of GON to Japan, arrangement of a technical tour for hydropower plants in Japan which represent applicable technologies.

3 It is sometimes called “separation of operations from infrastructure” in railway sector.

1.3 SURVEY POLICY

The Survey is divided into three (3) phases, i.e., i) survey of investment environment in power generation and collection of basic information necessary for applying the VSPPPM, ii) proposal of contractual arrangement and evaluation of feasibility for the Model Project and iii) identification of issues for implementing hydropower development with VSPPPM. Those phases are not necessarily proceeded in series but some portions can be studied in parallel with feedback to previous phase.

Major survey items and timeframe are summarized in Figure 1.3-1.

Phase A: Survey of investment environment in power generation and collection of basic information

1st Works in Japan
1st Site Survey
2nd Works in Japan
2nd Site Survey
3rd Works in Japan

A1 Data collection and analysis for background, basic information, relevant document
A2 Proposal of methodology and schedule for the Survey
A3 Section of Model Project for applying the Vertical Separation PPP
A4 Development of an Inception Report
A5 Holding a kick-off meeting, presentation of and discussion on the Inception Report
A6 Technical review on previous/on-going study for the Model Project
A7 Setting technical parameter for the financial model and evaluation of appropriateness

Phase B : Proposal of contractual arrangement and evaluation of feasibility for the Model Project

1st Site Survey
2nd Works in Japan
2nd Site Survey
3rd Works in Japan
3rd Site Survey
4th Works in Japan
4th Site Survey
5th Works in Japan

B1 Information collection and analysis of risk factor relating to the Vertical Separation PPP scheme
B2 Proposal of the Vertical Separation PPP model
B3 Study on risk sharing including international donor agencies
B4 Study on funding methodology
B5 Development of an Interim Report
B6 Establishment of a financial model and feasibility evaluation

Phase C: Identification of issues for implementing hydropower development with Vertical Separation PPP scheme

3rd Site Survey
4th Works in Japan
4th Site Survey
5th Works in Japan
5th Site Survey
Final Works in Japan

C1 Analysis of issues for participation of Japanese investors
C2 Establishment of contractual terms for Dam Lease Contract
C3 Identification of issues for implementing Vertical Separation PPP scheme
C4 Proposal of further JICA assistance
C5 Development of a Draft Final Report
C6 Presentation and consultation of the Draft Final Report
C7 Holding a Workshop

Figure 1.3-1 Major Survey Items and Timeframe

In the course of the Survey, however, institutional arrangement surrounding power sector has been significantly changed, especially for IPP business. Nepal Electricity Regulatory Commission (**NERC**) publicized new "Bylaw" in October 2019, which define new standard of PPA. The Survey schedule has been revised accordingly. Additionally, schedule seminar in Nepal has been cancelled due to world-wide outbreak of COVID-19 (corona virus).

Actual Survey schedule and details of survey items are shown in Figure 1.3-2 and Table 1.3-1 following this condition change.

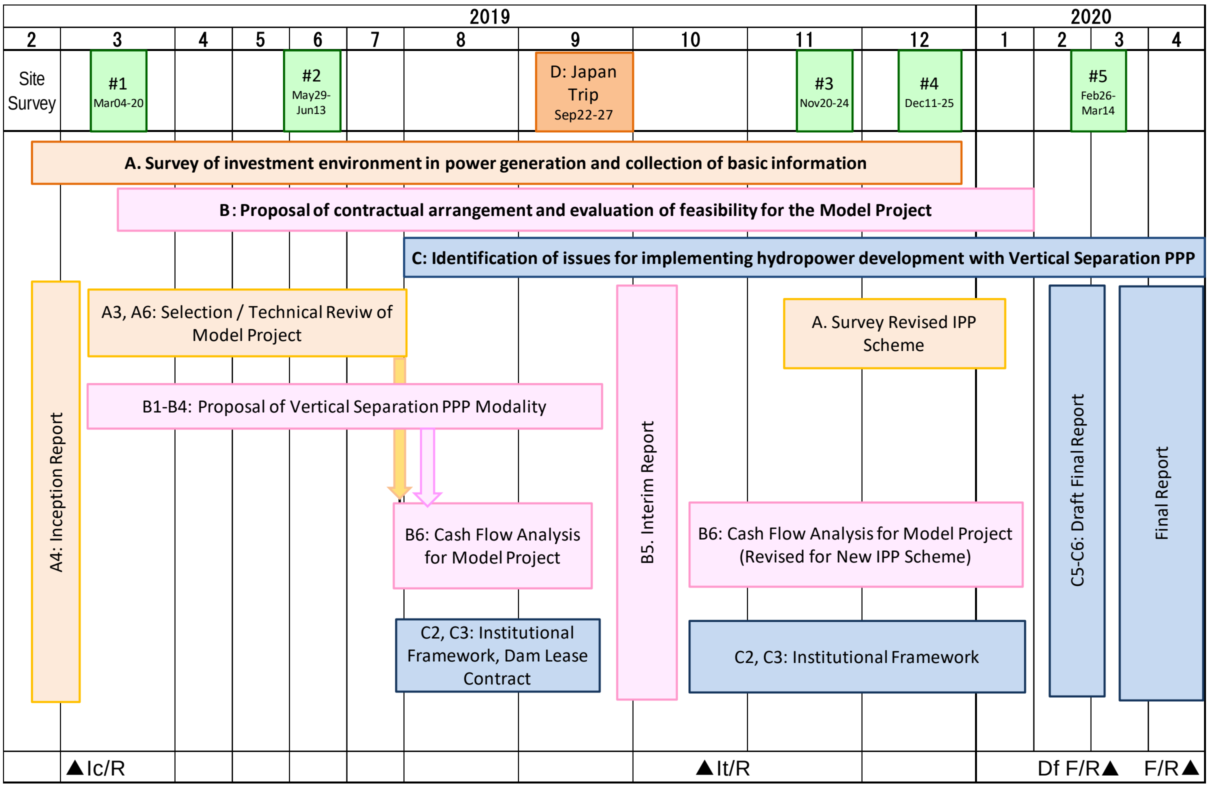


Figure 1.3-2 Overall Wok Flowchart

Table 1.3-1 Actual Survey Schedule

Survey Items		Note
1st work in Japan (Feb 2019)	A1: Data collection and analysis for background, basic information, relevant document	Basic information about Nepal's power sector is collected at 1st work in Japan, 1st and 2nd site surveys through interviews of related agencies and data provided by JICA.
	A1-1 Review of previous studies (provided by JICA)	
	A1-2 Survey of international experiences of the Vertical Separation PPP	
	A1-3 Identification of issues for private investment in hydropower sector in Nepal (Foreign investment environment considering PDA and PPA)	
	A2: Proposal of methodology and schedule for the Survey	
	A3: Section of Model Project for applying the Vertical Separation PPP	
	A4: Development of an Inception Report	
1st site survey (Mar 2019)	A5: Holding a kick-off meeting, presentation of and discussion on the Inception Report	Site survey result of the Model Project was also presented at the kick-off meeting.
	A6: Technical review on previous/on-going study for the Model Project	Site survey of the Model Project was conducted at the 1st and 2nd surveys. Updated FS report and Draft EIA report provided by JICA were reviewed.
	A6-1 Technical review and site reconnaissance	
	A6-2 Selection of the Model Project and consultation	

Survey Items		Note
	A7: Setting technical parameter for the financial model and evaluation of appropriateness	As a result, though technical concerns remain, technical parameters stated in the update FS Report was utilized for input of the financial analysis.
From 2nd work in Japan to 3rd site survey (May to Nov 2019)	B1: Information collection and analysis of risk factor relating to the Vertical Separation PPP scheme	Information regarding legal system, tax system, foreign currency exchange, foreign currency repatriation etc. were collected at the 1st and 2nd surveys. However, since concept of PPA for foreign IPP has been significantly changed in October 2019 and risk allocation policy has been revised, survey approach is revised at the 4th site survey.
	B2: Proposal of the Vertical Separation PPP model	
	B3: Study on risk sharing including international donor agencies	Risk allocation between the Dam Company and Generation Company is reflected in the Dam Lease Contract. Major contents of the Dam Lease Contract are studied.
	B4: Study on funding methodology	Financing conditions of ODA loan (to Dam Co) and commercial loan (to Gen Co) are studied.
	B5: Development of an Interim Report (Submitted on October 11, 2019)	Interim Report includes preliminary financial analysis (B6) and was presented to relating governmental agencies at the 4th survey.
	B6: Establishment of a financial model and feasibility evaluation	
	B6-1 Development of a financial cash flow model	
	B6-2 Consultation with GON about issues and improvement measures on PDA and PPA in consideration of financial model.	New policy for foreign IPP defines that the developers bear foreign currency exchange risk. Though the government announce that the foreign currency exchange risk hedge procedure is available, the system of the hedging is still under discussion. Evaluation of foreign currency exchange risk is therefore impossible.
	B6-3 Identification of issues for the Dam Lease Contract	Reviewed by legal firm.
	B6-4 Proposal and discussion about appropriate risk sharing system for the Vertical Separation PPP scheme	
Work in Japan	C1: Analysis of issues for participation of Japanese investors	
	C2: Establishment of contractual terms for Dam Utilization Contract	Reviewed by legal firm.
	C3: Identification of issues for implementing Vertical Separation PPP scheme	
	C4: Proposal of further JICA assistance	
	C5: Development of a Draft Final Report	
	D Inviting relevant GON agencies to Japan	September 22 to 27. JICA held a Nepal Investment Seminar in Tokyo.
5th site survey (Feb to Mar 2020)	C6: Presentation and consultation of the Draft Final Report	
	C7: Holding a Workshop	Workshop is cancelled due to outbreak of COVID-19 (corona virus).

SECTION 2 CURRENT STATUS OF POWER SECTOR AND INVESTMENT ENVIRONMENT IN NEPAL

2.1 CURRENT STATUS AND ISSUES OF NEPALESE POWER SECTOR

2.1.1 Power Development Policy

Power generation capacity in Nepal is approximately 1,182 MW according to NEA Annual Report (2018/19) in which hydropower generation counts 1,128 MW or 96%. Around 90% of hydropower plants, however, are ROR type and unable to regulate annual flow. Total capacity of the storage type hydropower is only 92 MW. Though NEA are making effort for developing storage-type hydropower and two (2) projects are under construction, Tanahu (140MW) by support of JICA, an ADB and Kulekhani III (14MW), new hydropower plants in recent 5 years are all ROR type.

Table 2.1-1 Power Sources in Nepal

Items	Owner/ Developer	Total Installed capacity (kW)				Remarks
		2012/2013		2018/2019		
Hydro Power	NEA	477,930	(62.35%)	567,930	(48.04%)	Storage-type 92,000kW
Hydro Power	IPP	230,589	(30.08%)	560,775	(47.43%)	All ROR type
Isolated Small Hydro	NEA	4,536	(0.59%)	4,536	(0.38%)	
Thermal Power	NEA	53,410	(6.97%)	53,410	(4.52%)	
Solar	NEA	100	(0.01%)	100	(0.01%)	
Total		**766,565**	**(100.00%)**	**1,182,215**	**(100.00%)**	

Source: NEA Annual Report Fiscal Year 2012/13, 2018/2019

Major electricity policies in Nepal are the Hydropower Development Policy of 2001 and the Action Plan on National Energy Crisis Mitigation and Electricity Development Decade of 2016 (**Action Plan 2016**). In May 2018, the Ministry of Energy, Water Resource and Irrigation (**MoEWRI**) established Energy, Water Resources and Irrigation's Sector's Status and Roadmap for the Future (usually called "White Paper") in which development goal in 10 years is announced.

The Action Plan 2016 was announced in February 2016 following the energy crisis triggered by border blockage with India in 2015/2016 and defined 10 years from 2016 to 2026 as overcoming period of the energy crisis. It set a policy agenda of legislation for improving energy security by promoting hydropower development. As summarized in Table 2.1-2, the contents of those policies indicate that GON is aiming to develop storage type hydropower for stable supply and great expectations for private investment.

Table 2.1-2 Summary of Hydropower Development Policy and Action Plan 2016

Hydropower Development Policy (2011)	Action Plan 2016
1) **Hydropower potentials shall be utilized to the maximum extent to meet the domestic demand** 2) Domestic supply projects as well as storage-type shall be developed as per requirement on competitive basis 3) **To encourage projects on BOO (Build Operate and Own) or BOT (Build Operate and Transfer) basis** 4) **To attract national and foreign investment through appropriate incentives and transparent process** 5) **To develop large scale storage-type projects and multi-purpose projects. Storage-type multi-purpose project shall yield maximum national benefit** 6) **To contribute environmental protection by promoting hydropower development as an alternative to biomass and thermal energy** 7) Appropriate consideration on resettlement families 8) To mobilize internal capital market for investment in power sector 9) To promote rural electrification 10) To control unauthorized leakage of electricity by appropriate legal provisions 11) To encourage electricity demand during off-peak period 12) To encourage electricity export 13) To improve electricity supply service at reasonable pricing through public sector reform 14) To provide reliable and qualitative electricity service to public 15) **To prioritize utilization of local labors for hydropower development** 16) **To develop an institution developing skilled manpower for hydropower development** 17) To promote energy conservation through demand side management.	1) Legal Reform a) Formulate New Electricity Act b) Approve Energy Crisis Mitigation Bill c) Formulate National Electricity Regulatory Commission Act d) **Arrangement of VAT refund incentive** e) **Arrangement to provide Income Tax Exemption** f) Amend Electricity Theft Control Act 2) Policy Decision a) Implement National Energy Security Policy b) **Investment in hydropower project through mobilization of local banks** c) **Adopt generation mix (Storage-type: 40-50%, Peaking ROR: 15-20%, ROR: 23-30%, Alternative: 5-10%)** d) Additional yearly compensation – ROW (Right-of-way) land acquisition e) Revision of valuation of land acquisition for hydropower plants f) Arrangement of community support program (0.75-0.5% of project cost) g) **Provide electricity services to all Nepalese people** h) Develop solar and wind power (10% of grid power) i) Carry out power conservation program j) Carry out technical audit of large consumers 3) Administrative Decision and Procedural Reform a) Simplification of working visa and work permit b) Provide project security c) **Conduct PPA in foreign currency** d) **Expansion of transmission lines** e) Simplification of environmental clearance 4) Structural Provision and Reform a) Formulation of central and district level coordination committee b) Establishment of National Electricity Generation Company c) Establishment of National Power Trade Company d) Prepare monitoring mechanism

It is worth noting that the White Paper indicates, among others;

Problems and Challenges

- Since the need of investment in energy sector cannot be fulfilled by the domestic financial sector and government, there is a need of low-priced foreign investment. In order to get such investment, foreign exchange risk needs to be addressed.

- There is a challenge to address the interests of people to invest in energy sector and to create a favorable environment for investment in potential projects.

Road Map

- The upcoming policy roadmap is established to make the country self-reliant in electricity through overall development of electricity sector, to reduce trade deficit by replacing other sources of energy by electricity, to expand internal and external market for the electricity and to deliver sustainable, reliable, easily available, quality and clean energy to the people by increasing their access to such energy

- Development of hydroelectricity and transmission line will be made more effective under the modalities like PPP, Build and Transfer, Build, Own, Operate and Transfer (**BOOT**), Engineering, Procurement, Construction and Financing

- Working Road Map: GON, NEA and its subsidiaries company and private developers will construct and operationalize hydropower projects of total installed capacity of 3,000MW in 3 years, 5,000MW in 5 years, 15,000MW (10,000MW for domestic consumption and 5,000MW for export) in 10 years.

- Under ‘one province, one mega project’ programme, construction of at least one big hydropower/solar project will be initiated in each province.

List of storage type hydropower project indicates 16 projects with total capacity 8,785MW.

Table 2.1-3 Storage Project List in White Paper

Province	Project Name	Output (MW)	Note
1	Tamor	762	
1	Dodh Koshi	800	
3	Sun Koshi 2	1,100	Export
3	San Koshi 3	536	Export
3	Khimti Shivalaya	500	
3	Kokhajor	111	
4	Budhi Gandaki	1,200	Export
4	Upper Seti	140	
4	Uttar Ganga	828	
4	Andhi Khola	180	
5	Naumure	245	
5	Kali Gandaki 2	870	
5	Madi	253	
5	Upper Jhimruk	100	
6	Nalgad	410	
7	West Seti	750	
Total Output		8,785	

From those governmental policies above, objectives of this Survey, i.e., establishing practical scheme of hydropower development under the VSPPPM, is consistent with the policy of GON.

2.1.2 Power Sector Reform Policy

GON stipulated Electricity Regulation Commission Act, 2074 (**ERC Act**), published in the Nepal Gazette on September 4, 2017. It was followed by Electricity Regulatory Commission Rules, 2018 (**ERC Rules**) and Bylaws Relating to Purchase/Sale of Electricity and Conditions to be fulfilled by the Licensees, 2076 (**ERC Bylaws**) announced in October 2019. Power sector reform policy can be read in the ERC Act and ERC Rules as follows;

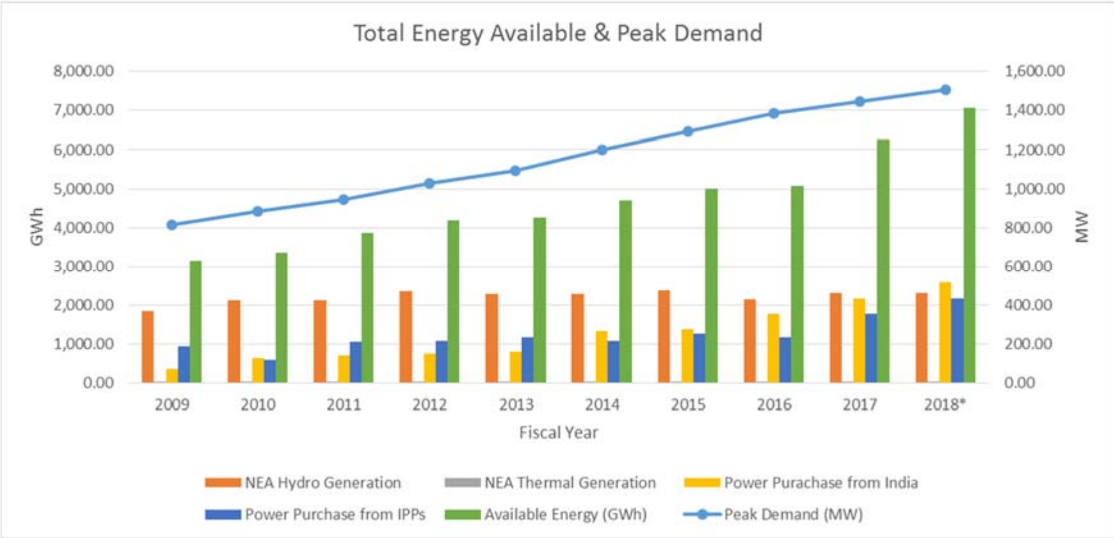
1) NERC establish and set a standard for the Grid Code and Distribution Code
2) Wholesale electricity market will be established
3) Licenses will be granted to companies who generate, transmit, distribute or trade the electricity
4) NERC determine and approve electricity tariff, wheeling charge, distribution charge, trading margin.
5) Several distribution companies (Distribution Licensees) will be established and purchase electricity from the wholesale electricity market (note: currently there is only one nationwide Distribution Licensee, NEA)
6) Until the establishment of the wholesale electricity market, a PPA can be agreed between generation companies (Generation Licensee) and NEA subject to the approval of NERC.
7) NERC maintain competitiveness of the electricity market.
8) NERC develop a Minimum Cost Extension Action Plan

As indicated in the ERC Act and ERC Rules, power sector reform policy is aiming the unbundling of NEA into generation company, transmission company and distribution company. According to NERC, however, the unbundling of NEA and establishment of wholesale market would take at least five (5) years.

The development of institutional framework is supported by World Bank (**WB**) and United States Agency for International Development (**USAID**) through i) Power Sector Reform and Sustainable Hydropower Development Project by International Development Association (**IDA**) in February 2016 (USD 20M equivalent Special Drawing Rights (**SDR**)), ii) First Programmatic Energy Sector Development Policy Financing by IDA in October 2018 (USD 100M equivalent SDR) and iii) Nepal Hydropower Development Program by USAID in 2015 (USD 9.9M).

2.1.3 Electricity Demand in Nepal

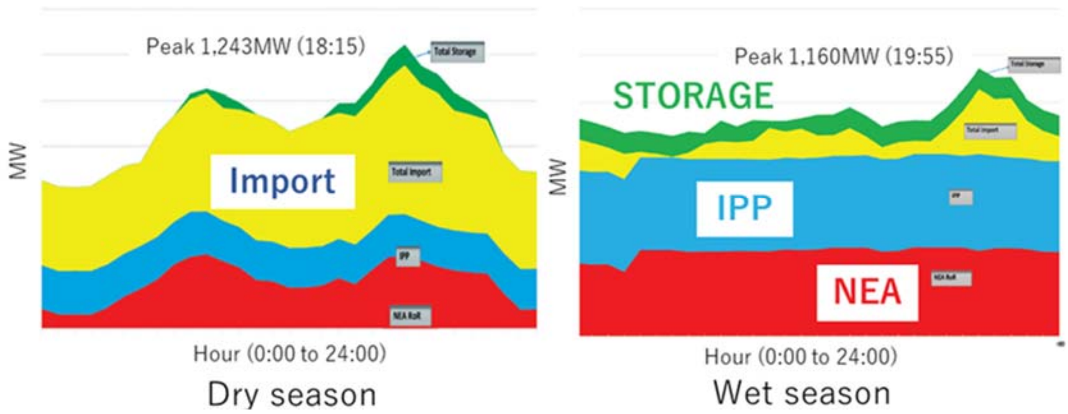
Electricity demand in Nepal records around 1,500 MW and it significantly exceeds supply capacity. Though some portion of demand-supply gap is supplemented by import electricity from India, scheduled brownout is executed when import is not enough. The fact that total electricity supply of 7,584 GWh consists of 4,605 GWh from domestic supply and 2,813 GWh from import suggests that the high hydropower potential in Nepal has not yet utilized.



Source: NEA Annual Report Fiscal Year 2017/2018

Figure 2.1-1 Electricity Demand (kWh) and Peak Demand (MW)

As indicated in Table 2.1-1, most of the hydropower plants in Nepal are ROR type and unable to regulate annual flow resulted in drop of generation ability during dry period. The shortage is influenced by the difference of flow amount between wet and dry season which is relatively significant. Representing daily demand curves are presented in Figure 2.1-2.



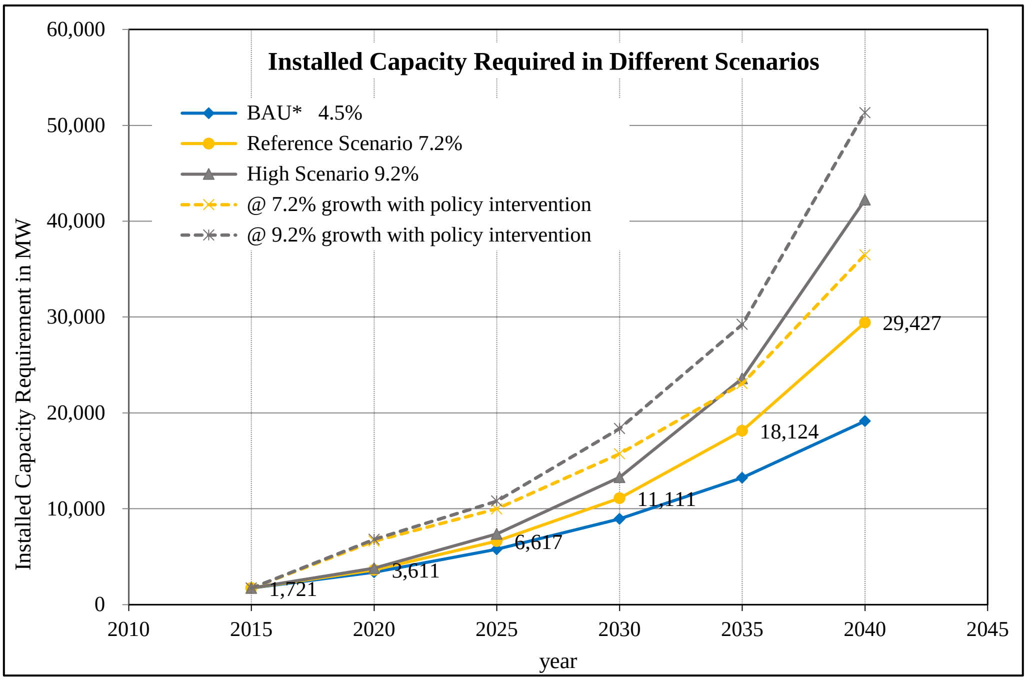
Source: NEA Annual Report 2018/19

Figure 2.1-2 Daily Demand Curve

According to the daily demand curve above, generation capacity during dry season is only around 200MW to 400MW corresponding to half of that of wet season. Domestic supply is also not enough at off-peak hours during dry season, which is covered by import energy from India.

It is therefore concluded that the storage type hydropower plants that has a capacity of annual regulation and thus supply electricity during dry season are essential.

Figure 2.1-3 shows long-term installed capacity requirement forecast by Water and Energy Commission Secretariat (**WECS**) until 2040. Install capacities of 3,600MW for 2020 and 6,600 to 7,00MW for 2025 are required for accommodating peak load.



Source: Electricity Demand Forecast Report (2015-2040), WECS, January 2017

Figure 2.1-3 Installed Capacity Requirement Forecast

Development road map in the White Paper is corresponding to the installed capacity requirement forecasted by WECS as shown in the right table.

	White Paper	WECS
2018		
2020		3,600MW
2021	3,000MW	
2023	5,000MW	
2025		6,600-7,000MW
2028	Domestic 10,000MW	

Assuming electricity consumption at off-peak hours grows by the same rate of that at peak hours, load demand in 2025 is expected 7,000MW at peak and 3,500MW at off-peak hours. According to NEA's report about PPA progress in May 2019, total capacity of 2,500MW ROR and Peaking Run of River (**PROR**) plants are under construction or under preparation with PPA and are expected to start operation in five (5) years. In order to meet the off-peak demand of 3,500MW in 2025, projects before PPA or financial closure have to be implemented at earliest.

Storage type hydropower plants under construction are Kulekhani III (14MW) and Tanahu (140MW) in August 2019. PROR projects under construction are Upper Tamakoshi (456MW), Raghugang (40MW), Upper Sanjen (14.8MW), Sanjen (42.5MW) and Upper Trishuli 3A (60MW). Total capacity of PROR project is 613MW and total capacity of PROR plus storage projects is 757MW. Storage type projects under preparation are Dudh Koshi (800MW), Nalsyau Gad (417MW), and Andhi Khola (180MW), but lead time of those storage type projects are more than 12 years according to the F/S reports. Even those large scale storage projects are in line, total installed capacity is 3,900MW (ROR, PROR and Storage), which is not enough for required installed capacity of 7,000MW in 2025 or 10,000MW in 2018.

It is concluded that even the ROR and PROR projects are developed as scheduled, new development of storage type projects is required to accommodate system demand in 2025 or 2028.

2.1.4 Private Investment in Hydropower Development

GON encourages private investment since Hydropower Policy in 1992 that allows private investment in hydropower sector in Nepal. NEA also develops hydropower plants of its own with balancing public/private development. As an IPP, foreign investment for supplying domestic energy were firstly made on Khimti 1 (60MW) and Upper Botekoshi or Botekoshi Khola (45MW) in 1996. Encouraged by formulation of governmental policy to overcome energy crisis, IPPs of Upper Marshyangdi (50MW) and Upper Made (25MW) has been commissioned by Chinese investors in 2016. In December 2016, construction of Lower Solu (82MW) started after financing close. The project is sponsored by an Indian developer.

Meanwhile, since NEA marked a big loss by devaluation of Nepalese Rupee for the first IPP because the payment was fully denominated by USD, a concept paper annexed to the Action Plan 2016, GON regulated PPA denominated foreign currency. Following this governmental policy, NEA determined maximum tariff[4] for purchasing electricity from IPPs in April 2017 and established Foreign Currency Denominated PPA Template (**PPA Template**) in October 2017. The PPA Template is the standard PPA applied to the ROR hydropower project above 100WW utilizing foreign currency loan.

Foreign investment have been made to Rasuwa-Botekoshi (120 MW) and Upper Trisuli-1 (216 MW) in accordance with the PPA Template. PPAs of those power plants were concluded in November 2017 to January 2018. It is said that tariffs in those PPAs follow standardized purchase tariff of NEA published in April 2017.

In the PPA of the Upper Trishuri-1 project, however, hedging of the currency exchange risk was to be discussed separately[5]. A newspaper reported on April 2, 2019 that the agreement had been reached among GON, NEA and project company and that the hedging cost was shared among GON, NEA and the project company. According to the paper, GON (represented by the Nepal Rastra Bank, **NRB**), NEA and the project company shoulder one third each of the estimated currency exchange risk amount. The project company is said to undertake responsibility of estimated risk amount (approximately 36 MUSD) by three (3) means, i) down payment at the commencement, ii) install payments after commencement and iii) free electricity for 14 to 26 years after COD.

Those IPP projects and other new IPP developments are all ROR type sponsored by local companies. No announcement was made about PPA negotiation for storage type hydropower development between NEA and foreign investors.

2.1.5 Impact of Power Sector Reform for Private Investment

ERC Act and ERC Rules states that a wholesale electricity market will be established and that generators and distributors (or traders) will sell/purchase electricity from the market except bi-lateral contract. Until the wholesale electricity market has been established, PPA is allowed between NEA and IPP subject to approval of NERC.

This policy will impact private participation in the hydropower development in Nepal since the investors may not be able to foresee long-term financial sustainability of the project and hence the projects become less bankability.

4 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)

5 Information from IFC

Standardized PPA to be applicable during transition period before wholesale electricity market is also revised by ERC Bylaw announced in October 2019. According to NERC and NEA, PPA Template is no longer valid.

Major changes for power purchase tariff in PPA Template and ERC Bylaw are summarized in the following table.

Table 2.1-4 Tariff Comparison between NEA and ERC

	NEA in 2017	ERC Bylaw in 2019
Tariff	Fixed tariff for each type, ROR, PROR, STORAGE If EIRR>17%, adjust tariff rate[1)]	100MW less: Fixed tariff 100MW above: Cost base If ROE>17%, adjust tariff rate
Payment Currency	By 10th year from COD: Foreign and local currency After 11th year: Local currency	Local Currency[2)]
Foreign Currency Exchange Risk Hedge	By Hedging Fund (to be established) Hedging cost is shared among GON, NEA and developer[3)].	Heading Regulation 2019[3)]

It should be noted that:

1) PPA Template literary state "in case Return on Equity (**ROE**) become above 17%, tariff rate is adjusted". However, according to information from IPP developers, the criteria is calculated by Equity Internal Rate of Return (**EIRR**).

2) Though it is not stated in the ERC Bylaw, NERC and NEA informed that electricity purchase payment will be made only by local currency.

3) Hedging mechanism in the PPA Template is that i) NEA's foreign currency payment portion is covered by a Hedge Fund, ii) Foreign currency portion is determined by debt/equity ratio at the COD, iii) Exchange rate is fixed at the PPA signing and iv) hedging cost is shared among GON, NEA and the generation company. Though hedging mechanism is not stated in the ERC Bylaw, governmental agencies (Ministry of Finance (**MoF**) and NRB) stated that the developer could utilize a hedging system in the Hedging Regulation 2019, which is applicable for hydropower development above 100MW. Though the details of the Hedging Regulation 2019 have not been determined, it is stated that i) exchange rate is fixed when foreign loan is deposited in NRB and ii) hedging duration is 10 years from such deposit. Sharing mechanism of hedging cost is not determined.

2.1.6 Institutional Procedure for IPP Development

IPP developers are required to obtain legitimate right to render its business in Nepal. Major laws and regulations relating to project development procedures for IPP projects are;

a. Electricity Act, 1992
b. Company Act, 1997
c. Electricity Regulatory Commission Act, 2017

d. Foreign Investment and Technology Transfer Act, 2019
e. Public Private Partnership and Investment Act, 2019
f. Hedging Relating Regulation, 2019

Followings indicate time series of major permits in accordance with current legal regulations.

[Preparation Stage]

a) Survey License

A Survey License is required to conduct an F/S to confirm technical, economic and financial perspectives for development of a potential hydropower project. Developers submit a request of Survey License to Department of Electricity Development (**DoED**) of the MoEWRI. DoED is responsible for processing the applications for all surveys and construction licenses on a "first-come first-served" basis. DoED may reject the application if a license has already been issued or where the applied project is on the GON Reserved Project List. DoED, however, may issue survey licenses for any GON Reserved Projects if any developer applies for the survey license of such projects as per the procedure laid down in the Electricity Licensing Directives, Electricity Act and Electricity Regulation along with upfront fees of NPR 1 million per MW. The Electricity Licensing Directive 2016 also specifies for minimum upfront fees of NPR 5 million and maximum of NPR 20 million, which shows that GON is planning to develop projects ranging from 5 MW to 20 MW under this mechanism.

Apart from procedure above, Investment Board of Nepal (**IBN**), which is a responsible governmental agency for negotiating development right on behalf of GON for hydropower projects over 200MW, publish a Project Showcase inviting private developers. Interested party may directly propose its interest to IBN for obtaining the Survey License.

After confirmation of DoED, MoEWRI issues a Survey License. An exclusive right for investing the potential project are granted to the developer by the Survey License. Standard review period for the license is 30 days and the developer is required to commence the survey and/or investigation within 3 months from the permit. Effective period of the Survey License is maximum 5 years. According to the Electricity Licensing Directive 2016, license holder will be granted the Generation License unless he transfers to others. This means that the obtaining Survey License is considered as the exclusive development right.

b) Foreign Investment (equity injection）; first step

Foreign Investment and Technology Transfer Act 2019 (**FITTA**) was approved by the President on March 27, 2019, which is a replacement of the Foreign Investment and Technology Transfer Act 1992. According to the FITTA, Department of Industry (**DoI**) approves foreign investment amounting less than 6 Billion NPR and IBN approves equal to or more than 6 Billion NPR projects. It is also stated in the Public Private Partnership and Investment Act 2018.

c) Registration of Company and Field of Business

After approval of foreign investment (equity injection), the developer apply company registration to the Office of Company Register (**OCR**) and apply field of business to

DoI. The application has to be made within 35 days after approval of foreign investment.

d) Foreign Investment (equity injection); second step

After registration of the company and field of investment, the developer has to obtain approval of foreign investment (equity injection) from NRB.

e) Project Development Agreement (PDA)

The developer (a license holder of the Survey License and a registered generation company) apply to commence PDA negotiation to IBN for hydropower project over 200MW in accordance with the Public Private Partnership and Investment Act 2018 (**PPPI Act**), promulgated in March 2019[6] and to MoEWRI for projects under 200MW.

For simplified reason, following procedures describes for projects over 200MW.

The IBN can implement the project by direct negotiation with the developer if:

a. the nature, financial or technical requirements of the project make it highly unlikely for competitive bidding to take place,

b. the project includes a unique concept or technology,

c. the project is listed to be implemented as a national priority project; or

d. the project is not considered fit by IBN to be implemented by other methods listed in the PPPI Act.

If IBN determines that it will be beneficial for the project to seek competitive bids, the IBN can decide to take the proposal through a Swiss Challenge[7]. If the proposer is not awarded the project, the winner of the Swiss Challenge must compensate the proposer for costs incurred in the research and development of the project.

After successful direct negotiation with IBN (or the proposer wins the project through the Swiss Challenge) and IBN has provided approval to enter into the PPP arrangement, the proposer and the IBN will first enter into a Memorandum of Understanding (**MOU**) and the proposer will be provided with project study approval under PPPI Act.

After the negotiation based on the MOU, the GON and the developer enter into the PDA. By signing PDA, the development right is granted to the developer while the developer is obliged to arrange financing and commence construction under certain conditions. Other licenses, e.g., Generation License have to be obtained in accordance with applicable laws and regulations.

Developer's rights and obligations below are agreed in accordance with the PDA for Upper Trishuli 1 project, signed on December 29, 2016[8].

6 Previously, IBN is responsible for the project with capacity above 500MW.

7 Though the definition is not stated in the PPPI Act, Swiss Challenge generally means a bidding procedure for infrastructure project that: i) a developer propose to undertake the development of projects under a certain condition to the government, ii) the government introduce details of the proposed project in public and invite other proposals (generally, a price proposal) and iii) the original proposer has a right to match the best proposal from others.

8 Time frame of this section is applied to Upper Trishuli 1 and is not consistent with standard time frame in the next section.

1) GON grant a right to the generation company for construction, generation and transmission of the electricity for 35 years from obtaining a Generation License.

2) The generation company is required to apply Generation License within 90 days from signing date of PDA and the GON approve within 120 days. Transmission Survey License shall be applied within 30 days from signing date of PDA and GON approve within 30 days.

3) The generation company is required to enter into a loan agreement within 24 months from the signing date of PDA (12 months extension may be allowed).

4) A Performance Security Agreement shall be concluded within 35 days from signing date of PDA and the generation company submit the Performance Security within 30 days from the loan agreement.

5) The generation company shall commence the construction of the power plant within 1 month from the loan agreement.

6) The generation company shall enter into PPA with NEA within 6 months from the signing date of the PDA.

Accordingly, major events after the PDA for the Upper Trishuli-1 case shall be as follows;

- Application of Generation License (3 months from PDA)
- PPA signing (6 months after PDA)
- Obtaining Generation License (7 months from PDA)
- Loan Agreement (31 months from PDA)
- Commencement of Construction (32 months from PDA)

[Development Stage]

a) Generation License and Transmission License

Generation and transmission licenses are applied to DoED. After the review of DoED, MoEWRI issues the licenses within 120 days. After obtaining licenses, the generation company is required to commence the construction of the power plant within 1 year. The effective periods of the licenses are 35 years (construction period 5 years plus 30 years) and may be extended up to 50 years. Applications of the Generation License and Transmission License shall be made within the effective period of the Survey License.

b) Connection Agreement

The generation company is required to enter into a MOU with NEA for connecting the power grid, which shall be reflected to PPA.

c) Power Purchase Agreement (PPA)

A PPA is entered into between the generation company and the off-taker, NEA. Power purchase tariff rate, power purchase amount, measures of payment, payment currency and other conditions are described in the PPA.

d) Approval of Loan Agreement

The generation company is required to obtain approval of the Loan Agreement from DoI, Industry and Investment Promotion Board (**IIPB**) and IBN. Prior to the first draw down, approval from NRB is also required.

e) Land Acquisition, Land Lease

Land area owned by a private company has a limitation according to the Land Law. In case the projects require more land than the limitation, the generation company is required to obtain approval of relaxing upper limit from Ministry of Land Reform and Management. GON has a right to acquire private land on behalf of the private company and to lease government-owned land to the generation company.

In accordance with the PPPIA, GON may take the responsibility for land acquisition and/or compensation in case the project is approves as a PPP project,

f) Other Approvals for Construction and Operation

Major permits which are required to obtain from relative governmental agencies are listed below:

- License for importing radio machines and communication systems and license for holding and using.
- Permission for the use of forest and to fell trees
- Permission for the construction in protected area, use of water resources in the area
- Permission to move large vehicles and transport heavy equipment (over 10 tons)
- License for import, transport and storage of explosives and approvals for the related security measures.
- Approval to open and operate offshore bank accounts
- Approval for offshore remittances (dividends, offshore loan repayment (interest, principal), proceeds from sale of equity)

2.2 EXISTING STUDIES FOR HYDROPOWER DEVELOPMENT IN NEPAL

At present, following studies have been carried out for storage type hydropower development.

1) Master Plan of Hydroelectric Development in Nepal, 1974, JICA
2) Gandaki River Basin Power Study, Basin Study, Basin Master Plan, 1979, United Nations Development Programme (**UNDP**)
3) Master Plan Study for Water Resource Development of the Upper Karnali River and Mahakali River Basin, 1993, JICA
4) Medium Hydropower Study Project, Power Sector Efficiency Project, 1997, WB and CIWEC
5) Identification and Feasibility Study of Storage Project, 2000-2004, NEA

Integrating those studies and each study for particular projects, JICA implemented a Nationwide Master Plan Study on Storage-type Hydroelectric Power Development in Nepal (2012 to 2014, hereinafter called **MP 2014**) including a proposal of long-term development plan. An update of MP2014 has been carried out by a Data Collection Survey on Hydropower Development Project in Federal Democratic Republic of Nepal (2016 to 2017) by JICA. Summaries of these two (2) studies are presented in this section.

2.2.1 Summary of MP 2014

The study commenced in February 2012 and the final report was reported to GON in February 2014. In the final report, ten (10) projects are reported as promising storage type hydropower projects. Summary of the MP 2014 is outlined as follows.

(1) Area of Study

Estimation of future power demand for 20 years beginning in 2013 was made and eligibility of storage type hydropower plants during this period was confirmed. The JICA survey team reviewed 65 storage type hydropower projects in the long-list presented by NEA from viewpoints of technical, environmental and social, economic, funding aspects etc. and proposed promising projects. Promising projects were sorted out by way of priority by evaluating order of development, magnitude of project, commissioning timing and financing source etc. As a result, a proposal of master plan is presented for development of storage type projects for 20 years from 2013.

(2) Power Demand Forecast

Power demand forecast was made by estimating actual demand growth of each sector (domestic, industrial, commercial/service, irrigation and others) from 1991 to 2011 considering GDP growth forecast for each sector. Base case scenario indicates growth rate of electricity demand (kWh) and peak demand (kW) as 5.8% for first 10 years, 7.7% for last 10 years and 6.8% in average. The actual demand growth from 2012 to 2017, however, shows higher growth rate than this demand forecast, such as 8.7% in electricity demand and 7.1% in peak demand according to NEA Annual Report 2017.

(3) Selection of Promising Projects

Following three (3) steps of studies were made on 67 storage-type hydropower projects listed up by NEA.

<u>**First Step**</u>

31 projects were selected by excluding projects which i) development stage had been matured, ii) duplicated with other project, iii) had technical difficulties or heavy environmental and social impacts.

- Project in detailed design stage or further
  Tanahu (140MW), Budhi Gandaki (600MW), Tamor (380MW), Kaligandaki-2 (660MW), Bagmati Multipurpose (140MW), Nisti-Panah (90.4MW)

- Projects with difficulties for development was excluded in terms of i) installed capacity >

1,000MW ii) height of dam > 300m iii) project cost > 2 Billion USD iv) annual flow regulation rate < 5% v) resettlement in reservoir > 500 houses vi) within national park, wildlife conservation area or world heritage.

<u>Second Step</u>

Evaluation was made on 31 projects by means of the Multi Criteria Analysis and superiority was compared by scoring. Evaluation items are followings;

- Hydrology: Reliability of hydrological data, Glacial Lake Outburst Flood (**GLOF**), sedimentation
- Geology: Geological condition, earthquakes
- Lead time to implementing projects
- Project benefit
- Natural environment: Forestry, Conservation Area, Fish, Rare Species
- Social environment: Impact by transmission line construction, resettlement, loss of farm land, indigenous people, tourism

<u>Third Step</u>

Ten (10) promising projects were selected from scoring in the second step. Conditions or requirements below were considered.

- Required total capacity; 2,900 MW capacity was scheduled to be developed by 2031/32 from demand forecast. Necessary storage type capacity of 2,600MW was determined excluding on-going development (Tanahu, Budhi Gandaki) plus 20 % margin.

- Result of scoring indicated many projects in the Western region had superiority. Considering demand area and transmission line construction, number of the promising projects were limited by five (5) projects in each drainage area.

- Four (4) projects with which IPP developers held the development license as ROR hydropower were excluded. Excluded projects are;
  Tila-1 (617.2MW), Bhanakot (810WM), Tamakoshi 3 (287MW), Dudh Koshi 2 (156.6MW)

Ten (10) projects indicated in Table 2.2-1 were finally selected as promising projects.

Among those, Kokhajor-1 was abandoned due to low project economics found by detailed study including site reconnaissance. As Lower Jhimruk is located in the reservoir area of Naumure project, Naumure was nominated as a promising project. It was noted that Naumure had a possibility to have a multi-purpose dam function integrating an irrigation project led by Ministry of Irrigation.

Table 2.2-1 Selected Projects (MP2014)

	Unit	Installed Capacity	Total Energy	Dry Energy	Project Cost	Unit Cost	EIRR	FIRR
		MW	GWh	GWh	MUSD	USD/kWh	%	%
1	Dudh Koshi	30.0	1,909.6	523.3	1,144.0	6.0	17.6	30.0
2	Sun Koshi 3	536.0	1,883.6	335.9	1,690.5	9.0	13.1	19.4
3	Lower Badigad	380.3	1,366.0	354.7	1,209.8	8.9	13.2	19.8
4	Andhi Khola	180.0	648.7	137.1	665.8	10.3	13.0	19.1
5	Chera-1	148.7	563.2	120.6	576.9	10.2	12.6	17.8
6	Madi	199.8	621.1	170.7	637.3	10.3	12.3	16.8
7	Nalsyau Gad	410.0	1,406.1	581.8	966.9	6.9	15.6	25.8
8	Naumure (W.Rapti)	245.0	1,157.5	309.9	954.5	8.2	15.2	25.3
9	(Kokhajor-1)	111.5	278.9	94.1	476.5	17.1	7.6	n.a.
10	(Lower Jhimruk)	142.5	454.7	94.4	520.9	11.5	10.9	11.5

Note: EIRR: Economic Internal Rate of Return
FIRR: Financial Internal Rate of Return

(4) Development Plan

Levels of project development stage were varied among selected projects such as F/S level, Pre-F/S level and/or desk-top study level, a development plan was proposed for prioritization.

The JICA survey team conducted technical studies including risk evaluation of GLOF, sedimentation impact, geological site reconnaissance, review of studies in the past, re-evaluation of annual energy production and preliminary environmental and social survey.

Cost of each project was also re-evaluated and necessary physical contingencies were estimated so that the level of details to be equal for the comparison purpose. Construction period were also re-estimated including evaluation of each transmission line and access roads construction.

A power system development software, Wien Automatic System Planning (**WASP**) IV, developed by International Atomic Energy Agency (**IAEA**) was then utilized for analyzing the most appropriate installation timeline to minimize total generation cost of the power system. Assumption and basic features for economic evaluation are listed below;

- On-going storage type projects, Kulekhani No.3, Tanahu and Budhi Gandaki be completed as scheduled,
- Imported electricity from India be maximum 12MW until 2014/15 then 162MW (based on discussion with NEA)
- ROR hydropower count Tamakoshi V (87MW, COD 2021/22) and Upper Arun (335MW, COD 2024/25), both of which is under preparation for construction, and 100MW commissioning afterwards,
- Discount rate be 10%,
- 90% of project cost be depreciated,
- Foreign currency be 80% and local currency 20%,
- Allowable Loss of Load Provability be 1.375%, with which 5 days deficit in a year,
- Cost of Energy not Supplied (**ENS Cost**) be 0.76USD/kWh

The most economically viable development plan for storage type hydropower projects is shown below.

Table 2.2-2 Storage-type Projects to be implemented (MP2014)

Project	Capacity (MW)	Commissioning Year (FY)			Remarks
		Base Case	High Case	Lower Case	
Kulekhani No.3	14	2015/16	2015/16	2015/16	Under construction
Tanahu	140	2020/21	2020/21	2020/21	LA[1)] has been concluded
Budhi Gandaki	600	2022/23	2022/23	2022/23	DD[2)] is ongoing
Dudh Koshi	300	2026/27	2026/27	2027/28	
Nalsyau Gad	410	2028/29	2027/28	2029/30	
Andhi Khola	180	2029/30	2029/30	2031/32	
Chera-1	149	2031/32	2029/30	---	
Madi	200	2031/32	2030/31	---	
Naumure	245	---	2030/31	---	
Sun Koshi No.3	536	---	2031/32	---	
Lower Badigad	380	---	2031/32	---	
Total Capacity	**---**	**1,993MW**	**3,154MW**	**1,644 MW**	

Note: 1) Loan Agreement
2) Detailed Design

2.2.2 Summary of Data Collection Survey on Hydropower Development Project

The survey was carried out from August 2017 to March 2018 for confirming progress, project viability and possibility of implementation by evaluating 10 promising projects identified in the MP 2014 plus additional five (5) projects proposed from NEA.

A proposal about technical and financial assistance was made for two (2) most promising projects, i.e., i) Nalsyau Gad, the most prioritized project and ii) Lower Seti, the quickest development expected project.

(1) Progress of Target Projects

13 projects were studied, out of which 10 projects identified in the MP 2014 and 3 projects proposed from NEA. Khimiti, Shivalaya Bubung projects (proposed by NEA) were excluded because of lack of information.

Table 2.2-3 Summary of Present Status of Promising Projects (JICA 2019)

No.	Project Name	Present study level	on-going study level	Present Status	Remarks	note
1	Nalsyau Gad	F/S (NEA)	F/S-Update (SMEC, MWH, Udaya)		GON fund SPC has been established	MP 2014
2	Dudh Koshi	F/S (FC)	F/S-Update and D/D (ELC and NEWJEC)	Survey license	ADB fund	MP 2014
3	Chara-1	desk study	No progress	Survey license		MP 2014
4	Andhi Khola	F/S (NEA)	F/S-Update (NEA)	Survey license		MP 2014
5	Madi	desk study	No progress			MP 2014
6	Lower Jhimruk	desk study	No progress			MP 2014
7	Kokhajor-1	desk study	No progress			MP 2014
8	Naumure	F/S (NEA)	F/S (DoED)		Multi-purpose project	MP 2014
9	Sun Koshi No.3	F/S (NEA)	F/S (DoED)			MP 2014
10	Lower Badigad	desk study	No progress			MP 2014
11	Uttar Ganga	desk study	F/S (NEA)	Survey license	SPC has been established	GON
12	Tamor	F/S (NEA)	F/S (NEA)	Survey license		GON
13	Lower Seti	desk study	F/S (THL)	Survey license		GON

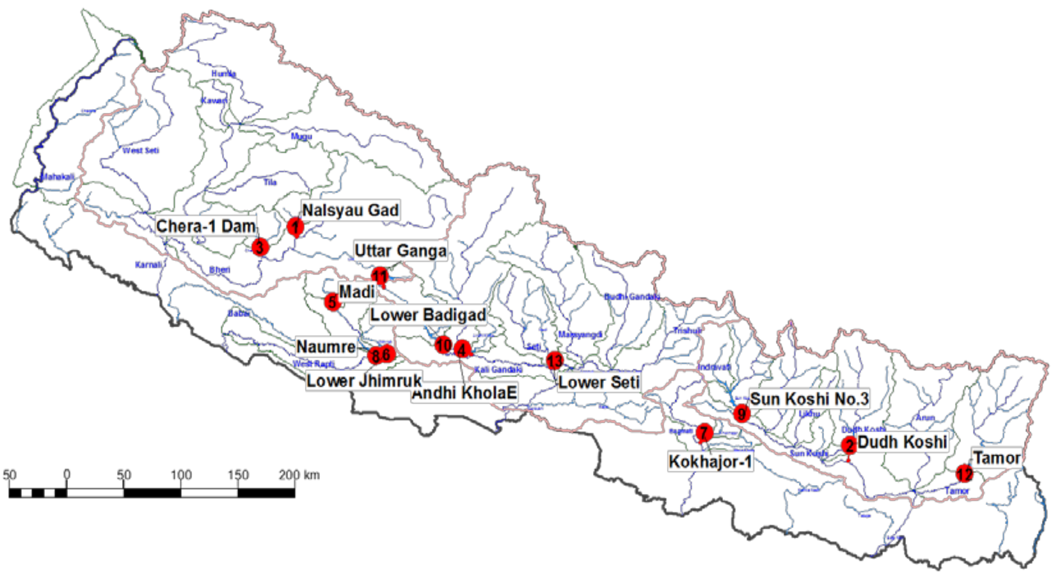


Figure 2.2-1 Locations of Promising Hydropower Projects selected in MP2014 and GON in 2017 (JICA 2019)

(2) Identification of Issues and Risks

Hydrological risk, geological risk, environmental and social risk, project cost and lead time and project economics were reviewed.

(3) Selection of Prioritized Storage-type Project

Progress of development stage, risk associated with project implementation and applicability of Japanese technology were considered for selecting prioritized storage type project.

The result of evaluation is presented in Table 2.2-4. Nalsyau Gad, Andhi Khola and Lower Seti projects were selected as prioritized projects.

Table 2.2-4 Current Conditions of Hydropower Projects in MP2014 and GON Proposal (JICA 2019)

No.	Project Name	Installed Capacity (MW)	Progress *1	Risk Consideration *2	Remarks	Priority *3
1	Nalsyau Gad	410	A	B	- Studies ongoing by international consultant by GON fund - Infrastructure improvement (road construction) is planned by GON - Transmission lines are planned until relatively near the project site - Project contributes to the local society - Cascade development can be considered for effective and efficient hydropower development	V
2	Dudh Koshi	300	A	B	- Studies ongoing by international consultant by ADB fund - Survey license is to be resubmitted because of the Project upgrading	
3	Chera-1	148.7	C	C	- Project is to be reconsidered because of other downstream project	
4	Andhi Khola	180	A	B	- Studies ongoing by NEA	V
5	Madi	199.8	C	C		
6	Lower Jhimruk	142.5	C	C	- To be affected by Naumre (No.8) located downstream of the river	
7	Kokhajor- 1	111.5	C	C		
8	Naumure (W. Rapti)	245	B	C		
9	Sun Koshi No.3	536	B	C		
10	Lower Badigad	380.3	C	C		
11	Uttar Ganga	821.0	B	C	- Trans-basin project	
12	Tamor	762.0	B	C	- Survey license is to be resubmitted because of the Project upgrading	
13	Lower Seti	104.0	B	B	- Studies ongoing by Tanahu Hydropower Co. Ltd. - Countermeasures for sediment will be cooperated with Tanahu project - Japan technologies such as coordination flushing can be applicable	V

*1 : Progress
A: FS completed. Update studies have been conducted after MP2014
B: Desk study level. Studies have been currently conducted after MP2014
C: No progress after MP2014

*2 : Risk Consideration
A: Relatively lower risk
B: Although risks exist, surveys and studies for countermeasures have been conducted
C: Risks exist. No/less further studies have been conducted.

*3 : Priority
V: Selected as priority projects for further studies

The JICA survey team conducted site surveys for selected three (3) projects and confirmed location, accessibility, topography, geology and environmental and social conditions. The JICA survey team also listed up issues and risks by examining existing study reports in terms of hydrology, sedimentation, generation planning, geology, civil structure and environmental and social conditions.

(4) Japanese Technology Applicable for Storage-type Hydropower

Japanese experiences and technology applicable for storage-type hydropower were introduced as follows.

1) Effective River System Development

Effective river system development is made by developing reservoir at the utmost upstream which regulates annual inflow then series of hydropower plants are developed in order to utilize heads and river flow except environmental flow. By applying the effective river system development, the maximum peak output can be obtained especially during dry season.

2) Sedimentation Countermeasures - Sediment Flashing, By-pass, Coordinating Sediment Flashing

Applicable countermeasures for sedimentation are flashing/sluicing and sediment bypass tunnel etc. In case dams are series at up and downstream, coordinated sediment flashing/ sluicing is effective.

(5) Demand Supply Gap

1) Current Demand Supply Gap

Peak demand in 2016 was 1,385 MW while total supply capacity was 856 MW in Nepal. The demand supply gap of 529MW causes maximum 11 hours load shedding from January to April. As NEA implemented demand side management such as restriction of industrial demand during peak hour and promotion of low power equipment like Light Emitting Diode (**LED**) in 2017, rotating load shedding were prevented. Annual load curve indicates maximum demand during dry season (winter) and minimum demand during wet season (summer).

2) Demand and Supply Forecast

Demand forecast was done by NEA before 2016 based on demand record in the past, which related to transmission system expansion, population growth of each region and economic growth. From 2017, WECS started demand forecast as a responsible governmental entity. Its demand forecast is analyzed by Model for Analysis of Energy Demand (**MAED**) based on fundamental data of medium-long term economic growth, technology innovation and population growth at regional level as well as nationwide level. The model considers three (3) scenarios (GDP growth rate 4.5%, 7.2% and 9.2%) and extra scenario with various policy interventions are made (see Section 2.1.2). WECS demand forecast resulted in different figures from NEA’s forecast.

3) Issues on Demand Forecast and Power Grid System

NEA power grid system divides the supply area into six (6) grid zones from west to east and the power operation is done independently in three (3) blocks for grid stability and current control. Supply demand balance should be considered in each grid.

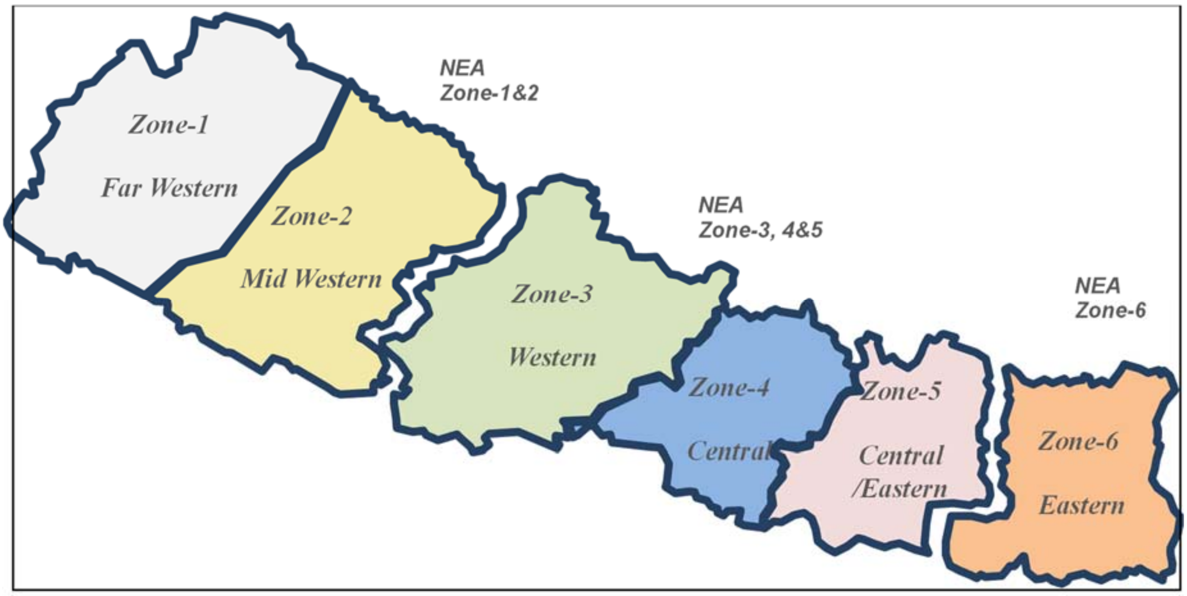


Figure 2.2-2 Operational Zone for NEA Power System (JICA 2019)

Estimated power flow at peak hour in 2024 is indicated in the following figure as a sample (by demand forecast of WECS, GDP growth rate 7.2%). From this flow, power demand excess supply capacity and 3,500MW import energy from India is necessary except Zone-5.

Power Flow at Peak Time in Dry Season (2024)

	Zone-1	Zone-2	Zone-3	Zone-4	Zone-5	Zone-6	Total
Available	23 MW	18 MW	879 MW	400 MW	897 MW	168 MW	2385 MW
Peak	228 MW	370 MW	1186 MW	2758 MW	461 MW	918 MW	5921 MW
Balance	-205 MW	-352 MW	-307 MW	-2358 MW	436 MW	-750 MW	-3536 MW

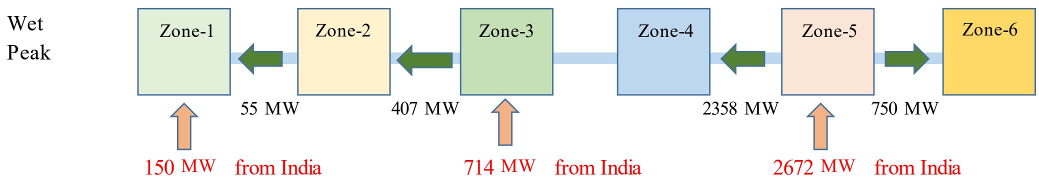


Figure 2.2-3 Power Flow at Peak Time in Dry Season (2024) (JICA 2019)

4) Issues on Power System

- Since liberalization of generation business, NEA ceased to establish long-term power develop plan, and there is no central governmental agency who consider nationwide long-term power strategy. Hence there is no long-term hydropower development plan pursuing the most effective power composition nor long-term power system development plan.

- Power supply capacity in Nepal varies seasonally due to hydropower plant while power generation in India can control supply capacity by coal and/or diesel. Interconnection system between Nepal and India should be considered in the long-term.

- As power system ranges approximately 850km in Nepal from west to east, length of transmission lines will be more than 400km. Installation of compensators and/or Static Var Compensator (**SVC**) is required to control reactive power generated from long-distance transmission line.

- As each zone connect to different power system in India, direct current (**DC**) connection stations in NEA power system should be considered.

- Energy export to India can be considered once the interconnection power system is established. Institutional arrangement for allowing energy export should be considered.

SECTION 3 IPP/PPP EXPERIENCES IN FOREIGN COUNTRIES

As a reference to study assisting measures for hydropower development in Nepal, procedures for IPP development and PPP concept in foreign countries are researched and presented in this section.

3.1 HYDROPOWER IPP DEVELOPMENT PROCEDURE IN THE PHILIPPINES

Power development used to be handled by a vertical integrated state enterprise, National Power Corporation (**NPC**) until 1987 when the government set up a policy of allowing private investors to participate in the power generation sector in order to resolve energy crisis in early 1980's. A BOT Law was promulgated in 1990 and the first IPP power station (Nabotas oil fired power plant) was installed in 1991. IPP projects in this period are all Build, Operation and Transfer (**BOT**) based projects, i.e., private investors construct and operate power plants and sold all generation to NPC until transfer.

Triggered by the Asian Currency Crisis in 1997, the financial status of NPC deteriorated due to the depreciation of local currency and foreign currency fixed PPA contract, the government considered structural reform of the power sector, The Electric Power Industry Reform Act (**EPIRA**), which is based on privatization and liberalization of the electricity market, has been established. The privatization and liberalization including the sales of NPC assets and creation of a wholesale electricity market has been promoted gradually. At present, all power plants are operated by private sector except small scale power stations for rural electrification. Power supplier sells energy to wholesale electricity market or through bilateral contract with power distributors. In other word, power suppliers have to take market risk.

Structure and characteristics of storage-type hydropower development by IPP before EPIRA is presented below;

- ♦ Electricity tariff in PPA is the sum of below items.

①	Capital Recovery Fee:	Sum of Capacity Fee and Energy Fee
	Capacity Fee:	Subject to availability of contracted capacity (kW), lump-sum amount is paid by foreign currency
	Energy Fee:	paid for generation (kWh) by foreign currency
②	Operating Fee:	paid for fixed operation and maintenance (**O&M**) by local currency with CPI adjustment

- ♦ Concession right including exclusive right to utilize river flow for the IPP is guaranteed by the Government Undertaking free of charge.
- ♦ Government of the Philippines guarantee the performance of NPC.
- ♦ Land acquisition and resettlement is a responsibility of NPC.
- ♦ Environmental and social protection measures and monitoring plan are approved by Department of Environment and Natural Resource (**DENR**). NPC and IPP shares responsibilities in accordance with an Environmental Compliance Certificate issued by DENR.

- Construction of the transmission line from the switching station to the nearest substation is a responsibility of NPC.

3.2 HYDROPOWER IPP DEVELOPMENT PROCEDURE IN LAO PDR

Lao PDR has abundant hydropower potential along the Mekong River and its tributaries, the theoretical potential is estimated to be over 25,000 MW, of which the commercially viable potential is 18,000 MW. The first large-scale hydropower in Laos is Nam Ngum I (155 MW, 1984) developed with the support of the Japanese government, the WB, etc. to supply power to the capital city, Vientiane as well as contributing foreign currency income by exporting energy to neighboring Thailand.

Based on experience of the Nam Ngum I, hydropower IPP development has been promoted as a motivation to acquire foreign currency by exporting electricity to neighboring countries. Since the 1990s when Laos has been politically stabilized, hydropower plants for mainly power export are being developed as IPP projects by overseas private investment. The first generation IPP projects are Theun-Hinboun (210 MW, 1998) and Huay Ho (150 MW, 1998) both of which were developed for exporting energy to Thailand. Currently Laos has 45 hydropower plants for export with 8,300 MW total capacity (as of 2017, including under construction and excluding plants less than 15MW), which holds 89% of the total hydropower capacity in Laos. Energy export has been expanded to Vietnam and China.

The Lao government obliges domestic supply of about 10% to IPPs who intend to develop export-oriented hydropower. IPP needs to conclude two PPAs, PPA for export power and PPA for domestic power sales.

Procedure for developing IPP hydropower are required to follow regulated procedures as follows (for developing power plant that has more than 15MW, which is approved by the central government). These procedures are the same for export IPP and domestic IPP.

1) The developer conclude a MOU with Lao government and proceed an F/S. For larger capacity plant more than 15MW, MOU is signed by the Ministry of Energy and Mines (**MEM**) and others by the provincial governor.

2) The developer report the result of the F/S and the developer and Lao government enter into a PDA. Commencement date of the construction and COD is defined in the PDA. Effective period of PDA is 18 months with allowable extension of 6 months (for domestic IPP) or 2 times of 6 months (for export IPP). The developer prepare construction during effective period of PDA and in parallel, negotiate PPA with off-taker(s) and financing. PDA is replaced by a Concession Agreement (**CA**) concluded between the developer and Lao government.

3) All permits necessary for the development of hydropower plant are included in the CA. Particular attention is paid to Environmental and Social Impact Assessment (**ESIA**) or Initial Environmental Examination (**IEE**; for transmission line construction or access road below designated magnitude) which the developer has to obtain approval from the Ministry of Natural Resource and Environment before CA. Approved environmental/social impact mitigating measures, monitoring plan etc. are described in the CA for clarifying developer's responsibility.

4) For export IPP, PPA negotiation is carried out with foreign off-taker and domestic off-taker,

Electricity de Laos (**EDL**).

5) Construction commences after conclusion of both PPAs, CA, contract with subcontractors and financial close.

Concession right of the IPP investor is secured in the CA in which responsibility/risk sharing mechanism are described. Major items in the CA is listed below:

- ✓ The Lao government grant an exclusive right to the developer for developing and operating the hydropower plant within concession period,
- ✓ Required land is leased to the developer free of charge,
- ✓ Concession period is 30 years,
- ✓ Tax incentives are considered and described,
- ✓ A certain rate of royalty against Gross Operating Revenue of the SPC is described,
- ✓ Environmental and social impact mitigating measures and monitoring plan. Note that resettlement is a responsibility of the developer,
- ✓ Political Force Majeure clauses is applicable for exporting country as well as Lao PDR.

The rate of royalty and tax incentives in the CA varied by each project. Lao government considers that the project economics of the hydropower is dependent on hydrological, topographical and geological situation and make arrangement with developers to promote hydropower development in order to keep profit balance between government and developer through discussion on project cash flow.

PPA of storage-type hydropower has characteristics below (case of Thailand):

- ✓ All generation is undertaken by the off-taker,
- ✓ Based on Take or Pay concept,
- ✓ Generation during peak hours (8 to 16 hours in weekdays) is purchased per kWh as the Primary Energy. Payment currency is local currency and USD.
- ✓ Other generation is purchased as the Secondary Energy with lower tariff rate. Payment is made in local currency.

3.3 HYDROPOWER IPP DEVELOPMENT PROCEDURE IN INDONESIA

Vertical integrated state enterprise, PT. PLN (Perusahaan Listrik Negara), took responsibility of power generation following the Electricity Law in 1985. Presidential degree in 1992 allow private participation in generation sector. The amended Electricity Law in 2002 intended privatization of PLN, creation of a wholesale electricity market and unbundling of power sectors, but the Supreme Court ruled that the privatization of electricity enterprise was in violation of the Constitution. As a result, present power generators consist of PLN, subsidiary companies of PLN and IPPs while transmission, distribution and electricity sales are handled by PLN. The electricity law in 2009 positioned PLN as a vertically integrated electricity enterprise.

BOT based IPP projects, mainly large scale fossil power plants, were initially introduced in early 1990's to solve the power shortage because of the financial difficulty of PLN.

For the large scale fossil power development, IPP developers are selected through tender process. However, hydropower IPP projects are basically developed on unsolicited proposal basis. After private investors conduct an F/S, the proposal is submitted to PLN for the project with 10MW capacity or more. PLN then review the proposal and check the consistency with long term demand supply plan. Once it is found the project is in line with the PLN's development policy, PPA conditions are negotiated between PLN and the IPP developer.

Recently, PLN introduced a new selection system for renewable power source in 2018. The new system indicates that PLN publishes required amount of generation (kW and kWh) and generation cost of PLN for each region and only projects that can offer lower tariff is able to obtain generation license. In case total capacity of IPP's offer exceed required capacity, PLN select and appoint projects that offer lower tariff until fulfilling the required capacity. In addition, IPP developers are required registration by passing prequalification process (DPT Process) of PLN, through which PLN evaluate developer's capability for development and operation of power plant.

General procedure of hydropower IPP in Indonesia is summarized below:

- ✓ Memorandum of Understanding (MOU): MOU is concluded between private developer and provincial government. The developer can obtain exclusive right to survey and investigation for designated area.
- ✓ F/S: Private developer conduct F/S within designated period in the MOU.
- ✓ ESIA: A part of ESIA is called AMDAL in Indonesia. The private developer conduct AMDAL survey following the regulations in parallel with F/S.
- ✓ Land Acquisition and Resettlement Action Plan (**LARAP**): LARAP survey is conducted in parallel with F/S.
- ✓ The private investor submit reports above to provincial governor, PLN and other responsible governmental agencies (e.g., AMDAL to Ministry of Environment). PLN review reports and check consistency with the Long Term Business Plan of PLN (**RUPTL**) and negotiate PPA condition with the developer.
- ✓ Land acquisition is a responsibility of private investor. In case the project is included in the PPP List of the government, PLN may be responsible for land acquisition.
- ✓ Resettlement is a responsibility of private investor.
- ✓ Construction of transmission line is basically responsibility of PLN.
- ✓ Tariff level is determined through negotiation between the developer and PLN. Recently considerable number of private IPP is proposed by local investors. In such cases, payment is made in local currency. In case foreign developer with foreign finance, payment in foreign currency is allowed.

3.4 HYDROPOWER IPP DEVELOPMENT PROCEDURE IN MYANMAR

Myanmar has abundant hydropower potential thanks to steep mountains and large rivers, such as the Ayeyarwadi, Chindwin, Sittaung and Thanlwin River with theoretical potential to be over 100,000 MW, of which the commercially viable potential to be 40,000 MW. Hydropower potential of Myanmar is the third largest among Asian countries after China and Nepal.

The first large-scale hydropower development after the World War II is the Baluchaung II (168 MW, 1974) by Japanese government funds and additional five (5) hydropower plants (total output 147 MW) were developed by the government by 2000. Hydropower development was accelerated after 2000 and present total capacity of hydropower in 2017 is 3,331MW. The largest hydropower plant is Yeywa (790 MW, 2010) developed by the government.

At the upstream of the Ayeyarwadi River near the border with China, hydropower development has been proceeding to export energy to China. Shweli I (600MW, 2009) and Dapein I (240 MW, 2010) were constructed and Chipwi Nge (99MW, 2013) has been commissioned. The Chipwi Nge plant was initially intended to provide electricity to the construction of Mitson (plan 6,000MW), which was abandoned by the newly appointed government after 2016 democratic election.

Those export-oriented hydropower plants are IPPs on BOT basis and most of generation is exported to China due to lack of power transmission system in the Northern area. Shweli I, which is connected to main power system, was developed by a joint venture company (it is called "Foreign Joint Venture" in Myanmar) of Yunnan United Power Development Corporation in China (80%) and Myanmar government (20%), Hydropower Implementation Bureau of First Power Department of Myanmar. During the operation period of 40 years, Myanmar government has a right to receive 15% of generation as "Free Share" from the Shweli I hydropower.

Recently, based on the increasing domestic demand and development of transmission line system, domestic IPP projects have been implemented by private investors. Mali (10.5 MW, 2006), Baluchaung 3 (52 MW, 2014) and Thauk Ye Khat II (120 MW, 2014) were developed as first generation IPPs but the investors and lenders are all domestic.

A private investors (private companies in Myanmar, Austria and Japan) obtained a development right of the Deedoke (plan 56MW) hydropower in August 2018, which is the first IPP project by foreign investors with international lenders on project finance basis. Another foreign investors (private companies of Myanmar, France and Japan) obtained a development right of the Shweli 3 (plan 671MW) hydropower in September 2018.

IPP development by foreign private investors has just commenced in Myanmar. Currently, procedure of hydropower IPP is as follows:

- ✓ Exclusive survey and study right is given to the developer by a MOU with Myanmar government.
- ✓ The developer conduct F/S and ESIA following applicable regulations during effective period of MOU.
- ✓ Myanmar government issues a Minutes of Agreement (**MOA**) or a Notice to Proceed (**NTP**) to the developer. NTP grants exclusive development right to the developer and describe outline of PPA conditions.
- ✓ The developer negotiate PPA, Joint Venture Agreement (**JVA**), Land Lease Agreement, CA based on NTP.

Note that the both MOUs of Deedoke and Shweli 3 were granted to other country's government.

3.5 EXAMPLE OF VERTICAL SEPARATION PPP MODEL

The Vertical Separation PPP Modality is historically initiated in railway system development where infrastructure development and railway operation are separated. Public entity is responsible for the infrastructure development such as land securing, area development, railway placement etc. while private investor conducts railway operation under concession right granted by the public entity, which is one of the schemes of PPP and was initiated in England and USA. In this Survey, a project in which the development of base infrastructure (in hydropower case, dam) is rendered by public entity and a particular business utilizing the said infrastructure and formulating/operating its own facilities (in hydropower case, generation facilities) is conducted by a private company is called as a Vertical Separation PPP Modality (VSPPPM) in broader sense.

Examples of the VSPPPM are introduced in this section.

(1) San Roque Multi-purpose Dam and Power Plant in the Philippines

San Roque hydropower plant is a storage type hydropower with 436MW capacity and was developed as a part of the San Roque Multi-purpose Dam project by an IPP developer. It was constructed and operated by a SPC and all generated energy was purchased by NPC during 25 years concession period after which the hydropower facilities will be transferred to the government. The BOT based PPA was signed in October 1997 and all three (3) units were commissioned in May 2003. After privatization of NPC, PPA obligation was transferred to a private company selected through competitive bidding and is still valid.

Figure 3.5-1 San Roque Dam and Hydropower Plant

The San Roque Multi-purpose Dam project is initiated by the Philippine government and its objectives are irrigation, flood control, water quality enhancement and power generation at the Agno River basin where the San Roque Dam is situated. PPA between NPC and SPC stipulates that the construction of the dam is a responsibility of the SPC and transferred to NPC after completion, that the construction cost of the dam is shouldered by the Philippine government through NPC and that SPC has a right to utilize reserved water in the reservoir for generation purpose free of charge during BOT period. The SPC, San Roque Power Corporation was initially established by investors of Sithe Energy (USA) , Marubeni (Japan) and Kansai Electric (Japan) and the Sithe Energy sold its share to Japanese investors after commissioning. Current shareholders are Marubeni and Kansai Electric.

The construction of the dam was a responsibility of the Philippine government for its nature of public purposes. The Philippines government arranged an Untied Loan provided by Japan Exim Bank (**JEXIM**, currently Japan Bank for International Cooperation, **JBIC**) for funding the construction cost of 400 MUSD. The SPC separately arranged project financing from international financing syndicate led by JEXIM utilizing the Overseas Investment Loan scheme.

The project development scheme indicates that the project with dam construction, which private investors cannot achieve expected attractive return (or extremely higher tariff is required), became bankable for lenders and affordable for private investors by applying separation concept of infrastructure development cost and public involvement (dam construction cost), which is one of the schemes of PPP. It is also an example of Japanese government involvement to develop a large scale infrastructure through PPP.

The construction of the multi-purpose dam was sub-contracted from NPC to SPC, then a contractor of SPC undertook construction of both dam and power facilities. Being the same contractor enabled schedule coordination between dam and power facilities and effective use of common facilities (crashing plant, disposal area etc.) and temporary facility. Operation of the dam including spillway gates operation is also sub-contracted to SPC. Those responsibility sharing are defined in the PPA.

Project scheme is illustrated in the following figure.

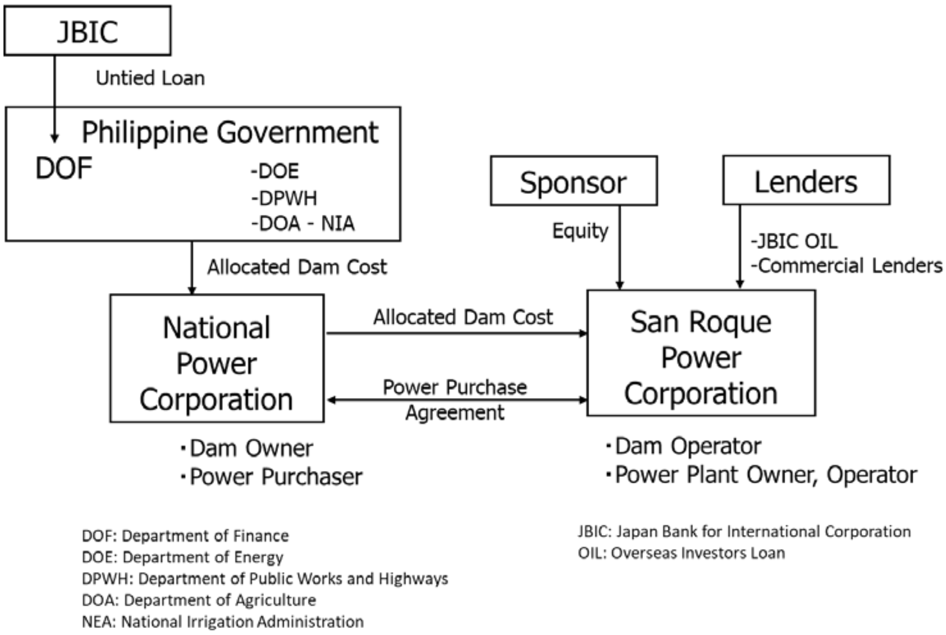


Figure 3.5-2 San Roque Multi-purpose Dam Project Scheme

(2) Phu My Power Plant Complex in Vietnam

A Yen Loan agreement was signed in January 1994 to support Phu My 1 Gas Combined Cycle Power Plant and Associated Transmission Lines and Substation at Ba Rịa-Vung Tau Province near Ho Chi Minh City. Phu My 1 power station is operated by Electricity of Vietnam (**EVN**) and the Yen Loan was provided for accommodating increased electricity demand in Southern part of Vietnam, stable supply of electricity and economic vitalization of the region. The Yen Loan was also intended to utilize for future expansion of Phu My power plant complex.

By utilizing common facilities after the commissioning of the Phu My 1, Phu My 2, Phu My 2-1, Phu My 2-1 Expansion, Phu My 3 and Phu My 4 power plants were constructed and the region forms Phu My power plant complex.

Figure 3.5-3 Phu My I Power Plant

Figure 3.5-4 Phu My Complex

Common facilities constructed by Yen Loan for Phu My 1 are listed below:

- Cooling Water Intake/Discharge Channel
- Water Treatment Plant/Sewage Water Treatment Plant
- 110kV/220kV Switchyard
- Heavy Fuel Oil Tanks
- Diesel Oil Tank
- Raw Water Storage Tank
- Administration Building
- Canteen Building
- Warehouse
- Workshop
- Causeway and jetty

Constructed power plants are introduced in the following table. All plants are gas combined cycle plants. Phu My 2-2 and Phu My 3 are BOT based IPP projects.

Table 3.5-1 Phu My Power Plants

Power Plant	Owner	Capacity(MW)	COD	Finance
Phu My 1	EVN	1,090	2000	OECF
Phu My 2-1	EVN	900	1997	WB
Phu My 2-2	IPP(1)	715	2005	Syndicate(1)
Phu My 3	IPP(2)	715	2004	Syndicate(2)
Phu My 4	EVN	450	2004	-

IPP(1): EDF (France), Sumitomo Corporation (Japan), Tokyo Electric Power Company Holding (ex. Tokyo Electric Power Co., Inc., Japan)

IPP(2): BP (England), Sembcorop (Singapore), Sojitsu Corporation (ex. Nissho-Iwai, Japan), Kyusyu Electric Power Co. Inc. (Japan)

Syndicate(1): ADB, JBIC, WB (guarantee), commercial lenders

Syndicate(2): JBIC, ADB, MIGA (guarantee), commercial lenders

Private IPP developers for Phu My 2-2 and Phu My 3 was able to invest the project because basic infrastructures were already completed by Vietnam government through Yen Loan.

(3) Paiton Power Plant Complex in Indonesia

PT. PLN developed Paiton complex and installed 2 units of 400MW coal fired power plants in 1994 (Paiton PLN or Paiton Unit #1 & #2), which is currently owned and operated by PT. PJB, a subsidiary company of PLN. The plant yard was developed considering future expansion of five (5) units.

The Paiton 1 (or Paiton Unit #7 & #8, each 615MW) and Paiton 2 (or Paiton Unit #5 & #6, each 610MW) coal fired power plants were developed as IPP projects in May 1999 and November 2000, respectively. After the Asian Financial Crisis, the Paiton 3 (or Paiton Unit #3, 815MW) was completed in 2012. PLN also added Paiton Unit #9 of 660MW in 2012. All IPP projects could enjoy cost saving because they could use already-developed space of Paiton complex and cooling water system, which were developed by PLN.

Paiton 1, Paiton 2 and Paiton 3 are BOT based IPP projects. Paiton 1 was awarded to a joint venture company comprised of US based Mission Energy, Japan's Mitsui & Co. and local Indonesian companies in 1995. The SPC successfully arranged financing with export credit agencies (**ECAs**) and insurers, such as NEXI (then Insurance department of Ministry of Economy, Trade and Industry of Japan), JBIC (then Export-Import Bank of Japan), US Export Import Bank and Overseas Private Investment Corporation of USA. Paiton 2 was awarded to a joint venture company comprised of Siemens Power Venture in German, PowerGen in UK and local Indonesian companies. The SPC of Paiton 2 arranged financing from an international consortium of commercial lenders. Paiton 3 development was awarded to a consortium of IPM Eagle (sponsored by the International Power of UK and Mitsui & Co. Ltd of Japan), the Mitsui & Co., the Tokyo Electric Power Company Holding of Japan and a local investor in Indonesia and financed by JBIC.

Because of the Asian Financial Crisis in 1997 and following depreciation of Indonesian currency, PLN had a difficulty of payment denominated in USD to Paiton 1 SPC at the commencement of commercial operation in 1999. PLN and lenders agreed to restructure the PPA and started negotiation how to solve the problem together with Indonesian government as a guarantor of PLN's obligation under PPA. Finally in 2003, PPA Amendment was agreed. In the restructuring plan, i) the capacity payment was reduced, ii) tenor of debt was prolonged, iii) concession period was prolonged from 30 years to 40 years, iv) fuel supply agreement was restructured and v) SPC issued a bond for debt payment and operational expenditures.

Major revised conditions in the PPA Amendment for Paiton 1 and Paiton 2 are listed below:

- Tariff consists of four (4) component as follows:
  ① Component A: to cover Capital Recovery Cost
  ② Component B: to cover Fixed O&M Cost
  ③ Component C: to cover Fuel Cost
  ④ Component D: to cover Variable O&M Cost

- ♦ Component A is a fixed payment and is paid subject to keeping availability. It is paid by USD.

- ♦ Component B is a fixed payment and paid by USD or Indonesia Rupiah. The amount is adjusted by CPI in US, Japan and Indonesia.

- ♦ Component C is to cover consumables and maintenance cost and varies in accordance with actual generation

- ♦ Land acquisition and construction of transmission line is a responsibility of PLN

- ♦ Concession period is 40 years for Paiton 1 and 30 years for Paiton 2. After the concession period, SPC will have a right to sell electricity to either PLN or large consumers. This means BOO scheme was applied.

- ♦ Indonesia government guarantee performance of PLN under PPA by a support letter.

Figure 3.5-5 shows a picture of the Paiton Power Plant Complex.

Figure 3.5-5 Photo of Paiton Complex in 2007

3.6 TARIFF STRUCTURES IN NEIGHBORING COUNTRIES

Tariff structures in neighboring countries are generally divided into three components.

The first portion is a tariff equivalent to capital recovery. This tariff portion is defined on a kW or kWh basis. In the case of the kWh base, the amount of generation which the off-taker is obliged to purchase is also defined. Generally, this portion is reduced after the completion of loan repayment. Payment currency is mainly denominated in hard currency, but even if payment is denominated in local currency, tariff rate is described as “hard currency equivalent local currency” where the exchange rates at the payment date is applied to designated local currency payment amount. These measures become important points for foreign investors to make investment decisions because the measures can reduce exchange risk on capital recovery.

The second portion is a tariff covering operation costs such as O&M, taxes and so on. This tariff portion is basically based on actual generated energy (kWh) and is adjusted according to the indexes such as consumer price index. The payments are often made in a mix of domestic and hard currencies. Even if the payment is conducted in local currency only, the exchange rate is adjustable same as described above.

The last portion is water usage and fuel costs. Basically a pass-through mechanism is applied to the payment.

SECTION 4 STORAGE HYDRO DEVELOPMENT BY IPP

Development of storage type hydropower plants requires i) big investment of more than 1 Billion USD, ii) technologies to handle Nepali specific natural condition such as earthquake, landslides, sedimentation management and/or GLOF and iii) possibly create severer environmental and social impact including inundated area of the reservoir as well as downstream riverine area.

Because of the magnitude of the development, sole GON or single institutional lender may not handle alone, therefore, private participation should be anticipated. GON also expects and encourages private sector involvement to hydropower developments in its policy statement (White Paper, for example; see Section 2.1.2) and laid down institutional system including tax incentives, standardization of PPA for foreign investment.

The VSPPPM is introduced in the next section for encouraging private participation. In this section, concerning points in the storage type hydropower development for enhancing private investment are discussed. Those points shall be also considered to apply the VSPPPM.

Two (2) major concerning points for enhancing private investment in storage type hydropower are;

1. Issues to apply current standardized PPA
2. PPA conditions taking storage operation into account

4.1 ISSUES TO APPLY CURRENT STANDARD PPA TO STORAGE HYDRO

4.1.1 Tariff Structure

In accordance with the ERC Bylaw announced in October 2019, tariff rate for hydropower project above 100MW is determined by cost base. The tariff rate can be referred to Schedule 5 in the ERC Bylaw.

Table 4.1-1 Schedule 5 of ERC Bylaw

3. The power purchase rate for the Reservoir Project fulfilling the conditions set out below shall be as state below. 3% simple escalation shall be adjusted annually for a maximum 8 times.
   a. Active Storage Volume of Reservoir Project shall not be less than the Volume corresponding to the design discharge of 15 days and dead Storage Volume shall be designed in a way that it does not get filled by the sediments, at lease for 50 years.
   b. The minimum energy of six months shall be 35% during the period of Mangsir 16 to Jestha 15.

Period	Purchase rate per unit (NPR/kWh)
Jestha 16- Mangsir 15 [May 29 or 30 – Nov 30 or Dec 1]	7.10 (If the electricity production during the wet season is increased by 50%, in comparison to the total annual production then, the wet season power purchase rate shall be deducted equivalent to the excess %)
(Mangsir 16- Jestha 15) [Dec 1 or 2 – May 28 or 29]	12.40

Section 8 sub-section 5 and sub-section 6 describe the tariff determination mechanism, it read:

8-5. Commission shall determine the power purchase rate for hydroelectricity projects above 100 megawatt pursuant to schedule 5 such that Return on Equity (ROE) shall not be more than 17%. However, it shall amend the power purchase rate by decreasing the power purchase rate if ROE seems to grow more than 17% pursuant to schedule 6.

8-6. For the determination of power purchase rate pursuant to sub-section 5, Electricity Seller shall make an application through Electricity Buyer to the Commission. Commission shall grant approval for power purchase rate on following basis:

a. Estimated cost of project,
b. Source of Loan and interest on loan,
c. Process of payment of principal and interest on loan,
d. Grants to be received on construction and operation,
e. Depreciation or advance depreciation,
f. Return on equity,
g. General expenses,
h. Operating expenses,
i . Repair and maintenance expenses,
j. Working expenses,
k. Revenue, tax and service charges
l. Additional Capitalization,
m. Loan and equity ratio,
n. Policy and regulations of Government of Nepal,
o. Any other basis as found reasonable by the Commission.

In case the ROE of the generation company exceed 17% (NPR base) in the operation stage, the unit price will be revised.

According to NERC, Section 8 sub-section 5 can be read that the Schedule 5 is only a reference for hydropower above 100MW (Tariff rate in Schedule 5 is applied to hydropower less than 100MW).

However, it implies that the tariff rate is only actual generation base. Considering that i) storage hydropower should be controlled by NEA (a system operator) and ii) annual fluctuation of hydrology gives vulnerable financial condition to the generator, fixed payment method should be applied to storage hydropower (See Section 4.2.4).

Note that the ERC Bylaw Schedule 5 is applied to hydropower project below 100MW and it mentions "3% simple escalation shall be adjusted annually for a maximum 8 times", therefore no escalation of tariff is allowed from 9^{th} year of COD. It is presumed that basically the tariff design policy does not consider the effects of inflation and the like.

4.1.2 Foreign Currency Payment Period

PPA Template (to be applicable ROR projects more than 100MW) of NEA stated foreign currency payment period should be less than 10 years. NERC and NEA informed to the Survey Team that ERC Bylaw prevail over PPA Template. Although it is not expressly stated in the ERC Bylaw, payment is made only by local currency according to NERC and NEA.

4.1.3 Foreign Exchange Risk Hedge

According to NERC, NEA, NRB and MoF, "Hedge Fund" described in PPA Template will not be established. They stated that together with cancellation of foreign currency payment, the developer should take foreign currency exchange risk and that the developer can utilize hedging mechanism prepared by the government by the Heading Regulation 2019.

Foreign currency exchange risk is generally taken by off-takers in the neighboring countries (See Section 3). This policy, therefore, makes foreign developers hesitate to invest in Nepal.

Hedging mechanism in the Hedging Regulation 2019 is summarized below:

1) Hedging mechanism is applied to foreign loan investment to Nepal for infrastructure projects such as hydropower (>100MW), transmission line (>30km, >220kVA), railway, express way (>50km), and other projects specified by GON,

2) Once foreign loan is disbursed, the project company deposit it to NRB,

3) NRB convert the foreign currency to local currency and deposit it to any banks in Nepal,

4) NRB issue a receipt (considered as a certificate) describing deposit date and amount,

5) The exchange rate is locked at the date of the foreign loan deposit,

6) The project developer can convert local currency to foreign currency at the locked exchange rate up to registered amount within 10 years for the date of deposit (valid duration may be extended).

According to NERC, the details including allocation of hedging fee and amount to be covered are under discussion among relating governmental agencies such as MoF, NRB and NERC.

It should be noted that in case the Hedging Regulation 2019 is applied, risk taken by the developer may increase than the Hedging Fund mechanism in the PPA Template because i) hedging covers only principal portion of foreign loan (interest during construction or during operation is not covered), ii) the developer has to take local currency devaluation risk until disbursement of the loan (risk cannot be fixed at PPA signing) and iii) hedging mechanism only cover 10 years from loan disbursement.

It should be also noted that 10-year hedging term automatically limits the loan repayment period to 10 years though it is the same condition in the PPA Template. If the repayment period is limited to 10 years, annual loan repayment amount becomes large and it will deteriorate equity return of the investors. The impact of the loan repayment period on equity return is evaluated by the cash flow model, and the results are described in Section 6.4.3 (2).

Figure 4.1-1 and Figure 4.1-2 illustrates the outline comparing the Hedge Fund and the Hedging Regulation 2019.

Note that the international lenders for IPP development based on project financing generally request to facilitate offshore accounts and utilize them for any USD based procedure such as disbursement of the loan or payment to the construction contractors. In the Hedging Regulation 2019, the developer is required to deposit foreign currency loan to an onshore bank account of NRB, which may be different procedure from general practice. Confirmation should be made whether transactions without passing the onshore bank account is entitled for hedging mechanism in the Hedging Regulation 2019.

Hedge Fund in PPA Template (2017)

- ✓ Exchange rate is locked at PPA singing.
- ✓ Foreign currency payment is made for maximum 10 years after COD.
- ✓ Foreign currency payment portion (%) is determined by Debt/Equity Ratio at COD＊.
- ✓ Hedge cost is shared by GON, NEA and Project Company.

Hedging Regulation 2075 (2019)

- ✓ Applied to infrastructure projects including hydropower project more than 100MW.
- ✓ Upon approval by GON, exchange rate of foreign currency loan deposited in NRB is locked for 10 years (5 years extension may be approved)

	Hedge Fund in PPA Template	***Hedging Regulation***
Fx Rate Fix timing:	PPA signing	Each disbursement of loan
Hedge Amount:	Principal + IDC + α*	Principal
Term:	COD+10 years	Each disbursement + 10 years
Hedge Cost	Shared by GON, NEA, SPC	[Not determined]

Figure 4.1-1 Hedging Mechanism Comparison between Hedging Regulation and Hedge Fund (1)

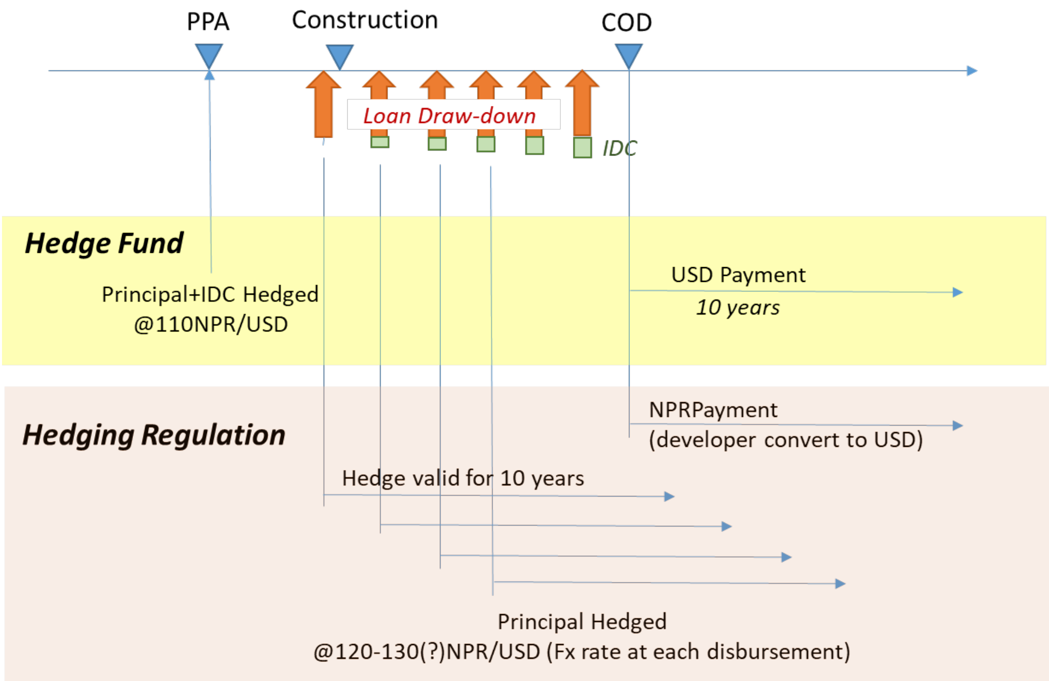


Figure 4.1-2 Hedging Mechanism Comparison between Hedging Regulation and Hedge Fund (2)

4.2 PPA STRUCTURE TAKING RESERVOIR OPERATION INTO ACCOUNT

4.2.1 Reservoir Operation Procedure

Variation of river discharge and power demand are mutually independent through the year. Generally in Nepal, river discharge is low during dry season (December to May) and high during wet season (June to November). Generation for ROR type hydropower plants varies in accordance with river discharge while storage type hydropower plants have an ability to regulate the generation annually or seasonally by utilizing big capacity of reservoir. Reservoir operation model shown in Figure 4.2-1 indicates that;

- During wet season, incoming flow is impounded in the reservoir so that the reservoir level reach to Full Supply Level (**FSL**). In case weather forecast indicate lower discharge during a wet season than average, impounding should be priority to generation. In case reservoir level reaches FSL, incoming discharge is utilized to generation as much as possible.

- During dry season, impounded water is utilized for generation until the reservoir level touches Lowest Operation Level (**LOL**).

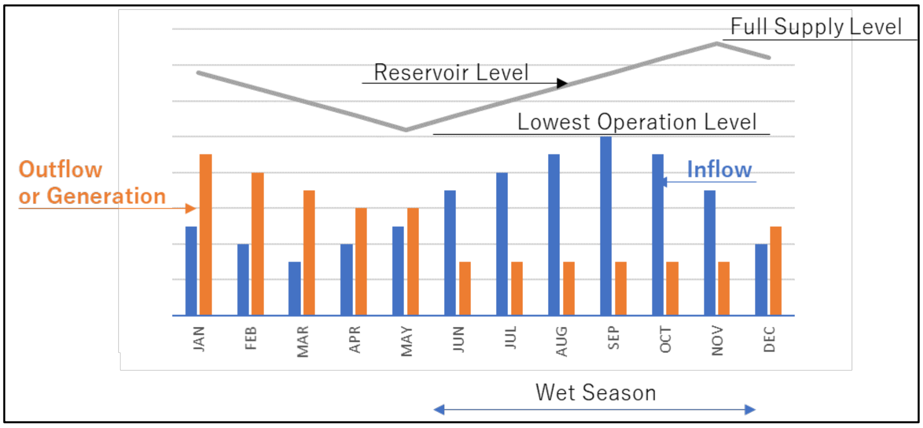


Figure 4.2-1 Basic Operation of Storage Type Hydropower

The reservoir operation above bring a certain benefit for downstream river use because of increase of river discharge during dry season.

As the bigger reservoir can impound more river discharge during wet season, it can generate more electricity during dry season. However, the bigger reservoir requires higher dam and leads higher cost and severer impact on environmental and social conditions.

According to the designated tariff structure regulated by the ERC Bylaw (Table 4.1-1), hydropower plants which can generate more than 35% of the annual generation during dry season are categorized as storage type hydropower plants.

As the impounded water can be utilized for generation regardless the river discharge, storage type hydropower plants give flexible capability to Nepal power system as base load and peak load suppliers. Even during wet season, the storage hydropower can follow sudden demand change by adjusting generation within minutes and stable the power system. In addition to this function, the adjustment capability of storage hydropower plants can contribute system stability when solar power and/or wind power, both of which cannot control generation, are introduced.

4.2.2 Reservoir Operation for Generation

Reservoir operation is divided into three (3) parts, namely i) impounding and release operation through hydraulic turbine (energy generation) ii) releasing impounded water for the purpose of environmental protection (environmental flow) and iii) emergency operation during flood, severe earthquake, sedimentation management and/or other occasions to keep dam and reservoir in safe and sound condition. The first operation is controlled by means of valves or gates (wicket gates, typically) and the second and third operation is done by either release gate or valve, spillway of the dam (in case dam is equipped with spillway gates, it is manipulated by the gates), sediment flushing gates and/or release valve or gates in the dam (called low level outlet or bottom outlet).

In this Section, the first operation (generation operation) is discussed.

In order to maximize benefit of storage type hydropower, system operator should handle fully reservoir and plant operation. In the case of IPP projects, which means generator is different from the system operator, following procedures should be necessary to coordinate between the generator (generation company) and the system operator (NEA).

1) Meteorological monitoring stations situated upstream of the reservoir, reservoir level monitoring system, data transmittal system and if necessary, water level monitoring station adjacent to the upstream end of the reservoir shall be equipped before commissioning. Responsibility sharing of installation and operation of those between the generation company and system operator (NEA) has to be defined in the PPA.

2) Before commissioning, the generation company submit to NEA a rule curve describing target reservoir level to maximize energy generation through the year taking historical hydrology into account. The generation company and NEA should agree and establish the rule curve. In case multi-purpose dam, other responsible governmental agencies should be involved to materialize other purposes e.g., flood control and/or irrigation.

3) At the beginning of each year during operation period, NEA shall establish monthly operation target describing target reservoir level of each month or day taking long-term weather forecast, demand forecast, availability of other generation plants (including regular maintenance plan) into account and notify it to the generation company. The annual/monthly operation target shall be re-considered periodically.

4) At the beginning of each month and week, NEA shall establish monthly and weekly operation target and notify it to the generation company. Monthly/weekly operation plan are established considering actual water level of the reservoir, detailed weather forecast, demand forecast, availability of other generation plants and transmission line congestion.

5) The generation company report to NEA constantly hourly data of incoming flow, outflow consisting of generation and environmental flow, generation, reservoir level and other necessary data for NEA to determine daily/hourly dispatch instructions.

6) NEA shall instruct to the generation company a dispatch instruction during designated period (day, hour, minute etc.).

The operation procedure concept above shall not apply to emergency situation including flood operation. As high dams have severe impact on riverine environment and residents in downstream area, emergency operation procedure shall be established among GON, local government units, NEA and the generation company for the purpose of keeping dam safety. Responsibility of emergency operation entailing spillway gates operation lies with the dam operator[9] under supervision of GON and shall be defined in relevant contractual documents including PDA and PPA.

4.2.3 Study of Applying Standard Tariff

In order to evaluate fluctuation of revenue when the Standard Tariff (Section 4.1.1) is applied, a reservoir routine simulation is made with 22-years hydrological data for a certain storage hydropower project. Annual generation of this 22-year period is calculated and annual revenue is estimated by applying the Standard Tariff as shown in Figure 4.2-2 (for simplified reason, tariff escalation is not considered). Annual revenue fluctuate from 62 MUSD to 158 MUSD, monthly revenue fluctuate from 3.4 MUSD to 28.6 MUSD. Average annual revenue for these 22 years is estimated 114 MUSD.

For the purpose of maximizing the function of storage type hydropower plants, it is essential that NEA, as an off-taker and a system operator, should plan the most efficient reservoir operation based on annual, monthly, weekly or daily rainfall forecast, demand forecast and generation capacity of other plants (schedule) and instruct the dispatch to the generation company. In such case, dispatch instruction of NEA considering long-term or short-term weather/demand forecast may impact stable revenue flow of the generation company. For example, in case NEA forecasts severe draught year at forthcoming dry season, NEA may want to store inflow during wet season without generation. In case generation is required during wet season for some reasons, NEA instruct generation and planned impoundment may not be achieved, which deteriorate generation capability during dry season.

Although operation of storage hydropower plants by NEA based on demand-supply balance and rainfall forecast could be the most efficient measure to maximize the function of storage hydropower, payment based on generation makes the financial status of the generation company vulnerable. Loan provider may consider it a risk factor for storage type hydropower development by private investor.

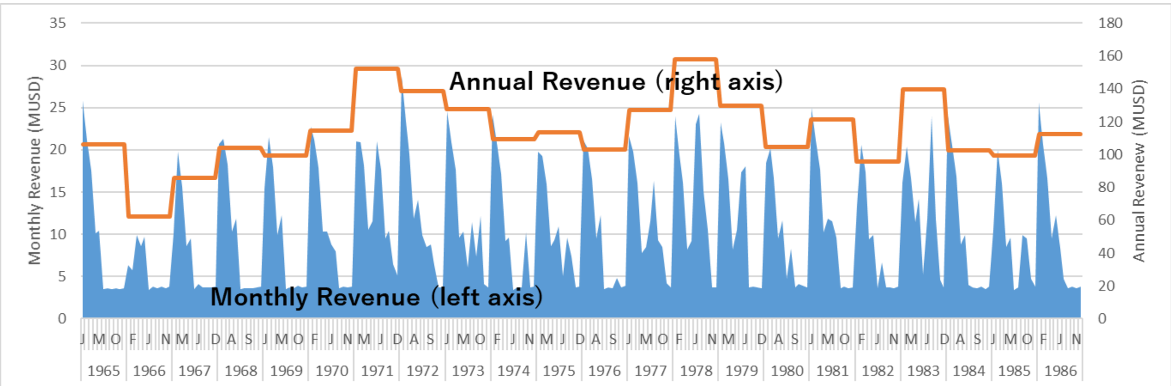


Figure 4.2-2 Revenue Flow Estimated by Reservoir Routine Simulation

9 In case of conventional IPP, a dam operator means the generation company. In case of the Vertical Separation PPP Modality, it means the dam company. See Section 5.3.

4.2.4 Proposal of New Tariff Scheme

Considering factors that i) reservoir operation shall be fully controlled by a system operator (NEA) in order to maximize the benefit of storage hydropower plants taking system demand and supply balance into account and ii) hydrological fluctuation makes generation company’s financial status vulnerable, a new tariff structure for storage hydropower is proposed.

Standard Tariff structure defines payment from NEA to the generation company is based on the actual generation (Energy Payment). With the Energy Payment structure, the generation company would try to maximize generation regardless the system demand/supply balance and annual reservoir operation plan. Energy Payment structure can also be considered a risk factor for stable revenue flow of the generation company when it applies to storage type hydropower development by private sector participation. If private investor and loan provider requires stable revenue flow under Energy Payment structure, NEA is required to guaranty a certain amount of generation with sacrificing demand-supply adjustment capability of the storage plants.

A fixed payment (Capacity Payment) structure is recommended for solving those concerns. Capacity Payment structure is that a certain amount of payment is guaranteed regardless the actual generation amount. This concept can be a solution for both maximizing storage hydropower benefit and stabilizing revenue flow of private investor.

Capacity Payment structure can be also considered a power purchase scheme that supports the abilities of storage type hydropower plants, which supply ancillary services, such as frequency adjustment, voltage adjustment and black start. Those abilities cannot be measured by kWh output.

Basic concept of the Capacity Payment is that the payment is made based on the availability of the storage hydropower plant. The generation company is obliged to keep the plant available at certain capacity (e.g., dependable capacity, MW) at any designated time of the year except approved scheduled maintenance. Designated time may be considered as peaking hours of the day (e.g., 4 to 6 hours of any weekdays through the year).

In order to keep stable operation of the plant, the generation company is required to be paid for minimum disbursement for O&M cost (for O&M personnel etc.) and for repayment of loan in terms of monthly and quarterly. Amount of the Capacity Payment shall be discussed at least to cover those minimum cost.

The ratio of the Capacity Payment and Energy Payment shall be discussed among NEA, generation company and loan provider considering characteristics of the project.

SECTION 5 PROPOSAL OF VSPPPM

PPA structure to accelerate storage hydro development by private participation have been discussed in the previous section. In some cases, because of the huge initial investment requirement, economics of the project are still not meet the investment criteria for private sector as well as lenders. JICA proposes a new PPP scheme, a Vertical Separation PPP Modality (VSPPPM).

5.1 BASIC CONCEPT OF VSPPPM

In the proposed VSPPPM, dam construction, which is normally share a big portion of total development cost, is supported by an ODA Loan, for example, Yen Loan. Favorable finance condition of the ODA Loan could reduce the financing cost of the project. As the ODA Loan is supplied through Ministry of Finance of GON, the dam construction is separated from construction of power related facilities and implemented by a governmental entity or government-funded private company. Dam is constructed, operated and maintained by such company (Dam Co). Generation facilities, from intake, powerhouse to outlet, are constructed and operated by a SPC (or Gen Co) formulated by private investors by utilizing impounded water behind the dam. Gen Co arrange project finance from commercial lenders and financial institutions for construction of power related facilities. Gen Co sell the energy to NEA and obtain payment under PPA. Some "Dam Lease Fee" have to be paid from Gen Co to Dam Co, which is a source of the repayment of ODA loan. Figure 5.1-1 illustrate the concept of this VSPPPM.

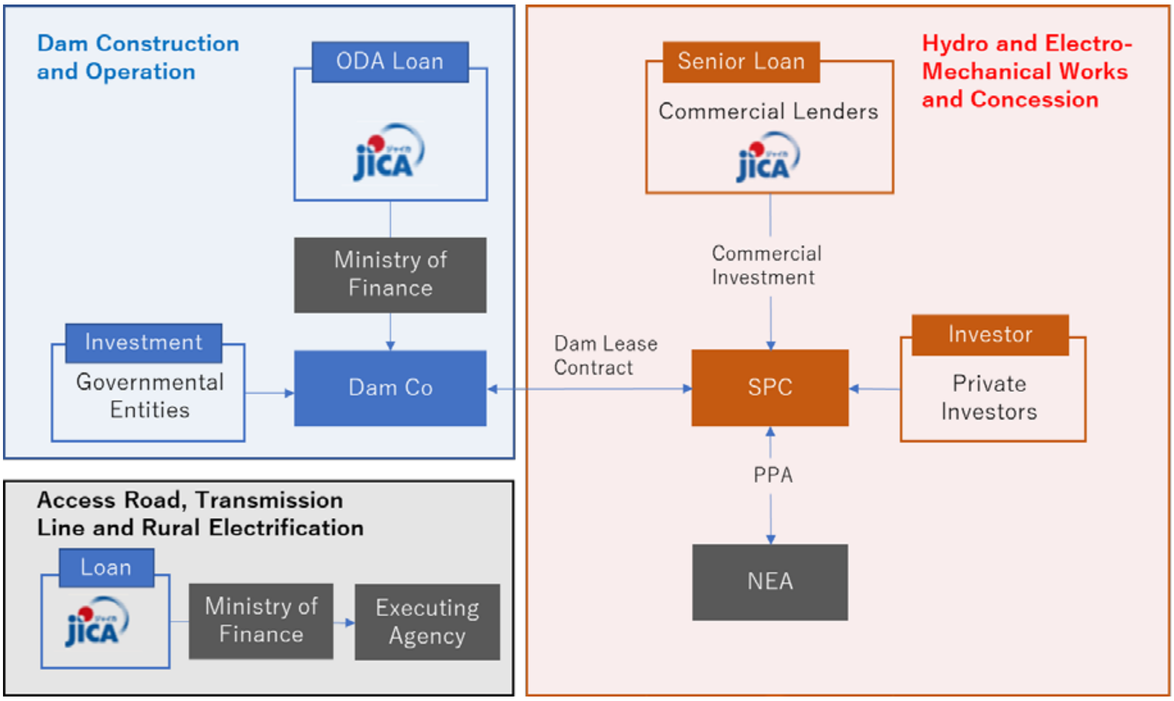


Figure 5.1-1 VSPPPM Concept

5.2 LEGAL POSITION OF THE VSPPPM

Conventional IPP structure is that the generation company acquires the Generation License and construct/operate generation facilities including a dam or weir. In the VSPPPM, Gen Co obtains the Generation License as well, however, legal position of the Dam Co is not clear under the Electricity Act. Section 3 of the Electricity Act requires any entity who wish to render a business of generation, transmission or distribution to generation, transmission or distribution license, respectively, but the one license is granted to one entity. Since Gen Co have to obtain and maintain the generation license under the PPA with NEA, the question is that under which license the Dam Co render its business. Section 8 of the Water Resources Act states that an entity is required to obtain a water utilization license for the utilization of water resources by submitting an application to the Water Resources Committee, but Section 9 of the Water Resources Act provides that the licenses relating to water utilization for generation of hydroelectricity must be governed by the laws relating to hydropower (i.e. the Electricity Act). As the purpose of the dam under VSPPPM is for generation, concession right under the Water Resource Act may not be applied.

According to the legal advisor of the Survey Team, it is recommended to apply Section 35 of the Electricity Act to clarify the legal position of the VSPPPM. Section 35 provides that irrespective of the other provisions of the Electricity Act, the government may, by agreement with any person or organization, develop or cause the development of energy generation, transmission or distribution in accordance with the terms set out in the applicable contract. Accordingly, Gen Co render its business by obtaining the generation license under Section 3 of the Electricity Act while Dam Co's business is authorized by Section 35 by obtaining the special license

Legal position of each entity is recommended to be confirmed in the PDA subject to governmental decision.

5.3 RESPONSIBILITY SHARING AMONG PARTIES

Responsibilities for implementing hydropower development among concerned parties are currently determined in the contractual structure, such as PDA and PPA. For applying VSPPPM, responsibility sharing including an additional player, Dam Co, has to be defined in the contractual structure.

As the Dam Co and Gen Co should coordinate construct and operate its facilities under VSPPPM, it is necessary that the Dam Co is identified and commit its performance at the PDA stage, when Gen Co is granted the exclusive development right from the government. It is therefore recommended to conclude PDA among GON, Dam Co and Gen Co. In addition to granting the development right to Gen Co, PDA also grant the development right to Dam Co and responsibilities of Dam Co shall be defined.

Agreement of the development schedule is also stated in the PDA as responsibility of each party. As the responsibilities of construction schedule for dam and power facilities of Dam Co and Gen Co are defined in the Dam Lease Contract, each contract should define detailed agreed schedule and any actions in case of delay under VSPPPM. Responsibilities of each party to keep agreed schedule are defined in the PDA, PPA and Dam Lease Contract. In order to obtain licenses/permits at an appropriate time, the cooperation of the government as well as the efforts of the Dam Co and Gen Co is essential. For this reason, it is desirable that the cooperation of related governmental authorities should be stated in the PDA as a governmental obligation, e.g., avoiding unreasonable or unnecessary requests, proper management of permitting process by authorized agency.

Since storage type hydropower plants requires big capacity of reservoir for regulate the river flow through dry season and wet season, generally it requires a high dam that impacts heavily on natural environment. Keeping dam safety in case of abnormal whether condition or natural disaster is foremost important to prevent adverse impact on downstream area due to the big size of the dam. “Dam Safety” includes not only appropriate design and construction but also emergency preparedness plan such as notification, warning and/or evacuation plan at downstream area as defined in the World Bank Operational Procedure 4.37. Though the Dam Co should take principal responsibility for the Dam Safety, it is necessary to coordinate with local government or state government on, for example, notification or warning at downstream area of dam gates operation during flooding. Roles and responsibilities of government for Dam Safety should be defined in the PDA.

Power generation can be done by cooperation of Dam Co and Gen Co under VSPPPM. In case the conventional power purchase system between Gen Co and NEA (an off-taker) is defined in the PPA, in which Gen Co takes responsibilities on operation and generation while NEA is obliged to purchase generated energy at the agreed pricing, the Gen Co principally takes responsibility of construction and operation including dam. Responsibility sharing between Gen Co and Dam Co is defined in the Dam Lease Contract. Responsibility relating to the dam undertook by Gen Co under PPA should pass through to Dam Co in the Dam Lease Contract.

PPA is concluded between NEA and Gen Co. PPA for storage type hydropower should include particular clauses for its characteristics. A reservoir operation rule (dispatch instruction by NEA as stated in Section 4.2) is one of the peculiar clause. Another peculiar clause in the PPA is the procedure for keeping Dam Safety stated above, for which responsibility sharing should be defined as it impacts on dam gates operation and/or reservoir operation. Specifically, NEA hand over reservoir operation responsibility to Dam Co at the emergency situation (with definition) when special operation of the dam to keep Dam Safety is required. NEA also accept any impact on power generation operation and release obligation of Gen Co as a result of emergency operation for keeping public safety at downstream area. For example, if reservoir operation to attenuate flood peak results in lowering the reservoir level from schedule and decreasing annual generation, NEA should accept the reduced annual generation. In case such emergency operation causes deduction of annual income of Gen Co in PPA structure, Gen Co is entitled to compensation from NEA or GON because Gen Co sacrifice its revenue for the purpose of keeping public safety at the emergency situation. If GON compensate such loss of income, it should be stated as GON’s responsibility in the PDA.

The Dam Lease Contract is an agreement between Dam Co and Gen Co. It should define responsible facilities of construction and operation for each party, exclusive right to utilized impounded water for generation purpose by Gen Co except emergency situation and the Dam Lease Fee as a compensation paid by Gen Co to Dam Co.

Since VSPPPM is made on the premise of the ODA loan and commercial loan based on project finance arranged by Gen Co, attention should be taken to loan agreements. For example, in case the emergency operation stated above result in loss of revenue of Gen Co, it impact on loan repayment of Gen Co and also ODA loan repayment of Dam Co through Dam Lease Fee. Such emergency situation should be recognized as a Force Majeure event in the loan agreements.

In order to respond to these concerns and maximize benefit of VSPPPM, some kind of agreements may be required among the GON, NEA, Dam Co, and Gen Co. PDA may be agreed by four parties including NEA, however, the current PDA requires the SPC (Gen Co) to enter into PPA after the PDA is signed. A tripartite agreement among NEA, Dam Co and Gen Co after signing of PDA and before signing of PPA, or more preferably, multipartite agreements including GON shall be considered necessary. Involvement of the lenders like Direct Contracts may be discussed considering ODA loan also.

Contracts are signed in the following order:

1. PDA
2. PPA and Dam Lease Agreement
3. ODA loan agreement, loan agreement between GON and Dam Co, loan agreement between Gen Co and commercial lenders.

PDA shall be made effective by confirming related contracts such as Dam Lease Contract, PPA and/or Wheeling Charge Contract for the development of the storage type hydropower project since those related contracts are also requirement of the loan agreements. High possibility of agreement of those contracts has to be confirmed at the signing of PDA. In particular, the Dam Lease Contract that stipulates the responsibility sharing, roles, rights and obligations of Dam Co and Gen Co is closely related to business development rights granted to Dam Co and Gen Co by the PDA. Principles of Dam Lease Contract as well as PPA should be agreed before PDA.

5.4 CONTRACTUAL STRUCTURE OF VSPPPM

Responsibility sharing mechanism under VSPPPM discussed in the previous section is proposed in Annex 2 of this report. Basic concept is introduced in this section.

5.4.1 Responsibility Sharing in PDA

PDA includes definitions and responsibility sharing.

- ***Identification of Dam Co and Gen Co***

  Dam Co may be subject to certain restrictions because the funding supported by the ODA Loan.

- ***Development rights by the government***

  GON grant development rights to Dam Co and Gen Co.

- ***Concession right by the government***

  GON grant concession right to Dam Co and Gen Co for a certain period.

- ***Water use right by the government***

  GON grant exclusive water use right to Dam Co and Gen Co

- ***Governmental Guarantee***

  GON guarantee performances of NEA under the PPA and of Dam Co under the Dam Lease Contact

- ***Application of ODA loan***

  GON commit application of the ODA loans to Dam Co.

- ***Setting the principle of sharing roles***

  Dam Co and Gen Co will conclude a Dam Lease Contract with the consent of GON including the followings.

  - Dam leasing to Gen Co by Dam Co,
  - Payment for the service by Gen Co to Dam Co

  In addition, it is necessary to determine the sharing roles between Dam Co and Gen Co for the purpose of safety measures and/or compensating the deteriorating efficiency caused by applying VSPPPM.

- ***Cooperation between PPA and Dam Lease Contract***

  The PPA that Gen Co will conclude with NEA as an off-taker shall be based on a Dam Lease Contract.

- ***Dam Safety***

  Procedure and responsibility sharing for keeping the Dam Safety.

- ***Regulations concerning licenses***

  Depending on the government judgment, there is a possibility that each Dam Co and Gen Co will be required to obtain similar licenses. Therefore, an agreement within the government is necessary to avoid unnecessary duplication. (Example: permission for environmental protection measures, permission for road construction).

- ***Tax system, preferential treatment***

  Incentives for income tax and customs duties given to Gen Co to promote power development should be given to Dam Co as well. Dam lease fee defined in the Dam Lease Contract should not be subject to VAT or any other taxation.

The same shall apply to consignment contracts that may be concluded between Dam Co and Gen Co from the viewpoints of safety management and efficiency.

Contracts between Dam and Gen Co may be;

- ✓ Sub-contract from Dam Co to Gen Co for the construction of the dam
- ✓ Sub-contract from Gen Co to Dam Co to render environmental protection measures for power plant construction.
- ✓ Sharing alarm devices and mutual consignment of equipment inspection.

- ***Royalty***

  Royalty paid by Gen Co to GON as a consideration for the power generation business right has a meaning as consideration for the dam business right as well. In other words, the government should not apply another royalty for the dam business right.

  Responsibilities of each party are tabulated below:

<u>Nepal Government</u>

Particular clauses for VSPPPM are indicated with underline.

a. <u>Arrangement of the ODA loan in accordance with agreed schedule</u>
b. Granting concessional business right to Gen Co during concession period
c. <u>Granting concessional business right to Dam Co during concession period (concession period may be the same of the ODA loan)</u>
d. <u>Granting special license to Dam Co under Electricity Act section 35</u>
e. Approval of dam safety procedure, supervision on Dam Co (Note: this clause should be included for projects involving big dam like storage type hydropower, not only specific clause for VSPPPM)
f. Granting exclusive water use right to Dam Co and Gen Go
g. Governmental Guarantee on performance of NEA under PPA and of <u>Dam Co under Dam Lease Contract</u>
h. Provision of governmental land (lease contract)
i. Cooperation of land acquisition of private land
j. Tax, Royalty
k. Guarantee of no-nationalization, repatriation
l. Cooperation of obtaining permits by Gen Co and Dam Co (Note: IBN is responsible as a single agency for hydropower projects above 200MW)
m. Compensation by GON due to Force Majeure, Default and Termination

<u>Dam Co</u>

a. Financing arrangement as per agreed schedule
b. Obtaining license for dam construction and operation
c. Obtaining necessary permits
d. Land acquisition, land lease contracts
e. Design and construction of dam and related facilities
f. Dam Safety
g. Release of environmental flow
h. Compensation by Dam Co due to Force Majeure, Default and Termination

<u>Gen Co</u>

a. Financing arrangement as per agreed schedule
b. Obtaining license for generation and transmission
c. Obtaining necessary permits
d. Land acquisition, land lease contracts
e. Concluding PPA with NEA
f. Design and construction of power related facilities
g. Compensation by Gen Co due to Force Majeure, Default and Termination

5.4.2 Responsibility Sharing in PPA

Responsibilities of each party are referred to the PPA Template and particular clauses for storage type hydropower are proposed. Penalty clauses will also be included.

NEA

a. Acknowledgement of Dam Lease Contract and Dam Co's obligation

b. Agreement of annual rule curve (annual operation rule)

c. Dispatch instruction except emergency situation

d. Purchase of generated energy at the designated unit price (Note: Payment structure is assumed to be Capacity Payment + Energy Payment. See Section 4.2.4. Take-or-pay clause is not necessary since generation is operated following dispatch instruction of NEA)

e. Construction and operation of energy receiving facilities as per agreed schedule

f. Energy purchase obligation during commissioning by agreed pricing

g. Dam operation procedure during emergency situation for securing dam safety and release Gen Co's obligation as consequences of emergency operation.

Gen Co

a. Financing arrangement as per agreed schedule

b. Design, construction, commissioning, completion as per agreed schedule

c. Performance guarantee

d. Keeping dependable capacity except agreed outage schedule (Note: based on Capacity Payment structure, see Section 4.2.4)

5.4.3 Basic Concept of Dam Lease Contract

Dam Co and Gen enter into a Dam Lease Contract to share responsibilities during preparation, construction and operation phases of the project. Some of the responsibilities may be better to be shared among GON, Dam Co, Gen Co and/or NEA and stated in PDA and/or PPA as previously discussed.

In this section, on the premises of that the responsibility sharing mechanism is defined in the contractual structure, outline of the Dam Lease Agreement is discussed. Involvement of government and/or NEA, if necessary, is also stated at each item.

Main purpose of the Dam Lease Contract is to ensure that the Dam Co lease the dam (or one function of the dam) and the Gen Co pays a fee for utilizing the dam and to secure stable and rational operation of the dam-power facility system.

The Dam Lease Contract is classified by three (3) stages, i.e., preparation stage, construction stage, and operation stage. In each period, responsibility sharing, cooperation obligation, schedule arrangement, measures and procedures etc. between Dam Co and Gen Co for both normal operation and emergencies shall be specified.

Generally, the ability of performing contractual obligation relies on the credibility of the contracting parties, but Dam Co and Gen Co are assumed to have poor credit, including financial position. Therefore, in order to make the Dam Lease Contract effective, Dam Co and Gen Co have to prove that the various contracts and approvals have been obtained or to be surely obtained. The ability to perform its obligation for project development and/or operation is secured by such facts. It is also required for proving credibility in the loan agreements. These points are also taken into account in the provisions of the Dam Lease Contract.

A draft outline of the Dam Lease Contract is annexed to this report, which explains the main items that are considered necessary at each development, construction and operation stage. The contents of the draft outline are summarized as follows.

(1) Finance Arrangement

Required funding by means of financing etc. shall be arranged at the appropriate timing for both Dam Co and Gen Co. Dam Co is responsible for arranging ODA loan between GON and donor country, arranging loan agreement between GON and Dam Co and arranging equity injection in accordance with agreed schedule (responsibility of GON is defined in the PDA). Gen Co is as well responsible to arrange financing and equity as per the agreed schedule.

(2) Safety

Generally, each party shall be responsible for securing safety for its facilities in possession or in operational arrangement. Procedures for cooperative actions and roles/responsibilities should be defined such as data exchange of monitoring or common use of alarm facilities for the purpose of securing safety operation.

For example, Dam Co is responsible for dam and related facilities, such as i) dam design for securing safety against expected earthquake, flooding and/or GLOF, ii) quality assurance during construction of the dam, iii) supervision and monitoring during construction and operation, iv) procedure of initial impoundment and v) emergency action plan for keeping Dam Safety. It is recommended that government establish an institutional system to keep and supervise the Dam Safety for preventing artificial disaster due to dam failure (responsibility of GON is defined in the PDA).

(3) Responsibility on Environment and Social

Each party is responsible for performing environmental and social management plan defined in the Environmental Impact Assessment (**EIA**) as per conditions of the environmental permit. Any activities which requires coordination such as funding for impact mitigating measures should be clarified and roles and responsibilities of each party should be defined.

For example, Dam Co is responsible relating to EIA for construction and operation of dam and related facility.

It is recommended that the EIA survey, monitoring and management common to both dam and power facilities be united and one party be responsible

Responsibility of GON relating to EIA is defined in the PDA.

(4) Land Acquisition

Acquisition of required land (or land use right) for each facility is responsibility of each party unless joint acquisition is allowed or preferred. Common land should be defined in the Dam Lease Contract and roles and responsibility of each party should be also defined.

Land lease of governmental land is defined in the PDA.
In case expropriation is required, GON should be responsible under agreement in the PDA.

(5) Specification and Design

In principle, each party is responsible for determining required function, specification and design criteria for each facility according to facility in possession or operational arrangement. Procedures for cooperative actions and roles/responsibilities should be defined such as data transmittal, interface, data format etc.

(6) Cooperation during Construction

In principle, each party is responsible to keep construction schedule for responsible facilities. Common facilities including access road should be defined and cooperative arrangement for construction and operation should be stated.

Incentives on legal and/or tax system (e.g., VAT exemption) may be applied in the PDA. In such case, it is worth considering for Dam Co to sub-contract dam construction to Gen Co so that single entity can manage the construction.

(7) Construction Schedule

In principle, each party is responsible for managing construction schedule for its facility in possession.

In case Dam Co failed to complete its facilities by scheduled completion date, Dam Co shall be obliged to pay compensation in accordance with the Dam Lease Contract while Gen Co is obliged to pay liquidated damage defined in the PPA. Pass-through mechanism is required between PPA and Dam Lease Contract on this matter.

On the other hand, in case Gen Co failed to complete its facility by schedule completion date, Gen Co is obliged to pay Dam Lease Fee under Dam Lease Contract and also obliged to pay penalty to NEA under PPA.

(8) Operational Procedure

Detailed operational plan and procedure, timing of operational adjustment or determination etc. should be defined in the Dam Lease Contract and also in PPA. It is recommended that the tripartite agreement among NEA, Dam Co and Gen Co, or multipartite agreement including GON be agreed for detailed operational procedure. Operational procedure should include revision of agreed plan and/or procedure for failed operation. Major items are tabulated below. Note that the procedure of schedule/unscheduled outage of the transmission line (including third party) is omitted.

a. Annual Rule Curve

(Example) Annual rule curve is established by NEA (PPA) and discussed between Dam Co and Gen Co. Dam Co and Gen Co shall propose revisions (if any) to NEA and three parties determine the detailed annual rule curve.

b. Operation Plan

(Example) Dam Co and Gen Co jointly submit annual/monthly/weekly operation plan to NEA considering regular inspection and maintenance schedule. Upon approval of NEA, both facilities are operated following approved plan unless change of circumstances (meteorological, geotechnical) or unscheduled outage. Revised schedule according to monitoring range or standard working duration shall be differentiated from unscheduled outage.

c. Monitoring and Supervisory Data

(Example) Dam Co is responsible for installing meteorological and hydrological monitoring stations, reservoir level gauge and data transmittal system. Acquired data shall be reported to Gen Co according to agreed contents, timeframe and format. Gen Co shall report them to NEA.

d. Dispatch Instruction

(Example) NEA instructs hourly dispatch to Gen Co and Gen Co shall operate the power facilities following NEA's instruction. Procedure of dispatch instruction is defined in the PPA. Gen Co shall notify the dispatch plan and actual operation to Dam Co.

e. Emergency Procedure

(Example) Dam Co is responsible for dam operation during emergency situation such as flooding, earthquake and/or failure of equipment. Dam Co is also responsible for establishing dam safety plan or emergency preparedness plan which includes information dissemination to downstream, flood warning, evacuation plan before initial impoundment and obtaining consent from regional government, central government, NEA and Gen Co. Items requiring coordination with Gen Co should be defined in the Dam Lease Agreement and roles/ responsibilities shall be agreed.

f. Periodical Inspection/Maintenance Report

(Example) Dam Co is responsible for reporting dam maintenance plan and inspection result etc., which may impact on power generation to Gen Co and NEA.

(9) Permits and licenses for project development

In order to conduct construction and operation of the dam and power generation facilities (including relating switching station and transmission lines), it is essential to obtain required permits and land acquisition. Omissions and delays related to permits and land acquisitions have a significant impact on the overall project schedule.

Therefore, it is necessary for both parties to confirm the preconditions for enabling project implementation.

(10) Agreement of design (required functions, specifications)

The required functions that a party provide to the other and specifications of equipment shall be agreed by both parties for preventing any problems during construction and operation stages.

(11) Agreement of schedule (construction, commissioning, commercial operation)

Storage type hydropower can be operated by facilitating both dam and power generation facilities. In case the construction schedule is delayed and the expected COD cannot be achieved, it will affect not only the project implementation or economics of both parties, but also off-taker and lenders. It is necessary to agree the construction schedule by both parties when signing the contract.

(12) Demarcation of responsible facilities

Some problem or malfunction of the equipment of a party may affect another party. A mechanism of compensation by affecting party for such cases shall be agreed including consideration of funds. Accordingly, demarcation of responsible facilities or equipment of Dam Co and Gen Co shall be agreed as well as defining contractual obligation to construct and operate such facilities. It should be noted that this demarcation of facilities or equipment may differ during construction stage and during operation stage.

(13) Dam lease fee

Dam lease fee that Gen Co pays to Dam Co for utilization of function of the dam is specified. The provisions include “Dam Lease Fee Calculation Method”, “Target Period”, “Unit Price”, “Payment Currency”, “Billing Method”, “Payment Method”, and “Payment Date”. In addition to these, adjustment and/or compensation method is stated in case electricity sales of Gen Co decrease, which will be the source of payment for dam lease fee.

(14) Liquidated Damage (completion date, performance guarantee, compensation method)

Any problems which fall in a party’s responsibility and trigger damages to another party are clarified and compensation method for damages is specified. The contents of Liquidated Damage (**LD**) shall be established taking LD clauses in the PPA into account..

(15) Force Majeure

Force Majeure events are defined as situations beyond the control of a party, whether directly or indirectly, and are outside the performance obligations of the party. Force Majeure events in the Dam Lease Contract should be aligned with the same in the PDA, PPA and loan agreement of both parties.

(16) Trial operation plan

Trial operation plan of the dam to confirm the function of equipment, check items and test procedures are specified.

(17) Proper maintenance of equipment

Both parties shall formulate and execute a periodic inspection plan and maintenance plan. Each party is obliged to keep its facilities properly maintained and secured to ensure their functions.

(18) Shared facilities used by Dam Co and Gen Co

Shared facilities and their owners (managers) are specified. In addition, it will stipulate how to deal with problems in shared facilities and how to share expenses associated with repairs.

(19) Reservoir operation plan (annually, monthly, repair and maintenance plan)

The power generation plan is prepared by Gen Co and submitted to NEA for approval, which is an off-taker as well as a system operator. The basis of this power generation plan is the reservoir operation plan. Dam Co and Gen Co shall discuss and establish a reservoir operation plan which also needs NEA's consent. The reservoir operation plan is reviewed at a certain frequency based on rainfall and power demand forecast among NEA, Gen Co and Dam Co. The reservoir operation plan also specify procedures for revision and necessary data for review taking regular inspection and/or maintenance schedule into account.

5.5 Risk Sharing Mechanism and Risk Matrix

Risk sharing mechanism described in the previous section and contents of each contract is illustrated below.

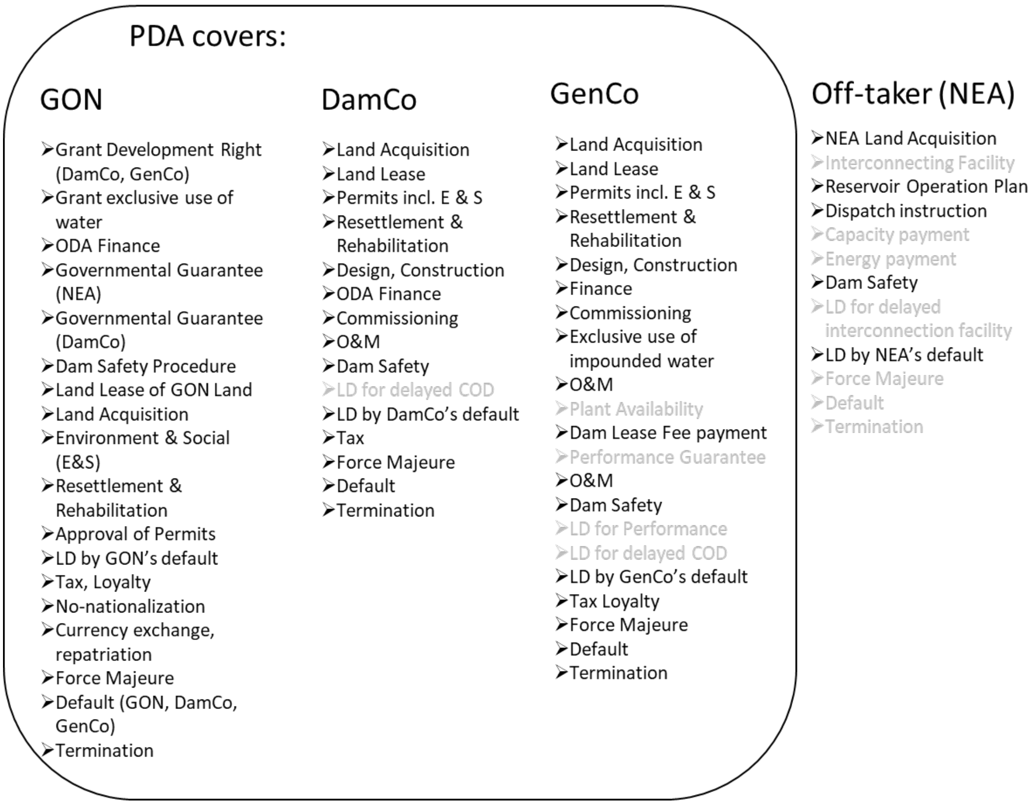


Figure 5.5-1 Risk Sharing Contents in PDA

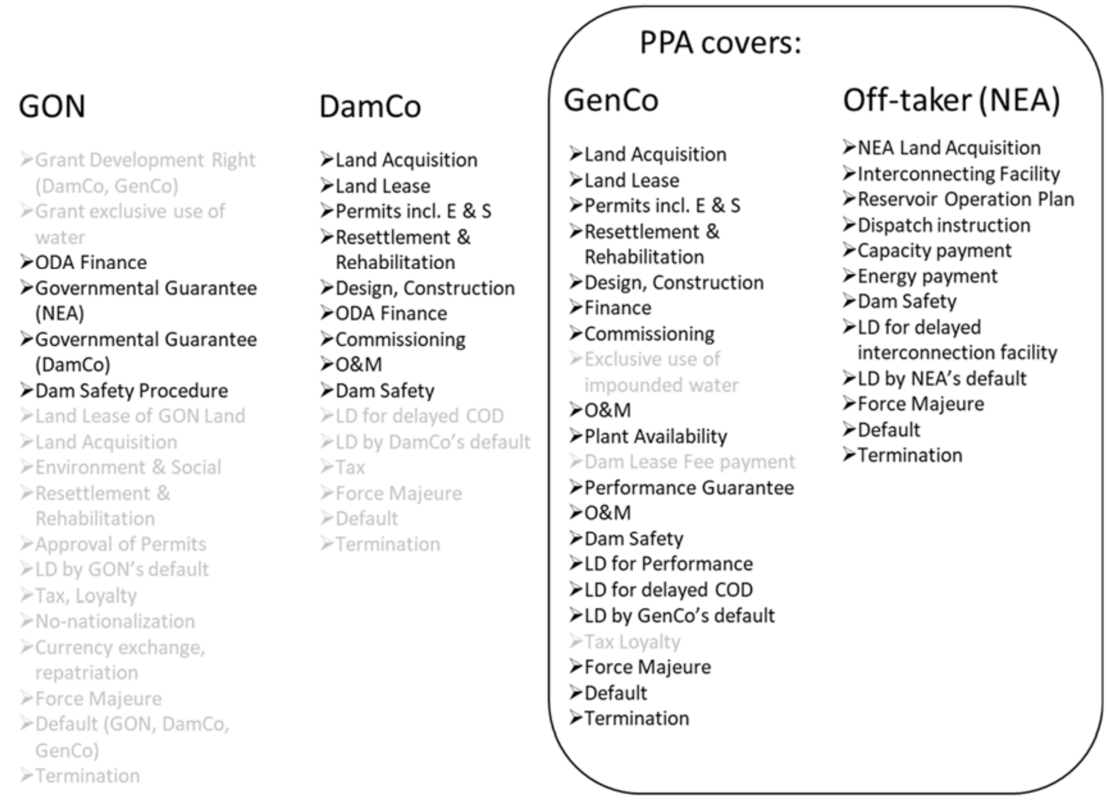


Figure 5.5-2 Risk Sharing Contents in PPA

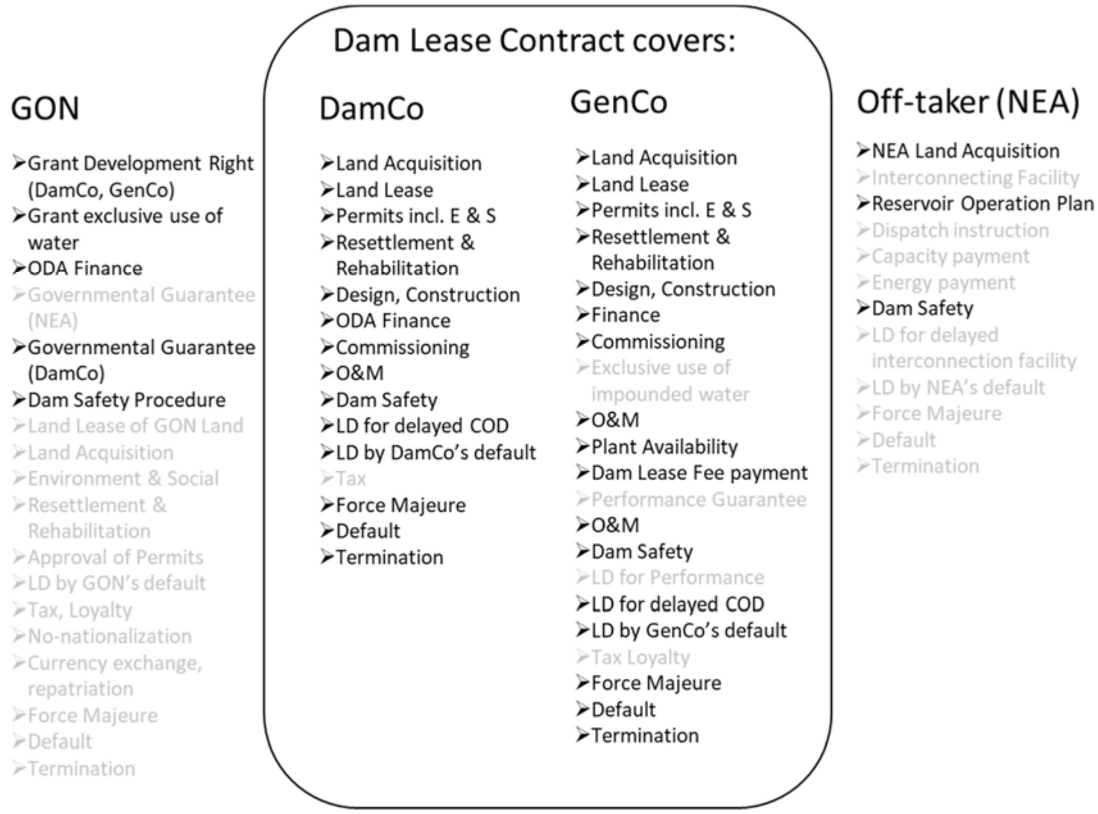


Figure 5.5-3 Risk Sharing Contents in Dam Lease Contract

Detailed responsibilities of each party in each contract are tabulated in a Risk Sharing Mechanism and a simplified Risk Matrix annexed to this report.

Risk Sharing Mechanism include current contractual structure of a conventional IPP and proposed risk sharing mechanism for the VSPPPM. The PDA of the Upper Trishuli 1 project and PPA Template are referred to for current status.

SECTION 6 PRELIMINARY ANALYSIS OF VSPPPM BY CASH FLOW MODEL

Effectiveness of the VSPPPM is validated in this Section. In order to quantify the effectiveness, a Model Project is selected from candidate storage type hydropower projects and a preliminary cash flow model is applied to the construction cost and schedule of the Model Project.

6.1 STORAGE HYDROPOWER DEVELOPMENT BY IPP

Figure 6.1-1 shows the relationship between project cost, capacity and annual energy production for 12 storage hydropower projects planned in Nepal[10]. Accuracy of the data on each project is almost feasibility study level. Selected Model Project has average characteristics among them.

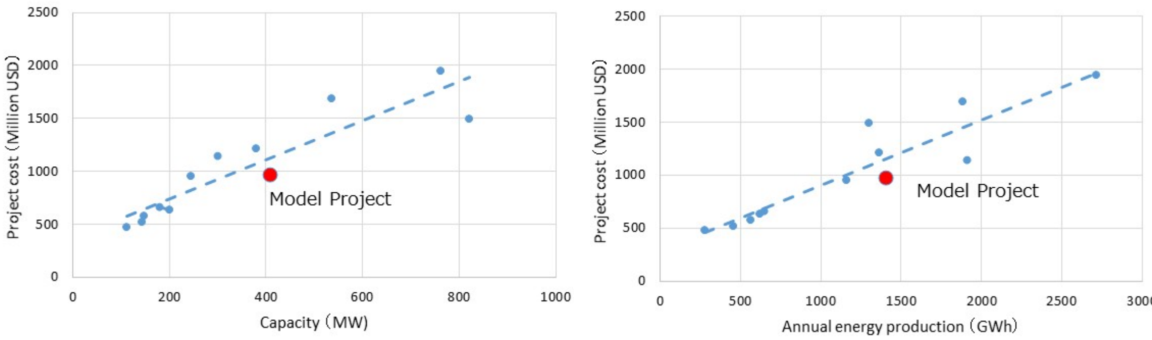


Figure 6.1-1 Project Cost for Candidate Sites on Storage Type Hydropower in Nepal

Those storage hydropower projects are assumed to develop by governmental funding (or NEA's own funding) with financing from international institutional lenders with positive economic impact (positive Economic Internal Rate of Return).

In case those projects are developed by private developers as IPP projects, loan conditions from commercial lenders should be taken into account. Simple calculation is made to check the financial viability from IPP point of view for those storage hydropower projects assuming:

- ✓ Annual energy production and project cost is quoted from previous study,
- ✓ Debt equity ratio is 70 to 30,
- ✓ Loan tenor is 10 years and interest rate is 7% per annum (other financial cost is not considered),
- ✓ Tariffs are 12.4 NPR / kWh in dry season and 7.1 NPR / kWh in wet season for storage type hydropower project, which are prescribed in Schedule 5 of the ERC Bylaw. They are the same value of NEA's tariff applicable to storage type hydropower project. Annual escalation of 3% on purchase tariff is considered until 8^{th} year from COD.

10 Nationwide Master Plan Study on Storage-type Hydroelectric Power Development in NEPAL (JICA: 2014) and Data Collection Survey on Hydropower Development Project in Federal Democratic Republic of Nepal (JICA: 2019)

Then revenue repayment ratio (annual revenue divided by repayment amount of the year) for each year is calculated. The ratio at 1st year and the average value for repayment period are shown in blue color column of Table 6.1-1. As references, the average ratio during the repayment period is also shown for the term of 15 and 20 years repayment period. Note that ERC Bylaw Schedule 5 says the tariff for storage type is applicable subject to 35% of annual energy being generated in dry season for projects below 100MW. As it is not clear whether the above projects are also bound by this rule, a trial calculation is made without considering this rule.

It is found that only 4 projects out of 12 project indicate revenue repayment ratio at the 1st year larger than 1.0 and only 5 projects show 1.0 or more value of indicator in 10 years average. If loan tenor is extended to 15 years and 20 years, the ratio becomes greater.

Although the project economics of hydropower development depends on technical conditions such as topography, hydrology and geology, this result implies that i) the tariff level is not enough for developing all storage hydropower projects by IPP and ii) extension of loan tenor may have a positive impact.

Table 6.1-1 Simple Test Result Revenue Repayment Ratio for Storage Hydropower Projects

	Installed Capacity	Annual Energy	Project Cost	Principal including IDC	(a) Annual Repayment		Eneregy in Dry Season	1st year (b) Revenue	1st year (b)/(a)	Average during repayment period: Repayment Preiod (years)		
Project	MW	GWh	MUSD	MUSD	MUSD	MNPR	%	MNPR		10	15	20
Nalsyau Gad	410	1,406	967	677	96	10,794	41	13,069	1.2	1.3	1.7	2.0
Dudh Koshi	300	1,910	1,144	801	114	12,770	27	16,331	1.3	1.4	1.8	2.1
Chara-1	149	563	577	404	58	6,441	21	4,638	0.7	0.8	1.0	1.2
Andhi Khola	180	649	666	466	66	7,434	21	5,331	0.7	0.8	1.0	1.2
Madi	200	621	637	446	63	7,110	28	5,315	0.7	0.8	1.0	1.2
Lower Jhimruk	143	455	521	365	52	5,816	21	3,730	0.6	0.7	0.9	1.0
Kokhajor-1	112	279	476	333	47	5,313	34	2,478	0.5	0.5	0.6	0.7
Naumure	245	1,158	955	669	95	10,660	27	9,862	0.9	1.0	1.3	1.5
Sun Koshi No.3	536	1,884	1,691	1,184	169	18,876	18	15,151	0.8	0.8	1.1	1.3
Lower Badigad	380	1,366	1,210	847	121	13,506	26	11,581	0.9	0.9	1.2	1.4
Uttar Ganga	821	1,299	1,489	1,042	148	16,621	100	16,110	1.0	1.0	1.4	1.6
Tamor	762	2,716	1,946	1,362	194	21,722	40	25,002	1.2	1.2	1.6	1.9

Recently, the feasibility study of the Model Project has been updated in 2019 (Updated F/S). Compared with the result reported in 2014, its project cost has been revised from 967 MUSD to 1,294 MUSD (increased by about 24%) and annual energy generation has been revised from 1,406 GWh to 1,232 GWh (decreased by about 12%).

Cash flow analysis is practiced based on the results of the Updated F/S of the Model Project, namely, construction cost and schedule with conditions of private investment. The Updated F/S assumes the development by a public sector and the project cost is estimated considering ODA Loan conditions while commercial loan conditions are considered in our cash flow model. The project cost of the Model Project, in the case of conventional IPP scheme, is estimated as 1, 434 MUSD. With this project cost and annual generation in the Updated F/S, the project cost per kWh is increased by 70%, compared with that estimated in the MP2014 (Figure 6.1-2).

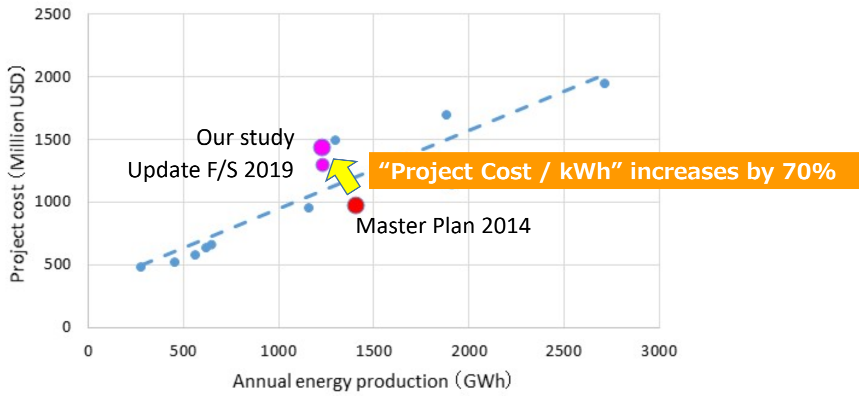


Figure 6.1-2 Project Cost per Annual Generation

6.2 PREREQUISITES APPLIED FOR THE CASH FLOW MODEL

Project economics of the Model Project from private perspective is examined with cash flow model. Effectiveness of VSPPPM is validated in Section 6.4.1 and the cash flow analysis considering new tariff regime is performed in the Section 6.4.3. In addition, impact on currency exchange rate is roughly estimated in Section 6.7 as a reference. This section describes the common conditions for all cash flow model.

Note that currency exchange rate is fixed as 112 NPR per 1 USD in cash flow model of Sections 6.4.2 and 6.4.3 for the purpose of clarifying effectiveness of the VSPPPM.

6.2.1 Construction Cost

The construction cost estimated in the Updated F/S of the model project is adopted.

For applying the VSPPPM, the construction cost is allocated to Dam Co and Gen Co considering the type of works. Costs of common works such as temporary facility is prorated according to the construction cost ratio of each company. In addition to the allocated cost, a cost for employing legal and financial advisors for formulating project finance is added to the construction cost of Gen Co. This cost is not necessary for Dam Co because of the assumption that Dam Co is organized by a public institution or its subsidiary and the ODA loan for Dam Co is provided by GON.

Table 6.2-1 shows the construction costs for two cases. The first case is that the Gen Co develops all facilities (corresponding to conventional IPP model case). The second case is that Dam Co and Gen Co develop the dam facility and generation facility, respectively, under the VSPPPM.

Table 6.2-1 Construction Cost

Unit: MUSD

Item		Conventional IPP	VSPPPM		
		Gen Co	Total	Dam Co	Gen Co
1	Preliminary Works and Access Roads	126	126	83	42
2	Civil Works	487	487	389	97
3	Hydro-mechanical	57	57	16	41
4	Electro-mechanical	116	116	0	116
5	Transmission Line and Substation	3	3	0	3
6	Allowance	79	79	49	30
7	Markups	105	105	65	40
8	Project Administration & Management	172	172	107	66
9	Advisory Fee for Legal and Financing on Project Finance (2% of the total items 1 to 8)	23	9	0	9
	Total	**1,167**	**1,153**	**709**	**444**

6.2.2 Financing Conditions

The financing model is assumed as shown in Figure 6.2-1 when the VSPPPM is applied to the project.

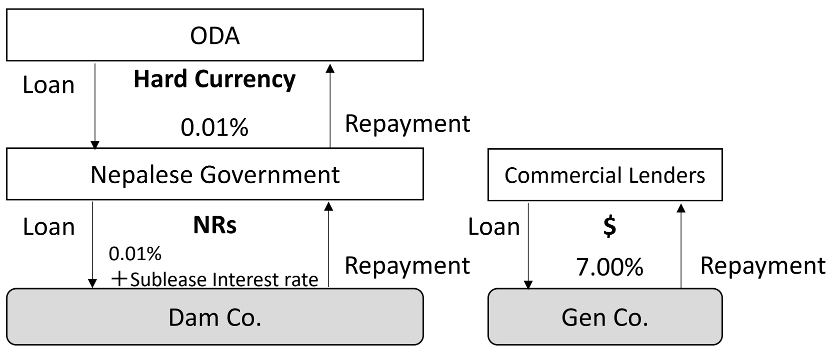


Figure 6.2-1 Loan Scheme of VSPPPM

The Gen Co receives a loan from foreign commercial lenders. Loan disbursement and repayment are executed by USD. The interest rate is assumed to be a spread addition to a swap rate. The swap rate is set at 3% because the swap rate on USD in the last three years has been in the mid 2% to mid 3% range[11]. The spread value is set at 4% referring to other hydropower project in Nepal.

11 The financial.com

Therefore, in this cash flow model, the interest rate on loans by commercial lenders is set at 7% (= 3% + 4%) by sum of the swap rate and the spread value. Debt equity ratio (D:E) of the Gen Co is set at 70:30.

GON receives a Yen Loan with interest rate at 0.01% and lends it to the Dam Co by converting it from Japanese Yen to Nepalese rupee. A fee for currency conversion and exchange rate risk is assumed to be imposed from GON to Dam Co as an additional interest of 3%. The total amount of the Yen Loan is set at 500 MUSD. The balance of the project cost of Dam Co is supplied by the shareholder's equity.

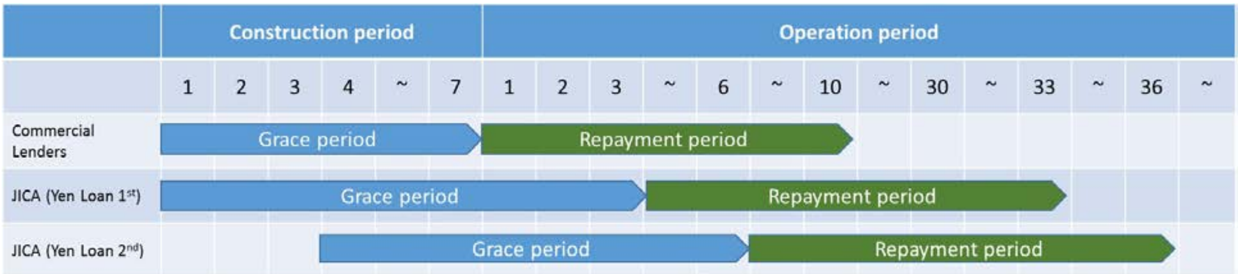
Table 6.2-2 shows the loan repayment schedule. In the case of a loan by commercial lenders, the repayment period is set at 10 years referring to the period that is prescribed in Hedging Regulation 2019 and in the PPA Template (both are 10 years) as Nepalese view of repayment period.

On the other hand, the repayment period of the Yen Loan is 40 years including the grace period of 10 years. Therefore, the repayment begins 10 years after the first withdrawal date and finishes 30 years after the beginning date.

In order to lighten the repayment at the beginning of the operating period, the Yen Loan is executed by two contracts not at once. The first Yen Loan corresponding to 250 MUSD is contracted at the first year of the construction period and the second one corresponding to the same amount is contracted at fourth year of the construction period.

An interest charge on the withdrawal amount is supposed to start at a withdrawal date.

Table 6.2-2 Schedule on Loan Repayment



6.2.3 Purchase Tariff of NEA

The effectiveness of the VSPPPM has been evaluated with the referenced tariff of the storage type hydropower generation indicated in Schedule 5 of ERC Bylaw. However the tariffs in the Schedule 5 are applied for hydropower projects up to 100 MW capacity, and does not restrict tariffs for projects over 100 MW capacity. Therefore, the feasibility has been evaluated under the condition quoting Section 8.5 of the ERC Bylaw also.

6.2.4 Dam Lease Fee

Dam lease fee consists of O&M expense, repayments, interest payments, taxes, internal reserve and dividends that are required for Dam Co to sustain their business. The EIRR (equity internal rate of return) of the Dam Co is set at 8% with reference to the long-term interest rate in Nepal[12]. In addition, the dam lease fee is set at fixed amount so that the Dam Co can secure the necessary income.

6.2.5 Foreign Currency Exchange Risk

As mentioned in previous sections, new PPA tariff policy was announced by NERC in October 2019 but the details of hedging mechanism are still under discussion among governmental agencies.

Therefore, the cash flow analysis does not consider an exchange rate variation and fluid hedging mechanisms under discussion, basically. Those impacts are discussed supplementary in Section 6.7.

6.2.6 Other Prerequisites

Other assumptions are as shown in Table 6.2-3.

Table 6.2-3 Other Prerequisites applied to the Cash Flow Model

Item	Conditions
Capacity	417 MW
Annual energy production	682.5 GWh (Dry season), 549.5 GWh (Wet season)
O&M expense	1% of total cost excluding Item 9 in Table 6.2-1 Assumed simple escalation at 6.4% annual
Depreciation rate, period	Straight-line depreciation at an annual rate of 5%, which corresponds to the depreciation period of 20 years. (accounting regulation in Nepal)
Internal Reserve for Repair	Assumed repair every 10 years 2 MUSD is built up every year for repairing dam facilities. For generation facilities as same.
Tax	
Corporate tax	For 10 years from COD 0% From 11th to 15th year 10% After 16th year 20%
Tax on interest	15%
Tax on Dividend	5%
Royalty	For 15 years from COD Capacity kW × 200NPR/kW + Income × 2% After the 16th year of COD Capacity kW × 1,500NPR/kW + Income × 10%

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6.3 BASIC DESIGN OF THE CASH FLOW MODEL

The basic design of the cash flow model is explained by taking the calculation process of the dividend amount as an example. Figure 6.3-1 shows the time sequence in the balance sheet (**B/S**). As a basic condition, depreciation is based on the straight-line method, and loan repayment is based on the principal and interest equal repayment. Due to the difference between depreciation and principal repayments in every year, the cash flow is controlled to keep a balance on the B/S.

Stage 1: Annual depreciation ≧ annual principal repayment

In the early stage of repayment period, the amount of the principal repayment is smaller than that of the depreciation, so the principal can be repaid within the depreciation. By arranging the balance on the B/S as cash (current assets), the balance on the B/S is maintained. Because this cash is the source of future principal repayment, it cannot be utilized for dividends.

Therefore, the net profit, which is calculated from the profit and loss statement (**P/L**), is the source of dividends. Since the depreciation cost exceeds the principal repayment, the amount of reserved cash becomes increasing during this stage. If the repayment period is lengthened, the amount of annual principal repayment decreases, and this situation continues for a long time.

Stage 2: Annual depreciation < Annual principal repayment

The amount of principal repayment increases year by year, and the amount exceeds the depreciation in course of time. In this stage, the loan repayment is carried out by utilizing the depreciation and withdrawing the cash accumulated in state 1. Eventually the cash consumed completely and the principal cannot be repaid within the depreciation. The shortfall is supplied by a part of the net profit. By arranging the shortfall on the B/S as retained earnings, the balance on the B/S is maintained.

The amount of dividends source is equal to or below net profit in this stage. This stage may start from COD depending on the asset composition, depreciation and loan repayment conditions.

Stage 3: After extinction

After completion of loan repayment, the source of the dividend is the sum of depreciation and net income during the year.

Stage 4

After the accumulated amount of depreciation reaches to the debt amount, the depreciation is reserved as cash. Because the project scheme is assumed as BOOT, after the concession period the power generation business is transferred to the Nepalese government. Therefore the cash is kept as the resource for a 100% capital reduction.

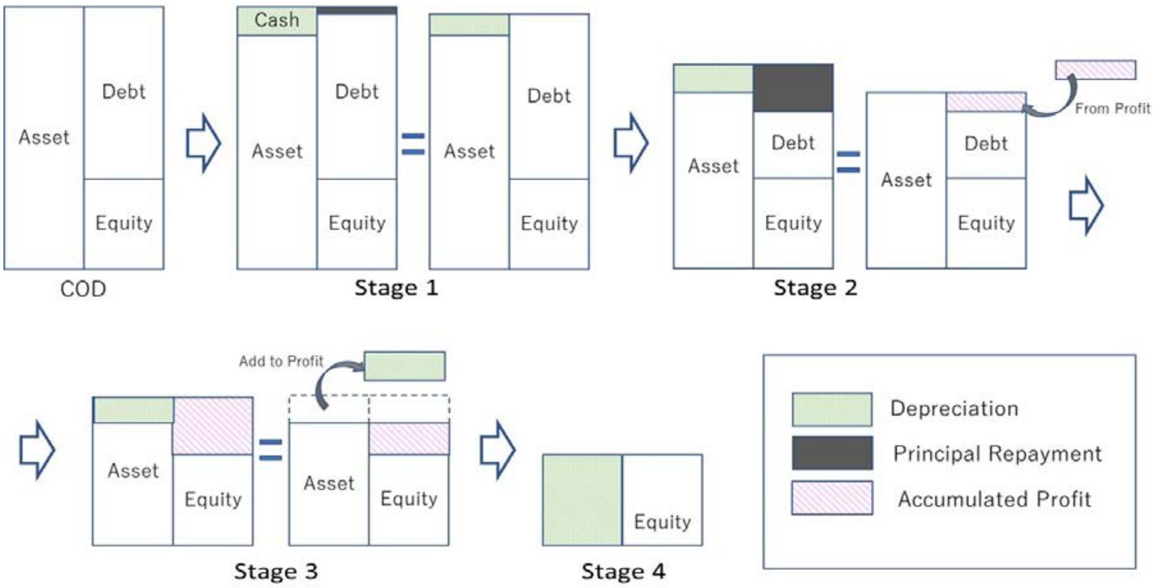


Figure 6.3-1 Explanation for the Basic Design of the Cash Flow Model

6.4 EVALUATION RESULTS BY THE CASH FLOW MODEL

6.4.1 Effectiveness of the VSPPPM

The main advantages of the VSPPPM compared to the conventional IPP scheme are illustrated in Figure 6.4-1.

(1) Separating dam development from Gen Co can reduce the project cost of Gen Co.

(2) Dam Co, a governmental agency, takes responsibility on dam construction, which enables a highly concessional ODA loans to be applied to the dam construction.

(3) Loan terms with different repayment periods can be utilized.

(4) As a result, the annual loan repayment in total can be suppressed.

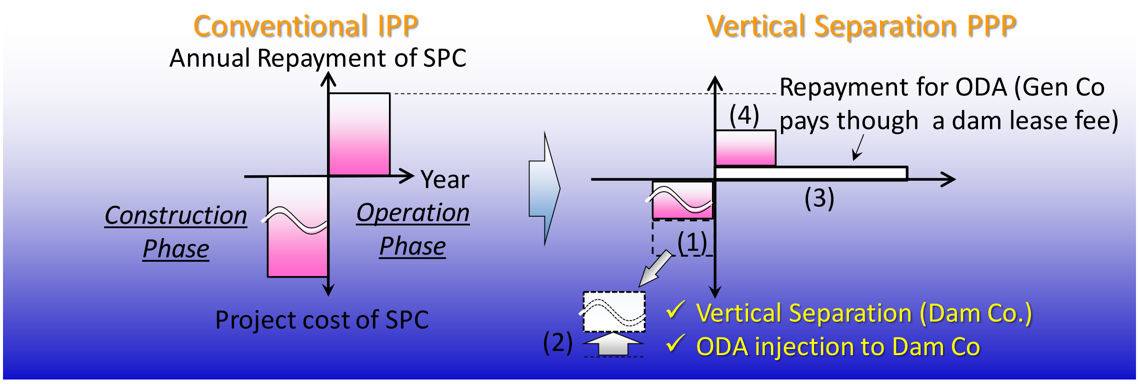


Figure 6.4-1 Advantages of the VSPPPM

Table 6.4-1 shows the project cost. The VSPPPM can reduce the project cost of Gen Co by 62% compared with typical IPP scheme. In addition, total amount of interest during construction decreases by 37%, because of highly concessional ODA loans to the dam project.

Table 6.4-1 Project Cost under Conventional IPP Scheme and VSPPPM

Item		Cost (MUSD)			
		Conventional IPP	VSPPPM		
		SPC	Total	Dam CO	Gen.CO
1	Construction Cost	1,167	1,153	709	444
2	Interest During Construction	231	145	59	86
3	Escalation	35	35	29	6
Project Cost		**1,434**	**1,332**	**796**	**536**
Debt (70% of Project Cost)		1,004	934	559	375
Equity (30% of Project Cost)		430	398	237	161

6.4.2 Fixed Tariff Case

Cash flow analysis has been performed based on the project cost and schedule of the Model Project. Tariffs stipulated in ERC Bylaw Schedule 5 (dry season 12.4 NPR/kWh, wet season 7.1 NPR/kWh with escalation for first 8 years. Hereinafter to be referred as “Standard Tariff”) and exchange rate of 112 NPR / USD are applied. The repayment period on Gen Co’s loan is 10 years. Note that the tariff rate in ERC Bylaw Schedule 5 is defined as a reference for hydropower above 100MW and is the same rate of NEA standard tariff in 2017.

Result of the cash flow analysis is shown in Figure 6.4-2. The left side of the figure shows the Gen Co’s cash flow under the conventional IPP scheme and the right side shows that under VSPPPM.

In each case, the expenditure during the loan repayment period exceeds the income. It should be noted though, expenditure during repayment period for VSPPPM case reduced significantly comparing with conventional IPP case. Focusing on the DSCR which is an index for bankability, the average DSCR is 0.7 for the typical scheme and 0.5 for the VSPPPM. Although effectiveness of VSPPPM is clarified, these values indicates that the project is not bankable for both cases.

DSCR is calculated by the equation shown as follow.

$$\frac{\dfrac{Revenue\ \ in\ \ NPR-(Expense\ \ in\ \ NPR)}{Exchange\ \ Rate\ \ at\ \ that\ \ time}+Repayment\ \ and\ \ Interest\ \ Payment\ \ in\ \ USD}{Repayment\ \ and\ \ Interest\ \ Payment\ \ in\ \ USD}$$

* Expense in NPR = O&M Fee + Dam Lease Fee +Royalty + Tax + Reserve for Repair
+ Repayment and Interest Payment + Hedging Cost

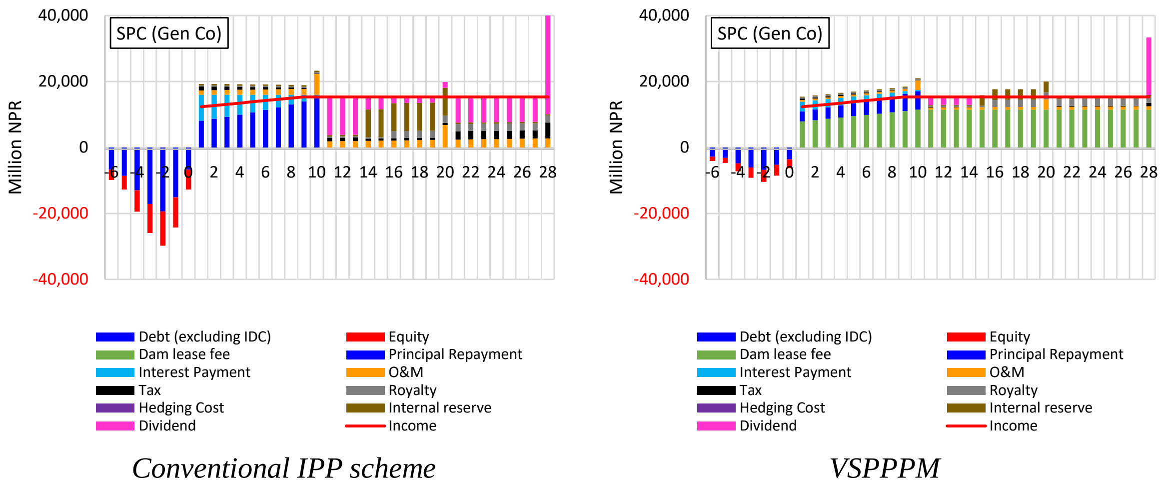


Figure 6.4-2 Gen Co's Cash Flow with Fixed Tariff

6.4.3 Variable Tariff Case

(1) Effectiveness of Vertical Separation PPP Modality

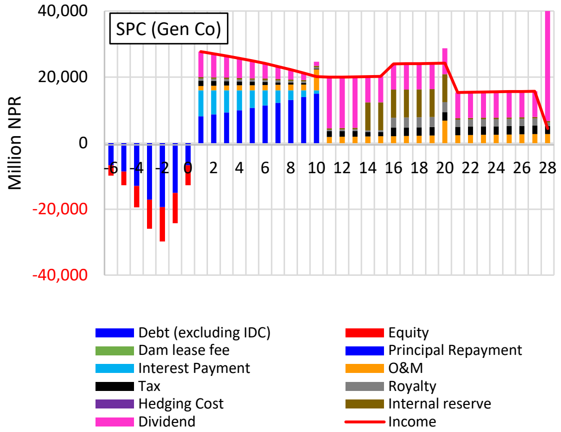
According to the ERC Bylaw Section 8.5, electricity purchase tariff from hydropower project above 100MW is determined by generation cost etc. (see Section 4.1.1). In case ROE is expected to exceed 17% (NPR base), the tariff is adjusted so as to keep ROE below 17%. While it is expected that a tariff may be determined at certain value by a negotiation in particular cases, this new tariff regime may allow tariff setting in accordance with annual generation cost of the year, which leads the variable tariff setting year by year. In this cash flow model, variable tariff is set so as to keep ROE 17%.

Generally, electricity purchase tariffs during the concession period are determined at the time of PPA conclusion, and applying this rule may allow tariffs to be set with a certain net profit proportionally with invested equity amount. As Section 8.5 of the ERC Bylaw also indicates that electricity purchase tariff is determined from not only generation cost but governmental policy, project economics for less feasible projects under fixed tariff system may be improved in case the tariff at a level of ensuring ROE of 17% is allowed.

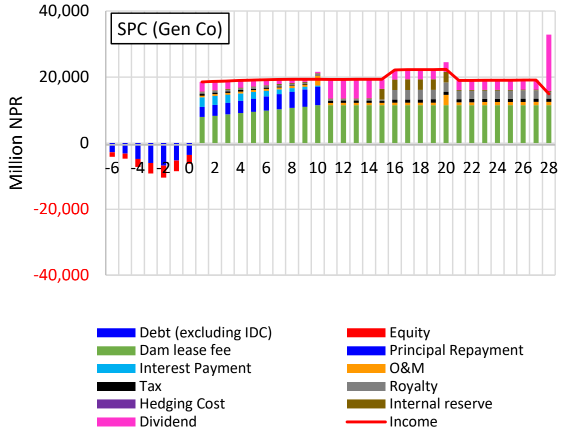
The feasibility evaluation by the cash flow model focuses on three indexes of Gen Co, which are DSCR, EIRR (equity internal rate of return), and equity payback period (for example, the period to achieve cumulative dividends of 100 to cover 100 initial equity investment).

The obtained output is also evaluated by three (3) indexes of purchase tariffs. First one is a tariff rate at the first operation year, second is a levelized tariff during concession period converted to the value at COD with 10% discount rate and the last is a maximum tariff during the concession period.

Result of the cash flow analysis for variable tariff case is shown in Figure 6.4-3. In both conventional IPP scheme and VSPPPM, the variable tariff makes Gen Co possible to obtain an income necessary for operation, which is different result from the fixed tariff case (See Figure 6.4-2).



Conventional IPP Scheme



VSPPPM

Figure 6.4-3 Gen Co's Cash Flow with Variable Tariff to Keep ROE 17%

Tariff of each year under the variable tariff scheme in the cash flow model is set to cover cost and profit. Annual cost in the profit and loss statement includes expenses (such as O&M expense, interest payment, royalty, taxes) plus depreciation. Profit is set so as to keep 17% of ROE. Year-by-year variation of each items in the figure above is explained as follows, taking conventional IPP scheme as an example.

As the loan repayment condition assumes principal and interest equal system, the interest payment decreases year by year. Therefore, the revenue decreases every year. After repayment is completed, the revenue is kept at almost constant, because there are no elements with large variation. The necessary revenue for keeping ROE 17% rises from 16th year following the increase of royalty payment. After depreciation period finish (from 21st year), the revenue decreases, since the revenue corresponding to the depreciation disappears.

On the other hand, even though the profit equal to ROE 17% is included in the revenue, the dividend during the repayment period decreases year by year. It is because the difference between principal repayment and depreciation. Since the amount of principal repayment increases year by year while depreciation is constant, when the amount of principal repayment exceeds the depreciation, the balance is compensated by the profit and such procedure resulted in decrease of profit, which is a source of dividend.

After repayment is completed, the revenue corresponding to depreciation becomes additional source of dividend. However, exceeding amount of paid-in capital cannot be allotted for dividend but should be kept in internal reserve. Since the Model Project is assumed to be BOOT base, Gen Co utilizes the internal reserve to return capital to shareholders at final commercial year (in this case, at 28th year).

Table 6.4-2 shows the major conditions and obtained indexes in the variable tariff case. The tariffs calculated by applying the Standard Tariff to the Model Project are shown in the right end column, as reference.

There are little difference on DSCR and EIRR obtained in both schemes. However, the tariff in the VSPPPM can suppress the tariff by about 17%, compared with the conventional IPP.

Table 6.4-2 Major Conditions and Obtained Index in Variable Tariff Case

Case	Case 00	Case 01	Standard Tariff (Reference)
Scheme	Conventional IPP	VSPPPM	―
Minimum DSCR Average DSCR	1.1 1.3	1.1 1.3	―
EIRR (NPR base) EIRR (USD base)	10.7% 10.7%	10.9% 10.9%	―
Equity Recovery Period	11 years	11 years	―
Initial Tariff Levelized Tariff Maximum Tariff	22.5 NPR/kWh 6.2 NPR/kWh 22.5 NPR/kWh	15.0 NPR/kWh 5.2 NPR/kWh 18.0 NPR/kWh	10.0 NPR/kWh 3.8 NPR/kWh 12.4 NPR/kW

Although the variable tariff based on ERC Bylaw limits a profit of a generation company, above results indicate that the new tariff scheme has a possibility to make a project that is difficult to develop under the fixed tariff condition to be feasible.

In addition, the results of cash flow analysis indicate the effectiveness of the VSPPPM comparing with the conventional IPP scheme, i.e., increase of equity return in fixed tariff system and decrease of tariff level in variable tariff system.

The tariff in Case 01 is evaluated from the viewpoint of price competitiveness. The Standard Tariff is assumed to be determined as a competitive tariff for a generation business with storage type hydropower in Nepal. When the Standard Tariff is applied to the Model Project, the purchase tariff for the first year is 10.0 NPR / kWh, the levelized tariff is 3.8 NPR / kWh and the maximum tariff is 12.4 NPR / kWh (right column of Table 6.4-2). As the levelized tariff obtained in Case 01 is about 1.4 times of the Standard Tariff, tariff reduction measures should be required for enhancing competitiveness of the Model Project .

(2) Measures for Profitability Improvement and Tariff Reduction

The effects on profitability improvement and tariff reduction by changing the conditions are verified based on the variable tariff and the VSPPPM. Sensitivity analysis are carried out with Case 01. Parameters are (1) repayment period of Gen Co’s commercial loan, (2) depreciation period on dam facilities (3) expected EIRR of Dam Co’s investors and (4) Percentage of dam lease fee borne by Gen Co. The results are shown in Table 6.4-3.

Table 6.4-3 Effects on Index by Changing Conditions

Case	Case 01	Case 02 (Base Case)	Case 03	Case 04	Case 05
Repayment Period	10 years	**<u>14 years</u>**	14 years	14 years	14 years
Depreciation Period on Dam Facility	20 years	20 years	**<u>50 years</u>**	50 years	50 years
EIRR of Dam Co	8%	8%	8%	**<u>3%</u>**	3%
Dam Lease Fee on Gen Co	100%	100%	100%	100%	**<u>50%</u>**
Minimum DSCR Average DSCR	1.1 1.3	1.3 1.6	1.3 1.6	1.3 1.6	1.3 1.6
EIRR (NPR base) EIRR (USD base)	10.9% 10.9%	11.8% 11.8%	11.8% 11.8%	11.8% 11.8%	11.8% 11.8%
Equity Recovery Period	11 years	7 years	7 years	7 years	7 years
Initial Tariff Levelized Tariff Maximum Tariff	15.0 NPR/kWh 5.2 NPR/kWh 18.0 NPR/kWh	15.0 NPR/kWh 5.3 NPR/kWh 18.1 NPR/kWh	13.6 NPR/kWh 4.7 NPR/kWh 15.8 NPR/kWh	12.6 NPR/kWh 4.3 NPR/kWh 14.2 NPR/kWh	10.5 NPR/kWh 3.4 NPR/kWh 11.0 NPR/kWh

In Case 02, the repayment period on Gen Co is extended from 10 years to 14 years intending to improve profitability of Gen Co. The period is set at 14 years by the following reason.

Since the revenue corresponding to depreciation is a source of principal repayment, when the amount of principal repayment exceeds depreciation, their balance should be compensated by the profit. This condition occurs in latter half of repayment period if setting the repayment period at 10 years. This situation causes profitability deterioration because of profit loss (Case 01). Extension of the repayment period increases total amount of revenue corresponding to depreciation accumulated during that period so that the compensation from the profit can be avoided. The repayment period maximizing EIRR of Gen Co is confirmed at 14 years under the conditions applied to the cash flow model (Case 02). Total amount of depreciation for the 14 years becomes equal to that of principal repayment. In other words, the 14 years corresponds to the depreciation period of 20 years multiplied by the debt ratio of 70%. To set the repayment period exceeding 14 years does not rise EIRR but only increases the total amount of interest payment.

Adjusting the repayment period at 14 years improves average DSCR by 0.2 point and EIRR by about 1 point. Since the tariff level is almost same, it would be appropriate to set the repayment period at 14 years.

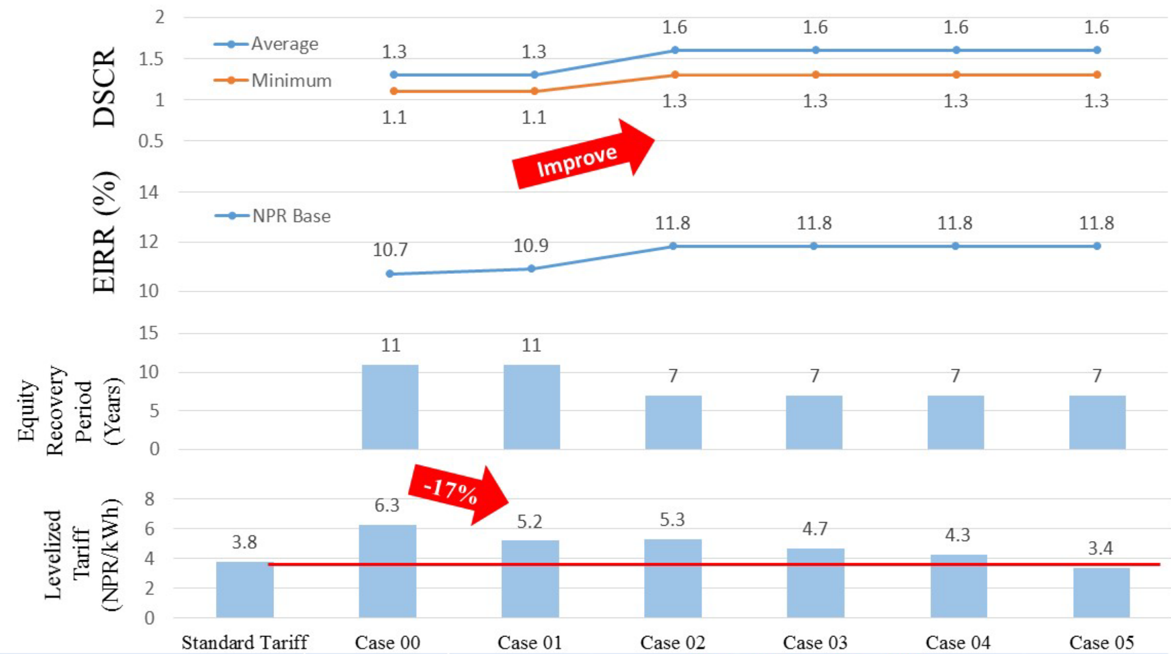
In Case 03, the depreciation period on Dam facilities is extended from 20 years to 50 years. Other conditions are same as in Case 02. Dam lease fee accounts for more than half of Gen Co's annual expenditures (See Figure 6.4-3). Therefore, to suppress the dam lease fee is essential for tariff reduction. Dam lease fee is set to cover the depreciation on the dam facilities in order to secure sound management of the Dam Co. Dam lease fee is utilized also for ODA loan repayment, but principal repayment is less than depreciation because of longer repayment period. Since straight-line depreciation is applied to the cash flow model, longer depreciation period can suppress the amount of annual depreciation. In addition, although 20 year depreciation period adopted in Case 01 follows accounting regulation in Nepal, actual durability of concrete structure is much longer. For example, according to the ministerial ordinance on the useful life of reservoirs, regulating reservoirs and waterways for hydropower is 57 years, in Japan. Extending the depreciation period from 20 years to 50 years, likes in Case 03, the amount of annual depreciation is decreased by 60%. As a result, the levelized tariff is suppressed by about 10%. The result suggest that extension on the depreciation period for the projects utilizing ODA loan having long tenor is worth to be considered.

In Case 04, expected EIRR of Dam Co’s investors is set at 3%. Other conditions are same as in Case 03. Assuming that Dam Co's sponsors are governmental entities, it is presumed that Dam Co's EIRR of 8% or less is acceptable. EIRR of 3% is about the same as the sublease interest rate from government to Dam Co and thus this assumption may be accepted. As a result, the levelized tariff declines by about 10% compared to Case 03.

Case 04 also includes the two changed conditions described above. If these three changes can be accepted, the levelized tariff becomes 1.1 times of the Standard Tariff. As the Model Project is regarded to contribute to improving energy security in Nepal, the levelized tariff in Case 04 may be acceptable. Noting that Gen Co’s EIRR and DSCR are also improved, these measures may attract foreign investors and lenders.

In order to obtain same level of levelized tariff as the Standard Tariff, reduction level of dam lease fee is examined in Case 05. Gen Co shoulders half of the dam lease fee estimated in Case 04. Another half may be shouldered by the government. It may be considerable because a high dam could contribute not only to promote local employment during construction period but also to enhance local economy development by its flow control, access roads and so on. Considering that Dam Co is a governmental entity, the government has an option to support construction and operation on Dam Co by injecting, for example, Viability Gap Fund (**VGF**) and/or subsidies. If this option is acceptable for the government, the levelized tariff becomes lower than the Standard Tariff by 10%.

Following figure summarizes the outputs by the cash flow analysis.



Project Scheme	Conv. IPP	Vertical Separation PPP				
Repayment Period (Gen Co)	10 years	10 years	14 years	14 years	14 years	14 years
Depreciation year for Dam	20 years	20 years	20 years	50 years	50 years	50 years
EIRR of Dam Co	8%	8%	8%	8%	3%	3%
Dam Lease Fee	100%	100%	100%	100%	100%	50%

Figure 6.4-4 Validity of VSPPPM and Effects of Measures

6.5 INFLUENCE OF PROJECT SCALE

The financial evaluation in the previous sub-section is conducted based on the results of Updated F/S. As a result, when the exchange rate variation is not considered, it is expected that a certain feasibility can be obtained by applying the VSPPPM under the condition of Case 02. However, tariff level to keep profitability of investors is around 14% higher than the Standard Tariff.

In order to examine impacts by project cost and annual generation, a different case is analyzed. Project cost and annual generation of the Model Project described in the Master Plan for Storage Hydropower Development in Nepal reported in 2014 are utilized as a different project scale model.

The cash flow model conditions of Case 02 is applied to different scale model project as Case 12.

Following tables shows the comparison of annual generation and project cost for the Model Project in the MP2014 and Updated F/S. Result of Updated F/S shows deduction of the annual generation by about 10% (however, dry season energy is increased) and increase of project cost by about 20% compared with MP2014.

Table 6.5-1 Specification Comparison between Updated F/S and Master Plan

	Updated F/S (2019)	Master Plan (2014)
Rated Power	417 MW	410 MW
Annual Energy	1,232 GWh	1,406 GWh
Dry Season	682.5 GWh (55%)	576.5 GWh (41%)
Wet Season	549.5 GWh (49%)	829.5 GWh (59%)

Table 6.5-2 Project Cost Comparison between Updated F/S and Master Plan

Item	Cost (MUSD)					
	Updated F/S Base			**Master Plan Base**		
	Total	Dam CO	Gen.CO	Total	Dam CO	Gen.CO
Preliminary Works and Access Roads	126	83	42	70	36	34
Civil Works	487	389	97	434	348	86
Hydro-mechanical	57	16	41	31	5	26
Electro-mechanical	116	0	116	115	0	115
Transmission Line and Substation	3	0	3	3	0	3
Base Cost	**789**	**488**	**299**	**652**	**388**	**264**
Allowance etc.	366	221	145	145	47	77
Construction Cost	**1,153**	**709**	**444**	**942**	**556**	**386**
Escalation	35	29	6	32	26	6
Interesting During Construction	145	59	86	122	47	74
Project Cost	**1,333**	**796**	**536**	**1,095**	**629**	**466**

Following table shows the results of cash flow model analysis.

Table 6.5-3 Project Cost Comparison between Updated F/S and Master Plan

	Updated F/S Base		Master Plan Base	
	Case 02 (Base Case)	Standard Tariff	Case 12	Standard Tariff
ROE (NPR base)	17%	—	17%	—
Repayment Period	14 years	—	14 years	—
Minimum DSCR Average DSCR	1.3 1.6	—	1.3 1.6	—
EIRR (NPR base) EIRR (USD base)	11.8% 11.8%	—	11.8% 11.8%	—
Equity Recovery Period	7 years	—	7 years	—
Initial Tariff Levelized Tariff Maximum Tariff	15.0 NPR/kWh 5.3 NPR/kWh 18.1 NPR/kWh	10.0 NPR/kWh 3.8 NPR/kWh 12.4 NPR/kWh	11.0 NPR/kWh **3.9 NPR/kWh** 13.1 NPR/kWh	9.3 NPR/kWh 3.6 NPR/kWh 11.5 NPR/kWh

It is found that EIRR and DSCR are the same as result of Updated F/S, but the levelized tariff is reduced from 5.3 NPR/kWh to 3.9 NPR/kWh, which is almost the same level of the Standard Tariff (3.6 NPR/kWh). It is concluded that in case the scale of the project is as much as the scale in the MP2014, the project may be implemented by private investment by applying VSPPPM with the same tariff level as the Standard Tariff.

6.6 APPLICABLE PROJECTS OF VSPPPM

From the financial evaluations described above, it is found that:

a. Model Project (Storage hydropower project with construction cost 1,167 MUSD without escalation and interest during construction (IDC) and annual generation 1,232 GWh) is not feasible as a conventional IPP project,

b. By applying VSPPPM with variable tariff scheme newly established by ERC Bylaw and some favorable adjustments for commercial loan tenor, depreciation period of the dam and Dam Co's profitability, feasibility and bankability becomes better to the level that private investors consider investment, but the tariff level shall be increased by 13% compared with the Standard Tariff, and

c. Financial evaluation of different scale of the project (Storage hydropower project with construction cost of 1,095 MUSD (after applying VSPPPM) and annual generation 1,406 GWh), the same feasibility and bankability can be achieved at the Standard Tariff level.

It is concluded that the VSPPPM has a potential to make un-feasible projects under conventional IPP scheme become feasible for private investors. As the characteristics of hydropower projects vary depending on physical conditions such as topography, geology and hydrology, though, it is difficult to generalize which projects can be applicable. The applicable projects may be suggested that the construction cost of dam is relatively higher compared with that of generation facilities because VSPPPM's effect on increasing project economics can be greater in those projects. In such cases, VSPPPM may be applied to Peak Run-of-river projects. It should be however noted that those analysis do not consider foreign currency exchange rate variation. The impact of exchange rate variation is supplementarily discussed in the next sub-Section.

6.7 IMPACT BY FOREIGN CURRENCY EXCHANGE RATE VARIATION

Since the hedging policy for exchange rate variation risk is still under discussion among governmental agencies, impacts brought by exchange rate variation are estimated as reference, with rough assumptions.

6.7.1 Exchange Rate Variation

Investments and loans on Gen Co are executed by the hard currency (assuming USD). In this case, repayments and dividends to foreign investors are denominated in USD. On the other hand, the income of the Gen Co is denominated in NPR. Therefore, currency conversion is necessary to evaluate the feasibility by a cash flow model. Exchange rates in the future has been assumed by referring to trend of the exchange rate in the past.

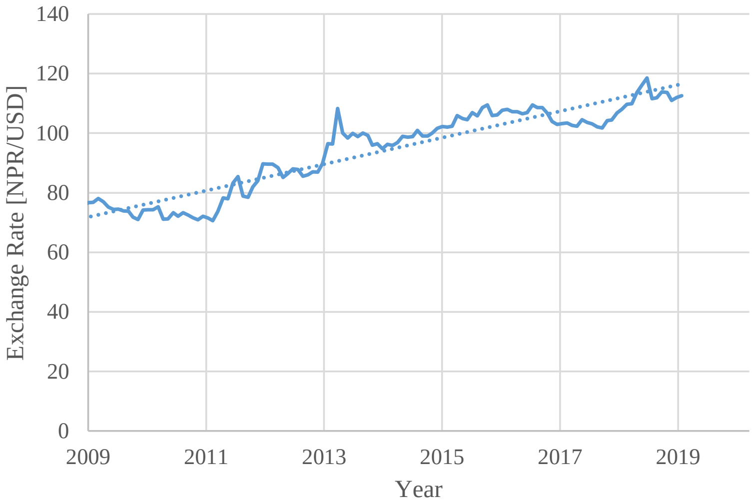


Figure 6.7-1 NPR-USD Exchange Rate over the Past 10 Years

Since NPR has been depreciating against USD at 4.4 NPR/year (4.7%/year) in average continuously from trend over the past 10 years (Figure 6.7-1), it is assumed that this trend will continue for about 10 years. This period corresponds to almost the construction period.

As a related matter, according to current situations for currency exchange hedging between INR and USD, there is a market with a reach up to five years, and a hedging cost is said to be roughly equivalent to a yield difference between the government bonds[13].

13 Information from financial institution

As mentioned in following Sub-Section, the current yield difference between INR and USD is around 5%. Therefore, the above assumption (average 4.7%/year) on the variation of INR is considered to be within the expected range from the current situation, with an assumption that the currency peg system between NPR and INR is maintained.

Setting assumptions for periods longer than 10 years is difficult. Although there is a 30-year government bond in INR and USD (yield difference is about 5%), it is actually difficult to find the hedging facilities with over 10 years reach. Interest rates and inflations affect to the exchange rate in a long-term, so the annual depreciation trend may exceed the above yield difference (5%). In any case, because of many uncertain factors, for the sake of brevity, it is assumed that the depreciation trend for the periods longer than 10 years continues to be the same as the above. It should be noted that these assumptions for the future exchange rates are aggressive setting.

6.7.2 Project Cost Considering Currency Exchange Rate Variation

Since project costs are estimated in USD, NPR-based project costs changes due to foreign exchange rate variation during the construction period.

Because Dam Co receives ODA loans in NPR financed by the government, exchange rates influence on the amount of principal. Therefore the amount of the annual repayment on Dam Co affects dam lease fee.

Gen Co's income from electricity sales is determined by PPA with the approval of NERC. There are no provisions in the ERC Bylaws on how to consider the effects of exchange rate variation.

Principal repayments, interest and dividends payments for foreign investors are major expenses which Gen Co should make by foreign currency. Additionally, Gen Co needs to accumulate reserves in a foreign currency for large-scale repairs of turbines, generators, etc. to avoid future exchange risk.

From latest information, it is found that (1) establishment of the Hedge Fund, which was described in the PPA Template was abolished, and (2) electricity purchase fee is paid in NPR entirely. According to government officials, there may be rooms to negotiate the risk allocation between Nepalese side and Gen Co on a project by project basis, but in principle, GON requires Gen Co to bear the currency exchange risk. Instead, a detailed procedure of hedging mechanism provided by GON is currently under discussion.

This suggests that foreign exchange gains and losses associated with foreign currency payments may not be recognized as expenses and may not be passed on to purchase tariff.

In the cash flow model, exchange gains and losses related to repayments and so on, are not set as expenses in P/L but are absorbed by net profit.

Although tariffs are determined at the time of the PPA signing, this cash flow model assumes that the tariffs are adjusted based on the project cost finalized at the time of COD. Because the Gen Co’s B/S would be based on the project cost denominated in NPR base and the project cost calculation is affected by the exchange rate at each disbursement during construction period. Annual net profit of Gen Co is set as multiplication of the equity on the B/S by an allowed ROE of 17%. In addition, the equity would keep at constant unless a capital increase or a capital reduction is performed.

Table 6.7-1 Major Conditions and Obtained Index

	Base Case	Case 1
Exchange Rate Variation	Not Considered	Considered
Dam Co	89,185 MNPR (796 MUSD)	104,484 MNPR (796 MUSD)
Gen Co	60,060 MNPR (536 MUSD)	70,684 MNPR (536 MUSD)

6.7.3 Hedging against Exchange Rate Variation Risk

Governmental policy on countermeasures against exchange risks is currently under discussion and details have not been determined, including how to allocate hedging costs. Therefore, this sub-section assumes hedging cost on the condition that Gen Co can procure a hedging facility in a market.

Although the hedging cost for currency exchange rate is determined by the market interest rate and the situations of demand and supply in the market, it is said that the cost is close to the yield difference between the two government bonds. Therefore, the cost (rate) has been assumed by referring to the actual situation on the yield difference of government bonds.

Figure 6.7-2 shows changes in yields on 10-year government bonds between India and the United States. The reason for referring to INR is based on the assumption that the conversion from NPR to USD is executed via INR of which transaction volume is higher than that of NPR.

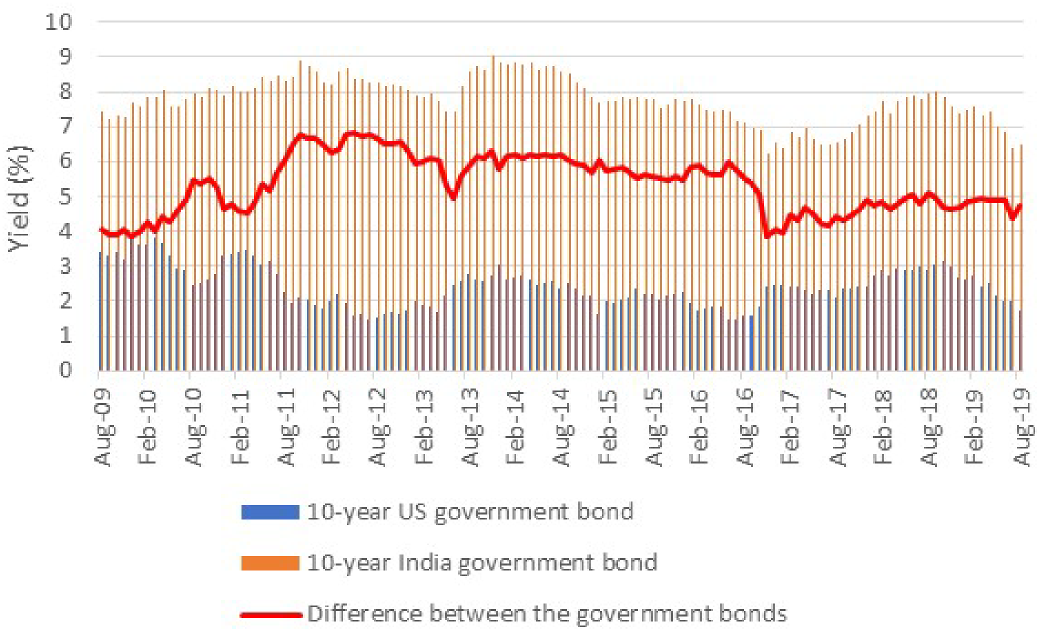


Figure 6.7-2 Yield on 10-year Government Bond

From the figure, the US government bond yield is 2.43% in average over the past 10 years, that for India is 7.78%, and the difference between them is 5.35%. Therefore, the cost of currency hedging has been set to be 5.35% of the amount of hedging target.

It should be noted that the value of 5.35% applied to the cash flow model, as well as the assumed exchange rate, is not derived from market conditions or long-term outlook. Because an existing hedge market between INR-USD has a reach only up to from 3 to 5 years.

Currency exchange rate hedge is started at COD and practiced step by step throughout its operation period. Therefore, it should be noted that the revenue is affected by the variation of the exchange rate after COD. The amount to be hedged covers the amount of loan repayment, dam lease fee and royalty from the income. The cost of currency hedging is set as 5.35% of the hedging amount. It is assumed that the reach of hedging is 5 years length. Therefore, the exchange rate at the date currency hedging contract is concluded has been applied to 5 years later from the contract date. In addition, it is assumed that the exchange rate at COD has been applied for 5 years from COD. This model image is shown in Table 6.7-2.

Table 6.7-2 Explanation on Exchange Rates before/after Practicing a Currency Hedging

Unit: NPR/USD

Operation	Estimated exchange rate	Exchange rate after practicing a currency hedging
1st year (COD)	147.2	147.2
2nd year	151.6	ditto
3rd year	156.0	ditto
4th year	160.4	ditto
5th year	164.8	147.2
6th year	169.2	151.6
7th year	173.6	156.0
~	~	~

Hedging cost covering interest during construction and interest payment is assumed to be cost items in the cash flow model in order to set the purchase tariff. On the other hand, hedging cost is spent from net profit of Gen Co.

As mentioned above, it is basic assumption that the Dam Co has received an Yen Loan via the government when the VSPPPM is applied. The Dam Co has not to bear the cost of currency hedging on the assumption that GON takes the exchange risk between NPR and JPY.

6.7.4 Cash Flow Considering Currency Exchange Rate Variation and Hedging Cost

An exchange rate goes up and down day by day as shown in Figure 6.7-1. A company usually purchases a hedging facility to stabilize business operations, i.e. to avoid uncertainties in the balance of payments due to the unpredictable exchange rate variation in future.[14]

Function of the hedging facility assumed in the cash flow model is explained using Table 6.7-2 as an example. The current exchange rate is 147.2 NPR = 1 USD. A company purchases the hedging facility to fix the exchange rate i.e. to apply the current exchange rate for a loan repayment in next year. When 100 USD is required in next year for the repayment, in order to apply the current exchange rate to the repayment, the company pays the hedging cost calculated as 100 USD × 5.35% × 147.2 NPR / USD = 787.5 NPR. In result, the expenditure becomes 15,507.5 NPR (14,720 NPR + 787.5 NPR) in total.

14 It is often difficult to apply hedging facilities to items with fluctuations, such as retained earnings, but for simplicity, it is supposed that currency hedging can be performed for these items as well, in the cash flow model.

Note that even if the exchange variation risks are hedged by a facility in a market, a user cannot escape from the effect caused by currency depreciation. This means that 440 NPR (= (151.6 NPR/USD－147.2 NPR/USD) × 100 USD) caused by the difference between current exchange rate and future one expected in a market is borne by a user as a part of the hedging cost.

Hedging costs are not inexpensive because a margin set by a supplier such as a fund or bank is included in the cost. Nevertheless, developers purchase hedging facility because it is difficult to predict future currency fluctuations. For example, if the exchange rate in next year becomes 159.2 = 1 USD caused by unexpected fluctuation with 5%, 412.5 NPR (= 15.92 NPR/USD－15,507.5 NPR) can be saved by the hedging facility.

When 100 USD is required after 5 years, the company burdens 787.5 NPR of hedging cost for each year, and fix the exchange rate after 5 years to the current 147.2 NPR = 1 USD. As a result, the expenditure becomes 18,657.1 NPR in total.

The impacts of the exchange rate variation have been evaluated based on Case 02 (base case). The results are shown in Table 6.7-3.

Table 6.7-3 Major Conditions and Obtained Index Considering Exchange Rate Variation

	Case 02 (Base Case)	Case 02-Ex1	Case 02-Ex2
Exchange Rate Variation	Not Considered	Considered	Considered
Total Profit after Tax During Concession Period	82,702 MNPR	97,332 MNPR	97,332 MNPR
Total Hedging Cost during Concession Period	N/A	Free	39,655 MNPR
Minimum DSCR Average DSCR	1.3 1.6	0.9 1.3	0.9 1.3
EIRR (NPR base) EIRR (USD base)	11.8% 11.8%	9.3% 7.1%	4.4% 2.2%
Equity Recovery Period	7 years	10 years	25 years
Initial Tariff Levelized Tariff Maximum Tariff	15.0 NPR/kWh 5.3 NPR/kWh 18.1 NPR/kWh	17.7 NPR/kWh 6.3 NPR/kWh 21.2 NPR/kWh	17.7 NPR/kWh 6.3 NPR/kWh 21.2 NPR/kWh

Case 02-Ex1 assumes that the hedging facility can be utilized for free. The tariff is adjusted to keep ROE at 17% (NPR base). On the other hand, the necessary amount in NPR for loan repayments and dividend payments denominated in USD increases due to the currency depreciation. If the increment, i.e., exchange loss can be included in cost items, Gen Co can keep certain level of income because of variable tariff system to keep ROE 17%. Such procedure, however, implies NEA take exchange risk and may not fit the governmental policy. Therefore, the exchange loss is absorbed in the net profit in the cash flow model[15]. As a result,

15 It is necessary for tariff calculation to convert interest payments in USD to in NPR. When not considering exchange rate variations, exchange rate is set at 112 NPR = 1 USD. When considering the variations, the rate is set at 131.9 NPR/USD (70,684 MNPR / 546 MUSD) calculated by the project cost.

DSCR drops below 1 and EIRR worsens to single digits.

In addition, the necessary tariff rises by about 18%. In the cash flow model, exchange rate variation after COD does not influence on the tariff because the effects are absorbed by the net profit. However, the exchange rate variation during construction period influences on the tariff. Because depreciation, interest payment and net profit, which are major elements determining the tariff, are calculated based on the assets of Gen Co. The amount of asset, in other words project cost, is varied by the exchange rate variation during construction.

Normally a user must bear hedging cost to utilize a hedging facility. Setting the hedge cost at 5.35% as mentioned in Sub-section 6.5 (3), the EIRR worsen, as shown in Case 02-Ex2, because the net profit decreases by the payment of the hedging cost. Even if Gen Co itself hedges the exchange risk by purchasing the facility in a market, the effect will not be appeared noticeably unless the exchange rate variations exceed expectations.

According to DSCR and EIRR values obtained in Case 02-Ex1 and –Ex2, the feasibility on the Model Project is extremely low, when the exchange rate variation are taken into account.

6.7.5 Issues on Hedging against Currency Exchange Rate Variation

The results in previous subsections are summarized that the Model Project cannot be feasible when considering exchange rate variation even if Gen Co purchases the hedging facility in a market. Since a reach of hedging facilities in a market may be only several years, consequently hedging costs and the exchange rates at conversion are affected by future exchange rates.

It is therefore difficult to quantitatively assess the exchange risk at a timing of PPA signing or loan agreement. Those uncertainty also remains in the hedging mechanism in the Hedging Regulation 2019. In addition, as the Hedging Regulation 2019 limits hedging target to principle of foreign loan and excludes interest during construction (though details are under discussion), such mechanism makes it difficult for private companies to participate in hydropower project development in Nepal.

As mentioned in Section 3, electricity purchase tariff is paid on mainly hard currency basis in many projects in neighboring countries and this tariff structure might aim to attract foreign investments. The tariff paid by the hard currency corresponds to a capital recovery fee and a part of O&M expenses. Additionally, the period adopting hard currency payment covers a concession period. The coverage range is wider than that of a hedging facility in a market and the system in the Hedging Regulation 2019.

The essential issue is that there are no hedging facilities or systems to hedge an exchange risks between NPR and USD which are suitable for projects with large-scale and long period like hydropower projects. In view of the government policy which intends to utilize foreign private investments, it is desirable that the Nepalese government or offtake bear the exchange risk more flexibly.

The most ideal countermeasure against the issue is to adopt the payment structure in which electric purchase fee is paid by hard currency entirely. If that is not possible, an off-taker bear all exchange risks or Nepalese government provide a hedging facility to off-takers. In latter case, the government might be required to bear the excess portion when the hedging cost borne by the off-taker exceeds a certain limit.

The hedging target by the hedging system or facility should cover the amount corresponding to the capital such as loan repayment including interest during construction and interest payment and equity, at least. Since a part of equipment and materials for maintenance or repair must be procured from overseas even after the completion of loan repayment, it is desirable to include these as hedged items.

In addition to this, it is essential to be able to convert NPR to necessary amount of USD in a timely manner and remit it oversea without delay. Their implementations have to be guaranteed by Nepalese government.

If the government provide appropriate hedging facility, feasibility of the Model Project increases. A cash flow model validate the feasibility of the Model Project on the assumption that although energy purchase fee is paid in NPR entirely, the Nepalese government develop and provide a hedging facility. The assumptions on the facility are as follows. (1) Hedging items are principal repayments including interest during construction, interest payments and dividends equivalent to a principal of equity. (2) exchange rate after COD is fixed to the exchange rate at PPA signing. (3) Gen Co does not required to bear the cost of hedging.

Usually, a hedging cost includes fees and profits of a provider such as hedging funds or banks, as well as spreads that take into account the liquidity of currency and policy trends in relevant countries. Since it is not clear that the hedging cost and its allocation which would be designed by Nepalese side, the hedging cost borne by Gen Co is assumed to be free of charge in the cash flow model. The result is shown in Table 6.7-4.

Table 6.7-4 Effect on Index When an Assuming Hedging Facility provided by Nepalese Side

	Case 02 (Base Case)	Case 02-Ex3	Standard Tariff (Reference)
Exchange Rate Variation	Not Considered	Considered	—
Total Profit after Tax During Concession Period	82,702 MNPR	97,332 MNPR	
Total Hedging Cost during Concession Period	N/A	22,469 MNPR	—
Minimum DSCR Average DSCR	1.3 1.6	1.3 1.6	—
EIRR (NPR base) EIRR (USD base)	11.8% 11.8%	11.2% 10.7%	—
Equity Recovery Period	7 years	6 years	—
Initial Tariff Levelized Tariff Maximum Tariff	15.0 NPR/kWh 5.3 NPR/kWh 18.1 NPR/kWh	17.7 NPR/kWh 6.2 NPR/kWh 21.2 NPR/kWh	10.0 NPR/kWh 3.8 NPR/kWh 12.4 NPR/kW

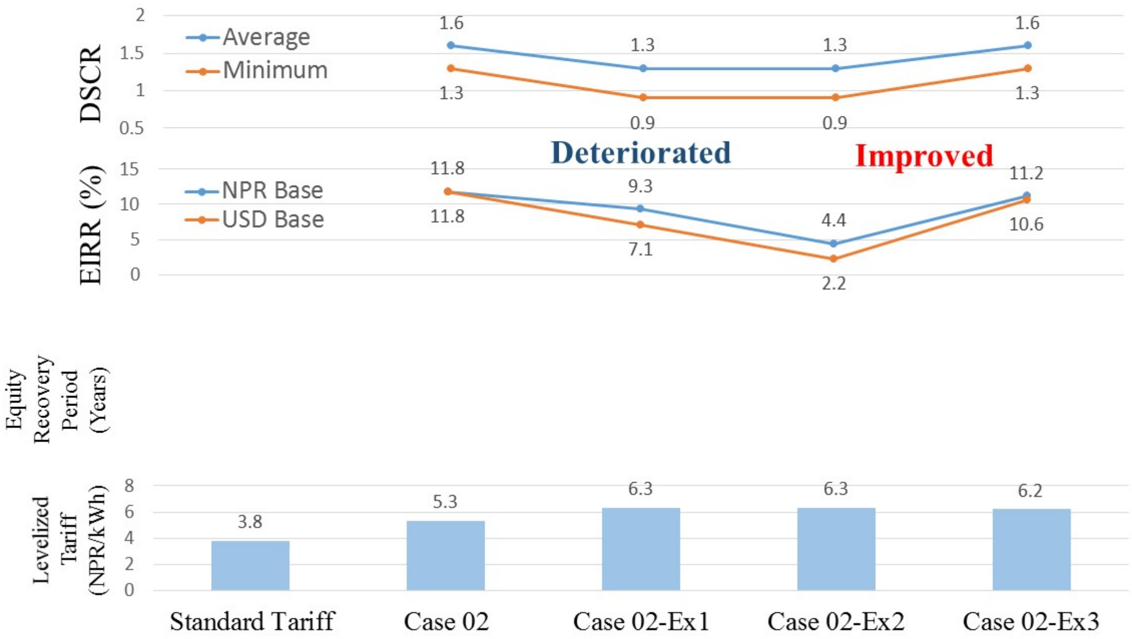
The feasibility of the Model Project is improved significantly when the government can provide the assumed hedging facility .

According to Case 02-Ex3, the indicators have recovered to the level of the base case (Case 02) that does not take account of exchange rate variation.

Applying the exchange rate at PPA signing to future exchange rates not only reduces the hedging cost, but also enables the company an operational outlook. This condition is almost equivalent to the condition that the amount of income necessary for expenditure in foreign currency is provided in foreign currency.

As mentioned above, the results are estimated on the condition that Gen Co does not bear the hedging cost. It should be noted that if Nepalese side requires Gen Co to bear the cost, the feasibility might be varied depending on the condition.

Following figure summarizes the outputs by the cash flow analysis.



Exchange Rate Variation	Not Consider	Consider			
Total Profit on Gen Co	82.7 BNPR	97.3 BNPR	97.3 BNPR	97.3 BNPR	
Total Hedging Cost on Gen Co	–	For Free	39.7 BNPR	22.5 BNPR	
Facility provided by GON	–	–	–	Available	

Figure 6.7-3 Impacts of Exchange Rate Variation on Feasibility

SECTION 7 ISSUES ON FOREIGN INVESTMENT

In the previous sections, characteristics of the Nepali power sector are overlooked, and the Vertical Separation PPP Modality is proposed to enhance foreign private investment in the power sector, especially in storage hydropower development. Each section contains issues and challenges for foreign investors in various aspects. Some issues are related not only to VSPPPM but also to storage hydropower development or even to investments on Nepali power sector. In this section, those issues and challenges are summarized.

7.1 FOREIGN INVESTMENT ENVIRONMENT

1) Foreign exchange rate variation risk

A governmental policy of hydropower development has been established in the Action Plan 2016 which encourages foreign investment in power sector by means of, among others, providing PPA denominated in foreign currency (Section 2.1.1). Following the Action Plan 2016, NEA announced PPA Template in which payment of electricity purchase from IPP was partially denominated in foreign currency for 10 years from COD to cover foreign exchange rate variation risk of investors and lenders (Section 2.1.4). The hedging mechanism (Hedge Fund) is stated to cover expected foreign exchange loss of NEA. NEA also determined and announced maximum purchase tariffs for each type of hydropower plant.

ERC Bylaw in 2019 revised the tariff determination criteria. Though it is not expressly stated in the ERC Bylaw, the power purchase tariff structure was revised to only local currency payment according to NERC and NEA (Sections 2.1.5, 4.1.1, 4.1.2). Instead of foreign currency payment, GON provide a hedging mechanism to foreign investors in infrastructure development in the Hedging Regulation 2019 (Section 4.1.3). Detailed procedure of the hedging, however, is still under discussion among related governmental agencies.

The Survey Team evaluates the effectiveness of VSPPPM in terms of investors' equity return and bankability and finds that the VSPPPM has a potential to make un-feasible projects become investable. However, since GON's hedging mechanism has not yet fixed, impact foreign currency exchange rate variation is not considered in the cash flow model (Section 6.4). With rough assumptions of exchange rate variation and hedging, the profitability and bankability are found reduced to un-feasible level (Section 6.7).

Local currency payment for foreign IPP projects are not found in neighboring countries (Section 3.6). In order to attract foreign investment in Nepali power sector, it is recommended to fix the hedging mechanism in favorable way for investors (Section 6.7).

It should be noted that since foreign investors and lenders require to fix the risk amount at the signing of PPA and/or loan agreement for arranging project financing, new procedures for hedging mechanism should meet this requirement. An alternative way may be that payment of off-taker shall be in foreign currency and hedging mechanism is applied to off-taker's currency exchange.

2) Tariff determination mechanism

ERC Bylaw revised electricity purchase tariff determination concept from the PPA Template, especially for hydropower projects over 100MW for which the purchase tariff is determined based on generation cost subject to ROE being less than 17% (Section 4.1.1). This new policy has a possibility to make un-feasible projects become investable if variable tariff scheme is accepted. This effect is confirmed by financial analysis for VSPPPM (Section 6.4.2, 6.4.3) and also can be expected for other types of hydropower development including PROR and ROR. The restriction of ROE 17% on local currency basis, however, may not be enough for foreign investment when foreign exchange variation is taken into account (Section 6.7).

On the other hand, as the restriction of maximum ROE, if it is simply applied, may deteriorate developer's incentive to develop more financially feasible project, additional arrangement may be necessary.

3) PPA structure

According to NERC and NEA, ERC Bylaw prevails over PPA Template (Section 4.1.2). ERC Bylaw, however, does not mention detailed power purchase conditions as stated in the PPA Template. It is not clear but power purchase conditions from IPP is expected to be agreed through negotiation on project by project basis, which means foreign investors cannot identify risks in the PPA at the initial stage of development.

In case power purchase conditions in the PPA Template is applied, liquidated damage amount if NEA fails to meet its obligation of constructing interconnection facilities is one of concerns for foreign investors. PPA Template Section 4.5 (a) read;

> *"In the event that Commercial Operation Date fails to occur on or prior to the Required Commercial Operation Date and if such failure is caused by the inability of NEA to complete NEA Interconnection Facilities by the Scheduled Synchronization Date of the first Unit for any reason other than any of the events specified in Article 6.3, then NEA shall pay to Company in the same currency as that of Purchase Price, as penalty an amount equal to the sale of forty five (45) percent to the total Contract Energy for the delay period derived on the basis of column H of Table II of Schedule 8 and applicable Purchase Price".*

As foreign investors arrange project financing with commercial lenders, the generation company's obligation of repayment commence from COD and 45% of expected revenue is not enough for repayment of debt. Such amount payable to generation company should be equal or greater than debt repayment to prevent bankrupt of the generation company.

Furthermore, PPA Template 4.5 (b) states that the amount of liquidated damage payable to NEA due to delay of power plant is 45% of expected revenue of generation company, as is the case when the construction of NEA Interconnection Facilities is delayed. This point is also a concern of foreign investors as it seems excessive compensation. It is necessary to pay attention when examining the contents of PPA (item 17 of Annex 2).

4) Legal structure

Electricity Act 1992 and related regulations are major governing laws regulating development procedure for IPP projects. Recently, ERC Act 2017 and PPPI Act 2019 were promulgated. Some procedures have been revised by those new regulations but it is not reflected in the Electricity Act. Conflicts among applicable laws and regulations are taken as an institutional risk for foreign investors.

PPPI Act requires application to IBN from IPP developers who want to develop hydropower plants over 200MW. IBN then publicize the detail of the proposed project and invite other bidders except unique projects. The original proposer has a right to match the best bid. In case the original proposer cancels the development, cost for development studies is compensated by the best bidder (Section 2.1.6). This procedure discourages IPP developer to pursue cost-effective project development.

7.2 STORAGE HYDROPOWER DEVELOPMENT

1) Tariff structure

Storage hydropower has a function of annual regulation of river discharge. In order to maximize such function and annual generation considering hydrology and system demand/supply balance, the system operator (NEA) should control the reservoir operation except emergency situation. The current generation based tariff structure (payment per actual generation; Energy Payment) cannot be applied as NEA control the generation. Annual/monthly hydrological fluctuation also make financial status of generation company vulnerable should the Energy Payment applied. Storage hydropower also has a function of ancillary services. Considering those factors, a fixed payment tariff structure (Capacity Payment) is recommendable for enhancing private investment (Section 4.2).

2) Dam Safety

Storage hydropower generally requires big dams for securing reservoir capacity enough for annual regulation. Since miss-operation or malfunction of spillway gate and/or dam breach cause a disastrous adverse impact on downstream societies, securing dam safety is foremost important. Procedure of securing dam safety should be reflected in institutional framework including PPA (Section 5.3).

Should the emergency operation of dam defined in the procedure cause impact on generation and lead non-performance or breach of Gen Co’s obligation in the PPA, NEA should accept such damage e.g., as Force Majeure event (Section 5.4).

3) Project preparation by GON

The Survey Team reviewed an updated feasibility study of a Model Project and recognize lack of geotechnical investigations and environmental surveys. Though it is still a feasibility level design stage and more detailed investigations/surveys are expected in the implementation stage, it is recommended to prepare a certain level of investigations from the initial stage of the development to provide an environment where foreign investors can evaluate business feasibility accurately in deciding investment.

7.3 VERTICAL SEPARATION PPP MODALITY

1) Institutional framework

The Survey Team proposed basic institutional framework for implementing VSPPPM. Responsibility sharing mechanism among GON, Dam Co, Gen Co and NEA should be explicitly and harmonizely defined in relevant contractual documents including PDA, PPA and Dam Lease Contract. Loan agreements with ODA lenders and commercial lenders also should be harmonized (Section 5.3).

2) Governmental guarantee

As seen in the previous PDA, governmental guarantee to NEA’s performance under PPA is essential requirement for foreign investors and lenders.

In addition to this governmental guarantee, performance capability of the Dam Co should be also considered under VSPPPM. Dam Co is expected to be a governmental entity, but a limited liability company under the Company Act. Dam Co’s obligation includes timely construction of dam and related facilities and compensation payable to Gen Co for covering liquidated damage under PPA in case COD is delayed due to Dam Co’s failure of its obligation. Considering financial stability of the Dam Co, it is required that GON guarantee Dam Co’s performance in the Dam Lease Contract (item 3 of Annex 2).

3) Loan tenor

Cash flow analysis find that a 10-year commercial loan repayment period will not be able to secure investment profitability with ROE limited to 17% at NPR base. Therefore, it was suggested that a loan repayment period of about 14 years would be appropriate for the Model Project instead (Section 6.4.3). It is expected that the appropriate commercial loan tenor may varies project by project. Flexible tenor for commercial loan should be accepted for attracting foreign investors.

4) Dam Lease Fee

Dam Lease Fee payable from Gen Co to Dam Co shares significant portion of Gen Co’s annual cost. In order to secure profitability of private investor, reduction of the Dam Lease Fee has a big impact. The Survey Team, through cash flow model analysis, proposed i) to amend depreciation period of dam from 20 years to 50 years and ii) to reduce expected return for equity holders of Dam Co from 8% to 3% (Section 6.4.3). Arrangement of reducing the Dam Lease Fee may be one of key issues for implementing VSPPPM.

SECTION 8 CONCLUSION

Storage hydropower development is considered essential for resolving both responding increase of electricity demand and securing energy security. Although the government of Nepal (GON) laid down the policy to utilize private investment for enhancing the storage hydropower development, no progress is made because of the huge magnitude of the investment. On the premise that the application of private investment to develop storage type hydropower projects, the Survey Team validates a Vertical Separation PPP Modality (VSPPPM) proposed by JICA and recommends it as a new hydropower development scheme. The VSPPPM is a scheme that construction and operation of dam and related facilities be separated from private Independent Power Producer (IPP) business and utilize Japanese ODA loan. The Survey Team validates the effectiveness of the VSPPPM. Institutional framework, concerns and items to be resolved for applying the VSPPPM are also proposed.

For the purpose of evaluating effectiveness of the VSPPPM, the Survey Team selected a Model Project, reviewed technical aspects and applied the project cost and construction schedule to a preliminary cash flow model.

(1) Summary

Model Project was initially studied in the feasibility study carried out by NEA and updated in June 2019 (Updated F/S) through site investigations and updated design. Updated F/S revised project cost and annual generation. In this Survey, cash flow analyses are carried out for the result of Updated F/S and validate effectiveness of the VSPPPM. Followings are summary of the analyses. As discussed in later parts, impact by foreign currency exchange rate variation is not considered since the exchange rate variation hedging policy is still under discussion among governmental agencies in base case scenario, but such impact is evaluated roughly by the cash flow analysis.

By applying VSPPPM, necessary electricity purchase tariff for making project bankable can be reduced by about 30%, which is a significant improvement. However, necessary tariff for the Model Project is still 40% higher than the Standard Tariff level introduced by NEA (2017) and by NERC (2019). By revising assumed conditions, i.e., i) loan repayment period from 10 years to 14 years, ii) depreciation period for dam facilities from 20 years (regulation) to 50 years and iii) expected equity internal rate of return (EIRR) for investors to dam company (Dam Co) from 8% to 3%, necessary tariff can be reduced to 10% higher level than the Standard Tariff.

Nepal government established NERC and power sector reform is underway. As the ERC Bylaw announced in October 2019 stipulates a new tariff determination policy based on generation cost subject to the Return on Equity (ROE) of the generation company being less than 17% (NPR base) and governmental policies are expected to be taken into account to determine the tariff flexibly. In such circumstance, there is a possibility that higher tariff than the Standard Tariff can be accepted by the government.

On the other hand, foreign currency exchange policy of the government has a big impact to foreign investment in, not only storage type hydropower, but also foreign investment decision for all power sector business. As of December 2019, the NERC and NEA representative stated that neither government nor NEA take currency exchange risk but assist developers to hedge principal portion of the loan through currency exchange market. The details of the hedging mechanism, however, are not determined, e.g., hedging cost sharing mechanism. Since foreign investors or lenders has to fix the risks at PPA signing or financial closure, it is recommended that the government clearly announce a policy to take currency exchange risk. As a result of the referenced estimate, it is found that cash flow analysis considering currency exchange variation results in the EIRR for foreign investors being single digit, which is not enough for investment.

In order to apply VSPPPM, roles and responsibilities of the government, dam company (Dam Co), generation company (Gen Co or SPC) and NEA should be clarified in the Project Development Agreement (PDA), Power Purchase Agreement (PPA) and Dam Lease Contract. The Survey Team recommends PDA be concluded among GON, Dam Co and Gen Co, and propose basic structure of each contract and outline of the Dam Lease Contract between Dam Co and Gen Co.

Operational procedure for storage type hydropower is also recommended. In order to maximize benefit of storage type hydropower, reservoir operation for generation purpose should be fully controlled by NEA as a system operator, who determine generation plan taking supply-demand balance into account and instruct electricity dispatch to Gen Co. As all generated energy should be instructed and purchased by NEA, tariff structure is recommended to have two (2) component, i.e., Capacity Payment (per kW) and Energy Payment (per kWh). Capacity Payment system stabilize Gen Co's financial status as well as Dam Co's as the source of the repayment of ODA loan is only a dam lease fee paid by Gen Co. Capacity Payment structure also corresponds payment for a specific function of the storage type hydropower, which is capability to supply ancillary services. The Survey Team recommends revision of purchase tariff structure in PPA for storage type hydropower considering those factors.

Another consideration for storage type hydropower should be made on emergency operation of the dam. As storage type hydropower requires high dam, environmental and social impact in case of failure of dam gates operation and/or breach of the dam is significant and should be avoided as the first priority. A system should be established to keep Dam Safety and prevent any hazard to downstream of the dam. Such system involves GON, local government unit located downstream of the dam, local residences, Dam Co, Gen Co and NEA. PDA, PPA, Dam Lease Contract should be structures so as to keep Dam Safety.

(2) PPA Structure

PPA was standardized by NEA in 2017 and negotiation between NEA and project developers was carried out based on such standardized PPA (PPA Template). In September 2017, however, NERC was established by enactment of ERC Act and ERC Act regulates that PPA should be approved by NERC. NERC promulgated a Bylaw Relating to Purchase/sale of Electricity and Conditions to be Fulfilled by the Licensee 2076 (ERC Bylaw) in which determination mechanism of electricity tariff in the PPA has been revised and NERC abandoned foreign currency payment. According to the ERC Bylaw, purchase tariff from hydropower project more than 100MW is determined based on the generation cost and negotiation, but the ROE of the project company should not be more than 17% calculated in NPR. In case ROE is expected to be greater than 17% during operation period, purchase tariff shall be revised so as to keep ROE less than 17%.

As the PPA Template was abolished, basic contract structure of PPA such as compensation mechanism for NEA's breach of obligations, definition of Force Majeure Event and relief etc. may be discussed project by project.

By terminating foreign currency payment system by NEA, the generation company has to take foreign currency exchange risk. Government of Nepal promulgated a Hedging Regulation 2019 to alleviate the impact for foreign currency loan. Government fix the exchange rate when loan is deposited in NRB and apply the fixed rate for converting local to foreign currency for 10 years (with extension, if approved) up to the deposited amount. The detailed procedures, however, are still under discussion among governmental agencies with respect to the area of coverage, hedging term and sharing mechanism of the hedging cost as of December 2019.

(3) Effectiveness of the VSPPPM

A Model Project is selected from several candidate storage projects for validating effectiveness of the VSPPPM.

Project cost and schedule of the Model Project described in the Updated F/S is applied to the preliminary cash flow analysis to validate investment viabilities of the Dam Co and Gen Co by the VSPPPM. Project cost is divided into two (2) parts, dam portion and generation portion, and each company construct and operate each facility funded by equity and loan. Power purchase tariff of NEA is assumed to be variable so as to keep ROE of the Gen Co to be 17% calculated in NPR.

Dam project cost is estimated to be 709 MUSD in the VSPPPM which is funded by Yen Loan and equity injection of investors of Dam Co. Project cost for power facilities is estimated 444 MUSD and Gen Co (SPC) arrange funding by equity from international investors and project financing based loan from international institutional lenders and/or commercial lenders. Revenue source is only from NEA for both companies. Dam Co operates the dam, repay the loan and distribute dividend to investors from a Dam Lease Fee paid by Gen Co. Dam Lease Fee is set so that the EIRR of investors for the Dam Co keep 8%.

Gen Co has to undertake foreign currency exchange risk and no mechanism of hedging has fixed yet as stated above. For validating effectiveness of the VSPPPM, cash flow analysis without considering foreign currency exchange variation is carried out as the base case. It is found that:

1) In the case of conventional IPP without the VSPPPM, power purchase tariff to keep ROE 17% is 6.2 NPR/kWh as levelized tariff during operational period with 10% discount rate. DSCR, which is a parameter of estimating bankability, is 1.1 as minimum DSCR and 1.3 as average DSCR during repayment period. EIRR of investors for Gen Co is 10.7% denominated in NPR. Gen Co's loan tenor is set as 10 years after COD.

2) In case of applying the VSPPPM, levelized tariff is 5.2 NPR/kWh. The reduced tariff represents effectiveness of the VSPPPM. Minimum DSCR is 1.1, average DSCR is 1.3 and EIRR is 10.9% denominated in NPR. On the other hand, levelized tariff calculated from Standard Tariff of NEA is 3.8 NPR/kWh. It means that even under VSPPPM, necessary tariff rate has to be increased by 40%.

3) Under the VSPPPM, by i) extending loan tenor to 14 years, ii) extending depreciation period of dam structure to 50 years (regulation indicates 20 years) and iii) reducing expected EIRR for dam investors to 3%, levelized tariff become 4.3 NPR/kWh, which is 10% increase from Standard Tariff and may be accepted because of enhancing energy security by storage type hydropower projects. These conditions are defined as base case.

4) EIRR of the base case is found 11.8%. Level of accepted risk of foreign investors varies and it cannot be generalized, but the result of the base case scenario may bring foreign investors to start studying the project investment. However, since this base case does not consider foreign currency exchange risk, such foreign investors are limited to those who can validate investment opportunity by Nepal Rupee basis.

It is found that the VSPPPM can attract private investment. PPA contents including tariff level, however, have to be flexible and other measures for enhancing project economics for foreign private investors have to be studies.

(4) Impact by Foreign Currency Exchange

Level of impact by foreign currency exchange variation on foreign investors is evaluated by cash flow model as a reference. Trend of the valuation of exchange rate between NPR and USD in recent 10 years indicates NPR devaluates 4.4 NPR/USD per year or 4.7% per year in average.

Foreign currency exchange variation in middle to long term with devaluation of local currency caused devaluation of income (NPR) against loan repayment (USD), which put pressure on revenue flow of Gen Co. In case dividend is denominated in USD, source of dividend also reduces.

Though such currency exchange variation also put impacts on construction costs of dam and power facilities, if the construction contracts are denominated in USD, no material impact on project cost is expected. Construction cost evaluated by NPR, however, is increased. Since the Dam Lease Fee from Gen Co to Dam Co paid in NPR is increased, devaluation of NPR result in increase of tariff under variable tariff system.

In case devaluation of NPR as 4.4 NPR against USD per year continues, levelized tariff is increased from 5.3 NPR/kWh to 6.3 NPR/kWh and EIRR is reduced from 11.8% to 7.1% (estimated by USD), which does not reach the level of foreign investment study.

Hedging mechanism for foreign currency exchange risk is still under discussion among governmental agencies and assuming the hedging mechanism may be premature. The Survey Team, therefore, roughly estimate the effectiveness of currency exchange rate hedging assuming that the Gen Co can purchase hedging product in private market. Cost of hedging is assumed to be 5.35% as indicated in the difference of the long-term government bond of India and US. Other assumptions are; devaluation of NPR is 4.4 NPR per year against USD, the Gen Co start hedging from COD and hedging product can cover 5 years forward. The result indicates that the EIRR of foreign investors reduced to 2.2%.

In case exchange rate is fixed at PPA signing, part of electricity selling revenue is exchanged to USD for 14 years from COD and Gen Co does not bear hedging cost, effectiveness of hedging is increased. With those assumption, levelized tariff is 4.9 NPR/kWh. Though levelized tariff slightly increased from base case, minimum DSCR, average DSCR and EIRR of foreign investors are improved to 1.3, 1.6 and 10.1%, respectively.

Considering foreign currency exchange variation risk, investment viability for foreign investors significantly aggravated, possibly, below the level of studying investment. In order to accelerate the foreign private investment to power sector in Nepal, it is ideal to change governmental policy so that the government or NEA to take exchange risk. Alternatively, at least, it is recommended that the government provides complete hedging mechanism reduce exchange risk for private investors.

(5) Institutional Framework

Unlike the conventional IPP project, since the VSPPPM requires cooperation of Dam Co and Gen Co for performing the hydropower project, rights and obligations of each party should be clearly defined and deeper involvement of GON including granting the development right is required. Following considerations in the institutional framework were recommended.

PDA should be applied not only granting development right to IPP developer (Gen Co) but granting development right of Dam Co for construction and operation of the dam. PDA should be concluded between GON, Gen Co and Dam Co. Agreement on development plan between Gen Co and Dam Co is a basis of PDA and ODA Loan, which is a part of dam development plan, should be considered as a responsibility of GON.

PPA is an agreement between off-taker, NEA and Gen Co and define responsibility of Gen Co to maintain generation facility and operate it as scheduled. Payment is made based on dispatched electric power. As storage type hydropower plants have a function of maximizing annual generation by utilizing the regulation capability of the reservoir, generation plan is significantly affected by reservoir operation and supply-demand balance. The reservoir operation, therefore, should be determined and controlled fully by NEA and be instructed to Gen Co except special situation like flooding.

On the other hand, management of the dam including reservoir is a responsibility of Dam Co, which means some involvement of Dam Co should be considered in PPA. In case PPA is concluded between NEA and Gen Co, Gen Co guaranty against NEA the required performance of construction and operation that is under responsibility of Dam Co, then responsibility of Dam Co is defined in the Dam Lease Contract. Taking public characteristics of the dam into account, it is recommended to have a tripartite agreement among NEA, Gen Co and Dam Co which can be considered as a supplemental agreement of PPA. Force Majeure event may be applied to the dam gates operation for preventing downstream disaster may be an example in the tripartite agreement.

Dam lease fee paid by Gen Co to Dam Co is defined in the Dam Lease Contract between Dam Co and Gen Co. As Dam Co utilize the dam lease fee for repayment of ODA loan, dam lease fee should be fix amount. As the source of dam lease fee is a sales revenue of Gen Co, payment structure in PPA should include Capacity Payment paid for availability of generation facility in addition to the actual generation based payment (Energy Payment). Capacity Payment concept is also corresponding to NEA’s control on the reservoir for maximizing storage hydropower function.

Responsibility sharing between Dam Co and Gen Co is defined in the Dam Lease Contract during development, construction and operation stages. A draft outline of Dam Lease Contract is proposed. It includes penalty clause in case a party fails to achieve its obligation. It is also recommended that remedy clauses for Force Majeure events such as change of governmental policy or natural disaster should be reflected in PPA and loan agreements of each party.

ANNEX 1

THE OUTLINE OF THE DAM LEASE CONTRACT (DRAFT)

The Outline of the Dam Lease Contract (Draft)

[Purpose of this draft]

When VSPPPM is applied to develop storage type hydropower plants the developer is divided into two (2) parties, namely, dam company (Dam Co) and power generation company (Gen Co). Determining responsibility sharing and cost sharing between Dam Co and Gen Co in advance is therefore required.

In this draft outline of the Dam Lease Contract, necessary items of agreement between Dam Co and Gen Co are listed. For each item, “Purpose”, “Example”, “Assumption”, and “Issue” are described.

[Assumptions in this contract outline]

- Contracting parties are Dam Co and Gen Co.

- Both parties agree on the development of a storage type hydropower project by mutual cooperation in good faith during preparation, construction and O&M stages of the project.

- Dam Co desires that Gen Co utilize the reservoir of the dam exclusively, and that Gen Co desires to utilize the reservoir owned by Dam Co. Under the conditions described in this Contract, Dam Co gives Gen Co an exclusive right to use of the reservoir for power generation purpose and Gen Co takes advantage of it.

- Dam Co own and maintains a dam, related facilities and associated reservoir[*1]. Gen Co owns and maintains hydropower plant and related facilities[*2].

- Dam Co and Gen Co may enter into a contract separately. In such cases, relationship with the conditions described in this Contract should be clarified if they outsource each other from the viewpoint of safety management and/or efficiency.[*3]

  *1: The main facilities owned by Dam Co are as follows.
  - Reservoir (including watershed management)
  - Dam
  - Ancillary Facilities - Spillway Gates, Sediment Scoring Gates, Dam Measuring Devices, Meteorological Survey Equipment (including equipment in upstream area and data communication system), Seismography, Information Dissemination System /Warning System for the Dam water release, Reservoir Water Level and Quality Monitoring System, Facilities relating to environmental and social management etc.

  *2: The main facilities owned by Gen Co are as follows.
  Intake, Headrace Tunnel, Surge Tank, Gate Chamber, Powerhouse, Tailrace Tunnel, Outlet, Monitoring Equipment for water level and quality, Electrical/mechanical equipment for power generation, Switching Station and equipment, Transmission Facility to delivery point, Supervisory Control and Data Acquisition (SCADA) system, Communication system

  *3: Subcontracting cases may be; Dam Co sub-contract Gen Co to construct the dam, Gen Co sub-contract Dam Co to render environmental protection works related to power plant construction.

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1 BASIC ELEMENTS OF CONTRACT

1.1 Conditions for Concluding a Dam Lease Contract

1) Permits and Licenses for Project Development

(Purpose)

In order to construct and operate dams and hydropower facilities (including related switching station and facilities such as transmission lines), permits and land acquisition are essential. At the time when the Dam Lease Contract is concluded or become effective, the related contracts that are the premise of these businesses must be obtained or at a certain progress. Required status of other contracts should be i) already obtained, ii) objectively observed to be obtained in a specific timeframe, or iii) structured to become effective when other related contract(s) is concluded/effective.

(Example)

- PDA
- Land ownership
- Environmental permission
- PPA
- Contracts relating to transmission (System Connection Agreement)
- Other permits, contracts etc. required for the project

(Assumption)

- Assuming conditions such as related major contracts (PPA, Dam Lease Contract, Connection Agreement etc.) are concluded at the same time (or becoming a similar situation) after PDA is signed. As those contracts are closely related to the development right granted by PDA (including development right of the dam), the outline of those major contracts should be principally agreed before signing PDA.

- The PDA meets all prerequisites for the project.

- At the time when the Dam Lease Contract is concluded or become effective, related contracts are concluded or in a certain condition to be concluded. For example, each party obtains approvals or licenses necessary for the construction and operation of the project, or shall have a reliable reason for obtaining such approvals or licenses.

(Issues)

The delay in obtaining license, concluding land acquisition and signing related contracts and lack of awareness regarding their process affects the schedule and operation plan.

2) Agreement of Designs (Required Functions, Specifications)

(Purpose)

Design, specifications and the functions of the facilities (e.g., function of the dam or information transmission system of the power facility) shall be mutually agreed by both parties and responsible party shall follow the agreed design.

(Example)

- Dam, Reservoir and related facilities
- Generation system and related facilities
- Measuring equipment, transmission equipment

(Assumption)

The confirmations of the design shall be agreed by the signing date of the Dam Lease Contract.

(Issues)

- If there are any unclear points left, it leaves the possibility of dispute over troubleshooting during operation.

- Even if the measuring instrument for hydrological information is owned by the government, it is necessary for Dam Co to ensure the supply of the information to Gen Co.

3) Agreement of Schedules (Construction, Commissioning, Commercial Operation)

(Purpose)

To clarify the schedule agreed by both parties when signing the Dam Lease Contract.

(Example)

- Construction schedules of each company's responsibility and overall schedule

- Preparation process and schedules of trial operation of the dam and commissioning of the generation facilities

(Assumption)

- Dam Co and Gen Co has completed the explanation to the local authority and the necessary measures have been implemented.

- The explanation and basic agreement with the off-taker and operator of the transmission system have been completed.

(Issues)

- If the work process is delayed by Dam Co or Gen Co, loss of revenue is imposed to both parties. For example, delays in dam construction affect the implementation and profitability of power generation projects.
  In addition, off-taker and lenders related to each business are affected. For this reason, off-taker responds to Gen Co and Gen Co to Dam Co to compensate the damage or loss or request surplus funds to cover such loss. Conversely, if the construction of the power plant is delayed, it may affect Dam Co's profits and the loan repayment conditions may not be satisfied.

- It is also necessary to consider the a recovery system such as meetings when the delay becomes possible.

1.2 Basics

1) Demarcation of Responsible Facilities

(Purpose)

It defines the demarcation point for the facilities under the control of Dam Co and Gen Co.

(Example)

- Dam Co has the following main facilities.
  - Reservoir (including watershed management)

- Dam

- Ancillary Facilities - Spillway Gates, Sedimentation Scoring Gates, Dam Measuring Devices, Meteorological Survey Equipment (including equipment in upstream area and data communication system), Seismography, Information Dissemination System /Warning System for the Dam water release, Reservoir Water Level and Quality Monitoring System, Facilities relating to environmental and social management etc.

- Gen Co has the following main facilities.
  Intake,
  Headrace Tunnel,
  Surge Tank,
  Gate Chamber,
  Powerhouse,
  Tailrace Tunnel,
  Outlet,
  Switching Station and equipment,
  Transmission Facility to delivery point,
  Supervisory Control and Data Acquisition (SCADA) system,
  Communication system

- The demarcation point will be the intake.

(Assumption)

The dam and intake facilities are not integrated and are installed at different places.

(Issues)

- In the event that a malfunction of the one party's responsible facility affect to other party, securing damage compensation and/or surplus funds should be required. Accordingly, the contractual responsibilities of Dam Co and Gen Co are to be established.

- It should be noted that this demarcation point may differ between construction and operation.

2) Responsibilities of Dam Co and Gen Co

(Purpose)

- Specify the responsibility sharing between Dam Co and Gen Co.

(Example)

- Dam Co and Gen Co manages and operates the facilities appropriately so that there are no problems in right of the purpose of the Dam Lease Contract.

- Both parties operate the reservoir according to the annual reservoir operation rules that Gen Co has agreed with off-taker in advance.

- Dam Co is responsible for the spillway gate operation. Dam Co may sub-contract to Gen Co to operate spillway gates following the instructions of Dam Co.

- Dam Co controls the water level of the reservoir in cases of emergency situation to prevent public hazards or reservoir operation with mutual agreements such as sediment removal. Rules for information exchange and/or notification to community/local government and operation procedures for these cases shall be determined.

(Assumption)

Nothing

(Issues)

- In addition to clarification of basic responsibility sharing, Dam Co and Gen Co prepare provisions depend on site situation and equipment conditions as necessary.

- If it is reasonable to outsource each other for the safety reasons, a separate contract may be prepared and concluded by Dam Co and Gen Co. In such cases, it is necessary to clarify the relationship with the Dam Lease Contract.

3) Dam Lease Fee

(Purpose)

Define basic responsibilities for the dam lease fee payments.

(Example)

- After COD as defined in PPA, Gen Co pay [ ] annually to Dam Co in the currency [ ].
  If the amount of payment after COD is changed depending on the year, this is specified.

- Dam Co compensates to Gen Co if the expected power generation is not possible due to failure of performing Dam Co's responsibility and Gen Co's business revenue decreases. For example, it may be assumed that power generation is not possible due to a dam facility malfunction or repair.

- Gen Co pays a dam lease fee to Dam Co even if it cannot generate electricity due to failure of performing Gen Co's responsibility.

(Assumption)

Nothing

(Issues)

- With regards to the decrease in revenue of Gen Co caused by NEA’s responsibilities as stipulated in PPA, it is necessary to consider a mechanism to deduct it from dam lease fees. For example, such the mechanism that the difference amount between Dam Co's assumed revenue and the actual revenue paid on the PPA is deducted from the dam lease fee when power generation plan is not possible due to an off-taker’s reason is considered.

- When introducing the above measures, confirmation by Dam Co, Gen Co, and NEA (or four parties including the government) is required.

- It should be reflected in the loan repayment conditions of Dam Co and Gen Co.

4) Calculation Method of the Dam Lease Fee

(Purpose)

The contents regarding the dam lease fee that Gen Co pays to Dam Co are specified.

The provisions include “Dam Lease Fee Calculation Method”, “Target Period”, “Unit Price”, “Payment Currency”, “Billing Method”, “Payment Method”, and such as “Payment Date”.

In addition to these, it provide for adjustments and compensation when Gen Co's electricity selling fees decrease caused by Dam Co’s responsibilities. Electricity fee will be the source of payment for dam lease fees.

(Example)

- Specify the method for calculating charges (including the method for calculating deductions).

- “Calculation period”, “Unit price”, “Payment currency”, “Billing method by Dam Co”, “Payment method by Gen Co”, “Due date” are specified.

- When Gen Co delay to pay fee, it is specify “Date of delay calculation” and “Calculation method for late payments”.

- Stipulates regarding deduction of dam lease fee or payment of compensation by Dam Co in the event of a malfunction [*1] in the provision of dam functions [*2].

*1 When restrictions of dam usage caused by failure of Dam Co exceed certain limits (quality, quantity, duration), or other significant malfunctions in providing dam functions

*2 In some cases, it is described separately as an LD item.

- Compensation payments are defined by these items as follows. "Defect Notification Procedure", "Compensation calculation method", "Date of calculation", "Amount (unit price)", "Currency", "Payment method”, "Due date".
- In case the restriction of dam usage continues over a certain period, termination of the Contract shall be considered.

(Assumption)

The dam lease fee is determined based on repayment of the ODA loan. It is appropriate payment structure that dam lease fees is paid on a flat monthly basis provided that Dam Co's responsibilities are satisfied.

(Issues)

Since the investment amount for dam construction is relatively large, in case payment of dam lease fee to Dam Co by Gen Co decreases more than initial business plan (including overdue), Dam Co may have difficulties to repay the ODA loan. In order to prevent such situation, risks such as deduction of power sales payment due to off-taker’s failure or payment overdue of the off-taker should be structured as pass-through mechanism between PPA and the Dam Lease Contract.

5) Liquidated Damage (LD)

(Purpose)

Clarify the assumed defects and compensation for damages when such defects occur or are revealed .

(Example)

[Operation]

- Definition of completion (start of operation) of dam construction and power plant construction
- The completion date of the power generation business like "initial charge", "initial synchronization with the power transmission and distribution network", "test", "trial operation" and "commercial operation" are notified by Gen Co to Dam Co.
- The completion date of the dam business like “initial impoundment”, “impoundment to the level where electric power can be generated”, “impoundment to the level where spillway gate can be operated” and “flood operation system completion” are notified by Dam Co to Gen Co.
- Compensation rules for any construction delay of each party.

[Function Guarantee]

Compensation if the incompliance with the design or specification, which had been previously agreed by Dam Co and/or Gen Co, causes or is deemed to cause problems in commercial operations.

[Compensation calculation method]

Compensation method (amount, currency, payment method).

(Assumption)

Nothing

(Issues)

LD compensates for decreasing revenue due to the failure of performing responsibilities to achieve the plan. Depending on decreasing amount of revenue, the loan repayment may be affected or in the worst case, the continuation of the power generation business may be affected. Therefore, LD clauses in the Contract should be in line with PPA and loan agreement.

6) Settlement of Disputes

(Purpose)

Specifies how to resolve a dispute between the parties regarding “default”, “termination” and “validity”.

(Example)

- Mutual discussion (for [   ] days after expressing disagreement by one party) for amicable resolution should be specified.
- If the discussion is unsuccessful, enter into steps of the “request to appraiser” or “arbitration”.
- Arbitration clause shall determine the arbitration rules, system, place of arbitration and language, for example;

  “According to ICC Arbitration Rules”

  “Arbitrator: One arbitrator shall be selected by each company, and selected two arbitrators shall appoint another arbitrator as a chairperson.”

  “Arbitration take place in Singapore with English”

(Assumption)

Amicable resolution with good faith

(Issues)

NERC may be involved because the functions of NERC includes dispute settlement among licensers. Since the role and authority of NERC are unclear, the contents involved in NERC are unknown. Therefore, mutual settlement is temporary specified.

7) Force Majeure

(Purpose)

Force Majeure clauses cover situations beyond the control of the affected party, whether directly or indirectly, and that are outside the performance obligations of this Contract.

(Example)

[Political Force Majeure]

Definition of Force Majeure events (war, social security, riots, demonstrations, terrorism, change of laws etc.)

[Other Force Majeure event]

Definition of matters (explosion, fire, earthquake, flood, drought, natural disaster)

[Action rules]

- In case Gen Co cannot generate electricity as planned, or the off-taker cannot purchase electricity due to the occurrence of Force Majeure event, the obligation of Gen Co to pay dam lease fees is reduced or exempted in the manner in line with the PPA.
- Definition of the Force Majeure events in the Dam Lease Contract should be aligned with PPA and loan agreements of both parties.
- If case Dam Co cannot provide the dam function due to Force Majeure event, Gen Co's obligation to pay the dam lease fee is reduced or exempted.
- In the case of political Force Majeure, Gen Co has the right to terminate the contract.

(Assumption)

Nothing

(Issues)

- Gen Co cannot pay a dam lease fee if Gen Co cannot generate due to Force Majeure. Therefore, contractual obligations under loan agreement of Dam Co, loan agreement of Gen Co and PPA should be suspended during the Force Majeure period.
- In the case of political Force Majeure, it may be possible to apply different mechanism as a government responsibility.
- These items are better to be agreed in the PDA.

8) Termination

(Purpose)

Cases of the termination of the Contract and procedure shall be specified if an irreparable event occurs and determined impossible to recover.

(Example)

- Gen Co becomes a bankruptcy, insolvency, settlement, dissolution or other similar event
- Dam Co becomes a bankruptcy, insolvency, settlement, dissolution, or other similar event
- If political Force Majeure event occurs and prevent construction or operation for a certain specified period, Gen Co is given a right to terminate the Contract.
- If the business execution is hindered by other Force Majeure events, the Contract expires after a certain period.

(Assumption)

Nothing.

(Issues)

In case the obligations of the Contract cannot be performed due to other party such as an off-taker, both companies may incur liabilities. Parties may need to consider insurance coverage against such cases.

9) Meeting

(Purpose)

Dam Co, Gen Co, and other related parties hold regular meetings to share progress, information and make various adjustments. It is also necessary as a means of negotiation and resolution in the event of a dispute.

(Example)

Hold the following meetings regularly or at the emergency situation if necessary.

- When the operation plan needs to be changed due to equipment failure or demand situation.
- Sharing schedule and progress of regular repair work and/or emergency repair work.
- Discussion of sharing progress on shared access roads or any other shared facilities and recovery methods in case of delay.

(Assumption)

The meeting is held between Dam Co and Gen Co.

(Issues)

- Involvement of NERC for resolving disputes is unclear.

- Governmental agencies, local authorities, local communities and/or contractors of construction works may be present when required. Involvement of third parties may be specified in the PDA.

- Procedure, selection of chairperson and resolution mechanism etc. need to be examined.

10) <u>Insurance</u>

(Purpose)

Clarify and define the minimum insurance coverage for both parties

(Example)

- For all business periods: "Third-party liability insurance" and "Injury insurance"

- From the date of initial financing to the COD: "construction insurance" and "transport insurance" or Construction All Risk insurance.

- From the start COD: ” property insurance”

(Assumption)

Each party confirms each other that both parties contract required insurance.

(Issues)

Both parties should agree insurance policy, area of coverage and deductibles to prevent dispute due to lack of insured.

2. CLARIFICATION OF THE ROLES

2.1 Construction Phase

1) <u>Preparations of Access Road</u>

(Purpose)

An agreement of shared facility. Project access road which branches from public road to the project site (powerhouse or dam) should be principally constructed and maintained by the party who solely utilize the road. A certain reach of the project access road may be utilized by both parties. The responsibility of construction and responsible area of each party should be specified.

The same concept applies when a shared power supply is required (only the matters concerning the access road are described below).

(Example)

- Provide definition of boundaries between public access roads and project access roads as well as rules for usage.

- Responsibilities of each party for constructing and maintaining shared access road should be defined including implementing party and cost allocation by mutual agreement.

- Management rules of construction and usage of access road by sharing the construction schedule of each party should be specified.

(Assumption)

- Access roads are classified as public access roads and project access roads. Project access roads are further divided into shared access roads and single access roads.

- Public access roads refers to public roads used for transportation which is constructed and maintained by governmental body. In case enlargement and/or rehabilitation is required for construction purpose, the responsibility and cost allocation should be discussed and determined among both parties and responsible governmental agencies.

- Project access roads may be transferred to the governmental agencies after completion of construction.

(Issues)

- Since the delay in the construction progress of one party affects the entire project schedule, compensation for the delay should be agreed as for the access road construction.

- In case public access road is expected to complete by the start of construction and it is delayed due to any reasons of responsible governmental body which cause the delay of the project schedule, it may be necessary to involve related responsible government to agree in a separate agreement.

2) Demarcation of Responsibilities for Construction

(Purpose)

This clause defines the demarcation of responsibilities and cost allocation for construction works by Dam Co and Gen Co.

(Example)

- Securing construction site. In particular, temporary construction site area should be identified. A common temporary site may be designated.

- Identify common facilities such as a disposal area and specify responsibility and measures of operation.

- Clarify and if any, specify any rules for efficient use of common construction materials. For example, Dam Co produces concrete and may sell it to Gen Co.

(Assumption)

Nothing

(Issues)

Nothing

3) Formulation of Trial Operation Plan

(Purpose)

This clause stipulates a procedure of test operation of dam related facilities and commissioning of generation facilities.

(Example)

- Prior notice and arrangement for trial operation and/or commissioning.
- Designate required water level necessary for trial operation and/or commissioning.
- Stipulate recovery measures for delays due to failures of trial operation and/or commissioning.

(Assumption)

Aiming to improve efficiency by conducting dam trial operation and commissioning of generation facilities with proper arrangement.

(Issues)

- Failure of keeping planned schedule of the Dam Co is subject to delayed LD.
- For scheduling commissioning tests, Gen Co needs to coordinate with off-taker. Since delay of commissioning tests due to failure of off-taker's performance should be defined in the PPA and also reflected in the Dam Lease Contract, a tripartite agreement among three (3) parties may be necessary.

  (assuming inclusion in LD items and matching between PPA and the Dam Lease Contracts).

2.2 Operation Phase

1) Proper Maintenance of Facilities

(Purpose)

- Both parties appropriately maintain and manage the responsible facilities to ensure the prescribed functions.
- In order to provide function of the dam to Gen Co, Dam Co is required to maintain the responsible facilities by conducting periodical inspection, to keep a record of

deterioration status of each facility and to establish proper maintenance schedule.

(Example)

- Dam Co reports the inspection plan and results to Gen Co, and should guaranty the required function against Gen Co.

- Dam Co is responsible for repair and/or replacement of the facilities to keep the required functions.

(Assumption)

Although Gen Co should also maintain proper function of generating facilities, failure of keeping generating function does not affect revenue flow of Dam Co (Gen Co is obliged to pay dam lease fee in such case). This clause therefore stipulates Dam Co's obligation for this reason.

(Issues)

- Procedure and compensation measures should be agreed in case failure of Dam Co affect the operation of generation facilities.

- For irregular situations, it is necessary to discuss what kind of content should be included in Force Majeure event as a special case.

2) Shared Facilities used by Dam Co and Gen Co

(Purpose)

The matters to be coordinated by each party regarding the use of shared access roads and shared power supply facilities shall be specified.

(Example)

- Do not occupy a shared access road.

- If a party cause a malfunction, such company need to contact and discuss with another party and promptly restore the condition.

(Assumption)

Nothing

(Issues)

Shared access roads may be transferred to the governmental body after completion of construction. In case the proper maintenance is not conducted after the transfer and the project operation is affected, an agreement may be required with the responsible government.

3) Reservoir Operation Plan (Annual, Monthly, Repair and Maintenance Plan)

(Purpose)

- The annual reservoir operation plan shall be established between Gen Co and NEA considering the maintenance work schedule by Dam Co and Gen Co.
- The both parties shall coordinate to formulate a maintenance plan in order to minimize the impact of maintenance work on the power generation.
- Maintenance work is reflected in the short-term reservoir operation plan in consultation with Gen Co and NEA.
- Emergency inspection and/or maintenance work after flooding or earthquake should be designated including rules to distinguish between planned maintenance and unplanned maintenance.

(Example)

- Make a repair plan in line with the planned power outage.
- Set the maximum and minimum water levels that the power generation plan is reflected to.

(Assumption)

Annual reservoir operation plan is established in the PPA as a basic plan. NEA shall periodically (semi-annually, quarterly, monthly and weekly) adjust annual operation plan considering weather forecast and supply-demand balance and instruct dispatch to Gen Co.

(Issues)

- It is necessary to consider compensation when the reservoir operation plan cannot be maintained due to inappropriate dam operation by Dam Co.
- As the reservoir operation plan is greatly affected by rainfall, it is necessary to establish a system to maximize annual generation by analyzing meteorological and hydrological data.

4) Checking Sedimentation Status

(Purpose)

This clause specify that Dam Co should keep record of sedimentation in order to provide the function of the dam without any problems and takes any countermeasures to prevent adverse impact. In case sediment flushing gates are equipped in the dam the generation cannot be done during sediment flushing.

(Example)

- Dam Co should regularly checks and keep records of sedimentation.

- Dam Co guarantees the accuracy of sedimentation survey to Gen Co.
- Dam Co takes responsibility if the exceed sediment which is not expected in the design affect the operation of the generating facilities.

(Assumption)

- Dam Co is responsible for the content related to the dam function.
- Assess the guarantee in the event of an impact on the operation plan, consider how to pay the dam lease fee.

(Issues)

- Adjustment method when the operation plan is affected.
- Sudden reductions in reservoir capacity due to disaster like large-scale land slide in upstream area may be considered aa a Force Majeure event.
- Although operation of sediment flushing gates is measures to keep function of the reservoir, the sediment flushing cause significant impact to generation operation as well as downstream environment. It is necessary to keep coordination among related stakeholders to conduct the sediment flushing operation. For example, as sediment flushing requires a certain amount of running water, it may increase downstream water level when flushing is conducted in wet season. On the other hand, sediment flushing during dry season cause severer impact on generation. Those impact should be examined for establishing sediment flushing procedure.

5) Dam Safety Plan

(Purpose)

Considering public nature of the dam, Dam Co shall establish a Dam Safety Plan for the purpose of preventing downstream hazards by the dam operation, and need to agree with government agencies and downstream local communities.

(Example)

- Dam Co establish a Dam Safety Plan in consultation with relevant government agencies and downstream communities and with consent of Gen Co before the initial impoundment of the dam.
- Discuss and clarify roles of relating governmental agency to render watershed management.
- Establish inspection and maintenance plan of the dam.
- Installation of monitoring equipment such as rainfall gauges in the basin for appropriate prediction of flood and glacier lake outburst flood.
- Definition floods, establishment of the dam gate operation rules during floods and

measures of information dissemination to downstream area.

- Establishment of emergency inspection procedures during floods and earthquakes and procedures of repair.

(Assumption)

Nothing

(Issues)

Dam Co is responsible for downstream hazard caused by dam operation or dam failure, which is relating to public safety and has priority to power generation. The emergency procedure should be agreed with the off-taker in case the disaster prevention measures affect the generation. For this reason, such impact caused by emergency operation should be categorized as the Force Majeure event in the PPA. This problem is common to storage type hydropower with spillway gates, regardless of the VSPPPM.

6) <u>Dealing with Floods and Impact on Power Generation after Flood</u>

(Purpose)

When flooding of a certain scale or larger is predicted, it is necessary to stop the power generation operation based on the Dam Safety Plan and minimize downstream impact by operating the dam gate. Dam Co is responsible for the gate operation and judgment based on the Dam Safety Plan. However, when the flood forecast does not correspond the actual result, the water level may draw down below the planning level, which may affect the power generation operation in dry season. Except for misjudgment, Dam Co and Gen Co need to confirm that public safety is prioritized and should be reflected in the PPA with NEA.

(Example)

- Dam Co notifies Gen Co if the reservoir water level draws down below the annual plan level as a result of dam gate operation after flooding.
- Gen Co discusses to revise the annual power generation plan with NEA.
- Force Majeure event may be applied when dam gate operations are deemed appropriate.

(Issues)

A tripartite agreement among Dam Co, Gen Co, and NEA is required.

7) <u>Stop due to Equipment Failure</u>

(Purpose)

This clause stipulates the “procedure”, “contents”, and “implementation time” when malfunction of dam equipment has an adverse impact on dam functions.

(Example)

- Dam Co promptly notifies Gen Co in the event of a failure that affects power generation operation.

- Dam Co should consider measures for resolving defects and take measures in consultation with Gen Co.

- Defect of dam equipment may cause inability of generation operation and impact revenue of Gen Co, which is subject to the compensation.

(Assumption)

Dam equipment is insured.

(Issues)

- How to evaluate the impact on power generation operation due to the failure of dam facilities. Clarify responsibility in the event that the adverse impact on generation increases due to inappropriate judgement or treatment.

- There is a possibility that the water level will rise due to equipment failure of the off-taker or transmission line, and that the reservoir operation plan has to be revised. Operational procedure for such case should be in line with PPA.

3. EMERGENCY SUCH AS DISASTERS

1) Emergency Measures, System (Initial Action, Recovery, Post-Processing)

(Purpose)

Both parties stipulate measures and systems for emergencies such as natural disasters.

(Example)

- Both parties establish emergency procedure for each events such as an earthquake or flood (it may be included in the Dam Safety Plan).

- Clarify the organization and instruction system in “daytime”, ”nighttime”, “initial movement” and “recovery”.

(Assumption)

The latest information such as emergency contact and organization charts of both parties is shared and updated.

(Issues)

Emergency countermeasure costs that each company covers need to be clarified.

2) Costs for Repair

(Purpose)

Specify the sharing mechanism of repair costs due to natural disasters. In particular, clarify the facilities that require early recovery, such as shared access roads and shared power sources. This stipulation enables early recovery.

(Example)

- Dam Co repair facilities essential for early restoration, such as shared access roads under the management of governmental agency. Dam Co temporally covers the repair cost. Dam Co charges and settles the repair cost with the government afterwards.

- Dam Co immediately repairs when cracks are found in the dam body or takes appropriate action where the risk of landslides increases due to an earthquake.

(Assumption)

Principally, restoration is carried out at the expense of the responsible party.

(Issues)

If a large-scale renovation is required and the power generation plan is changed, it is necessary to consider the adjustment of dam lease fees.

ANNEX 2

RISK SHARING MECHANISM

Risk Sharing Mechanism

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
Parties to Project Agreements and Counterparty Risk					
1.	Parties to PPA	NEA Project Company	-	Maintain basic risk allocation between GenCo and NEA. GenCo is responsible for all "generating related facilities" including dam under PPA, but the responsibilities should be passed through to DamCo under Dam Lease Contract (**DLC**). However, NEA should acknowledge dam related responsibility being shouldered by DamCo in a multi-partite agreement (see Item 4, "Government Coordination Agreement")	**PPA** NEA and GenCo to be parties in PPA.
2.	Parties to PDA	GoN (represented by the MoEWRI) Project Company	-	Though DamCo may be a governmental entity, private investment (domestic) in DamCo is expected. Therefore, DamCo is not regarded as a part of GoN and the responsibilities of GoN against DamCo and vice versa should be defined in the PDA.	**PDA:** GoN, DamCo and GenCo
3.	Government Guarantee	PDA: • NEA's payment obligations under the PPA are guaranteed by GoN to the extent that the letter of credit provided by NEA under the PPA (for two months of the USD portion of the tariff) has been fully drawn. • The Project Company is also indemnified by GoN for any liabilities incurred due to NEA's obligations in the PPA becoming unenforceable, invalid or illegal.	-	GoN's performance guarantee to NEA's obligation against GenCo should be maintained for private investment. GoN should also guarantee performance obligation of DamCo under DLC. The VSPPPM anticipates DamCo paying compensation to GenCo under the DLC where GenCo has either (i) incurred liability for delay or performance liquidated damages under the PPA; or (ii) suffered a loss in revenue under the PPA, in each case because of DamCo's failure to perform its obligations under the DLC. DamCo's ability to meet its payment obligations under the DLC will be of key concern.	**PDA:** **NEA obligations under the PPA:** GoN should be required to: • guarantee NEA's payment obligations under the PPA • indemnify GenCo for any liabilities incurred due to NEA's obligations under the PPA becoming unenforceable, invalid or illegal. **DamCo obligation under DLC** • guarantee DamCo's payment obligations under the DLC • indemnify GenCo for any liabilities incurred due to DamCo's obligations under the DLC becoming unenforceable, invalid or illegal.
4.	Coordination/Linkage between Governmental Project Agreements	**PDA:** There are linkages to the PPA throughout the PDA, e.g.: • the execution of the PPA is a condition subsequent to the effectiveness of the PDA, to be jointly achieved by both GoN and the Project Company; • NEA's event of default under the PPA is also a GoN event of default under the PDA; • GoN is required to guarantee NEA's payment obligations under the PPA and indemnify the Project Company if any of NEA's obligations become unenforceable, invalid or illegal (see Item 3 above); and • GoN is required to compensate the Project Company for lost revenues under the PPA that are due to changes in law, political force majeure or GoN's breach of the water rights granted to the Project Company. **PPA:** Unlike the PDA, the PPA has been drafted to operate independently of the PDA with very limited linkages to the PDA. Whilst the PPA states that it will automatically terminate if the PDA is terminated, its effectiveness is not linked to the effectiveness of the PDA, nor is there any GoN cross default language.	Not in-line with regional practice. It is more common for all key project agreements with governmental counterparties to be linked, with a breach by one governmental counterparty of its obligations under one governmental project agreement also triggering a breach by the other governmental counterparties under the other governmental project agreements.	A multipartite agreement (the "**Government Coordination Agreement**") to be entered into between DamCo, NEA, GoN and GenCo may be needed to coordinate and link each party's obligations as set out in the PPA, PDA, DLC and any GoN land lease agreements.	**Government Coordination Agreement** • GenCo's obligations in the PPA and the other governmental project agreements which need to carried out by, or in coordination with, GoN, DamCo or any of the other governmental counterparties; and • defaults by GoN, DamCo or any of the other governmental counterparties under the PDA, Dam Lease Agreement and other governmental project agreements which cause GenCo to be in default of its obligations under the PPA and the other governmental project agreements - GenCo should be relived from liability for all such defaults (including any consequential liability for performance or delay liquidated damages).

<table>
<tr><th>No.</th><th>Risk</th><th>Nepal Risk Allocation Current Status
(UT1 PDA, PPA Template)</th><th>General Remarks and Recommended Changes</th><th>VSPPPM Position</th><th>Proposal on VSPPM Position</th></tr>
<tr><td colspan="6">Initial Effectiveness of Project Agreements</td></tr>
<tr><td>5.</td><td>Conditions Precedent and Conditions Subsequent</td><td><u>PDA:</u>
• Effective on signing, but subject to conditions subsequent to be achieved by each of GON and the Project Company, including (i) GoN procuring that the Ministry of Law, Justice and Parliamentary Affairs issue capacity and enforceability legal opinions within 30 days of the date of the PDA; (ii) the Project Company executing, and GoN procuring the execution of the PPA within six months of the date of the PDA; (iii) GoN effecting the lease or transfer of the relevant land to the Project Company within the times required under the PDA; (iv) GoN executing, and procuring that the other relevant GoN instrumentalities executing the lender direct agreement no later than 60 days before the anticipated financial close date; (v) the Project Company achieving financial close within 24 months from the issuance of the generation license; and (vi) the Project Company issuing a "notice to proceed" to the construction contractors within one month of financial close.
• Failure by a party to achieve conditions subsequent within the required time (plus a remedy period of 180 days) will constitute an event of default entitling the other party to terminate.

<u>PPA:</u>
• Effective upon (i) NRB granting permission for the Project Company to bring foreign currency into Nepal for the purposes of the Project; and (ii) NEA confirming receipt of a performance guarantee provided by the Project Company.
• Project Company is required to achieve financial close within 24 months of the date of the PPA, failing which NEA can call on the full amount of the performance guarantee provided by the Project Company prior to the execution of the PPA.</td><td>Not aligned with regional practice.
As mentioned in Item 4 above, the PPA and PDA are not directly linked, and the execution and effectiveness of the PDA is not a condition precedent to the effectiveness of the PPA. Given the importance of the PDA to the Project, its effectiveness should be a condition precedent under the PPA, or alternatively, the PDA should be executed before the PPA.</td><td>GoN/DamCo is responsible for achieving financial close on the ODA Loan and loan agreement between MoF and DamCo.
GenCo is responsible for achieving financial close on the private loan.</td><td><u>PDA</u>
Effective on signing subject to conditions subsequent to be achieved by GoN, DamCo and GenCo including
• GoN obtain Legal opinion
• Execution of PPA, DLC
• GoN effecting the lease or transfer of relevant land to DamCo and GenCo
• Financial closing of ODA Loan, Loan Agreement between MoF and DamCo and GenCo's private loan
• Notice to Proceed issued by DamCo and GenCo to construction contractors

<u>DLC</u>
• PDA and PPA
• Financial closing

<u>PPA</u>
• Legal approval of foreign investment and loan
• PDA and DLA
• Financial closing</td></tr>
<tr><td>6.</td><td>Permits</td><td><u>PDA:</u>
• GoN required to procure that the GoN instrumentalities grant the Project Company the relevant permits for the Project, provided that the Project Company has made the necessary applications and complied with all associated obligations.
• Failure to grant permits (if the Project Company has made the necessary applications and complied with all associated obligations) and non-renewal or revocation of permits (not due to Project Company breach) is a GoN event of default under the PDA, entitling the Project Company to terminate and recover the termination payment described in Item 40 below.

<u>PPA:</u>
• Project Company responsible for acquiring and renewing all permits required for the construction and operation of the Project.
• NEA only required to make reasonable efforts to support and assist the Project Company in doing so.</td><td>Generally in-line with regional precedents (in terms of risk allocation), although it is more usual to see permitting risk designated as a political force majeure event, with corresponding relief, rather than as a government event of default.
The key permits in Nepal which will require the longest lead times to obtain are generally as follows:
• electricity generation license;
• EIA/IEE;
• land ceiling exemption and mortgage approval (see Item 7 below);
• leasing GoN land (see Item 7 below);
• approval of financing/loan documents from NRB; and
• approval to open and maintain offshore accounts.</td><td>Development concession rights and is granted by GoN to each DamCo and GenCo.

GoN may grant the development right to DamCo by applying a special permit following Electricity Act Section 35.

DamCo and GenCo are each responsible for taking out necessary permits for their respective facilities.</td><td><u>PDA</u>
• GoN grant development and concession rights to each DamCo and GenCo. DamCo and GenCo is required to obtain necessary permits.
• GoN instrumentalities grant the DamCo and GenCo the relevant permits
• Failure to grant permits constitutes GoN event of default
• To the extent that GoN's breach of its permitting obligation delays COD, entitle GenCo to an extension of time for achieving COD and compensation for lost revenue.

<u>DLC</u>
• Each party is responsible to obtain necessary permits.
• Failure of obtaining permit by a party constitute party's event of default. In such case, another company is entitled to terminate the contract and compensation.
• To the extent that DamCo's breach delays COD, entitle GenCo to an extension of time for achieving COD and compensation for lost revenue

<u>PPA</u>
• acknowledge GoN's and DamCo's permitting obligations under the PDA and DLC;
• relieve GenCo from breach of the PPA where such breach is due to GoN's/DamCo's breach of its permitting obligations under the PDA/DLC</td></tr>
</table>

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
					• to the extent that such breach delays COD, entitle GenCo to an extension of time for achieving COD
Project Site					
7.	Land Access Right	**General:** • Projects are built on private land and/or land leased from the GoN, with most projects featuring a mix of both. • Project Companies with foreign investments are entitled to own land in Nepal as companies incorporated in Nepal are treated as Nepalese persons, irrespective of foreign shareholding. • However, hydropower projects will require ownership of more land than the maximum ceiling prescribed for all persons (including companies), which is 3.815 hectares (in mountainous regions). Projects will require approval from the council of ministers to acquire land above this ceiling (this land ceiling is not relevant for land leased from the government). **PDA** • Private land – Project Company required to take reasonable steps to acquire privately owned land necessary for the Project, but if it is unable to acquire or enter into appropriate arrangements for the acquisition of all or any portion of such land within an agreed timeframe (usually one year from PDA signing date), it can request GoN to acquire such land as per Land Acquisition Act 1977. • Project Company is liable for all costs and expenses associated with such GoN acquisition. • GoN land - GoN required to lease to the Project Company GoN land necessary for the Project. • Execution of the corresponding land lease agreement is a condition subsequent to be fulfilled by the GoN. • Failure by the GoN to lease such GoN land to the Project Company will constitute a GoN event of default, entitling the Project Company to terminate and recover the termination payment described in Item 40 below. **PPA** • NEA land - NEA required to grant the Project Company access rights over all land owned or controlled by NEA, as is necessary for Project Company to develop, operate and maintain the Project. • Private land – there are no express provisions requiring NEA to assist the Project Company in securing access to private land.	Generally in-line with regional precedents. Notwithstanding the contractual risk allocation resting with the government after one year, land acquisition issues can still result in material delays to project timelines in Nepal. This is not particular to Nepal however and is perhaps the single most fundamental issue for sponsors across a number of Asian jurisdictions.	DamCo and GenCo are each responsible for land acquisition for their respective facilities. For land on which the Dam is to be constructed, if DamCo is regarded as a governmental entity, a different land acquisition process will apply and the PDA will need to be amended to reflect this. For land that is already owned by GoN (or another governmental instrumentality), it cannot be simply transferred to another government entity (section 24 of the Land Revenue Act).	**PDA** Current contractual obligations described in PDA is applied also to DamCo. DLC reflect such obligations. **PPA** NEA acknowledge land for the dam is acquired by DamCo. **DLC** Each parity is responsible for acquire the land for its responsible facilities.
8.	Access Road	**PDA:** • GoN required to procure that the relevant governmental instrumentalities (i) allow the Project Company and its contractors to use existing public roads, bridges and tunnels; and (ii) grant all necessary permits required for the Project Company to construct, modify or improve existing public roads, bridges and tunnels. • Project Company is otherwise responsible for constructing, modifying or improving public roads, bridges and tunnels needed to access the Site.	-	Responsibility for construction and maintenance of access roads to be agreed among GoN, DamCo and GenCo. Common access road should be defined in DLC. Responsible party for construction and maintenance of common access road should be stated.	**PDA** • GoN should be responsible for the construction/upgrading of all public access roads within the time agreed in the overall construction schedule, with delay liquidated damages payable to GenCo for any delay by GoN in achieving such milestone (see Item 17 below for further detail on the overall construction schedule). • DamCo and/or GenCo is responsible for access road dedicated to construction and/or operation purpose of facilities. **DLC** • Responsibility of common access road • Cooperation to utilize common access road
9.	Ground Conditions	**PDA:**	Other Force Majeure Event defined in PDA	-	**PDA**

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
		• Unforeseeable site and geological conditions and the discovery of any antiquities or other objects of cultural and religious value are included as "Other Force Majeure Events" (to the extent that they were not identified in the EIA or detailed project/engineering report). • Project Company entitled to suspend performance and seek an extension of time, though there is no express entitlement to recover the additional costs incurred in overcoming such conditions, or recover lost revenues under the PPA. **PPA:** • Not expressly addressed, though unforeseeable ground conditions would likely constitute a force majeure event entitling the Project Company to suspend its obligations and seek an extension of time (but there is no entitlement to recover the additional costs of overcoming such conditions, or deemed payments).	should be reflected in PPA,		Contractual obligations in current PDA should be maintained and applied to both DamCo and GenCo.
10.	Resettlement of affected persons	**PDA:** • Project Company responsible for preparing and implementing resettlement and rehabilitation plan for project affected people. • Project Company must sell/issue up to 10% of its shares to project affected people, and ensure that at least 2/3rds of distributable profits are paid as dividends to shareholders (see Item 51 below for further detail).	-	DamCo and GenCo are each responsible for resettlement of persons on land to be used for their respective facilities.	**PDA** Contractual obligations in current PDA should be maintained and applied to both DamCo and GenCo. [GenCo's obligation of share allocation to PAPs may be re-arranged since affected people by dam and power facilities are different.]
11.	Access rights for transmission lines	Same principles as set out in Item 7 above apply. Though the Project Company is responsible for the construction of the transmission line up to the delivery point (i.e. the NEA substation), GoN is ultimately responsible for securing all land that is required for this purpose (including acquiring any private land, to the extent that GenCo is unable to do so).	-	-	**PDA and PPA** Contractual obligations in current PDA and PPA should be maintained.
Funding and Lenders					
12.	Lender step in rights	**PDA:** • GoN required to and procure that the relevant governmental counterparties enter into a direct agreement with lenders and the Project Company in relation to the PPA, PDA and land lease agreement. • A form of direct agreement is appended to the PDA. **PPA:** • NEA required to enter into a direct agreement with lenders and the Project Company in relation to the PPA.	-	Lender's step in rights are only applied to private loan lenders for GenCo.	**PDA and PPA** Contractual obligations in current PDA and PPA should be maintained.
13.	Assignment to Lenders and Security	**PDA and PPA:** both NEA and GoN required to consent to the Project Company's assignment to lenders of its rights under the PPA and PDA.	-	Private lenders may want a security assignment over the lease of the Dam, and that ODA lender may not take any security over the Dam or other aspects of the Project.	**PDA and PPA** Contractual obligations in current PDA and PPA should be maintained. **DLC** GenCo is entitled to assign its interests on DLC to the private lenders without having to obtain DamCo's prior consent.
Construction Responsibility					
14.	Project Design	**PDA:** • Whilst GoN and the project review panel (see Item 16 below) have rights to review the design, the Project Company is solely responsible for preparing it. **PPA:** • Project Company is solely responsible for Project's design.	-	DamCo and GenCo is responsible for design of its responsible facilities. Design and specifications should be agreed by both parties. In case delay of dam construction due to dam design causes delay of COD, DamCo is responsible for compensating liquidated damage payable from GenCo to NEA under PPA and loss	**PDA and PPA** • Acknowledge design responsibility lies on each DamCo and GenCo. • Relieve GenCo from breach of PDA/PPA where such breach is due to issues with the Dam's design • In case such design issues delay GenCo's ability to achieve COD or otherwise prevents GenCo from performing its

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
				of revenue of GenCo. In case delay of power facility construction due to power facility design, GenCo is responsible for Dam Lease Fee..	obligations under the PPA, entitle GenCo to an extension of time for achieving COD **<u>DLC</u>** • Each party is responsible for designing its facilities. • In case failure of design responsibility of DamCo delay Geon's ability to achieve COD or otherwise prevents GenCo from performing its obligations under PPA, DamCo is obliged to compensate for lost revenue commencing from the original scheduled COD,
15.	Construction	**<u>PDA and PPA:</u>** The Project Company is responsible for the construction of the entire Project (other than the portion of the transmission line from the delivery point to the national grid).	-	DamCo and GenCo is responsible for construction of its responsible facilities.	**<u>PDA and PPA</u>** • Acknowledge construction responsibilities lies with DamCo for dam and GenCo for power facilities • Relieve GenCo from breach of the PPA/PDA where such breach is due to issues with the Dam's construction (including any construction delay, or defects in construction) • In case DamCo's breach of its construction obligations delays GenCo's ability to achieve COD or otherwise prevents GenCo from performing its obligations under the PPA/PDA, entitle GenCo to an extension of time for achieving COD **<u>DLC</u>** • Each party is responsible for construction of its facilities. • In case failure of construction responsibility of DamCo delay Geon's ability to achieve COD or otherwise prevents GenCo from performing its obligations under PPA, DamCo is obliged to compensate for lost revenue commencing from the original scheduled COD, • in case GenCo fail to achieve construction schedule, GenCo remain obliged to pay Dam Lease Fee under DLC
16.	Co-completion/ coordination risk - project review Panel and coordination committees	**<u>PDA</u>** • An independent project review panel comprising of experts in geological and geotechnical engineering, hydropower engineering, dam safety and E&S matters is established to due diligence and maintain oversight of the development and construction phase of the Project. • The project review panel owes its duties to both the GoN and the Project Company and is required to be in place until six months after COD (or such later time as required by lenders). **<u>PPA:</u>** • A coordination committee comprising of representatives from both the Project Company and NEA is established to coordinate the construction and operation of the Project, the interconnection facilities and the transmission line (to which both the Project Company and NEA have joint responsibilities to construct – see Item 20 below). The powers and duties of the coordination committee include: • coordination of the respective programs of the parties for the construction and commissioning of any and all related NEA interconnection facilities, the transmission line and the Project, and agreement, where necessary, on the respective commissioning procedures; • discussion of the steps to be taken on the occurrence of any force majeure event, or any shutdown or reduction in capacity for any other reason; • consultation on the insurance program to be undertaken by Company for the purposes of the PPA;	Note that the procedure of project review panel follows WB guideline. Other lenders may have other procedure.	Both DamCo and GenCo should cooperate and closely coordinate the construction schedule for effective schedule management.	**<u>PDA and PPA</u>** Contractual obligations in current PDA/PPA should be maintained and applied to both DamCo and GenCo.

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
		• the development, finalization and amendments of the operating procedures; • safety matters affecting all parties or the contractors; • finalization of the scheduled outage plan for each contract year; • any other mutually agreed matter affecting the construction and operation of the Project.			
17.	Construction Schedule, Delay Risk and liquidated damages	**PDA:** • Project Company is required to prepare a construction schedule for the Project, which is subject to input from GoN and the project review panel referred to in Item 16 above. • Project Company is entitled to claim an extension to the Scheduled COD and the term where it is delayed due to (i) force majeure, (ii) changes in law, (iii) extra-ordinary construction delays (essentially unforeseeable delays that are beyond the Project Company's reasonable control, could not have been prevented or avoided despite the exercise of diligence and for which the Project Company has taken all reasonable precautions to prevent or avoid), or (iv) GoN's breach of the PDA; and (v) delay in land acquisition. A further six months extension would also apply where the Project Company determines that this is necessary (essentially a grace period before delay liquidated damages begin to accrue). • There is no right to deemed generation payments/compensation for lost revenue where COD is delayed due to GoN defaulting on its obligations under the PDA, or NEA or any other governmental counterparty defaulting on its obligations under the other governmental project agreements. Though the Project Company is entitled to recover compensation for additional costs incurred due to governmental force majeure occurring pre-COD, this does not cover lost revenue (see Item 35 below). • Delay liquidated damages are payable by the Project Company to GoN if COD is not achieved by the scheduled COD. **PPA:** • Project Company is required to comply with the project construction schedule appended to the PPA and achieve COD by the scheduled COD. • Liquidated damages are payable to NEA if the Project Company's delay in completing the transmission line from the project site to the delivery point (i.e. the NEA substation) results in a delay in achieving COD by the scheduled COD. • Liquidated damages are payable by NEA to the Project Company if NEA fails to complete the portion of the transmission line from the delivery point to the national grid by the scheduled date, though this is only sized at 45% of the estimated revenues (see Item 20 below).	The lack of an express entitlement to deemed generation payments/ compensation for lost revenue where COD is delayed due to GoN, NEA or any other governmental counterparty defaulting on its obligations under the governmental project agreements – in some jurisdictions this is dealt with through the governmental force majeure regime, which would cover actions by other governmental authorities that impede the Project Company's performance, and entitle the Project Company to deemed generation payments if COD is delayed as a consequence. This is however not the case under the PPA or PDA Project Company's liability to pay delay liquidated damages under both the PDA and PPA for COD delay – delay liquidated damages are usually payable under one agreement only.	The construction schedule should be managed by GenCo and DamCo. Construction of interconnection facilities (such as transmission line) is responsibility of NEA. Liquidated damage amount of current PPA Template (45% of contract energy) should be revised to cover repayment of commercial loan and ODA loan. **Adjustments and Extensions of Time** The grounds under which GenCo is entitled to an extension of time to all millstones under the construction schedule (including to scheduled COD) will need to be aligned across the PPA, PDA and DLC, and any extension of time granted under one governmental project agreement should trigger an automatic extension under the other governmental project agreements. The grounds for extension should include any breach by any of the governmental counterparties under any of the governmental project agreements (to the extent that such breach impedes GenCo's performance). **Liquidated Damages** For COD delays that are due to GenCo's default, there should only be a single set of delay liquidated damages that are payable by GenCo (either to NEA under the PPA or GoN PDA, but not under both the PPA and PDA). In case COD delays that are due to DamCo's default of its obligations under the DLC, DamCo is obliged to pay liquidated damages to cover GenCo's liquidated damages payable to NEA under PPA. Alternatively, for the PPA and PDA to make clear that no liability for liquated damages would arise where the delay is due to any of the other governmental counterparties (including DamCo) failing to perform their obligations under the other governmental project agreements. GenCo should also be entitled to compensation for lost revenue from the original Scheduled COD where COD is delayed due to DamCo, NEA, GoN or any other governmental counterparty defaulting on its obligations under the other governmental project agreements.	**PDA** • DamCo and GenCo is obliged to keep agreed construction schedule including any milestones and COD • In case COD delays due to GoN's failure of its obligation, DamCo and GenCo is entitled to compensation and lost revenue. **PPA** • GenCo is obliged to keep COD schedule and any milestones of commissioning. • In case COD is delayed due to GenCo's failure of its obligation, liquidated damages are payable from GenCo to NEA. (The amount of liquidated damage shall be reconsidered because "45% of expected revenue" in PPA Template is excessive. It should be equal amount of NEA's loss caused by the delay.) • In case COD is delayed due to DamCo's failure of its obligation, [alternative 1] liquidated damages are payable from GenCo to NEA or [alternative 2] liquidate damages are payable from DamCo to NEA • In case COD is delayed due to failure of NEA's obligation, NEA shall compensate GenCo to cover loan repayment of commercial loan and ODA loan. (45% of expected revenue in the PPA Template is not enough.) **DLC** • DamCo and GenCo is obliged to keep agreed construction schedule including any milestones and COD • In case COD is delayed due to DamCo's failure of its obligation, liquidated damages are payable [alternative 1] to GenCo or [alternative 2] to NEA. In such case, DamCo is also responsible to compensate lost revenue of GenCo.
18.	Cost overruns	**PDA and PPA:** The Project Company is responsible for funding construction cost overruns, other than cost overruns arising out of specific circumstances that are beyond the Project Company's control (such as changes in law and political force majeure occurring pre-COD, to which there are specific rights to recover compensation – see Items 35 and 37	-	-	**PDA and PPA** Contractual obligations in current PDA/ PPA should be maintained and applied to both DamCo and GenCo.

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		below).			
19.	Testing/Commissioning	**PPA:** • The Project Company is solely responsible for the testing and commissioning of the Project and the portion of the transmission line up to the NEA substation; and • NEA is solely responsible for the testing and commissioning of the portion of the transmission line from the NEA substation to the national grid, provided that, in each case, such testing and commissioning is carried out in coordination with the coordination committee (see Item 16 above). **PDA:** • The Project Company is solely responsible for the testing and commissioning of the Project in accordance with the PPA, as witnessed by the NEA and GoN (or the project monitoring unit appointed by GoN to act on its behalf).	-	The preparation of all testing and commissioning plans, and the carrying out of all performance tests will require coordination between NEA, DamCo and GenCo.	**PDA and PPA** Contractual obligations in current PDA/ PPA should be maintained and applied to both DamCo and GenCo. **DLC** The preparation of all testing and commissioning plans, and the carrying out of all trial operation and performance tests should be undertaken by DamCo and GenCo jointly (or by the applicable EPC contractors), and be subject to the oversight of the coordination committee referred to in Item 16 above.
20.	Connection/Transmission	**PPA:** • Project Company is required to carry out the necessary construction works for the transmission line from the project site to the delivery point (i.e. the NEA substation) by the scheduled date. • If a failure to do so results in a delay in achieving the commercial operation date, the Project Company is liable to NEA for liquidated damages equal to 45% of the estimated revenues (based on the contracted capacity) for the period of delay. • NEA is required to carry out the necessary construction works for the transmission line from the delivery point to the national grid by the scheduled date. If NEA fails to do so by the scheduled date, NEA is liable to the Project Company for liquidated damages equal to 45% of the estimated revenues (based on the contracted capacity) for the period of delay.	The off-taker should generally take 100% risk on interconnection (as it is ultimately responsible for transmission and distribution system) and the Project Company should be paid either (i) on a 100% deemed basis (based on contracted capacity) or (ii) compensation to cover debt service and other unavoidable costs, in each case for any period of delay in interconnection by power purchaser. Termination right should also apply for prolonged delay.	-	**PPA** **Liquidated Damages** To the extent that NEA is responsible for carrying out interconnection works, and there is delay in the completion of such works, then GenCo should be entitled to compensation for lost revenue from the original Scheduled COD, sized at 100% of the payment defined in payment schedule as if the project has been commissioned. (rather than 45% of the contracted capacity). In case any other governmental counterparty is responsible for interconnection works, PDA should include the responsibility of GoN instead of NEA.
Environmental Responsibilities					
21.	Preparation of EIA	EIA is prepared by the Project Company and approved by the Ministry of Science, Technology and Environment before the PDA is executed. It is then appended to, and forms part of the PDA.	-	DamCo and GenCo is responsible for EIA covering its facilities. Alternatively, any party may take responsibility for both dam and power facilities for simpler procedure.	**PDA** Responsible party is defined. **DLC** Responsible party is defined. Mutual coordination and cooperation including implementing procedure should be stated.
22.	Compliance with environmental/ social management and monitoring plans as per EIA	Under the PDA the Project Company is required to comply with the EIA and implement all environmental/social management and monitoring plans as per the EIA.	-	Dam - DamCo responsible for complying with the EIA and implementing all environmental/social management and monitoring plans as per the EIA. Generation Facilities – GenCo responsible for complying with the EIA and implementing all environmental/social management and monitoring plans as per the EIA.	**PDA and DLC:** DLC to set out, and PDA to be amended to reflect each of DamCo and GenCo's responsibilities to comply with the EIA and implementing all environmental/social management and monitoring plans as per the EIA.
Operational and Maintenance Responsibilities					
23.	Day to Day Operations	**PDA and PPA:** The Project Company is responsible for day to day operations and complying with NEA's dispatch instructions.	-	Dispatch instructions are made by NEA to GenCo. GenCo is responsible for operating the Project as per NEA's dispatch instructions.	**PPA** • NEA is responsible for reservoir operation except during emergency situation. • Dispatch instruction is made by NEA. GenCo is responsible for day to day operation. • Information exchange procedure between NEA and GenCo is defined.

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
					DLC • Information exchange procedure between DamCo and GenCo is defined.
24.	Operating procedures and operating plans	**PDA:** • The Project Company is required to prepare operation and maintenance procedures and manuals no later than 60 days before COD, which are required to be updated from time to time. **PPA:** • Operating procedures are jointly developed by the Project Company and NEA and finalized before the scheduled synchronization date of the first unit. • The operating procedures will address matters such as availability declarations, dispatch procedures, emergency plans, outage scheduling, capacity and energy reporting, operating logs and the creation of an operating committee (see Item 25 below).	-	Details of operational procedures during operation phase should be agreed and defined in the PDA and reflected in the PPA and DLC. Annual rule curve, which is a basis of reservoir operation, should be agreed between NEA, Dam Co and Gen Co. Annual/monthly/weekly operation plan will need to be determined by NEA beforehand and communicated to GenCo and DamCo. Those plans should be developed based on weather forecasts, demand forecasts and the scheduled maintenance plan that is submitted by DamCo and GenCo.	**PDA** • NEA is responsible to prepare annual rule curve by consultation with DamCo and GenCo. • GenCo and DamCo is responsible to prepare operation and maintenance procedures for its facilities. **PPA** Contractual obligations in current PPA should be maintained and applied to both DamCo and GenCo. **DLC** Each party is responsible to prepare operation and maintenance procedures for its facilities.by consultation with other party.
25.	Operating committee	**PPA:** The operating committee comprises of two representatives from each of the Project Company and NEA. Its duties include: • implementing and administering the operating procedures; • recommending amendments on operating procedures; • reviewing and revising protection schemes and devices; • reviewing of emergency plans; • coordinating the operation and maintenance of the interconnection facilities including maintenance outages; • safety matters; • any other matter affecting the operation of the Project as referred to by the coordinating committee (see Item 16 above)	-	DamCo is a party for operating committee.	**PPA and DLC:** To the extent that DamCo will retain responsibility for operating and maintaining the Dam, then the operating committee mechanism should be expanded to include DamCo. The amended operating committee mechanism in the PPA will need to be replicated in the DLC, or alternatively, in the Government Coordination Agreement if all governmental counterparties agree to execute such agreement.
26.	Reporting obligations	**PDA and PPA:** Both documents set out the Project Company's ongoing reporting obligations, including in relation to daily availability declarations, scheduling and outages.	-	Since NEA is responsible for determining day to day operation, required data such as meteorological data, hydrological data, reservoir water level, operating status etc. should be reported to NEA from DamCo and GenCo	**PPA, PDA and DLC:** DLC to set out, and PPA and PDA to be amended to reflect the split in reporting responsibility between DamCo and GenCo.
27.	Dam Safety and Emergency Operation	**PDA:** The Project Company is required to prepare before COD: • an emergency preparedness plan, setting out each of GoN and the Project Company's roles in the event of a dam failure, or when expected operational outflow release will threaten property, life or economic operations dependent on river flow levels; and • a disaster management plan which takes into account different flood eventualities and other natural disasters. **PPA:** • Emergency operation plans are developed by the Project Company and NEA jointly (through the operating committee) before COD. • Each party is required to take necessary actions to prevent or mitigate injury to persons and damage to property during an emergency.	Emergency preparedness plan and disaster management plan may be combined into one document.	Dam operation during emergencies (such as flooding due to glacier lake outbursts, earthquake, failure of equipment etc.) should be the responsibility of DamCo under supervision of responsible governmental entity. The operational procedure should be defined in an emergency dam operation manual, which is a part of the emergence preparedness plan. Emergency preparedness plan should be agreed before the initial impoundment of the dam among the relevant governmental bodies (Ministry of Land Management and Cooperatives and any relevant agencies to be proposed), local government units in downstream area, NEA, Dam Co. and GenCo.. Since the Dam has to be operated so as to prevent adverse impact on downstream areas during natural disasters, any negative impact including	**PDA** • Definition of emergency situation • DamCo should establish emergency preparedness plan before initial impounding, which should be approved by GoN. • DamCo is responsible for emergency dam operation under supervision of responsible governmental agency. • In case emergency dam operation result in any adverse impact on generation and revenue of GenCo, GenCo is entitled to compensation. **PPA** • Acknowledge that DamCo is responsible for reservoir operation during emergency situation. • In case emergency dam operation result in any failure of GenCo's obligation under PPA, NEA indemnify GenCo from its obligation.

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
				consequential damage (e.g., loss of revenue) on power generation caused by such dam operation shall be exempted from responsibilities of GenCo against NEA.	**DLC** • DamCo is responsible for preparing emergency preparedness plan • DamCo is responsible for emergency dam operation so as to prevent natural disaster in downstream area.
28.	Maintenance and Periodical Inspections to Ensure Dam Safety	**PDA:** • The Project Company is responsible for the maintenance of the Project. **PPA:** • The Project Company is responsible for the maintenance of the Project, including the transmission line up to the delivery point. • NEA is responsible for the maintenance of the transmission line from the delivery point.	-	**Dam:** DamCo assumes all maintenance responsibilities, including periodic inspections to ensure the safety of the Dam and carrying out regular sedimentation surveys. Compensation payable by DamCo to GenCo under the Dam Lease Agreement where DamCo's default of its maintenance obligations impacts on GenCo's generation and revenues under the PPA. **Generation Facilities**: GenCo assumes all maintenance responsibilities.	**PPA** • Acknowledge that DamCo is responsible for maintenance and inspection of dam **DLC** • DamCo is responsible for maintenance of dam • In case failure of GenCo's obligation due to failure of dam maintenance, GenCo is entitled to compensation including lost revenue.
29.	Hydrological risk and water rights	**PDA:** • There are detailed provisions granting the Project Company rights to utilise water, and which require GoN to: (i) procure that third parties in Nepal do not interrupt or adversely impact on the availability of water; (ii) coordinate between the Project Company and the owners or operators of other projects (either upstream or downstream) to ensure that the Project is not adversely impacted; (iii) undertake such activities as may be required to ensure that the Project is not adversely affected where the flow or availability of water is diverted or reduced within Nepal due to non-natural reasons. • GoN is required to compensate the Project Company for loss of revenue under the PPA due to GoN's breach of such obligations. • GoN is not otherwise liable to the Company for any adverse impact on the availability of water due to natural events. • Drought in the catchment area is also a non-political force majeure event, although no further clarity is provided on what would constitute "drought". A non-political force majeure event which results in a reduction in the availability of water would entitle the Project Company to an extension of the term, suspend performance and agree with GoN on "appropriate and reasonable" amendments to the PDA.	For reservoir type hydropower project, reservoir is fully operated by the system operator (NEA) for maximizing the benefit. NEA may instruct dispatch or cease to dispatch following system requirement. Annual and monthly hydrological fluctuation will deteriorate GenCo's financial stability which also deteriorate bankability of the project. For reasons above, a certain part of NEA's payment under PPA should be constant. It is recommendable to introduce capacity payment system. Introducing capacity payment system means NEA undertake hydrological risk. NEA is responsible to pay capacity charge subject to plant availability regardless actual dispatched energy.	DamCo also requires stable income from GenCo by means of dam lease fee to repay the ODA loan. Capacity payment system can enhance DamCo's ability of repayment.	**PDA** • Maintain current contractual obligation for water usage right. • Drought is not a part of force majeure event **PPA** • Purchase tariff consists of i) capacity payment and ii) energy payment • Capacity payment is subject to availability of the generation during designated period of time.
30.	Reduced capacity/availability	**PPA:** • **Event of Default for Unavailability** - a Project Company event of default will occur if either: (i) partial unavailability results in the electrical output being between 60% and 75% of the monthly contracted capacity for either seven consecutive months or 10 months in any contract year; or (ii) total unavailability or partial unavailability results in the electrical output being less than 60% of the monthly contracted capacity for either four consecutive months or seven months in any contract year. • No event of default will occur if the unavailability arises: (i) out of any act or omission of NEA; or (ii) during a scheduled outage, maintenance outage or forced outage due to or during a force majeure event. • There is no ability to reduce the contracted capacity on COD even if the tested capacity is lower. • **Unavailability Liquidated Damages -** Except where due to a dispatch instruction, NEA's act or omission, a scheduled outage, maintenance outage or force majeure event, if the Project Company is unable to deliver at least 80% of the contracted capacity for a given month, liquidated damages will be payable by the Project Company to the NEA per the following formula: [0.8 x Contract Energy for the month – Electrical Output] x tariff	PPA Template is designed for RoR hydropower plants (note that even for RoR plants, obligation of GenCo to produce contracted capacity with liquidated damage is not common). Since storage hydropower plants is controlled by NEA except emergency situation, those clauses are not necessary.	-	Not applied to storage type hydropower plants

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
		• Such liquidated damages may be deducted/set-off by the NEA against payments owing from NEA. • These liquidated damages are payable on an ongoing basis. • Unless the PPA is amended, the contracted capacity stays as it is (despite the tested capacity of the plant actually being lower).			
Revenue Risks					
31.	Offtake/payment risk	**PPA:** • Payment is made on a take or pay basis, with the Project Company entitled to be paid each month for actual electrical output delivered plus deemed generation payments. • Deemed generation is the energy which is available but not delivered due to conditions of the grid or power system beyond the Project's control resulting in the spillage of water. • Deemed generation specifically carves out circumstances where the Project is not available due to force majeure, scheduled or maintenance outages, or reduced output or grid outages attributable to the Project Company. • Deemed generation is calculated by reference to the declared availability or contracted capacity (whichever is lower). • NEA's obligation to pay deemed generation will not arise until the aggregate number of hours of such reduction or interruption exceeds 168 hours (calculated on a pro-rata basis, based on the installed capacity).	Since storage hydropower plants is controlled by NEA except emergency situation, those clauses are not necessary. Tariff structure with capacity payment is based on availability of the plant. No take-or-pay scheme is required.	-	Not applied to storage type hydropower plants
32.	Electricity Tariff and escalation	**PPA:** • Pursuant to the ELC Bylaw issued by Electricity Regulatory Commission, purchase tariff for hydropower plants more than 100MW is determined by "cost plus modality" basis. • NEA is also entitled to adjust the tariff downwards if the ROE exceeds 17% (in order to maintain the 17% ROE). • Both the PPA and the tariff will need to be approved by the Electricity Regulatory Commission.	-	-	-
33.	Tariff Currency and Devaluation Risk	Electricity Regulatory Commission and NEA stated tariff is only paid by local currency.	Big concern for foreign investors and lenders	-	-
34.	Exchange risk and offshore accounts	GoN have not determined hedging mechanism for currency exchange rate variation risk.	Big concern for foreign investors and lenders	-	-
Force Majeure					
35.	Political Force Majeure	**PDA:** The following events are categorized as political force majeure: • politically motivated strikes; • war by or against Nepal; • revolution, mutiny, rebellion; • blockade for over 30 days or import restriction or rationing; • failure or breakdown of Nepalese gird system; • radioactive, biological contamination by GoN entities; • analogous events. If the Project Company is affected by a political force majeure event, it will be entitled to: • suspend performance; • claim compensation for the additional costs incurred as a result of such event, as well as loss of PPA revenue (to the extent that the political force majeure event occurred after COD).	Misalignment of definitions in PDA and PPA is not in line with regional norms. Political force majeure in other jurisdictions may also be defined to include: (i) actions by government and relevant authorities/off-taker; (ii) changes in law; (iii) failure to obtain or non-renewal of permits; and (iv) expropriation. The PDA instead includes all of these events as GoN events of default which still ultimately entitle the Project Company to terminate and recover a termination payment.	Political and non-political force majeure provisions under the DLC will need to be aligned with the PPA and PDA. If either GenCo cannot generate power, or NEA cannot take power due to a force majeure event under the PPA, then GenCo's obligation to pay dam lease fees under the DL/PDA should also be reduced or exempted in-line with the PPA.	**PDA and PPA:** Definition of political and non-political force majeure event should be aligned in both PDA and PPA. No governmental counterparty should be entitled to claim force majeure (and consequential force majeure relief) to the extent that the event is due to a breach by either NEA, GoN or DamCo under any of the other governmental project agreements. This can be addressed in each of the PPA and PDA. In case COD is delayed by political force majeure, GenCo should be entitled to compensation for lost revenue.

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		For political force majeure occurring pre-COD, there is no express entitlement to payment of lost revenue, though the list of compensation payable in such event does cover the Project Company's payment obligations under the financing documents, together with any additional financing costs which may be incurred. Such compensation is not paid out to the Project Company in a single lump sum, but rather, by a combination of the following (referred to as "staggered remedies"): • setting-off against the Project Company's liability for delay LDs; • reducing the energy royalty and capacity royalty payable by the Company post-COD (see Item 52 below); and • exempting the Project Company from taxes which would otherwise be payable. If after applying such staggered remedies, the Project Company has still not recovered the full compensation that it would otherwise have been entitled to, the Project Company will be entitled to an extension of the term. **PPA:** • There is a limited political force majeure definition which is not used in the PPA. The definition is also not aligned with the one in the PDA. • Any force majeure event affecting the Project Company would entitle the Project Company to (i) suspend performance (and be relieved of its obligations to pay liquidated damages for reduced output); and (ii) seek an extension of the term (if it had not received business interruption or advance loss of profit insurance in an amount equal to the full amount of deemed generation payments). • There is no entitlement to deemed generation payments (as the Project Company would not be available) or other compensation. • It however appears that the Project Company may be entitled to recover deemed generation payments where it is available to generate but NEA is unable to take power (including due to both political and non-political force majeure events affecting NEA). This however would not cover force majeure events occurring pre-COD.			
36.	Non-political Force Majeure	**PDA:** Non-political force majeure events include (but are not limited to): • acts of god, including drought, floods, earthquake, landslides, mudslides, etc.; • geological surprises and unforeseen site conditions; • fire or explosion; • epidemic; • discovery of antiquities; • air crash, shipwreck, failure or delay of transportation; • strikes; • war; • blockade, embargo; • radioactive, biological contamination; • analogous events. Strikes primarily arising because of working conditions which are reasonable, failure to maintain government approvals, failure to take into account site conditions and mechanical or electrical failure are excluded from force majeure events. If the Project Company is affected by a non-political force majeure event, it will be entitled to suspend performance and seek an extension of time, though there is no entitlement to recover the additional costs incurred in overcoming such event, or recover revenues lost under the PPA. There is also no entitlement to recover compensation for non-political force majeure	Misalignment of definitions in PDA and PPA is not in line with regional norms. Flooding with magnitude over certain level and requiring emergency dam operation should be included in Non-political force majeure event. Any failure of GenCo's obligation due to emergency dam operation should be accepted.	See item 35 above	See item 35 above

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		events affecting GoN. **PPA:** • The non-political force majeure definition is not aligned with the definition in the PDA (but does include force majeure events listed under the PDA). • See Item 35 above in relation to political force majeure for the consequences of a non-political force majeure arising - same position applies.			
Other Political and Regulatory Risks					
37.	Change in law/Change in tax	**PDA:** • GoN is required to compensate the Project Company for additional liabilities incurred in aggregate above NPR 20 million (equivalent to around USD 200,000) resulting from any change in law and change in tax after the agreement date. • A change in law restricting the Project Company's ability to perform its obligations under the PDA and PPA or restricting its right to receive payment or enforce its rights is a GoN event of default, entitling the Project Company to terminate and recover the termination payment described in Item 40 below. • The generation license, other Nepalese laws, and legal principles applied by courts also grant various protections against any retrospective change in legislation and withdrawal of legal rights that breach legitimate expectations. **PPA:** There is no change in law provision in the PPA.	-	-	**PDA** Current procedure and consequential entitlement is applied to both DamCo and GenCo. [the amount of additional liability should be determined project by project]
38.	Expropriation	**General:** • There is protection against expropriation under the Industrial Enterprise Act for "energy industries" and Foreign Investment and Technology Transfer Act for industries with foreign investment. To qualify for protection under the Industrial Enterprise Act, the Project Company will need to register as 'energy industry' pursuant to schedule 3 of the Industrial Enterprise Act. • Section 29 of the Electricity Act also provides protection for all assets relating to the generation, transmission and distribution of electricity, provided that the generation capacity is above 1000 kW. • Further protection from expropriation can also be set out in the terms of the generation license issued for the specific project. **PDA:** • Expropriation is a GoN event of default entitling the Project Company to terminate and recover the termination payment described in Item 40 below. **PPA:** This is not expressly addressed in the PPA.	-	-	**PDA** Current procedure and consequential entitlement is applied to both DamCo and GenCo.
39.	Off-taker reorganization	The government guarantee in the PDA of NEA obligations under the PPA will also guarantee obligations of any successor or permitted assignees in the event NEA is reorganized.	-	-	Current contractual obligation is maintained and applied to both DamCo and GenCo.
Termination Risk					
40.	Government Default	**PDA:** GoN events of default includes: • payment default; • expropriation;	It would be preferable if the NEA cross default language currently included in the list of GoN events of default under the PDA is also included under the list of NEA events of default in the PPA. In practice this may not be of concern given that the PPA states that it will automatically terminate if the PDA is also terminated, and termination	An event of default by either NEA, GoN under any of the governmental project agreements should trigger an event of default by all of the governmental counterparties under the other governmental project agreements. Termination of any one of the governmental project agreements should similarly trigger the	Current contractual procedure and entitlement is maintained and applied to both DamCo and GenCo.

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
		• failure to achieve commercial operation by scheduled date because of breach of agreement by government; • non-compliance of expert or arbitral tribunal order; • material change in law; • non-fulfillment of condition subsequent; • event of default under the PPA attributable to the NEA and event of default under GoN land lease agreement attributable to GoN; • breach of any representations and warranties by GoN under the PDA; • failure to grant or renew permits; • other material breach. The Project Company can terminate the PDA if the GoN event of default is not cured within a defined cure period, in which case the following payments will apply: • GoN event of default prior to financial close: reasonable and prudent costs for project development including for project land + transfer taxes; or • GoN event of default on or after financial close: debt + any undisputed sums due and owing from GoN, NEA or other GoN instrumentalities + finance costs + equity (including shareholder loans) + 120% of equity + transfer taxes - insurance proceeds - any remaining amount in a debt service reserve account. **<u>PPA:</u>** NEA event of default is limited to: • dissolution of NEA other than as permitted by the PPA; • transfer of its rights other than as permitted by the PPA; • payment default exceeding 45 days after the due date; and • failure to perform any other material obligation under the PPA that is not remedied within 60 days of written notice. Following termination by the Project Company, there is only an entitlement to recover damages under general law. No fixed termination payments apply.	payments are dealt with under the PDA.	automatic termination of the other governmental project agreements. Both of these matters can be addressed in each of the PPA and PDA.	
41.	Project Company Default	**<u>PDA:</u>** Project Company events of default include: • breach of payment obligations for 60 days; • insolvency events; • failure to achieve commercial operation as scheduled; • failure to deliver the performance security or handover guarantee; • abandonment; • breach of shareholding restrictions; • event of default under the PPA or GoN land lease agreements attributable to the Project Company; • breach of representations and warranties; • noncompliance with expert or arbitral tribunal order; • non-fulfillment of condition subsequent; • other material breach. GoN can terminate the PDA if the Project Company event of default is not cured within a defined cure period, in which case the following payments will apply: Project Company event of default prior to financial close: project land acquired at cost price + transfer taxes + other project assets that GoN wishes to acquire at fair price determined by expert; or	-	Definition of DamCo's default should be added in PDA and DLC. NEA acknowledge DamCo's default in PPA. Rather than allowing DamCo's defaults under DLC to trigger a GenCo's default under the PPA, PDA/PPA should provide that no GenCo default will arise to the extent that it is due to a default by DamCo under DLC. GenCo's default trigger termination of PPA and DLC. Consequential procedure at DamCo's default should be defined (e.g., GoN's taking over DamCo).	Current contractual procedure and entitlement is maintained. DamCo's default should be defined in PDA and PPA.

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
		Company event of default on or after financial close: debt + any undisputed sums due and owing from GoN, NEA or other GoN instrumentalities + finance costs + transfer taxes - insurance proceeds - any remaining amount in a debt service reserve account. **PPA:** The Project Company is required to compensate NEA for any damages it incurs as a consequence of termination for the Project Company's default.			
42.	Termination by Political Force Majeure	**PDA:** Either GoN or the Project Company can terminate due to a prolonged political force majeure or change in law (unless GoN has continued to pay the Project Company for the revenue shortfall under the PPA) , in which case the following payments will apply: • Prolonged political force majeure or change in law over 24 months prior to financial close: reasonable and prudent costs for project development including for project land + transfer taxes; or • Prolonged political force majeure or change in law over 24 months after financial close: debt + any undisputed sums due and owing from GoN, NEA or other GoN instrumentalities + finance costs + equity (including shareholder loans) +120% of equity + transfer taxes - insurance proceeds - any remaining amount in a debt service reserve account. **PPA:** • The unaffected party can terminate for a prolonged force majeure event (though the PPA will automatically terminate if the PDA is terminated). • No fixed termination payments apply.	-	A corresponding right to terminate for prolonged political force majeure events will need to be included in the DLC.	Current contractual procedure and entitlement is maintained and applied to both GenCo and DamCo.
43.	Termination by Non-Political Force Majeure	**PDA:** Either GoN or the Project Company can terminate due to a prolonged non-political force majeure event, in which case the following payments will apply: • Prolonged non-political force majeure over 24 months prior to financial close: project land acquired at cost price + transfer taxes + other project assets that GoN wishes to acquire at fair price determined by expert; or • Prolonged non-political force majeure over 24 months on or after financial close: debt + any undisputed sums due and owing from GoN, NEA or other GoN instrumentalities + finance costs + equity (including shareholder loans) + transfer taxes - insurance proceeds - any remaining amount in a debt service reserve account. **PPA:** • The unaffected party can terminate for a prolonged force majeure event (though the PPA will automatically terminate if the PDA is terminated). • No fixed termination payments apply.	-	A corresponding right to terminate for prolonged non-political force majeure will need to be included in the DLC.	Current contractual procedure and entitlement is maintained and applied to both GenCo and DamCo.
44.	Delay in Land Acquisition	**PDA:** Either GoN or the Project Company can terminate due to a prolonged delay with land acquisition, in which case the following payments will apply: • Land acquisition delay prior to financial close: reasonable and prudent costs for project development including for project land + transfer taxes; or • Land acquisition delay on or after financial close: debt + any undisputed sums due and owing from GoN, NEA or other GoN instrumentalities + finance costs + equity (including shareholder loans) + 120% of equity + transfer taxes - insurance proceeds - any remaining amount in a debt service reserve account. **PPA:** • This is not expressly addressed in the PPA.	-	-	Current contractual procedure and entitlement is maintained and applied to both GenCo and DamCo.

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
Jurisdiction					
45.	Governing law	PDA: English law. PPA: Nepalese law.	-	-	PDA: English law PPA: Nepalese law DLC: English law
46.	Dispute resolution	**PDA:** • Technical disputes are resolved by offshore expert determination in Singapore. • Other disputes are determined by offshore arbitration in Singapore applying SIAC Arbitration Rules. Arbitration agreement is governed by English law. • Both expert determination and arbitration is conducted in English. **PPA:** • Onshore arbitration conducted in Kathmandu, Nepal applying under UNICITRAL Rules. • Arbitration is conducted in English.	-	-	**PDA, PPA and DLC:** All project agreements are better to be governed by the same offshore arbitration mechanism, each with a joinder of claims provision included.
Insurance					
47.	Project Company Insurances	**PDA:** • General liability insurance. • Insurance covering loss, damage or destruction of all assets on the project site. • Such insurances as are otherwise required by law or the PPA. **PPA:** • Prior to COD – contractor's all risk insurance, general liability insurance, loss of profit cover and such other insurances as may be required by law. • From COD – third party liability insurance, general liability insurance, employee compensation insurance, business interruption insurance, and such other insurance as may be required by law.	-	DLC include required insurance by DamCo.	Current contractual obligation is maintained and applied to both GenCo and DamCo.
48.	NEA/GoN insurances	There is no requirement for NEA or GoN to take out any insurances.	Generally in-line with regional precedents, though it is not unusual for the off-taker to still be required to take out general liability and third party liability insurance	-	-
Taxes, Royalties and other Payments by Project Company					
49.	Tax exemptions (Income taxes)	**General:** • Full income tax exemptions for the first 10 years from the date of commercial operation and 50% income tax exemption for the next five years for projects with COD prior to 12 April 2024, is provided by the Income Tax Act 2002. • No additional approvals are required for the Company to benefit from such income tax exemptions. **PDA:** • These tax exemptions are repeated in the PDA. • The Project Company is also protected with respect to these exemptions (and more generally) through the change in law and change in tax provision in the PDA.	Incentives for foreign developer should be considered.	Tax exemptions for DamCo should be considered.	-
50.	Tax exemption (Customs Duties and VAT subsidy)	**General:** • As per the Finance Act, the GoN will charge customs duties at the lowest rate of one percent for the import of electromechanical and other equipment on the recommendation of DoED.	Incentives for foreign developer should be considered.	Dam Lease Fee should be VAT exempt.	-

No.	Risk	Nepal Risk Allocation Current Status (UT1 PDA, PPA Template)	General Remarks and Recommended Changes	VSPPPM Position	Proposal on VSPPM Position
		• As per the Budget of Fiscal Year 2014/2015, the GoN will also provide a subsidy of NPR 5 million per MW of installed capacity for projects achieving COD by 12 April 2024, as it is complicated in Nepal to establish transparent procedures for VAT refunds. However, GoN has not disbursed this subsidy yet. **PDA:** • These tax exemptions are repeated in the PDA. • The Project Company is also protected with respect to these exemptions (and more generally) through the change in law and change in tax provision in the PDA.			
51.	Free Shares/Free Power/Shares for Project Affected People	**General:** • Free shares and free power have so far only been requested by the GoN on (i) power export projects that have been awarded through a competitive bidding process and (ii) domestic supply projects out of the GoN Reserved Projects awarded through competitive bidding or direct negotiation process. They have not been featured on domestic supply projects developed through ordinary licensing modality. • Action Plan 2016 provides that all hydropower projects must allot 10% of their shares to the residents of project affected areas. Such persons are required to pay for the shares they receive at par value. Also, the persons who are to be provided compensation by the project due to land acquisition or resettlement are to be provided an option to obtain shares instead of financial compensation. These requirements have also been reflected in the terms of the generation licenses granted to recent hydropower projects. • Projects raising funds through an IPO are required to allot 10% of their issued capital to residents of project-affected area. Such persons are required to pay for the shares they receive at par value. **PDA:** • The Project Company is required to provide an option for project affected people residing permanently in the districts of the project area to purchase at par value directly or indirectly up to 10% of the shares in the Project Company. • It is likely that these shares will be held indirectly through a public limited company established for this purpose.	The concept of shares being allocated to residents in the project-affected area will also require further discussion – highly unusual and likely to be of concern to lenders.	Discussion should be made whether free share of DamCo or GenCo is provided to which people affected by dam or power facilities. It may be determined project by project.	To be discussed with GoN
52.	Royalties	**General:** • Royalties are usually charged by the GoN and are payable monthly on a pro-rata basis at the following rates that are prescribed in the Electricity Act: First fifteen years following COD: NPR 200 per KW capacity per annum, plus 2% of gross revenues per annum. After such fifteen years: NPR 1500 per KW capacity per annum, plus 10% of gross revenues per annum. • In projects that have been licensed by the GoN through a competitive bidding process where the PPA rates have been fixed by the GoN as part of the tender, parties proposing higher royalties will be awarded the project. **PDA:** • The requirement to pay such royalties are repeated in the PDA.	Royalty for domestic power supply project is not common. Amount of royalty is better to be discussed project by project.	-	-

ANNEX 3

SIMPLIFIED RISK MATRIX

Simplified Risk Matrix

	GoN	NEA	Dam Co	Gen Co
Pre-construction				
Political				
Delay obtaining permits	✓			
Objection from stakeholders, NGOs	✓			
Administrative				
Delay land acquisition/resettlement	✓			
Physical				
New findings of endangered species/critical habitat	✓			
Commercial				
Contractor's bid higher than budget			✓	✓
Environmental				
Delay of environmental/social permits	✓			
Construction				
Political				
Political Force Majeure	✓	✓		
Change of Laws	✓	✓		
Administrative				
Delay of site access due to land clearance	✓			
Physical				
Construction delay due to flooding, land slide below Force Majeure criteria			✓	✓
Natural disaster as Force Majeure	✓	✓		
Technical				
Failure of construction due to inappropriate design			✓	✓
Poor performance of Contractor			✓	✓
Poor quality of constructed structures			✓	✓
Unforeseen geotechnical condition	✓	✓		
Increased volume of excavation due to geology			✓	✓
Accidents/safety			✓	✓
Unavailability of construction materials			✓	✓
Change in the design			✓	✓
Delay of energy receiving facilities		✓		
Commercial				
Hyper inflation			✓	✓
Insolvency of Contractor			✓	✓
Labor disputes			✓	✓
Environmental				
Disturbance of sacred places			✓	✓
Findings of fossils, antiquities	✓	✓		
Operation				
Political				
Political Force Majeure	✓	✓		
Change in Laws	✓	✓		
Physical				
Landslides in reservoirs during operation			✓	✓
Landslides in access roads during operation			✓	✓
Lessen energy generation due to draught		✓		
Natural disaster as Force Majeure	✓	✓		
Technical				
Operation problems related to poor maintenance or lack of spare parts			✓	✓
Unexpected large sedimentation or landslide causing loss of effective storage capacity				
Commercial				
Hyper inflation			✓	✓
Labor disputes			✓	✓