NEPAL
MINISTRY OF ENERGY, WATER RESOURCES AND IRRIGATION

PROJECT ON INTEGRATED POWER SYSTEM DEVELOPMENT PLAN IN NEPAL

FINAL REPORT

December 2024

JAPAN INTERNATIONAL COOPERATION AGENCY

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Project on Integrated Power System Development Plan in Nepal
Final Report

STRUCTURE OF THE REPORT

Abbreviations

Symbol	English
3E	Energy Security, Economy and Environment
ADB	Asian Development Bank
AEPC	Alternative Energy Promotion Center
AIIB	Asian Infrastructure Investment Bank
ARAP	Abbreviated Resettlement Action Plan
BBIN	Bangladesh, Bhutan, India and Nepal
BEA	Brief Environmental Assessment
BESS	Battery Energy Storage System
BOO	Build Own and Operate
BOOT	Build Own Operate and Transfer
BOT	Build Operate and Transfer
BPDB	Bangladesh Power Development Board
BT	Build and Transfer
C/P	Counterpart
CA	Concession Agreement
CAPEX	Capital Expenditure
CB	Circuit Breaker
CBET	Cross Border Electricity Trade
CBS	Central Bureau of Statistics
CCGT	Gas Turbine Combined Cycle
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CF	Cash Flow
CIT	Citizen Investment Trust
CN	Carbon-Neutral
CO2	carbon dioxide
COD	Commercial Operation Date
COP	The Conference of the Parties
CRED	Community Rural Electrification Department
CREEs	Community Rural Electrification Entities
D/L	Distribution line
DfID	Department for International Development
DFS	Detailed Feasibility Study
DISCO	Distribution Company
DoED	Department of Electricity Development
DoI	Department of Industry
DP	Development Partners
DPR	Detailed Project Report
DSCR	Debt Service Coverage Ratio
DSM	Deviation Settlement Mechanism
E flow	Environmental flow
EBF	Equity Backed Finance
EC	European Commission

Symbol	English
EDF	Électricité de France
EGAT	Electricity Generating Authority of Thailand
EIA	Environmental Impact Assessment
EIB	European Infrastructure Bank
EIRR	Economic Internal Rate of Return
EIRR	Equity Internal Rate of Return
EOI	Expression of Interest
EPA	Environmental Protection Act
EPCF	Engineering, Procurement, Construction and Financing
EPF	Employee Provident Fund
EPR	Environmental Protection Rules
ERC	Electricity Regulatory Commission
ESIA	Environmental and Social Impact Assessment
ESMS	Environmental and social management system
EV	Electric Vehicle
F/S	Feasibility Study
FCV	Fuel Cell Vehicle
FITT	Foreign Investment and Technology Transfer Act
FPIC	Free, Prior and Informed Consent
FSL	Full Spillway Level
FY	Fiscal Year
GDP	Gross Domestic Product
GE	Gas Engine
GIS	Geographic Information System
GLOF	Glacial Lake Outburst Flood
GNI	Gross National Income
GoN	Government of Nepal
GT	Gas Turbine
HEP	Hydro Electric Project
HIDCL	Hydroelectricity Investment and Development Company Ltd.
HPP	Hydro Power Plant
HPX	Hindustan Power Exchange
HVDC	High Voltage Direct Current
IAEA	International Atomic Energy Agency
IBA	Important Bird and Biodiversity Areas
IBN	Investment Board of Nepal
ICB	International Competitive Bidding
ICIMOD	International Centre for Integrated Mountain Development
IDA	International Development Association
IEA	International Energy Agency
IEE	Initial Environmental Examination
IEX	Indian Energy Exchange Limited
IFC	International Finance Corporation
IFRS	International Financial Reporting Standards

Symbol	English
ILO	International Labor Organization
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
IPO	Initial Public Offering
IPP	Independent Power Producer
IPP	Indigenous Peoples Plan
IPPAN	Independent Power Producers' Association, Nepal
IPSDP	Integrated Power System Development Plan
IRR	Internal Rate of Return
IRRP	Integrated Resource and Resilience Planning
IUCN	International Union for Conservation of Nature
JCC	Joint Coordination Committee
JEPX	Japan Electric Power Exchange
JICA	Japan International Cooperation Agency
JV	Joint Venture
JVA	Joint Venture Agreement
KBA	Key Biodiversity Area
KfW	German Development Bank
LCOE	Levelized Cost of Electricity
LD	Liquidated Damages
LDC	Load Dispatch Centre
LHV	Lower Heating Value
LOL	Lowest Operation Level
LOLP	Loss of Load Probability
LPG	Liquefied Petroleum Gas
LRMC	Long-Run Marginal Cost
LV	Low voltage (<1kV), typically 400/230V
MAED	Model for Analysis of Energy Demand
MCA	Millennium Challenge Account
MCC	Millennium Challenge Corporation
MCP	Market Clearing Price
MCV	Market Clearing Volume
MIGA	Multilateral Investment Guarantee Agency
MOA	Memorandum of Agreement
MoEWRI	Ministry of Energy, Water Resources and Irrigation
MoF	Ministry of Finance
MoI	Ministry of Industry
MOU	Memorandum of Understanding
MV	Medium Voltage (≥1kV; ≤33kV)
NCC	Nepal Chamber of Commerce
NEA	Nepal Electricity Authority
NEPSE	Nepal Stock Exchange
NERC	Nepal Electricity Regulatory Commission
NGO	Non-Governmental Organization

Symbol	English
NHPC	National Hydroelectric Power Corporation
NPTCL	Nepal Power Trading Company Limited
NRB	Nepal Rastra Bank
NREF	National Renewable Energy Framework
NRREP	National Rural and Renewable Energy Programme
NTFPs	Non-Timber Forest Products
NTP	Notice to Proceed
NVVN	NTPC Vidyut Vyapar Nigam Ltd.
O&M	Operation and Maintenance
ODA	Official Development Assistance
OPEX	Operating Expense
PCC	Project Coordinate Committee
PDA	Project Development Agreement
PDP	Power Development Plan
PEC	Power Exchange Committee
PGCIL	Power Grid Corporation of India
PGDP	Power Generation Development Planning
PMD	Project Management Directorate
PMITD	Planning, Monitoring & IT Directorate
PMU	Project Management Unit
PPA	Power Purchase Agreement
PPP	Public Private Partnership
PROR	Peaking Run of River
PS	Pumped Storage
PSC	Project Steering Committee
PSP	Power System Planning
PTA	Power Trade Agreement
PTC	Power Transmission Compnany Limited
PXIL	Power Exchange India Limited
PXIL	Power Exchange India Limited
QBS	Quality Based Selection
QCBS	Quality -Cost Based Selection
RBS	Rastriya Beema Sansthan
RFP	Request for Proposal
RLDC	Regional Load Dispatch Center
ROA	Return On Asset
ROE	Return on Equity
ROR	Run of River
ROW	Right of Way
RPC	Regional Power Committee
RPGCL	Rastriya Prasaran Grid Co. Ltd.
RPO	Renewable Energy Purchase Obligation
S/S	Substation
SAIDI	System Average Interruption Duration Index

Symbol	English
SAIFI	System Average Interruption. Frequency Index
SARI/EI	South Asia Regional Initiative for Energy Integration
SCADA	Supervisory Control And Data Acquisition
SEA	Strategic Environmental Assessment
SERC	State Electricity Regulatory Commission
SESA	Strategic Environment and Social Assessment
SEZ	Special Economic Zone
SJVN	Satluj Jal Vidyut Nigam
SOE	State Owned Enterprises
SOP	Standard Operation Procedure
SPC	Special Purpose Company
STO	Storage
T&D	Transmission and Distribution Line
T/L	Transmission line
TA	Technical Assistance
TAS	Transaction Advisory Service
TSDP	Transmission System Development Plan of Nepal
TSL	Two Step Loan
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
USAID	United States Agency for International Development
VAT	Value Added Tax
VRE	Variable Renewable Energy
VUCL	Vidhyut Utpadan Co., Ltd.
WASP	Wien Automatic System Planning
WB	World Bank
WEC	Water and Energy Commission
WECS	Water and Energy Commission Secretariat
WG	Working Group
ZEB	Net Zero Energy Building

EXECUTIVE SUMMARY

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Executive Summary

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1. INTRODUCTION

1.1 BACKGROUND

The Nepal has abundant hydropower resources, with an estimated hydropower of 83GW and an economically viable hydropower of 42GW. GoN (Government of Nepal) formulated policy papers such as "Action Plan on Crisis Prevention of National Energy and 10 years, Hydropower development (2016)" and "Energy, Water Resources and Irrigation's Sector's Status and Roadmap for the Future" (commonly known as, "White Paper" in 2018) and has decided to make power development as a highly priority with a clear intention to accelerate the power development. On the other hand, the amount of development achieved is still behind the targets set by various policies. Load shedding due to insufficient supply capacity had continued until the mid-2010s. The supply and demand situation has been drastically improved owed to increase of electricity supply by import from India since 2016. However, power generation development has not progressed and Nepal has continued to rely on electricity import particularly during the dry season. The share of electricity imports reached 21.8% in 2019/20 and the outflow of foreign currency became a major issue in Nepal.

In this context, new power plants that have been under development such as Upper Tamakoshi (456 MW) began operations since 2021. Installed hydropower capacity increase 1,446.8 MW in 2021 and 2,685 MW in 2023, showing remarkable growth in recent years. In 2023, the annual power generation reached to 11,026 GWh against a domestic electricity demand of 11,546 GWh. Power imports during the dry season accounted for 1,855 GWh (15% of domestic demand), while power exports during the rainy season reached 1,333 GWh, bringing imports and exports closer to balance. Financially, NEA (Nepal Electricity Authority) has improved financial conditions and increased profits owed to the opportunity to export electricity to India since 2019. These developments are the result of the past decade of efforts and this growth is expected to continue for the next few years.

It is also important to note that Nepal still has considerable development potential and there remains a significant gap with the hydropower target of 15,000 MW by 2030 as outlined in policies such as the White Paper. Its factors are expensive costs of power generation facilities and transmission line facilities due to steep mountain terrain, constrain of national credit capability and investment capability, inadequacy of private investment utilization institution, unplanned issues of construction licenses to IPP (Independent Power Producer), poor collaboration among government, regulating agencies related to power development and power authority and so on. Also, it is issuing that comprehensive long-term power development plan which shall be shared by relevant agencies including IPP.

In order to develop power supply system systematically it is necessary that MoEWRI (Ministry of Energy, Water Resources and Irrigation) who has jurisdiction over National Energy policy shall formulate "IPSDP (Integrated Power System Development Plan)" which covers power generation method, priority of power development, scale and timing of power development, procurement method of financial resources, investment plan including sharing role between private and public funds in collaboration with JICA (Japan International Cooperation Agency).

1.2 OBJECTIVES

Objectives of IPSDP are to indicate the vision and target until 2040 to achieve stable domestic power supply and power export to neighboring countries by the development of clean energy.

1.3 BASIC APPROACHES ON IPSDP

Based on the background and objectives, the basic approaches of 3E (Energy security, Economy and Environment) + Policy on IPSDP are described as follows;

Energy Security
- *to achieve the reliable electric power supply by domestic primary energy*
- *to contribute to realize the stable power supply through the interactive and flexible power trade*

Economy :Reduction of Financial Burden and Economic Growth
- *to establish the electricity tariff at a lower financial burden*
- *to grow up the economy and earn foreign currency through the power trade*

Environment :Environmental and Social Considerations
- *to ensure that the development is acceptable and affordable to the social and ecological environment*
- *to contribute to the reduction of CO_2 emission with the supply of clean energy*

Policy : In line with the policies in the power sector
- *to be consistent with "Energy Development Roadmap and Work Plan" prepared by MoEWRI in 2023 under approval by Cabinet.*
- *to be aligned with this policy which indicates the target of hydropower development 28GW in 2035 and 86 work plans in comprehensive fields of power sector.*

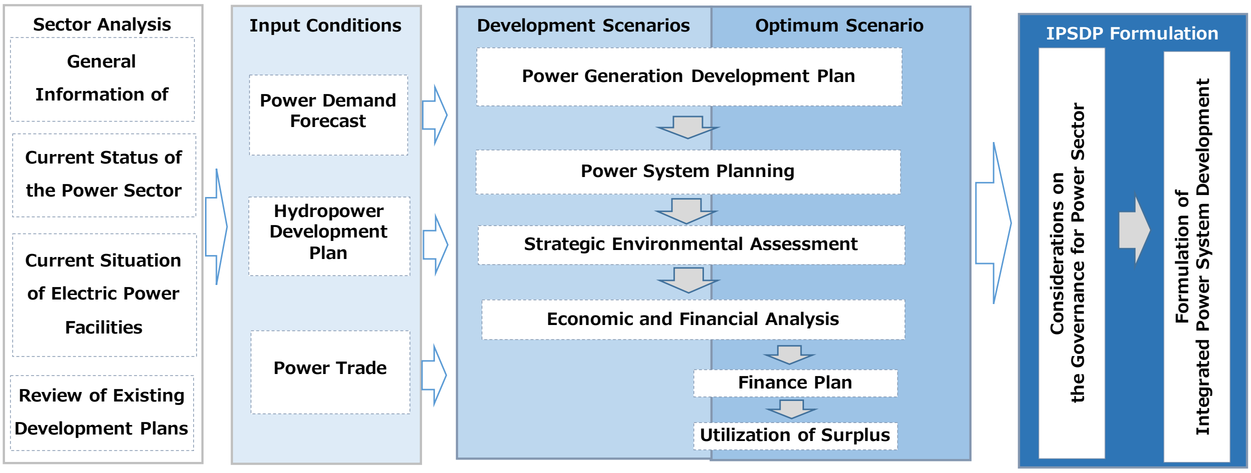
Currently, the MoEWRI is developing the "Energy Development Roadmap and Work Plan 2035" as its energy policy up to 2035 which is under discussion by the cabinet. This roadmap sets the development goals by 2035 to include a power demand consumption of 40,710 GWh (3.4 times increase), total power generation capacity of 28,713 MW (10.2 times increase), transformer capacity of 40,000 MVA (4.5 times increase), and power exports of 15,000 MW (23.7 times increase). 85 work plans are proposed in four areas: "1. Improvement of the legal system", "2. Capacity development for GoN", "3. Promotion of infrastructure development" and "4. Establishment of business function on power market". It is necessary for IPSDP to align with such higher-level policies, particularly considering the achievement of the goals set forth in this Energy Development Roadmap and Work Plan.

2. IPSDP

2.1 OUTLINE OF IPSDP

Outline of studies for IPSDP are;

- to clarify the situation of power demand forecast, hydropower development plan and power trade with neighboring countries based on power sector analysis,
- to prepare Development Scenarios which indicate the direction of development on power sector involving PGDP (Power Generation Development Planning), PSP (Power System Planning), SEA (Strategic Environmental Assessment) and economic and financial analysis
- to select Optimum Scenario from comparison of Development Scenario and update it as the main body of IPSDP considering comprehensive perspectives of power trade with neighboring countries, finance plan for investment and energy transition and
- to formulate IPSDP as the middle and long term development plan which indicates "Vision" and "Target" of power sector in Nepal.



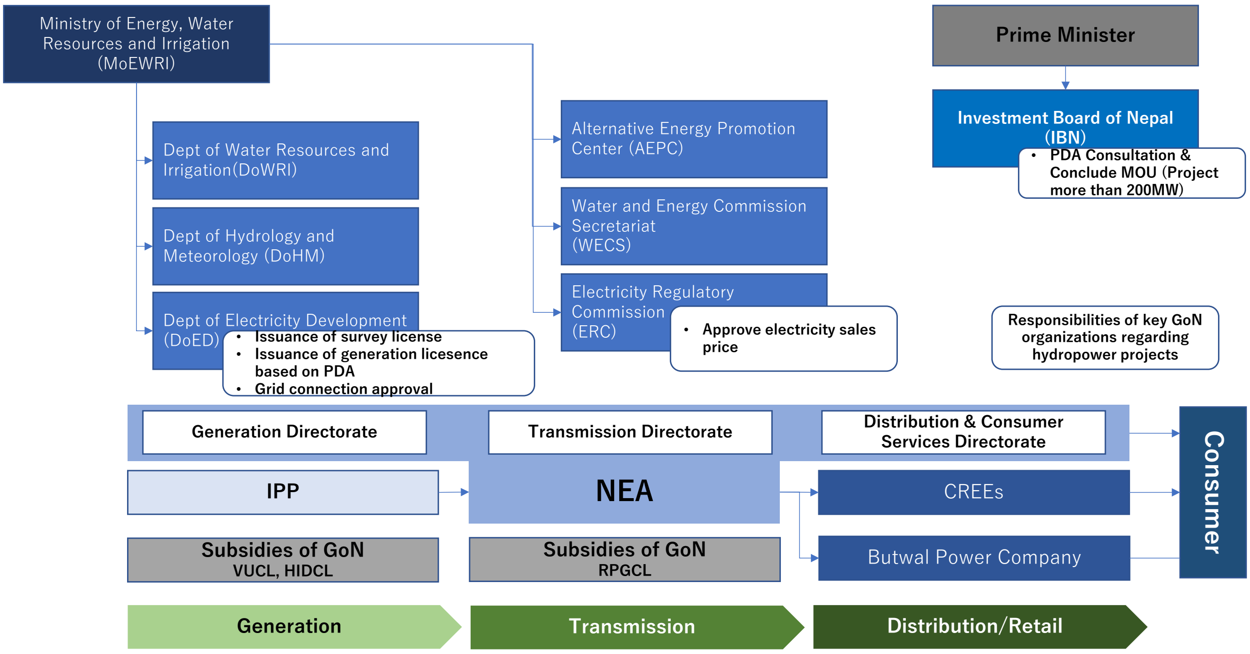
Source: JICA Study Team

Figure 2.1-1 Flowchart of IPSDP Studies

2.2 BASIC UNDERSTANDINGS OF THE DEVELOPMENT IN POWER SECTOR

2.2.1 Organizational Structure of the Power Sector

Figure 2.2-1 shows the structure of the power businesses in Nepal. Among the administrative bodies involved in the power sector in Nepal are MoEWRI, which is responsible for policies and laws related to energy development and use, DoED (Department of Electricity Development), a unit of the ministry, which is responsible for issuing licenses for power generation businesses, ERC (Electricity Regulatory Commission), which regulates and supervises power businesses, including PPA (power purchase agreement) and retail tariffs, WECS (Water and Energy Commissions) and AEPC (Alternative Energy Promotion Center).



Source: JICA Study Team

Figure 2.2-1 Structure of Power Businesses in Nepal

The country's electricity business has a vertically integrated structure, with NEA handling generation, transmission and distribution of electricity. In the generation sector, however, many IPPs have entered the market under the Electricity Act of 1992.

Other government organizations in the power sector include RPGCL (Rastriya Prasaran Grid Company Limited), VUCL (Vidhyut Utpadan Co., Ltd.), and HIDCL (Hydroelectricity Investment and Development Company Ltd.). Additionally, organizations closely related to the power sector include IBN (Investment Board of Nepal) and IPPAN (Independent Power Producers' Association, Nepal). It is important for IPSDP to proceed with discussions in collaboration with these related organizations.

2.2.2 Involvement of Existing and On-going Power Development Plans in the Power Sector

Various DPs (Development Partners) have supported development studies and planning for the power sector in Nepal. In addition, WECS, RPGCL and NEA have also formulated their development plans, leading to a situation where numerous plans coexist. IPSDP shall involve them shown in Table 2.2-1 as a foundation of studies and guidance of the direction of future overviews.

Table 2.2-1 Major Policies and Development Plans in the Power Sector

Field	Name	Date[1]	Agency	Assistance
Power Sector	Nationwide Master Plan Study on Storage-type Hydroelectric Power Development	2014	NEA	JICA
	Review in Data Collection Survey on Hydropower Development Project	2018	NEA	JICA
	Irrigation Master Plan	2019	DWRI	ADB
	Hydropower Potential of Nepal	2019	WECS	-
	World Bank/WECS: Preparation of River Basin Plans and Hydropower Development Master Plans and Strategic Environmental and Social Assessment	2024	WECS	WB
Power System	Transmission System Development Plan of Nepal	2018	RPGCL	
	The Distribution System/Rural Electrification Master Plan of Nepal	2022	NEA	ADB

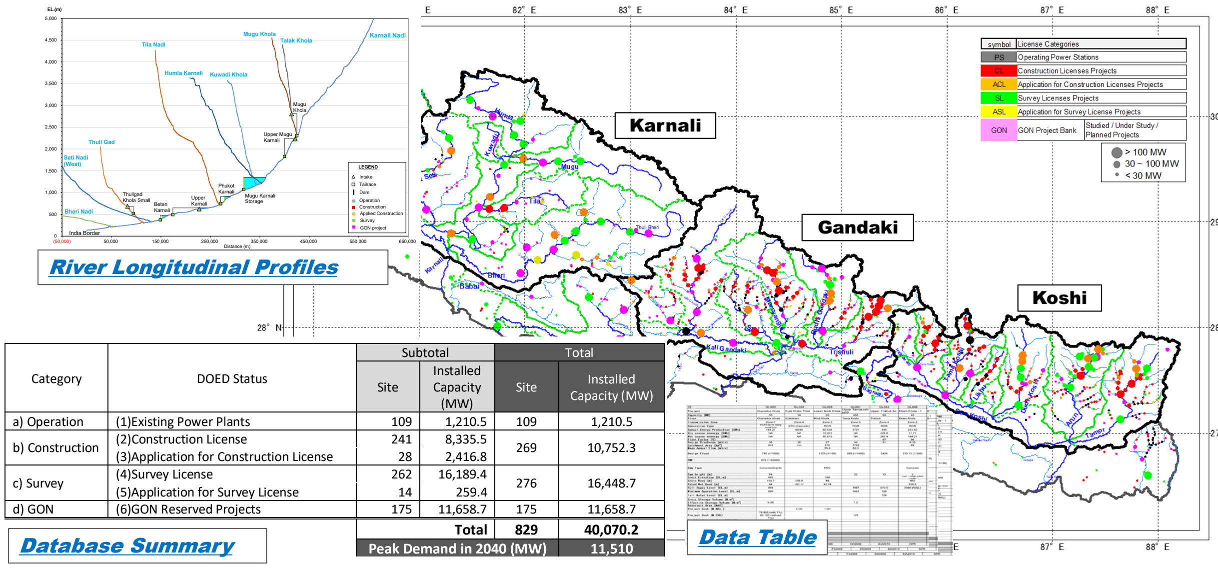
Source: JICA Study Team

2.2.3 Hydropower Development Plan

Hydropower is unique power sources which output and annual power generation are depended on natural conditions at project sites. Therefore, accuracy of these information directly affects to the quality of power generation development planning and power system planning in Nepal where hydropower is majority of the power sources. DoED of MoEWRI has been authorized to manage administrative process of generation and transmission projects over 1MW and more such as survey, construction and operation. The DoED Project list is widely recognized as the development list of generation and transmission and is assumed to be a reliable information source which is regularly updated by DoED Including the GoN Projects, the list covers almost all of identified hydropower potential in Nepal. Based on the progress of development, the projects are classified into the categories of a) Operation, b) Construction (Construction License and Application for Construction License), c) Survey (Survey License and Application for Survey License) and d) GoN. Information of irrigation and large storage hydropower projects which are excluded from DoED is also collected as much as possible.

In this study, key information such as coordinates of site, power planning, hydrological information, salient features of facilities, accessibility, environmental and social considerations and project cost are collected. Finally, hydropower database is developed including the inventory of basic information, GIS (Geographic Information System) map and river profiles (Figure 2.2-2).

[1] All dates taking effect are per the Western calendar system.



Category	DOED Status	Subtotal Site	Subtotal Installed Capacity (MW)	Total Site	Total Installed Capacity (MW)
a) Operation	(1)Existing Power Plants	109	1,210.5	109	1,210.5
b) Construction	(2)Construction License	241	8,335.5	269	10,752.3
	(3)Application for Construction License	28	2,416.8		
c) Survey	(4)Survey License	262	16,189.4	276	16,448.7
	(5)Application for Survey License	14	259.4		
d) GON	(6)GON Reserved Projects	175	11,658.7	175	11,658.7
			Total	829	40,070.2
			Peak Demand in 2040 (MW)		11,510

Source: JICA Study Team

Figure 2.2-2 Outline of Hydropower Database

Based on the results of considerations in this Section, lessons for power generation development planning are shown in Table 2.2-2.

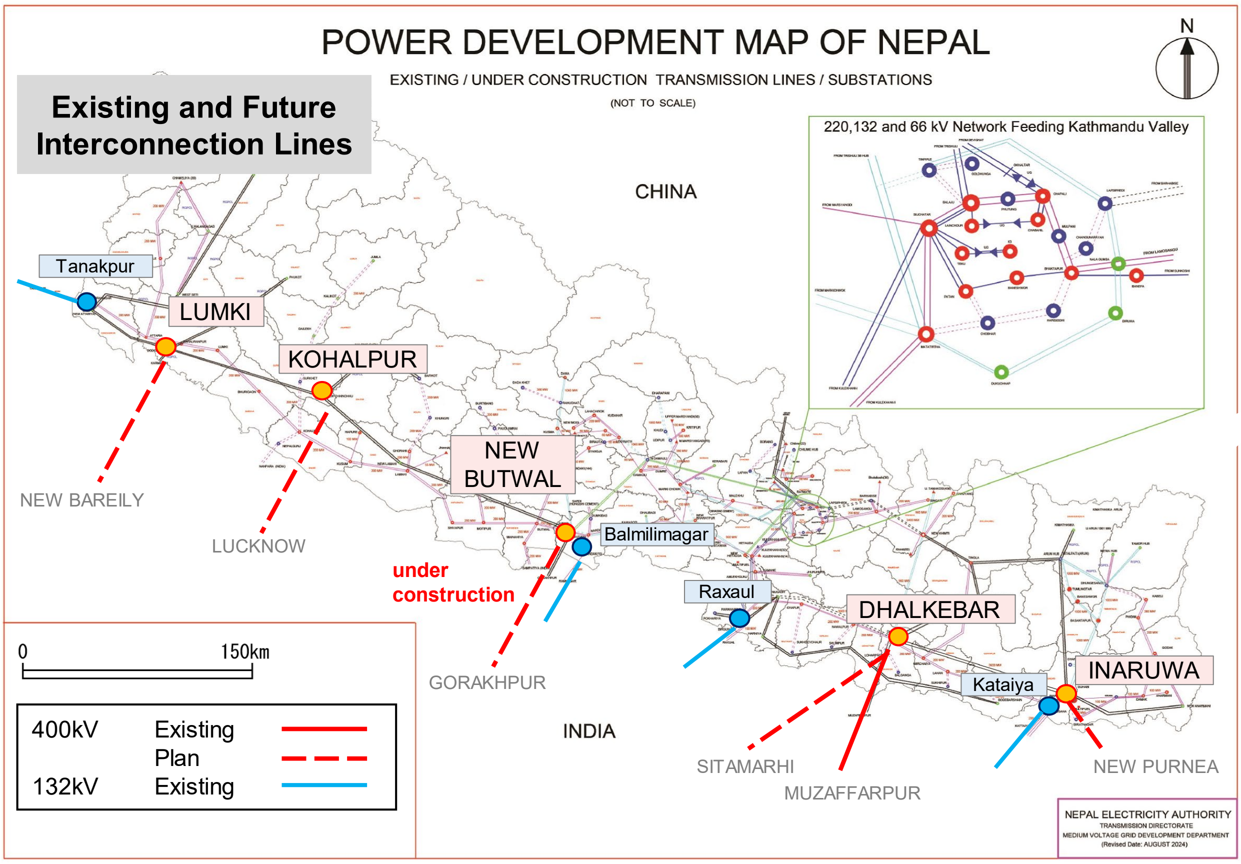
Table 2.2-2 Lessons for Power Generation Development Planning

Item	Lessons
Development Capacity (MW)	➢ The installed capacity of the DoED Project List is updated to 40,070.2 MW (829 sites) based on the information collected. It exceeds domestic power demand of 11,510MW in 2040. ➢ In addition to the consideration of significant drop of power generation in dry season, it is also important to take into account the power export in order to set appropriate development capacity.
Annual Power Generation (GWh)	➢ Power generation of ROR (Run of River), PROR (Peaking Run of River) and STO (Storage) in dry season falls to about 32.6% of the total in wet season. It is important to utilize reservoir and cascade operations but it is still difficult to resolve the difference and planning should be based on these seasonal fluctuations. ➢ Based on past experience, the annual power generation in a drought year falls by approximately 20% from the design value. Thus, it is necessary to set an appropriate reserve margins to ensure supply reliability. ➢ With regard to the amount of power generation, development of only b) Construction will require electricity imports except June, July and August. If c) Survey is developed, the shortfall will be largely eliminated. Finally, if GoN is also developed, it will be possible to supply electricity on its own, including during drought years. ➢ If hydropower is developed, surplus electricity will need to be exported, mainly during the rainy season. If not developed, the shortfall will need to be imported, mainly during the dry season.
Levelized Cost of Energy (cents/kWh)	➢ The average LCOE (Levelized Cost of Energy) are ROR: 4.0 cents/kWh, PROR: 5.0 cents/kWh and STO: 9.2 cents/kWh which are competitive power sources compared to thermal power plants, even taking into account the increase of project costs. ➢ NEA wholesale price for domestic consumers (8.2 cents/kWh) and the Indian electricity market IEX wholesale price (5.0 cents/kWh) are above LCOE of most of sites. ➢ In addition to domestic supply, it is necessary to consider power export to neighboring countries such as India and Bangladesh. It is also required to maximize values of hydropower and improve wholesale economics, such as improving day and year round regulating capacity.

Source: JICA Study Team

2.2.4 Power Trade

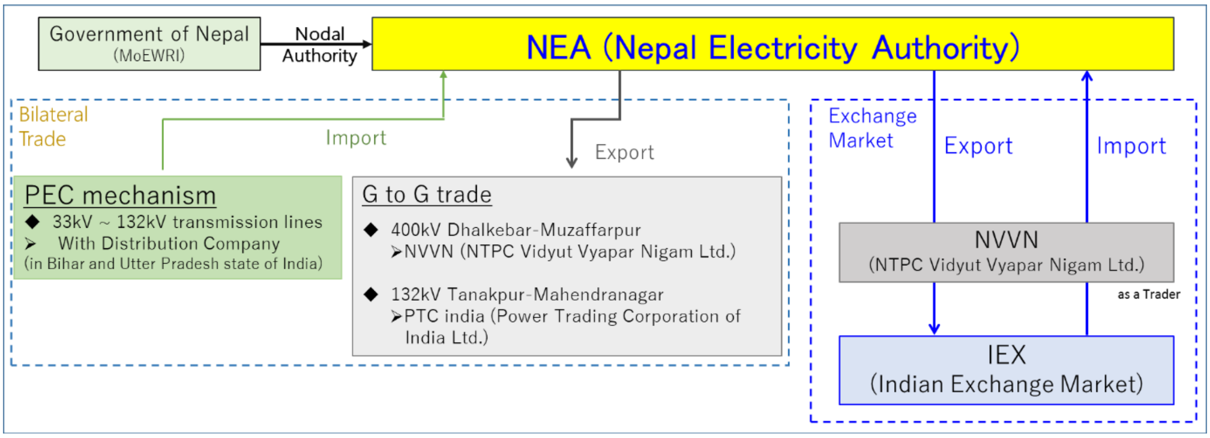
Figure 2.2-3 shows the current status and future plans for interconnection lines. Nepal has been exchanging electricity with India, and there are interconnection lines between Nepal and India such as 400kV Dhalkebar - Muzaffarpur transmission line, 132kV, 33kV and 11kV transmission lines. Each interconnection line is used for both imports and exports. There are plans to construct five(5) 400kV interconnection lines between Nepal and India for 2040.



Source: JICA Study Team based on NEA documents

Figure 2.2-3 Current Status and Future Plans for Interconnection Lines

Nepal trades electricity almost exclusively with India, either through Bilateral trade or through the IEX (Indian Exchange Market). With regard to power imports from India, Nepal is importing power through long-term contracts with NVVN (NTPC Vidyut Vyapar Nigam Ltd.) based on India's power trading guidelines and through IEX. On the other hand, the Day Ahead Market in IEX is the main source of income for power export, however, in order to secure stable income for power development, medium- and long-term PPAs with future price prospects are needed.



Source: JICA Study Team

Figure 2.2-4 Current Power Trade Scheme between Nepal and India

2.3 THE STUDY FOR DEVELOPMENT SCENARIOS

In this Section, Development Scenarios for the power generation mix are developed and the direction of the power sector is considered based on several perspectives, including the legal systems, policies, natural conditions, current status of primary energy.

2.3.1 Direction of Development Scenarios

Based on the results and analysis on Section 2.2, the following approaches are assumed to be important for the study of the future power generation mix. Several Development Scenarios will be composed with obvious concepts in order to explore the direction of the power sector in which Nepal aims based on 3E (Energy Security, Economy and Environment) + Policy.

- PGDP in Nepal will basically be dominated by hydropower and the power generation mix will depend on its possibility to be developed. In other words, the success or failure of hydropower development will determine the direction of the power sector.

- If the hydropower developments on the DoED Project List are fully developed, how much surplus power will be generated compared to electricity demand, whether export is feasible in terms of generation costs, flexibility and timing, and whether financing the development costs is feasible.

- What action will be required if the planned hydropower development is not realized? In case of the shortfall, what is the scale of required amount of power trade imported from neighboring countries, mainly India and how much is necessary for the expense of it?

- Will renewable energy such as solar power contribute to the power generation mix? What is the impact on imports and exports in terms of power trade and supply capacity on peak time?

Understandings above imply that the supply and demand of power is balanced by hydropower and power trade in Nepal. Therefore the capacity of hydropower development determine the direction of the power generation development planning.

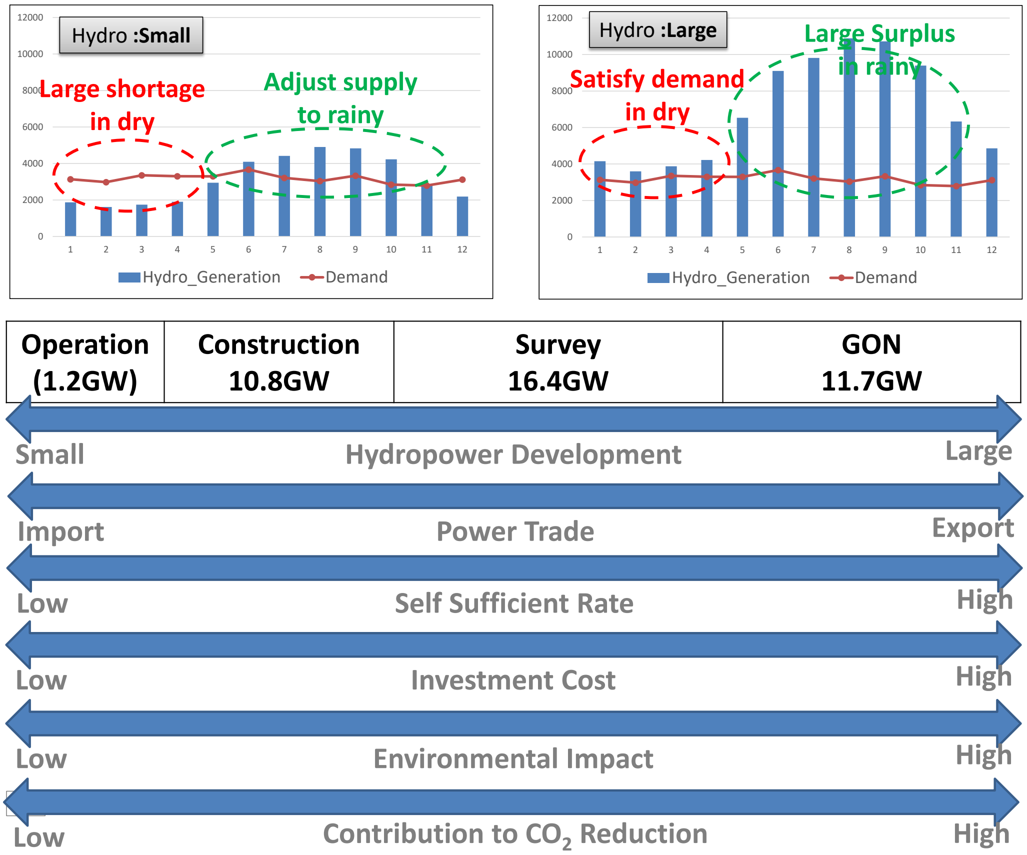
(i) Development capacity of hydropower is small

- *Hydropower is developed in order to meet peak demand in rainy season*
- *Shortages are supplemented by power import in dry season.*

(ii) Development capacity of hydropower is large

- *Hydropower is developed to meet peak demand in dry season and excessed electricity generated is exported.*

It is important to consider two overall approaches for the future direction: (i) Restrict hydropower development and accept power import in dry season or (ii) Promote hydropower development and power export. It is necessary to recognize the trade-off of hydropower development in amount of power trade, capital investment cost and environmental and social impacts in order to respond growing power demand in Nepal. These concepts are summarized in Figure 2.3-1.



Source: JICA Study Team

Figure 2.3-1 Direction by the Development Capacity of Hydropower[2]

In terms of 3E + Policy, if the development capacity of hydropower is large, energy security is improved owed to the increase of self-sufficiency rated of electric power and export to neighbouring countries. Increase of export also contribute to the economy in Nepal by earning foreign currency and climate change through the reduction of CO_2 emission. At the same time, it is also essential to consider the feasibility of financing, the selection of economically viable projects and negative environmental impacts.

If the development capacity of hydropower does not meet demand, it is necessary to prepare

[2] Operation :Commissioned projects, Construction :Projects holding or applying Construction Licenses, Survey ; Projects holding or applying Survey Licenses and GoN: Projects without Licenses

options to supplement shortages by the introduction of renewable energy or power trade. There are also benefits in terms of environmental impacts and lower capital investment costs in the development with small scale. These impacts need to be assessed from various perspectives in comparison of Development Scenarios.

2.3.2 Setting of Development Scenarios

Four Development Scenarios in PGDP will be set up: Scenario 1: Power Import, Scenario 2: Renewable and Scenario 3: Hydro Middle and Scenario 4: Hydro Maximum. The concepts of these scenarios are as follows.

Table 2.3-1 Setting Conditions of each Scenario

Item	Scenario 1 Power Import	Scenario 2 Renewable	Scenario 3 Hydro Middle	Scenario 4 Hydro Maximum
New Hydropower	a) Operation b) Construction	a) Operation b) Construction	a) Operation b) Construction c) Survey	a) Operation b) Construction c) Survey d) GoN
Renewable Ration against Power Demand (GWh)	10%	25%	10%	10%
Power Trade	Dry :Import Rainy :Export	Dry :Import Rainy :Export	Dry :Import Rainy :Import	Dry :Import Rainy :Import

Source: JICA Study Team

(Scenario 1 :Power Import)
- ✓ **Only committed hydropower projects** with Construction License are developed.
- ✓ Shortage of electricity is supplemented **by import** in dry season. Surplus is partially exported in rainy season.

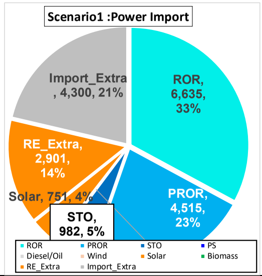
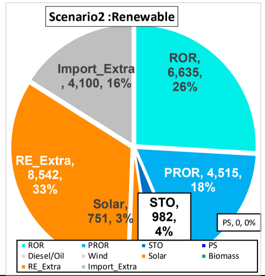
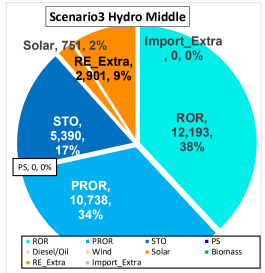
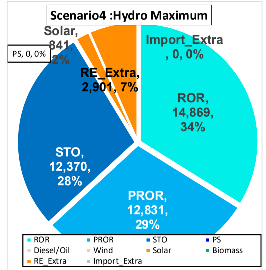
(Scenario 2 :Renewable)
- ✓ **Only committed hydropower projects** with Construction License are developed.
- ✓ Shortage of electricity is supplemented **by import and solar** in dry season. Surplus is partially exported in rainy season.

(Scenario 3 :Hydro Middle)
- ✓ **Committed and promising hydropower projects** with Construction License and Survey License are developed.
- ✓ Surplus electricity is exported. In drought year, it may be necessary to import electricity in dry season.

(Scenario 4 :Hydro Maximum)
- ✓ **All hydropower projects** which are proposed in DOED List are developed.
- ✓ Surplus electricity is exported.

Scenarios 1 and 2 correspond to (i) small hydropower development, setting scenarios when the demand in dry season is supplied by hydropower and power import from India. Scenario 2 increases the introduction of renewable energy compared to Scenario 1 in order to verify whether renewable energy contributes to improvement of the balance between power supply and demand. Scenarios 3 and 4 correspond to (ii) large hydropower development, setting scenarios with power supply throughout the year by hydropower. The scenarios compare the power supply and demand balance, export volumes and investment costs between the developments of hydropower in intermediate or maximum levels. Summary of comparison of Development Scenarios are shown in Table 2.3-2.

Table 2.3-2 Summary of the Evaluation of Development Scenarios

Evaluation Items		Scenario 1 Power Import	Scenario 2 Renewable	Scenario 3 Hydro Middle	Scenario 4 Hydro Maximum
Generation Mix					
		20,158MW	25,599MW	32,048MW	43,887MW
(1) Energy Security	Self Sufficiency Rate of Power Generation (%)	85.4%	99.7%	188.2%	230.1%
	International Issues	Interruption of power imports		Interruption of power exports	
	Grid Stability	None	Impacts by VRE	None	
(2) Economy	Cumulated Investment Cost	19,138 MUSD (1,015MUSD/year)	24,838 MUSD (1,307MUSD/year)	48,345 MUSD (2,544MUSD/year)	70,531 MUSD (3,712MUSD/year)
	Cumulated Balance of Power Trade	7,360MUSD	10,820MUSD	30,366MUSD	41,270MUSD
	Vulnerability for Fuel Cost	Fuel Inflation in India		None	
(3) Environmental and Social considerations	Natural and Social Impacts	Relatively small		Intermediate	Large
	Cumulated CO_2 Emissions (million ton)	69.1 million ton	52.4 million ton	39.5 million ton	44.5 million ton
	CO_2 Emissions Rate (g-CO_2 /kWh)	172.5 g-CO_2/kWh	111.4 g-CO_2/kWh	27.0 g-CO_2/kWh	25.0 g-CO_2/kWh
	Cumulated Reduction of CO_2 Emissions by Power Export (million ton)	169.1 million ton	205.7 million ton	505.7 million ton	684.3 million ton
Policy	Target of 15000MW in 2030	Not achieved		Achieved	
	Introduction of ARE	Achieved			

Source: JICA Study Team

2.3.3 Analysis Results of Development Scenarios and Selection of Optimum Scenario

The future direction of the power generation development planning in Nepal is discussed by comparing each scenario based on 3E + Policy. The results of the comparative study of each Scenario based on 3E + Policy are summarized in Table 2.3-3.

Table 2.3-3 Comparison of Development Scenarios based on 3E + Policy

Scenarios	Considerations
Scenario 1 Power Import	Power Import is assumed to be a feasible Scenario with low capital investment and environmental impact. However, it has low energy self-sufficiency in 2040, supply risks of power import interruptions and cost escalation risks such as fuel inflation. It is also difficult to achieve the goals set out in the policy of power sector.
Scenario 2 Renewable	Renewable as same as Scenario 1, the capital investment cost and environmental impact is relatively lower and the import dependency is also low owed to the generation of renewable energy. On the other hand, it is necessary to include the regulation capacity from neighbouring countries against the intermittency of VRE (Variable Renewable Energy) mainly derived from solar in order to secure the grid stability.
Scenario 3 Hydro Middle	Hydro Middle requires power imports only during February but it is possible to supply power to domestic demand and neighbouring countries even in drought years. Although the capital investment required is high, it is assumed to be feasible in case of power trade promoted. The environmental impact is also significant and measures to reduce the impact based on the results of the SEA are important.
Scenario 4 Hydro Maximum	Hydro Maximum can secure to supply power to domestic demand and neighbouring countries even in the drought year. Compared to Scenario 3, the capital investment and environmental impact would also be very high and feasibility needs to be fully considered.

Source: JICA Study Team

Based on the results of the comparative study of Development Scenarios described above taking into account the evaluation of 3E and consistency with the Policy, Scenario 3: Hydro Middle is selected as the base case for Optimum Scenario which development scale can be optimized.

Direction of future development by IPSDP suggest that basic strategy of power sector is to satisfy the domestic demand in dry season and to export surplus electricity to neighbouring countries in rainy season by domestic clean energy of hydropower and renewable energy.

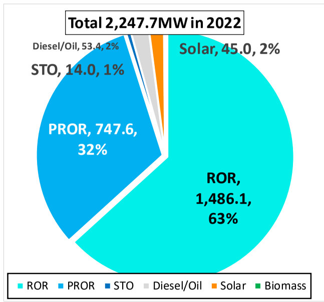
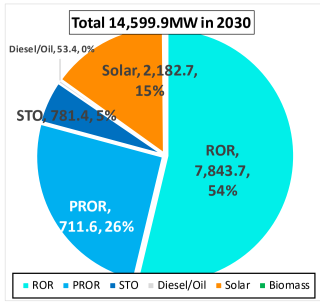
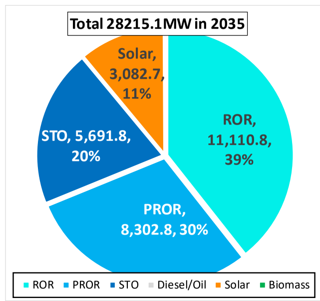
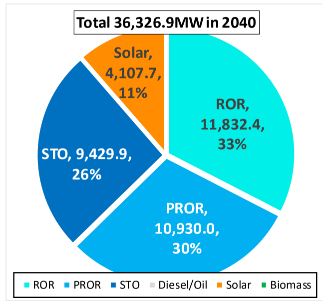
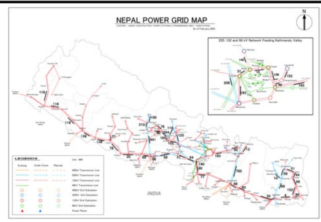
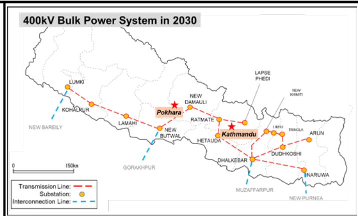
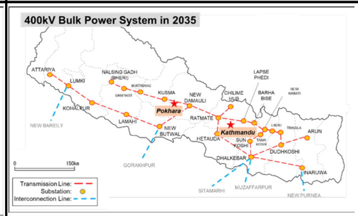
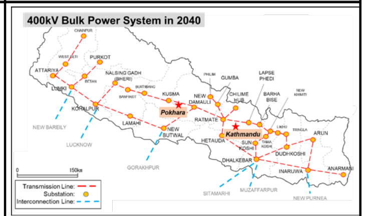
2.4 FORMULATION OF OPTIMUM SCENARIO

This section updates Scenario 3: Hydropower Middle which is selected as the Optimum Scenario and formulates the PGDP, PSP, SEA, economic and financial analysis, financing and utilization of surplus energy in IPSDP. The Optimum Scenario analysis reflects the following updates of three input conditions:

- Power Demand Forecast (Update the input conditions from 2021 to 2023)
- Generation Project List (Update DoED List from May, 2021 to March 2023 and execution of screening of hydropower projects)
- CO_2 Emission Factor of India in Power Trade (820g-CO_2/kWh→716 g-CO_2/kWh)

Analysis results of Optimum Scenario is summarized in and major study items are described below;

Table 2.4-1 Summary of Optimum Scenario

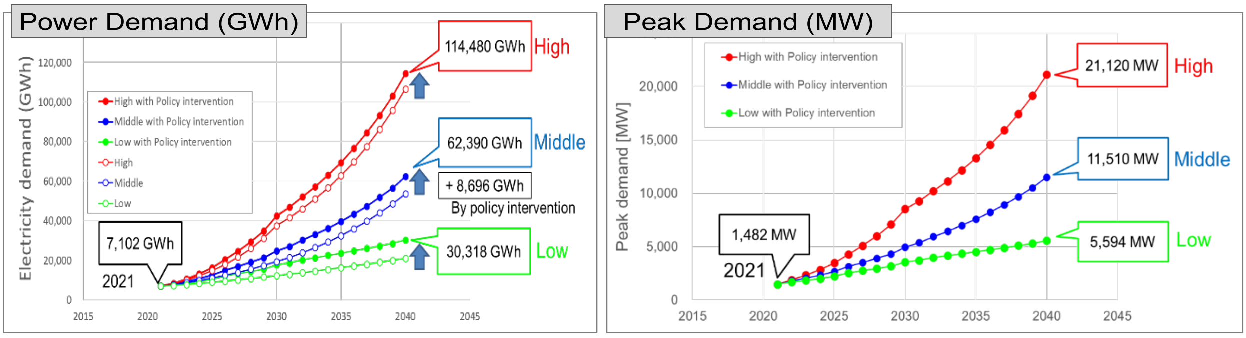
Item	2022/23	2030	2035	2040
Power Demand Forecast				
Power Consumption (GWh)	9,347GWh	24,737GWh	39,638GWh	62,390GWh
Power Demand (MW)	1,986W	4,949MW	7,581MW	11,510MW
Energy Consumption Per capita	320.5kWh/capita	774kWh/capita	1,184kWh/capita	1,779kWh/capita
Power Generation Development Planning				
Installed Capacity				
Annual Power Generation (Power Trade)	10,693GWh (-521GWh)	56,737GWh (25,859GWh)	102,527GWh (55,233GWh)	133,185GWh (61,370GWh)
Self Sufficient Rate	86.3%	183.7%	216.8%	185.5%
CO2 Emission	128.3kg-CO_2/kWh	31.8kg-CO_2/kWh	25.4kg-CO_2/kWh	29.0kg-CO_2/kWh
Power System Planning				
Power System				
Total Length of Transmission Line	400kV 78 km and 220&132kV 4,068km	400kV 1,149 km and 220&132kV 4,988km	400kV 1,818km and 220&132kV 5,563km	400kV 2,487 km and 220&132kV 6,138 km
Total Capacity of Transformer	400kV 945 MVA / 220&132kV 4,917 MVA	400kV 9,625 MVA / 220&132kV 13,317 MVA	400kV 15,050 MVA / 220&132kV 18,567 MVA	400kV 20,475 MVA / 220&132kV 23,817 MVA
Economic and Financial Analysis				
Accumulated Investment (Generation)	-	23,207MUSD	42,642MUSD	53,063MUSD
Accumulated Investment (Transmission)	-	3,573MUSD	5,970MUSD	8,687MUSD
Total Cost	-	26,780MUSD	48,612MUSD	61,750MUSD

Source: JICA Study Team

2.4.1 Power Demand Forecast

The results of the power demand forecast and the per capita electricity consumption (kWh/capita) × GDP (Gross Domestic Product) (USD/capita) comparison for various countries are shown in Figure 2.4-1 and Figure 2.4-2, respectively. The power demand forecast, taking into account various policies such as EV (Electric Vehicle), E-cooking, and SEZ (Special Economic Zones), assumes that the power demand (GWh) and peak demand (MW) will grow from 7,102 GWh and 1,482 MW in 2021 to 62,390 GWh (8.8 times) and 11,510 MW (7.8 times) respectively by 2040.

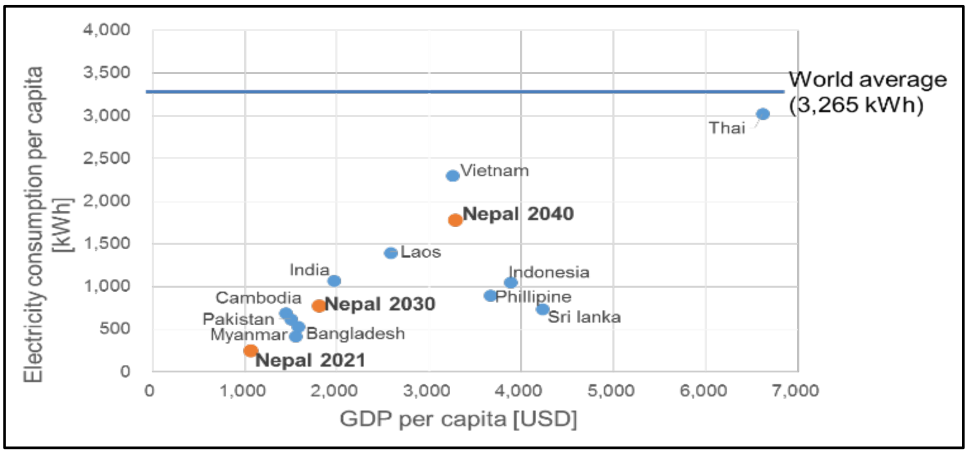
Per capita electricity consumption is expected to grow from 242 kWh/capita in 2021 to 1,779 kWh/capita by 2040. While the growth rate indicates a significant increase, the demand forecast results are generally reasonable and not excessive when compared to the world average of 3,265 kWh/capita and other countries in South Asia and Southeast Asia. It remains necessary to continue efforts to stimulate further demand, such as through industrial development and energy transition.



Middle Case	Unit	Year				
		2021 (Current)	2025	2030	2035	2040
Electricity Consumption	[GWh]	7,102	12,590	24,737	39,638	62,390
Growth rate	%/year	-	10.19	11.25	5.86	5.09
X times of 2021	-	-	1.77	3.48	5.58	8.78
Peak Demand	[MW]	1,482	2,675	4,949	7,581	11,510
Growth rate	%/year	-	15.40	14.49	9.89	9.50
X times of 2021	-	-	1.81	3.34	5.12	7.77
kWh per capita	[kWh/capita]	242	413	774	1,184	1,779
Growth rate	%/year	-	23.12	21.19	10.28	10.50
X times of 2021	-	-	1.71	3.20	4.90	7.37

Source: JICA Study Team

Figure 2.4-1 Power Demand Forecast (Left :Power Demand (GWh), Right :Peak Demand (MW))



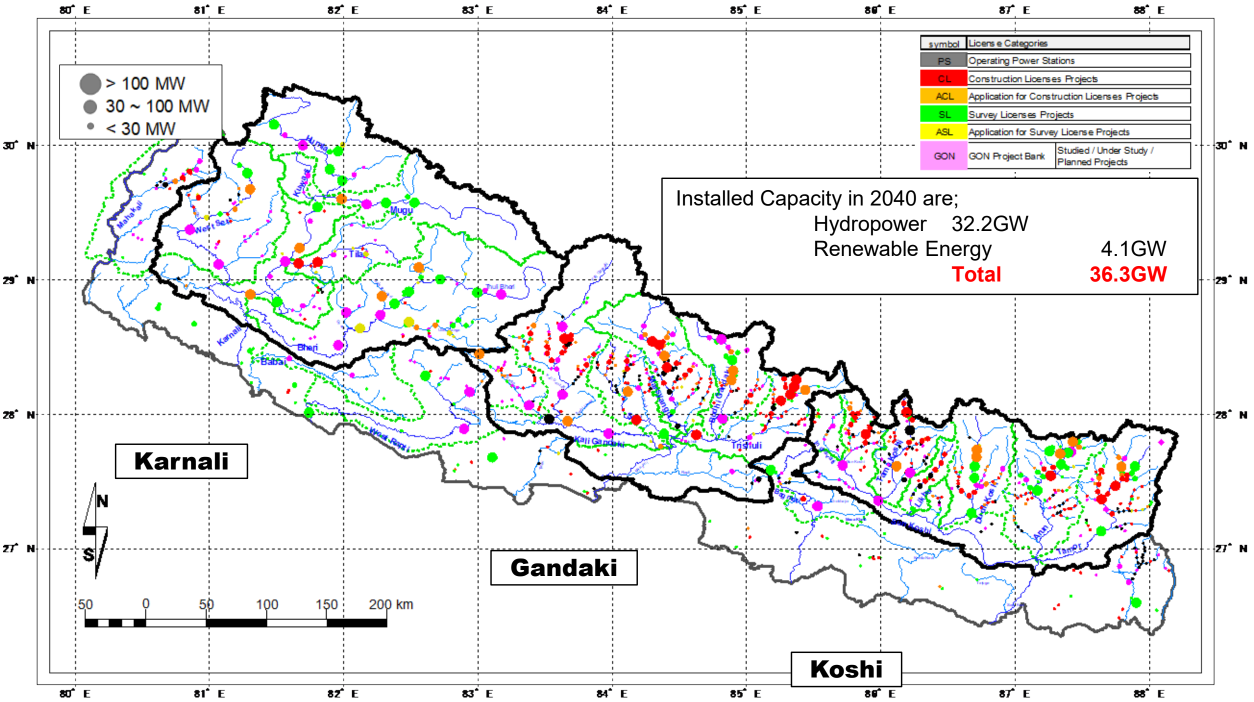
Source: JICA Study Team

Figure 2.4-2 The Relationship Between GDP Per Capita and Electricity Consumption Per Capita for Each Country in South and Southeast Asia

2.4.2 Power Generation Development Planning

(1) Installed Capacity (MW)

PGDP focused on the development of clean energy of hydropower and other renewables, assessed hydropower potential of major river basins in Nepal and clarified required capacity through rainy and dry seasons. The installed capacity, which was 2.7 GW as of 2023, is expected to reach the development target of 28 GW by 2035 as indicated in the Energy Development Roadmap and Work Plan and further increase to 36.3 GW by 2040. The generation mix in 2040 will be as follows: ROR: 13.3 GW (37%), PROR: 10.1 GW (28%), STO: 8.1 GW (23%) and renewable energy: 4.1 GW (12%).



Source: JICA Study Team

Figure 2.4-3 Hydropower Sites and Installed Capacity (GW)

Table 2.4-2 organizes the installed capacity and progress of hydropower development sites in each river basins listed in IPSDP. The gray hatch indicates over 50% completion in categories a) + b), highlighting river systems with substantial progress in operation and construction.

Among the three major rivers, development have been relatively advanced in Gandaki and Koshi rivers. Particularly, Gandaki River with Seti, Marshandhi, and Trishuli has many sites under construction. Conversely, there are many river systems undeveloped such as Karnali River, West Seti River, Bheri River, Dudhkoshi River and Tamor River despite having abundant hydropower potential. These underdeveloped river basin account for 53% of the total development capacity and it is an important and urgent issue to realize the development outlined in IPSDP.

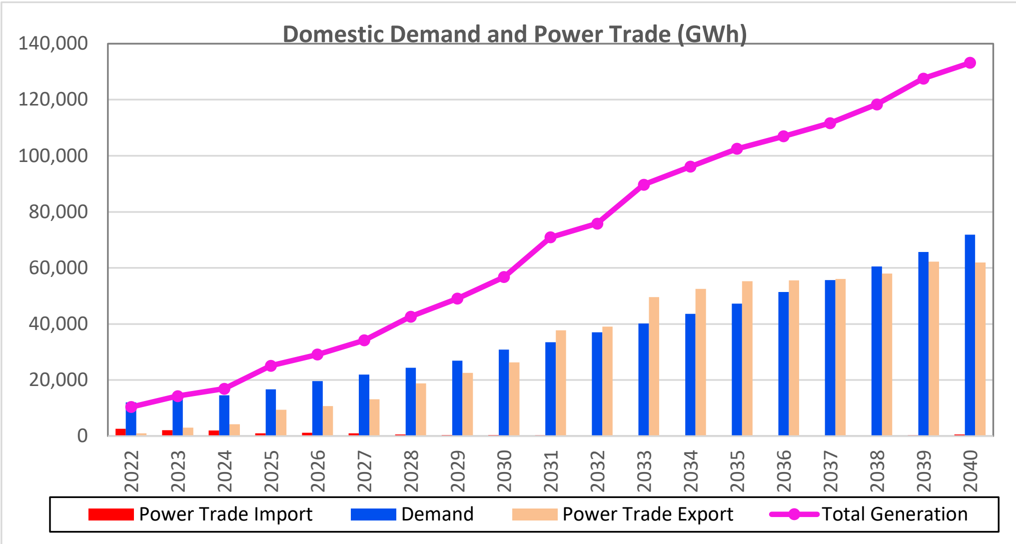
Table 2.4-2 Capacity of Hydropower Development Sites by River System and Progress in IPSDP (MW)

River		a) Existing (Operation)		b) Committed (Construction)		c) Prioritized (Survery)		d) Optimized (GON)		Total
Karnali	Karnali	11.9	0.2%	1,068.4	22.3%	2,888.5	60.3%	821.1	17.1%	4,789.9
Karnali	Tiala Nadi	0.0	0.0%	621.7	83.1%	126.6	16.9%	0.0	0.0%	748.3
Karnali	Seti	12.0	0.7%	385.5	22.8%	236.4	14.0%	1,059.0	62.6%	1,692.9
Karnali	Bheri	0.0	0.0%	644.3	22.7%	1,569.1	55.4%	618.8	21.8%	2,832.1
Gandaki	Kali Gandaki	217.5	20.8%	819.0	78.5%	6.7	0.6%	0.0	0.0%	1,043.2
Gandaki	Modi Khola	45.0	20.1%	175.0	78.2%	3.8	1.7%	0.0	0.0%	223.8
Gandaki	Badigad Khola	7.5	0.6%	898.1	68.0%	35.0	2.7%	380.3	28.8%	1,321.0
Gandaki	Myagdi Khola	0.0	0.0%	250.7	86.1%	40.4	13.9%	0.0	0.0%	291.0
Gandaki	Seti Gandaki	94.5	10.0%	621.5	66.0%	225.1	23.9%	0.0	0.0%	941.1
Gandaki	Marshandi	255.3	13.4%	1,509.8	79.3%	139.7	7.3%	0.0	0.0%	1,904.8
Gandaki	Budhi Gandaki	13.5	0.6%	950.4	40.6%	174.6	7.5%	1,200.0	51.3%	2,338.4
Gandaki	Trishuli	134.5	10.1%	1,075.0	80.6%	123.5	9.3%	0.0	0.0%	1,333.0
Gandaki	Other Tributaries	76.4	76.2%	7.0	7.0%	16.8	16.8%	0.0	0.0%	100.2
Koshi	Sun Koshi	17.5	2.3%	38.5	5.1%	19.3	2.6%	680.0	90.0%	755.3
Koshi	Indrawati Nadi	10.5	20.8%	29.1	57.6%	10.9	21.6%	0.0	0.0%	50.4
Koshi	Balephi Khola	4.2	1.2%	307.7	89.8%	30.8	9.0%	0.0	0.0%	342.7
Koshi	Bhote Koshi	89.3	27.3%	233.4	71.5%	3.7	1.1%	0.0	0.0%	326.3
Koshi	Likhu Khola	131.8	33.9%	239.0	61.5%	18.0	4.6%	0.0	0.0%	388.8
Koshi	Tama Koshi	603.4	26.2%	1,249.2	54.3%	51.0	2.2%	396.5	17.2%	2,300.0
Koshi	Dudh Koshi	27.1	1.2%	857.8	38.9%	971.1	44.0%	350.0	15.9%	2,206.0
Koshi	Arun	33.2	1.0%	1,915.9	55.1%	1,525.9	43.9%	0.0	0.0%	3,475.1
Koshi	Tamor	95.3	5.2%	1,331.9	73.2%	392.9	21.6%	0.0	0.0%	1,820.2
Koshi	Koshi DS	155.5	28.3%	59.3	10.8%	335.0	60.9%	0.0	0.0%	549.8
Other Rivers		173.6	9.1%	309.7	16.3%	1,088.6	57.1%	334.0	17.5%	1,905.9
Total		2,209.5	6.6%	15,597.8	46.3%	10,033.4	29.8%	5,839.7	17.3%	33,680.4

*Gray hatch indicate river basins over 50% by a) Existing + b) Committed Source: JICA Study Team

(2) Power Generation (GWh)

The domestic power demand, power generation and power trade until 2040 are shown in Figure 2.4-4. The power generation is expected to increase from 10,693GWh in 2023 to 133,185GWh by 2040. In terms of power trade, the export volume will steadily increase from 2024 onwards. It is expected to account for about 50% of the total power generation from 2030 onwards. Additionally, since main electricity export destinations, India and Bangladesh, primarily rely on thermal power generation, it is expected to contribute to the improvement of power supply reliability and the reduction of CO_2 emissions in these countries, potentially contributing to a reduction of 44,351 thousand tons of CO_2 emissions by 2040.



Source: JICA Study Team

Figure 2.4-4 Domestic Power Demand, Power Generation and Power Trade until 2040 (GWh)

(3) Hydropower Priority Projects

This section selects priority projects from among the hydropower development sites introduced in the Optimum Scenario to accelerate future hydropower development. Evaluation criteria for selection of hydropower priority projects are installed capacity, power generation scheme, governmental developers, contribution to cascade operation, results of screening, consistency with policy, power trade, commitment of DPs and negative impacts on environment.

Out of the 643 sites to be elaborated in Optimum Scenario excluding 140 existing power plants, 503 sites were scored using the above selection criteria. Analysis results were confirmed between Nepalese side and JICA Study Team. As a result, the top 26 sites with scores of 5 or higher were selected as priority hydropower projects. The list of hydropower priority projects is shown in Table 2.4-3.

It should be noted that projects in this list are selected within the scope of this study and the possibility of each site must be ultimately determined through F/S (Feasibility Studies) and ESIA (Environmental Impact Assessments). In particular, ESIA requires comprehensive studies for individual site conditions and this report does not guarantee the implementation of each site.

Furthermore, the list includes sites where development rights are held by government entities such as NEA and VUCL, as well as those held by private companies, considering all as important projects regardless of the developer's attributes.

Table 2.4-3 List of Hydropower Priority Projects

Status in DoED List	Commis-sioning	Name	River System	Generation Scheme	Installed Capacity (MW)	Annual Power Generation (GWh)
Construction	2026	Tanahu HEP	Trishuli	STO	140	503
	2025	Arun 3	Arun	PROR	900	3,466
	2030	Tila-1 Hydropower Project	Karnali	PROR	299	
	2030	Tila-2 Hydropower Project	Karnali	PROR	297	
	2030	Upper Marsyangdi 1	Trishuli	PROR	102	587
Application for Construction License	2029	Budhi Gandaki Ka	Trishuli	PROR	226	641
	2038	Adhikhola Storage HEP	Kaligandaki	STO	180	693
	2038	Betan Karnali HEP	Karnali	PROR	442	2,319
	2032	Phukot Karnali HEP	Karnali	PROR	480	2,448
	2034	Chainpur Seti HEP	Karnali	PROR	210	1,158
	2039	Kimathanka Arun HEP	Arun	PROR	450	2,558
	2035	Begnas- Rupa Storage HEP	Trishuli	STO	150	206
	2032	Nalsyau Gad Storage HEP	Karnali	STO	417	1,232
Survey	2030	Tamor Storage	Tamor	STO	200	1,079
	2030	Jagdulla HEP	Karnali	PROR	106	615
	2031	Lower Seti (Tanahu) HEP	Trishuli	STO	126	521
	2037	Bajhang Upper Seti HEP	Karnali	PROR	216	1,245
	2034	Dudhkoshi Storage HEP	Sunkoshi	STO	635	3,362
	2028	Madi Storage HEP	Others	STO	156	456
	2033	Upper Arun HEP	Arun	PROR	1,061	4,478
	2035	Kulekhani Sisneri Pumped Storage HEP	Others	STO	100	317
	2031	Budhigandaki Prok-1 HEP	Trishuli	PROR	103	
Application for Survey License	2030	Bheri 4 HEP	Bheri	STO	271	1,593
GON Projects	2038	Bharbung HEP	Bheri	STO	470	1,339
	2033	SR-06 Storage	Karnali	STO	309	1,684
	2035	Sunkoshi 3	Sunkoshi	STO	680	2,300
	2033	West Seti Storage HPP	Karnali	STO	750	2,876

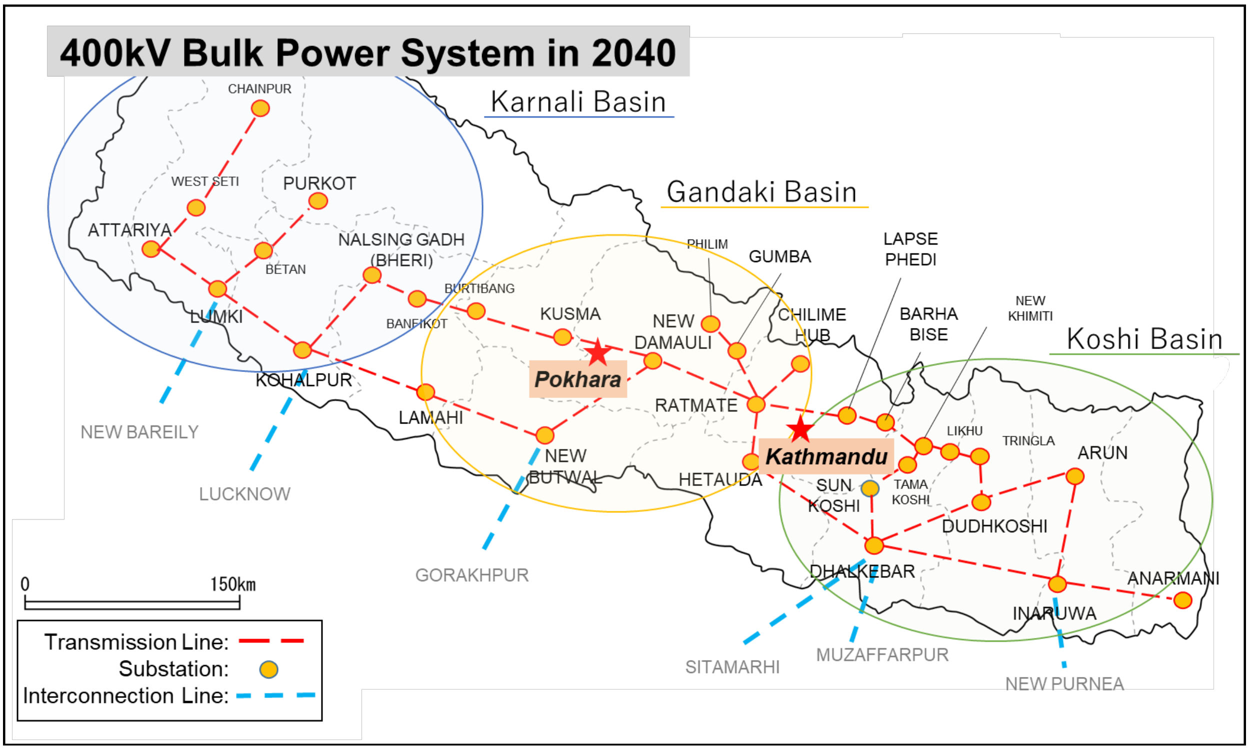
Source: JICA Study Team

2.4.3 The Power System Plan (PSP) and power trade with neigh boring countries

(1) Power System Plan (PSP)

The PSP considered the 400kV backbone system, the lower-level systems around major cities, and the interconnection line with India. The results are shown in Figure 2.4-5. The 400kV backbone system is projected to grow from a transmission line length of 78 km and transformer capacity of 945 MVA in 2023 to 2,487 km and 20,475 MVA by 2040. It will form a grid consisting of two east-west 400kV routes across the country and north-south routes developed along major rivers. Additionally, domestic 220kV/132kV/66kV systems, including the urban distribution networks in Kathmandu, Pokhara, and Butwal, will also be reinforced.

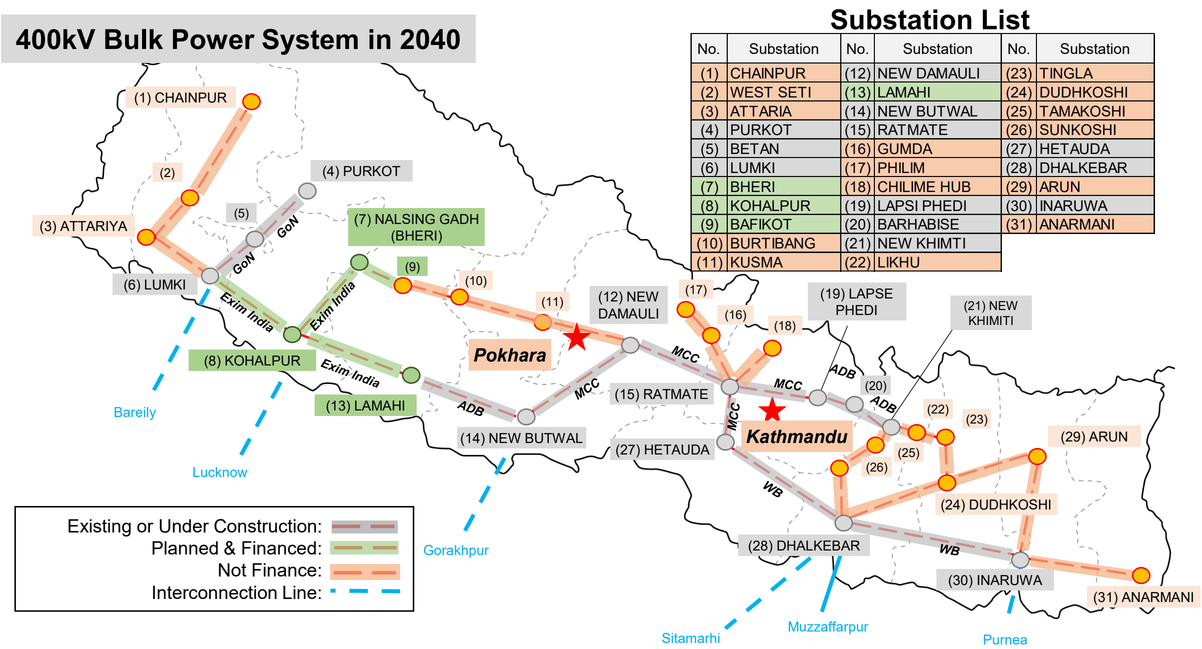
Power trade with neighboring countries will be conducted via India, with six 400kV interconnection lines planned. For development sites beyond 2035, direct exports through dedicated interconnection lines will be required to ensure stable and efficient system operation.



Source: JICA Study Team

Figure 2.4-5 Major backbone systems and international interconnection lines in 2040

Figure 2.4-6 summarizes the development status of the 400 kV domestic grid.



Substation List

No.	Substation	No.	Substation	No.	Substation
(1)	CHAINPUR	(12)	NEW DAMAULI	(23)	TINGLA
(2)	WEST SETI	(13)	LAMAHI	(24)	DUDHKOSHI
(3)	ATTARIA	(14)	NEW BUTWAL	(25)	TAMAKOSHI
(4)	PURKOT	(15)	RATMATE	(26)	SUNKOSHI
(5)	BETAN	(16)	GUMDA	(27)	HETAUDA
(6)	LUMKI	(17)	PHILIM	(28)	DHALKEBAR
(7)	BHERI	(18)	CHILIME HUB	(29)	ARUN
(8)	KOHALPUR	(19)	LAPSI PHEDI	(30)	INARUWA
(9)	BAFIKOT	(20)	BARHABISE	(31)	ANARMANI
(10)	BURTIBANG	(21)	NEW KHIMTI		
(11)	KUSMA	(22)	LIKHU		

Source: Prepared by JICA Study Team

Figure 2.4-6 Current status of development plans for 400kV grid and interconnection lines

With the support of MCC, WB, ADB, etc., the 400 kV domestic grid is under construction or planned for most of the major cities in the country, including Kathmandu and Pokhara. As for the interconnection lines, the existing Dhalkebar-Muzzaffapur interconnection line and the New

Butwal-Gorakhpur interconnection line under construction are capable of handling power imports to major cities in the country and hydropower exports in the Gandaki water system and western Koshi water system, both of which are already under construction.

On the other hand, in consideration of future export expansion, it will be necessary to develop 400 kV domestic grids and interconnection lines for water systems that will be developed in the future, such as the West Seti, Karnali, Bheri, Dudhokoshi, Arun, and Tamor water systems. Based on this recognition, the issues of grid development for power export are summarized.

Table 2.4-4 Future 400kV interconnection line and target water system

400kV Interconnection line	400kV Nepal grid	Target water system	Operators
Lumki – Bareily	Chaipur Seti – West Seti – Attariya	West Seti	RPGCL (Only West Seti – Attariya)
	Phurkot – Betan – Lumki	Karnali	RPGCL
Kohalpur – Lucknow	Bheri – Kohalpur	Bheri	NEA
Dhalkebar – Sitamarhi	New-Khimti – Tamakoshi – Sunkoshi – Dalkebar	Sunkoshi, Tamakoshi, Dudhokoshi	NEA
Inaruwa – Purnea	Arun – Inaruwa	Arun, Tamor	NEA、RPGCL

Source: JICA Study Team

These domestic and interconnection lines will be developed in a north-south direction, connecting each water system to India rather than building a conventional east-west grid connecting domestic demand centres. It is also important to promote the development of power sources and systems from the perspective of integrated development of water systems, regarding the future development of power transmission lines as a single package.

(2) Power Trade

In addition to infrastructure development, it is also important to establish institutional arrangements such as establishing distribution channel between power trading companies and IPPs and power companies/customers in India and Bangladesh, granting preferential treatment for clean energy, and applying for power grid connection in each country in order to mitigate the concentration of wholesale to NEA.

1) Wholesale scheme of electricity from the viewpoint of power generators

Table 2.4-5 and Table 2.4-6 show the possible future power trade scheme and a comparison of each scheme of wholesaling from the viewpoint of power generators. 1) is a conventional trade and 2), 3) are new trading schemes assuming power exports.

Table 2.4-5 Wholesale suppliers of electricity from the viewpoint of power generators

Wholesale customer	Content
1) NEA	This is a conventional scheme of trading that is completed through domestic transactions with NEA. Since NEA distributes the purchased power to the domestic retail market and the surplus to India, the generators are not directly involved in power trade. Although the purchase price will be lower for the generator, it is assumed that this will continue to be the mainstream scheme for small and medium-sized power generation projects in Nepal, as it does not require any administrative procedures such as grid connection applications or PPAs with customers in other countries.
2) Power trading company	This is a scheme through power trading companies. In the future, Nepal's Electricity Act will be amended to allow power trading business, and it is expected that the function of power distribution, which NEA is responsible for, will be partially transferred to Nepal Trading Companies. NEA has established NPTCL (Nepal Power Trading Company Ltd.), the first trading company in Nepal, in 2021, and NPTCL is expected to operate this trading business for the time being. The power generation companies will be able to choose whether to use the PPA with the power trading companies as the price at which they sell electricity, or whether the price will be linked to the market.
3) Direct trade with DISCO/Customer in India/Bangladesh	This is a scheme in which power generation companies deal directly with power distribution companies and major customers in India and Bangladesh, and it offers economies of scale in structuring project financing with the participation of investors from various countries.

Source: JICA Study Team

Table 2.4-6 Comparison of Electricity Suppliers from the Power Generator's Perspective

Scheme	1) NEA	2) Trading Company	3) Direct Trade
Purchaser	NEA	Trading Company	Large consumers in overseas
Selling Price	PPA with NEA	PPA with Trading Company Market Price	PPA with Consumers
Pros	- Purchase volume and price are secured. - There are transmission costs only with Nepal.	<PPA> - Purchase volume and price are secured. <Market> - Electricity can be sold when surplus power is generated.	- Purchase volume and price are secured. - IPP can chose the customer with the best contract conditions by themselves.
Cons	- Limited amount of NEA purchases.	- The purpose and function of the Trading Company has not yet been determined.	- IPPs need to secure their own customers - Transmission costs are incurred outside of the Nepal in addition to within Nepal

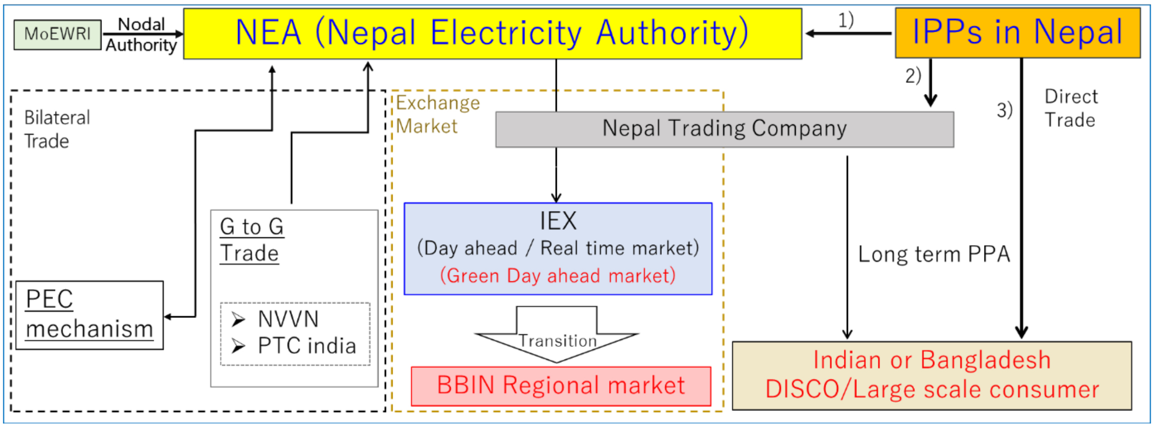
Source: JICA Study Team

When looking at power trade from the perspective of a power generator, wholesale customers and the wholesale price are important factors in considering business feasibility. PPA's electricity selling price is 5.68 NRs/kWh (4.4 cents/kWh) on average in 2023/24 for NEA domestic trade, and 8.77 NRs/kWh (6.6 cents/kWh) for export, with the latter being higher. It is desirable for power generators to have a scheme that allows them to consider both domestic trading and exports as wholesale customers. There is no restriction on each power generator to choose only one form of trading for these 1), 2), and 3), and flexible combinations are expected to be possible.

For example, during the dry season, power could be sold to Nepal through NEA in the scheme of 1), and during the rainy season, power could be sold to India and Bangladesh in the scheme of 2) and 3). If this type of trade is possible, the power generation plans required, especially for medium to large scale projects, are expected to change.

2) Proposed power trading scheme

Figure 2.4-7 shows the proposed trading scheme from the perspective of both the NEA and the power generator.



Source: JICA Study Team

Figure 2.4-7 Proposed power trading scheme

As mentioned above, the diversification of wholesale customers for power generators is expected to reduce NEA's financial risk and promote the participation of Indian and Bangladesh generators.

It is also expected to add value to hydropower, a clean energy source. IEX also has a green market for renewable energy, which is traded at about 10% higher than the regular market. If NEA can conclude an agreement with the Indian government to participate in the green market, it will lead to increase earnings for NEA. As mentioned above, India plans to increase its procurement of electricity derived from renewable energy sources, and the market is expected to expand in the future. In addition to IEX, it will also be necessary to conclude long-term relative contracts (PPAs) with power distribution companies and large customers in India and Bangladesh in order to secure long-term stable power export.

In addition, the proposal to build an interconnection line directly between Nepal and Bangladesh and the proposal for Bangladesh to participate in IEX, as India foresees a potential of IEX's development as a broad-based power exchange market in South Asia, would contribute to increasing the volume of electricity trade between Nepal and Bangladesh.

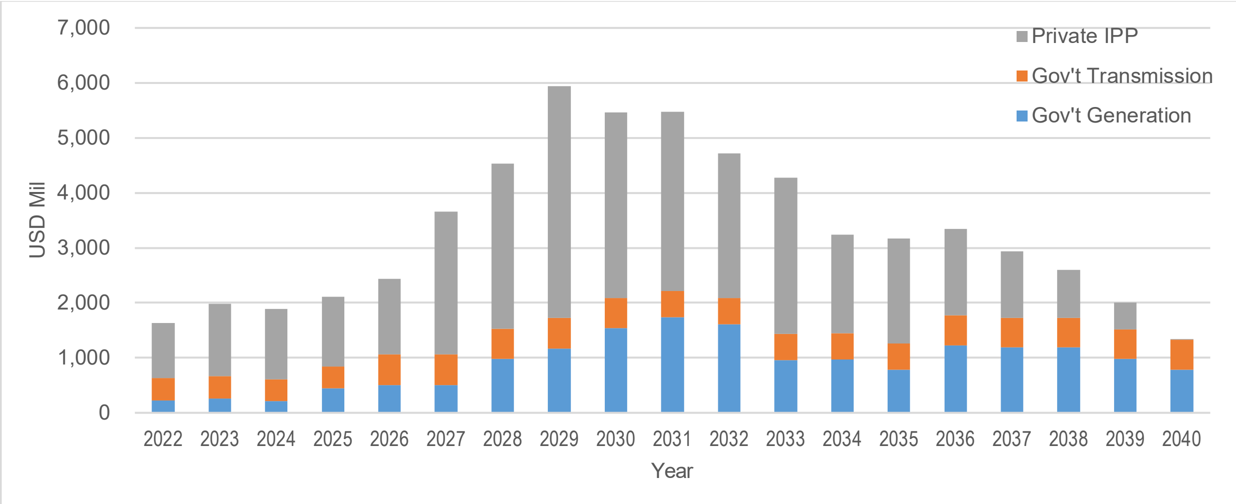
However, in order to ensure the supply of electricity to the domestic market, it will also be necessary to require a certain amount of domestic supply throughout the year when granting licenses to power generators. This will require improvement of NEA's capacity to plan for supply and demand, coordination with the DoED, which issues development rights, or the ERC, which evaluates PPAs, as well as coordination with power generators and trading companies.

2.4.4 Financial Analysis of IPSDP

As shown in Figure 2.4-8, the IPSDP requires a large capital investment of 61,750 MUSD cumulatively, or 3,431 MUSD per year on average, until 2040 for power generation, transmission, and distribution. In order for Nepal's power sector to implement the IPSDP, the plan is evaluated from the following two perspectives.

i) Financially sustainable operation of the sector at reasonable electricity tariff levels
ii) Financing plan considering Nepal's domestic and international fund raising capacity

Regarding i), the government-related organizations that will be implementing the IPSDP as the government is firstly analyzed, creating a cash flow table for the IPSDP period for that organization, and analyzing the fundraising required for investment and the level of electricity tariffs. Then, the impact on the macro economy based on the results of the financial analysis is conducted. Regarding ii), the attributes of operators and fundraising assumed from the scale of development and profitability are categorized and an outlook for capital demand and investment and financing during the IPSDP period based on the characteristics of investors and lenders is presented.



Note: The classification of government (estimated)/private (estimated) was made by the JICA Study Team after confirming the proponents of each target project. Projects that were clearly being promoted by the Nepalese government were classified as "Investment by the Nepalese government (estimated)" and all others as "Investment by the private sector (estimated)". PPPs (Public Private Partnership) were classified as the latter.

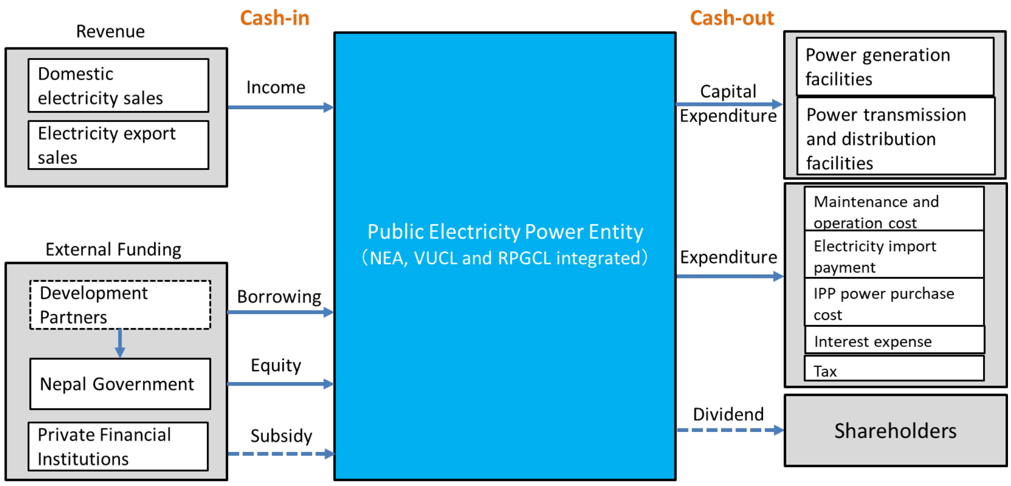
Source: JICA Study Team

Figure 2.4-8 IPSDP funding needs

(1) Financial Analysis of IPSDP

1) Financial Flow involved in Public Electric Power Company

In financial analysis, a public electric power company which consists of NEA, VUCL and RPGCL is analyzed. The financial flow involved in the public power is shown in the Table 2.4-9.



Source: JICA Study Team

Figure 2.4-9 Basic Funding Flows in Nepal's Electricity Sector

2) Cash Flow analysis

In this section, a cash flow analysis will be carried out based on the three cases shown in the following table. The amount obtained by deducting the repayment amount of the loan from the income obtained through business activities will be reserved as funds in the hands of the public power utility and used as the source of investment for the following years. If the above funds are insufficient for the amount required for investment, the necessary funds for investment will be covered by borrowing and shareholder investment. The ratio of borrowing to shareholder investment will be 7:3. The borrowing interest rate applied 5.0%, which is the current average fundraising interest rate of NEA, and 10.0%, which is the average interest rate of commercial banks in Nepal.

Table 2.4-7 Cases of Cash Flow Analysis

Cases	Assumptions
Benchmark Case (Based on the current electricity price)	The current electricity tariffs, electricity export selling prices, and purchase prices from IPPs are maintained at the current pricing levels.
Case 1 (Cash Short)	In Case 1, the domestic electricity tariff level at which public electric power utilities will have a negative cash balance in any year after 2023. This is the electricity tariff level at which a cash shortfall will occur even if the funds necessary for investment are procured through borrowing and investment.
Case 2 (Without loan and shareholder investment)	The domestic electricity tariff level is set so that the funds saved through business activities over the analysis period exceed the funds required for investment. In this case, all of the funds required for capital investment can be covered by business revenues.

Source: JICA Study Team

The electricity tariff levels and the profit level of the public entities ROE (Return on Equity) and ROA (Return On Asset) for each case are shown in Table 2.4-8.

Table 2.4-8 The level of electricity tariffs

Electricity Tariffs and Profit Level		Interest Rate (%) 5.0%	Interest Rate (%) 10.0%
Case	Case 1	0.054 dollars/kWh (ROE:3.0% ROA:1.0%)	0.058 dollars/kWh (ROE:2.0% ROA:0.0%)
	Benchmark Case[3]	0.070 dollars/kWh (ROE:10.0% ROA:5.0%)	0.070 dollars/kWh (ROE:8.0% ROA:4.0%)
	Case 2	0.130 dollars/kWh (ROE:18.0% ROA:15.0%)	0,132 dollars/kWh (ROE:18.0% ROA:15.0%)

Source: JICA Study Team

The results suggest the electricity tariffs can be suppressed to \$0.055/kWh considering cash position perspective alone. However, the suppressed electricity tariff forced the GoN to raise funding externally, hence increasing uncertainty of procurement and the government's financial burden. On the other hand, if all capital investment funds are covered by the revenues of public electric power utilities, electricity tariffs need to raise double from the current level, which would increase the burden on citizens. If IPSPD is implemented maintaining the current electricity tariff level of \$0.070/kWh, capital investment can be promoted using the revenues of public electric power utilities combined with borrowing and investment. The results also suggest that applying current tariff could avoid an over-burden of citizens due to a significant increase of electricity tariffs.

3) Sensitivity analysis of electricity export sales prices

In addition to examining domestic electricity rates, the selling price of electricity exports is also examined. The benchmark case applies an electricity selling price of \$0.070/kWh based on the performance of IEX. The electricity sales price setting will have a significant impact on the business operations of the power sector in Nepal. Therefore, the study examines the changes of electricity sales prices' impact to the profit margins and financial status of public power utilities in Nepal.

The analysis uses 0.030 dollars/kWh, 0.040 dollars/kWh, 0.050 dollars/kWh, and 0.060 dollars/kWh to set prices that have fallen from 0.070 dollars/kWh. The lowest price of 0.030 dollars/kWh was set based on the 2020 IEX annual average trading fee of 0.031 dollars/kWh, assuming that the selling price of electricity exports falls to this level. Note that conditions other than the selling price of electricity exports are the same as those used in the benchmark case. The results calculated using the above variable settings are shown in the table below.

Table 2.4-9 Result of sensitivity analysis of electricity export sales prices

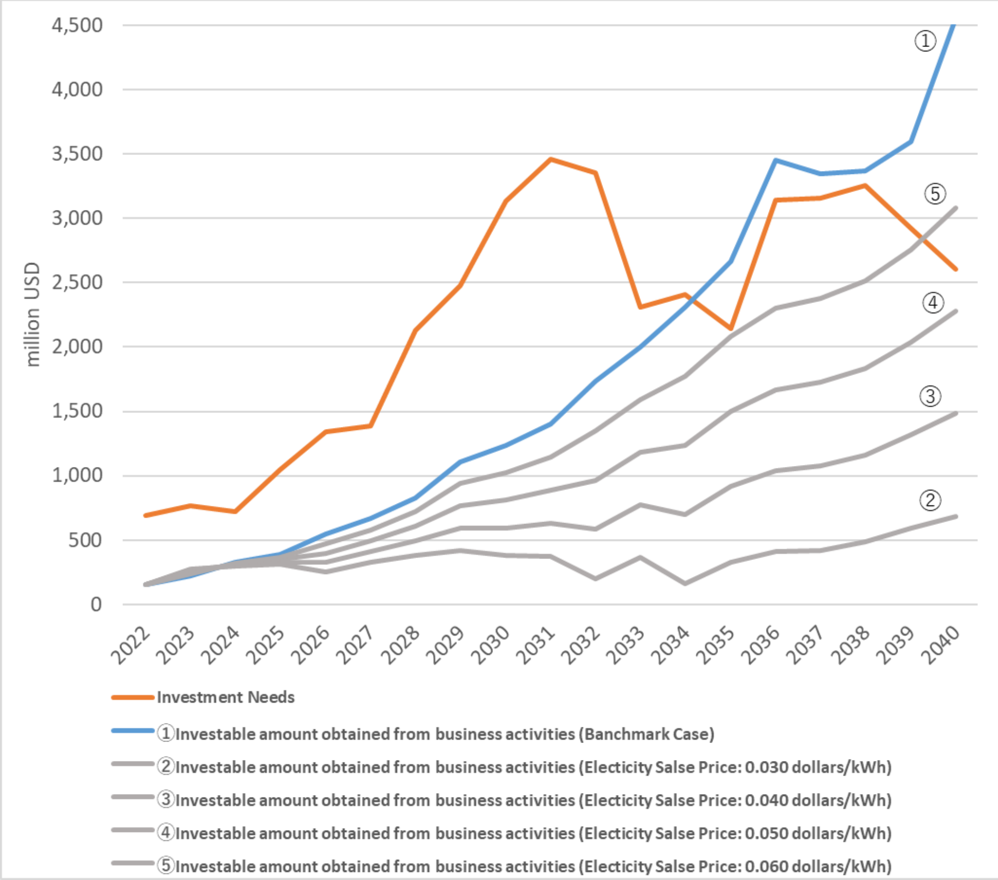
Result of Analysis		Electricity Export Sales Prices（dollars/kWh） 0.030 dollars/kWh	0.040 dollars/kWh	0.050 dollars/kWh	0.060 dollars/kWh	0.070 dollars/kWh
Profit Level	ROE	-39.0%	-4.0%	4.0%	7.0%	10.0%
	ROA	-3.0%	0.0%	2.0%	4.0%	5.0%
Financial Status	Cash Short	No	No	No	No	No
	Insolvency	Yes	No	No	No	No

Source: JICA Study Team

Even if the selling price for electricity exports falls to \$0.030/kWh, Nepalese power sector will barely be able to avoid a cash shortfall, but as a result of the accumulation of deficits, their net assets will become negative and will become insolvent. In addition to the public power utility

3 In the cash flow analysis in the previous section, an interest rate of 5.0% is used as the benchmark case.

having a significant shortage of cash on hand, power sector needs to raise more external funds (loans and shareholder contributions) for capital investment than in the benchmark case. As capital contributions from the Nepalese government will increase, there is a possibility that the public power utility will go bankrupt due to insolvency (profit margins are ROE: -39.0% and ROA: -3.0%). Figure 2.4-10 indicates relationship between available investment amount from cash on hand and the amount of capital investment need.



Source: JICA Study Team

Figure 2.4-10 Relationship between available investment amount from cash on hand and capital investment amount

One possible way to make up for the loss of revenue from electricity exports would be to raise domestic electricity tariffs, but this would increase the burden on the public. Therefore, if the selling price of electricity exports falls, it may become necessary to reconsider the plans envisaged in the IPSDP by taking measures such as discontinuing unprofitable projects through careful review of the projects, improving the profitability of projects by reviewing the costs of new projects, and increasing the added value of electricity sales. However, there are limits to how much a business profitability can be reviewed, and in reality, if the selling price of electricity exports falls to a level where ROE and ROA become negative (below 0.050 dollars/kWh), it is expected that a review of the development plan itself will be necessary. Considering the current electricity situation in neighboring countries, it is unlikely that the selling price for electricity exports will deviate significantly from $0.070/kWh. However, it is necessary to update periodically a medium- to long-term plan such as the IPSDP in response to business environment’s changes.

(2) Impact on the macro economy

This section considers the impact of implementing the IPSDP on Nepal's macro economy. Specifically, we consider the impact on external debt, foreign exchange reserves, trade balance due to electricity exports, GDP due to electricity exports, and domestic employment. Note that the cash flow of public power utilities in the following analysis is based on the benchmark case of domestic electricity selling price (0.070 dollars/kWh) and borrowing interest rate (5%). However, since the GDP growth rate described below is based on real GDP, the inflation rate of 3% considered in the financial analysis is not taken into account. The results of the impact on the macro economy are shown in Table 2.4-10.

Regarding the analysis of the impact on the macro economy, the study estimated the impact of borrowing and shareholder investments by public power utilities in capital investment under the IPSDP on external debt and foreign exchange reserves. As a result, it was confirmed that external debt will increase as capital investment increases, peaking in the early 2030s, but is not significantly higher than other countries. In addition, the effect of electricity exports is a maximum 5% increase in GDP and a maximum 14% improvement in the trade deficit. Furthermore, hydropower development is expected to create jobs, and IPSDP development is expected to contribute to economic growth.

Table 2.4-10 Impact on the macro economy

Indicators	Analysis Result
External Debt	The impact of capital investment in the IPSDP on external debt was analyzed in two cases: 15% (Case 1) and 100% (Case 2) of the external debt of borrowings and shareholder contributions accepted by public power utilities based on the current Nepalese government budget structure. The results show that the external debt-to-GDP ratio will rise to a maximum of 21.4% in Case 1 and 32.5% in Case 2 from around 2031 to 2032, when capital demand is high. However, these figures are not particularly high compared to other developing countries in Asia.
Foreign Exchange Reserves	We estimated the ratio of foreign exchange reserves to external debt and how many months' worth of imports the foreign exchange reserves are equivalent to. The foreign exchange reserve ratio was 1.44 in Case 1 of the analysis of external debt, and 1.01 in Case 2, both of which exceeded the benchmark of 1. In terms of the value of imports, foreign exchange reserves equivalent to more than 10 months' worth of imports were secured throughout the analysis period, exceeding the benchmark level of 3 months.
Impact of electricity exports on the trade balance	If the average trade deficit of 32% of GDP over the past 10 years is taken as the baseline trade deficit, it is estimated that electricity exports could improve the trade deficit by up to 14%.
The impact of electricity exports on GDP	The amount of revenue from electricity export sales is expected to grow year by year, and it is estimated that it will increase GDP by up to about 5% compared to a situation without IPSDP exports.
Job Creation	The number of unemployed people in 2022/2023 is estimated to be around 980,000, but based on rough estimates of job creation through IPSDP, it is expected that up to 85,000 jobs will be created per 1,000 MW hydropower plant, which could lead to a reduction in the number of unemployed people of around 9%.

Source: JICA Study Team

2.4.5 Investment Plan

In this section, how to finance the individual projects included in the IPSDP is considered.

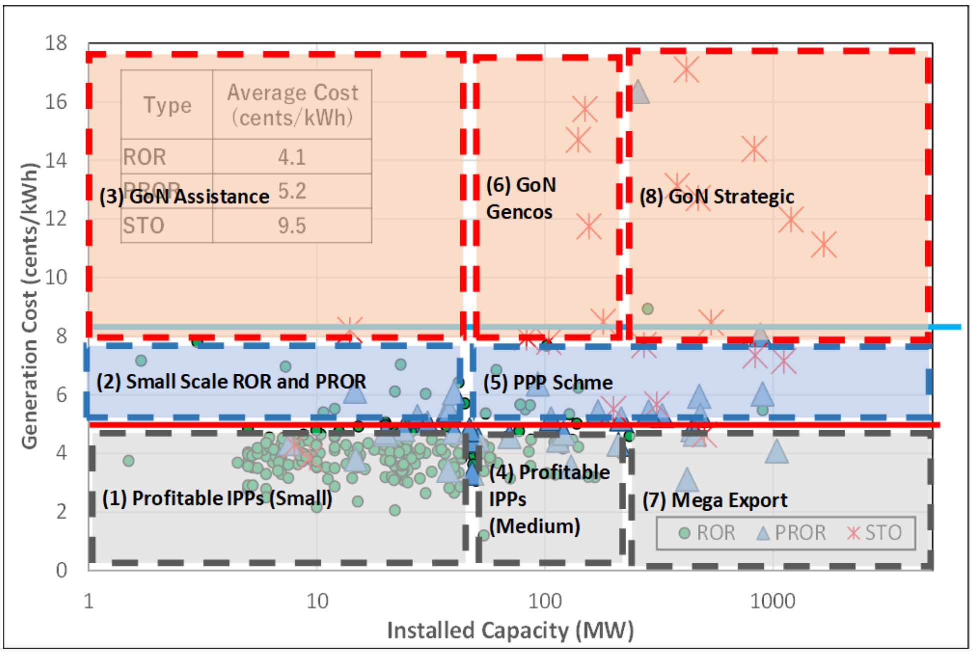
(1) Considerations regarding fund procurement based on business scale and profitability

Power development projects are likely to have different investors and lenders depending on the project scale, profitability, and the composition of participating entities. In particular, in hydroelectric power projects, the scale of the project determines the development period and required investment amount, so the composition of investors and lenders varies.

Regarding the size of the hydroelectric power projects to be analyzed, small-scale generally refers to projects of less than 1 MW, but in this study, considering the situation in Nepal and projects in other countries, it is assumed that the projects of 50 MW or less are assumed to be small-scale, which can be funded within Nepal mainly through corporate finance. Medium scale broadly refers to projects up to 200 MW that do not require IBN investment permission, and both corporate and project finance are assumed. Hydroelectric power plants over 200 MW are subject to IBN approval, and mainly project finance is assumed. Public support, including the use of ODA (Official Development Assistance), is expected to be applied to projects of medium or larger scale.

Power transmission and distribution projects need to be operated as an entire power system, not as individual business units like power generation projects, and profitability varies greatly depending on the business unit. In the future, the Electricity Act is expected to be amended to open up the power transmission and distribution business to the private sector, but as this is a highly public-interest business that aims to provide a stable supply of electricity to the people of Nepal, there is a strong tendency for the financing associated with the construction of power transmission lines to be mainly provided by public funds.

In this study, as shown in Figure 2.4-11 and Table 2.4-11, hydropower projects that should be developed in the IPSDP were evaluated based on the axis of generation cost and business scale (installed capacity) and classified into eight categories. The generation cost was considered based on the LCOE described in Section 2.2.3. In the analysis, projects with an LCOE of 5.0 cents/kWh or less were classified into a category that is highly profitable and can be funded by private funds, and those with an LCOE of 5.0-8.0 cents/kWh were classified into a category that is medium profitable and therefore should be borrowed under more favorable conditions than the private sector, such as partial PPP loans, for which private financing is insufficient. Furthermore, projects with an LCOE exceeding 8.0 cents/kWh are classified as requiring loans from development aid agencies because they are not profitable.



Source: JICA Study Team

Figure 2.4-11 Distribution of IPSDP Priority Development Projects

Table 2.4-11 Basic Concept of Project Categories and Financing Methods in IPSDP

Profitability	Category	Capacity	Sites	Output	Investment Amount	Source of Finance	
				(MW)	(USD Mil	Gov't	Private
High	(1) Profitable IPPs (Small)	Less than 50MW	493	5,915.40	8,975.20	—	◎
	(4) Profitable IPPs (Medium)	50～200MW	60	5,614.10	8,652.00	△	◎
	(7) Mega Export	More than 200MW				○	◎
Medium	(2) Small Scale ROR and PROR	Less than 50MW	24	434.4	889.7	△	○
	(5) PPP Scheme	More than 50MW	24	6,658.40	12,822.40	○	○
Low	(3) GoN Assistance	Less than 50MW	8	88	139.5	○	△
	(6) GoN PROR/STO Projects	50～200MW	8	1,128.00	2,351.80	◎	—
	(8) GoN Strategic Project	More than 200MZ	11	6,811.90	15,279.40	◎	—
-	(9)Others (inc Solar)	-	82	4,188.10	4,213.50	—	◎
	(10) Power System	-	-	-	9,496	◎	△

Source: JICA Study Team

For projects in categories (1), (4), and (7) with relatively high profitability, private funds are expected to be utilized to the maximum extent possible. Small-scale projects are expected to be corporate financed, but since there are many sites, it is desirable to speed up the loan and various approval processes. For medium to large-scale projects, project finance from domestic and foreign investors and operators is expected, and private financing from development financial institutions is also expected to be utilized. Since the operators who can participate in large-scale projects are particularly limited, it is expected that they will be implemented by an SPC (Special Purpose Company) consisting of government-affiliated operators such as NEA, major domestic conglomerates, major international developers, and Indian power companies.

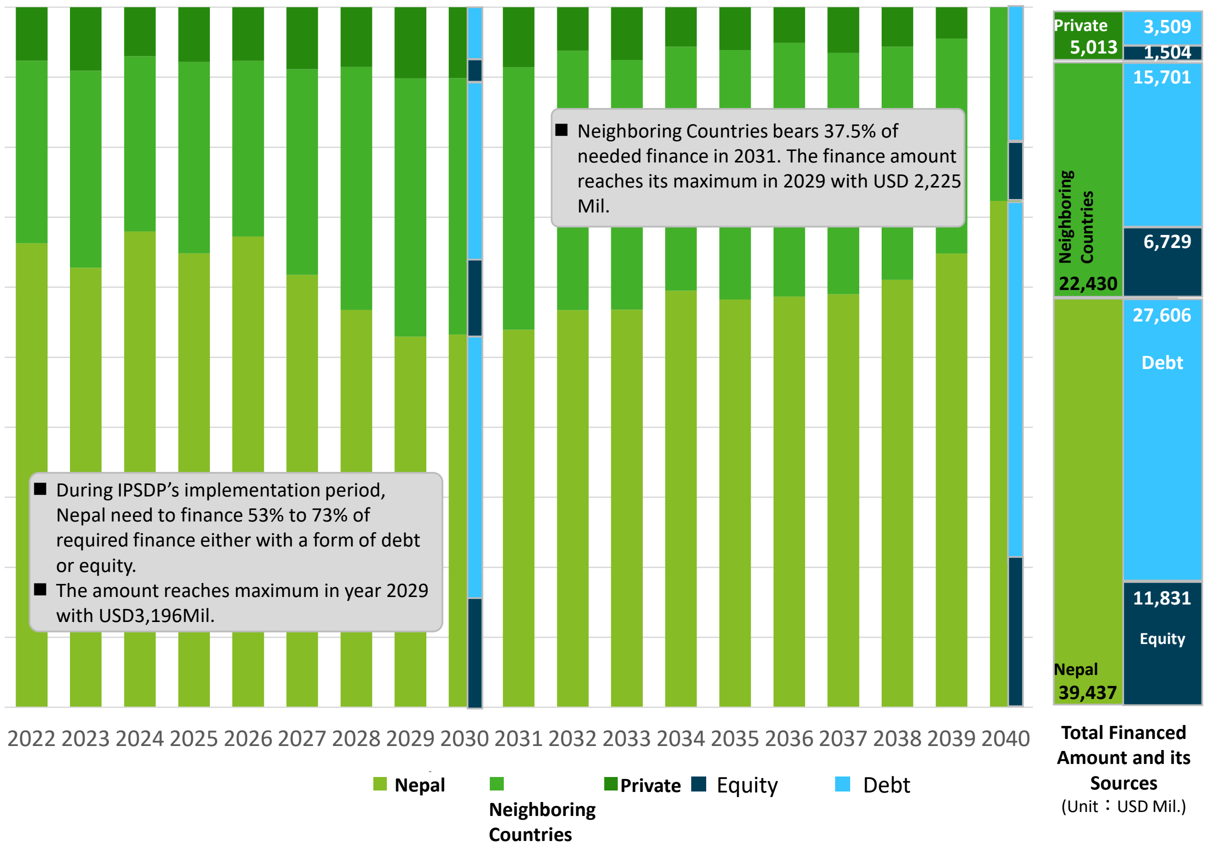
For projects in categories (2) and (5) with medium profitability, if the project is small and cannot be expected to be profitable on its own, it is expected that support will be provided in bulk through funds, or that government-affiliated operators such as HIDCL will join in support. For medium to large-scale projects, in addition to various power generation formats such as ROR, PROR, and STO, it is expected that a variety of players will participate as developers, including medium to large-scale domestic and foreign developers, government-affiliated operators, and Indian power companies. Financing needs to be structured for each project, and it is expected that there will be a wide variety of support methods. It is necessary to consider a flexible structure that combines support measures that can be applied to each player.

Low-profit projects in project categories (3), (6), and (8) with relatively low profitability include regulated power sources such as STO. It is difficult to evaluate the business value of STO power sources based solely on hourly value such as LCOE, and many locations do not show feasibility or profitability through financial analysis. Therefore, development by government-affiliated businesses with the support of development aid agencies or joint development with IPPs is expected. In addition to utilizing support schemes such as EBF (Equity Backed Finance) and overseas investment and loans, it will be important to utilize ODA budgets not only for Nepal, but also for neighboring countries that are potential destinations for electricity.

(2) Investment Plan for IPSDP Implementation

This section examines the outlook for financiers and investors for projects that were prioritized in the IPSDP, based on the characteristics of the projects, and shows the trends in capital demand and the amount of investment and loans during the IPSDP period. Based on this distribution and characteristics, a model of the investors and loan providers for the projects was envisaged, and an attempt was made to allocate investors and lenders based on this model. As shown in Figure 2.4-12 and Table 2.4-12, capital demand during the IPSDP period will peak between 2029 and 2032, when construction of many projects will be concentrated, and then gradually decline.

Debt will also peak at USD 4,225 million in 2029, decrease to USD 2,411 million by 2034, increase to USD 2,481 million in 2036, and decrease gradually thereafter. This projection is for hydropower projects currently captured in the IPSDP. It is expected that investment trends through 2030 will attract private sector investment, noting that figures presented below does not depict the inflow of stimulated private sector investment.



Source: JICA Study Team

Figure 2.4-12 Proportional trend and Source of Finance

Table 2.4-12 Trend of Finances by Sources during IPSDP period

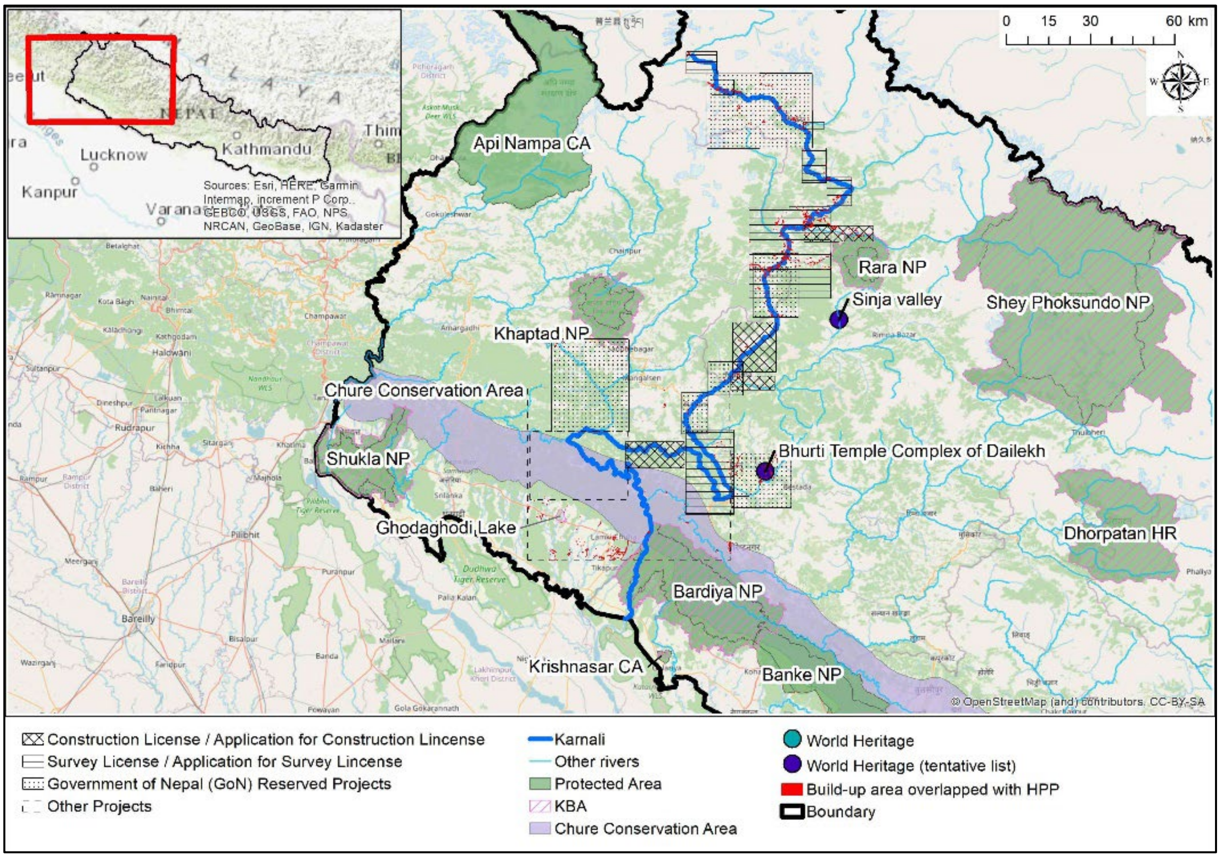
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Nepal	5,194	5,992	6,185	6,498	7,427	9,785	10,675	13,207	12,353	12,405	11,077	10,286	8,314	8,166	8,470	7,763	7,151	6,070	4,635
Neighboring Countries	978	1,381	1,371	1,562	1,833	2,914	3,362	4,651	4,271	4,248	3,524	3,222	2,348	2,357	2,451	2,185	1,873	1,363	678
Private	217	301	251	267	295	549	639	805	617	645	497	501	307	296	277	245	186	123	480

(Unit : USD Mil)

Source: JICA Study Team

2.4.6 Strategic Environmental Assessment

The optimal scenario selected in this master plan was evaluated from environmental and social viewpoints. The points to be considered, such as cumulative impacts, for hydropower development for each river and river basin were analyzed. Then, the impacts on protected areas (national parks, areas important from the biodiversity perspective KBA (Key Biodiversity Area), ecosystems (both aquatic and terrestrial ecosystems, especially migratory fish and rare species listed in the IUCN (International Union for Conservation of Nature) Red List), cultural heritage, etc. were examined; and points to be considered for environmental and social considerations, such as mitigation measures for the anticipated impacts, were also considered.



Source: JICA Study Team

Figure 2.4-13 Evaluation of Optimum Scenarios (Example) - Karnali River

It is recommended to avoid as much as possible environmental and social impacts caused by projects in line with the mitigation hierarchy, and then to examine measures to minimize, reduce, and mitigate those impacts that cannot be avoided. In the process, it is important to provide opportunities for stakeholders, such as the central government, provincial governments, and affected people, to express their opinions and to hold meaningful consultations. In addition, appropriate monitoring should be carried out; and if any concerns are identified during the monitoring, corrective measures should be taken. The main points to keep in mind are as follows.

Table 2.4-13 Points for Environmental and Social Considerations in SEA (Mitigation Measures etc.)

Items	Points for Environmental and Social Considerations in SEA (Mitigation Measures etc.)
Basin-wide cumulative impact assessment / Cooperation and collaboration between project developers	• In Nepal, the progress of development plans varies from river basin to river basin and cumulative impacts can be significant in some river basins due to multiple hydropower projects; therefore, it is necessary to evaluate the cumulative impacts for each river basin and consider appropriate mitigation measures from the perspective of river basin management. In particular, in river basins where development plans would be concentrated, such as the Gandaki River basin (where many existing power plants are located near demand areas and development is progressing), it is recommended to carry out development that takes cumulative impacts into account at an early stage. In addition, it is recommended that Nepal strategically consider free-flowing rivers in order to avoid significant cumulative impacts on each river system and to conserve the flow rate and continuity of the river basins. • Environmental management is also sometimes not properly implemented from the perspective of watershed management in Nepal; and there are cases that environmental measures (such as the installation of fish passages to allow migratory fish to move around) are not carried out effectively in multiple hydropower projects located along the same river basin. It is recommended that cooperation and collaboration among project developers along the basin, including private hydropower developers, be promoted in order to properly conduct river basin management.

Items	Points for Environmental and Social Considerations in SEA (Mitigation Measures etc.)
E flow	• Hydropower projects may affect E flow (environmental flow), including minimum water flow, and may cause changes in the flow rate of the entire river and downstream areas, as well as habitat fragmentation. If adverse effects are anticipated by hydropower development, it is advisable to refer to guidelines such as "IFC Good practice handbook - Environmental flows for hydropower projects (2018)" and to develop and implement an E flow management plan based on evaluation of E flows.
Protected areas	• When developing a project within a protected area (national park, wildlife sanctuary, hunting reserve, conservation area, buffer zone) defined in the local country's National Parks and Wildlife Conservation Act (2029/1973), permission from the authorities must be obtained prior to development. Damming or modifying the flow of rivers is prohibited, and restrictions such as maintenance flow are required for hydropower development. In addition, when implementing within a Ramsar site based on an international treaty, the project must be carried out in accordance with the management plan of each Ramsar site. It is advisable to plan and implement the project in accordance with the mitigation hierarchy.
Ecosystem / Forest	• Water intake, storage, and discharge associated with hydroelectric power generation projects may change river flow rates and water levels, potentially affecting ecosystems such as aquatic organisms and waterfowl. There is also a concern that the construction of dams and intake weirs could cut off river channels and impede the upstream migration of migratory fish. When such impacts are anticipated, it is necessary to evaluate the impact on E flow and aquatic ecosystems and reflect them in environmental management plans and monitoring plans. • In addition, deforestation due to hydroelectric development is expected to have permanent or temporary effects on flora and fauna. In particular, when a project is planned within a KBA or critical habitat is identified, the consideration should be given to minimizing the impact in the layout of the project plan, including access roads and other ancillary facilities. In addition, when local residents rely on forest use for timber and NTFPs (Non-timber Forest Products) as a source of income and adverse effects from the project are expected, it is recommended that livelihood restoration plans be formulated and implemented based on discussions with affected people.
Appropriate compensation for land acquisition, involuntary resettlement, and loss of livelihood, distribution of benefits, etc.	• One of the challenges facing hydropower development in Nepal is compensation for projects involving resettlement and land acquisition, which has led to criticism from NGOs (Non-Governmental Organizations) and complaints from residents. It is desirable to formulate and implement a resettlement action plan that includes payment of compensation at replacement cost. In particular, when large-scale resettlement is required for reservoir-type hydroelectric power plants or power transmission lines, it is important to secure sufficient budgets and implementation systems. • In addition to physical resettlement, if economic resettlement such as loss of livelihood occurs, it is recommended that livelihood restoration plans be formulated and implemented in accordance with procedures stipulated in local national laws (Land Acquisition Act (2034/1977), Real Estate Expropriation Act (2013/1956)), and with reference to good practices of hydropower projects in Nepal undertaken by the World Bank and other international donors. • Looking at the country as a whole, the benefits of power development are concentrated in the urban areas of Kathmandu and Pokhara, while the areas directly affected by the development are those surrounding the site. It is desirable to consider correcting these disparities in benefits.
Indigenous Peoples	• The National Foundation for Development of Indigenous Nationalities Act defines 59 ethnic groups as indigenous peoples, and they are widely distributed in the mountainous areas where hydroelectric power projects are planned. In addition, Nepal has ratified the ILO (International Labor Organization) Convention on Indigenous and Tribal Peoples in Independent Countries (No. 169). If adverse effects on indigenous peoples are anticipated, it is recommended that meaningful consultations be held with indigenous peoples affected by the projects from an early planning stage and that their consent be obtained based on the principle of FPIC (Free, Prior and Informed Consent). In addition, if indigenous peoples are included among the affected peoples, it is advisable to formulate an IPP (Indigenous Peoples Plan) and implement measures accordingly.
Natural hazards	• Natural disasters in Nepal include landslides caused by heavy rains during the monsoon season. In addition, projects may suffer significant physical damage due to GLOFs (glacial lake outburst floods). When selecting project sites, it is advisable to avoid areas with high disaster risks such as landslides and GLOFs, and to develop emergency response plans in the event of a disasters etc.
Climate change	• Nepal has formulated policies such as the National Climate Change Policy (2076/2019), and hydropower is considered to be a desirable form of power generation in terms of greenhouse gas emissions. However, as mentioned above, it is recommended to evaluate physical risks associated with climate change in relation to the risks of GLOFs, etc., and to consider alternatives and incorporate them into the design.

Source: JICA Study Team

3. DEVELOPMENT MILLSTONES AND FUTURE OUTLOOK FOR IPSDP

This Chapter consolidates the results of IPSDP studies cross-sectionally, presents the milestones and pathway towards realizing IPSDP and indicates the necessary transformations and future outlook of power sector. Finally, challenges and recommendations to carry out IPSDP are summarized.

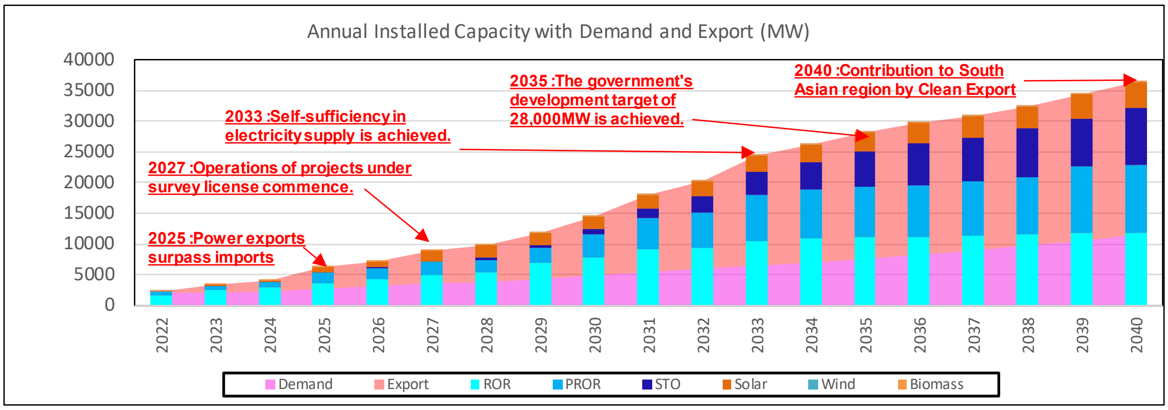
3.1 DEVELOPMENT MILESTONES AND PATHWAYS TOWARDS 2040 IN IPSDP

Figure 3.1-1 summarize the installed capacity, domestic demand, power trade and major milestones towards 2040 in IPSDP. Development milestones of IPSDP are; achieving net-zero in power trade (2025), commencement of operation of power generation projects currently under survey (2027), achieving self-sufficiency through a year (2033), meeting government targets in roadmap (2035) and contributing to stable power supply to domestic and neighboring countries (2040).

From 2023 to 2025, 4,110.2MW of installed capacity will have been developed. It is important to steadily implement the projects currently under construction that have already obtained a Construction License. From 2026 to 2030, 8,250.6MW of installed capacity will have been developed. The projects currently under construction are expected to commence operations between 2026 and 2027. From 2028 onwards, projects currently with a Survey License or identified by GoN will also start operations. Active participation from international developers, investors, and banks including those from India and Bangladesh is facilitated.

From 2031 to 2035, 13,669.0MW of installed capacity will have been developed. Development will shift from small and medium ROR to large-scale PROR and STO projects over 200MW. In this period, commencement of major projects under Survey License will reach the peak of development, achieving power self-sufficiency including the dry season by 2033. As surplus electricity is available through the year after 2030, energy transition initiatives will advance the utilization of low-carbon fuels like hydrogen and ammonia. These continuous efforts will lead the achievement of development target indicated in the Energy Development Roadmap and Work Plan 2035.From 2036 to 2040, 8,112.0MW of installed capacity will have been developed. Large-scale STO HPPs (Hydro Power Plant) and development of upstream areas in each river basin will progress. As domestic power supply is stable year-round, new power sources will be developed for direct export to neighboring countries.

Achieving these milestones requires the implementation of various measures, including technical considerations, finance, institutional and legal frameworks and human resource development. Considering the timeline and the progress of each project, it is assumed that projects currently under construction with a Construction License will be required to commence operations by 2027. Ensuring the steady execution and progress monitoring of these projects is essential. Conversely, numerous projects with a Survey License and GoN projects need to be proceeded towards commercialization. To achieve the MoEWRI development target of 28GW by 2035, these projects need to commence operations between 2031 and 2035. Therefore, construction works of them are required to start by 2026-2030. These are urgent issues in various fields to be carried out in few years involving not only the power sector but also other sectors.



Item			～2025	2026 -2030	2031 - 2035	2036 - 2040
Generation	Hydro	GoN Entities	Rasuwagadhi (111MW), Sanjen (42.5MW), Upper Modi A (42MW), Rahughat (40MW), Upper Trishuli 3B (37MW), Madhya Bhotekoshi (102MW)	Tanahu HEP (140MW), Tamor Storage (200MW), Madi Storage HEP (156MW)	Lower Seti(126MW), Uttarganga STO (828MW), Phukot Karnali (480MW), Nalsyau Gad STO (417MW), Upper Arun (1061MW), Chainpur Seti (210MW), Dudhkoshi STO (635MW), Sunkoshi 3 STO (680MW)	Betan Karnali (442MW) Kimathanka Arun (450MW), Bharbung (470MW), Mugu Karnali STO (1670MW)
			408MW (509MUSD)	**1113MW (2216MUSD)**	**4900MW (8558MUSD)**	**2969MW (6130MUSD)**
		IPPs	Upper Trishuli-1 (216MW), Arun 3 (900MW)	Manang Marsyangdi (282MW), Budhi Gandaki Ka (226MW), Bheri 4 HEP (271MW), Tila-1 (299MW), Tila-2 (297MW)	Lower Badigad STO (380MW), Budhi Gandaki (340MW), Upper Marsyangdi -2 (327MW), Dudh Koshi-IV (350MW), Upper Tamor (285MW), Bheri-2 (270MW), West Seti STO (750MW), SR-06 STO (309MW) Tamakoshi 3 (650MW), Khimti Shivalaya STO (396MW)	Bajhang Upper Seti (216MW), Naumure STO (218MW), Upper Mugu Karnali (240MW), Bheri-1 (270MW), Humla Karnali-Cascade (637MW)
			2902MW (4267MUSD)	**5782MW (9661MUSD)**	**7869MW (14776MUSD)**	**4118MW (7963MUSD)**
	RE		**800.2MW (823MUSD)**	**1355.6MW (1363MUSD)**	**900MW (950MUSD)**	**1025MW (925MUSD)**
	Technical Studies		Planning for Cascade Operation utilizing STO Considerations of access road for hydropower corridors	Introduction of pumped storage Innovation of generation planning considering export		
	Construction		**1) HPPs in Construction Licenses**	**2) HPPs in Survey Licenses**	**3) HPPs in GoN categories**	
Power System	400kV Bulk Power System		NEW BUTWAL - NEW DAMAULI - RATMATE - LAPSI PHEDI, RATMATE – HETAUDA – DHALKEBAR – INARUWA	LUMKI – KOHALPUR – LAMAHI - NEW BUTWAL, DHALKEBAR - NEW KHIMTI - DUDHKOSHI, DHALKEBAR – DUDHKOSHI – ARUN	ATTARIA - LUMKI, NALSING GADH - NEW DAMAULI, LAPSI PHEDI - NEW KHIMTI	CHAINPUR - ATTARIA, PURKOT - LUMKI, NALSING GADH - KOHALPUR, PHILIM – RATMATE - CHILIME HUB, ARUN – INARUWA - ANARMANI
	Interconnection Lines		NEW BUTWAL - GORAKHPUR	LUMKI - BAREILY, INARUWA - PURNEA	DHALKEBAR 2 - MUZAFFARPUR	KOHALPUR - LUCKNOW
	Major Cities Demand		Kathmandu 506 MW (LAPSI PHEDI, RATMATE) Birgunj 302 MW (HETAUDA) Pokhara 195 MW (NEW DAMAULI) Dhalkebar 126 MW (DHALKEBAR)	Kathmandu 935 MW (LAPSI PHEDI, RATMATE) Birgunj 570 MW (HETAUDA) Pokhara 371 MW (NEW DAMAULI) Dhalkebar 368 MW (DHALKEBAR) Lumbini 637 MW (NEW BUTWAL)	Kathmandu 1,329 MW (LAPSI PHEDI, RATMATE) Birgunj 873 MW (HETAUDA) Pokhara 403 MW (NEW DAMAULI) Dhalkebar 564 MW (DHALKEBAR) Lumbini 975 MW (NEW BUTWAL)	Kathmandu 2,017 MW (LAPSI PHEDI, RATMATE) Birgunj 1,326 MW (HETAUDA) Pokhara 612 MW (NEW DAMAULI) Dhalkebar 856MW (DHALKEBAR) Lumbini 1,481 MW (NEW BUTWAL)
	Cost		**1213MUSD**	**2765MUSD**	**2397MUSD**	**2717MUSD**
	Technical Studies		Power system operation planning with power trade Interconnection studies with neighboring countries	Harmonization between power system and VRE Power System Planning for Western Province		
	Construction		**Reinforcement of Interconnection Lines and Domestic Bulk Power System**	**Establishment of 400kV Bulk Power System**		**Operation of Transmission Lines for Direct Export**
Developer			Matching between domestic HPPs and potential developers Facilitation of involvement of foreign developers	Establishment of SPCs		
Finance			Enhancing the finance capacity of domestic finance	Involvement of Indian/Bangladesh Investors Utilization of Sovereign or PPP loans for Nepal, India and Bangladesh		
Rule & Regulation			Establishment of modality of power trade in PPA, grid interconnection and related regulations			
Capacity Development			Restructuring the Power Sector	Scale-up of governmental entities in quantity and quality		
Energy Transition			Facilitation of electrification by EV, E-cooking or Heat pumps Research and development for green hydrogen or ammonia		Energy transition by utilizing surplus electricity	

Source: JICA Study Team

Figure 3.1-1 Development Milestones and Pathways in IPSDP

3.2 CHALLENGES OF IPSDP

To realize IPSDP, it is crucial to steadily execute the currently ongoing projects by 2026. From 2027 onwards, it will be necessary to develop the currently surveyed projects. Many of these new developments lack established implementation structures and financing. Feedback from local private and government operators indicates that it is difficult for individual license-holding developers to undertake large-scale projects alone. Meanwhile, domestic resources are already being utilized, making the promotion of participation by foreign developers, investors, banks, and development aid agencies an urgent task. To achieve development post-2027, issues such as integrated river basin development, access road development, securing transmission routes, and promoting power trade must be addressed. Additionally, enhancing the capacity of government organizations and the entire power sector is also necessary.

Many of these challenges need to be addressed promptly to achieve development post-2028. However, as the various fields are closely related, it is difficult to solve them through the efforts of individual government organizations alone. Inter-organizational cooperation is crucial. For instance, while NEA's risk in expanding power trade does not directly affect the technical considerations of power sources and systems as an electrical phenomenon, it is closely related to financial aspects, such as who bears the financial risk in power trade, institutional aspects, such as whether organizations other than NEA will be involved in the power trade, and governance aspects, such as adjusting interests among various stakeholders, including neighboring countries.

This section organizes the major challenges, summarizing knowledge and experiences of JICA Study Team through IPSDP studies and comments obtained from various stakeholders. Although issues of power sector are closely related each other, these are classified into the following five categories;

(1) Clean export
(2) Expansion of the Nepal power system
(3) Business structure of power sector
(4) Finance / Private Investment
(5) Energy Transition

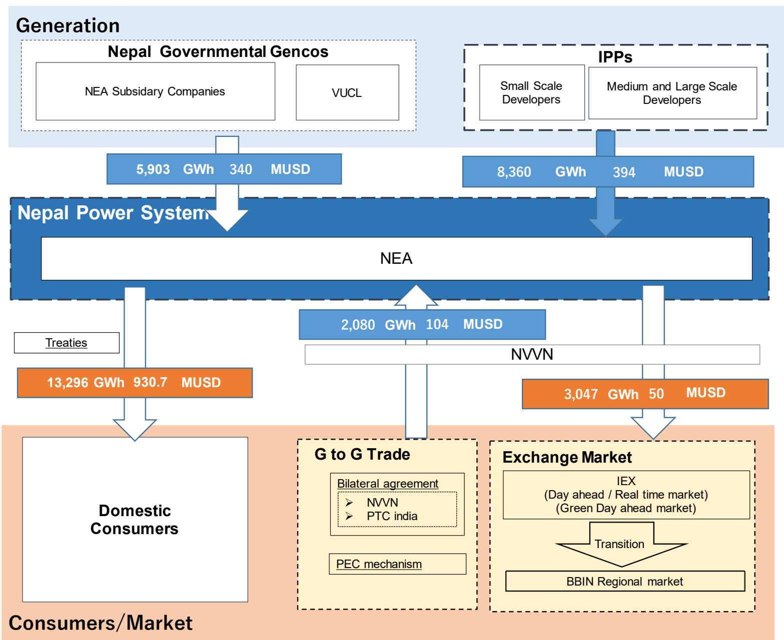
Major topics and relation with generation, power system, finance, legal framework and governance are integrated in Table 3.2-1.

Table 3.2-1 Challenges in the Five Necessary Transformations in the Nepalese Power Sector

Item	Generation	Power System	Finance	Institutional / Legal	Governance
1.Clean Export					
Concentration of risks on NEA for expansion of clean export	✓	✓	✓	✓	✓
Securement of power supply reliability for domestic demand	✓	✓		✓	✓
Technical issues on expansion of power trade		✓			
Development scheme on interconnection lines		✓		✓	✓
Issues on legal framework for power trade	✓	✓		✓	
Insufficient experiences on export oriented hydropower projects by Nepalese developers	✓	✓	✓	✓	
2.Expansion of the Nepal Power System					
Necessary adaptation measures against climate change risks.	✓	✓		✓	
Necessity of integrated river basin development	✓			✓	✓
Capacity development on tunnel design and construction	✓			✓	
Need to improve system planning capabilities.		✓		✓	
Interconnection of VRE		✓		✓	
Mitigation of environmental and social impacts	✓	✓	✓	✓	
3.Business Structure of Power Sector					
Necessity of capacity development of GoN	✓	✓		✓	
Clarification of role of government organizations and sector reforms.	✓	✓		✓	✓
Shortage of domestic contractors	✓	✓		✓	
Necessity of international standard PPA	✓			✓	✓
4.Finance/Private Investment					
Finance from domestic investors or lenders	✓	✓	✓	✓	
Necessity of promotion of FDI	✓	✓	✓	✓	
Enhancement of assistance by development partners	✓	✓	✓	✓	
5.Energy Transition					
Promotion of electrification	✓	✓	✓	✓	
Establishment of legal framework and supply chain in Green Hydrogen	✓	✓	✓	✓	

3.3 REQUIRED TRANSFORMATIONS AND FUTURE OUTLOOK FOR THE POWER SECTOR

Figure 3.3-1 illustrates the current business structure of power sector in 2023.



- Financial risk is concentrated in NEA, as it functions as the single buyer.
- NEA's dual roles in generation and transmission/distribution lack transparency in decision-making processes and financial performance.
- There is unclear role distribution between NEA and public power entities like VUCL and RPGCL,
- NEA's near-monopoly in transmission/distribution results in a lack of competition, potentially increasing costs.
- A strategic and speedy decision-making organizational structure is required for power trade.

Source: JICA Study Team

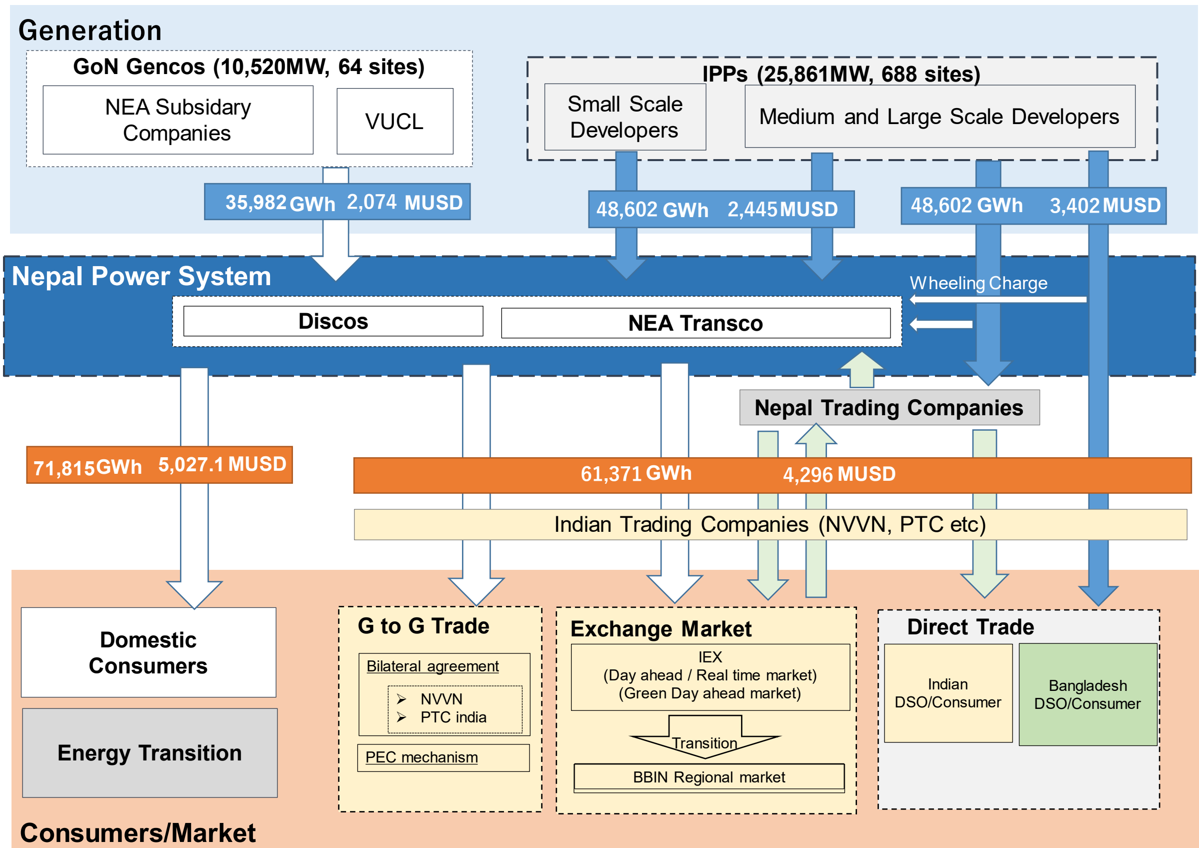
Figure 3.3-1 Business Structure of the Power Sector in 2023

As of 2024, the power sector has achieved stable power supply and better financial conditions owed to development over the past decade. However, to achieve the development outlined in IPSDP, the following transformations are required:

(1) Expansion of Clean Export
(2) Significant Scale Expansion of the Power System
(3) Reform of the Power Sector
(4) Expansion of Finance/Private Investment
(5) Energy Transition

Figure 3.3-2 illustrates the envisioned business structure of the power sector in 2035, reflecting the five required transformations.

In 2035, power sector in Nepal will see dramatic expansion in terms of supply-demand scale, clean export, institutional structure and cash flow. The installed capacity and number of power plant sites will be 7,497 MW and 58 sites for government entities such as NEA and VUCL, and 20,718 MW and 654 sites for IPPs. The power system will have a 400 kV backbone transmission lines from east to west across the country with a total length of 1,818 km and six 400 kV international interconnection lines.



Source: JICA Study Team

Figure 3.3-2 Future Outlook for the Power Sector in 2035

The amount of power market business and sales revenue will also increase significantly. Domestic consumption will be 39,966 GWh (44.3%) with a revenue of 3,311 MUSD and Clean Export will be 50,259 GWh (55.7%) with a revenue of 3,518 MUSD, out of the total sales volume of 90,224 GWh. Clean Export will particularly account for 6% of the national GDP, developing into an export industry that would earn foreign currency. The institutional structure of power sector will also be significantly transformed with the establishment of power trading companies alongside NEA unbundling to generation, transmission, and distribution.

Nepal has substantial potential for energy transition including CO_2 reduction in neighboring countries through Clean Export. It is also expected to promote electrification of energy derived from fossil fuels and the utilization of green hydrogen and ammonia.

3.4 CHALLENGES AND RECOMMENDATIONS FOR IPSDP

The milestones and pathways suggest that technical studies for Clean Export, strengthening and attracting IPPs, securing domestic and international financing, power system planning and capacity development of human resources must be completed within the next few years to achieve large-scale development beyond 2030. In other words, immediate actions are required to realize massive expansion of power sector. It is critical to deal with these issues but these tasks involve various fields and domestic stakeholders and international agencies. It seems to be challenging to achieve solely through the activities of individual agencies and requiring various adjustments. Considering the limited resources of relevant agencies such as MoEWRI, DoED, ERC, NEA, and development partners, it is also important to focus on priority issues that Nepal must address urgently. In this context, following five pilot projects are proposed;

- Sunkoshi-3 HPP for Clean Export
- Phukot Karnali HPP as Pioneer of Karnali River Basin
- Transaction Advisory Services for Capacity Development
- Assistance of Domestic Financial Capacity
- Implementation of Pilot Project for Energy Transition

To resolve these situations, implementation of pilot projects is expected to be effective, encompassing many of the identified issues. Once pilot projects indicate solution of these issues such as PPA, interconnection with foreign grid, setting of transmission wheeling charge or physical infrastructure development, these could be good benchmarks for subsequent projects.

As these pilot projects are required to explore various new fields with a lot of issues or unforeseeable risks, it supposed to be challenging for IPPs or private sector to deal with these pilot projects. Therefore, it might be reasonable to select GoN entities such as NEA or VUCL as implementing agencies and to execute these pilot projects under the assistance from GoN and development partners.

Based on understandings above, issues and recommendation of pilot projects are summarized in Table 3.4-1.

Table 3.4-1 Challenges and Recommendations on IPSDP

Item	Sunkoshi-3 HPP	Phukot Karnali HPP	Transactionary Advisory Service	Enhancemen of HIDCL	Energy Transition
1.Expansion of Clean Export					
Concentration of risks on NEA for expansion of clean export	Establish direct trade scheme with India and BPDB				
Securement of power supply reliability for domestic demand	Improve dry season supply capacity	Improve dry season supply capacity			
Technical issues on expansion of power trade	Review and establish generation plans considering three-country interconnection	Promote development of Lumki-Bareily interconnection line			
Development scheme on interconnection lines	Establish and operate three-country interconnection				
Issues on legal framework for power trade	Facilitate smooth expansion of power trade by involving India and BPDB				
Insufficient experiences on export oriented hydropower projects by Nepalese developers	Project implementation by NEA	Participation of VUCL	Advisory support for NEA and/or VUCL		
2.Significant Expansion of the Nepalese Power System,					
Necessary adaptation measures against climate change risks.	Develop 400kV substations and transmission lines in Sunkoshi basin	Develop access roads in Surkhet to Karnali basin Phukot - Lumki 400kV T/L			
Necessity of integrated river basin development		Promote development of Karnali main river and Tila river basin			
Capacity development on tunnel design and construction		Undertake the first large-scale tunnel construction in Karnali basins			
Need to improve system planning capabilities.	Develop three-country interconnection plan	Develop power system plan for western area			
Interconnection of VRE					
Mitigation of environmental and social impacts	Implement study of international standards including transmission lines	Implement study of international standards including transmission lines			
3.Reforming the Electricity Sector					
Necessity of capacity development of GoN	Improve NEA's capabilities	Improve VUCL's capabilities	Strengthen organizational structure of the power sector and coordination with other ministries		
Clarification of role of government organizations and sector reforms.			Promote organizational restructuring along with power law revision		
Shortage of domestic contractors	Involve Indian developers and BPDB	Involve NHPC	Expand the sector to include contractors, equipment suppliers, construction consultants, legal advisors		
Necessity of international standard PPA	Consider PPAs with India and Bangladesh	Consider PPAs with India			
4.Expanding Finance/Private Investment					
Finance from domestic investors or lenders				Strengthen HIDCL and private banks	
Necessity of promotion of FDI	Encourage entry of developers and financial institutions from India and Bangladesh	Promote financing by NHPC		Matchmaking between foreign and domestic businesses on India and Bangladesh Expand clean energy use in energy-intensive industries	
Enhancement of assistance by development partners	Ensure cross-regional involvement of development partners including India and Bangladesh	Support VUCL		Propose finance promotion measures such as loans, PPPs, sector loans, TSLs"	
5.Energy Transition					
Promotion of electrification					Propose new electrification promotion measures such as heat pumps
Establishment of legal framework and supply chain in Green Hydrogen					Propose pilot projects for green hydrogen and ammonia

Source: JICA Study Team

FINAL REPORT

Project on Integrated Power System Development Plan in Nepal
Final Report

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1. OUTLINE OF THE STUDY

1.1 BACKGROUND

The Nepal has abundant hydropower resources, with an estimated hydropower of 83GW and an economically viable hydropower of 42GW. JICA (Japan International Cooperation Agency) carried out "Nationwide Master Plan Study on Storage-type Hydroelectric Power Development in Nepal" in 2014 and development of 2,000MW storage-type hydroelectric power until 2032 was proposed. Based on this master plan study GoN (Government of Nepal) formulated policy papers such as "Action Plan on Crisis Prevention of National Energy and 10 years, Hydropower development (2016)", "Energy, Water Resources and Irrigation's Sector's Status and Roadmap for the Future" (commonly known as, "White Paper" in 2018). GoN has decided to make power development as a highly priority. GoN has made a clear intention to accelerate the power development.

However, power development satisfying the present power demand has not yet achieved. Hydropower generation installed capacity (1,446.8MW) is slightly below the peak power demand of 1,482MW in 2021 and the hydropower resources have not utilized sufficiently. Installed capacity developed by IPP (Independent Power Producer) accounts for around 50% of total installed capacity and most of hydropower plants including ones of IPP are ROR (Run of River) type hydropower ones, which is generated by taking river flow from the intake and sending it to the power plants without a reservoir. In the dry season when the river flow is decreasing, power output is reduced largely, therefore gap between power demand and supply becomes serious issue. To supply a gap, the energy of 2,826 GWh, which accounts for around 30% of present total power demand (8,978 GWh) is imported from India in 2021. From the viewpoint of energy security, the own power development is important issue.

In spite that the policy target is set by White paper and so on, the power development is not making progress on target. Its factors are expensive costs of power generation facilities and transmission line facilities due to steep mountain terrain, constrain of national credit capability and investment capability, inadequacy of private investment utilization institution, unplanned issues of construction licenses to IPP, poor collaboration among government, regulating agencies related to power development and power authority and so on. Also, it is issuing that comprehensive long-term PDP (Power Development Plan) which shall be shared by relevant agencies including IPP. For example, RPGCL (Rastriya Prasaran Grid Co. Ltd.) established in 2015 formulates TSDP (Transmission System Development Plan of Nepal) for backbone transmission line network mainly above 220kV, which was supported by WB (World Bank) in 2018. TSPD for transmission line network below 132kW is formulated by getting support from ADB (Asian Development Bank). But the forecast of development of domestic power resources including decarbonization and renewable energy, regulation, policy and formulation of common understanding among enterprises regarding power interchange to India etc. are not made sufficiently.

In order to develop power supply system systematically it is necessary that MoEWRI (Ministry of Energy, Water Resources and Irrigation) who has jurisdiction over National Energy policy shall formulate power development master plan which covers kinds of power sources, power generation method, priority of power development, scale and timing of power development, procurement method of financial resources, investment plan including sharing role between private and public funds and so on, in addition endorsement process of power development shall be made clear and regulating function among the relevant agencies shall be established.

According to the above background, MoEWRI shall formulate power development plan (IPSDP (Integrated Power System Development Plan)) of overall power sector, concretize sharing role among government affiliated agencies and public-private sectors and enhance cooperation. For the purpose of promoting the priority projects by conducting the above, MoEWRI requested the Integrated Power System Development Plan Project (hereinafter referred to as "Project") to JICA in August 2019.

1.2 OBJECTIVES

In this Project it is aimed that the IPSDP is endorsed as National plan and power development is promoted based on this Plan. The following activities are carried out.

- Review the current situation and prospects of power sector in Nepal and surrounding countries.
- Domestic load forecast (power and energy) at different economic growth rate and probable demand at the neighboring market.
- Formulation of the vision, guiding principle and scenarios for power development based on review of existing plans.
- Improvement of the power system planning consistent with the power development plan based on review of existing plans.
- Study on the Interconnection with neighboring countries.
- Financial schemes and economic and financial analysis for project implementation.
- Formulation of the governance mechanism for power sector development such as organizational institution, coordination function among relevant agencies, concretization of endorsement process, Electric Utility management etc.
- The environmental and social considerations (comparative study of alternatives including environmental and social impacts based on SEA (Strategic Environmental Assessment) concept)
- The formulation of the Integrated Power System Development Plan of Nepal (including road map for promoting implementation)
- Capacity Development for formulation of the Integrated Power System Development Plan of Nepal (including On-the-Job Training)

1.3 OBJECTIVE AREA

The areas will be surveyed in overall Nepal

1.4 SURVEY IMPLEMENTATION SYSTEM

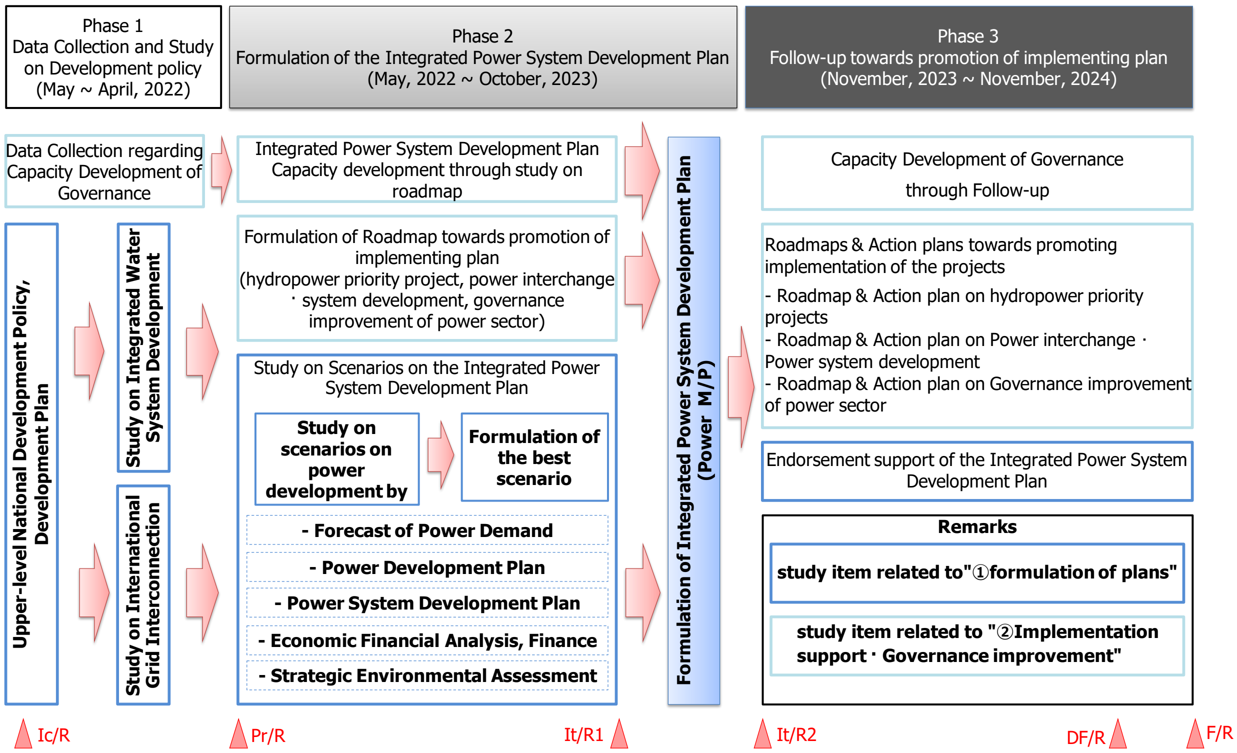
Relevant government ministries and agencies, Institutes is shown below.

Implementing agency: MoEWRI

Relevant agencies: DoED (Department of Electricity Development)
WECS (Water and Energy Commission Secretariat)

RPGCL
NEA (Nepal Electricity Authority)
VUCL (Vidhyut Utpadan Co., Ltd.)
NERC (Nepal Electricity Regulatory Commission)

1.5 OUTLINE OF THE PROJECT



Source: JICA Study Team

Figure 1.5-1 Relationship between the Flow of the Study and the Basic Approach

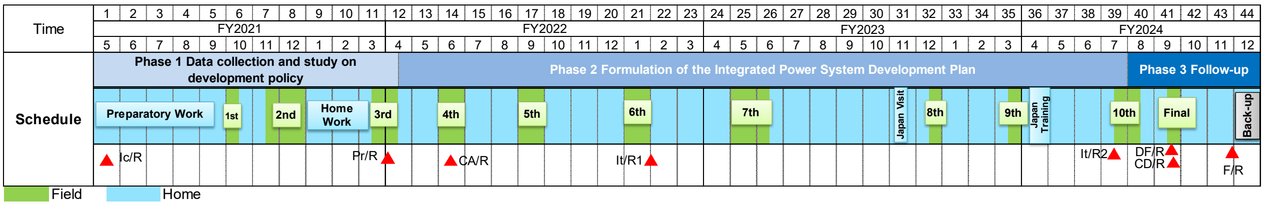
Outline of the Study is divided into the following two (2) points. The relationship between the flow of the Study and the basic approach of technical aspect is shown in Figure 1.5-1.

1) Formulation of the Integrated Power System Development Plan
2) Implementation support and governance improvement for enforcing plans and regulations

1) is middle-long term plan formation which indicates the purpose and direction in the sector development, 2) is the activity related to project implementation such as 3-year plan at hand. Necessary measures and main implementing body are different in 1) and 2), but power sector development is implementing smoothly by functioning as series of sequence. In Nepal, where organizational change in the power sector is in transition period, enhancement of governance is very important for the purpose of promoting power development. In this Project it is recognized that functioning the flow of 1) and 2) by collaboration among the stakeholders, relevant agencies of GoN, JICA and JICA Study Team is very important.

Under the above recognition this Project is assumed to be implemented by three (3) phases consisting of Phase 1 “Data collection and study on development policy”, Phase 2 “Formulation of the IPSDP”, Phase 3 “Follow-up towards promotion of implementing plan”. In Phase 1 and

Phase 2 under collaboration of each stakeholder electric power master plan, roadmap and action plan are formulated and in Phase 3 implementation of plan and regulation is supported. It takes notice not only outcome of master plan but also capacity improvement of governance through its review process are important.

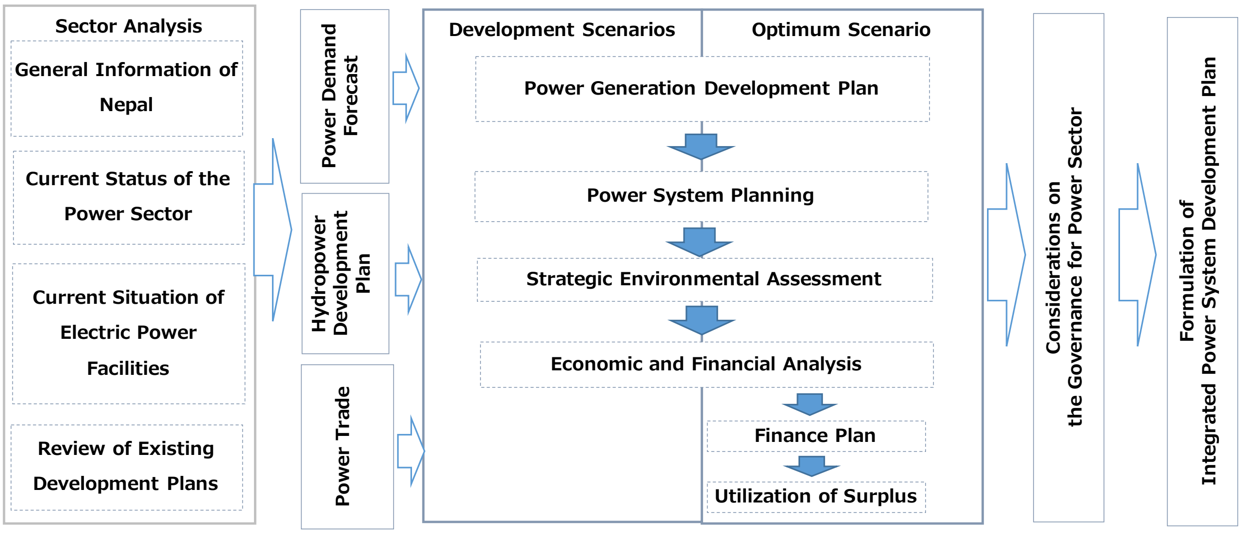


Source: JICA Study Team

Figure 1.5-2 Summary of Work Schedule

1.6 OUTLINE OF THE SUMMARY

The main report describes the technical studies for IPSDP. The Chapter 2 summarizes outline of current power sector and the Chapter 3 prepares the power demand forecast (GWh) and peak demand until 2040. The Chapter 4 develops the hydropower database for the DoED Project List and considers the contribution and issues on middle and long term development of hydropower projects. The Chapter 5 summarizes the power trade with India, Bangladesh and China and the direction of interconnections with them. Finally, the Chapter 6 prepares Development Scenarios focusing the generation mix and select the Optimum Scenario based on the comparison of generation, power system, SEA and economic and financial analysis. Chapter 7 finalizes the development plan for the selected optimal scenario by optimizing power generation, power system, SEA, economic and financial analysis, and energy transition. Chapter 8 examines, analyzes, and provides recommendations on power sector governance. Chapter 9 consolidates the results of IPSDP studies cross-sectionally, presents the milestones and pathway towards realizing IPSDP and indicates the necessary transformations and future outlook of power sector. Finally, challenges and recommendations to carry out IPSDP are summarized. It shall be noted that details of analysis are excluded from the main report and descried in the Annexes.



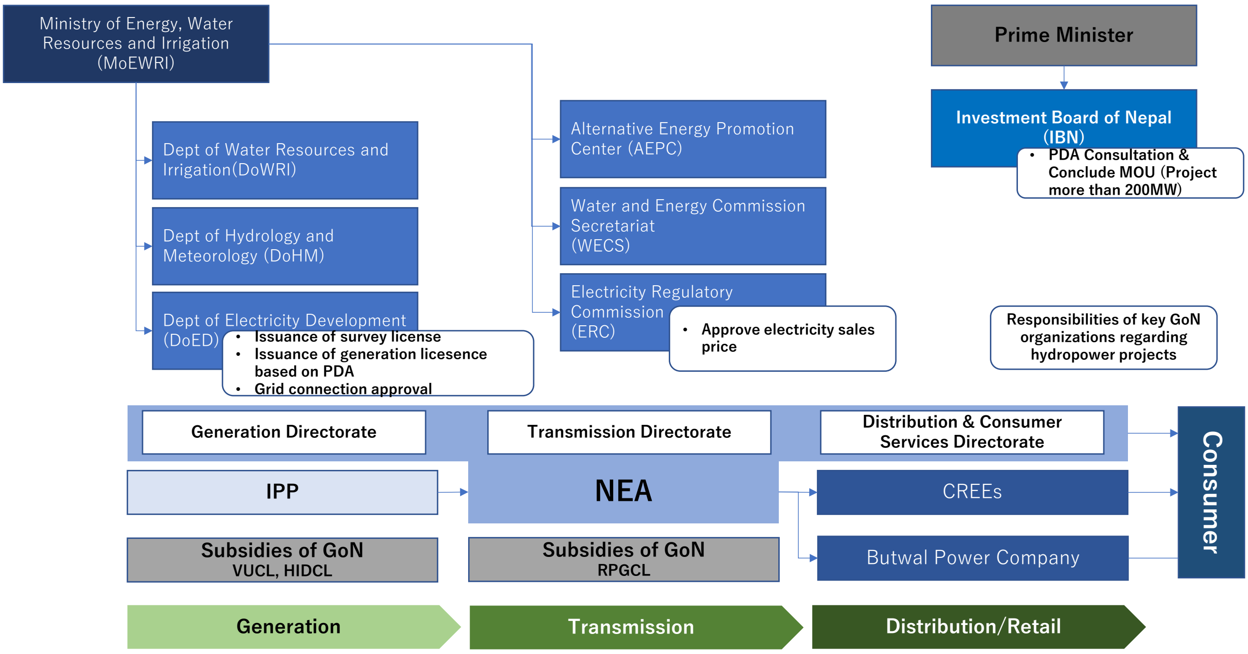
Source: JICA Study Team

Figure 1.6-1 Flow of the Project

2. CURRENT SITUATION OF THE ELECTRIC POWER SECTOR

2.1 ORGANIZATIONAL STRUCTURE OF THE POWER SECTOR

Figure 2.1-1 shows the structure of the power businesses in Nepal. Among the administrative bodies involved in the power sector in Nepal are MoEWRI, which is responsible for policies and laws related to energy development and use, DoED, a unit of the ministry, which is responsible for issuing licenses for power generation businesses, ERC (Electricity Regulatory Commission), which regulates and supervises power businesses, including PPA (power purchase agreement) and retail tariffs, WECS and AEPC (Alternative Energy Promotion Center).



Source: JICA Study Team

Figure 2.1-1 Structure of Power Businesses in Nepal

The country's electricity business has a vertically integrated structure, with NEA handling generation, transmission and distribution of electricity. In the generation sector, however, many IPPs have entered the market under the Electricity Act of 1992.

Other government organizations in the power sector include RPGCL, VUCL, and HIDCL (Hydroelectricity Investment and Development Company Ltd.). Additionally, organizations closely related to the power sector include IBN (Investment Board of Nepal) and IPPAN (Independent Power Producers' Association, Nepal). It is important for IPSDP to proceed with discussions in collaboration with these related organizations.

2.1.1 Major Administrative Entities involved in the Power Sector

(1) Ministry of Energy, Water Resources and Irrigation (MoEWRI)

MoEWRI is the competent ministry for the electricity business in Nepal. It is responsible for formulating policies and laws related to the development, conservation and use of energy and water resources, developing river basin plans and master plans, developing power sources, developing laws and standards related to domestic and cross-border transmission systems and power transactions, identifying and implementing projects at the federal level or across multiple provinces for dam, multipurpose water resource use, irrigation and waterborne disaster management, and conducting surveys, research and technological development related to energy, water resources and irrigation.[1]

The ministry was formed in March 2018 when the Ministry of Water Resources and the Ministry of Irrigation were abolished and the water and irrigation departments merged into the then Ministry of Energy[2]. It has three departments: DoED, Department of Water Resources and Irrigation, and Department of Hydrology and Meteorology[3]. Under its umbrella are WECS, AEPC, Groundwater Resources Development Board, Water Resources Research and Development Centre, NEA, VUCL, RPGCL and HIDCL[4].

(2) Department of Electricity Development (DoED)

DoED is a division of MoEWRI and responsible for practical matters related to electricity business policies, such as issuing power generation business licenses. The department's main function is to ensure the transparency of the regulatory framework and promote private participation in the power sector through one-window service for various applications and procedures[5]. However, as we will discuss later, it is still in the process of realizing a one-window service.

The department's predecessor was the Electricity Development Center, established in July 1993 under the then Ministry of Water Resources to attract private investment in the power sector. It was renamed DoED in February 2000 and became the current department of MoEWRI at the time of reorganization of ministries in March 2018.[6]

(3) Water and Energy Commission Secretariat (WECS)

WEC (Water and Energy Commission) was established in 1975 for the purpose of integrated and accelerated development of water and energy resources. Under the chairpersonship of Minister of MoEWRI, the commission is composed of ministers from relevant ministries, members of the National Planning Commission, external experts, etc., and meets more than twice a year[7].

The commission reviews multi-purpose, large and medium-sized water resources projects, formulates and conduct researches on policies and strategies in water and energy development, formulates policies and analyzes operations in bilateral and multilateral projects, and coordinates related policies[8].

Under MoEWRI, WECS was established in 1981 as the permanent secretariat of the WEC. It consists of the Water Resources Division, the Energy Planning Division, the Social, Economic and Environment Division, and the Legal and Institutional Arrangement Division[9]. It has about 50 staff[10].

[1] MoEWRI website https://moewri.gov.np/pages/about-the-ministry
[2] myRepublica "Government restructuring its ministries" (2 March 2018) https://myrepublica.nagariknetwork.com/news/37259/
[3] MoEWRI website https://moewri.gov.np/pages/departments
[4] Ibid. https://moewri.gov.np/pages/organizations
[5] DoED website http://www.doed.gov.np/pages/about-us
[6] Ibid.
[7] WECS website http://www.wecs.gov.np/pages/about-wecs?lan=en
[8] Ibid. https://www.wecs.gov.np/pages/objectives-and-mandate
[9] Ibid. http://www.wecs.gov.np/pages/divisions
[10] JEPIC (2020) " Electricity Business in Overseas Countries, Part 2, 2020"

(4) Alternative Energy Promotion Centre (AEPC)

APEC was established in 1996 under MoEWRI to promote the development and use of alternative/renewable energy. It functions as an intermediary between the private sector that operates alternative/renewable energy and related ministries and agencies, and is responsible for formulating and promoting implementation of policies and plans related to alternative/renewable energy and energy efficiency[11].

AEPC has implemented a number of alternative/renewable energy programs. These include NRREP (National Rural and Renewable Energy Programme), Nepal Renewable Energy Programme and the Waste to Energy Initiative.

(5) Electricity Regulatory Commission (ERC)

ERC is the regulatory and supervisory body for Nepal's electricity sector. It was created in 2018 under the ERC Act, replacing the Electricity Tariff Fixation Commission[12]. It is in charge of approving PPA tariffs between NEA and IPP and retail electricity tariffs and setting standards for the construction of electricity facilities[13]. Under the chairpersonship and secretary, the commission consists of the Regulation and Supervision Department, the Tariff and Economic Analysis Department and the Technical and Engineering Department, according to its website.[14]

However, as of June 2022, only the chairperson, secretary, senior engineer, junior engineer, general affairs officer, finance officer, and 2 others were enrolled[15]. The Cabinet decides on the organizational structure and the Public Service Commission appoints officials[16]. At the beginning of 2022, there were reports of conflict with the government, with the government pointing to poor operations and demanding an explanation from the ERC chairperson, who refused to do so[17]. The case has now reached the Supreme Court, which has granted a stay of the government's decision and allowed the ERC chairman and its members to complete their terms. In this way, the ERC appears to be underperforming, despite its very important role due to lack of coordination between ministries and agencies.

USAID (United States Agency for International Development) is working to make the ERC a fully independent regulatory body and to transfer the DoED's current authority to issue licenses to the commission, but this has not happened at this time due to government opposition[18].

(6) Investment Board Nepal (IBN)

IBN is a government agency chaired by the prime minister that was set up to promote domestic and foreign investment. It was established in 2011 under the Investment Board Act and reconstituted in 2019 under the PPP (Public Private Partnership) and Investment Act. It is responsible for approval of infrastructure development of more than 6 billion NPR. As of September 2022, the IBN Secretariat has jurisdiction over the following hydropower projects: [19]

- Arun- 3 Hydropower
- Upper Karnali Hydropower

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[11] AEPC website https://www.aepc.gov.np/roles-and-responsibilities
[12] JEPIC (2020) " Electricity Business in Overseas Countries, Part 2, 2020"; ERC website https://www.erc.gov.np/page/introduction
[13] JEPIC (2020) " Electricity Business in Overseas Countries, Part 2, 2020"
[14] ERC website https://www.erc.gov.np/page/organizational-structure
[15] Based on an interview with ERC in June 2022
[16] Ibid.
[17] The Himalayan "Probe panel seeks clarification from ERC Chair Singh" (6 Feb 2022) https://thehimalayantimes.com/nepal/probe-panel-seeks-clarification-from-erc-chair-singh
[18] Based on an interview with USAID in March 2022
[19] IBN website https://ibn.gov.np/ibn-faq

- Upper Marsyangdhi-2 Hydropower
- Tamor Hydropower
- Lower Arun Hydropower
- West Seti + SR 6 Hydropower

2.1.2 Major Corporate Entities involved in the Power Sector

The following sections overview major corporate entities involved in the power sector, namely NEA, VUCL, RPGCL and IPPs.

(1) Nepal Electricity Authority (NEA)

NEA is a vertically integrated state-owned utility that generates, transmits, distributes and retails electricity. It was established in 1985 under the NEA Act by merging the power division of the then Ministry of Water Resources with the Nepal Electricity Corporation[20].

An organizational chart of the NEA is shown in Figure 2.1-2. It consists of the Generation Directorate, the Transmission Directorate, the Distribution and Consumer Services Directorate, the Planning, Monitoring and Information Technology Directorate, the Engineering Services Directorate, the NEA Subsidy Company Monitoring Directorate, the Project Management Directorate, the Finance Directorate and the Administration Directorate. The largest of these is the Distribution and Consumer Services Directorate, with about 7,000 staff, followed by the Transmission Directorate (about 2,000 staff) and the Generation Directorate (1,000-1,500 staff)[21]. It has more than 250 branches in Nepal and over 10,000 full-time employees[22].

The Board of directors, the highest decision-making body, is chaired by MoEWRI's secretary of Energy and is composed of seven members: the president of NEA, the secretary of the Ministry of Finance, one representative each from the Federation of Nepalese Chambers of Commerce & Industry and consumer groups, and two electricity experts[23].

As of the end of the 2021/22 fiscal year (July 2022), NEA owned 20 hydroelectric and 2 thermal power plants, total 627 MW of generating capacity under the Generation Directorate. The Transmission Directorate owned 5,329 km transmission lines from 66 kV to 400 kV. The Distribution and Consumer Services Directorate had 4,766,021 customers and sells 8,623 GWh of electricity. [24] The Power Trade Department of the Planning, Monitoring and Information Technology Directorate is responsible for PPAs with IPPs[25].

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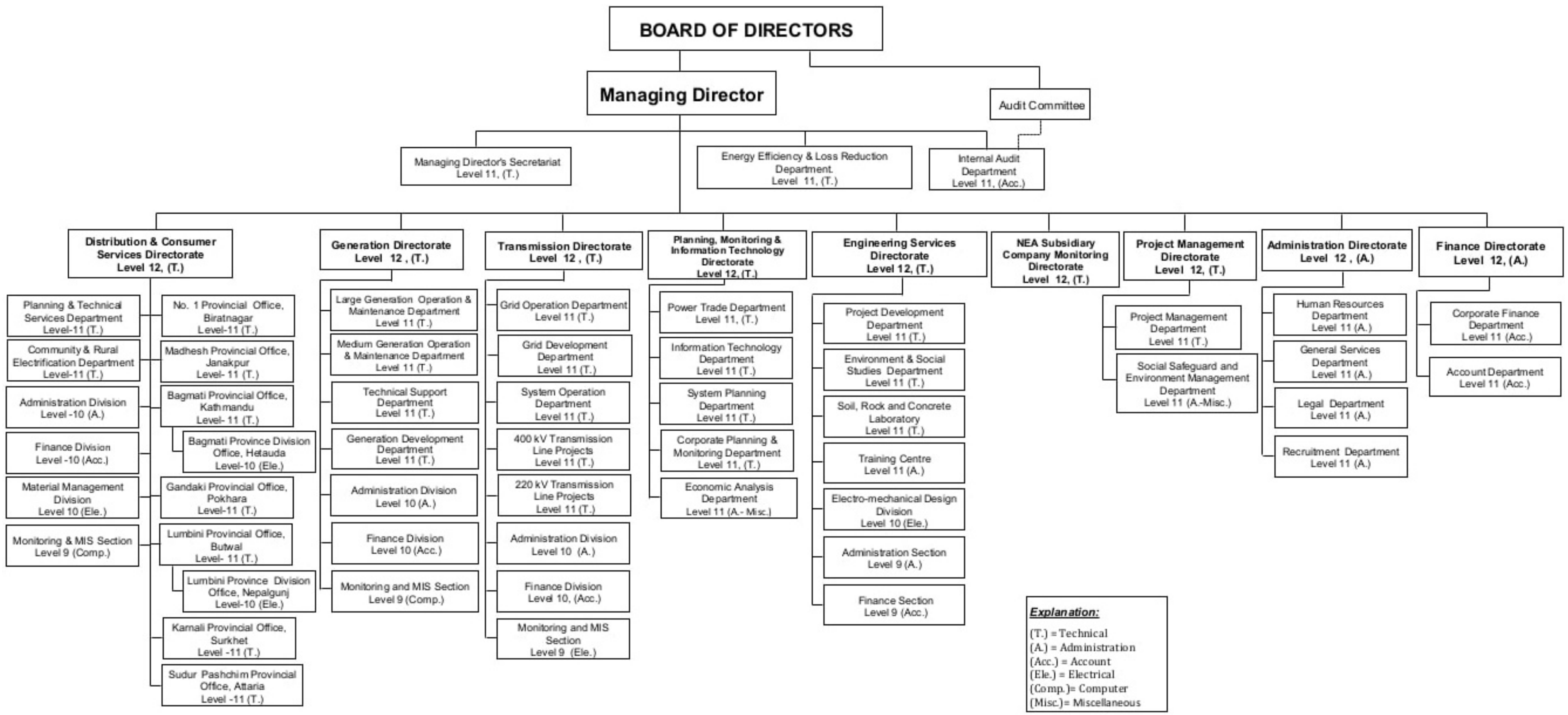
[20] JEPIC (2020) " Electricity Business in Overseas Countries, Part 2, 2020"
[21] Based on an interview with NEA in March 2022
[22] NEA's publication (23 July 2021) https://www.nea.org.np/admin/assets/uploads/supportive_docs/1627033091_EOI_notice_for_PMC__ERP_and_RMS_Implementations.pdf
[23] Ibid.
[24] NEA Annual Report 2021/22
[25] Based on an interview with NEA in March 2022



Source: NEA website (https://www.nea.org.np/organizational_structure)

Figure 2.1-2 NEA Organization Chart (as of September 2022)

(2) Vidhyut Utpadan Company Limited (VUCL)

VUCL was established in 2006 to implement large-scale hydropower projects in PPP[26]. MoEWRI is the largest shareholder with a 20% stake, followed by the general public (17%) and NEA (10%) (see Table 2.1-1). It has yet to go public[27]. Shareholders are thus more publicly inclined, but the company jointly invest in power generation projects with private companies. As of March 2022, the company, including subsidiaries, had about 70 employees, 40 of whom are engineers[28].

Table 2.1-1 VUCL Shareholder Composition

Shareholder	Investment amount (mil NPR)	Equity stake
MoEWRI	4,000	20%
General Public	3,400	17%
NEA	2,000	10%
Employees Provident Fund	2,000	10%
Nepal Doorsanchar Company Limited[29]	2,000	10%
Project-Affected Local People	2,000	10%
Ministry of Finance	1,000	5%
Ministry of Law, Justice and Parliamentary Affairs	1,000	5%
Citizen Investment Trust[30]	1,000	5%
Hydroelectricity Investment and Development Company Limited[31]	800	4%
Rastriya Beema Sansthan[32]	400	2%
Under-privileged people	400	2%
Total	20,000	100%

Source: VUCL website (https://www.vucl.org/pages/capital-structure)

As of September 2022, VUCL had invested in 6 hydropower projects shown in Table 2.1-2 and Figure 2.1-3, but none of them are operational. In addition, VUCL sometimes proposes projects. The Mugu Karnali Storage HEP and Jagdulla PRoR HEP projects were those proposed by VUCL (unsolicited proposals)[33]. Furthermore, all the generated electricity will be purchased by NEA[34].

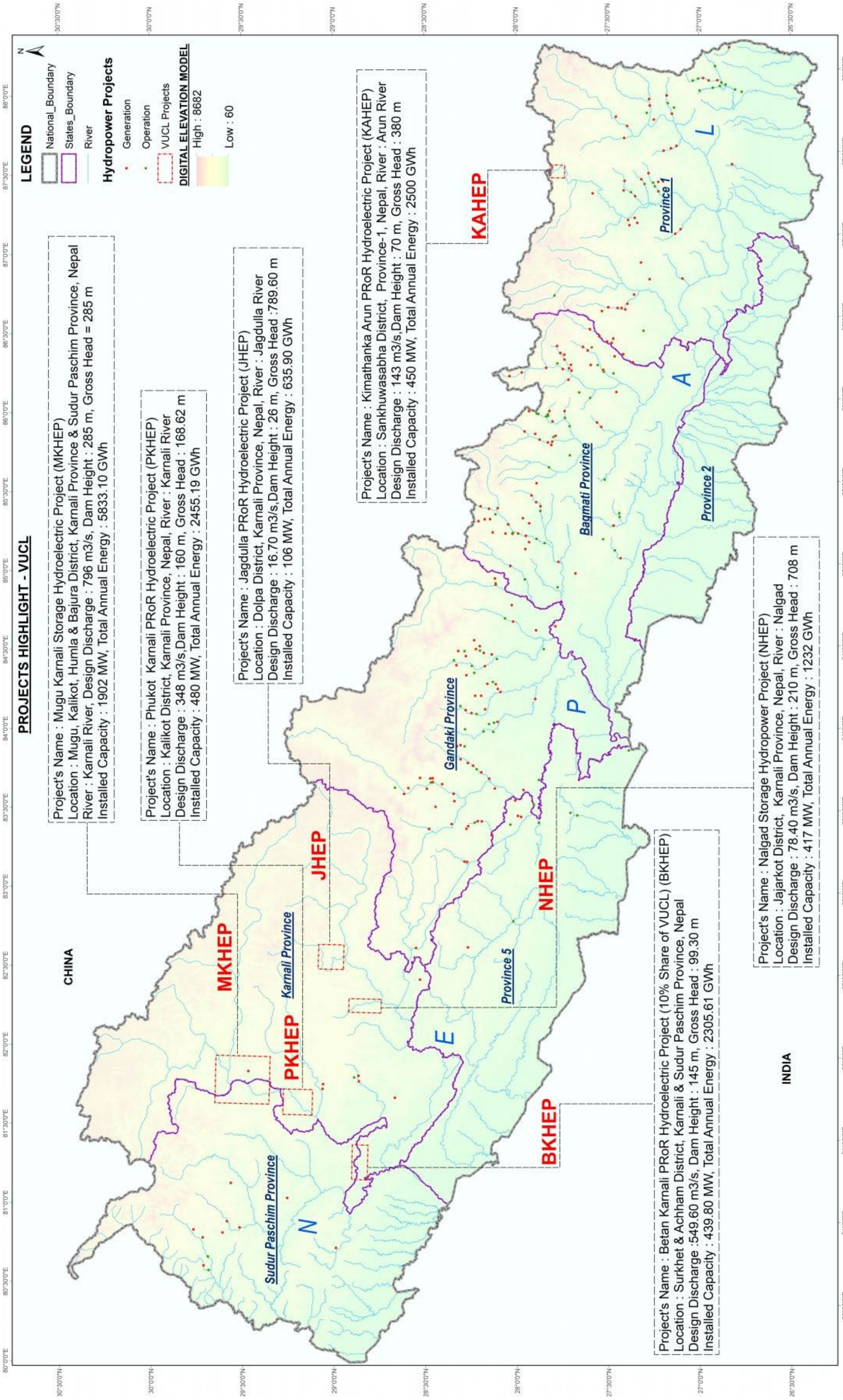
[26] VUCL website https://www.vucl.org/pages/about-us
[27] Ibid. https://www.vucl.org/pages/capital-structure
[28] Based on an interview with VUCL in March 2022
[29] Nepal Telecom
[30] Public citizen trust and investment agency established by the Government of Nepal
[31] A government-affiliated hydropower investment and development company owned by the government of Nepal (50%), three state-owned companies (30%) and the general public (20%)
[32] State-owned insurance company
[33] Based on an interview with VUCL in March 2022
[34] Ibid.

Table 2.1-2 List of VUCL's Projects (as of September 2022)

Project	Capacity	USD/NPR	Established	SPC shareholders
Jagdulla PRoR[35] HEP[36]	106 MW	220 mil USD	2017	General Public .... 33% VUCL .... 26% Hydroelectricity Investment and Development Company Limited .... 10% Local People of Dolpa (Projected Affected) .... 10% Nepal Vidhyut Pradhikaran .... 9% Karnali Pradesh Sarkar .... 5% Transmission Line Affected Local People .... 3% Project Employee .... 3% Local Level (Jagdulla Gaupalika and Mudkechula Gaupalika) 1%
Nalgad Storage HEP	410 MW	737.34 mil USD	n/a	VUCL .... 75% General Public .... 13% Project-Affected Local People .... 10% Under-Privileged People 2%
Phukot Karnali PROR HEP	480 MW	791.8 mil USD	n/a	VUCL[37]
Kimathanka Arun HEP	454 MW	n/a	n/a	
Mugu Karnali Storage HEP	1,902 MW	n/a	n/a	
Betan Karnali PRoR HEP	439 MW	74,000 mil NPR	2017	Karmachari Sanchaya Kosh representing its ontributors .... 40% Karmachari Sanchaya Kosh .... 15% General Public .... 13% NEA .... 10% VUCL .... 10% Project-Affected Local People .... 10% Families with Very Low-Income 2%

Source: VUCL and SPCs websites

35 Peaking Run of the River
36 Hydro Electric Project
37 It is likely that VUCL is a single or majority investor.



Source: VUCL website (https://www.vucl.org/pages/about-us)

Figure 2.1-3 Location of VUCL's Projects

As mentioned above, the government is looking to unbundle NEA's businesses, and as a phased measure, the RPGCL was established in 2015 to oversee the transmission sector. NEA is the largest shareholder with a 48% stake, followed by MoEWRI (24%), Ministry of Finance (11%) and others (see Table 2.1-3).

Table 2.1-3 RPGCL Shareholder Composition (as of September 2022)

Shareholder	Investment amount (mil NPR)	Equity stake
NEA	12,069	48.3%
MoEWRI	6,034	24.1%
Ministry of Finance	2,759	11.0%
Ministry of Defense	690	2.8%
Ministry of Home Affairs	690	2.8%
Ministry of Forestry and Environment	690	2.8%
Ministry of Education, Science and Technology	690	2.8%
Ministry of Land Management, Cooperatives and Poverty Alleviation	690	2.8%
Ministry of Communication and Information Technology	690	2.8%
Total	25,000	100%

Source: RPGCL website (https://www.rpgcl.com/pages/capital-structure)

According to an interviews with VUCL, as of March 2022, it held licenses for 8 projects (2 projects of 132 kV, 2 projects of 220 kV, 4 projects of 400 kV) and plans to apply for 1 more[38]. Of these, 2 projects of 132 kV are under construction, both with government funding. As of September 2022, the website shows 7 transmission projects listed in Table 2.1-4.

Table 2.1-4 List of RPGCL's Projects (as of September 2022)

Project	Voltage	Capacity	Extension
Phukot - Karmadev	400kV	2500MW	121km
Bheri Corridor	400kV	2500MW	150km
Haitar-Sitalpati (Arun Corridor)	400kV	2260MW	35km
West Seti - Dododhara	400kV	2000MW	180km
Tamor - Change	220kV	700MW	60km
Mewa - Change	132kV	150MW	50km
Kerabari-New Marsyangdi	132kV	120MW	31.52km

Source: RPGCL website (https://www.rpgcl.com/)

Project sites may be selected by RPGCL or at the request of a hydropower company. RPGCL is not obligated to provide grid connection even if requested by IPP and make a decision based on economic rationality.[39]

As for the connection to the NEA-owned grids, the Interconnection Agreement has been discussed, and as of March 2022, the board of directors of both companies had approved a draft of the agreement, which is still awaiting signature[40].

38 Based on an interview with RPGCL in March 2022
39 Ibid.
40 Ibid.

(3) IPPs

In Nepal, IPPs plays an important role in developing power plants, mainly hydropower. As shown in Table 2.1-5, IPPs have a share of slightly less than 50% based on installed capacity. As of the end of the 2021/22 fiscal year (July 2022), IPPs, including NEA subsidiaries, owned 132 projects in operation, with 141 others (3,281 MW) at the construction stage and 84 (1,553 MW) at the planning and development stage. In addition, the number of PPAs signed between NEA and IPP reached 357 and 6,366 MW.[41] The list of IPP projects is shown in Section 3.1.1.

Table 2.1-5 Shares of Power Plants in Operation by Owner

Owner	Power Type	Capacity	Share of power type	Overall share
NEA	Hydro	583MW	28%	27%
	Thermal	53MW	100%	2%
	Solar	22MW	39%	1%
	Subtotal	658MW	-	30%
NEA subsidiary	Hydro	478MW	23%	22%
	Subtotal	478MW	-	22%
IPP	Hydro	1,021MW	49%	47%
	Solar	33MW	61%	2%
	Subtotal	1,054MW	-	48%
Total		2,190MW	-	100%

Source: NEA Annual Report 2021/22

While the majority of IPPs are domestic capital, limited projects involving foreign investors, many of which are Indian or Chinese. IPP projects with foreign capital are shown in Table 2.1-6.

41 NEA Annual Report 2021/22

Table 2.1-6 List of IPP Projects with Foreign Capital[42]

Category	IPP	Project	MW	Nationality of funds
In operation	Himal Power Ltd.	Khimti Khola	60	Norway
	Sinohydro-Sagarmatha Power Company (P) Ltd.	Upper Marsyangdi "A"	50	China 90%, Nepal 10%
	Madi Power Pvt. Ltd.	Upper Madi	25	China 100%
	Mandu Hydropower Ltd.	Bagmati Khola Small	22	China/Nepal
Under construction	Essel-Clean Solu Hydropower Pvt. Ltd.	Lower Solu	82	Nepal/India
	Global Hydropower Associate Pvt. Ltd.	Likhu-2	33.4	Nepal/India
	Paan Himalaya Energy Private Limited	Likhu-1	51.4	Nepal/India
	Numbur Himalaya Hydropower Pvt. Ltd.	Likhu Khola A	24.2	Nepal/India
	Swet-Ganga Hydropower and Construction Ltd.	Lower Likhu	28.1	Nepal/Europe (Dolma)
	Nilgiri Khola Hydropower Co. Ltd.	Nilgiri Khola	38	Nepal/China
	Nilgiri Khola Hydropower Co. Ltd.	Nilgiri Khola-2	62	Nepal/China
	Makari Gad Hydropower Pvt. Ltd.	Makarigad	10	Sri Lanka
	Nepal Water and Energy Development Company Pvt. Ltd.	Upper Trishuli - 1	216	Korea
	Nasa Hydropower Pvt. Ltd.	Lapche Khola	99.4	Nepal/India
	Blue Energy Pvt. Ltd.	Super Trishuli	70	India
In development	Salasungi Power Limited	Sanjen Khola	78	China
	Langtang Bhotekoshi Hydropower Company Pvt. Ltd.	Rasuwa Bhotekoshi	120	China
	Manang Marsyangdi Hydropower Company Pvt. Ltd.	Manang Marsyangdi	135	Nepal/China
Total			1,204.5	

Source: Material provided by IPPAN (received in June 2022)

As an industry association, there exists IPPAN.

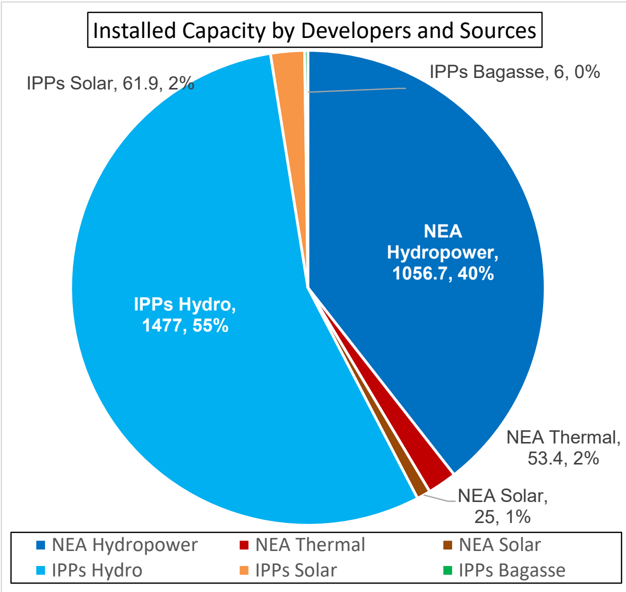
2.2 STATUS OF EXISTING POWER FACILITIES

2.2.1 Existing Power Plants

Regarding the existing power plants in Nepal on 2023, NEA has 1,056.7MW of hydropower plants, 53.4MW of thermal power plants and 25MW of solar power plants and IPPs have 1,544.5MW of hydropower plants and solar power plants. Total installed capacity is 2,680.1MW.

The peak demand for domestic power in 2023 is 1,870 MW. While the total installed capacity significantly exceeds the demand, power imports are necessary during the dry season[43] when hydropower output declines.

42 Since the information sources are different, the names of the projects do not necessarily match those in the previous table.
43 In this report, the dry season (January-May and December) and the rainy season (June-November) are described.



Source: NEA Annual Report 2022/2023

Figure 2.2-1 Installed Capacity by Developers in Nepal (MW)

(1) Existing Power Plants

The list of NEA power plants are shown in Table 2.2-1.

NEA owns 20 hydropower plants with the installed capacity of 573.3MW, designed annual power generation of 3,360,830MWh and average plant factor of 67%. The majority generation scheme of hydropower plants is ROR or PROR (Peaking Run of River). Hydropower plants by NEA had been developed mainly on the Gandaki river system including Kaligandaki A (144MW), Mid-Marsyangdi (70MW), Marsyangdi (69MW) and Upper Trishuli 3A. Only Kulekhani I and Kulekhani II cascade plants are operated as STO (Storage) in Nepal.

There are only two diesel thermal power plants with the installed capacity of 53.4MW including Mutifuel (39MW) and Hetauda Diesel (14.4MW). These are currently stand-by owed to the increase of the power trade with India.

There were 126 operating IPP hydropower projects of over 1 MW as of 2024, with a total capacity of 2,055.2 MW. While the majority of the projects are small and medium sized hydropower with a capacity of 30 MW or less, 11 power plants with a capacity of more than 30 MW (totaling 929.9 MW) have commenced operations in the past three years, starting with the PROR Upper Tamakoshi (456 MW) in July 2021. It is expected that IPPs continue to operate large-scale hydropower plants in the future.

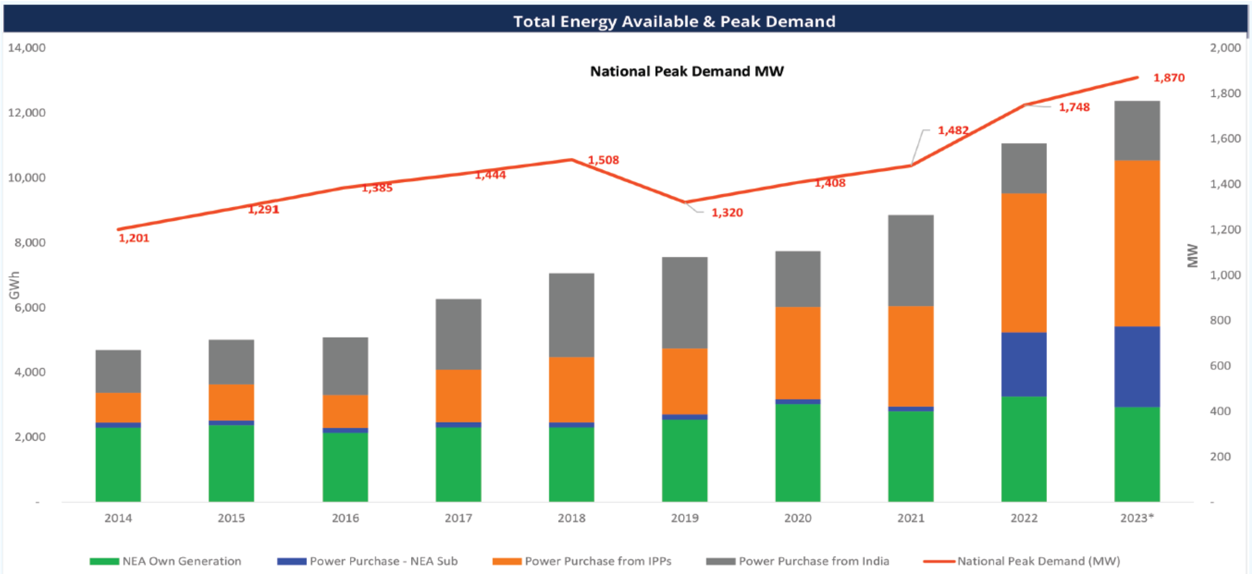
Table 2.2-1 List of Existing Power Plants owned by NEA

S. No.	Power Stations	Total Installed Capacity	Design Generation (MWh)	Designed Plant Factor	Actual Generation (MWh) and Plant Factor (%)									
					FY 2075/76		FY 2077/78		FY 2078/79		FY 2079/80		Average	
1	Kaligandaki 'A'	144.0	842,000	67%	871,914	69%	871,466	69%	817,713	65%	974,832	77%	883,981	70%
2	Mid-Marsyangdi	70.0	398,000	65%	471,323	77%	446,625	73%	398,846	65%	468,270	76%	446,266	73%
3	Marsyandi	69.0	462,500	77%	475,176	79%	443,852	73%	398,920	66%	464,272	77%	445,555	74%
4	Upper Trishuli 3A	60.0	489,760	93%	16,186	3%	407,551	78%	314,768	60%	432,852	82%	292,839	56%
5	Kulekhani I	60.0	211,000	40%	91,184	17%	162,972	31%	195,157	37%	178,400	34%	156,928	30%
6	Kulekhani II	32.0	104,600	37%	44,677	16%	81,483	29%	95,229	34%	82,816	30%	76,051	27%
7	Chameliya	30.0	184,200	70%	161,396	61%	160,812	61%	151,247	58%	53,910	21%	131,841	50%
8	Trishuli	24.0	163,000	78%	123,741	59%	128,973	61%	121,211	58%	37,187	18%	102,778	49%
9	Gandak	15.0	106,380	81%	11,951	9%	10,338	8%	12,123	9%	5,817	4%	10,057	8%
10	Modi	14.8	92,500	71%	69,401	54%	66,913	52%	60,471	47%	3,990	3%	50,193	39%
11	Devighat	15.0	114,000	87%	86,851	66%	92,053	70%	85,429	65%	3,890	3%	67,056	51%
12	Kulekhani III	14.0	40,850	33%	0	0%	20,365	17%	35,565	29%	36,424	30%	23,089	19%
13	Sunkoshi	10.1	70,000	80%	62,157	71%	62,246	71%	55,917	64%	6,354	7%	46,668	53%
14	Puwa	6.2	48,000	88%	34,193	63%	34,915	64%	34,477	63%	3,778	7%	26,841	49%
15	Chatara	3.2	6,000	21%	2,698	10%	1,822	6%	3,352	12%	3,522	13%	2,848	10%
16	Panauti	2.4	6,970	33%	3,006	14%	2,887	14%	2,948	14%	3	0%	2,211	11%
17	Seti	1.5	9,800	75%	10,030	76%	11,158	85%	11,682	89%	9,955	76%	10,706	81%
18	Fewa	1.0	6,500	74%	1,532	17%	2,127	24%	1,851	21%	1,863	21%	1,843	21%
19	Sundarijal	0.6	4,770	85%	3,587	64%	2,815	50%	3,922	70%	612	11%	2,734	49%
20	Pharping	0.5	-		-	-	-	-	-	-	49	-	49	-
	Total (Hydro)	573.3	3,360,830	67%	2,541,000	51%	3,011,372	60%	3,242,451	65%	2,897,029	58%	2,922,963	58%
21	Multifuel	39.0	-	-	-	-	3	0%	3	0%	0	0%	2	
22	Hetauda Diesel	14.4	-	-	116	0%	57	0%	57	0%	33	0%	66	
	Total (Thermal)	53.4	-		116		60		60		33		67	
	Grand Total	626.7	3,360,830	61%	2,541,116	46%	3,011,432	55%	3,242,483	59%	2,897,042	53%	2,923,018	53%

Source: NEA Annual Report 2022/2023

(2) Power Generation

Available amount of annual power by operators in Nepal is shown in Figure 2.2-2. Available amount of annual power has increased 2.64 times in nine years from 4,687GWh in 2014 to 12,369GWh in 2023. In recent years there has been a particularly significant increase in the power output of IPPs and the NEA subsidiary with 5.6 times increase from 919 GWh to 5,148 GWh for IPPs and 16.477 times increase from 151 GWh to 2,488 GWh for the NEA subsidiary between 2014 and 2023.The monthly electricity production of NEA-owned power plants in 2022/2023 in Figure 2.2-3 shows that the highest electricity production is in the rainy season in Shrawan (mid-July to mid-August) at 311.5 GWh and the lowest in the dry season in Magh (mid-January to mid-February) at 155.4 GWh in the dry season. As a comparison of monthly electricity production, the dry season only accounts for 49.9% of that of the wet season. On the other hand, major power plants in NEA, such as Kaligandaki A (144 MW), Mid-Marsyangdi (70 MW), Marsyangdi (69 MW) and Upper Trishuli 3A (60 MW), have a PROR of nearly 70% plant factor in both designed and actual. These are relatively less fluctuation of seasonal decrease in the dry season. Although efforts have been made in order to reduce this seasonal fluctuation of power generation between rainy and dry season by promoting the development of STO plants, it should be noted that there is still a large difference as the nature of hydropower which is depended on characteristics of natural flow and topographic conditions.

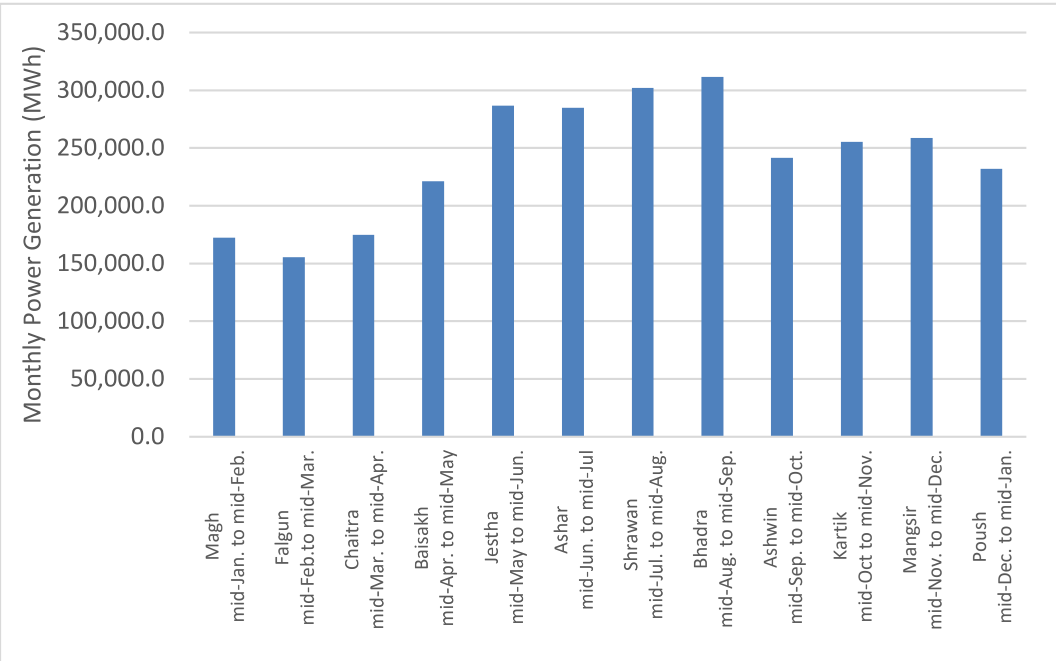


Particulars	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023*
Availability (GWh)										
NEA Own Generation	2,298	2,368	2,133	2,305	2,308	2,548	3,021	2,804	3,259	2,930
Power Purchase - NEA Sub	151	147	154	155	149	157	155	148	1,976	2,488
Power Purchase from IPPs	919	1,122	1,012	1,623	2,019	2,033	2,836	3,093	4,286	5,118
Power Purchase from India	1,319	1,370	1,778	2,175	2,582	2,813	1,729	2,806	1,543	1,833
Total Availability (GWh)	**4,687**	**5,007**	**5,077**	**6,258**	**7,058**	**7,551**	**7,741**	**8,851**	**11,064**	**12,369**
National Peak Demand (MW)	1,201	1,291	1,385	1,444	1,508	1,320	1,408	1,482	1,748	1,870
System Peak Demand Including Export (MW)									1,964	1,986

* Provisional Figures (Subject to audit)

Source: NEA Annual Report 2022/2023

Figure 2.2-2 Available Amount of Annual Power (GWh) by Operators in 2022/2023



Source: NEA Annual Report 2022/2023

Figure 2.2-3 Monthly Power Generation (MWh) of NEA Owned Power Plants in 2022/2023

2.2.2 Existing Transmission Line and Substation

The current power system consists of 220kV, 132kV, and 66kV T/L (Transmission line) and S/S (Substation). The main T/L is the 132kV T/L that runs east to west through southern Nepal, and this main T/L connects Anarmani in the east to Mahendranagar in the west. The main demand areas are located in the central hills, including the Kathmandu basin, and in the south, including industrial areas such as Butwal, Birgunj and Biratnagar. In addition, many hydropower plants are located in the central and northern parts of Nepal, and these power plants mainly supply electricity to demand areas in the central and southern regions through 132kV T/L.

Table 2.2-2 shows the outline of the facility, and the power system diagram (including under construction and planned) and the location map are shown in Figure 2.2-4 and Figure 2.2-5.

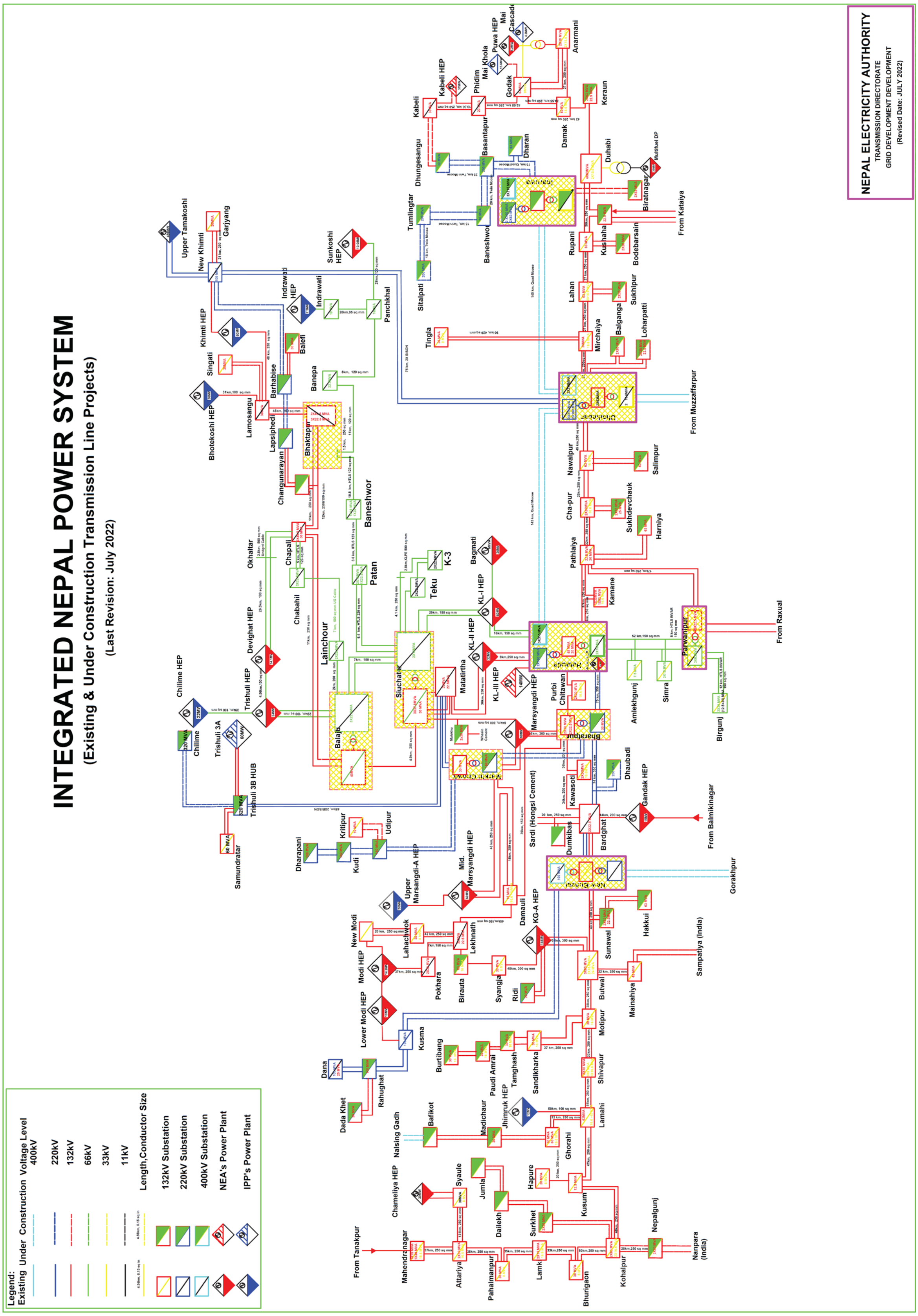
The power system of Nepal is interconnected with the system of India by the international interconnection line, and if the power plants in Nepal cannot supply the demand, the shortage power is supplied by importing power from India through these interconnection lines. Details will be given in the chapter on power interchange.

Currently, there are only four 220kV T/L (one of which is 400kV specification), but in the future, with the development of power plants and the increasing demand, the introduction of bulk systems such as 400kV will be expanded.

Table 2.2-2 Outline of Transmission Lines and Substations (As of 2022 year)

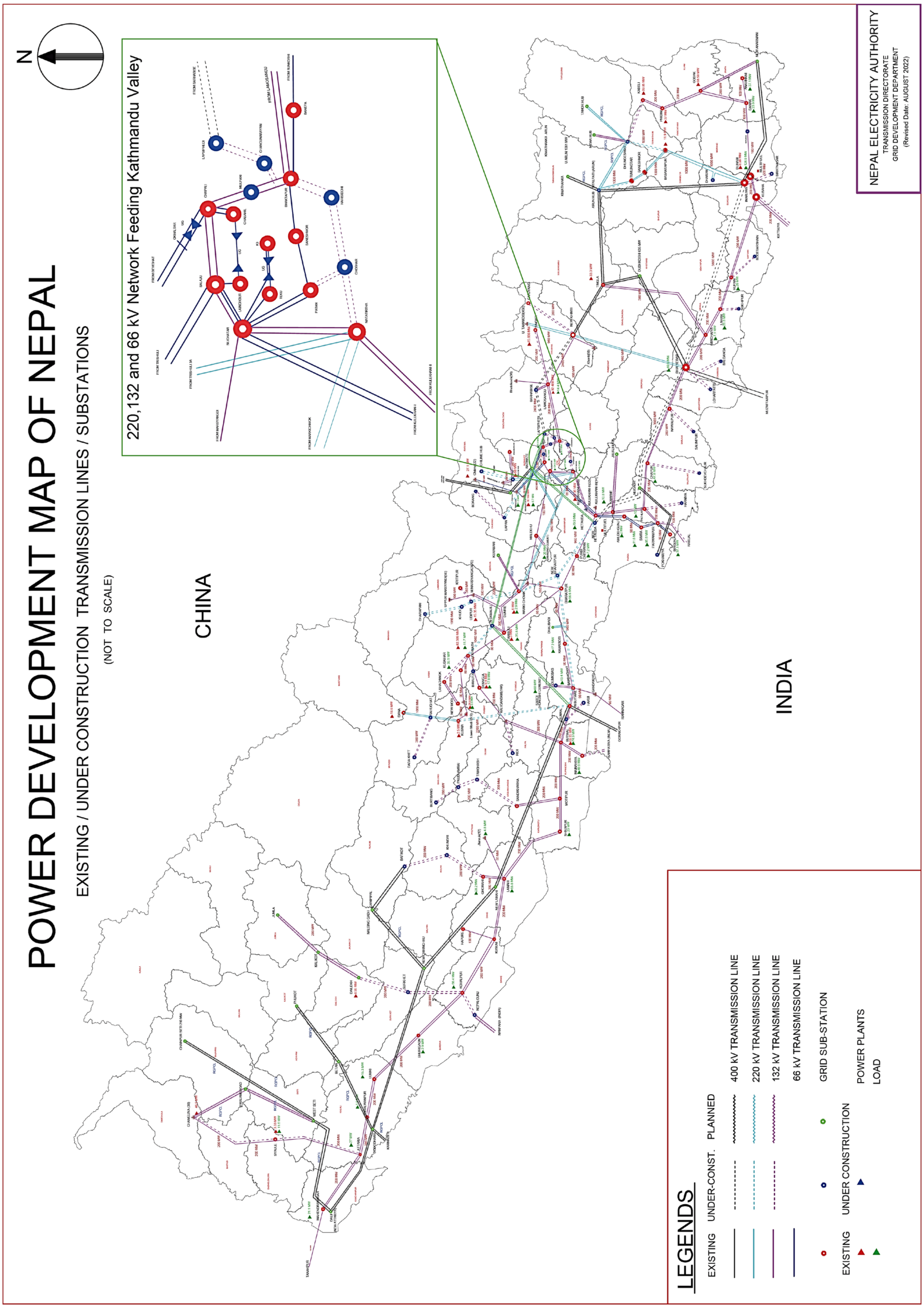
	400kV	220kV	132kV	66kV	Total
Number of transmission line	1	6	45	17	69
Length of transmission line (km)	78	603	3,460	514	4,655
Number of substation	1	4	52	13	70
Capacity of substation (MVA)	945	1,350	3,567	661	6,523

Source: JICA Study Team based on NEA Year Book 2021/2022



Source: NEA Year Book 2021/2022

Figure 2.2-4 Power system diagram in Nepal (including under construction and planned, as of 2022 year)



Source: NEA Year Book 2021/2022

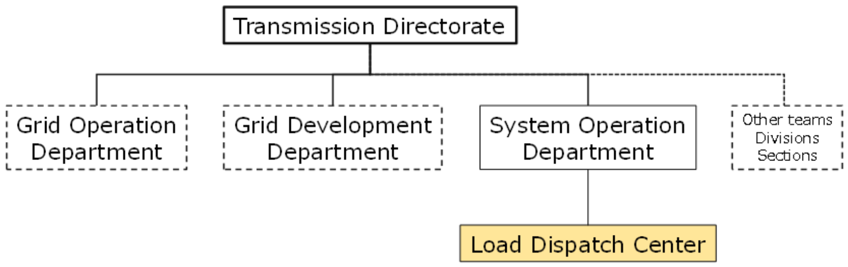
Figure 2.2-5 Power system location map (As of 2022 year)

2.2.3 System of Power System Operation

(1) System of Power System Operation

In Nepal, LDC (Load Dispatch Centre) operations, monitors and controls (Supply and Demand adjustment / grid control) all Nepali power grids. LDC is at Siuchatar in Kathmandu city and belongs to System Operation Department of Transmission Directorate.

LDC monitors frequency of power grid using a grid monitoring panel, and adjusts an output of reservoir typed hydropower of NEA and the amount of import from India (monitoring power flow in an international connection line). LDC has 5 persons per team and 3 shifts as the operation system, and each member operates power stations, substations/transmission lines and international connection lines. Operators in power stations and substations control their facilities by a contact from LDC, and LDC collects information of the facilities in real time through SCADA (Supervisory Control And Data Acquisition) system. The SCADA system has a remote control function, but it is not used for actual operations.



Source: JICA Study Team

Figure 2.2-6 Outline of Transmission Directorate Organization Chart

LDC is involved in an actual practice for power trade with India, and conducts daily power trade through IEX (Indian Exchange Market) as one of media of power trade with India. The management work for the results of the trade is carried out by Power Trade Department, and LDC periodically hands in the report to Power Trade Department.

(2) Operation Standard

Table 2.2-3 shows the power quality standard on power grid operation based on Grid Code published by NEA.

Table 2.2-3 Standard of Power Quality on Power Grid Operation

Items	Power Quality
Frequency	50Hz within ±2.5% (48.75~51.25Hz)
Voltage	【220kV or more】 Rated voltage within ±5% 【132kV or less 】 Rated voltage within ±10%
System Loss	Less than 4.5%

Source: NEA Grid Coad

SARI/EI (South Asia Regional Initiative for Energy Integration) defines a common minimum grid code for South Asia, which sets out rules, guidelines, and standards to be followed by South Asian countries, while operating their power systems in the most secure, reliable, economical, and efficient manner. Some of these are listed in Table 2.2-4.

The common minimum grid code for South Asia deviates from the NEA grid code in some operational aspects. In the future, NEA may be required to meet the South Asia Shared Minimum Grid Code, which is a more stringent standard.

Table 2.2-4 Organization of a common minimum grid code for South Asia

Items	Contents
1. Connection Code	・Procedure for Inter Country connection ・Important Technical Requirements for Connectivity to the Grid ・Connection Agreement
2. Operation Code	・Frequency Band 49.9 – 50.05 Hz ・Voltage Band for 400 kV at inter. Point 380-420 kV ・System Security- Protection Coordination & periodic Protection testing ・Restoration Plans including Black Start ・Periodic Reports – Daily, Monthly Reports ・Outage Planning

Source: Data collection survey for regional grid integration in BBIN final report

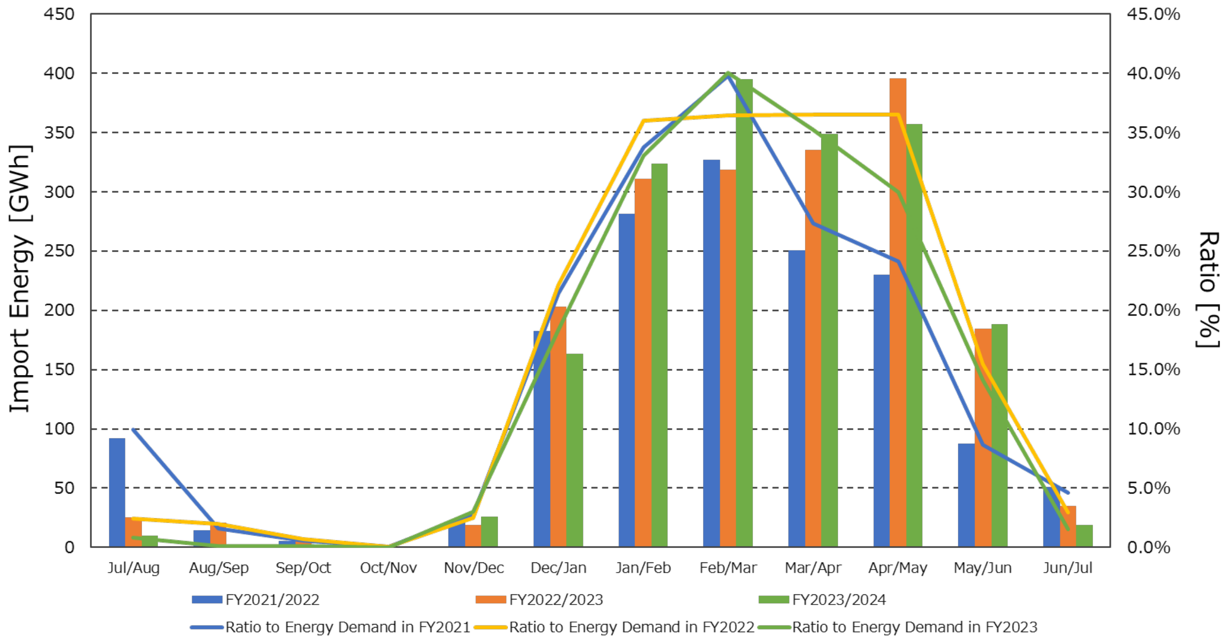
2.3 RESULTS OF POWER TRADE WITH INDIA

The countries currently trading are India and Bangladesh, which is a three-country linkage via India. For Bangladesh, the actual trade through India is only one day, 15 November 2024. Therefore, this section describes Nepal's power trade performance with India.

Figure 2.3-1 shows the monthly importing energy and the percentage of it against monthly domestic peak demand of the year in FY2021/2022[44], FY2022/2023 and FY2023/2024. Nepal lacks electricity during the dry season and imports electricity from India to cover domestic supply.

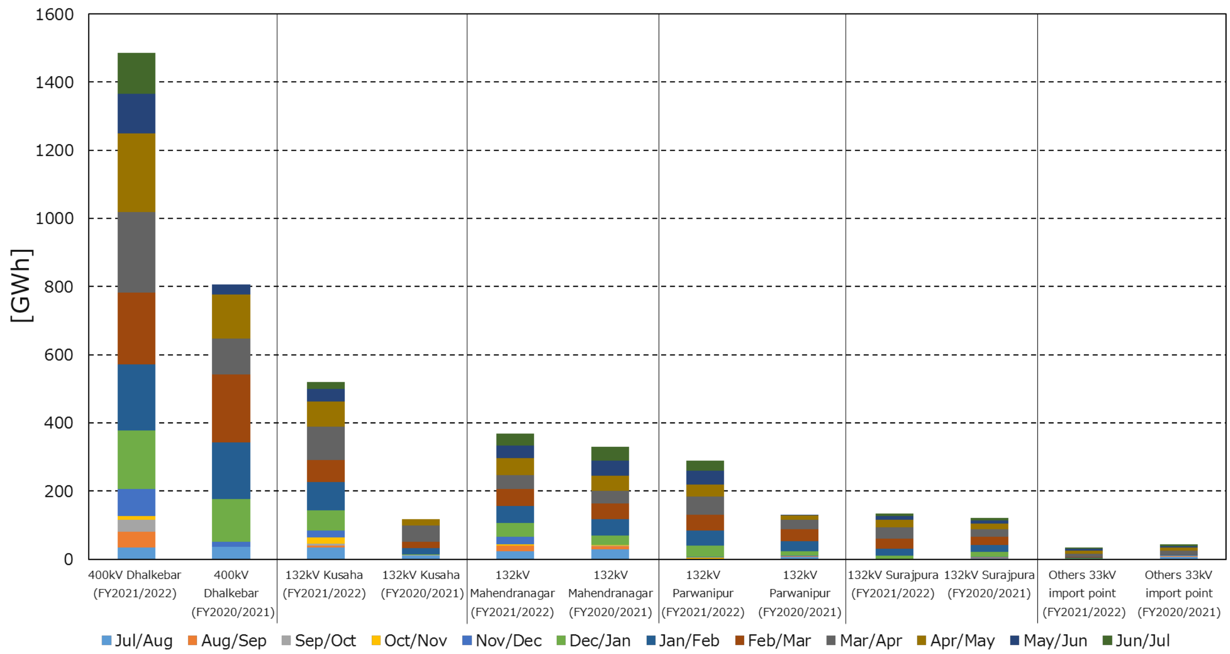
The amount of importing power of each international interconnection line from India is shown in Figure 2.3-2. Since electricity imports per individual transmission line were published until FY2021/2022, data for FY2020/2021 and FY2021/2022 are shown. This figure indicate that power imports from India were conducted mainly through 400 kV transmission lines, but also some through 132 kV and other transmission lines. The 132kV Mahendranagar transmission line in western Nepal is used for power imports because the western part of the country is far from domestic power sources.

[44] FY (Fiscal Year)



Source: JICA Study Team

Figure 2.3-1 Monthly[45] amount of imported electricity in the past three years and the percentage of imported electricity to consumed electricity



Source: JICA Study Team

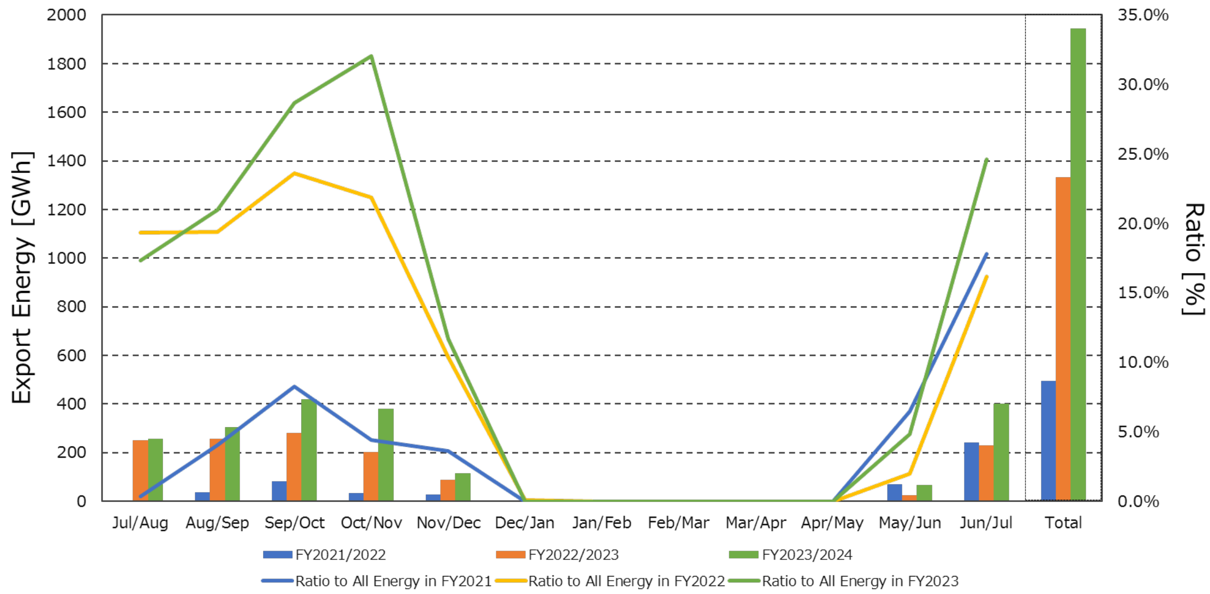
Figure 2.3-2 Imported Energy from different lines in FY2020/21 and FY 2021/22

On the other hand, Figure 2.3-3 shows the monthly amount of exporting power to India and the percentage of the amount of the exporting power for the total amount of power produced of the year in FY2021/2022, FY2022/2023 and FY2023/2024. The three-year trend shows that power exports are implemented during the rainy season, while little power export during the dry season.

[45] For Figures 2.4-1~2.4-4, months are listed in Bikram history. For example, for Jul/Aug, it refers to 7/17 - 8/16.

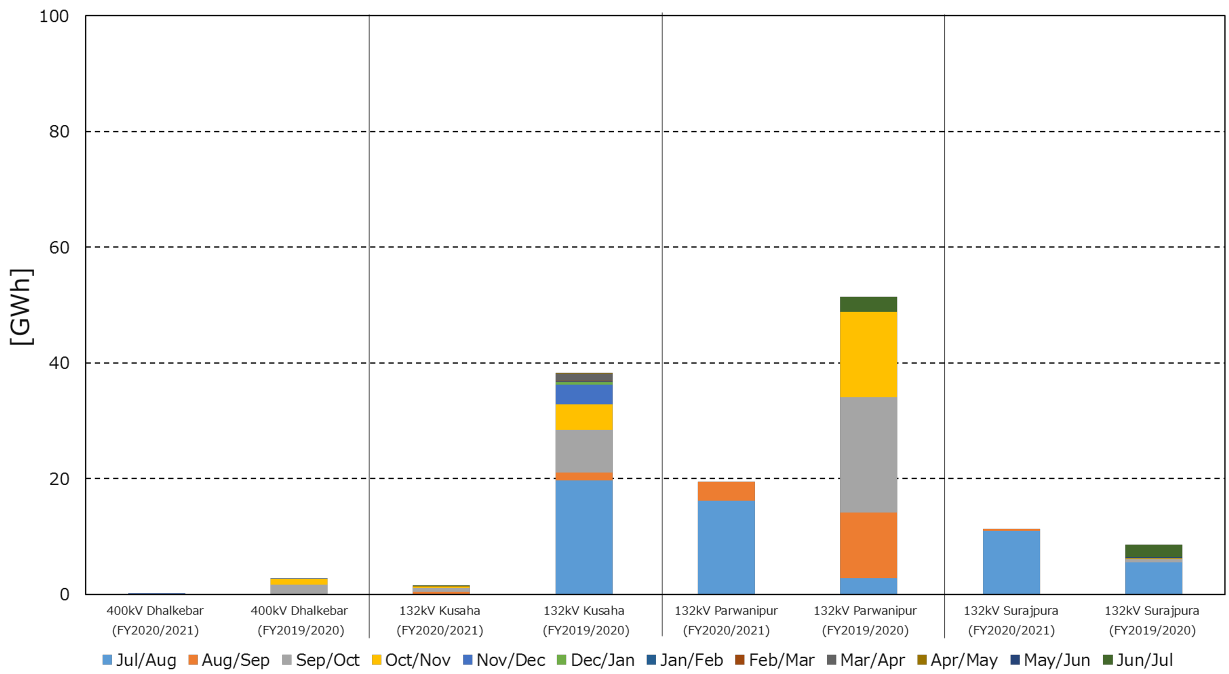
In addition to the increase in generating capacity from new hydropower development, the expansion of export quotas is expected to lead to an increase in export volume.

The amount of exporting power of each international interconnection line is shown in Figure 2.3-4. Since electricity exports per individual transmission line were published until FY2020/2021, data for FY2019/2020 and FY2020/2021 are shown. Power exported mostly through 132kV transmission lines.



Source: JICA Study Team

Figure 2.3-3 Monthly amount of exported electricity in the past three years and the percentage of exported electricity for the total generation amount of the year



Source: JICA Study Team

Figure 2.3-4 Exported from different lines in FY2019/20 and FY 2020/21

2.4 INVOLVEMENT OF EXISTING AND ON-GOING POWER DEVELOPMENT PLANS IN THE POWER SECTOR

Various DPs (Development Partners) have supported development studies and planning for the power sector in Nepal. In addition, WECS, RPGCL and NEA have also formulated their development plans, leading to a situation where numerous plans coexist. IPSDP shall involve them shown in Table 2.4-1 as a foundation of studies and guidance of the direction of future overviews.

Table 2.4-1 Major Policies and Development Plans in the Power Sector

Field	Name	Date[46]	Agency	Assistance
Power Sector	Nationwide Master Plan Study on Storage-type Hydroelectric Power Development	2014	NEA	JICA
	Review in Data Collection Survey on Hydropower Development Project	2018	NEA	JICA
	Irrigation Master Plan	2019	DWRI	ADB
	Hydropower Potential of Nepal	2019	WECS	-
	WB/WECS: Preparation of River Basin Plans and Hydropower Development Master Plans and Strategic Environmental and Social Assessment	2024	WECS	WB
Power System	Transmission System Development Plan of Nepal	2018	RPGCL	
	The Distribution System/Rural Electrification Master Plan of Nepal	2022	NEA	ADB

Source: JICA Study Team

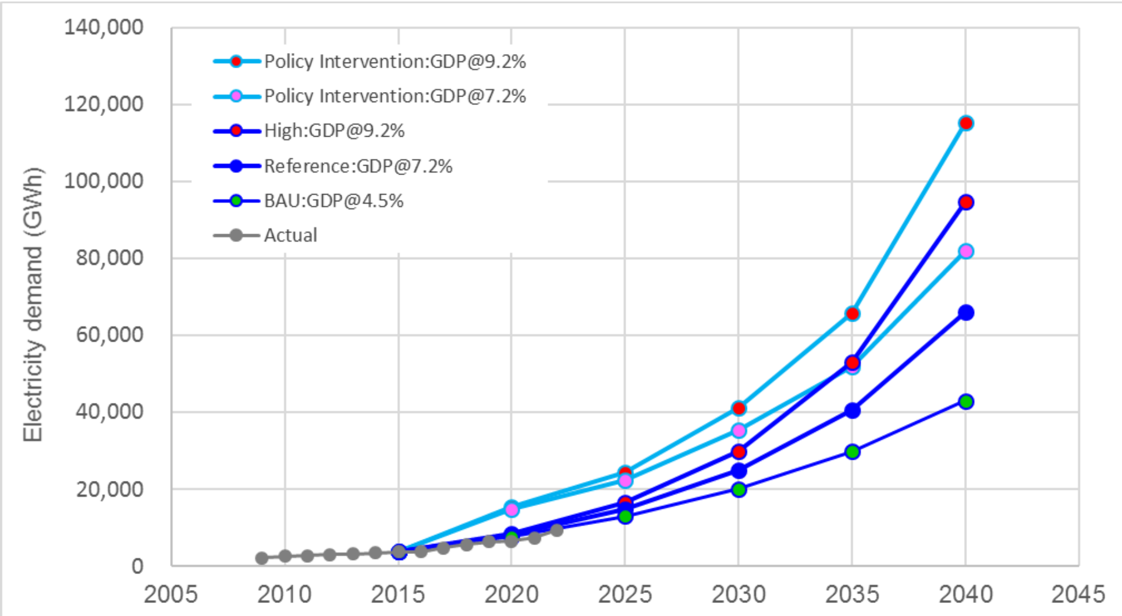
[46] All dates taking effect are per the Western calendar system.

3. POWER DEMAND FORECAST

3.1 EXISTING POWER DEMAND FORECAST IN NEPAL

Nepal's power demand forecasts are presented in The Electricity Demand Forecast Report (2015-2040) by WECS in January 2017. The validity of the electricity demand forecast by WECS is verified based on actual power demand in recent years.

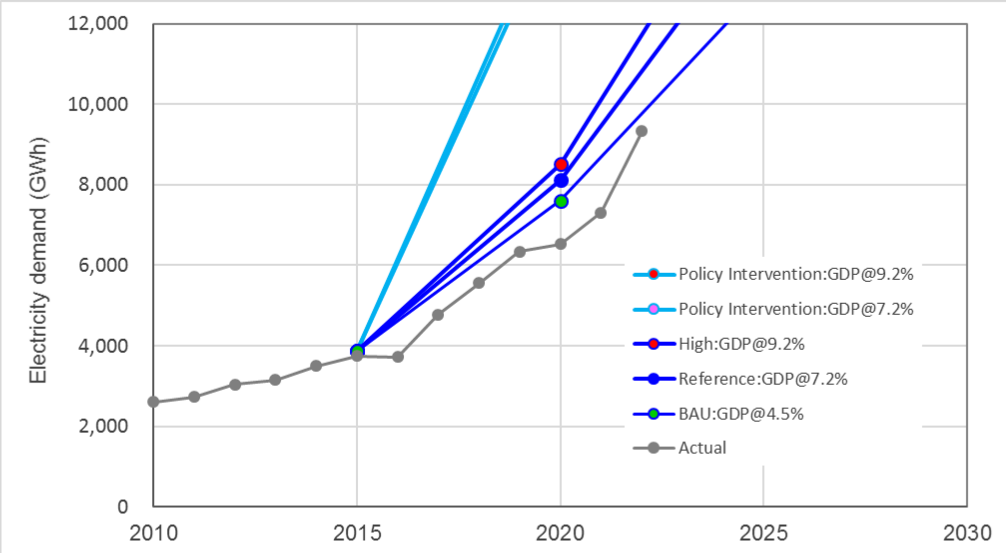
In the past, power demand has been forecasted by NEA. The projections by NEA were based on historical data on grid expansion, population growth, and economic growth. The NEA projections did not consider policy interventions that would affect power demand, such as converting energy sources to electricity. Therefore, WECS conducted power demand forecast in 2017, considering new policies and plans. Figure 3.1-1 shows the power demand forecast by WECS.



Source: JICA Study Team based on Power demand Forecast Report (2015-2040), Annual Report 2021/2022

Figure 3.1-1 Existing Power Demand Forecasts in Nepal

Comparing existing power demand forecasts with actual values, the trends align until 2019, except for the policy intervention scenario. On the other hand, a significant deviation is observed in the WECS policy intervention scenario, which is likely due to the fact that the assumed conditions for the forecast were not met. As shown in Figure 3.2-2, a deviation between the forecast and actual values also occurred in 2020, even in the scenario without policy intervention. In addition, with seven years having passed since the WECS demand forecast, it is now time to revise the electricity demand forecast.



Source: JICA Study Team based on Power demand Forecast Report (2015-2040), Annual Report 2021/2022

Figure 3.1-2 Comparison of Actual and Forecast

3.2 POWER DEMAND FORECAST METHOD

In this section, we study the power demand forecasting methodology and the population and GDP (Gross Domestic Product) used in the analysis. Regarding the power demand forecasting method, considering the availability of necessary data and policy targets, we study the methods suitable for Nepal by referring to the NEA and Japanese demand forecast. It is anticipated that Nepal will expand its power exports to India and Bangladesh in the future. These exports will be covered by surplus electricity after supplying internal demand. The demand forecast in this chapter targets internal demand.

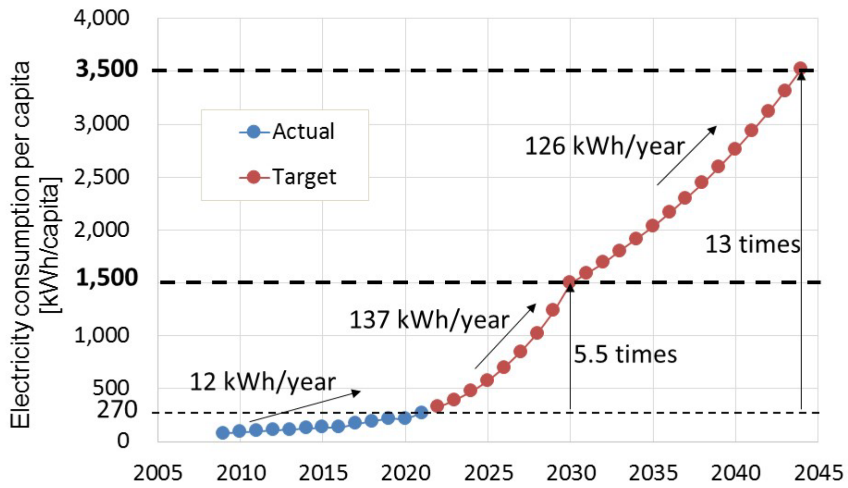
3.2.1 Sector Classification

According to the actual electricity sales in Nepal in 2021, the domestic, industrial, and commercial sectors accounted for 88% of the total, with the share of other sectors being very small. Therefore, we classify the sectors other than the three sectors as the "others" sector and forecast the power demand up to 2040 based on past data for the four sectors (domestic, industrial, commercial, and others).

3.2.2 Growth Scenario

Three growth scenarios are set for each sector: High, Middle, and Low. The High case is the highest growth scenario. The growth rate uses the policy target values. The Middle case is the scenario considered most realistic. The growth rate is set based on data from the past ten years. The Low case represents the lowest growth scenario. The growth rate is set assuming that growth will continue as it has for the past ten years.

As mentioned earlier, policy targets in Nepal are set extremely high, therefore the policy targets have been set as the High case. As an example, Figure 3.2-1 shows a graph of electricity consumption per capita. The actual results are increasing at an average of 12 kWh per year, while the policy targets (Nepal SDG Status and Roadmap 2016-2030, The Fifteenth Plan) are very high: 1500 kWh for 2030 and 137 kWh/year as growth, and 3500 kWh for 2044 and 126 kWh/year as growth.



Source: JICA Study Team

Figure 3.2-1 Electricity Consumption per Capita (Actual and Policy Targets)

The electricity demand forecast method is based on the creation of predictive equations from historical data. However, the impact of future policy interventions on electricity demand is not reflected in the historical data and must be considered separately. Policies that will affect future electricity demand need to be considered and reflected in electricity demand.

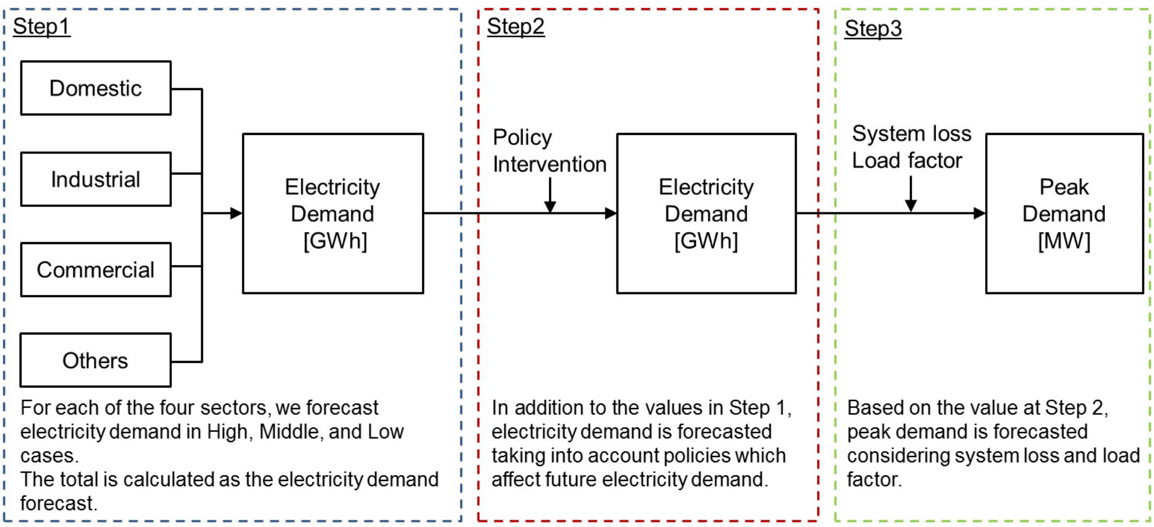
3.2.3 Power Demand Forecast Flow

Figure 3.2-2 shows the power demand forecast flow.

In Step 1, electricity demand in the four sectors is forecasted based on historical data (without policy intervention).

The impact of policy intervention on electricity demand is studied in Step 2. The impact of the policy intervention determined in Step 2 is added to the electricity demand forecast determined in Step 1 to finally forecast electricity demand through 2040, taking into account the policy intervention.

In step 3, peak demand is calculated using the electricity demand obtained in step 2.



Source: JICA Study Team

Figure 3.2-2 Power Demand Forecast Flow

3.2.4 Population Transition Forecast

The population is considered to be highly correlated with electricity demand and is an important parameter in electricity demand forecasting. The population is also used in JICA study team's electricity demand projections. Appropriate forecast of future population transition is important in electricity demand forecast.

In Nepal, a census was conducted in 2021, and the survey showed a population growth rate of 0.93 %/year. We discussed the population growth rate in the WG (Working Group) and decided to adopt 0.93 %/year for the population growth rate. This figure is close to the average growth rate projected by the United Nations until 2040, and is considered a reasonable number.

3.2.5 GDP Transition Forecast

GDP is a very important parameter for electricity demand forecasting because it is highly correlated with the electricity demand. It is crucial to accurately forecast future GDP for effective electricity demand forecasting.

Assuming that past growth will continue, the average growth rate of the past ten years was adopted for the Low case. For the Middle case, the maximum value predicted from actual results was assumed to make a realistic assumption. The GDP growth rates for the Low and Middle cases were derived by statistically processing the GDP growth rates from the past ten years.

Regarding the GDP growth rate, the target values announced by GoN are higher than in the past. Therefore, the policy target values were applied to the High case of the growth scenarios.

Table 3.2-1 shows GDP growth rates for each growth scenario. From these assumed GDP growth rates, future GDP is obtained to forecast electricity demand.

Table 3.2-1 Assumed GDP Growth Rate for Each Growth Scenario

Growth scenario	Industrial GDP (%)	Commercial GDP (%)	Others GDP (%)
High case : Policy target	13.2 - 14.6	9.9 - 10.7	9.6 - 10.3
Middle case : Maximum value assumed from historical data	10.14	7.71	7.12
Low case : Historical average value	4.95	4.63	4.38

Source: JICA Study Team

3.3 ELECTRICITY DEMAND FORECAST

The electricity demand forecast by the JICA study team is classified into four sectors to forecast electricity demand. And three growth scenarios have been set for each sector. The electricity demand forecast for each sector is based on historical data to create predictive equation.

3.3.1 Domestic Sector

Electricity demand in the Domestic Sector is considered to be most correlated with population. However, using population alone as a parameter is insufficient as a forecast, since only the impact of population is reflected in the forecast. In order to reflect factors other than population, electricity consumption per capita is added as a parameter, taking into account the existence of policy targets and availability of data, with reference to the electricity demand forecast for the Domestic Sector in Japan. The predictive equation is developed as follows:

Predictive equation:

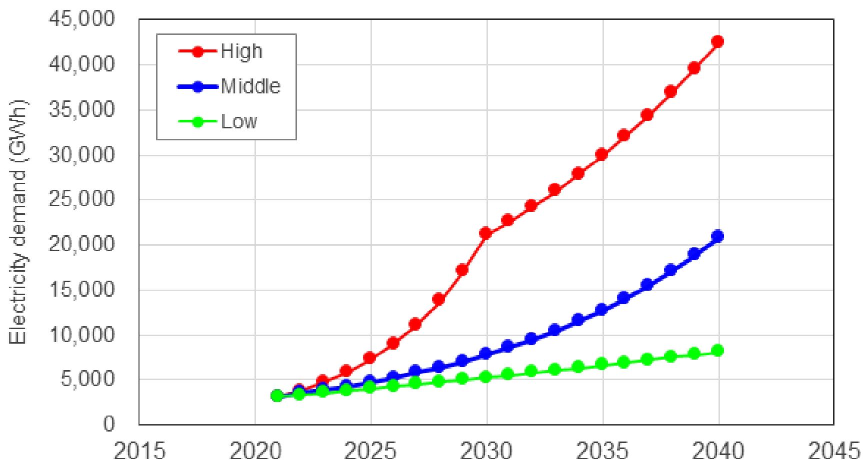
(Population) × (Electricity consumption per capita for household use [kWh])

The population growth rate is assumed constant at 0.93% as described in Section 3.2.4 and is common to the three growth scenarios.

The electricity consumption per capita for households is forecasted based on an increasing rate for each growth scenario. For the Low and Middle cases, the domestic electricity consumption per capita was calculated for both growth scenarios by approximating a curve with the past ten years of residential electricity consumption per capita data to obtain a predictive equation for residential electricity consumption per capita after 2022.

For Low case, a linear approximation is adopted, assuming that historical growth continues. For Middle case, an exponential approximation is adopted, assuming a constant growth rate. For High case, the policy target value of electricity consumption per capita is adopted. The policy targets for electricity consumption per capita for Nepal are 1500 kWh in 2030 (Nepal SDG Status and Roadmap 2016-2030) and 3500 kWh in 2044 (The Fifteenth Plan (FY 2019/20 - 2023/24)). Based on these values, the electricity consumption per capita for households is obtained until 2040.

The calculation results of electricity demand for the Domestic Sector until 2040 are shown in Figure 3.3-1.



Source: JICA Study Team

Figure 3.3-1 Electricity Demand Forecast for the Domestic Sector (Through 2040)

3.3.2 Industrial Sector

For forecasting electricity demand in the industrial sector in Japan, the predictive equation is obtained by regression analysis using the industrial production index as an explanatory variable. With reference to the Japanese method and taking into account the existence of policy targets, the following predictive equations were obtained by regression analysis using industrial GDP[47] as the explanatory variable, which is considered to be highly correlated with electricity demand in the industrial sector, and the electricity demand in the industry[48] as the dependent variable.

$$\text{Predictive equation: } 0.144 \times a_1 - 2051.87 \text{ , } \quad a_1\text{: Industrial GDP}$$

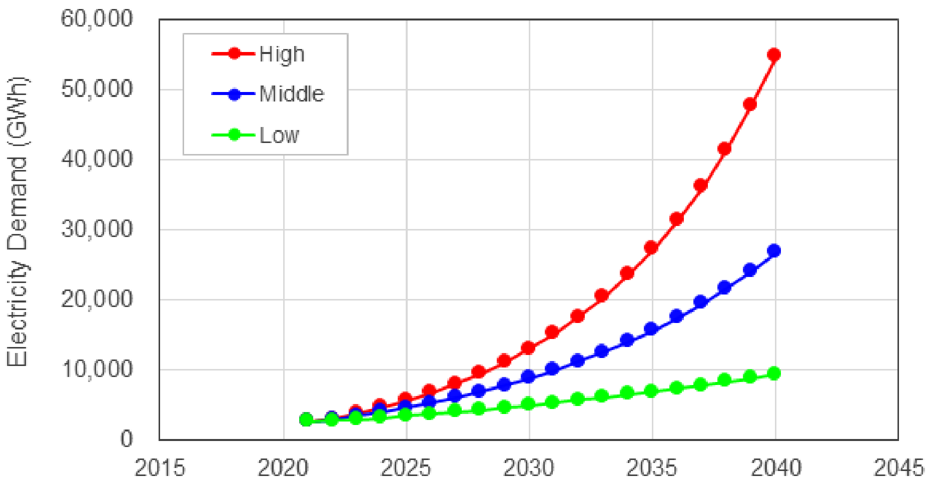
Each growth scenario sets the growth rate of industrial GDP through 2040, as described in Section 3.2.5. Figure 3.3-1 shows the growth rate of industrial GDP.

Table 3.3-1 Growth Rate Assumptions in the Industrial Sector

	Low (%)	Middle (%)	High (%)
2022	4.95	10.14	13.20
2023			14.60
2024			14.60
2025 - 2040			14.13

Source: JICA Study Team

As described above, the industrial GDP was obtained from the assumed growth rates, and the electricity demand for the Industrial Sector is calculated through 2040 using the predictive equation. The results are shown in Figure 3.3-2.



Source: JICA Study Team

Figure 3.3-2 Electricity Demand Forecast for the Industrial Sector (Through 2040)

3.3.3 Commercial Sector

For the Commercial Sector, the predictive equation was obtained based on the same idea as for the Industrial Sector. The following predictive equation was obtained through regression analysis using commercial GDP[49] as the explanatory variable, which is considered to have the highest correlation with electricity demand in the commercial sector, and commercial electricity demand[50] as the dependent variable.

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47 Source: NEA Annual Report 2017/2018, 2020/2021
48 Source: MoF Economic survey 2020/2021
49 Source: NEA Annual Report 2017/2018, 2020/2021
50 Source: MoF Economic survey 2020/2021

$$\text{Predictive equation: } 0.0068 \times a_2 - 307.37 \text{ , } a_2 \text{ : Commercial GDP}$$

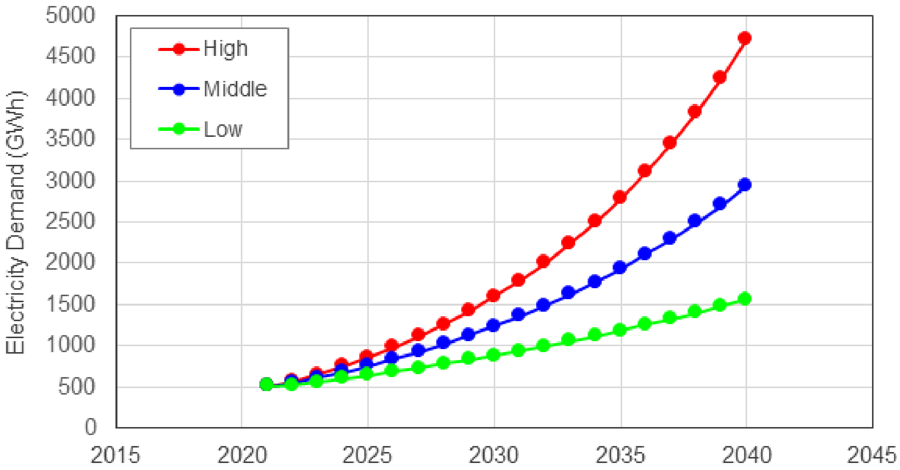
Each growth scenario sets the growth rate of the commercial GDP shown in Figure 3.3-2, as described in Section 3.2.5.

Table 3.3-2 Growth Rate Assumptions in Commercial Sector

	Low (%)	Middle (%)	High (%)
2022	4.63	7.71	10.70
2023			9.90
2024 – 2040			10.2

Source: JICA Study Team

As described above, commercial GDP was obtained from the assumed growth rates, and the predictive equations were used to calculate electricity demand in the Commercial Sector through 2040. The results are shown in Figure 3.3-3.



Source: JICA Study Team

Figure 3.3-3 Electricity Demand Forecast for the Commercial Sector (Through 2040)

3.3.4 Other Sector

The Other Sector includes a variety of sectors and does not have a specific GDP value. Therefore, the following predictive equation was obtained through regression analysis using national GDP and population as explanatory variables.

$$\text{Predictive equation: } 2.58 \times 10^{-8} \times a_3 + 6.16 \times 10^{-5} \times \mathrm{b} - 1962.83 \text{ ,}$$
$$\text{where } a_3\text{: National GDP, b: Population}$$

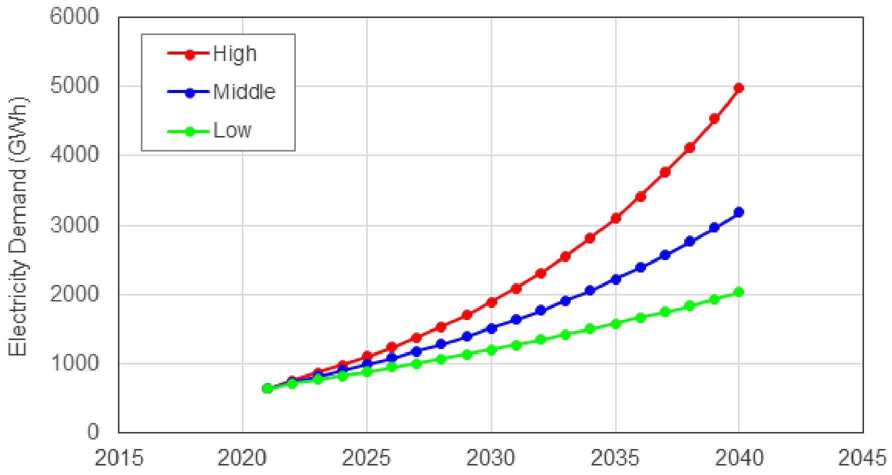
Each growth scenario sets the growth rate of GDP described in Section 3.2.5. The population growth rate was set at 0.93% for each growth scenario. Table 3.3-3 shows the growth rates of GDP and population assumed through 2040.

Table 3.3-3 Growth Rate Assumptions in Others Sector

	GDP growth rate (%)			Population growth rate (%)
	Low	Middle	High	
2022	4.38	7.12	9.60	0.93
2023			10.30	
2024			9.60	
2025 – 2040			9.83	

Source: JICA Study Team

As described above, GDP and population based on the assumed growth rates were obtained, and predictive equations were used to calculate electricity demand for the Other Sector by 2040. The calculation results are shown in Figure 3.3-4.

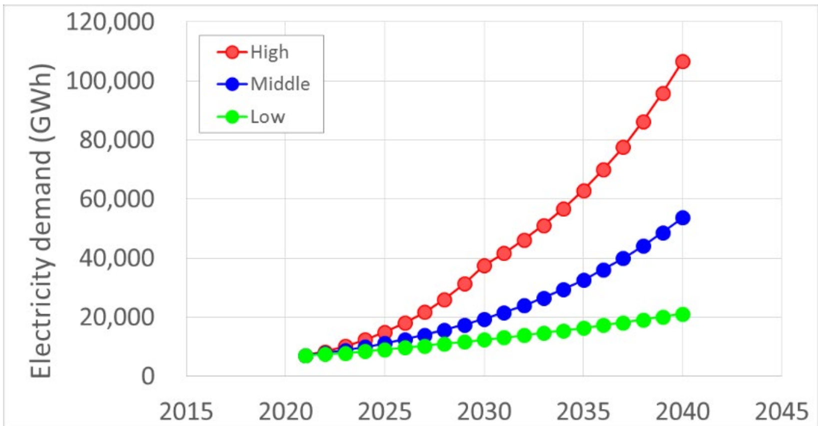


Source: JICA Study Team

Figure 3.3-4 Electricity Demand Forecast for the Other Sector (until 2040)

3.3.5 The Result of Electricity Demand Forecast

Figure 3.3-5 shows the results of electricity demand forecast in Nepal based on historical data: in the Middle case, electricity demand will be 53,774 GWh in 2040, approximately 7.6 times higher than that in 2021.



Source: JICA Study Team

Figure 3.3-5 Results of Electricity Demand Forecast

3.4 ELECTRICITY DEMAND FORECAST CONSIDERING POLICY INTERVENTION

This section examines new policies, i.e., factors not included in the existing sectoral electricity demand forecasts. The electricity demand forecast considering policy intervention is calculated by adding the demand forecast value due to policy intervention calculated in this section, to the demand forecast value forecasted for each of the four sectors in the previous section.

3.4.1 Policies considering Electricity Demand

The seven new policies considered in this report are listed in Table 3.4-1. For each policy, the electricity demand associated with achieving the policy targets was calculated. It should be noted that in the demand forecasts considering policy interventions, the same values were assumed for the High, Middle, and Low scenarios.

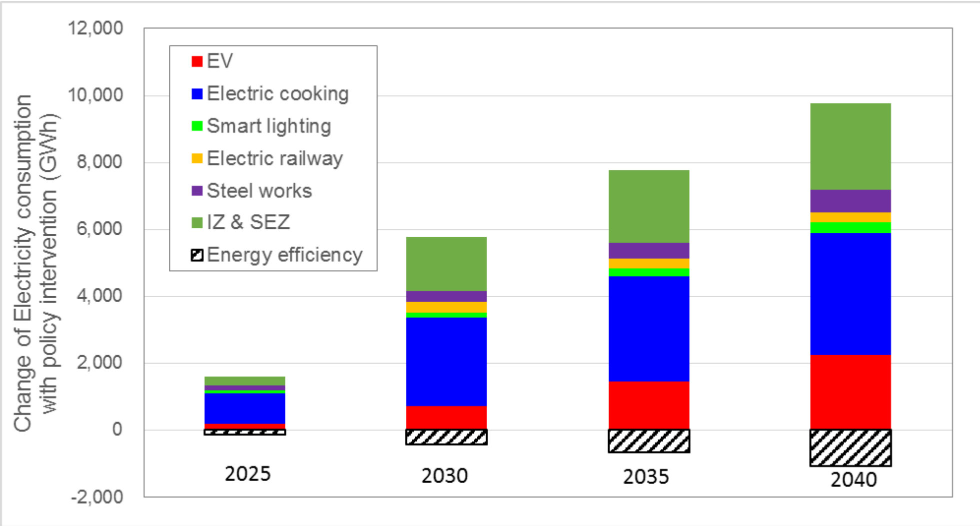
Table 3.4-1 Policy Interventions and Their Sources

Policy	Source	Target
Electric vehicles (EV)	- Assessment of Electric Mobility Targets for Nepal's 2020 Nationally Determined Contributions (NDC) - Nepal SDGs Status and Roadmap 2016-2030	- By 2025, 25% of private vehicle, 20% of public vehicle sales is EV By 2030, 90% of private vehicle, 60% of public vehicle sales is EV - Electric vehicles in public transport systems (%) 2015:1%, 2019:5%, 2022:20%, 2025:35%, 2030:50%
Electric cooking	Nepal SDGs Status and Roadmap 2016-2030:	30% of cooking heat sources is wood, 39% is LPG, and the remaining 31% is electricity in 2030
Smart Street Light	NEA Annual Report 2020/2021	Smart street light (solar LED street lights) is introduced to the same extent as 2018 onward
Electric railway	The Fifteenth Plan (Fiscal Year 2019/20 – 2023/24) By National Planning Commission	900 km electric railway will start operation in 2030.
Steelwork	Several references such as Federation of Nepalese Chamber of Commerce and Industry	Assumed after 2022, a new steelwork will start operation every two years.
Industrial zone and Special economic zone	- Follow Up Data Collection Survey for Transmission and Distribution Network Development - Special Economic Zone Authority (SEZA)	Development of 10 industrial districts and 14 special economic zones
Improvement of energy efficiency	National Energy Efficiency Strategy, 2075	0.84%(2022)→1.68%(2030)→1.68%(2040)

Source: JICA Study Team

3.4.2 Impact of Policy Interventions on Electricity Demand

The impact of each policy on electricity demand in the Middle case is shown in Figure 3.4-1. Electricity consumption from electric vehicles and electric cooking accounts for more than half of the electricity demand by policy. Energy efficiency measures have the effect of reducing electricity consumption, but the value is not so large. The total electricity demand for all policies is 8,696 GWh in 2040 in Middle case. The policies will increase electricity demand by more than 10%.

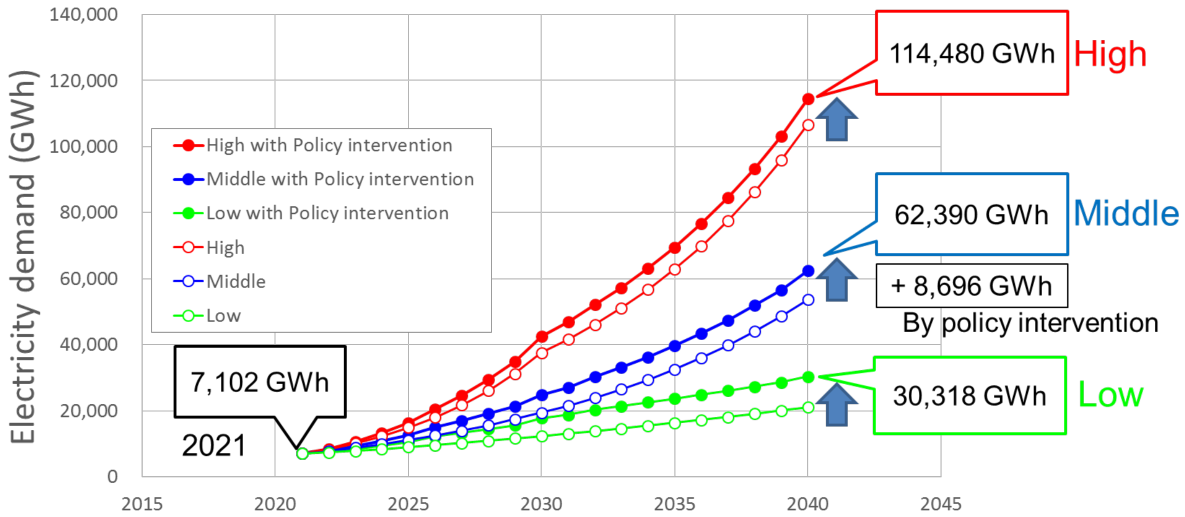


Source: JICA Study Team

Figure 3.4-1 Electricity Demand Considering Policy Intervention in Middle Case

3.4.3 Electricity Demand Forecast Considering Policy Intervention

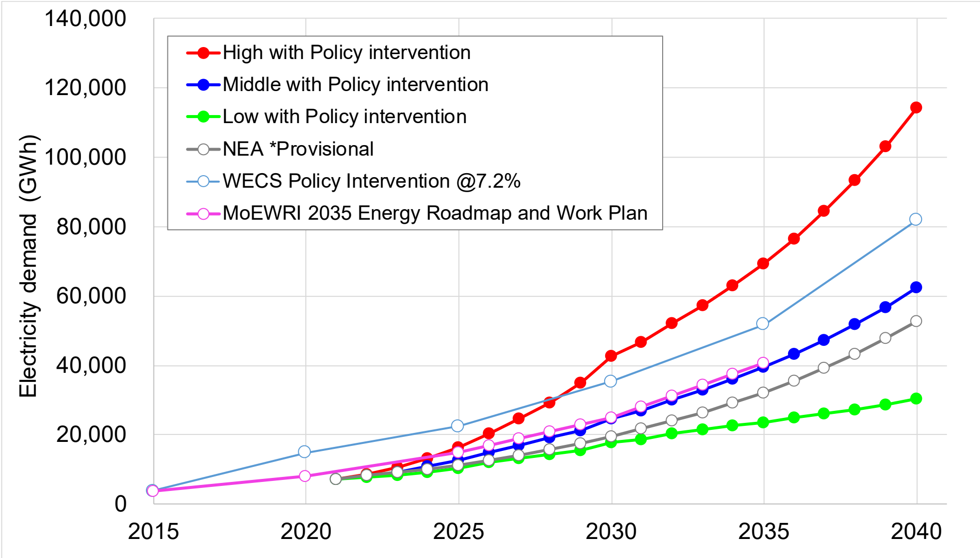
To summarize this section, we discuss electricity demand forecasts that consider policy intervention. Figure 3.4-2 shows a comparison of electricity demand with and without policy intervention. When the policy intervention is considered, 8,696 GWh increased, and it is forecasted to be 62,390 GWh. This is 8.78 times greater than the electricity demand in 2021.



Source: JICA Study Team

Figure 3.4-2 Comparison of Electricity Demand with and without Policy Intervention

Next, a comparison is made with existing electricity demand forecasts in Nepal. Figure 3.4-3 compare the electricity demand forecast of JICA Study Team, MoEWRI, WECS, and NEA. The electricity demand for Middle case differs by about 20,000 GWh from that of by WECS (with policy intervention, growth rate of 7.2%, Reference case). The reasons for this are that there is a twice as large difference in electricity demand as of 2020, and that different policies are taken into consideration. On the other hand, the electricity demand forecast for Middle case is close to that MoEWRI' latest assumption from "Energy Roadmap and Work Plan 2035" which has been under discussion on November, 2024 and NEA's one. A reason for this is the use of close values for GDP growth rate, etc.

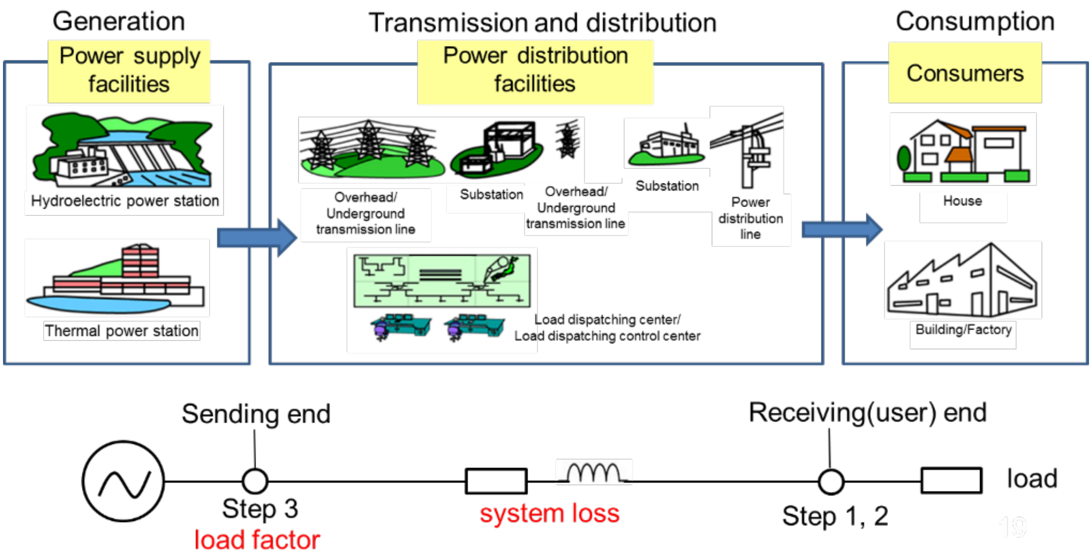


Source: JICA Study Team

Figure 3.4-3 Comparison of Electricity Demand Forecasts by JICA Study Team, MoEWRI, WECS, and NEA

3.5 PEAK DEMAND FORECAST

In the previous sections, electricity demand has been forecasted at the receiving end, as shown in Figure 3.5-1. In the peak demand forecast discussed in this section, on the other hand, the peak demand at the sending end was forecasted. This is because power for station operation varies depending on the type of power source, and the power generation capacity is determined after considering the type of power source in the power development plan.

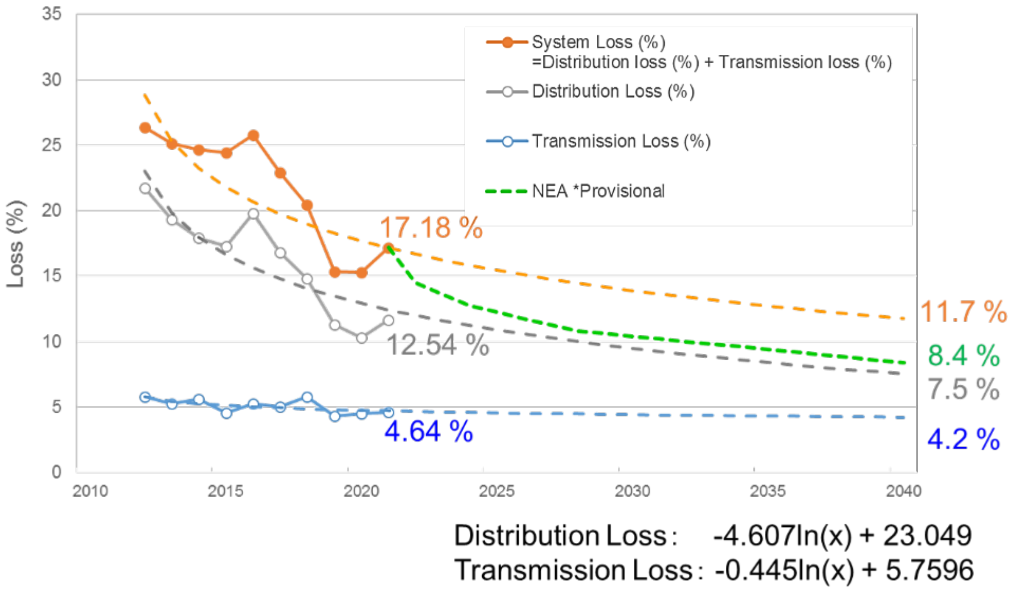


Source: JICA Study Team

Figure 3.5-1 Power Flow and Electrical Diagram

3.5.1 System Loss Forecast

For the system loss forecast, distribution loss and transmission loss until 2040 were calculated, based on the data from 2012 to 2021. The results of the system loss forecast until 2040 are shown in Figure 3.5-2.

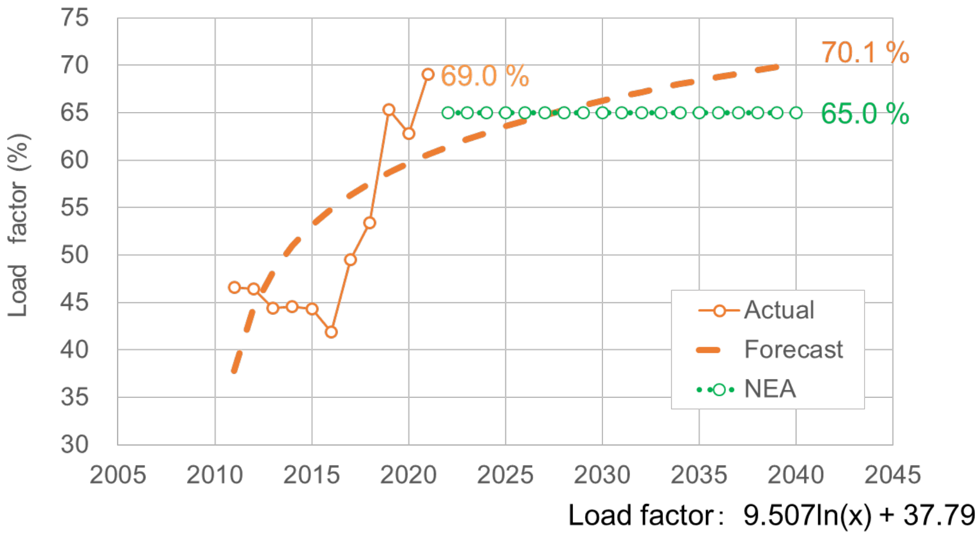


Source: JICA Study Team

Figure 3.5-2 System Loss Forecast

3.5.2 Load Factor Forecast

For the load factor forecast, we created a curve fitting equation based on load factor data from 2012 to 2021 and calculated the load factors up to 2040. The forecast results for load factors up to 2040 are shown in Figure 3.5-3.



Source: JICA Study Team

Figure 3.5-3 Load Factor Forecast

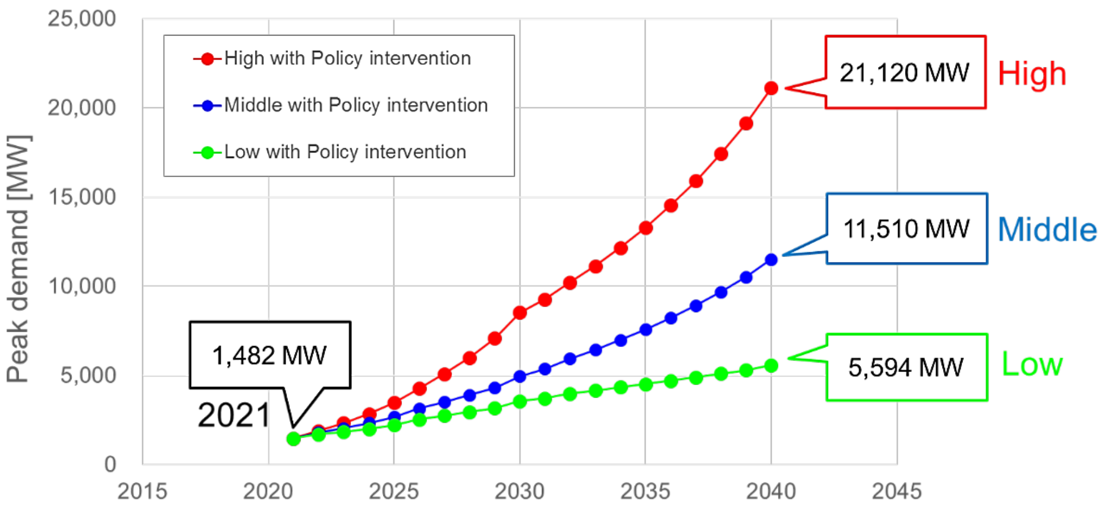
3.5.3 Peak Demand Forecast

Peak demand is forecasted based on the results of the electricity demand forecast with policy intervention, as calculated in Section 3.4, taking into account system loss and load factor. Peak demand can be expressed by the equation below.

$$\mathrm{MW} = \mathrm{GWh} \times \frac{1}{24 \times 365} \times \frac{1}{1 - \mathrm{Loss}} \times \frac{1}{\mathrm{LF}} \times 1000$$

MW : Peak demand
GWh : Electricity demand
Loss : System loss
LF : Load factor

The results of peak demand forecast are shown in Figure 3.5-4. While the actual value in 2021 was 1,482 MW, it is forecasted to be 11,510 MW in 2040 in the Middle case, which is 7.8 times higher.



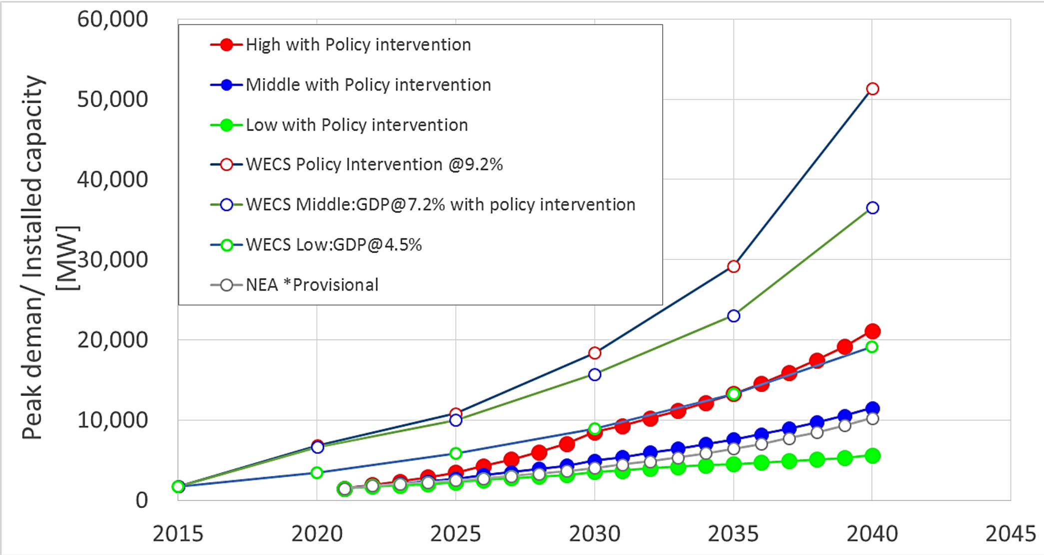
Source: JICA Study Team

Figure 3.5-4 The Result of Peak Demand Forecast

3.5.4 Comparison with Existing Peak Demand Forecast in Nepal

We compared the peak demand forecast by JICA Study Team with that of NEA and WECS. Figure 3.5-5 shows the comparison. The peak demand forecast by JICA Study Team numerically differs significantly from the forecast by WECS. The causes of this difference were discussed.

Given the assumptions for calculating peak demand, the value of peak demand forecast by WECS is considered to be the installed capacity of the power plant. On the other hand, peak demand forecast by JICA Study Team is the peak demand at the sending end. This difference is responsible for the difference in forecasted values. Peak demand forecast by NEA is calculated at the sending end, as is the case with JICA Study Team, and the forecasted value by NEA is close to that by JICA Study Team.



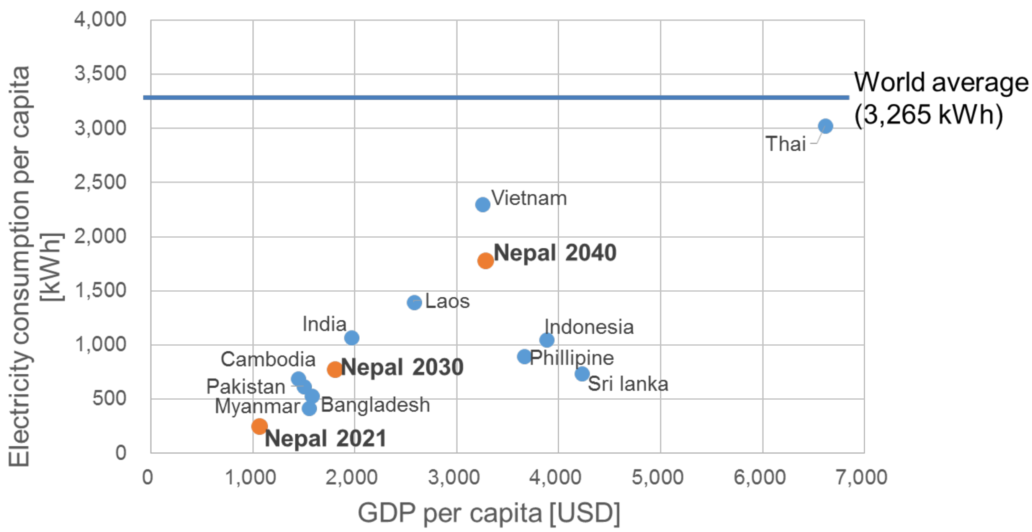
Source: JICA Study Team

Figure 3.5-5 Comparison of Peak Demand Forecast

3.6 THE RESULTS OF POWER DEMAND FORECAST

Figure 3.6-1 shows the relationship between GDP per capita and electricity consumption per capita for each country in South and Southeast Asia. For Nepal, the actual values for 2021 and the Middle case forecasts for 2030 and 2040 are shown in orange, respectively. For the other countries, the actual values for 2019 are shown in blue.

The evolution of Nepal's data shows that the plot position moves to the upper right as the years pass, resulting in an increase in electricity consumption as the economy grows. The data for Nepal is located within the distribution for the other South and Southeast Asian countries, suggesting that the demand forecast results are generally reasonable.



Source: JICA Study Team

Figure 3.6-1 The Relationship Between GDP Per Capita and Electricity Consumption Per Capita for Each Country in South and Southeast Asia

Table 3.6-1 summarizes the results for the Middle case, including five-year electricity demand, peak electricity demand, and electricity demands per capita from 2021 to 2040, as well as their annual growth rates and multipliers to the 2021 value. Electricity demand was 7,102 GWh in 2021 and is forecasted to be 62,390 GWh in 2040, which is 8.78 times to the value in 2021. Peak demand was 1,482 MW in 2021, and is forecasted to be 11,510 MW in 2040, which is 7.77 times to the value in 2021. Electricity demand per capita was 242 kWh/capita in 2021 and is forecasted to be 1,779 kWh/capita in 2040, which is 7.37 times the value in 2021.

As shown by comparisons with existing forecast results in Figure 3.5-5 and comparisons with other countries in Figure 3.6-1, the Middle case assumes realistic growth, and the Middle case values will be used for power supply development planning and grid planning.

Table 3.6-1 The Results of Electricity Consumption, Peak Demand, and Electricity Demands Per Capita

Middle Case	Unit	Year				
		2021(Current)	2025	2030	2035	2040
Electricity Consumption	[GWh]	7,102	12,590	24,737	39,638	62,390
Growth rate	%/year	-	10.19	11.25	5.86	5.09
X times of 2021	-	-	1.77	3.48	5.58	8.78
Peak Demand	[MW]	1,482	2,675	4,949	7,581	11,510
Growth rate	%/year	-	15.40	14.49	9.89	9.50
X times of 2021	-	-	1.81	3.34	5.12	7.77
kWh per capita	[kWh/capita]	242	413	774	1,184	1,779
Growth rate	%/year	-	23.12	21.19	10.28	10.50
X times of 2021	-	-	1.71	3.20	4.90	7.37

Source: JICA Study Team

4. HYDROPOWER DEVELOPMENT PLANNING

4.1 DATA COLLECTION AND DEVELOPMENT OF DATABASE FOR HYDROPOWER IN NEPAL

4.1.1 The DoED Project List

DoED of MoEWRI has been authorized to manage administrative process of generation and transmission projects over 1MW and more such as survey, construction and operation. These power generation projects include those promoted by government owned developers such as VUCL and NEA. The projects are classified into the category shown in Table 4.1-1 based on the progress of development.

Table 4.1-1 Category of the DoED Project List based on the Progress

Category	Explanation
Power Plants	Projects under operation
Survey License	Projects licensed to study generation, transmission, distribution survey of the project
Application for Survey License	
Construction License	Projects licensed for construction and operation of the project
Application for Construction License	
GoN Reserved Projects	Projects which are owned by GoN for study / survey and construction
Other Projects	“Forwarded to Local Government” or “Selected for Competitive Bidding”

Source: JICA Study Team based on DoED List

Developers who obtained a Survey License need to complete F/S (Feasibility Study) and EIA (Environmental Impact Assessment) or IEE (Initial Environmental Evaluation) within five years. If the result of studies show that the project is feasible, the developer applies to DoED for the Construction License. After the evaluation and approval by DoED, MoEWRI issues the Construction License for the developer. Power plants that have completed construction and are in operation are registered as Power Plants”. Sites of which development licenses have not been obtained by developers are classified into GoN Projects which include projects where DoED is carrying out studies or which the license has been canceled. In addition, there is the category of “Other Projects” on which sites of Forwarded to Local Government and Selected for Competitive Bidding are registered. Projects under the jurisdiction of DoED are published on the website http://www.doed.gov.np/issued_licenses.php.

The DoED Project list is widely recognized as the development list of generation and transmission and is assumed to be a reliable information source which is regularly updated by DoED Including the GoN Projects, the list covers almost all of identified hydropower potential in Nepal. PGDP (Power Generation Development Planning) will be studied based on this list in principal.

Regarding the timing of data collection, it shall be noted that Progress Report is prepared based on the information as of May, 2021 but it will be updated to the latest one when the Optimum Scenario of IPSDP is studied.

The DoED Project list is widely recognized as the development list of generation and transmission and is assumed to be a reliable information source which is regularly updated by DoED Including the GoN Projects, the list covers almost all of identified hydropower potential in Nepal. PGDP will be studied based on this list in principal. Regarding the timing of data collection, it shall be noted that database had been prepared based on the information as of May, 2021 and was updated on March, 2023.

4.1.2 Development of Hydropower Database

Hydropower is unique power sources which output and annual power generation are depended on natural conditions at project sites. Therefore, accuracy of these information directly affects to the quality of PGDP and PSP (Power System Planning) in Nepal where hydropower is majority of the power sources. In this study, key information such as coordinates of site, power planning, hydrological information, salient features of facilities, accessibility, environmental and social considerations and project cost will be collected in order to provide the basis of technical studies. In particular, feasibility of cascade operation is studied on the development of hydropower projects with reservoir type, considering reservoir capacity, regulation of river flow and supply – demand regulating function such as maximum output and peak hours

It shall be noted that hydropower development information, particularly IPP projects carried out by private companies is highly confidential and must be handled with the utmost care.

Major items of data collection in this Project is shown in Table 4.1-2.

Table 4.1-2 Major Data Collection Items

Category	Item
Basic Information	Project Name, Category, Sub-Category, Capacity (MW), Region, TL-Zone, Basin_1, Basin_2, Basin_3, River, Lic No. / Appn No., Issue Date / Appn Date Validity, PPA date, R-COD (COD), Promoter Address, Latitude N, Longitude E, District
Power Planning	Generation type, Capacity [MW], Annual Energy Production [GWh], Dry season energy [GWh], Wet season energy [GWh], Peaking Hour, Plant Factor [%], Design Discharge [m^3/s], Gross Head [m], Rated Net Head [m], Monthly Generation [GWh], Maximum Output [MW]
Hydrology	Catchment Area [km^2], Mean Annual Flow [m^3/s], Design Flood [m3/s], PMF [m^3/s], Riparian Release [m^3/s]
Reservoir	Full Supply Level [EL.m], Minimum Operation Level [EL.m], Tail Water Level [EL.m], Gross Storage Volume [$M.m^3$], Effective Storage Volume [$M.m^3$], Reservoir Area [km^2]
Salient Feature	Dam Type, Dam height [m], Crest Elevation [EL.m], Headrace tunnel [km], Powerhouse Type, Voltage of T/L [kV], Length of T/L [km], Connected Substation, Project Cost [M.NRs.], Project Cost [M.USD], Specific Project Cost [USD/kW], Generation Cost [Usc/kW], B/C, Data Source
Environmental Information	Resettlement, Protected area, Submerged area [km^2], Indigenous people and Religious/Cultural heritage

Source: JICA Study Team

While the DoED list of projects is as of the time the information was collected, each site is constantly being updated and many sites have different values in the list as a result of the data collection. In such cases, IPSDP will reflect the most up-to-date information in its considerations, but the database will contain information from both points in time, specifying when the information was collected and the source of the information.

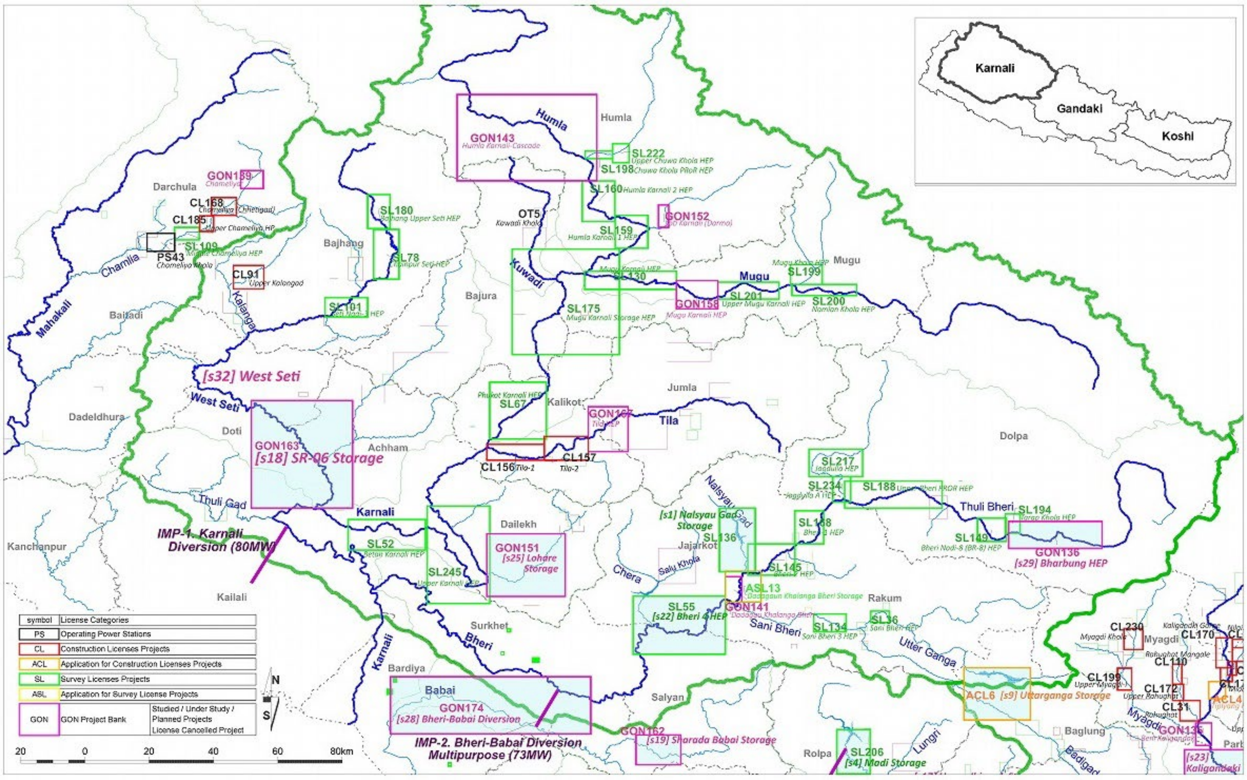
4.2 ESTABLISHMENT OF HYDROPOWER DEVELOPMENT DATABASE

In this Study, the study team updated this and established practical hydropower development database by updating the latest development status. Inventory data is compiled by Excel and coordinates and geographic information are developed in ArcGIS/Google Earth. The summary of data collection is presented in Table 4.2-1 and examples of database are shown below;

Table 4.2-1 Summary of Data Collection on Hydropower Projects

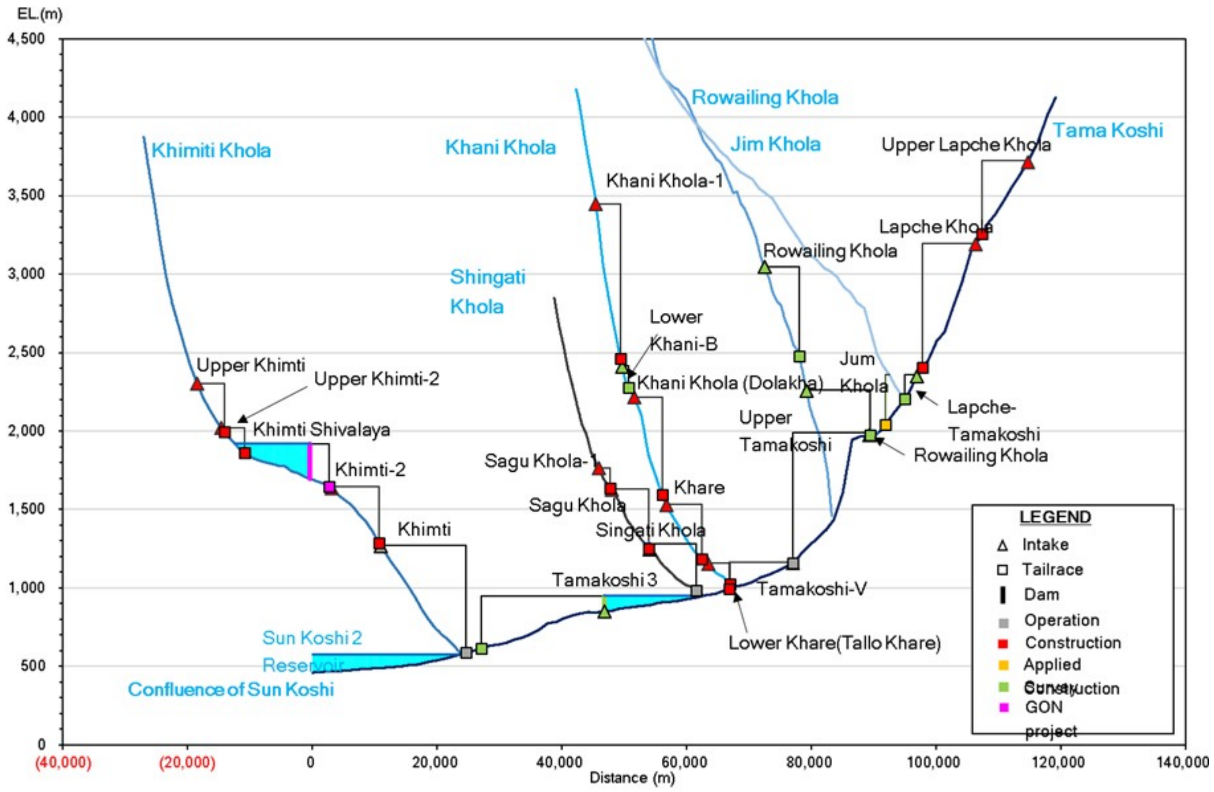
Category	DOED Status	Subtotal		Basic Data Entry			Data Entry (incl. Project Layout)		
		Site	Installed Capacity (MW)	Site	Installed Capacity (MW)	% in Capacity	Site	Installed Capacity (MW)	% in Capacity
a) Existing	(1)Existing Power Plants	109	1,222	76	908	74%	3	194	16%
b) Committed	(2)Construction License	241	8,317	215	8,551	77%	124	7,007	63%
	(3)Application for Construction License	28	2,735						
c) Prioritized	(4)Survey License	263	16,522	146	14,828	88%	118	12,151	72%
	(5)Application for Survey License	14	259						
d) Optimized	(6)GON Reserved Projects	183	15,849	11	8,960	57%	16	4,772	30%
Total	-	838	44,904	452	33,248	74%	261	24,123	54%

Source: JICA Study Team



Source: JICA Study Team

Figure 4.2-1 Example of Hydropower Development Database (1): Watershed Map of Karnali



Source: JICA Study Team

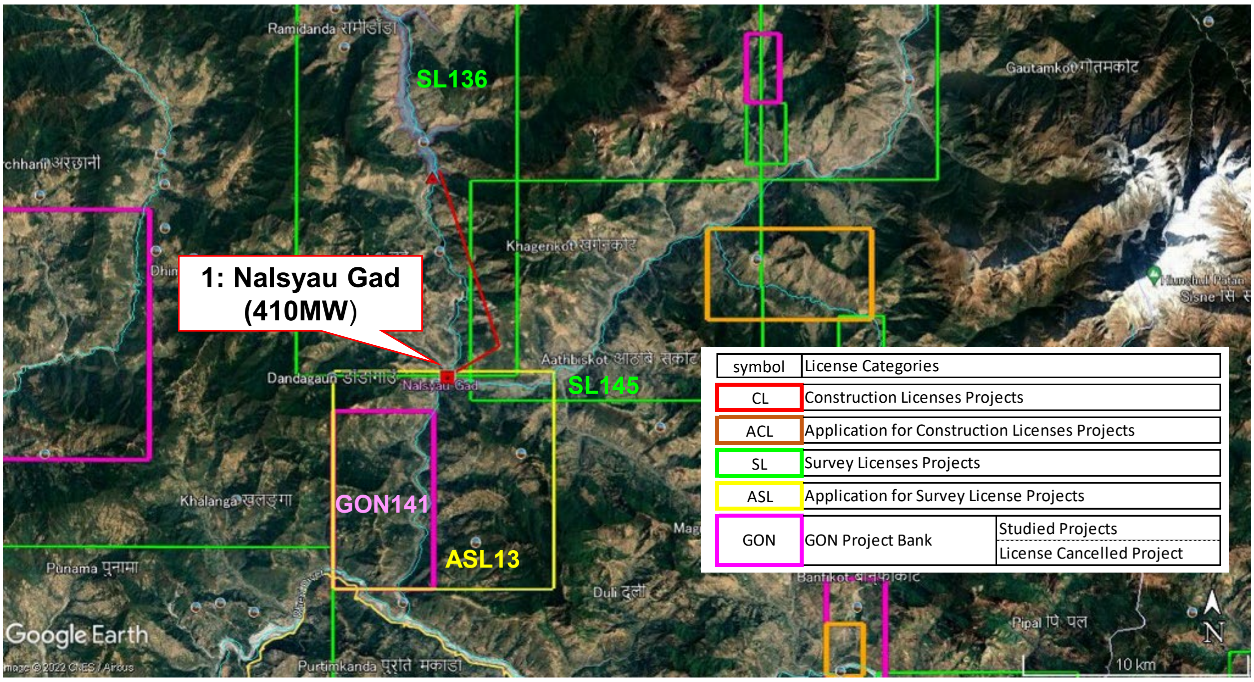
Figure 4.2-2 Example of Hydropower Development Database (2): River Longitudinal Profiles

ID	GL020	GL024	GL038	GL041	GL043	GL046
Project	Chameliya Khola	Kule Khani Third	Lower Modi Khola	Upper Tamakoshi HPP	Upper Trishuli 3A	Khani Khola - 1
Capacity [MW]	30	14	20	456	60	40
River	Chameliya Khola	Kulekhani	Modi Khola	Tama Koshi	Trishuli	Khani Khola
Transmission Zone	Zone-1	Zone-4	Zone-3	Zone-5	Zone-4	Zone-5
Generation type	ROR (6-hr daily peaking)	STO (Cascade)	ROR	ROR	ROR	ROR
Annual Energy Production [GWh]	184.21	40.85	60.538	1727	490	231.92
Dry season eneergy [GWh]	NA	NA	10.023	NA	226.6	37.71
Wet season eneergy [GWh]	NA	NA	50.515	NA	263.4	194.21
Plant Factor [%]					87	66
Design Discharge [m3/s]	36	16	27	44	51	6.38
Catchment Area [km^2]	835	143	575	1745		69
Mean Annual Flow [m3/s]			55.9	60.3		
Design Flood	710 (1/1000)		1123 (1/100)	885 (1/1000)	2424	130.12 (1/100)
PMF	970 (1/10000)					
Dam Type	ConcreteGravity		RCC			Concrete
Dam height [m]	54			22	10	3
Crest Elevation [EL.m]	892		768			3391.7 (High Flood Level)
Gross Head [m]	103.7	109.8	48			963
Rated Net Head [m]	94	103.17	42.74			939.5
Full Suppy Level [EL.m]	888			1987	870.5	3388 (NWL)
Minimum Operation Level [EL.m]	880			1981	726	
Tail Water Level [EL.m]					726	
Gross Storage Volume [M.m^3]				-		
Effective Storage Volume [M.m^3]	0.68			1.2		
Reservoir Area [km2]						
Project Cost [M.NRs.]		2,334	1,493			
Project Cost [M.USD]	78.853 (with T/L) 63.182 (without T/L)			125		
Specific Capacity Cost [USD/kW]	2,509					
Specific Energy Cost [UScents/kWh]	5.81					
B/C	1.46					
EIRR [%]						
FIRR [%]						
Riparian Release [m3/s]	2.0 (Mar-Apr)					
Transmission Line [km]						
Access Road [km]						
Headrace tunnel [km]						
Data Source	EIA2006	DR	FS2008	DD2008	EIA2010	DPR

| Data Source | EIA2006 | DR | FS2008 | DD2008 | EIA2010 | DPR |
| Data Source | EIA2006 | DR | FS2008 | DD2008 | EIA2010 | DPR |

Source: JICA Study Team

Figure 4.2-3 Example of Hydropower Development Database (3): Examples of Data Table



*: Colored boxes indicates the areas of issued/applying projects (information from DoED web site)

Source: JICA Study Team

Figure 4.2-4 Example of Hydropower Development Database (5): Examples of Licenses Status

4.3 CONSIDERATIONS ON INTEGRATED RIVER SYSTEM DEVELOPMENT

This section presents the consideration on integrated river system development based on the conditions of the projects on each river system summarized in the above section including storage projects.

4.3.1 Potentials on Storage-type Hydropower Project

The list of STO type projects including DoED’s list and IMP2019 are summarized as below. The project information for IMP2019 (from No.30 to No.43 of Table 4.3-1) is limited, and need to be collected. Additional new potentials for storage type projects could not be found as presented in the above section.

Table 4.3-1 Potentials on Storage-type Hydropower Development Projects

No.	Status*	PNO*	Project Name	River System	River Name	Lic. No	Capacity [MW]	Design Discharge [m3/s]	Dam height [m]	Full Suppy Level [EL.m]	Tail Water Level [EL.m]	Gross Storage Volume [M.m3]	Effective Storage Volume [M.m3]	Remarks
1	SL	SL136	Nalsyau Gad Storage HEP	BER	Bheri	962	417	78.4	210	1570	867.6	419.6	296.3	Study on-going under SL (LNO.962)
2	SL	SL184	Dudhkoshi Storage HEP	SUN	DudhKoshi	1029	835	242.8	210	636	304.8	1503	1264	Study on-going under SL (LNO.1029)
3	SL	SL51	Adhikhola Storage HEP	KAG	KaliGandak	821	180	81.4	157	678.7	368.48	336.5	238.7	Applying CL by NEA
4	SL	SL206	Madi Storage HEP	OTR	Rapti	1084	156	90	-	970	-	-	323	Study on-going under SL (LNO.1084)
5	GON	GON149	Kokhajor Storage HEP	OTR	Bagmati	-	116	120	-	460	223.65	257.512	166.894	Study on-going by DoED
6	GON	GON160	Naumure Storage Project	OTR	Rapti	-	220	156.36	169	524	360	1066.85	694.33	Ready for Construction
7	GON	GON165	Sunkoshi 3	SUN	SunKoshi	-	536	519.71	-	700	583.7	1220	555	Study on-going by DoED
8	GON	GON154	Lower Badigad Storage HEP	KAG	Badigad	-	380.3	232.6	191	-	-	995.9	505.5	Study on-going by DoED
9	ACL	ACL6	Uttarganga Storage	KAG	Badigad	8704	828	78.71	200	2885	1530	463	427.8	Applying CL by NEA
10	SL	SL246	Tamor Storage	TMR	Tamor	666	200	259	110	450	352	-	130.34	Study on-going under IBN
11	SL	SL119	Lower Seti (Tanahu) HEP	TRI	Seti	930	104	145.34	-	287	200	-	-	Study on-going under SL (LNO.930)
12	GON	GON164	Sunkoshi 2	SUN	SunKoshi	-	1116	1065.52	-	575	424.6	4550	2800	Study on-going by DoED
13	GON	GON148	Khimti Shivalaya Storage HPP	SUN	TamaKoshi	-	396.5	99	231	1920	1675	692	-	Study on-going by DoED
14	GON	GON175	Budhi Gandaki Storage	TRI	BudhiGanda	-	1200	672	263	540	323.3	4467	2226	Study on-going by DoED
15	CL	CL96	Tanahu HEP	TRI	Seti	157	140	128.1	140	415	289.2	295.14	166.82	Under Construction by THL
16	GON	GON145	Kaligandaki 2 Storage HEP	KAG	KaliGandak	-	500	355.36	-	360	220	3601.65	1544.76	Study on-going by DoED (considering decreasing 840-->520MW)
17	GON	GON171	Upper Jhimruk Storage Project	OTR	Rapti	-	-	-	-	-	-	-	-	PreFS by DoED (not attractive)
18	GON	GON163	SR06 Storage	KAR	SetiWest	-	309	300	162	520	400	548	378	Study on-going under IBN
19	GON	GON162	Sharada Babai Storage HPP	OTR	Babai	-	-	-	-	-	-	-	-	Study on-going by DoED
20	SL	SL108	Tamakoshi 3 HEP	SUN	TamaKoshi	918	880	304.8	96	940	606.5	157	137	Study on-going by TBI under SL (LNO.918), planning as PROR
21	GON	GON16	Bheri3 storage (BR3)	BER	Bheri	-	-	-	-	-	-	-	-	to be considered of Bheri-Babai(no.28) and BR4(no.22)
22	SL	SL55	Bheri 4 HEP	BER	Bheri	829	271.4	-	160	725	600	-	-	Study on-going by IPP under SL (LNO.829) Considering combining with Chera-1
23	GON	GON146	Kaligandaki Storage HEP	KAG	KaliGandak	-	844.3	479.88	217	750	-	2043	-	under study by DoED as multipurpose (520MW)
24	SL	SL31	Lantang Khola Reservoir HEP	TRI	Trishuli	780	310	26.28	-	-	-	-	-	Study on-going by IPP under SL (LNO.780)
25	GON	GON151	Lohare River Storage	KAR	Karnali	-	-	-	-	-	-	-	-	Based on Desk Study, not feasible
26	SL	SL124	Begnas Rupa Storage HEP	TRI	Seti	938	150	302	7	-	-	-	-	Study on-going by NEA under SL(LNO.938)
27	ACL	ACL10	Himchuli Dordi HEP	TRI	Marshandi	7467	57	6.62	4	550	352	-	1900	Study on-going by DoED
28	SL	SL175	Mugu Karnali Storage HEP	KAR	MuguKarna	1020	1670	654	287	1350	-	5265	4190	Study on-going by IPP
29	GON	GON136	Bharbung HEP	BER	Bheri	-	470.1	79.24	188	3438	2687	386.3	322.6	Study on-going by DoED
30	GON	GON174	BheriBabai Diversion Project	BER	Bheri	-	-	-	-	-	-	-	-	Under Construction by DoWRI
31	GON	GON147	Kankai Multipurpose Project	SUN	SunKoshi	-	61.2	102	85	195	122.8	1483.97	652.2	Study on-going by DoED
32	-	-	West Seti	KAR	SetiWest	-	-	-	-	-	-	-	-	Study on-going under IBN
33	-	-	Sunkoshi-1 Storage	SUN	SunKoshi	-	-	-	-	-	-	-	-	Study on-going by DoED
34	-	-	Bagmati Multipurpose	OTR	Bagmati	-	-	-	-	-	-	-	-	DoWRI
35	-	-	Karnali Diversion	KAR	Karnali	-	-	-	-	-	-	-	-	DoWRI, IMP2019
36	-	-	Kaligandaki Tinau Diversion	KAG	KaliGandak	-	-	-	-	-	-	-	-	DoWRI, IMP2019
37	-	-	Sunkoshi Marin Diversion	SUN	SunKoshi	-	-	-	-	-	-	-	-	DoWRI, IMP2019
38	-	-	Sunkoshi Kamala Diversion	SUN	SunKoshi	-	-	-	-	-	-	-	-	DoWRI, IMP2019
39	-	-	Tamor Morang Diversion	TMR	Tamor	-	-	-	-	-	-	-	-	DoWRI, IMP2019
40	-	-	Kaligandaki Nawalparasi Diversion	KAG	KaliGandak	-	-	-	-	-	-	-	-	DoWRI, IMP2019
41	-	-	Trishuli Shaktikhor Diversion	TRI	Trishuli	-	-	-	-	-	-	-	-	DoWRI, IMP2019
42	-	-	Karnali Chisapani	KAR	Karnali	-	10800	-	-	-	-	-	-	No progress. Impact to protected area
43	-	-	Pancheswor Multipurpose	MAH	Mahakali	-	6480	-	-	-	-	-	-	Indo-Nepal
44	-	-	Rupaligad Regulating	MAH	Mahakali	-	240	-	-	-	-	-	-	Indo-Nepal
45		-	Sapta Kosi Multipurpose	SUN	SaptaKosi	-	3489							Indo-Nepal

*PNO : Project No. including its status; CL : Construction License, SL: Survey License, ACL: Applying CL, ASL: Applying SL, GON: Government Reserved, PS: Operating

**River system; KAR: Karnali, BER: Bheri, KAG: KaliGandaki, TRI: Trishuli, SUN: SunKoshi, ARN: Arun, TMR: Tamor, MAH: Mahakari, OTR: Others

Source: JICA Study Team

4.3.2 Considerations on Integrated River System Development

This section presents the consideration on integrated river system development based on the information and discussions summarized in the above sections. The results is summarized in Table 4.3-2 below. Additionally, the focal points in consideration of integrated river development are shown below.

First, "1. Project Progress," indicates the general status of the project progress (Survey or Construction phase). There is little room for revising the plan for river systems or rivers in the "Construction" phase, while those in the "Study" phase have more flexibility.

"2. Issues on Cascade Operation," suggests topics related to cascade operation (to be confirmed: considerable issues or few: few issues). For river systems classified as "to be confirmed," it is recommended for GoN to confirm power discharge and other operation rules from the perspective of cascade operation.

Furthermore, after organizing the potential for plan revisions and issues from the perspective of cascade operation for each river system, "3. Rooms for Review Study on Integrated River System Development" classifies the river systems in four categories: Recommended for re-examination (Recommended), possibility for major plan revisions exists but is not clearly necessary (Possible), little room for revision (Small), and significantly dependent on the IMP2019 plan (Confirmation of IMP2019).

It is concluded that for future integrated river system development, the first step is to gather planning information, including water management and layout of the multipurpose projects in IMP2019. Additionally, as part of the examination towards optimal operation for integrated river system development, there is particularly room for re-examination in the Karnali River system (especially the main Karnali River), the Bheri River system, and the lower Kaligandaki River, including the Badigad River tributary. The lower Kaligandaki River, the Sunkoshi /Dudhkoshi River, Babai River, Rapti River, and Bagmati River, is greatly influenced by IMP2019, so these plans should be considered in future discussions.

Table 4.3-2 Summary of Project Progress and Considerations on Integrated River System Development

River System	River	Number of STO projects (tributary)	1. Project Progress	2. Issues on Cascade Operation	3. Rooms for Review Study on Integrated River System Development
Karnali	Karnali	1	Study	to be confirmed	**Recommended**
	SetiWest	2	Study	few	Possible
	Tila	-	Construction	few	Small
	HumlaKarnali	-	Study	few	Possible
Bheri	Bheri	2 + 1 (Lohare)	Study	to be confirmed	**Recommended**
	SanoBheri	1	Study	to be confirmed	**Recommended**
Kaligandaki	Kaligandaki	2 + 1 (Andhikhola)	US*: Construction DS*: Study	US* : to be confirmed DS*: to be confirmed	US* : small DS* : Confirmation of IMP2019
	Badigad	2	Study	to be confirmed	**Recommended**
	Modi	-	Construction	few	Small
	Myagdi	-	Construction	few	Small
Trishuli	Trishuli	0 + 1 (Lantang)	Construction	to be confirmed	Small
	Seti	2 + 1 (Begnas Rupa)	Construction/Study	to be confirmed	Possible
	Marsyangdi	-	Construction	to be confirmed	Small
	BudhiGandaki	1	Study	few	Small
Sun Koshi	Sunkoshi	3	Study	to be confirmed	Confirmation of IMP2019
	BhoteKoshi	-	Construction	to be confirmed	Small
	Dudhkoshi	1	Study/Construction	to be confirmed	Confirmation of IMP2019
	Likhu	-	Construction	to be confirmed	Small
	TamaKoshi/Khimiti	2 + 1 (Khimiti)	Study/Construction	few	Small
	Balephi	-	Construction	few	Small
Arun	Arun	-	Study/Construction	few	Small
Tamor	Tamor	1	Study/Construction	few	Small
Mahakari	Chamaliya	-	Study/Construction	few	Small
Others	Babai	2	Study/Construction	few	Confirmation of IMP2019
	Rapti	2 + 1 (Jhimruk)	Study	few	Confirmation of IMP2019
	Bagmati	0 + 1 (Kokhajor)	Study	few	Confirmation of IMP2019

* US: Upstream of the river, DS: Downstream of the river

<1. Project Progress >
If many of projects are under construction, there are few rooms revising the plan/design. On the other hand, if under study stage, there will be rooms for reviewing the projects
<2. Issues on Cascade Operation>
If many issues to be found (to be confirmed), it will be necessary to review some of projects when MoEWRI proceed development.
<3. Rooms for Review Study on Integrated River System Development>
Recommended: Reviewing study is recommended. / Possible: there are rooms for review / small: The rooms for reviewing study are small / Confirmation of IMP2019: it depends on IMP2019

Source: JICA Study Team

4.4 FINDINGS OF HYDROPOWER DEVELOPMENT FOR POWER GENERATION DEVELOPMENT PLANNING

4.4.1 Considerations on Development Capacity (MW)

Development capacity is categorized into a) Operation, b) Construction (Construction License, Application for Construction License), c) Survey (Survey License, Application for Survey License) and d) GoN as shown in the DoED Project List based on the progress. Table 4.4-1 shows the number of hydropower locations and development capacities at each category.

Table 4.4-1 Development Capacity and Numbers of Sites by Progress

Category	DoED Status	Subtotal		Total	
		Site	Installed Capacity (MW)	Site	Installed Capacity (MW)
a) Operation	(1)Existing Power Plants	109	1,210.5	109	1,210.5
b) Construction	(2)Construction License	241	8,335.5	269	10,752.3
	(3)Application for Construction License	28	2,416.8		
c) Survey	(4)Survey License	262	16,189.4	276	16,448.7
	(5)Application for Survey License	14	259.4		
d) GoN	(6)GoN Reserved Projects	175	11,658.7	175	11,658.7
			Total	**829**	**40,070.2**
		Peak Demand in 2040 (MW)			**10,352.2**

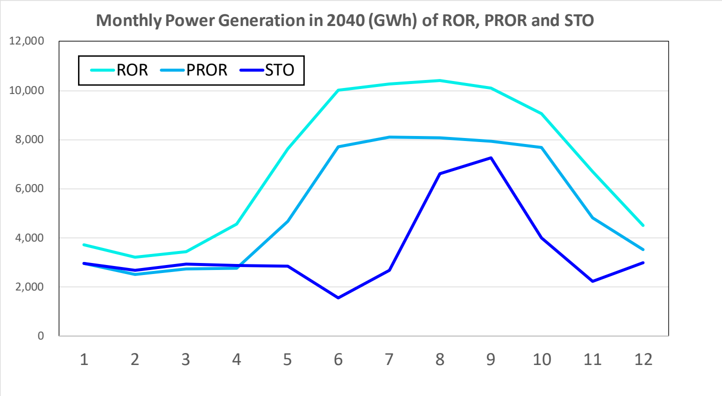
Source: JICA Study Team

The maximum power demand in 2040 shown in Chapter 3 is 11,510 MW. In terms of simple output alone, 11,962.8 MW aggregated from a) Operation + b) Construction exceeds the demand. However, it is necessary to check whether it is possible to supply electricity by the entire power system against the maximum power demand throughout the year including seasonal fluctuations in hydropower and reduced output during drought conditions.

In general, hydropower-centered power supply configurations tend to have a larger developed capacity relative to maximum demand to compensate for reduced output during the dry season. In Nepal, it is important to consider development capacity from the perspective of power exports in addition to domestic demand.

4.4.2 Assumptions of Monthly Power Generation for PGDP

The monthly power generation ratio of ROR, PROR and STO listed in the DoED Project List is estimated. Planned values of sites which information has already been collected as described in the previous section are directly applied. For sites for which no information is available, the monthly power generation is estimated based on the operating performance of the existing plants of NEA and the assumed values from available F/S and patterned as the operating conditions of the ROR, PROR and STO. The monthly power generation (GWh) for projects of the DoED Project List obtained is shown in Figure 4.4-1.



Type	Nos.	Capacity (MW)	Annual Power Generation (GWh)
ROR	737	14,869	83,633
PROR	65	12,831	63,494
STO	35	12,370	41,638
Total	837	40,070	188,765

Source: JICA Study Team

Figure 4.4-1 Monthly Power Generation of the DoED Project List

Development of a number of PROR and STO sites are planned in the DoED Project List mainly in Survey and GoN. Calculating the monthly power generation of these sites, power generation is composed of 38.3% by ROR, 29.8% by PROR and 31.9% by STO in February and it is possible to secure the sufficient regulation capacity in power system operation.

On the other hand, in terms of monthly power generation ratio, only 32.6% of electricity is generated in February compared to the highest one in August. It should be recognized that there are still seasonal differences in the amount of power generation during the wet and dry seasons even with the utilization of PROR and STO.

These seasonal fluctuations in the amount of power generation (GWh) are a characteristic of hydropower as a power source and similar trends are observed in other countries. In tropical climates with rainfall throughout the year such as Indonesia, the differences are relatively small but in countries such as Myanmar and Laos, where the dry season is severe, the amount of power generation may drop to 10% in some areas. It should be noted that in Nepal, although there is little rainfall in the dry season, the water retention capacity of glaciers in mountainous areas mitigate the decline in flow and the seasonal variations are not extremely large as in other countries.

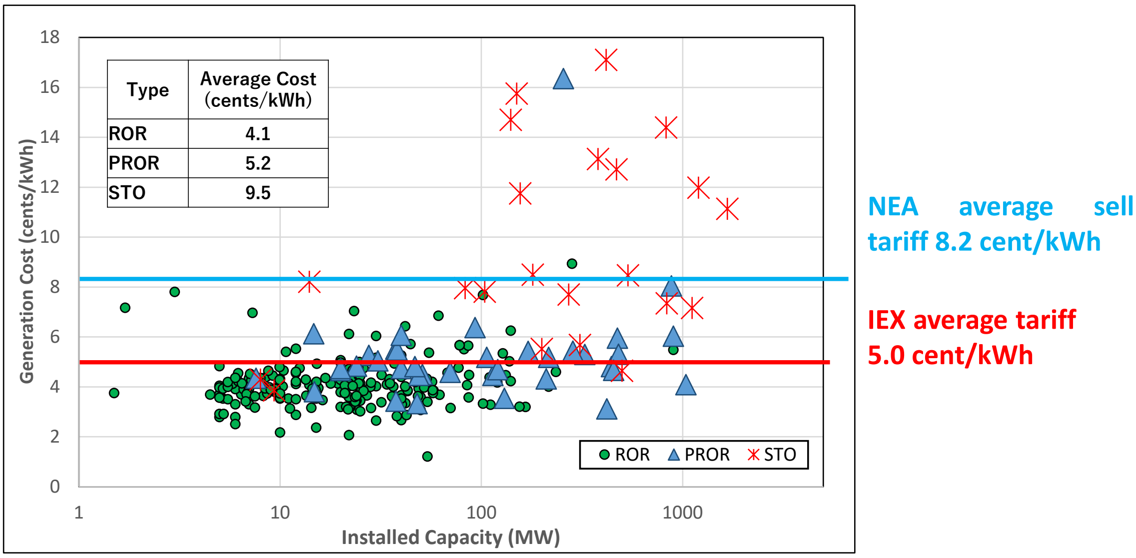
In the future, it will be important to reduce these seasonal fluctuations through the utilization of reservoir operations and the promotion of cascade operations in each river system. On the other hand, these seasonal fluctuations themselves derive from the nature of hydropower characteristics and it is not realistic to completely eliminate them. Therefore, when considering PGDP, it is necessary to accept these seasonal fluctuations in hydropower.

Hydropower output and generation varies considerably depending on the annual water supply and drought. In addition to seasonal fluctuations, it is also necessary to consider annual variation of water availability. From the perspective of PGDP, it is important to take drought years into account which remarkably reduce supply capacity and reliability in Nepal, where the power is mainly supplied by hydropower. It is necessary to set the development capacity to ensure a stable supply of electricity even in drought years. In this Study, the design and actual annual power generation for each NEA power plants for the past 12 years (FY2067/2068: 2011 - FY2078/79: 2022) are analyzed. As a result, it is confirmed that 20% of power generation decrease in the drought year. The impact of these drought years will also be taken into account in the PGDP.

4.4.3 Considerations on Generation Cost

The generation cost for the DoED Project List is estimated in this Section. The feasibility of domestic supply and power export is also considered from the aspect of cost. In this Study, IEA LCOE (Levelised Cost of Electricity) is used as an assessment method for the economic viability of generation cost. This method estimates the cost of power generation (cents/kWh) based on capital investment costs (USD/kW), maintenance costs (USD/kW-year) and plant factor (%). LCOE is widely used as an evaluation method for each power source. On the other hand, it should be noted that kW value of each power source and regulation capacity such as ancillary services are not reflected in LCOE. Therefore PROR and STO are at a relative disadvantage due to the simple kWh value assessment.

An average LCOE of 4.0 cents/kWh is obtained for ROR (187 sites), 5.0 cents/kWh for PROR (25 sites) and 9.2 cents/kWh for STO (16 sites).



Source: JICA Study Team

Figure 4.4-2 Distribution Map of LCOE and Installed Capacity for the DoED Project List

Distribution map of LCOE and installed capacity for the DoED Project List is shown in Figure 4.4-2. It also includes the relation with NEA wholesale price of 8.2 cents/kWh for consumers in 2021 and the average wholesale price of 5.0 cents in 2021 for the Indian electricity market IEX

As these figures show, the wholesale price of IEX is above most of LCOE for the DoED Project List. Actually, power exports through IEX have already started since 2022 and it is assumed that there is potential for new hydropower projects in Nepal to wholesale power to IEX, although overheads such as wheeling charges of transmission lines need to be taken into account. Regarding some PROR and STO projects, their LCOE are most likely to be above NEA 2021 wholesale price for consumers. However, kW values and regulation capacity such as ancillary services also need to be assessed for these power sources.

As discussed in the previous section, power export to neighboring countries such as India and Bangladesh need to be considered in addition to domestic demand. In particular, it is envisaged that measures to maximize the value of hydropower and improve wholesale economics, such as improving day and year round operation in power generation as regulating capacity, will also be important.

NEA's wholesale price for domestic consumers is average 7.36 cents/kWh (9.52 NRp/kWh), while the average wholesale price in the Indian power market (IEX) is 6.64 cents/kWh (8.86 NRp/kWh) in 2023. The IEX price shows an increasing trend with an exchange rate of 1USD = 130NRp. On the other hand, due to recent inflation trends, generation costs have been rising since 2021. Assuming an inflation rate of 25% from 2021 to 2023, the LCOE for each power source is 5.0 cents/kWh for ROR, 6.25 cents/kWh for PROR, and 11.5 cents/kWh for STO. It shall be noted that this price increase does not significantly affect the overall argument.

5. POWER TRADE BETWEEN NEPAL AND NEIGHBORING COUNTRIES

5.1 CURRENT STATUS OF POWER TRADE WITH NEIGHBOURING COUNTRIES AND DEMAND SUPPLY OUTLOOK

Due to hydropower development in Nepal, surplus power is expected to increase in future. Therefore, it is extremely important for the development of Nepal's future power system to smoothly implement power trade, especially in the export of electricity during the rainy season. In addition, the current mechanism with the NEA as a single buyer is maintained, the NEA will be at risk of having a large amount of surplus power. In this chapter, the current status of power trade with neighboring countries and the future power supply and demand outlook of neighboring countries are reviewed.

5.1.1 Current Status of Power Trade in Nepal

(1) Current status and development plan of interconnection lines

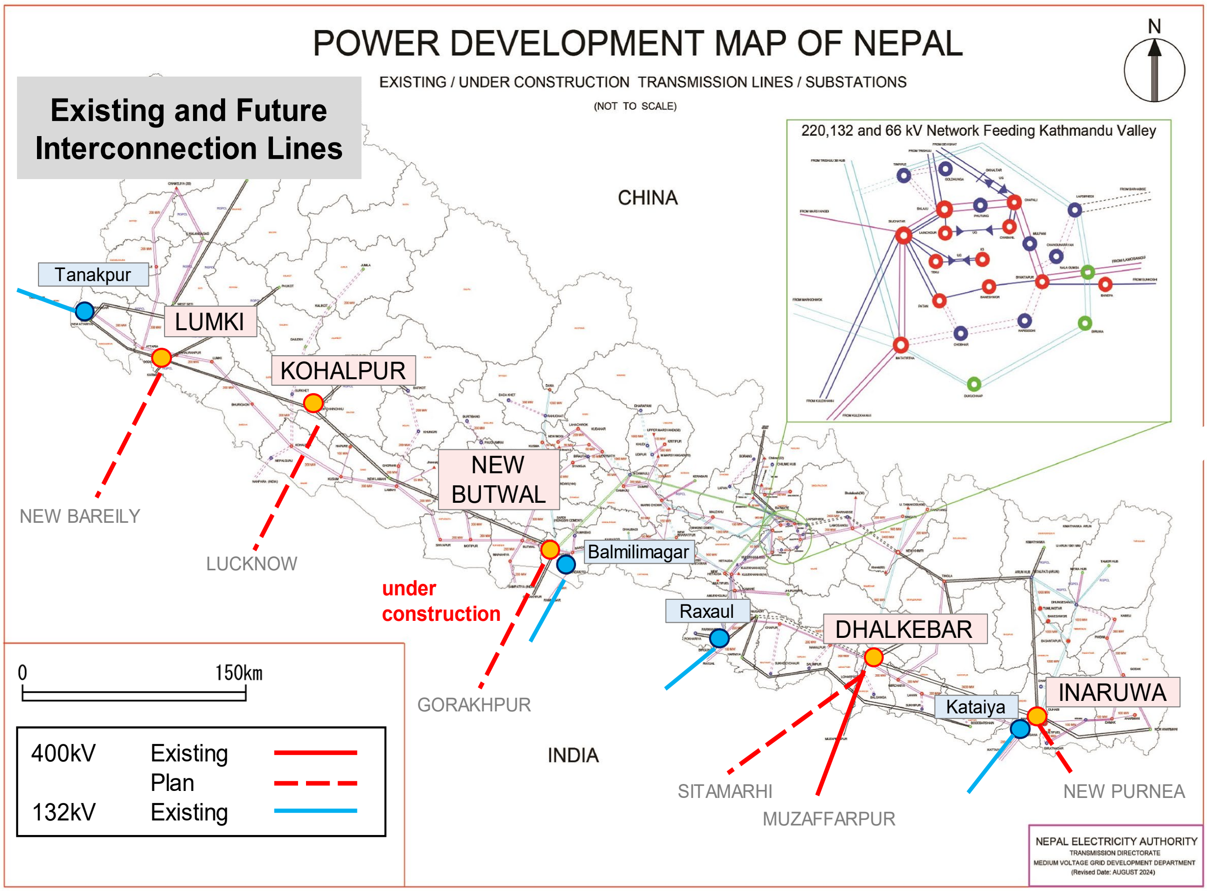
Nepal has been exchanging electricity with India, and there are international interconnection lines between Nepal and India such as 400kV Dhalkebar – Muzaffarpur transmission line, 132kV and 33kV transmission lines. 400kV Dhalkebar – Muzaffarpur transmission line started to be operated as a 220kV transmission line from 2018 and was raised to 400kV as the voltage level in 2020. Table 5.1-1 lists the existing and planned interconnection lines, and Figure 5.1-1 shows the 400 kV and 132 kV international interconnection lines.

Table 5.1-1 International Interconnection Lines between Nepal and India (400kV, 132kV, 33kV)

Voltage (kV)	Cross Border Points / Lines	Trade type	Operation year	Length(km) (Nepal side)	Length(km) (India side)	Import volume (GWh)[*4]	Export volume (GWh)[*4]	Capacity (MW)
AC 33[*2]	Siraha - Jaynagar	PEC mechanism	Under operation	-		42.6	0.0	-
	Birgunj - Raxaul							
	Sursant (Jaleshwor) -Sitamadi							
	Biratnagar - Kataiya							
	Nepalgunj-Nanpara							
AC 132	Kushaha - Kataiya	PEC mechanism and IEX	Under operation	13	13[*3]	116.6	1.5	200
	Parwanipur - Raxaul			16	3[*3]	128.1	19.5	100
	Gandaki - Ramnagar			-		120.4	11.3	100
	Mahendranagar - Tanakpur	G to G trade and IEX		12	4	329.1	0.0	100
AC 400	Dhalkebar - Muzaffarpur	G to G trade and IEX	2020	78	62	806.4	0.1	1250
	New Butwal - Gorakhpur	-	Under construction	15	120	-		2500
	Lumki - Bareily	-	2030	42	161	-		3000
	Inaruwa - Purnea	-	2030	49	59	-		1800
	Dhalkebar-Sitamarhi	-	2035	-		-		-
	Kohalpur-Lucknow	-	2040	-		-		-
	Kohalpur-Lucknow	-	2040	-		-		-

※1 Unavailable data is shown in "-". ※2 Currently not used ※3 Measured from a map ※4 FY2021/2022 results ※5 FY2020/2021 results

Source: Annual report 2021/2022, Nepal Electricity Authority / JICA Study Team



Source: A year Book-Fiscal Year 2022/2023, Transmission/Project Management Directorate, NEA

Figure 5.1-1 Map of Existing International Interconnection Lines between Nepal and India

There are plans to construct five (5) 400kV international interconnection lines between Nepal and India for 2040. Especially, Nepal and Indian agreed on 400kV New Butwal – Gorakhpur international interconnection line, which is planned to start operating in 2025, starting to be constructed by establishing a new company in a ministerial-level meeting held in the beginning of 2022.

New interconnection lines for 2030 include the Lumki (Dodohara)-Bareily interconnection line, which will transmit hydroelectric power from the western Karnali system; the Inaruwa-Purnea interconnection line, which will transmit power from the Arun and Tamor systems; and the Dhalkebar- Sitamarhi interconnection line, which transmits hydroelectric power from the Arun and Tamor systems.

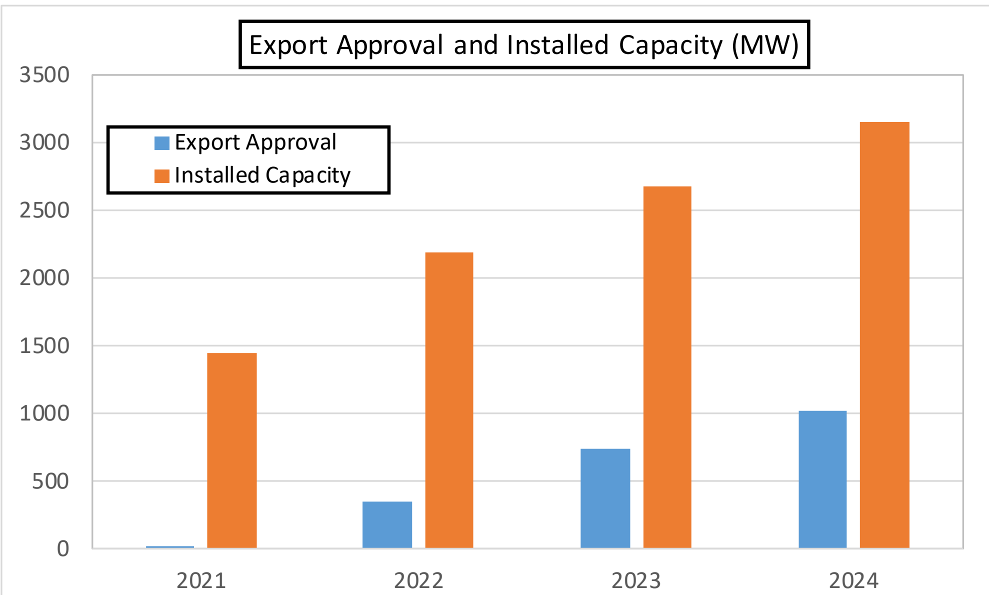
(2) Hydropower plants for export.

Power exports to India require export licenses on a plant-by-plant basis, starting in 2021 with the Devighat (14.6 MW) and Chilime (21.4 MW) hydroelectric power plants, totaling 36 MW. The list of hydropower plants for export as at October 2024 and the export permitted capacity for each year are shown in Table 5.1-2 and Figure 5.1-2 respectively.

Table 5.1-2 List of approved hydropower plants for export as at October 2024

Starting Year of Export	Time Period for Export	Project Name	Capacity (MW)	Duration	Remarks
2021	All Time	Devighat Hydropower Project	14.6	Annual Update	to IEX
2022		Kaligandaki ‘A’ Hydropower Project	140.0		
2022		Likhu IV Hydropower Project	51.0		
2022		Marsyangdi Hydropower Project	67.0		
2022		Middle Marsyangdi Hydropower Project	68.0		
2023		Kabeli B-1 Hydro Power Project	24.3		
2023		Lower Modi Hydro Power Project	19.4		
2023		Solu Hydropower Project	22.8		
2023		Upper Balephi A	34.9		
2023		Upper Chameliya	37.3		
2023		Upper Dordi A	24.3		
2023		Upper Kalangagad Hydro Power Project	32.7		
2024		Dordi 1	11.6		
2024		Down Piluwa	10.0		
2024		Dudhkunda	11.6		
2024		Gandak	14.6		
2024		Mathilo Solu	19.2		
2024		Maya Khola	14.5		
2024		Modi	14.4		
2024		Tallo Khare	10.7		
2024		Uppalo Khimti	11.6		
2024		Upper Khimti II	6.8		
2023	June to October	Dordi Khola	26.2	5 years (2023 - 2027)	Converted from IEX to Haryana Discom
2023		Solu Khola (Dudhkoshi) Hydro Power Project	83.4		Converted from IEX to Haryana Discom
2023		Mistri Khola	40.7		to Haryana Dicom
2023		Super Madi	42.7		to Haryana Dicom
2023		Upper Chaku'A'	7.0		to Haryana Dicom
2024		Likhu 1	75.0		to Haryana Dicom
2024		Likhu 2	50.9		to Haryana Dicom
2024	June to November	Chilime Hydropower Project	21.4	5 years (2024 - 2028)	Started with IEX in 2021 and converted to Bangladesh trade in 2024
2024		Trishuli Hydropower Project	23.3		Started with IEX in 2023 and converted to Bangladesh trade in 2024
		Total	**1,031.9**		

Source: JICA Study Team by CEA documents



Source: JICA Study Team by NEA documents

Figure 5.1-2 Approved export capacity to India and installed capacity in Nepal in 2021-2024

The hydropower plant capacity licensed for export to India has expanded significantly since 2021, growing by more than 300 MW/year, 362 MW in 2022, 758 MW in 2023 and 1,032 MW in 2024 respectively.

There are significant day-to-day changes, such as the change of export destination for Chilime Hydro and Trishuli Hydro from IEX to Bangladesh following the start of electricity exports to Bangladesh. It should be noted that this table is current as of October 2024.

The power export agreement and the trade type is summarized in Table 5.1-3 and the interconnection lines and hydropower plants related to power exports is listed in Table 5.1-4. As of October 2024, the capacity of power plants approved to export electricity to India is approximately 1,000 MW. In January 2024, Nepal and India agreed to trade up to 10,000 MW by 2035 for future power exports, and the current trading volume between India and Nepal is equivalent to about 10% of the total trading volume agreed upon.

Table 5.1-3 Power export agreements and trade type

Agreement				Trade Type
Country	Date	Content	Capacity	
India	1992	Nepal - India Power Exchange Committee (PEC) was constituted for consultation of power trade. This mechanism has been used mainly for imports since the past. Prices and trading volumes are determined annually by the committee.	-	PEC Mechanism
	2014 October	The contract is for power trading between Nepal and India for a period of 25 years. After 25 years, the contract will be automatically renewed every 10 years if there are no objections from either party.	-	G to G Trade
	2021 October	Power exports through IEX has started in October 2021. The list of power plants for this trade will be renewed annually.	36.0MW (2021) 362.0MW (2022) 557.7MW (2023) 661.3MW (2024)	IEX
	2023 September	Export to the Indian state of Haryana during Nepal's rainy season from June 1 to October 31 for five years starting in 2023.	109.6MW (2023) 325.9MW (2024)	G to G Trade Haryana Discom
Bangladesh	2024 October	For five years starting in 2024, 40 MW will be exported to Bangladesh via India. This will take place between 15 June and 15 November, the rainy season in Nepal.	40.0MW	G to G Trade Bangladesh

Source: JICA Study Team by NEA and CEA documents

Table 5.1-4 The trades related to export and interconnection lines and hydropower plants for export (MW)

Country/Trade			2021	2022	2023	2024
India	IEX	TL	400kV Dhalkebar - Muzaffarpur	400kV Dhalkebar - Muzaffarpur	400kV Dhalkebar - Muzaffarpur	400kV Dhalkebar - Muzaffarpur 132kV Kushaha - Kataiya 132kV Parwanipur - Raxaul 132kV Gandaki Ramnagar 132kV Mahendranagar - Tanakpur
India	IEX	HPP (MW)	Chilime 21.4 Devighat 14.6	Chilime 21.4 Devighat 14.6 Kaligandaki 'A' 140.0 Likhu IV 51.0 Marsyangdi 67.0 Middle Marsyangdi 68.0	Chilime 21.4 Devighat 14.6 Kaligandaki 'A' 140.0 Likhu IV 51.0 Marsyangdi 67.0 Middle Marsyangdi 68.0 Kabeli B-1 24.2 Lower Modi 19.4 Solu 22.8 Upper Balephi A 34.9 Upper Chameliya 37.3 Upper Dordi A 24.2 Upper Kalangagad 32.7	Devighat 14.6 Kaligandaki 'A' 140.0 Likhu IV 51.0 Marsyangdi 67.0 Middle Marsyangdi 68.0 Kabeli B-1 24.2 Lower Modi 19.4 Solu 22.8 Upper Balephi A 34.9 Upper Chameliya 37.3 Upper Dordi A 24.2 Upper Kalangagad 32.7 Dordi 1 11.6 Down Piluwa 9.9 Dudhkunda 11.6 Gandak 14.6 Mathilo Solu 19.2 Maya Khola 14.4 Modi 14.4 Tallo Khare 10.6 Uppalo Khimti 11.6 Upper Khimti II 6.8
India	IEX		**Subtotal 36.0**	**362.0**	**557.7**	**661.3**
India	G to G Trade Haryana Discom	TL			400kV Dhalkebar - Muzaffarpur	400kV Dhalkebar - Muzaffarpur
India	G to G Trade Haryana Discom	HPP (MW)			Dordi Khola 26.1 Solu Khola (Dudhkoshi) 83.4	Dordi Khola 26.1 Solu Khola (Dudhkosh 83.4 Mistri Khola 40.7 Super Madi 42.6 Upper Chaku'A' 6.9 Likhu 1 75.0 Likhu 2 50.8
India	G to G Trade Haryana Discom		**Subtotal**		**109.6**	**325.9**
Bangladesh	Bangladesh/ G to G Trade	TL				400kV Dhalkebar - Muzaffarpur
Bangladesh	Bangladesh/ G to G Trade	HPP (MW)				Chilime 21.4 Trishuli 23.2
Bangladesh	Bangladesh/ G to G Trade		**Subtotal**			**40.0**
Total		TL	**400kV Dhalkebar - Muzaffarpur**	**400kV Dhalkebar - Muzaffarpur**	**400kV Dhalkebar - Muzaffarpur**	**400kV Dhalkebar - Muzaffarpur 132kV Kushaha - Kataiya 132kV Parwanipur - Raxaul 132kV Gandaki Ramnagar 132kV Mahendranagar - Tanakpur**
Total		HPP (MW)	**36.0**	**362.0**	**667.3**	**1,027.2**

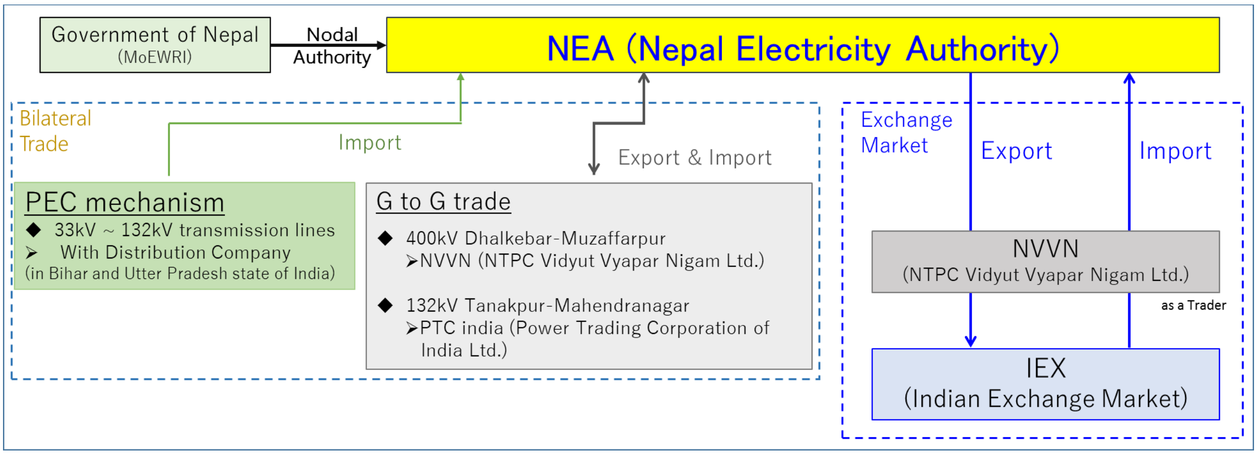
Source: JICA Study Team by NEA and CEA documents

5.1.2 Power Trade Scheme

Most of Nepal's power trades have been with India, with only one day of transactions with Bangladesh, on November, 2024. Therefore, this section describes in detail the scheme of Nepal's current power trade with India.

In Nepal, NEA is designated by GoN as "Nodal Authority" and conducts the power trade with India. The Power Trade between Nepal and India can be divided into two categories in broad strokes, and one is Bilateral method and the other is a transaction through IEX (Detail about IEX is provided in section 5.1.2 (2)). Bilateral trade has PEC (Power Exchange Committee) mechanism which is a power trade with distribution companies in India and G to G trade executed under

"Guidelines for Import Export Cross Border of Electricity 2018 India" formulated in 2018. Its image is shown in Figure 5.1-3.



Source: JICA Study Team

Figure 5.1-3 Relationship of Power Trade between Nepal and India

All power plants exporting to India, regardless of the type of trade, are required to obtain permission from India. The permission will be conducted by CEA in accordance with Guidelines for Import Export Cross Border of Electricity 2018 and Procedure for Approval and Facilitating Import/Export (Cross Border) of Electricity.

For the power plants to be traded on the IEX, NEA submits an application every year, which is approved by CEA. For bilateral trade, once permission is obtained, no annual application is required for the duration of the contract. With regard to the seasons when power exports are allowed, power plants permitted to export power through IEX are allowed to export throughout the year, while those to Haryana and Bangladesh are set to export only during the rainy season.

For the trade that started in November 2024 with Bangladesh, it is a G to G trade, but the scheme for further trades with Bangladesh for the future has not been decided. NEA has an outlook that the first step will be to expand G to G trade, based on the history of expanding trade with India. Also, there are no decisions yet regarding trading with China. So far the trade would start as a G to G trade scheme same as in India and Bangladesh.

Main information of the trade is summarized as below.

(1) Bilateral Trade

1) PEC mechanism

- ➢ This is one of the mechanisms for power trading between Nepal and India.
- ➢ The meeting for this mechanism is held once a year. The amount of power trade and its tariff is mainly discussed. This mechanism is applied to power trading in areas remote from the 400kV interconnection point with India.

2) G to G Trade

- ➢ G to G Trade is based on the agreement between the governments of Nepal and India on the volume and price of the trade, and the exchange of electricity within the agreed volume. In the past, it was used for imports from India to compensate for Nepal's electricity shortage,

but now it is used for export to India.
The 400 kV Dhalkebar - Muzaffarpur transmission line is traded through NVVN[51] (NTPC Vidyut Vyapar Nigam Ltd).

- The 132kV Tanakpur – Mahendranagar transmission line is traded through PTCL[52] (PTC India Limited) and the current trading capacity is 75 MW. These trading capacities are fixed on a monthly basis and updated annually. Both NVVN and PTCL are recognized trading companies by the Indian government. The difference between NVVN and PTCL is that NVVN has both rights of a trader and a Nodal Agency but PTCL has only the right of a trader. Only Nodal Agency can get involved in a process of settlement of power trade, so PTCL cannot do that. For example, in case that a default on the contract etc. happens on power trade, the penalty etc. are dealt with through NVVN.

(2) IEX

There are three electricity markets in India: IEX, HPX India (Hindustan Power Exchange), and PXIL (Power Exchange India Limited). Among them, IEX is currently used by NEA for trading.

NEA started to export power generated by the Kaligandaki-A hydropower plant and Marsyangdi hydropower plant. The permitted trading volume is frequently updated according to the development of power sources and the supply and demand situation in India, and at present, exports to India are set at 661 MW and imports from India at 0 MW, as shown in Table 5.1-2, and electricity through IEX Imports are not possible (as of 2024).

Power imports from India are conducted through Bilateral trade. On the other hand, since Nepal and India are connected to the grid through AC transmission line, when there is a shortage of supply relative to demand in Nepal, imports are unintentionally made, which is subject to the Deviation Settlement Mechanism (DSM). (Details of the DSM are described below.)

Future increases in the maximum trading volume are being coordinated with the Indian government. On the other hand, it is difficult to make a stable outlook for the short-term trading volume. Trading on the IEX includes the "Day-Ahead Market," the "Term Ahead Market," and the "Real Time Market. There is also a market that focuses on renewable energy such as solar and wind power (Green Market). The largest volume of trade is in the Day-Ahead Market.

Table 5.1-5 Trading period and target power sources per market

Market	Period	Power source
Day Ahead	Tomorrow	All power sources
Real Time	On that day	
Term Ahead	Up to 90 days	
Green Day Ahead	Tomorrow	Renewable energy[53]
Green Term Ahead	Up to 90 days	

Source: JICA Study Team

As shown in Table 5.1-5, IEX has five main markets. The following is a summary of transactions in the Day-Ahead Market and the Green Day-Ahead Market, the two markets with the highest

[51] NVVN was established in 2002 to expand power trading in India. NVVN has also been designated as the central agency for cross-border power trading within India as well as with Bangladesh, Bhutan, and Nepal.
[52] PTCL was established in 1999 with the objective of power trading to achieve economic efficiency and security of supply and to expand power trading in India. It also plays a role in the development of electricity markets within India and in South Asia.
[53] Renewable energy in this context refers to solar, wind, biomass, and hydroelectric power generation.

transaction volume.

1) Day-Ahead Market

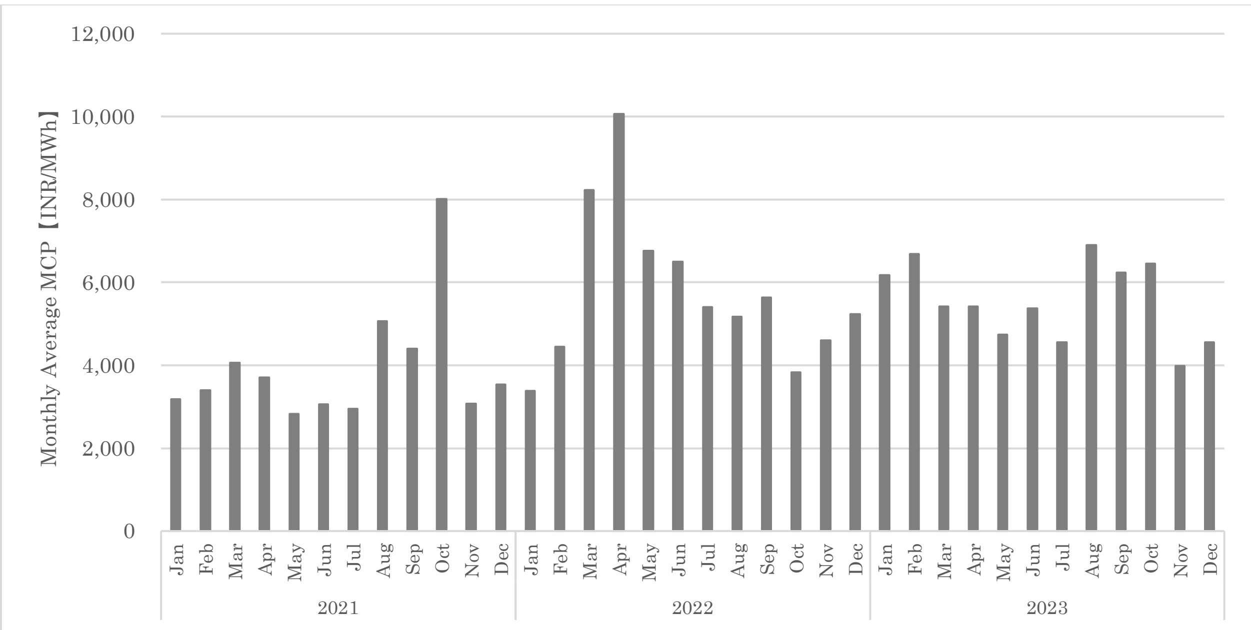
The mechanism is basically the same as in the Japan Electric Power Exchange (JEPX), where buyers and sellers bid blindly without disclosing the other party's bidding trends, and the Market Clearing Price (MCP) and the Market Clearing Volume (MCV) are determined at the intersection of the supply-demand curve.

2) Green Day-Ahead Market

The main market for renewable energy trading on IEX is the Green Day-Ahead Market. This market has been in operation since October 2021 amid the global trend of achieving decarbonization, India is also formulating plans to reduce greenhouse gases. As a measure to promote the introduction of renewable energy, it requires power distribution companies to procure a certain percentage of renewable energy. Therefore, it is expected that the trading volume in this market will increase in the future.

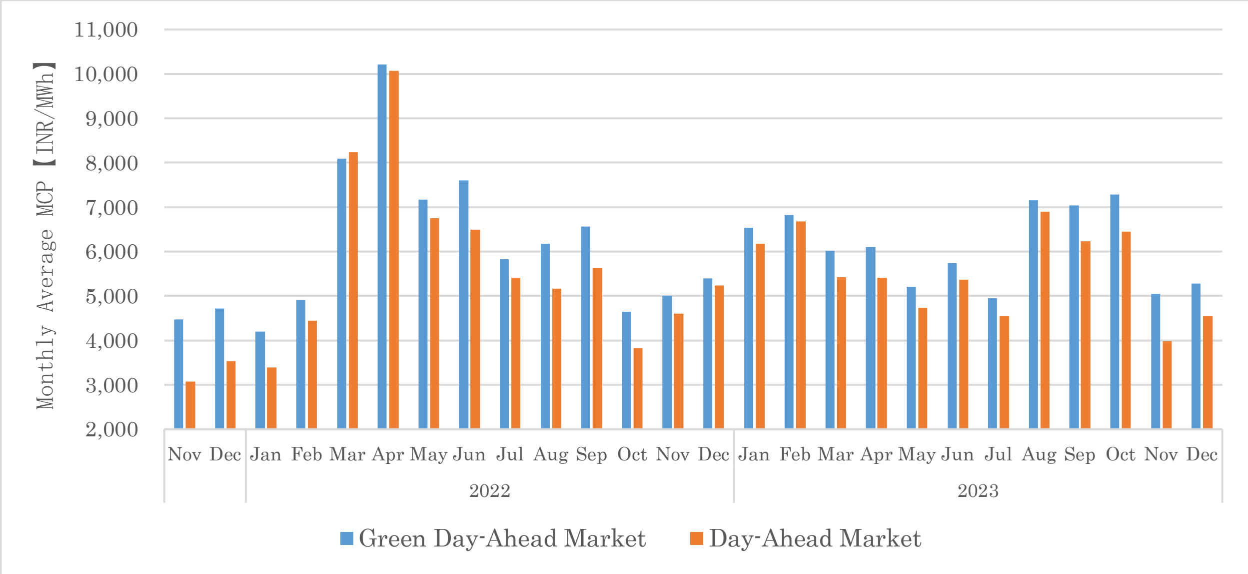
The results of comparing MCP and MCV with the trading performance on the Day-Ahead Market from November 2021 to December 2023 are shown in Figure 5.1-4 and Figure 5.1-5.

The amount of electricity traded on the Green Day-Ahead Market during the period from November 2021 to December 2023 was approximately 5.4% of the amount traded on the regular Day-Ahead Market. Regarding prices, Green Day-Ahead Market is trading at about 10% higher prices.



Source: JICA Study Team from IEX HP

Figure 5.1-4 Monthly Average of IEX Price (MCP) comparison (INR/MWh)



Source: JICA Study Team from IEX HP

Figure 5.1-5 Monthly Average of IEX Volume (MCV) comparison (MWh)

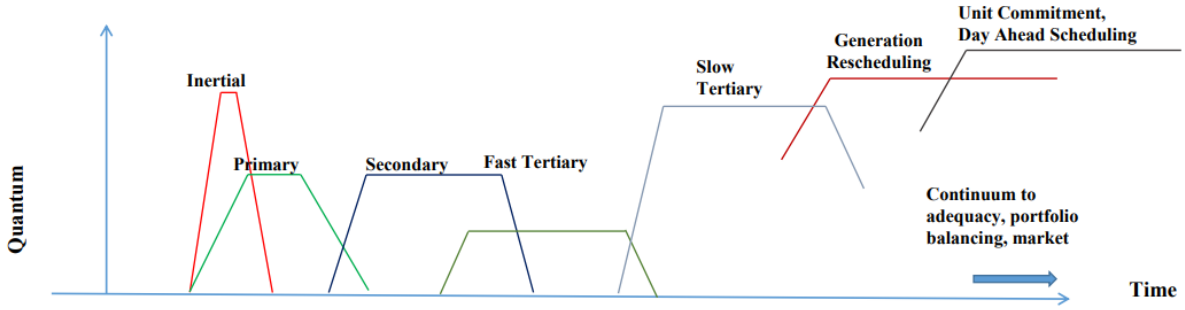
(3) Deviation Settlement Mechanism (DSM)

DSM is a system that is applied in the electricity market when the contracted quantity does not match the actual volume traded.

The DSM is applied either nationwide system managed by Central Electricity Regulatory Commission (CERC), or states level system managed by each State Electricity Regulatory Commission (SERC). Generators that trade power with interstates and supply power across states are subject to DSM system by CERC, and generators that supply power in a state and distribution companies are subject to DSM systems by SERC. Therefore, Nepal is applied to DSM by CERC regarding exporting power to India. For each state's DSM system, the basic policy on how to set prices and penalties is in accordance with CERC.

(4) Efforts to establish an Ancillary Market

India is preparing for an ancillary market. Figure 5.1-6 shows a schematic diagram of the design of the Ancillary Market in India. For example, Secondary service requires generation within 30 seconds to 5 minutes of command, and the plan is to secure about 4,000 MW. The Fast Tertiary service requires power generation within 5 to 30 minutes of command, and is planned to secure approximately 1,000 MW. In the future, hydropower plants in Nepal are also expected to participate in the Ancillary Market.



Response → Attribute ↓	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling/Market	Unit Commitment
Time	First few secs	Few sec - 5 min	30 s – 15 min	5 - 30 min	> 15 – 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 4000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC / RLDC	NLDC	NLDC / SLDC	RLDC / SLDC	RLDC / SLDC
Manual / Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralize d	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	Roadmap on Reserves	Ancillary Regulations	Ancillary Regulations	IEGC	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation	Existing	Partly Existing	Yet to start	Yet to start	Existing	Existing	Existing

Source: Report of Expert Group to review and suggest measures for bringing power system operation closer to National Reference Frequency, CERC, Nov 2017)

Figure 5.1-6 Overview of the Ancillary Market in India

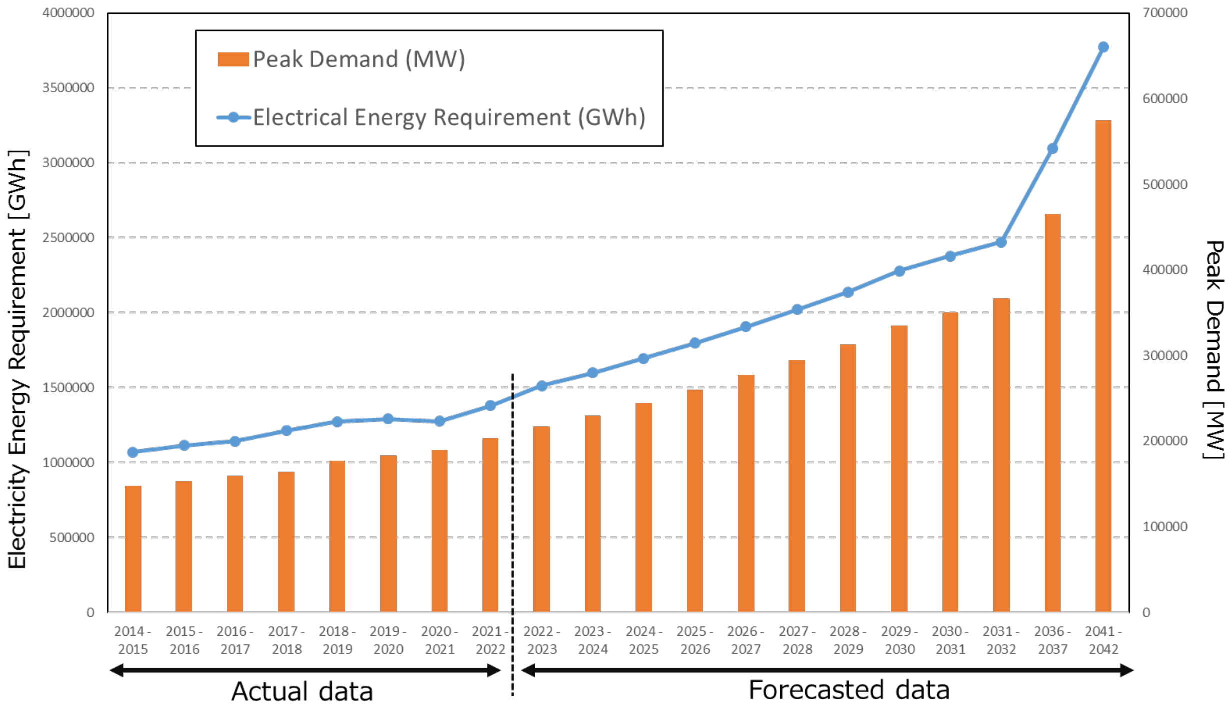
5.2 OUTLOOK FOR POWER TRADE IN NEPAL

5.2.1 Electricity Supply and Demand Outlook in India

(1) Electricity Demand Forecast

The result of the generated amount including T&D losses in India is approx. 1,210TWh in FY2018, approx. 1,300TWh in FY2019 and approx. 1,280TWh in FY2020, which basically shows that the amount has increased (It decreased a little in FY2020 due to the impact of COVID-19). Also, peak demand in India has increased; approx. 177GW in FY2018, approx. 180GW in FY2019 and approx. 190GW in FY2020.

CEA made a report, 20th Electric Power Survey in November 2022, and the report has the power demand forecast for every year to 2041/2042. Figure 5.2-1 shows the actual and forecasted data of Energy Requirement including T&D losses and of Peak Demand. It is forecasted that the peak demand reaches 574GW and the electricity energy requirement does 3,776TWh at 2041/2042.



Source: JICA Study Team from 20th Electric Power Survey

Figure 5.2-1 Actual and forecasted data of Energy Requirement including T&D losses and of Peak Demand

(2) Future Energy Policy

Based on the Electricity Act formulated in 2003, Central Electricity Authority (CEA) makes the National Energy Plan. They also made ten-year National Electricity Plan Volume I (Generation).

At the 21st Conference of the Parties (COP21) to the United Nations Framework Convention on Climate Change (UNFCCC), emission of greenhouse gas will decrease by 33 to 35% to GDP ratio compared with 2005 by 2030, and Power Sector is also subject to the policy. Based on the policy, the National Electricity Plan says that aging thermal power plants that cannot follow the environment regulation are going to be abolished by 46.29GW from 2022 to 2027. Table 5.2-1 shows the power development plans in India through 2032. India will not abolish coal-thermal power plants completely and will install new ones by about 35GW by 2032. Although India consider reducing CO2 emission, they think that coal is a significant energy source by 2040 at least.

Table 5.2-1 Power development plan by power source in India

	2022～2027	2027～2032
Thermal	approx. 26GW	approx. 25GW
Nuclear	approx. 6GW	approx. 7GW
Hydro	approx. 11GW	approx. 10GW
Solar	approx. 132GW	approx. 179GW
Wind	approx. 33GW	approx. 49GW
Biomass	approx. 2GW	approx. 3GW
Pumped storage	approx. 3GW	approx. 19GW
total	approx. 212GW	approx. 292GW

Source: JICA Study Team from REPORT ON TWENTIETH ELECTRIC POWER SURVEY OF INDIA (VOLUME-I)

The Indian government has introduced a policy for certain consumers, including distribution companies, to procure a certain percentage of electricity from renewable energy sources, and the percentage is shown in Table 5.2-2. In addition, hydropower plants only covered electricity from within India, but from April 2024, it has been decided that hydropower plant from outside India will also be covered by this system.

Table 5.2-2 Renewable energy procurement ratio required for distribution companies in India

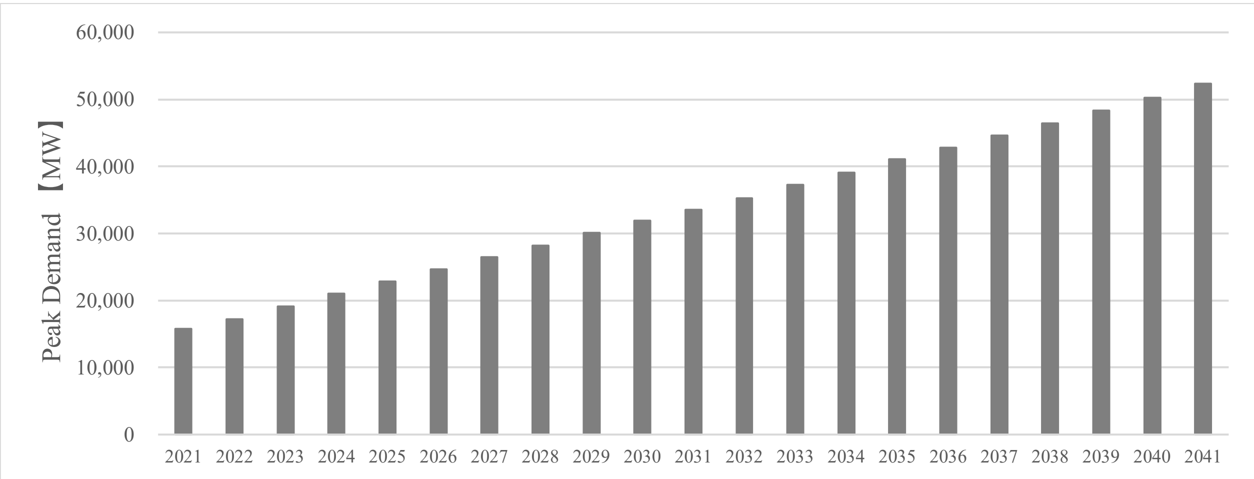
Year	Wind Renewable Energy	Hydro Renewable Energy	Distributed Renewable Energy	Other Renewable Energy	Total Renewable Energy
2024-25	0.67%	0.38%	1.50%	27.35%	29.91%
2025-26	1.45%	1.22%	2.10%	28.24%	33.01%
2026-27	1.97%	1.34%	2.70%	29.94%	35.95%
2027-28	2.45%	1.42%	3.30%	31.64%	38.81%
2028-29	2.95%	1.42%	3.90%	33.10%	41.36%
2029-30	3.48%	1.33%	4.50%	34.02%	43.33%

Source: JICA Study Team from Ministry of Power HP

5.2.2 Electricity Supply and Demand Outlook in Bangladesh

(1) Electricity Demand Forecast

The Integrated Energy and Power Master Plan (IEPMP) 2023 was developed by the Government of Bangladesh. In the plan, peak demand projections to 2041 are shown in Figure 5.2-2. Peak demand is expected to increase by 2.5 times by 2041. It is forecasted that the peak demand reaches 52GW at 2041.



Source: JICA Study Team from Integrated Energy and Power Maser Plan 2023

Figure 5.2-2 Peak Demand Forecast in Bangladesh

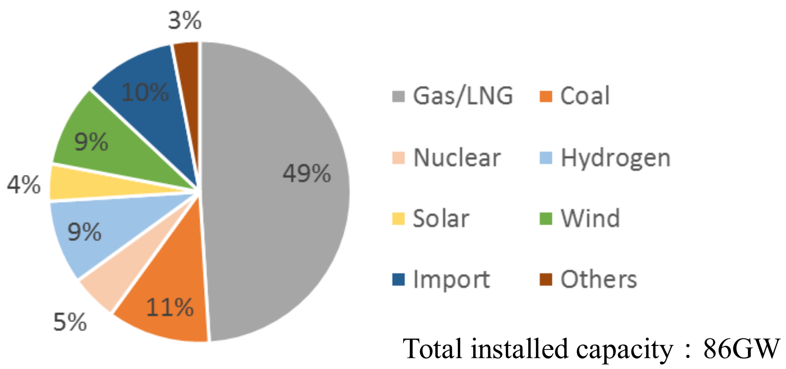
(2) Future Energy Policy

Government of Bangladesh published "8th five-year plan" in December, 2020. It says that Power Sector has been the most significant, which was also stated in "7th five-year plan". Also, it says that the strategy for Power Sector is mentioned, whose goals are mainly that "Optimal Energy Mix and Reduction of T&D losses" and "Implementation of power system with minimum costs by utilizing renewable energies and so on. The following policy is one of the nine major policies listed for the power sector:

> *Enhance the exploitation of gas, coal, renewable resources, increased energy imports particularly hydropower from neighbouring Bhutan and Nepal in order to optimize the energy mix and reduce the dependence on imported furnace oil and HSD. In this regard hydropower, given its abundance in the neighbouring countries and expected cheaper cost of production, will be given prime importance among other renewable resources. The other renewable resources include wind power, solar energy, biomass and waste to power, where the core strategic goal will be to make the energy available at optimum rate to all consumers;*

The detailed strategy aims to shift from high cost power sources such as HSD (High Speed Diesel) and generators using Furnace Oil to renewable energies and to structure Energy Mix with low costs such as Coal-Fired thermal power plants and so on. Also, it mentions that power trade of hydropower plants of neighboring countries is the most significant factor and it designs a plan to increase the amount of power trade among Bhutan, India and Nepal.

Figure 5.2-3 shows the power source composition of Bangladesh in 2041. As of 2041, Bangladesh still has a high percentage of fossil fuel-derived power sources, so importing hydroelectric power from Nepal is an option for Bangladesh, which wants to increase its share of renewable energy.



Source: JICA Study Team from Integrated Energy and Power Maser Plan 2023

Figure 5.2-3 Peak Demand Forecast in Bangladesh

5.3 CURRENT STATUS OF PLANS TO EXPAND EXPORTS

Efforts to expand electricity exports can be broadly classified into two types of trades: one involving exports from the NEA power grid to the power grids of neighboring countries such as India and Bangladesh, and the other involving exports from individual power generation projects in Nepal to neighboring countries. The former is the Bilateral Trade (PEC mechanism, G to G Trade) and expansion of IEX, while the latter assumes export-oriented hydropower projects such as Arun 3. This section summarizes the current status of projects related to electricity exports under consideration as of November 2024, divided into both formats.

5.3.1 Status of Electricity Exports from Nepal's Grid

Nepal is in discussions with neighboring countries of India and Bangladesh to expand export volume. The current status of discussions with neighboring countries is shown in Table 5.3-1.

Table 5.3-1 Status of negotiations with Neighbouring countries

Country	Period	Status of negotiations
India	January, 2024	Both parties have agreed to export up to 10,000 MW of electricity from Nepal to India over the next 10 years.
	April, 2024	The Indian government has established an obligation for Indian electricity consumers to purchase hydropower, and as part of this obligation, it has established a provision that allows for purchases from hydropower outside of the country to be accounted for.
	May, 2024	Nepal is in discussions with the Indian states of Haryana and Bihar to conclude medium-term power purchase agreements. Of these, discussions are underway with the state of Haryana for a bilateral trade with local government to export 400 MW of power between June and November for a period of five years.
	August, 2024	India has approved the export of an additional 251 MW from 12 new hydropower projects in Nepal for trading on IEX. Nepal can export 941 MW of electricity from 28 hydropower projects in total.
Bangladesh	October, 2024	A government-to-government trade between Nepal and Bangladesh to export 40 MW of electricity to Bangladesh over a 5 year period has been approved between Nepal, India, and Bangladesh. For this tripartite G to G trade, electricity will be exported from Nepal to Bangladesh over a five-month period from June to November, which is Nepal's rainy season. The CEA permit was granted on November 15, 2024, and exports from Nepal to Bangladesh were implemented, only for one day as for 2024. The unit price for trade between Bangladesh and Nepal will be 6.4 cents/kWh, and metering will be done in Muzaffarpur in India. In addition, Bangladesh will pay to India a transmission charge and cost equivalent to transmission losses occurring within India.

Source: JICA Study Team based on interviews with NEA Power Trade Division

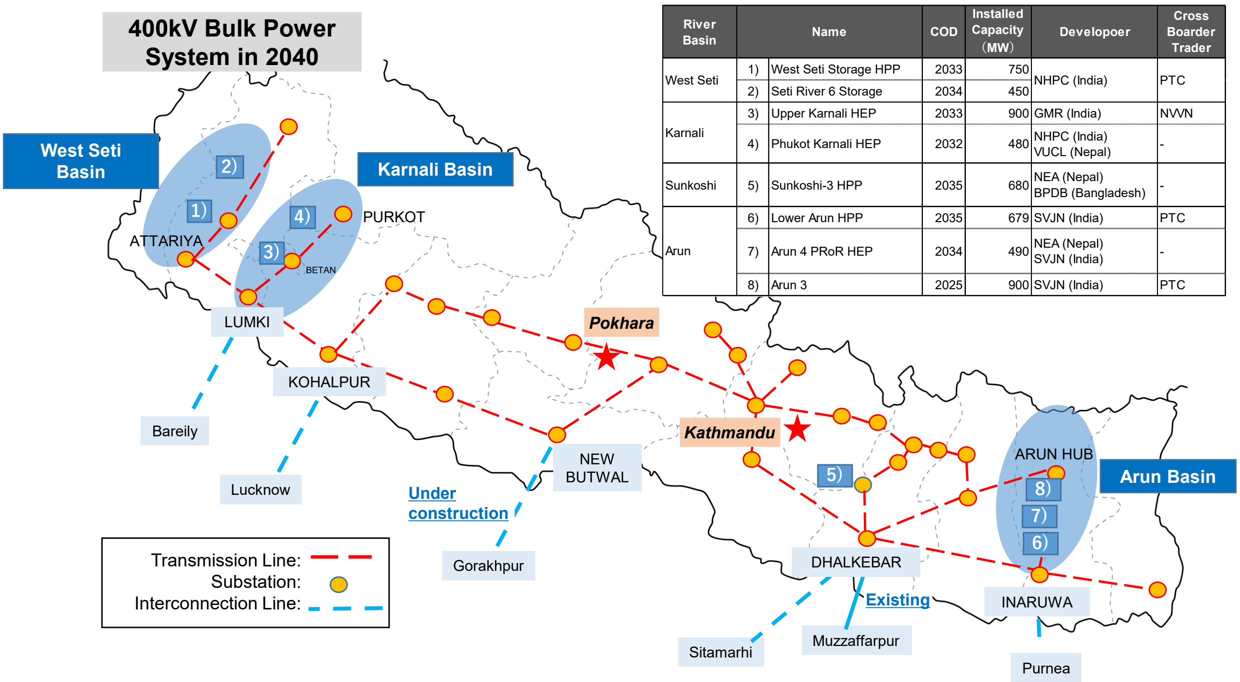
Regarding power exports from NEA's grid, power exports to India have been increasing every year, and a MOU has been signed that sets a maximum of 10,000 MW for exports to India over the next 10 years. In addition, an agreement to export 40 MW of electricity to Bangladesh has also been signed, and this trade is expected to expand in the future.

In the Energy Development Roadmap and Work Plan 2035 being developed by MoEWRI, power exports for 2035 are planned to be 10,000 MW for India and 5,000 MW for Bangladesh. The Power Development Plan has been formulated with this in mind and Nepal's power generation capacity in 2035 is 28,215 MW and domestic demand is 7,581 MW, ensuring sufficient supply capacity.

While power exports are expected to expand over the medium to long term, the current IEX trade, which is the main power export scheme, requires approval for each power plant every year for exporting power to India. Therefore, NEA is unable to make stable sales forecasts for the medium to long-term, and is forced to bear the risk of purchasing power from IPPs.

5.3.2 Status of Exports from Individual Hydropower Plants

Hydroelectric power plant for export is located in the West Seti, Karnali, Sunkoshi, and Arun water systems. The West Seti and Arun water systems are led by NHPC and SVJN, respectively, which are Indian public corporations. These have a different trade scheme described in 8.1.1 (2): they are expected to sell power directly to NVVN, PTC or the distribution companies in India, rather than through the NEA. This section summarizes the status of hydropower development for export in these water systems and discusses future issues, including the domestic grid and interconnection lines. Figure 5.3-1 provides an overview and location map of the eight export-oriented hydropower sites currently planned and under construction in Nepal, and summarizes the implementation status of each water system.



River Basin		Name	COD	Installed Capacity (MW)	Developoer	Cross Boarder Trader
West Seti	1)	West Seti Storage HPP	2033	750	NHPC (India)	PTC
	2)	Seti River 6 Storage	2034	450		
Karnali	3)	Upper Karnali HEP	2033	900	GMR (India)	NVVN
	4)	Phukot Karnali HEP	2032	480	NHPC (India) VUCL (Nepal)	-
Sunkoshi	5)	Sunkoshi-3 HPP	2035	680	NEA (Nepal) BPDB (Bangladesh)	-
Arun	6)	Lower Arun HPP	2035	679	SVJN (India)	PTC
	7)	Arun 4 PRoR HEP	2034	490	NEA (Nepal) SVJN (India)	-
	8)	Arun 3	2025	900	SVJN (India)	PTC

Source: JICA Study Team

Figure 5.3-1 Location map of hydroelectric power plants and transmission lines for export

(1) West Seti water system

In the West Seti system, two hydroelectric projects are planned for export: 1) West Seti HPP (750 MW) and 2) Seti River 6 Storage (450 MW). Although this system has long been recognized as a promising hydropower potential and technical studies have been conducted, no concrete development plan had been raised due to its remote location away from the main grid. However, in August 2022, NHPC obtained a Survey License from IBN and is currently conducting an F/S update and EIA.

These points are expected to be supplied to India through the Lumki - Bareily interconnection line via the West Seti - Attariya transmission line, which will be developed along the West Seti River, part of the domestic 400kV system. It is announced that PTC India, a trading company, will be in charge of supplying power to India.

West Seti and Seti River 6 are large STOs (Storage), so environmental impacts are also a concern, but from the perspective of power export, the development of the West Seti-Attariya-Lumki 400 kV domestic transmission line and the Lumki - Bareily international interconnection line will be a challenge. Since it is expected that the two sites will be operational in the early 2030s, the developers and financing for both the 400 kV domestic grid and the interconnection line have not yet been decided.

(2) Karnali water system

In the Karnali water system, two sites, 3) Upper Karnali HEP (900 MW) and 4) Phurkot Karnali HEP (480 MW), are planned as hydropower plant for export.

Upper Karnali has development rights held by GMR, an Indian infrastructure company, which signed a Project Development Agreement with IBN in 2014. The site is envisioned to supply electricity to Nepal, India, and Bangladesh, and the PPA was signed with Bangladesh Power Development Board (BPDB) of Bangladesh and NVVN of India in 2023. However, the term of the PDA (Project Development Agreement) has been repeatedly extended due to the lack of funding prospects, and in May 2023, the Supreme Court indicated that it would not allow further extensions, and in August 2024, IBN notified the expiration of the PDA in January 2025.

VUCL of Nepal holds the development rights for Phurkot Karnali, and a Detailed Project Report (DPR) has been completed. In the interview with VUCL, VUCL stated that it expects to implement the project with NHPC, but that it will also consider Nepal-led development if the two parties are unable to reach an agreement. VUCL is considering signing a Memorandum of Understanding (MOU) with India's NHPC for the development of the site in 2023, with NHPC holding 51% and VUCL 49%, with India taking the lead in implementation. In the hearing from VUCL, VUCL stated that it expects to implement the project with NHPC, but that it will consider Nepal's initiative in the event that the two parties cannot reach an agreement.

These export points on the Karnali water system are expected to supply power to India via the Phurkot - Betan - Lumki transmission line on the 400 kV domestic grid and through the Lumki - Bareily interconnection line. The Upper Karnali is expected to be supplied to India via the Phurkot - Betan - Lumki transmission line. Upper Karnali is also expected to supply power to Bangladesh, but the India-Bangladesh flow has not been studied at this time. Export to Bangladesh will be subject to Nepalese and Indian tariffs. NVVN is expected to be in charge of settlement.

In terms of power exports, the development of the Phurkot - Betan - Lumki transmission line and the Lumki - Bareily interconnection line for the 400 kV domestic system is a concern. Phurkot - Betan - Lumki transmission line is to be constructed by RPGCL, but interviews with VUCL indicate that it is at the study stage at this time. In addition, VUCL has no experience in hydropower development and recognizes the need to strengthen its technical, environmental, commercial, and legal capabilities in establishing a joint venture (JV) with NHPC, a large hydropower operator in India. In the future, it will be necessary to proceed with JVA (Joint Venture Agreement), grid interconnection with India, and PPA negotiations with Indian trading companies and customers.

(3) Sunkoshi water system

In the Sunkoshi water system, 5) Sunkoshi 3 HPP (680 MW) is planned as a hydropower site for export. This site is being developed under the leadership of NEA, and is expected to export electricity to Bangladesh and India. According to interviews with NEA, a D/D (Detailed Design) consultant is currently being recruited and discussions with the Indian side began last year. The Indian operator has been in discussions since last year, and will be considering the project implementation structure, including financing. The participants also shared the understanding that the site is not economically feasible, and that a loan from a development assistance organization will be required.

The Sunkoshi 3 sites are easily accessible from the road and can be easily connected to the domestic grid. The 400 kV domestic Sunkoshi - Dhalkebar 400 kV transmission line is expected to be constructed and exported to India and Bangladesh via the existing Dhalkebar - Muzzaffapur or Sitamathi, and these developments should also be pursued.

In terms of power export, it is necessary to confirm the transmission line capacity for the development of a 400 kV domestic grid and for export from the existing Dhalkebar interconnection line. NEA has abundant experience in domestic hydropower development, and also has experience in inter-grid power exchange with NVVN and PTC in India. However, this is the first case of developing an individual plant-to-grid power plant for export, and NEA will need to take the initiative in studying the feasibility of PPA, grid interconnection, and transmission charges.

(4) Arun water system

In the Arun water system, 6) Lower Arun HPP (679 MW), 7) Arun 4 PRoR (490 MW), and 8) Arun 3 (900 MW) are planned as hydropower sites for export. For these power plants, SVJN, a power company in the Indian state of Himachal Pradesh, has been granted development rights by IBN for Lower Arun and Arun 3, and joint development with SVJN is being considered for Arun 4, although NEA has the development rights. Arun 3 is the only export hydropower site that is in the construction phase and is scheduled to be operational in 2025. Lower Arun has also signed a PDA for 2023 and regarding trading company Arun 3 and Lower Arun are expected to be handled by PTC.

Regarding transmission lines, SVJN is developing the Arun 3 - Dhalkebar transmission line for the 400 kV domestic system and the Dhalkebar - Sitamarhi interconnection line for the export of Arun 3. Once Arun 3 – Dhalkebar transmission line is developed, it will be possible to export electricity from this system. On the other hand, the Lower Arun will be exported from Inaruwa due to its location, and the Upper Arun (1060 MW) and Kimarathanka Arun (456 MW) are planned to be developed upstream of the Arun water system, and the Arun Hub - Inaruwa 400 kV domestic transmission line will be developed. Therefore, future power exports from the Arun water system, including the Lower Arun, are being considered for transmission via the Arun Hub - Inaruwa transmission line.

Arun 3, the first export project in Nepal, is expected to be operational within the next few years, although it has been delayed from the initial plan. SVJN, an Indian public company, is leading the development of the project from the power plant to the transmission line, and Nepal's involvement in the financial, commercial, and legal aspects of the project is limited. Although 21.9% of Free Power has been obtained as a benefit to Nepal, Nepal has not accumulated experience and achievements as an implementing agency in terms of promoting electricity exports. For this reason, the Nepalese side is expected to be involved in Arun 4 and other projects in the future.

6. THE STUDY FOR DEVELOPMENT SCENARIOS

As shown in Figure 1.6-1 of the report structure, this Chapter describes studies for Development Scenarios based on the findings from Chapter 3 Power Demand Forecast, Chapter 4 Hydropower Development Plan, and Chapter 5 Power Trade. Firstly, basic approaches for planning are set from the perspectives of energy security, finance, environmental and social considerations and policy in power sector. Then, based on the available capacity for hydropower development, the future development direction will be considered and multiple Development Scenarios are prepared, analyzing PGDP, PSP and SEA. Finally, based on the comparison of Development Scenarios, Optimum Scenario is selected from the comprehensive perspectives.

6.1 BASIC APPROACHES ON POWER GENERATION DEVELOPMENT PLANNING

Based on the law, policy and development plan related to the electric power sector in Nepal, the basic approaches of 3E (Energy security, Economy and Environment) + Policy on PGDP of IPSDP are described as follows;

6.1.1 Energy Security

As stable electric power supply and energy security is significantly vital issues for Nepal, improvement of energy self-sufficiency will contribute to the stable operation of the Country. The IEA defines energy security as the uninterrupted availability of energy sources at an affordable price. Energy security has many aspects: long-term energy security mainly deals with timely investments to supply energy in line with economic developments and environmental needs. On the other hand, short-term energy security focuses on the ability of the energy system to react promptly to sudden changes in the supply-demand balance.

Despite of the abundant hydropower potential which is much more than the power demand in Nepal, 30% of electric power for the domestic supply is currently imported from India. IPSDP aims to achieve the reliable electric power supply by domestic primary energy and to contribute to realize the stable power supply in the regional power pool through the interactive and flexible power trade with BBIN (Bangladesh, Bhutan, India and Nepal) + China.

6.1.2 Reduction of Financial Burden and Economic Growth (Economy)

Development of the power system require huge initial investment and O&M (operation and maintenance) cost in long term. Therefore, the power development plan without the actual situation and practical strategies could increase the future financial burden of people and disturb the improvement of living standard and economic growth. In addition, increase of power import may lead to the outflow of foreign currency.

Electric power supply will be established at a lower financial burden for the people through clean and cheap hydropower and renewable energy. Furthermore, export of clean energy will be really important proposition after the fulfillment of domestic power demand. From the perspective of job creation through the development itself and foreign currency earning through the power trade, hydropower expected to be considered as the future growth industry and be promoted in Nepal

6.1.3 Environmental and Social Considerations (Environment)

Each development scenario anticipates environmental and social impacts caused by power generation and system development. In order to avoid and minimize environmental and social impacts from an early stage of development, a comparative analysis of development scenarios was conducted, taking into consideration environmental and social aspects such as protected areas, Chure conservation areas, KBA (Key Biodiversity Areas), forests, farmland, residential areas, and climate change. In evaluating the development scenarios, the data of the development areas assumed in each scenario was overlaid with both data of each environmental and social component and of the project list provided by DoED, and only the overlapping areas were calculated.

6.1.4 Policy in the Power Sector (Policy)

GoN considers the hydropower development as the one of fundamental policy and it is important to secure the consistency between IPSDP and their policy.

Policy objectives in higher level polices in the power sector is “Energy, Water Resources and Irrigation Sector’s Current Status and Roadmap for Future (White Paper)” published by MoEWRI in 2018.

Currently, the MoEWRI is developing the "Energy Development Roadmap and Work Plan 2035" as its energy policy up to 2035 which is under discussion by the cabinet. This roadmap sets the development goals by 2035 to include a power demand consumption of 40,710 GWh (3.4 times increase), total power generation capacity of 28,713 MW (10.2 times increase), transformer capacity of 40,000 MVA (4.5 times increase), and power exports of 15,000 MW (23.7 times increase). 85 work plans are proposed in four areas: “1. Improvement of the legal system”, “2. Capacity development for GoN”, “3. Promotion of infrastructure development” and “4. Establishment of business function on power market”. It is necessary for IPSDP to align with such higher-level policies, particularly considering the achievement of the goals set forth in this Energy Development Roadmap and Work Plan.

6.2 SETTING OF DEVELOPMENT SCENARIOS

In this Section, Development Scenarios for the power generation mix are developed and the direction of the power sector is considered based on several perspectives, including the legal systems, policies, natural conditions, current status of primary energy.

Based on the results and analysis on the power sector in Nepal, the following approaches are assumed to be important for the study of the future power generation mix.

- PGDP in Nepal will basically be dominated by hydropower and the power generation mix will depend on its possibility to be developed. In other words, the success or failure of hydropower development will determine the direction of the power sector.

- If the hydropower developments on the DoED Project List are fully developed, how much surplus power will be generated compared to electricity demand, whether export is feasible in terms of generation costs, flexibility and timing, and whether financing the development costs is feasible.

- What action will be required if the planned hydropower development is not realized? In case of the shortfall, what is the scale of required amount of power trade imported from neighboring countries, mainly India and how much is necessary for the expense of it?

- Will renewable energy such as solar power contribute to the power generation mix? What is the impact on imports and exports in terms of power trade and supply capacity on peak time?

Several Development Scenarios will be composed with obvious concepts in order to explore the direction of the power sector in which Nepal aims based on 3E + Policy.

6.2.1 Direction in accordance with the Development Capacity of Hydropower

As indicated in Chapter 4, amount of hydropower generation in Nepal varies widely between rainy and dry seasons. It is only about 30% of electricity generated in dry season compared to rainy season. Although the effect of the regulating capacity of reservoir operation of STO to reduce these fluctuations is confirmed in this Study, it should be noted that there is still a large gap in the amount of power generation between dry and rainy season.

In terms of PGDP, the shortfalls caused by monthly fluctuations of hydropower output are usually adjusted by thermal power such as gas and coal power. On the other hand, the alternative for regulation of power generation is assumed to be responded by power trade with India. In addition, surplus power is assumed to be exported to neighbouring countries or be utilized for storage / electrification. The utilization of surplus power such as power storage or electrification will be considered in Optimum Scenario, while power export is assumed in Development Scenarios.

Based on the results of the Study in Chapter 4 and Chapter 5, it is assumed that the supply and demand of power is balanced by hydropower and power trade in Nepal. Therefore the capacity of hydropower development determine the direction of the power generation development planning.

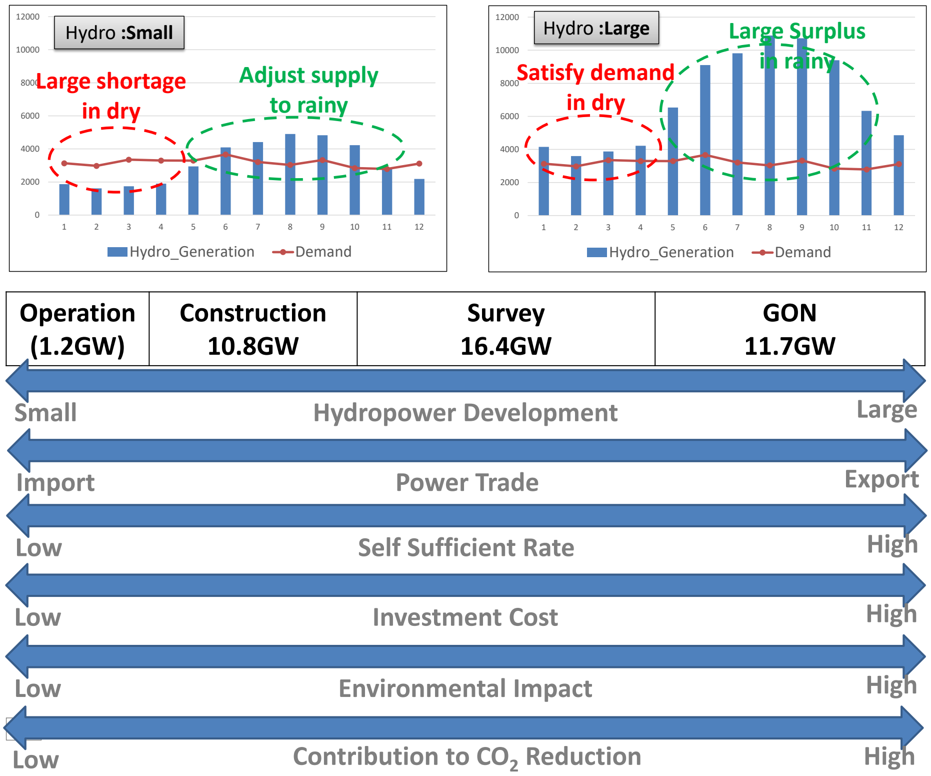
(i) Development capacity of hydropower is small
Hydropower is developed in order to meet peak demand in rainy season and shortages are supplemented by power import in dry season.

(ii) Development capacity of hydropower is large
Hydropower is developed to meet peak demand in dry season and excessed electricity generated is exported.

In other words, it is important to consider two overall approaches for the future direction: (1) Restrict hydropower development and accept power import in dry season or (2) Promote hydropower development and power export. It is necessary to recognize the trade-off of hydropower development in amount of power trade, capital investment cost and environmental and social impacts in order to respond growing power demand in Nepal. These concepts are summarised in Figure 6.2-1.

In terms of 3E + Policy, if the development capacity of hydropower is large, energy security is improved owed to the increase of self-sufficiency rated of electric power and export to neighbouring countries. Increase of export also contribute to the economy in Nepal by earning foreign currency and climate change through the reduction of CO_2 emission. At the same time, it is also essential to consider the feasibility of financing, the selection of economically viable projects and negative environmental impacts.

If the development capacity of hydropower does not meet demand, it is necessary to prepare options to supplement shortages by the introduction of renewable energy or power trade. There are also benefits in terms of environmental impacts and lower capital investment costs in the development with small scale. These impacts need to be assessed from various perspectives in comparison of Development Scenarios.



Source: JICA Study Team

Figure 6.2-1 Direction by the Development Capacity of Hydropower

6.2.2 Direction from Time Scale

Development capacity of hydropower by the progress is shown in Figure 6.2-2

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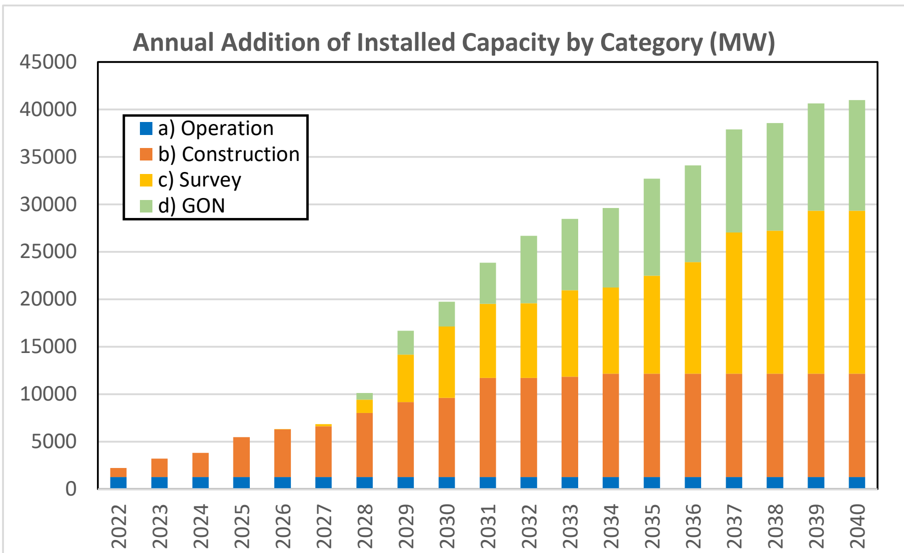


Source: JICA Study Team

Figure 6.2-2 Development capacity of hydropower by the Progress

When looking at the power generation development over the short, medium and long term timeframes, the direction of generation scheme and power systems in (i) (ii) are summarized as follows.

Short-term power development is mainly carried out by the committed ongoing projects in b) Construction which are progressed regardless of the direction of scenarios. As these projects build up, power export in rainy season will increase but import is still required in dry season. Power export is expected to exceed import in 2025 as an annual balance of power trade. Although it is assumed that the projects of b) Construction will be steadily developed, there is no difference in the short-term outlook between (i) and (ii) due to the limited commission in b) Construction. In the power system planning, the 400 kV backbone system and international interconnection lines are planned correspondingly.

Looking to the medium and long-term outlook beyond 2025, the development of projects in c) Survey and d) GoN is important. Some of these projects can be commissioned as early as 2026 or later. The developable capacity will increase from 2028. As capacity of b) Construction is only 10.8 GW, the development of c) Survey and d) GoN is required to achieve the policy target with the development of 15,000MW until 2030.

If these hydropower developments do not progress in case of (i), power import will increase as demand increases. It is also necessary to confirm the both amount of import and export in power trade to design the capacity of interconnection lines.

In the case of (ii) which development is progressing, the trend of short-term export growth is expected to continue and import will no longer be required in dry season in the early 2030s. By this time, it is necessary to prepare generation plans aiming to exports in projects of c) Survey and d) GoN considering the power generation development planning that are consistent with the supply and demand plans of export destinations such as India and Bangladesh. In addition, in the power system planning, it is necessary to verify whether power export is feasible with the currently planned international interconnection lines.

6.2.3 Setting of Development Scenarios

Four Development Scenarios in PGDP will be set up: Scenario 1: Power Import, Scenario 2: Renewable and Scenario 3: Hydro Middle and Scenario 4: Hydro Maximum. The concepts of these scenarios are as follows.

Table 6.2-1 Setting Conditions of each Scenario

Item	Scenario 1 Power Import	Scenario 2 Renewable	Scenario 3 Hydro Middle	Scenario 4 Hydro Maximum
Hydropower	a) Operation b) Construction	a) Operation b) Construction	a) Operation b) Construction c) Survey	a) Operation b) Construction c) Survey d) GoN
Renewable Ration against Power Demand (GWh)	10%	25%	10%	10%
Power Trade	Dry :Import Rainy :Export	Dry :Import Rainy :Export	Dry :Import Rainy :Import	Dry :Import Rainy :Import

Source: JICA Study Team

(Scenario 1 :Power Import)
- ✓ **Only committed hydropower projects** with Construction License are developed.
- ✓ Shortage of electricity is supplemented **by import** in dry season. Surplus is partially exported in rainy season.

(Scenario 2 :Renewable)
- ✓ **Only committed hydropower projects** with Construction License are developed.
- ✓ Shortage of electricity is supplemented **by import and solar** in dry season. Surplus is partially exported in rainy season.

(Scenario 3 :Hydro Middle)
- ✓ **Committed and promising hydropower projects** with Construction License and Survey License are developed.
- ✓ Surplus electricity is exported. In drought year, it may be necessary to import electricity in dry season.

(Scenario 4 :Hydro Maximum)
- ✓ **All hydropower projects** which are proposed in DOED List are developed.
- ✓ Surplus electricity is exported.

Scenarios 1 and 2 correspond to (i) small hydropower development, setting scenarios when the demand in dry season is supplied by hydropower and power import from India. Scenario 2 increases the introduction of renewable energy compared to Scenario 1 in order to verify whether renewable energy contributes to improvement of the balance between power supply and demand. Scenarios 3 and 4 correspond to (ii) large hydropower development, setting scenarios with power supply throughout the year by hydropower. The scenarios compare the power supply and demand balance, export volumes and investment costs between the developments of hydropower in intermediate or maximum levels.

These scenario settings examine the scale of hydropower development and generation mix in Nepal, selecting the Optimum Scenario for future development.

6.3 POWER GENERATION DEVELOPMENT PLANNING

6.3.1 Comparison of Power Sources

(1) Comparison of Power Sources

Table 6.3-1 Evaluation Criteria for the Comparison of each Power Sources

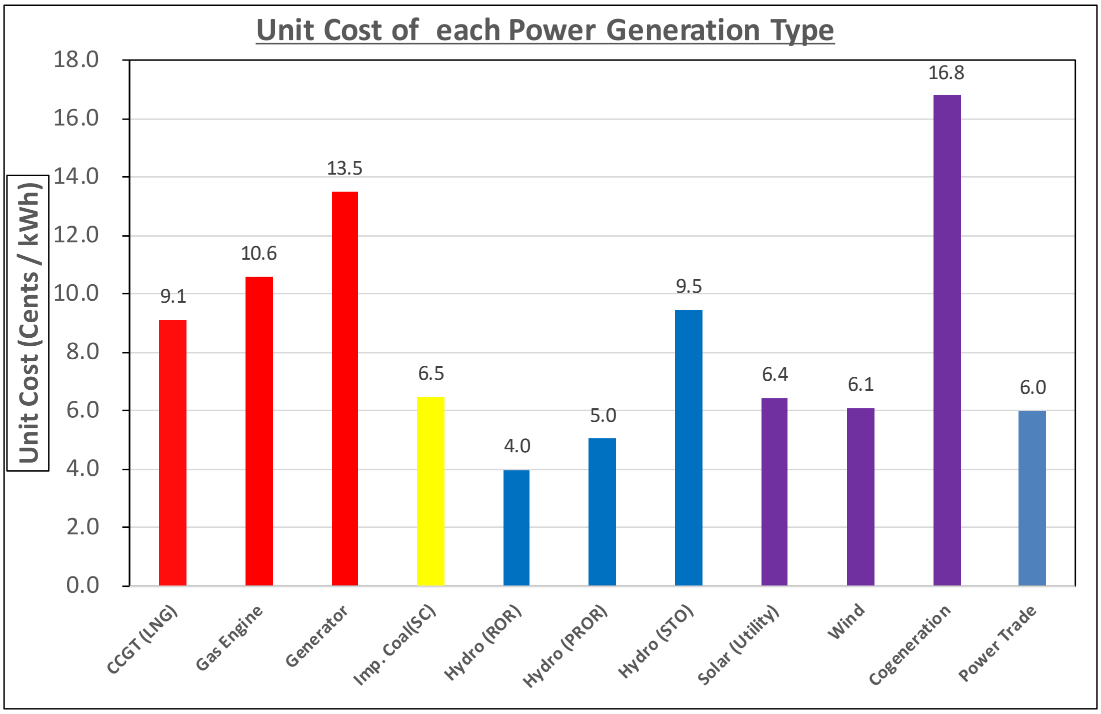
Item		Evaluation
(1) Energy Security	Utilization of Domestic Energy	Sources are derived from domestic or imported.
	Impact by International Issues	Uncertain risks such as bilateral disputes.
(2) Economy	Levelised Cost of Electricity	Cents/kWh
	Regulating Function of Generation	Output is controllable or not.
	Vulnerability for Fuel Cost Fluctuation	Risks of inflation
(3) Environmental and Social considerations	Natural and Social Impacts	Negative affects due to the development such as deforestation, destruction of ecosystem or resettlement.
	Impacts on Climate Change	Emission of GHG (g-CO_2 /kWh)

Source: JICA Study Team

In this section, a comparative evaluation of hydropower (ROR, PROR, STO, PS), thermal power (gas and coal), renewable energy (solar, wind and biomass) and power trade is carried out to select power sources to be applied in PGDP. The evaluation criteria based on the 3E are shown in Table

6.3-1. Although the content of project costs, reservoir capacity and environmental impact differs greatly depending on the characteristics of individual sites, each power source is assessed qualitatively to ascertain the direction of the power sources required for Nepal. The characteristics of individual sites are discussed in the Optimum Scenario.

The LCOE calculated under these assumptions is shown in Figure 6.3-1



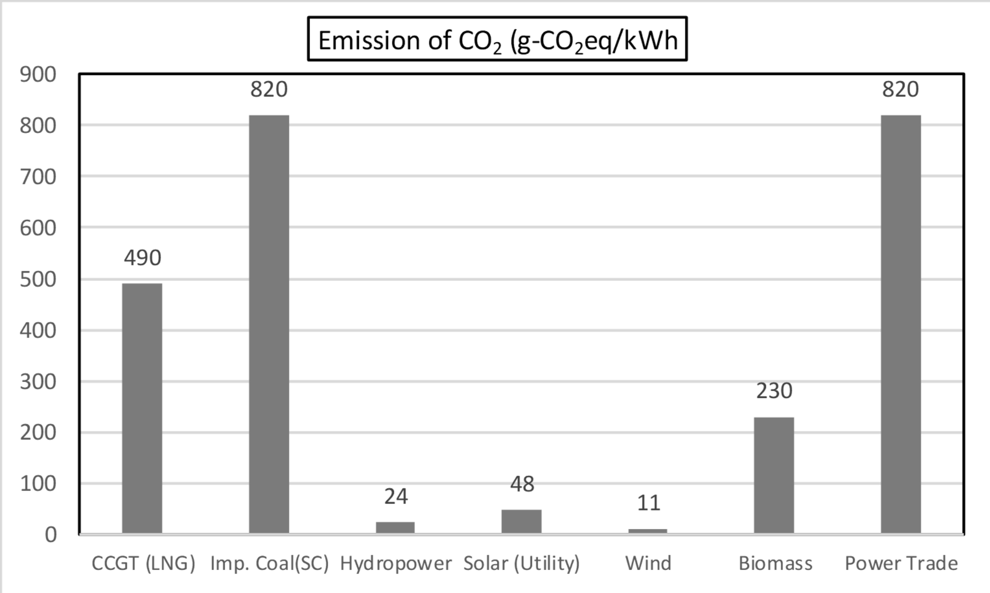
Source: JICA Study Team

Figure 6.3-1 Results of LCOE for each Power Sources

The main thermal power sources are CCGT (Gas Turbine Combined Cycle) at 9.1 cents/kWh and coal-fired at 6.5 cents/kWh. Gas Engine and Generator, which are less thermally efficiency, are more expensive at 10.6 cents/kWh and 13.5 cents/kWh respectively. For hydropower, ROR is the cheapest at 5.5 cents/kWh, PROR at 5.6 cents/kWh and STO at 7.7 cents/kWh. It should be noted that STO is low plant factor and the kW value and regulating capacity are not evaluated in the LCOE. Renewable energy sources are 6.4 cents/kWh for solar, 6.1 cents/kWh for wind and 16.8 cents/kWh for biomass.

Electricity from India is cheap at 6.0 cents/kWh, but coal-fired, hydropower and solar/wind power are at a competitive level with it. On the other hand, price of the power trade is highly volatile. It shall be noted that the tariff for power trade hikes in March 2022.

As an impact on climate change, the Lifetime-based CO_2 emissions per kWh (g-CO_2 eq/kWh) for each power source are summarized in Figure 6.3-2, based on the Technology-specific Cost and Performance Parameters (2014) published by the IPCC (Intergovernmental Panel on Climate Change). For power trade, the country-wide emissions for India in 2018 are applied.



Source: Technology-specific Cost and Performance Parameters (2014), IPCC

Figure 6.3-2 CO_2 Emission (g-CO_2 eq/kWh) of each Power Sources

The highest emissions are from coal-fired power at 820 g-CO_2 eq/kWh, with the same value for electricity supplied from India. IPCC estimation apply to supercritical for coal for power generation, but India has many older, subcritical, lignite-using power plants. The country as a whole includes gas-fired, hydropower and renewable for hydropower, solar and wind power, CO_2 is generated during the equipment manufacturing and construction stages, but it is lower than thermal power in absolute terms. For biomass, CO_2 is generated in the fuel procurement and combustion process.

(2) Evaluation of each Power Source

1) Utilization of Domestic Energy

A summary of the evaluation of power sources is presented in Table 6.3-2. Hydropower is the most important power source in Nepal in terms of policy and is expected to be developed as far as possible where it is economically viable and acceptable in environmental and social considerations. Renewable energy is also expected to be utilized as inexpensive domestic energy sources as long as they are affordable in the power system operation. However, it should be noted that it may be more economical to secure the regulating capacity of hydropower as a value added power source against solar fluctuation in India from the aspect of power trade.

If a comparison is made between domestic thermal power plants and power trade, it is assumed that from the perspective of energy security, there will still be a heavy reliance on India for both options. Power trade is relatively cheaper while inflation risks are supposed. However even fossil fuel imports essentially pose the same concerns. It will be more practical to continue to strengthen power trade with India in order to stabilise electricity supply in Nepal.

On the other hand, the tariff for import from India is volatized with unit cost of 38 NRp / kWh (31.4 cents/kWh) due to the rapid increase of fossil fuels in the world. Increase of cost for the power trade will be heavy financial burden for Nepal. Although power trade is necessary for the stable power supply, reduction of the dependence on the power supply should be considered.

2) Input of Power Sources in IPSDP

The results of the comparison in this section summarize PGDP as follows:

- The plan will be based on hydropower and renewable energy as domestically produced clean energy sources, and on power trade including the export of surpluses and imports of shortfalls.
- Hydropower, a domestically produced clean energy source, will continue to be the main power source, and development will be promoted to the maximum extent within the acceptable and affordable amount in the aspect of economy and environmental and social considerations.
- Renewable energy, which are also domestically produced clean energies, will be developed with a focus on solar power, which has large-scale potential. The amount of installed capacity will be considered based on the flexibility of power system and the added value of the regulating power in power trade.
- Power trade will be based on exports when a surplus of electricity is generated, and imports when there is a shortage of domestic supply capacity during the dry season.

Table 6.3-2 Summary of Comparison of Each Power Source

Sources	Type	(1) Energy Security		(2) Economy			(3) Environmental and Social considerations	
		Utilization of Domestic Energy	Impact by International Issues	Levelised Cost of Electricity	Regulating Function of Generation	Vulnerability for Fuel Cost Fluctuation	Natural and Social Impacts	Impacts on Climate Change
Hydropower	Run of River	Hydropower is domestic clean energy.	None	3.98 cents/kWh	Daily stable but seasonably fluctuated	None	Relatively small	24 g-CO2/kWh
	Peaking Run of River	Hydropower is domestic clean energy.	None	5.04 cents/kWh	1-6 hour peaking but seasonably fluctuated.	None	Dam and regulating pond cause negative impacts.	24 g-CO2/kWh
	Storage	Hydropower is domestic clean energy.	None	9.45 cents/kWh	Daily peaking and seasonable regulation.	None	Dam and reservoir causes serious impacts	24 g-CO2/kWh
	Pumped Storage	Hydropower is domestic clean energy.	None	32.35 cents/kWh	Variable controll in short period as a battery.	None	Dam and regulating pond cause negative impacts.	24 g-CO2/kWh
Thermal Power	Gas Power Plants (Imported LNG)	LNG will be imported from India	Bilateral diputes may cause interruption of fuel supply.	9.11 cents/kWh	Output is controllable.	LNG price is fluctuating by the market. Inflation risk should be considered.	Countermeasures to emissions are required.	490 g-CO2/kWh
	Gas Engines (Imported LNG)	LNG will be imported from India	Bilateral diputes may cause interruption of fuel supply.	10.59 cents/kWh	Output is controllable.	LNG price is fluctuating by the market. Inflation risk should be considered.	Countermeasures to emissions are required.	566 g-CO2/kWh
	Hybrid Generator (Heavy Oil)	Heavy oil will be imported from foreign countries	Bilateral diputes may cause interruption of fuel supply.	13.49 cents/kWh	Output is controllable.	Heavy oil price is fluctuating by the market. Inflation risk should be considered.	Countermeasures to emissions are required.	848 g-CO2/kWh
	Super Critical Coal Power Plants (Imported Coal)	Coal will be imported from foreign countries	Bilateral diputes may cause interruption of fuel supply.	6.48 cents/kWh	Stable but difficult to change output in short time.	Coal price is fluctuating by the market but affects of inflation against generation cost is relatively smaller.	Countermeasures to emissions and yard are required.	820 g-CO2/kWh
Renewable Energy	Solar	Solar is domestic clean energy.	None	5.64 cents/kWh	Output is based on sunshine and is required to be regulated by other sources.	None	Relatively small.	48 g-CO2/kWh
	Wind	Wind is domestic clean energy.	None	6.1 cents/kWh	Output is based on wind and is required to be regulated by other sources.	None	Relatively small.	11g-CO2/kWh
	Biomass	Domestic biomass energy is utilized.	None	16.77 cents/kWh	Generally stable.	None	Countermeasures to emissions are required.	230 g-CO2/kWh
Power Trade		Import from India, Bangladesh and China.	Bilateral risks with partner courtiers should be considered.	6.00 - 30.0 cents/kWh	Controllable within the range of the contract of power trade.	depending on supply sources	Only interconnection.	820 g-CO2/kWh (Average emission of India in 2018)

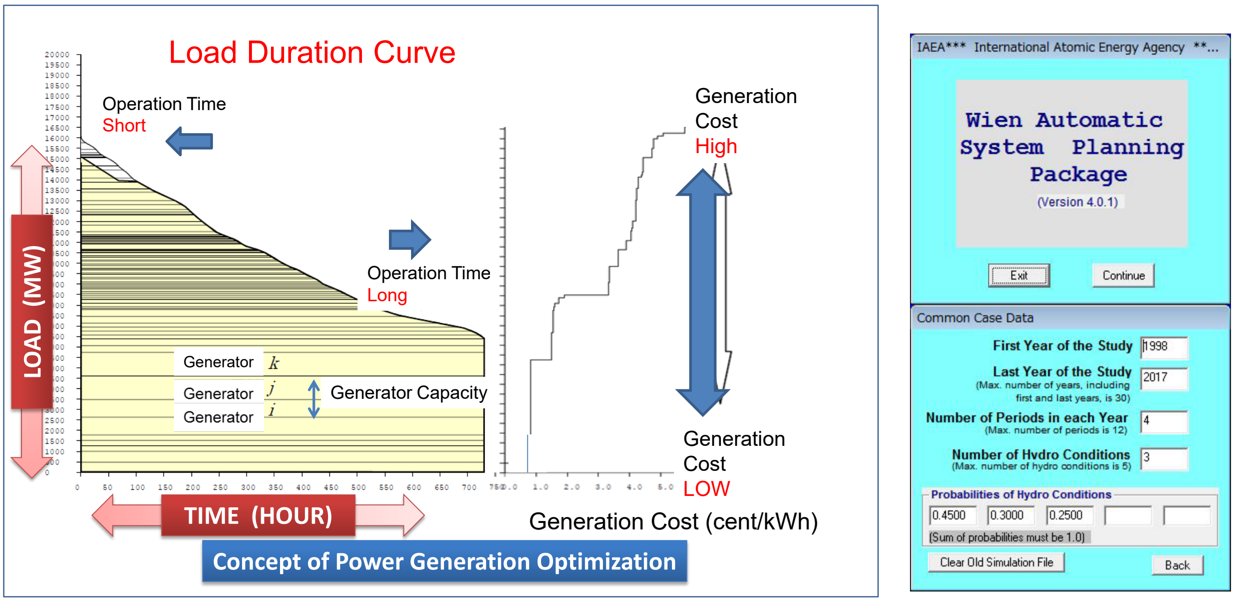
Source: JICA Study Team

6.3.2 Methodologies and Design Conditions on PGDP

In IPSDP, WASP (Wien Automatic System Planning) is applied to the analysis tool of PGDP. WASP is developed for optimization tool of power generation development by IAEA (International Atomic Energy Agency) and is widely utilized in formulation of development plan in many countries. Basic concept of WASP is minimization of objective function (Generation Cost) by Dynamic Programming, namely optimization of power generation planning by least cost. Based on the load duration curve, the power generation facilities of lower construction and operation costs are simulated to be operated sequentially. Outline of WASP ad image of optimization of PGDP by least cost operation are shown in Figure 6.3-3 and Table 6.3-3.

The analysis conditions and operating criteria for PGDP are shown in Table 6.3-3. The analysis period is 2022-2040 and the base case is applied to the power demand forecast.

For the operating criteria, reserve margin of supply capacity is set at 5% in February, 2040 which is lowest output in hydropower plants considering the drought case and Loss of Load Probability is set at 1 day per year from 2027 onwards.



Source: JICA Study Team

Figure 6.3-3 Outline of WASP

Table 6.3-3 Design Conditions of PGDP

Item	Description
Analysis Period	2022 - 2040
Demand	Base Case Development Scenarios :Power demand 56,112GWh and Peak 10,352MW (ver.1) Optimum Scenario :Power demand 62,390GWh and Peak 11,510MW (ver.2)
Tool	Wien Automatic System Planning Package IV (WASP IV) to find optimal expansion plan
Operation Criteria	Reserve Margin : 5% in dry season in 2040 LOLP (Loss of Load Probability) : 1 day per year from beginning of 2027

Source: JICA Study Team

6.3.3 Results of the Analysis for Development Scenarios

This Section describes the results of analysis of Development Scenarios of Sscenario 1: Power Import, Scenario 2: Renewable and Scenario 3: Hydro Middle and Scenario 4: Hydro Maximum.

Results of the comparison of Development Scenarios are shown below;

(1) Installed Capacity

A comparison of the installed capacity of each Scenario in 2040 is shown in Figure 6.3-4. Installed capacity of Development Scenarios are Scenario 1: 20,104MW, Scenario 2: 25,546MW, Scenario 3: 31,994MW and Scenario 4:43,833MW. With regard to the ratios to the capacity of Scenario 1 as 100%, these of Scenario 2, Scenario 3 and Scenario 4 are 127%, 159% and 200% respectively.

Regarding the generation mix, hydropower projects to be developed in Scenarios 1 and 2 is mostly ROR and PROR. STO accounts for a low proportion in them. The power supply in dry season has to be regulated by power import. In Scenario 2, renewable energy accounts for as much as 36% of power generation, particularly during dry season, when solar PV occupies most of the daytime power output. Sufficient regulating power is required for the introduction of solar power of VRE (Variable Renewable Energy) which has large output fluctuations. However supply capacity in the domestic sources is insufficient and needs to be regulated from India connected to the power system of Nepal during this time.

Table 6.3-4 Summary of Installed Capacity of each Scenarios (MW)

Scenario 1 Power Import

Year	Hydro			RE	Power Trade	Total
	ROR	PROR	STO			
2025	3,410.5	1,740.0	154.0	412.2	0	5,717
2030	6,092.7	3,358.1	154.0	1,672.5	1,200	12,477
2035	6,634.6	4,515.1	982.0	2,672.5	2,700	17,504
2040	6,634.6	4,515.1	982.0	3,672.5	4,300	20,104

Scenario 2 Renewable

Year	Hydro			RE	Power Trade	Total
	ROR	PROR	STO			
2025	3,410.5	1,740.0	154.0	712.2	0	6,017
2030	6,092.7	3,358.1	154.0	3,072.5	1,100	13,777
2035	6,634.6	4,515.1	982.0	5,872.5	2,500	20,504
2040	6,634.6	4,515.1	982.0	9,314.0	4,100	25,546

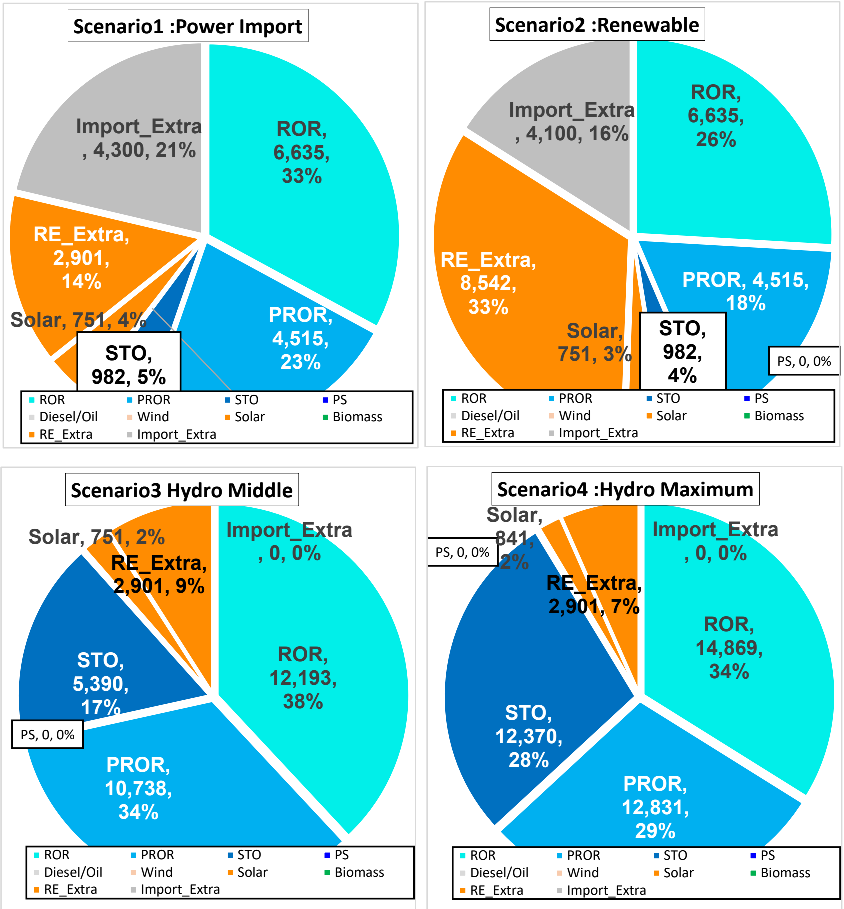
Scenario 3 Hydro Middle

Year	Hydro			RE	Power Trade	Total
	ROR	PROR	STO			
2025	3,410.5	1,740.0	154.0	412.2	0	5,717
2030	10,612.0	4,726.1	790.7	1,572.5	0	17,701
2035	11,482.8	7,191.5	2,813.3	2,572.5	0	24,060
2040	12,192.8	10,737.9	5,390.3	3,672.5	0	31,994

Scenario 4 Hydro Maximum

Year	Hydro			RE	Power Trade	Total
	ROR	PROR	STO			
2025	3,410.5	1,740.0	154.0	412.2	0	5,717
2030	13,176.4	4,726.1	925.7	1,662.5	0	20,491
2035	14,159.2	8,312.5	9,322.9	2,662.5	0	34,457
2040	14,869.2	12,831.0	12,370.0	3,762.5	0	43,833

Source: JICA Study Team



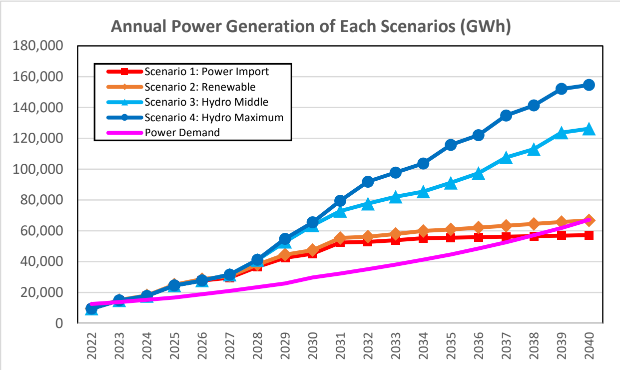
Source: JICA Study Team

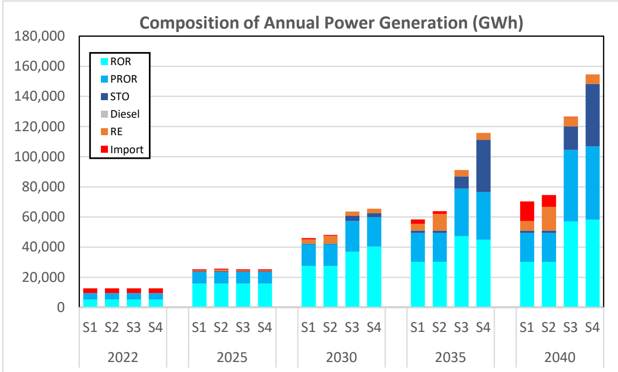
Figure 6.3-4 Comparison of Installed Capacity (MW)

(2) Annual Power Generation

Figure 6.3-5 shows a comparison of annual power generation and composition by source and Figure 6.3-6 shows the self-sufficient rate of power generation. The gap between Scenario 1&2 and Scenario 3&4 is widening after 2027 when the commissioning of hydropower projects on c) Survey and d) GoN begin. The annual power generation of Scenario 1 is 57,389GWh, Scenario 2 is 67,028GWh, Scenario 3 is 126,466GWh and Scenario 4 is 154,640GWh in 2040. With regard to the ratio to Scenario 1 as 100%, Scenario 2, Scenario 3 and Scenario 4 would generate 117%, 220% and 269% of the electricity, respectively.

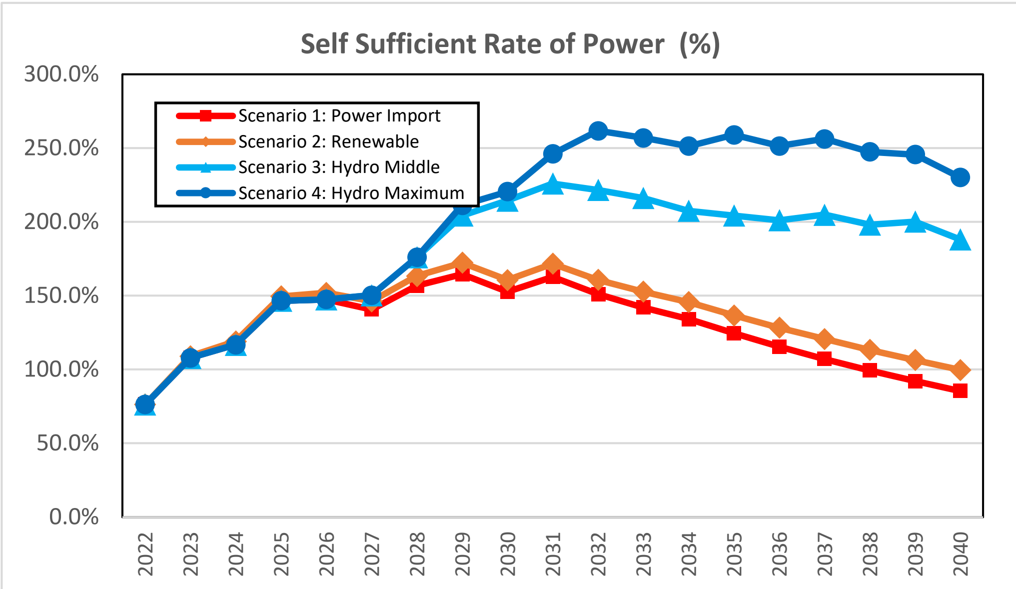
With regard to the composition of power generation by scheme, the share of PROR increases in each scenario after 2025 and the share of STO increases after 2035 particularly in Scenario 4. In Scenarios 1 and 2, power imports are required mainly during dry season after 2035. It should be noted that imports will also be required even in Scenario 3 in February, the driest month, although the share of it is very small.





Source: JICA Study Team

Figure 6.3-5 Comparison of Annual Power Generation (GWh)



Source: JICA Study Team

Figure 6.3-6 Comparison of Self-Sufficient Rate of Power Generation

As with the self-sufficient rate of power generation, the difference between Scenarios 1& 2 and Scenarios 3&4 widens after 2027 as same as the annual power generation. As hydropower development under each Scenario generally peaks in the early 2030s, the self-sufficient rate has been a gradual decline since then. In 2040, Scenario 2 will have a self-sufficient rate of approximately 100%, while Scenario 1 will have 85.4% which means that Nepal alone will not be able to respond to domestic power demand.

The results of the composition of annual power generation by scheme and the self-sufficient rate of power generation indicate difficulties in balancing between the demand and supply in Nepal which generation mix is heavily depended on hydropower. It is necessary to recognize that electricity is imported during dry season in Scenarios 1 and 2 which significantly exceed the peak power demand in terms of installed capacity. Furthermore, Scenario 3 may require a small amount of electricity imports during dry season in February.

These results indicate following remarkable findings in the medium to long term;

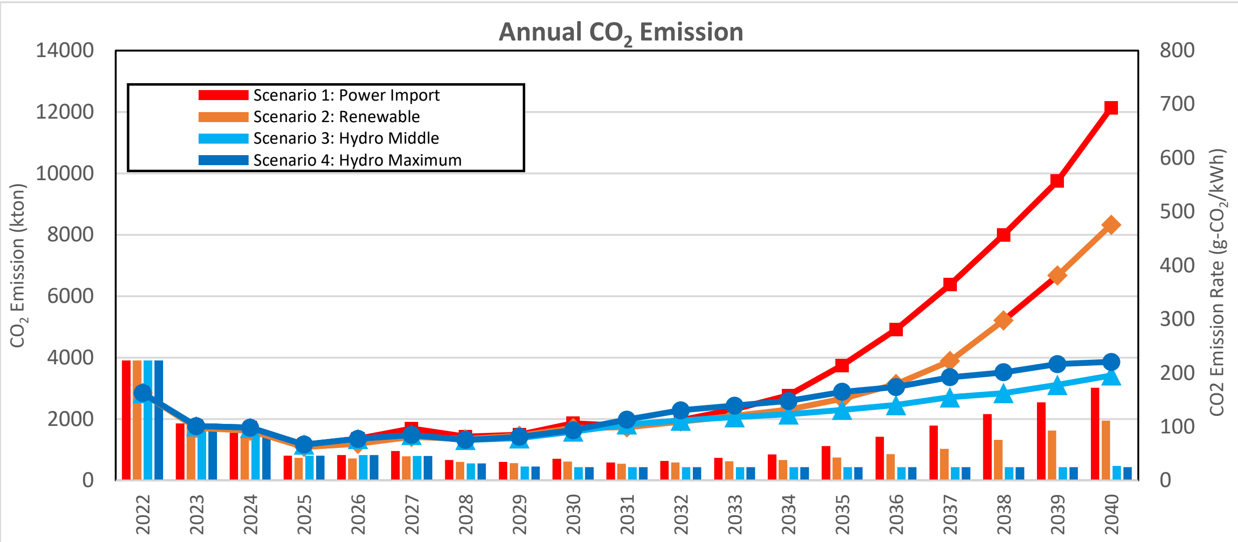
- It will be necessary to develop almost double the domestic demand in terms of annual power generation in order to secure self-sufficiency in dry season including drought years

- Huge amount of power export is required in rainy season in all Scenarios

(3) CO_2 Emission

The annual CO_2 emissions (kton) and emissions rate (g-CO2/kWh) are shown in Figure 6.3-7 and reductions of CO_2 emission by power export to neighbouring countries (kton) are shown in Figure 6.3-8. As power generation is mainly composed of hydropower and renewable energy in Nepal, CO_2 emissions are still lower than in other countries even in 2022. Emissions rate will be gradual declines as the introduction of hydropower increases in all Scenarios.

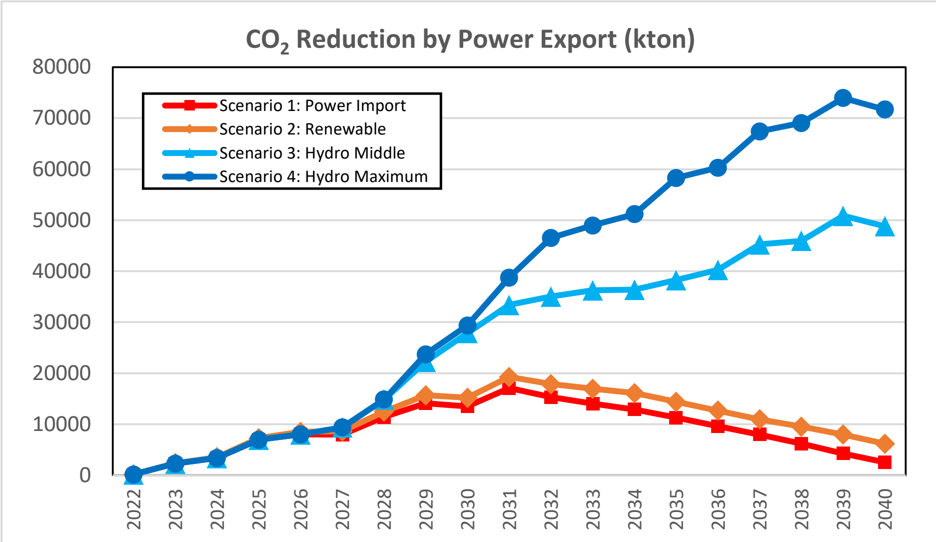
CO_2 emissions will increase in Scenarios 1 and 2, as hydropower development decreases and electricity imports increase. Emissions will remain at extremely low levels in Scenarios 3 and 4. However, it should be noted that emissions are low compared to neighbouring countries even in Scenarios 1 and 2.



Source: JICA Study Team

Figure 6.3-7 Comparison of CO_2 Emissions and Rate

In Scenarios 3 and 4, reductions of CO_2 emissions by electricity exports will increase after 2027 when hydropower development is accelerated and it really contributes to reduction of CO_2 emission in India and Bangla which are mainly depended on thermal power in power supply. At present, incentives from these CO_2 reductions have not been institutionalised. However, if a carbon tax or other incentive system is developed in the future, benefits such as carbon credits may be available in addition to the power purchase which contribute to the increase of income for Nepal. In case of the carbon tax with 30USD/ton, the reduction in Scenario 4 in 2040 is 70,531kton equivalent to 2,115.9MUSD in price.



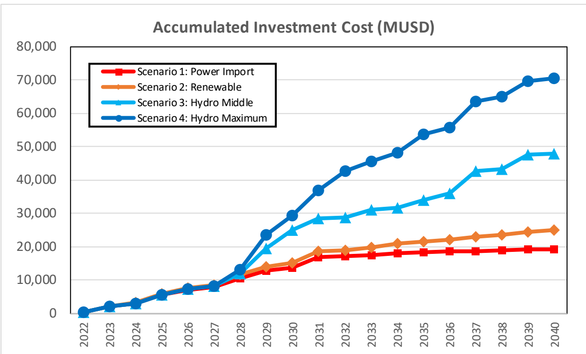
Source: JICA Study Team

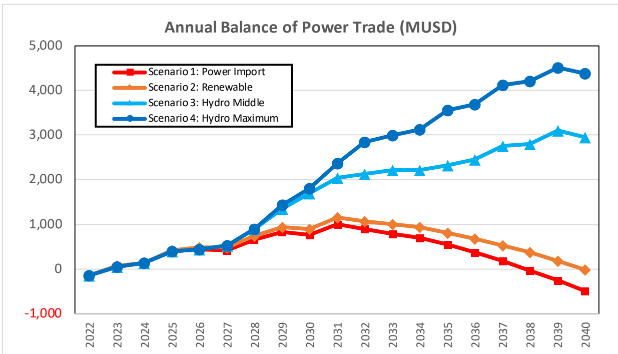
Figure 6.3-8 Comparison of CO_2 Emissions by Power Export

(4) Cost for Power Generation Development

The cumulative investment cost and balance of power trade (MUSD) for the power generation development planning are shown in Figure 6.3-9. The cumulative cost and annual average amounts until 2040 are 19,138MUSD (1,015MUSD/year) for Scenario 1, 24,838MUSD (1,307MUSD/year) for Scenario 2, Scenario 3 is 48,345MUSD (2,544MUSD/year) and Scenario 4 is 70,531MUSD (3,712MUSD/year). In terms of ratios to Scenario 1 as 100%, Scenario 2, Scenario 3 and Scenario 4 would cost 130%, 253% and 369% respectively.

As same as power generation and CO_2 emissions, the gap is wides after 2027 when new hydropower projects are start to commission in c) Survey and d) GoN.





Source: JICA Study Team

Figure 6.3-9 Comparison of the Cumulative Investment Cost and Balance of Power Trade

Although the balance of power trade also shows similar trend, power import increases in Scenario 1 and 2. Finally, expenditures by imports will exceed income by export in 2038 for Scenario 1 and in 2040 for Scenario 2 again. Annual balance of the power trade in 2040 is -492MUSD in Scenario 1, -9MUSD in Scenario2, 2,963MUSD in Scenario3 and 4,372MUSD in Scenario 4.

Compared to Scenarios 1 and 2, the capital investment cost in Scenarios 3 and 4 is extremely large. It is necessary to consider the viability of project finance in Nepal. On the other hand, if power exports are realised, income from power trade will also be significant.

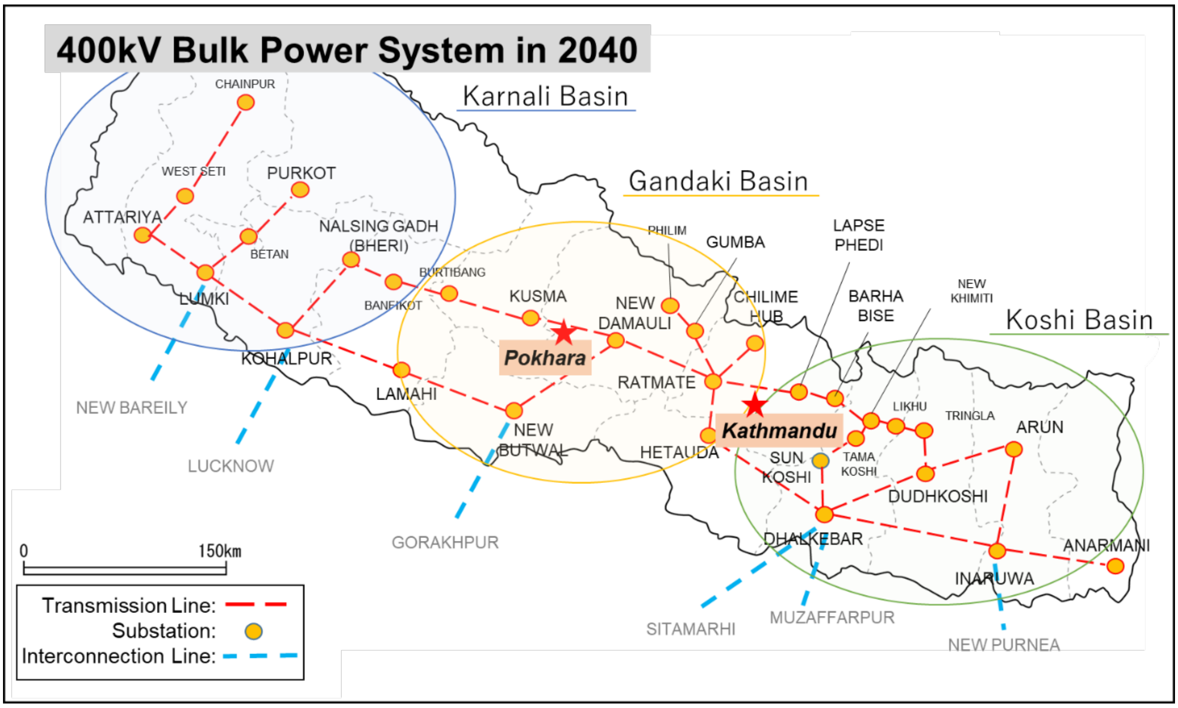
6.4 POWER SYSTEM PLANNING

6.4.1 Study of Power System Planning/Power System Analysis in Each Power Generation Development Scenario

(1) Precondition of Power System Planning/Power System Analysis in Each Power Generation Development Scenario

1) 400kV Trunk Line System

The 400kV trunk line system in Nepal proposed in this master plan in 2040 was proposed through discussions with NEA and RPGCL based on the existing system and past development plans, as shown in Figure 6.4-1. The future 400kV trunk line system in Nepal will be studied using this system. Here, the red dashed lines indicate the 400kV transmission lines, and the orange dots indicate the locations of the 400kV substations. The circle also encloses the Karnali, Gandaki and Koshi rivers, which are the major water systems of the country.



Source: JICA Study Team based on NEA Year Book 2022/2023

Figure 6.4-1 400kV trunk line system (as of 2040 year)

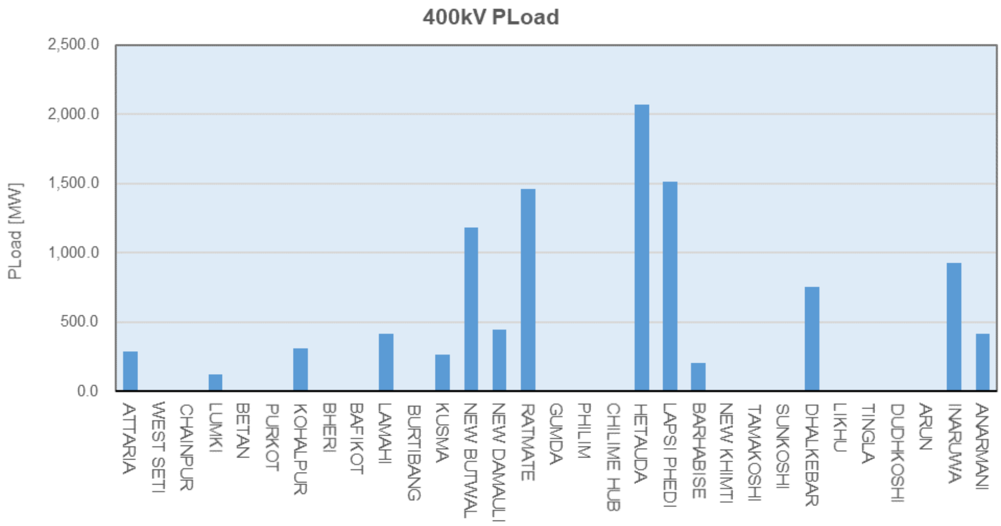
As the basic concept of this system, along the existing 132 kV transmission line that runs east to west, the south route of the 400 kV transmission line that will be the backbone of the first route, and to make this system more robust, The North route of the 400kV transmission line of the second route is planned.

In addition to these east-west routes, north-south transmission lines are planned to connect the power plants along the main rivers of Nepal's three major rivers, the Karnari, Gandaki and Koshi Rivers. The transmission lines along these river systems will be interconnected with two east-west transmission lines to deliver electricity from each power station to the country or abroad. Nepal's domestic power system in 2040 will consist of these two east-west transmission lines and the transmission lines that will be constructed along major north-south rivers.

This 400kV trunk line is based on the NEA's future plan, and was proposed while exchanging opinions with the power system WG members. The adequacy of this system will be verified by simulation, reflecting the results of the demand forecast and the scenarios of the power generation development plan.

In addition to the domestic grid, it is also important to study power trade with India and other BBIN countries in this study, and the configuration of these grids is also an important point. Based on the possibility that the future power trade with India planned by NEA, will be six 400kV interconnection lines, scenarios 1 to 4 will be verified based on power trade through these six lines at NEA's request.

2) Load allocation method and results for 400kV system as of 2040 year (common scenario)



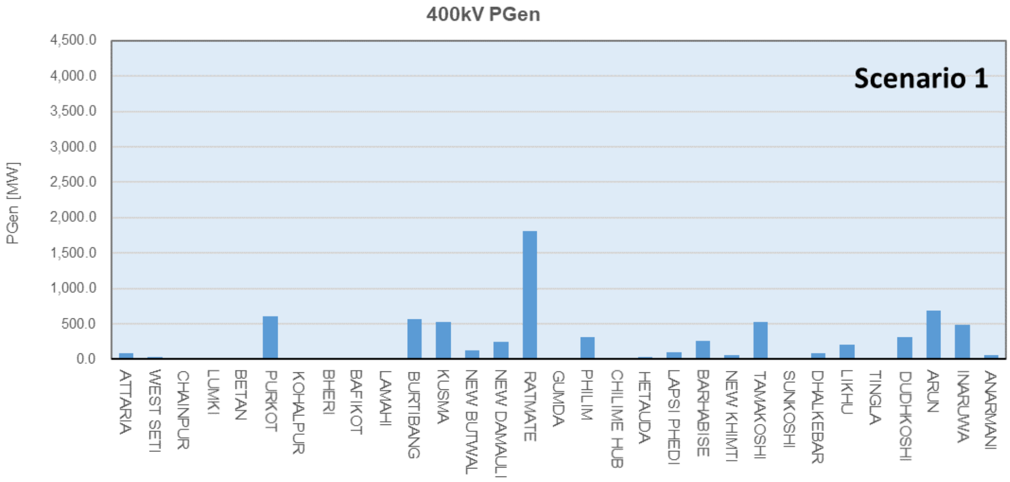
Source: JICA Study Team

Figure 6.4-2 Load allocation of 400kV system (based on actual data)

In the 400kV system mentioned above, the load allocation of 400kV substations was calculated based on the peak demand in 2040 in the demand forecast in Chapter 3 and the latest actual substation load. Here, the actual load of the existing substations is multiplied by the growth rate to predict the load in 2040, and by aggregating them as the load of the nearest 400kV substation, the load of the 400kV substation in 2040 is calculated. The results are shown in Figure 6.4-2. The load was applied during the rainy season (August).

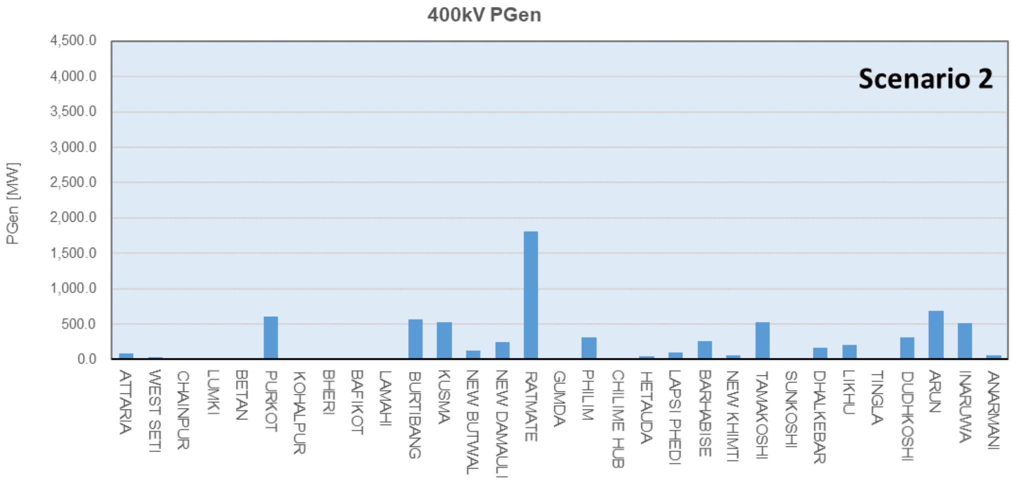
3) Power generation allocation methods and results for 400kV systems as of 2040 year (4 scenarios)

In the 400kV system mentioned above, the power allocation of the 400kV substation was calculated from the power output based on the power development amount in 2040 in the power development plan in Section 6.3. Here, the power generation capacity of the 400kV substation in 2040 was calculated by aggregating the power output of each power station to the nearest 400kV substation. The results of scenarios 1 to 4 are shown in Figure 6.4-3, Figure 6.4-4, Figure 6.4-5 and Figure 6.4-6. In addition, the power output is assumed to be during the rainy season (August).



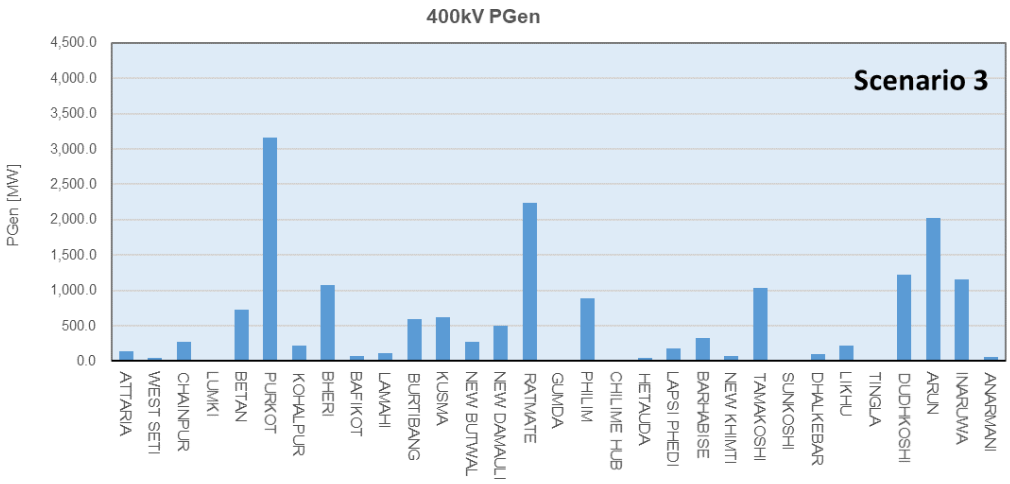
Source: JICA Study Team

Figure 6.4-3 Scenario 1 Power generation allocation of 400kV system



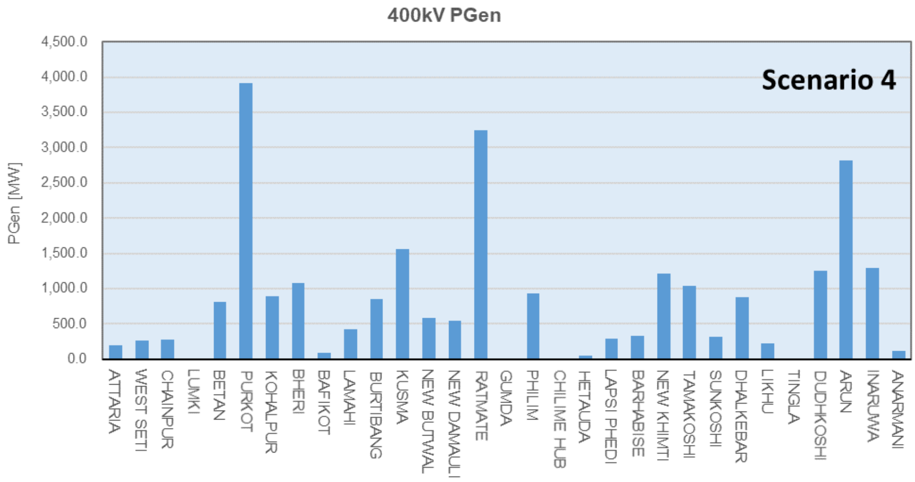
Source: JICA Study Team

Figure 6.4-4 Scenario 2 Power generation allocation of 400kV system



Source: JICA Study Team

Figure 6.4-5 Scenario 3 Power generation allocation of 400kV system



Source: JICA Study Team

Figure 6.4-6 Scenario 4 Power generation allocation of 400kV system

(2) Study criteria

Generally, for power system analysis

i. Power flow calculation
ii. Voltage calculation
iii. Short-circuit current calculation
iv. Stability simulation

These four items are being studied, and in this study also, based on the NEA grid code, these analyzes will be carried out and the adequacy of the system will be verified.

The criteria for study are as follows;

- Power flow calculation: The power flow of each 400kV transmission line must be within the heat capacity of 2,618 MW[54]
- Voltage calculation: The bus voltage of each 400kV substation must be within 400kV±5%
- Short-circuit current calculation: The breakdown current of each substation must be within 40kA
- Stability simulation: The most severe single-circuit fault on a 400 kV transmission line (assuming a three-phase short-circuit fault near the transmission end substation) is eliminated after 5 cycles, and the generator can be operated stably.

6.4.2 Power System Analysis Results and Evaluation in Each Power Generation Development Scenario

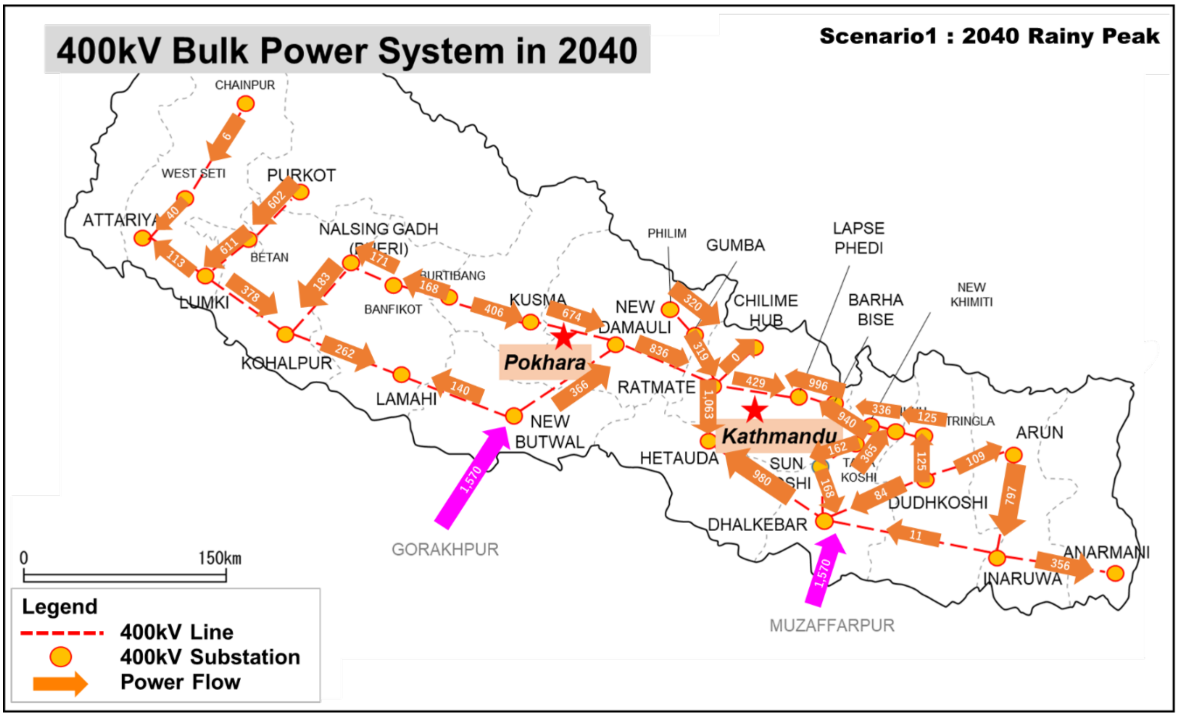
(1) Power Flow Calculation

Based on the preconditions described in the previous section, we carried out the power system analysis based on the power plant location, the power output, and load assumptions for scenarios 1 to 4 of the power generation development plan, targeting the 400kV trunk line system, and the resulting power flow diagram. Are shown in Figure 6.4-7, Figure 6.4-8, Figure 6.4-9 and Figure

[54] 1.732 x 400 (kV) x 0.829 (A) (current capacity of ACSR410sq) x 4 (conductor) x 0.95 (power factor) x 1.2 (long-term overload factor in Nepal) = 2,618 MW

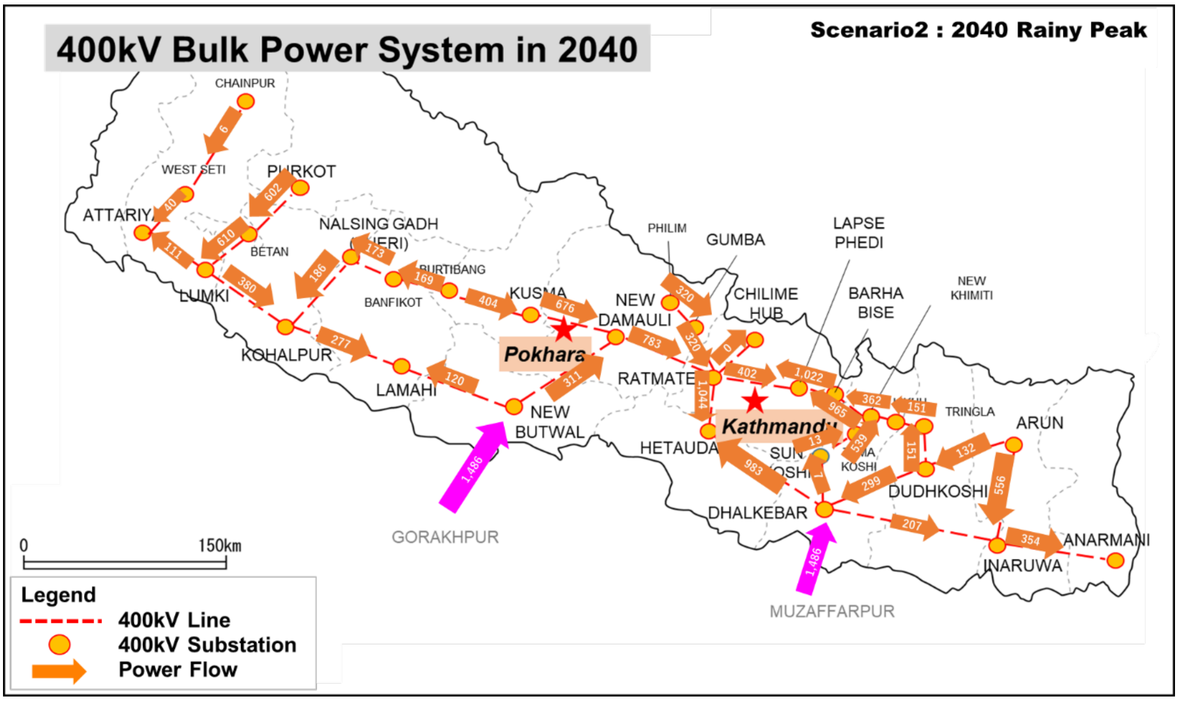
6.4-10. The arrows in the figure represent power flows in transmission lines.

In each scenario, the power flow of each transmission line was found to be within the allowable range of heat capacity.



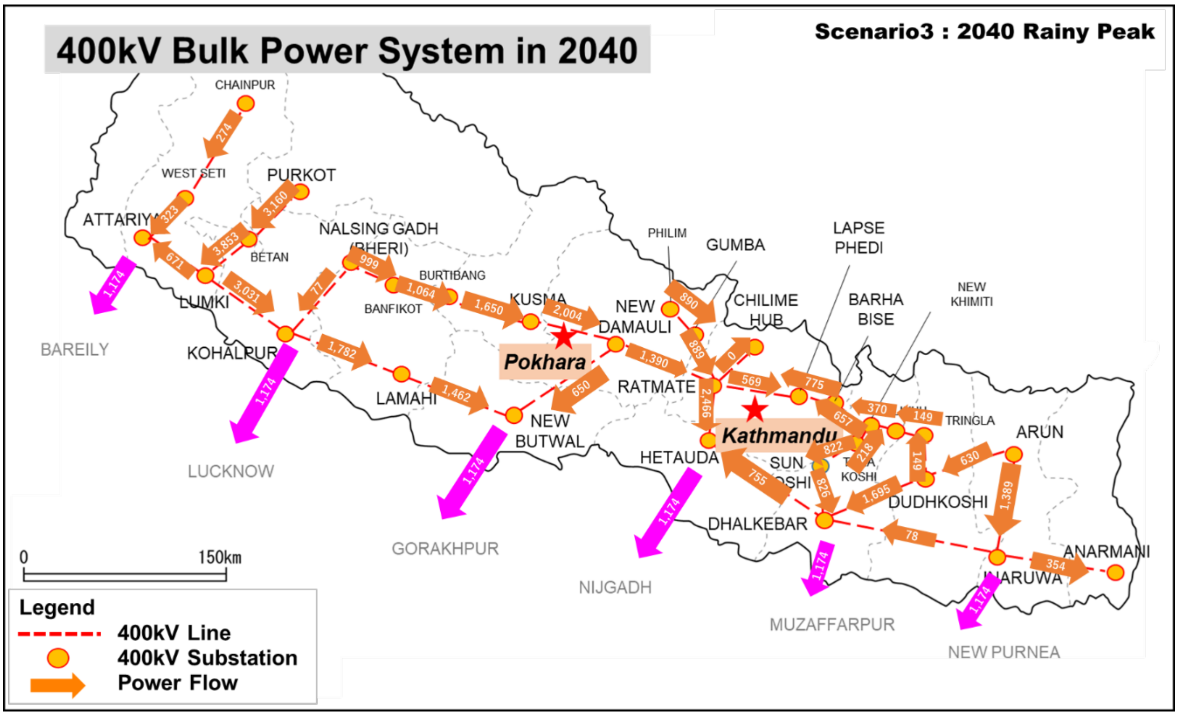
Source: JICA Study Team

Figure 6.4-7 Scenario 1 Power flow as of 2040 year, rainy season, peak time



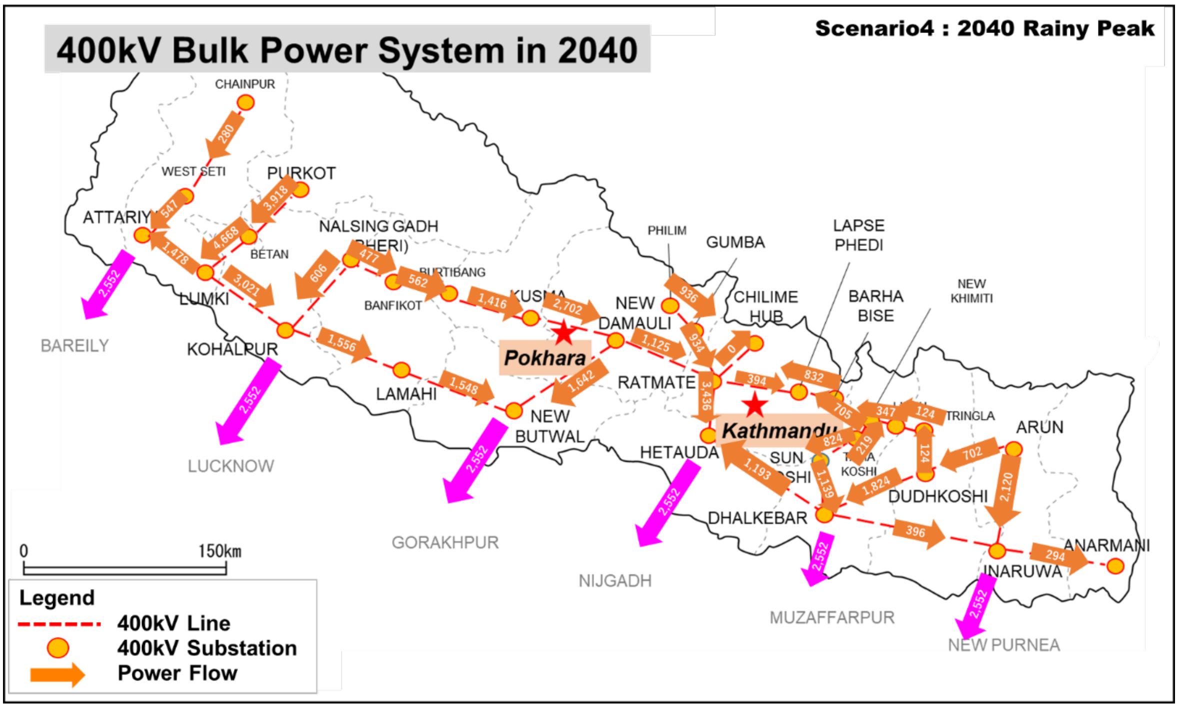
Source: JICA Study Team

Figure 6.4-8 Scenario 2 Power flow as of 2040 year, rainy season, peak time



Source: JICA Study Team

Figure 6.4-9 Scenario 3 Power flow as of 2040 year, rainy season, peak time

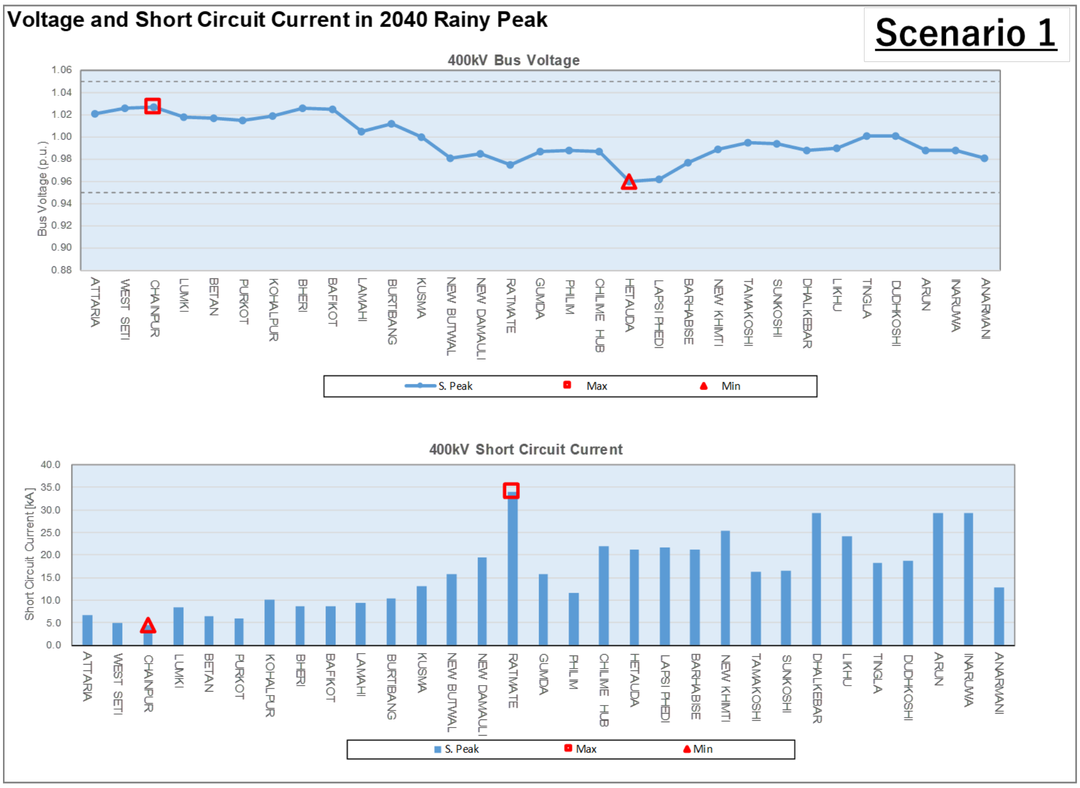


Source: JICA Study Team

Figure 6.4-10 Scenario 4 Power flow as of 2040 year, rainy season, peak time

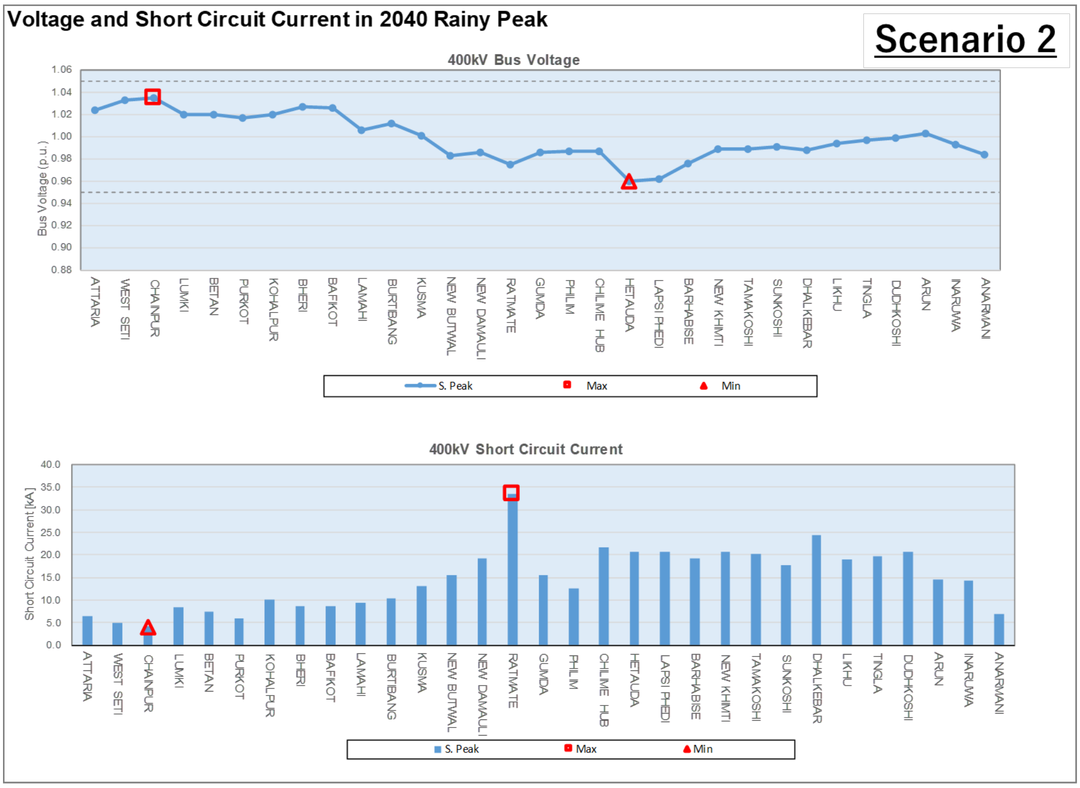
(2) Voltage and short-circuit current calculation

Figure 6.4-11, Figure 6.4-12, Figure 6.4-13 and Figure 6.4-14 show the voltage and short-circuit current results. The horizontal axis is the substation name, and the vertical axis is the voltage value and the short-circuit current value at the time of the accident at each substation. Regarding voltage, in each scenario, it was confirmed that the voltage at substations such as Hetauda, which are close to major demand areas, tends to be low, and was within ±5% of the voltage reference value. Regarding the short-circuit current, in each scenario, the short-circuit current of Ratmate near the main demand area tends to be large, and it was confirmed that it was within 40kA, which is the capacity of a general 400kV circuit breaker.



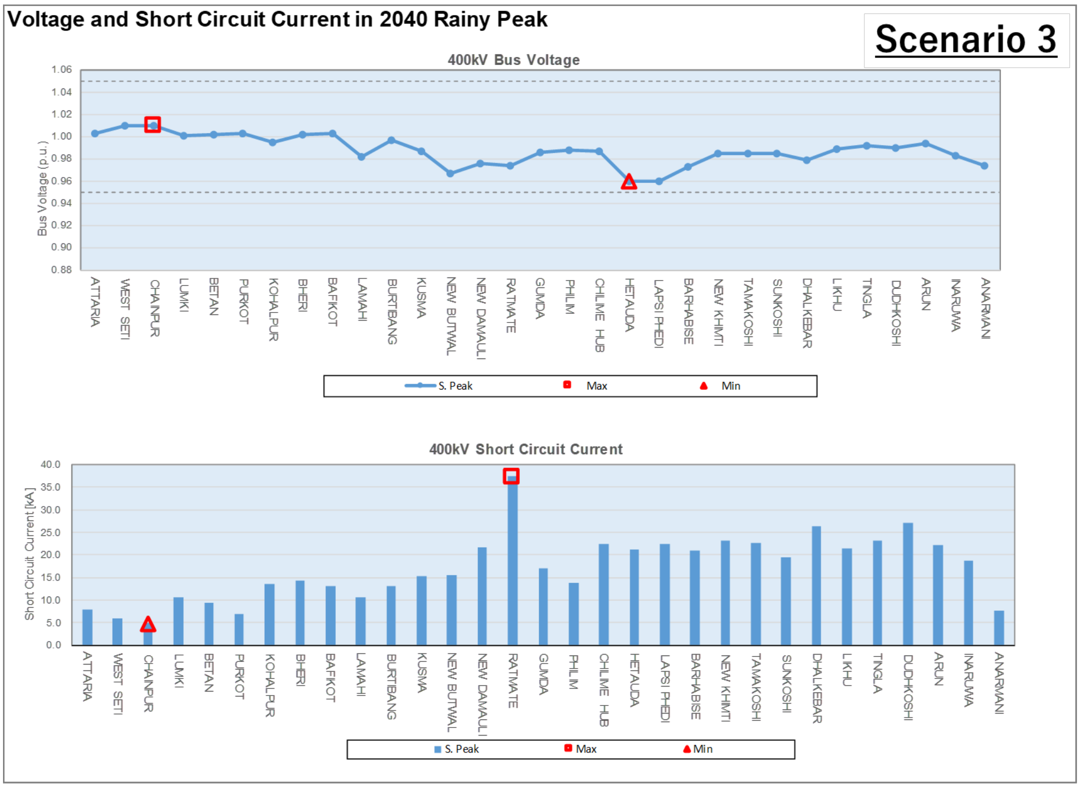
Source: JICA Study Team

Figure 6.4-11 Scenario 1 Voltage & Short-circuit current as of 2040 year, rainy season, peak time



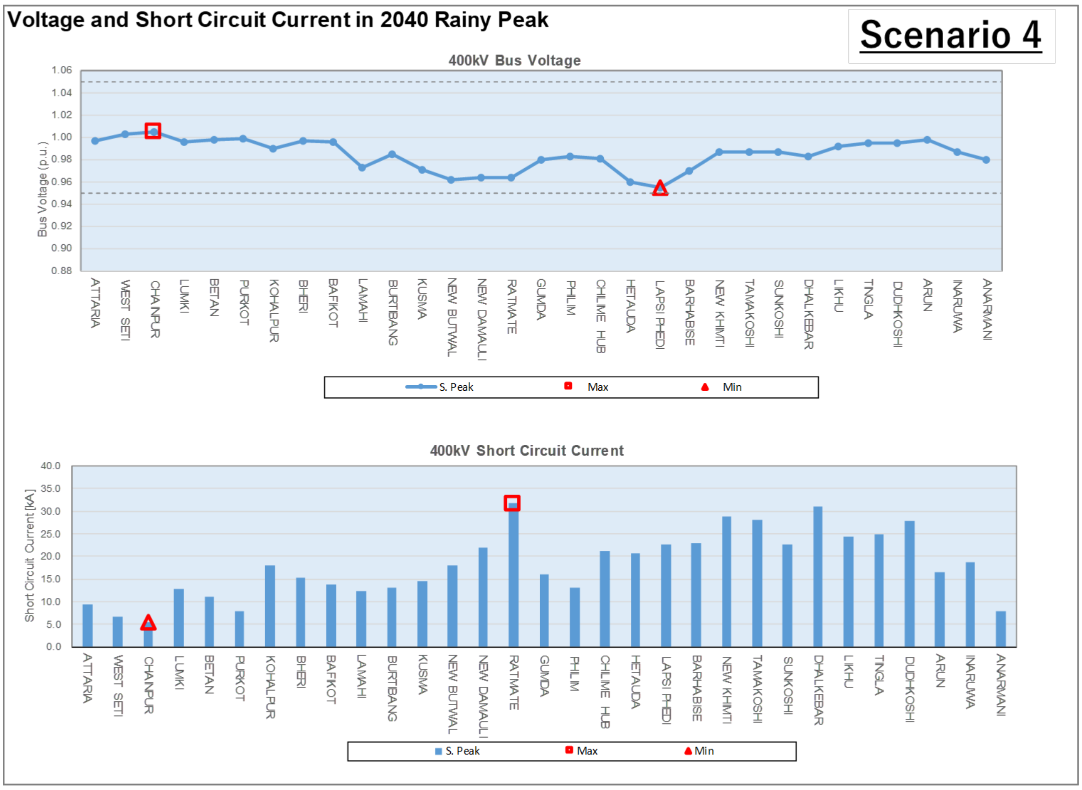
Source: JICA Study Team

Figure 6.4-12 Scenario 2 Voltage & Short-circuit current as of 2040 year, rainy season, peak time



Source: JICA Study Team

Figure 6.4-13 Scenario 3 Voltage & Short-circuit current as of 2040 year, rainy season, peak time



Source: JICA Study Team

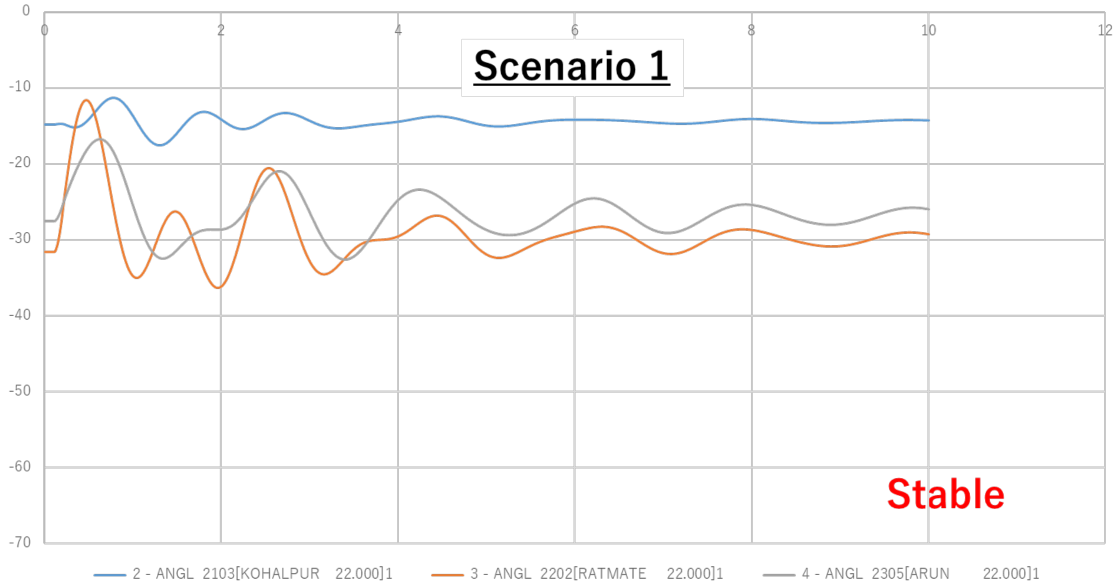
Figure 6.4-14 Scenario 4 Voltage & Short-circuit current as of 2040 year, rainy season, peak time

(3) Stability simulation

The system stability simulation results are shown in Figure 6.4-15, Figure 6.4-16, Figure 6.4-17 and Figure 6.4-18. These graphs show the phase difference between the base generator and the transmission line when a fault occurs.

For scenarios 3 and 4, when power export by interconnection lines, the system stability was unstable. The reason is that, with power export through interconnection lines to India, the flow of domestic transmission lines, such as from Purkot on the western side to Lumki, increases power flow, impacting system stability during faults.

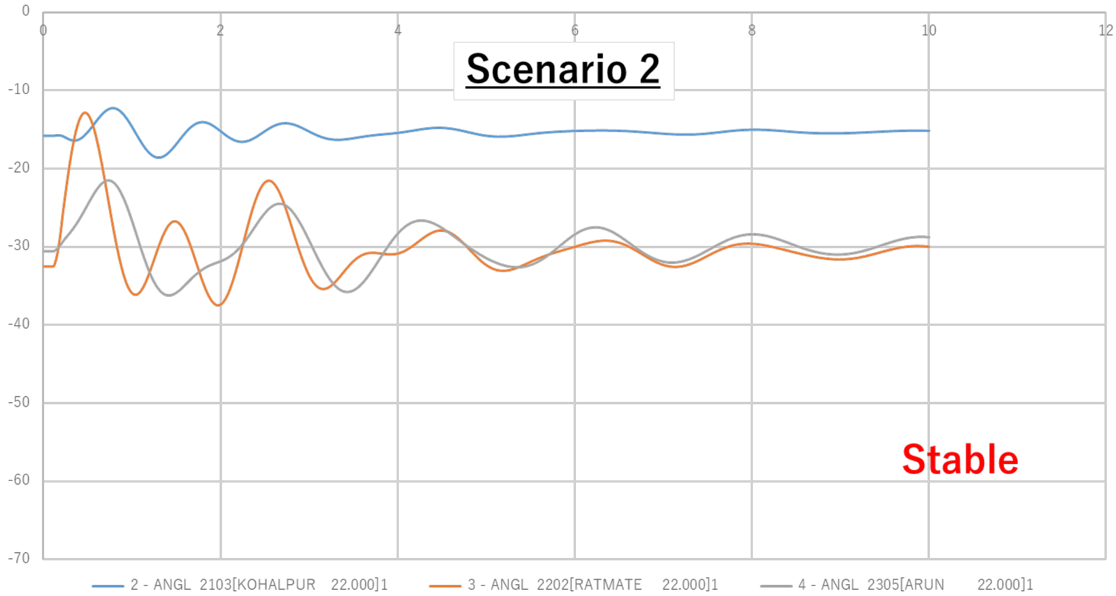
Regarding scenarios 3 and 4, system stability was achieved when some power sources were directly exported to India. A detailed explanation of direct export will be given later. The system analysis results shown in Figure 6.4-17 and Figure 6.4-18 shows the case with some power sources directly exported to India (partially direct export).



Ratmate-Hetauda T/L (max power flow point), Ratmate side, 5cycle accident

Source: JICA Study Team

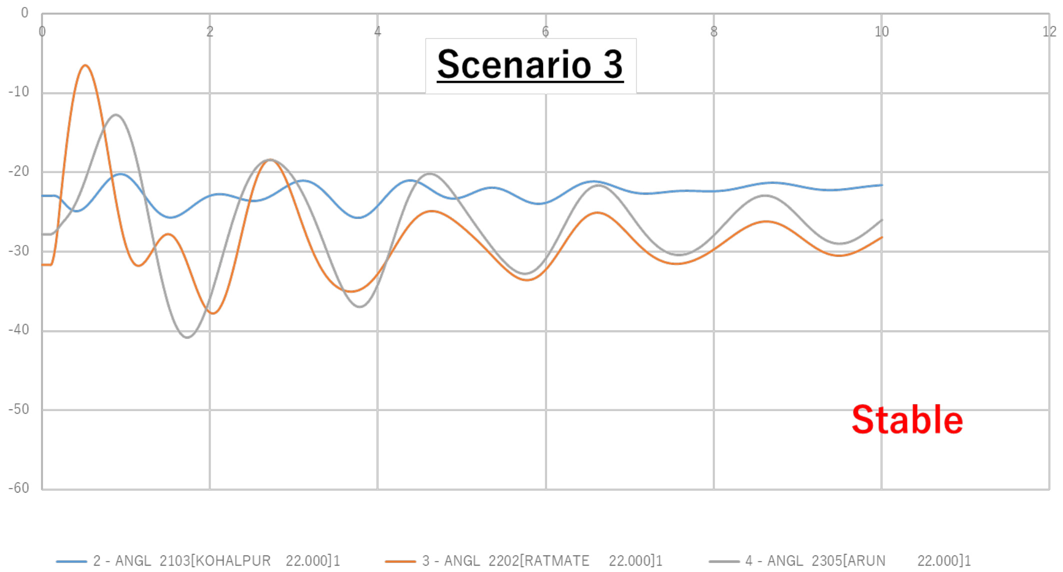
Figure 6.4-15 Scenario 1 Stability simulation as of 2040 year, rainy season, peak time



Ratmate-Hetauda T/L (max power flow point), Ratmate side, 5cycle accident

Source: JICA Study Team

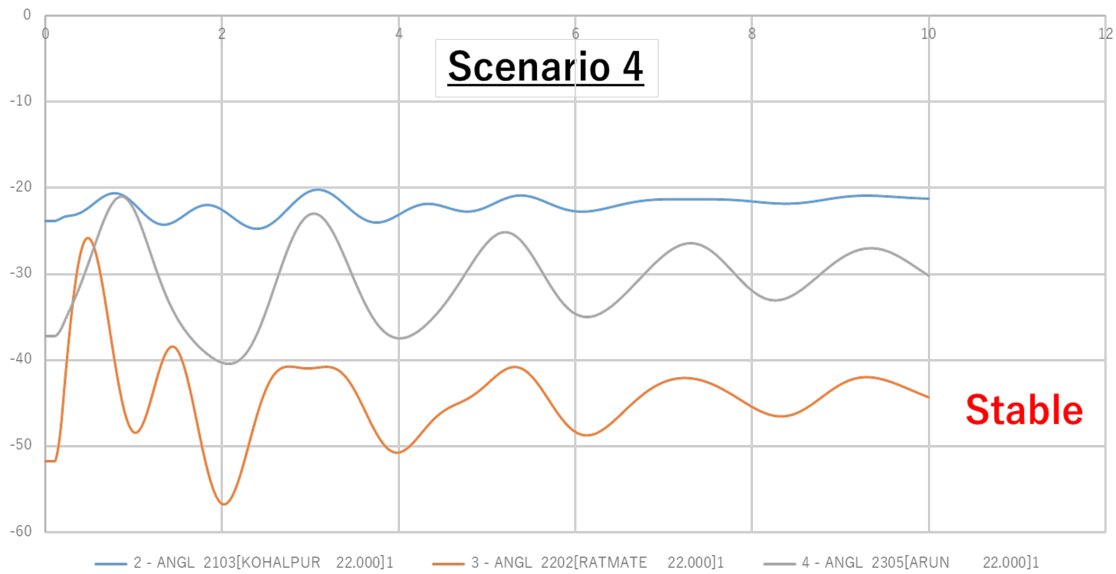
Figure 6.4-16 Scenario 2 Stability simulation as of 2040 year, rainy season, peak time



Ratmate-Hetauda T/L (max power flow point), Ratmate side, 5cycle accident
(Direct Export: 2.53GW (Purkot))

Source: JICA Study Team

Figure 6.4-17 Scenario 3 Stability simulation as of 2040 year, rainy season, peak time



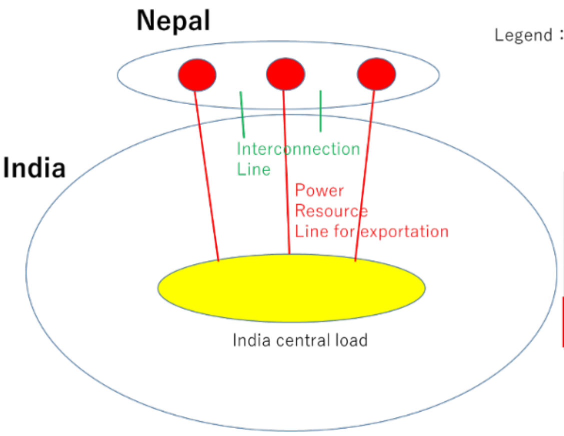
Ratmate-Hetauda T/L (max power flow point), Ratmate side, 5cycle accident
(Direct Export: 9.23GW (Purkot, Ratmate, Arun, Kusma))

Source: JICA Study Team

Figure 6.4-18 Scenario 4 Stability simulation as of 2040 year, rainy season, peak time

6.4.3 Study of Electricity Export Methods (Comparison of direct power source line exports and interconnection line exports)

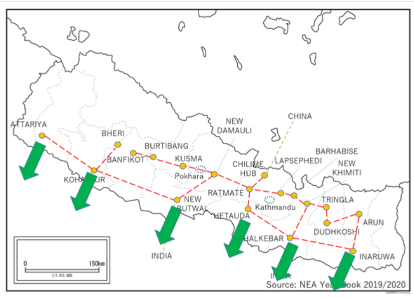
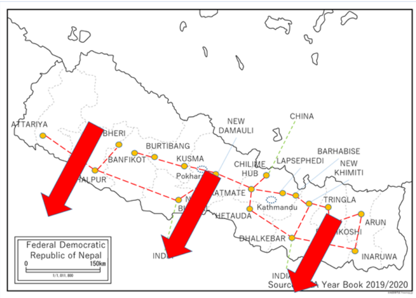
Currently, the power system plan planned by NEA is to export to India with six lines, but as discussed in Scenarios 3 and 4 above, if there were a large power flow flows in the future, the stability could not converge. Therefore, in this study, we are considering two plans for exporting to India. (Figure 6.4-19 and Figure 6.4-20).



PGDP Scenario	Min Export Amount(GW)	Max Export Amount(GW)
1	-5.0	1.5
2	-4.8	1.7
3	3.8	15.7
4	11.2	26.8

Source: JICA Study Team

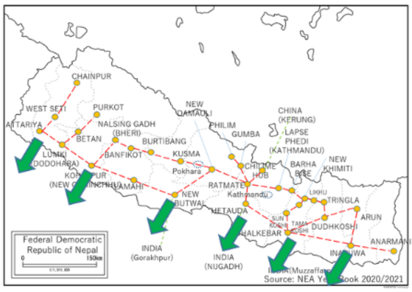
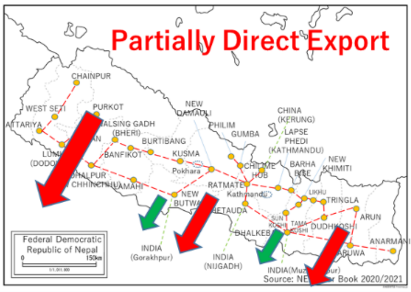
Figure 6.4-19 System configuration for large-capacity power export (image)

Plan	Export to India By Interconnection line Plan A	Export to India By resource line directly Plan B
System Configuration		
Reliability	Power flow of domestic line are impacted by export power amount, the damage of the power source drop out is large.	Power flow of domestic lines are independent of export power amount, the power system is stable
Cost	Surplus domestic line expansion shall be necessary	Domestic line expansion are not impacted by export power amount, the cost can be reduced

Source: JICA Study Team

Figure 6.4-20 Comparison between the export plan (A) using interconnection lines and the direct export plan (B) using power source lines

In this system analysis, we proposed Plan A', which adopts partially direct export while utilizing the interconnection lines. (Figure 6.4-21) Here, some of the power plants are exported directly to India, and some are exported via the domestic system to export the surplus. By comparison, it was confirmed that the stability of the system tends to be maintained.

Plan	Export to India By Interconnection line Plan A	Export to India By resource line directly＋ Interconnection Line Plan A‘
System Configuration		
Dynamic Stability Simulation	For Scenario 3 and Scenario 4, **Unstable**	For Scenario 3 and Scenario 4, **Stable** by <u>partially direct export</u>
Voltage	For Scenario 3 and Scenario4, some voltage is **not within ±5%**	For Scenario 3 and Scenario4, each voltage is **within ±5%** by <u>partially direct export</u>

Source: JICA Study Team

Figure 6.4-21 Comparison between interconnection line export method (A) and partially direct export method

As shown in the power flow diagram above, power imports and exports differ by scenario. For the system stability simulation, there was a tendency for system stability to diverge as power exports increased (Scenarios 3 and 4). Therefore, the interconnection line method was changed for scenarios 3 and 4 as follows.

Table 6.4-1 The Interconnection line for each scenario

Item	Power trade	Method	Interconnection point
Scenario 1	Import	Interconnection line to be constructed early	2 transmission line
Scenario 2	Import	Interconnection line to be constructed early	2 transmission line
Scenario 3	Export	Partial direct interconnect line to India	6 transmission line
Scenario 4	Export	Partial direct interconnect line to India	6 transmission line

Source：JICA Study Team

Discussions were held with WG members, including the NEA, regarding these power export concepts, and they generally understood the necessity of the export method.

6.4.4 Summary

1. System analysis results of 400kV bulk power systems corresponding to four power development plans were carried out, and it was confirmed that the system of each scenario satisfied the technical criteria and was appropriate.

2. It was confirmed that exporting some hydropower plants directly to India tends to be technically advantageous as a method of exporting large-scale hydropower.

3. We were able to introduce this result to the members of the System WG including NEA during the 5th field visit, and we were able to gain their understanding.

4. In the future, we plan to carry out a more detailed study on the power system plan corresponding to one optimal power generation development scenario and verify the adequacy of the power system plan.

6.5 ENVIRONMENTAL AND SOCIAL CONSIDERATIONS

6.5.1 Policy of SEA

This project falls under the sectors/characteristics that are likely to have an impact on the general public, or areas that are likely to be impacted, as listed in the "Guidelines for Environmental and Social Considerations" (published in April 2010). However, in consideration of the sector, project content, and area characteristics, it was judged that the undesirable impact on the environment would not be significant, and therefore the project was classified under Category B. The concept of SEA was introduced in IPSDP.

The EPA (Environmental Protection Act) 2019 and EPR (Environmental Protection Rules) 2020 stipulate the procedure of SEA in Nepal. However, since this procedure was recently introduced, no previous cases were confirmed in Nepal. The discussions with the implementing agency, MoEWRI, were held regarding the process to be applied to IPSDP, and as a result, it was confirmed that IPSDP would be an internal document approved by MoEWRI and would not require the SEA procedures in EPA 2019 and EPR 2020[55].

The following points were taken into consideration under the SEA. During the scoping stage of the SEA and the preparation of the draft IPSDP, environmental working groups and stakeholder consultations were held, and the opinions of stakeholders were reflected in the results of the SEA.

❖ To minimize negative impacts and maximize positive impacts; to manage and monitor the residual impacts. In the study, especially cumulative impacts along river basins of hydropower development projects were taken into careful consideration. The results were be incorporated into IPSDP.

❖ To conduct meaningful consultation at the earlier stage of the study in order to ensure transparency and accountability of IPSDP.

❖ In Nepal since SEA has not been fully conducted before, the concepts and approach of SEA were closely discussed with the implantation agency which should be mainly in charge of environmental and social considerations in Nepal, so that environmental and social considerations would be appropriately implemented from IPSDP preparation stage to the monitoring stage.

6.5.2 Scoping

The outline of the baseline information for each power source assumed in the development scenarios and the points to be noted in terms of environmental and social aspects in SEA are summarized below.

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[55] The SEA procedures stipulated in EPR 2020 are not necessarily applied even in the Pokhara City Wastewater Management Master Plan in Nepal (implemented after the implementation of EPR 2020). Each ministry in charge has some flexibilities on how to apply the procedures according to the situation. Note that this SEA is a part of this IPSDP; and a separate SEA report will not be prepared under the IPSDP.

(1) Hydropower Plant

The following points need to be paid attention to in SEA. (1) The situation of the development plan is different for each river system, and (2) The evaluation should consider that environmental and social impacts are different depending on the power generation method (ROR, PROR, STO).

❖ Physical environment/Natural environment

- Impacts on downstream discharge (E-flow) are expected due to the construction of reservoirs and regulating reservoirs.
- Impediments to the migration of aquatic organisms by dams and impacts on river ecosystems due to changes in flow rate are expected. A particular attention to cumulative impacts is necessary in river systems where hydropower development is concentrated.
- ROR hydropower development projects are not expected to change flow rate or have significant impacts on ecosystems.

❖ Social environment

- For hydropower development, large-scale involuntary resettlement and land acquisition are expected if there are houses within the planned reservoir or regulating pond. If fisheries are being carried out downstream of power generation facilities, attention should be paid to the impact on fisheries due to changes in flow rate, water quality, etc.
- Large-scale involuntary resettlement and land acquisition are not expected for ROR type hydropower development projects.

Table 6.5-1 Items to be Taken into Considerations for Hydroelectric Power Generation in SEA

No.	Items to be taken into considerations for SEA	Hydropower		
		ROR	PROR	STO
1	E flow	B	A	A
2	Air pollution	B	B	B
3	Water pollution	B	B	B
4	Waste	B	B	B
5	Protected areas	C	C	C
6	Ecosystem	B	A	A
7	Land acquisition/ Involuntary resettlement	B	A	A
8	Indigenous peoples	C	C	C
9	Natural hazards (landslide, flood etc.)	C	C	C
10	Climate change	C	C	C

Note: A (Significant impact anticipated), B (Moderate impact anticipated), C (Impact can vary depending on site locations), D (no or negligible impact)
ROR: Run of River, PROR: Peaking Run of River, STO: Storage
Source: JICA Study Team

(2) Renewable

Hydropower is the main power source in Nepal, but IPSDP considers the installation of renewable energy toward 2040. In this SEA, solar power generation was examined in consideration of the following points, since solar power generation is more likely to be introduced among renewable energies.

- SEA will pay attention to land acquisition and accompanying resettlement for evaluation, especially for large-scale solar power generation.

- Since Nepal is mountainous in the north-central part of the country, large-scale development is difficult in steep mountainous areas. From the viewpoint of securing suitable land, it is assumed that solar power will be introduced in the southern part of the country, mainly in the Terai Plain. On the other hand, since the Terai Plain is an agricultural area, it is necessary to pay attention to the impact on livelihoods.

Table 6.5-2 Items to be Taken into Considerations for Renewable Energy (Solar Power) in SEA

No.	Items to be taken into considerations for SEA	Renewable energy (Solar)
1	E flow	D
2	Air pollution	B
3	Water pollution	B
4	Waste	B
5	Protected areas	C
6	Ecosystem	B
7	Land acquisition/ Involuntary resettlement	A
8	Indigenous peoples	C
9	Natural hazards (landslide, flood etc.)	C
10	Climate change	C

Note: A (Significant impact anticipated), B (Moderate impact anticipated), C (Impact can vary depending on site locations), D (no or negligible impact)

Source: JICA Study Team

(3) Others

SEA considers the following as environmental and social impacts common to all power sources.

❖ Transmission lines

- In Nepal, ROW (Right of Way) is established under overhead transmission lines[56]. Construction of structures within the RoW is not permitted, so in the case there are residential structures within the RoW of the transmission line, they will be subject to relocation. In addition, land acquisition is required for the tower section. Also, when there is farmland under the transmission line when it is constructed, the farmland will be temporarily unusable, so the attention must be paid to the impact on livelihoods.

❖ Protected areas/ Ecosystems

- Nepal designated 12 National Parks, 1 Wildlife Reserve and 1 Hunting, 6 Conservation Areas, and 13 Buffer Zones as Protected Area under the National Parks and Wildlife Conservation Act. Any development in these areas must be approved by the authorities prior to development. Acts of damming or altering the flow of rivers are prohibited, and in hydropower development, restrictions on maintenance flow, etc. are required.
- 31 KBAs have been identified throughout Nepal.
- SEA examines information on Protected Areas and important habitats to avoid significant impacts.

❖ Indigenous Peoples

- Under the National Foundation for the Development of Indigenous Nationalities Act, 59 ethnic groups are defined as indigenous peoples (*Janajati* in the local language), distributed

[56] RoW is stipulated by voltage of transmission line with 46m of 400kV, 30m of 220kV and 18m of 132/66kV

throughout the country.

- Consideration should be given to making plans that adequately reflect the opinions of stakeholders, as there are cases of opposition from local residents in existing reservoir-type hydropower development projects.
- In particular, Nepal ratified the ILO (International Labor Organization) Convention on Indigenous and Tribal Peoples in Independent Countries (No. 169) in 2007, and indigenous peoples will be taken into consideration in the master planning process.

Based on the above, the main objectives and judgment criteria of SEA in IPSDP are shown in the table below.

Table 6.5-3 SEA Objectives and Decision-making Criteria

	Items	Objectives of SEA	Decision-making criteria of SEA
1	E flow	• Avoidance/mitigation of impacts to E flow	• Does IPSDP avoid the impact on E flow?
2	Air pollution	• Reduction of air pollution power sector • Proper management of air pollutants	• Does IPSDP contribute to the reduction of air pollutants from power sector? • Does IPSDP encourage the establishment of air pollutant monitoring?
3	Water pollution	• Reduction of water contaminants in power sector • Proper management of water contaminants	• Does IPSDP contribute to the reduction of water contaminants from power sector? • Does IPSDP encourage the establishment of water contaminants monitoring?
4	Waste	• Proper management of waste (including hazardous waste)	• Is there a potential for significant environmental and social impacts from waste generated?
5	Protected areas	• Avoidance of impacts on protected areas in power sector	• Does IPSDP avoid projects within protected areas?
6	Ecosystem	• Avoidance/mitigation of impacts to critical habitat	• Does IPSDP encourage the development of a system to avoid and manage impacts to critical habitat?
7	Land acquisition/ Involuntary resettlement	• Avoidance or minimization of land acquisition and involuntary resettlement	• Does IPSDP take land constraints into account?
8	Indigenous peoples	• Avoidance/mitigation of impacts to cultures of indigenous peoples	• Does IPSDP include opinions from indigenous peoples?
9	Natural disaster (landslide, flood etc.)	• Response to natural hazards such as landslide, etc.	• Does IPSDP address the risk of natural disasters?
10	Climate change	• Reduction of CO_2 emission in power sector • Response to disasters in light of the impacts of climate change	• Do the study results of scenarios (including power mix) contribute to the reduction of CO_2 emissions? • Does IPSDP address the increased risk of disasters due to climate change?

Source: JICA Study Team

6.5.3 Evaluation of Environmental and Social Aspects of Development Scenarios

A comparative evaluation was conducted on the four development scenarios prepared in IPSDP ((a) Power import, (b) Renewable, (c) Hydropower middle, (d) Hydropower maximum) from the environmental and social aspects. The results of the comparative evaluation are shown in Table 6.5-4.

In the power import scenario, the impact on the environment (protected areas and forests, etc.) and on the social aspects (farmland and housing, etc.) is relatively minor compared to other scenarios, but greenhouse gas emissions are expected to be larger and have a relatively large impact on climate change. In the renewable energy utilization scenario, the impact on the environment and social aspects is similar to the power import scenario, while greenhouse gas emissions will be relatively lower than in the power import scenario due to the promotion of renewable energy. In the maximum hydropower development scenario, the impact on the environment and social aspects is expected to be relatively significant compared to other scenarios, while greenhouse gas emissions will be relatively lower.

Table 6.5-4 Comparative Analysis of Development Scenarios

	Item	Power import	Renewable	Hydro middle	Hydro maximum
1	Environment: Protected areas, Chure conservation area, KBA, Forest	C	C	B	A
2	Social: Farmland, residential areas	C	C	B	A
3	Climate change	A	B	C	C

Note: A (relatively significant impact expected), B (some impact expected), C (relatively minor impact expected)

Source: JICA Study Team

6.6 SELECTION OF OPTIMUM SCENARIO

The future direction of the power generation development planning in Nepal is discussed by comparing each scenario based on the results of the comparative study of each Scenario based on 3E + Policy are summarized in Table 6.6-1.

In terms of energy security, the self-sufficient rate of power generation is below 100% in Scenarios 1 and 2 in 2040. It is necessary to rely on power imports from India. For Scenarios 3 and 4, the self-sufficiency is almost secured. In the event of international problems with neighbouring countries such as India, domestic power supply may be disrupted in Scenarios 1 and 2. It may not be possible to export electricity in Scenarios 3 and 4, making it difficult to recover the investment cost in each power plant. All Scenarios carry the risk of international problems with neighbouring countries but meanings are different. For scenarios 3 and 4, domestic power supply is possibly maintained and energy self-sufficiency can be improved through an effort to promote electrification. In Scenario 2, the grid stability during periods of low demand which happen in dry season is supposed to fragile due to the massive introduction of renewable energy.

The development capacity of hydropower has a trade-off relation with financial burden and economic growth through electricity exports. If large-scale development is pursued as shown in Scenarios 3 and 4, power exports will increase. If not realised, exports will decrease as shown in Scenarios 1 and 2. However, in both scenarios, the accumulated balance of power trade is in surplus and the promotion of power exports is important regardless of which Scenario is chosen. In terms of vulnerability to fuel inflation, Scenarios 1 and 2 which require electricity imports, have these risks. In the event of global fuel inflation such as 2022, the risk of financial burden caused by the rapid inflation of power purchase cost from India needs to be considered.

With regard to environmental and social considerations, the impact on the natural and social environment will increase if hydropower development goes ahead. In particular, large STO projects which are mainly included in d) GoN require large reservoirs and have a significant environmental impact.

In terms of climate change actions, further hydropower development would make a significant contribution to reduction of regional CO_2 emissions by power trade with neighbouring countries in where thermal power plants play main roles in power generation. In addition, incentives from these reductions can be expected in the future.

In terms of consistency with Nepal's electricity policy, the development of 15,000 MW in 2030 is not achievable in Scenarios 1 and 2 with the development of only b) Construction. However, Scenarios 3 and 4 can accomplish it with the development of c) Survey and d) GoN. In addition, it is possible to achieve the introduction target of 10% in domestic power demand by alternative energy sources including renewable energy.

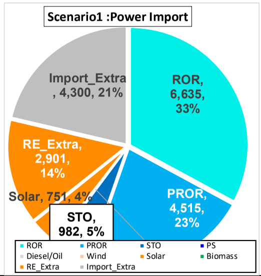
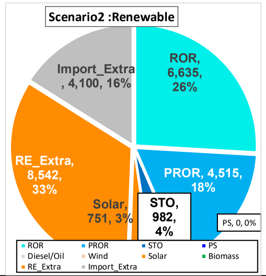
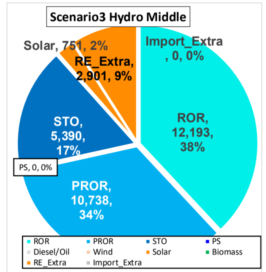
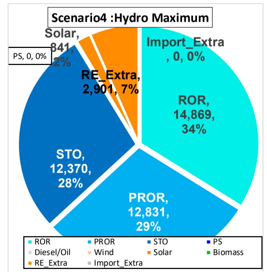
Summary of evaluation each Scenario in accordance with 3E + Policy are as follows;

- Scenario 1: Power Import is assumed to be a feasible Scenario with low capital investment and environmental impact. However, it has low energy self-sufficiency in 2040, supply risks of power import interruptions and cost escalation risks such as fuel inflation. It is also difficult to achieve the goals set out in the policy of power sector.
- Scenario 2: Renewable as same as Scenario 1, the capital investment cost and environmental impact is relatively lower and the import dependency is also low owed to the generation of renewable energy. On the other hand, it is necessary to include the regulation capacity from neighbouring countries against the intermittency of VRE mainly derived from solar in order to secure the grid stability.
- Scenario 3: Hydro Middle requires power imports only during February but it is possible to supply power to domestic demand and neighbouring countries even in drought years. Although the capital investment required is high, it is assumed to be feasible in case of power trade promoted. The environmental impact is also significant and measures to reduce the impact based on the results of the SEA are important.
- Scenario 4: Hydro Maximum can secure to supply power to domestic demand and neighbouring countries even in the drought year. Compared to Scenario 3, the capital investment and environmental impact would also be very high and feasibility needs to be fully considered.

Based on the results of the comparative study of Development Scenarios described above taking into account the evaluation of 3E and consistency with the Policy, Scenario 3: Hydro Middle is selected as the base case for Optimum Scenario which development scale can be optimized.

Direction of future development by IPSDP suggest that basic strategy of power sector is to satisfy the domestic demand in dry season and to export surplus electricity to neighbouring countries in rainy season by domestic clean energy of hydropower and renewable energy.

Table 6.6-1 Summary of the Evaluation of Development Scenarios

Evaluation Items		Scenario 1 Power Import	Scenario 2 Renewable	Scenario 3 Hydro Middle	Scenario 4 Hydro Maximum
Generation Mix					
		20,158MW	25,599MW	32,048MW	43,887MW
(1) Energy Security	Self Sufficiency Rate of Power Generation (%)	85.4%	99.7%	188.2%	230.1%
	International Issues	Interruption of power imports		Interruption of power exports	
	Grid Stability	None	Impacts by VRE	None	
(2) Economy	Cumulated Investment Cost	19,138 MUSD (1,015MUSD/year)	24,838 MUSD (1,307MUSD/year)	48,345 MUSD (2,544MUSD/year)	70,531 MUSD (3,712MUSD/year)
	Cumulated Balance of Power Trade	7,360MUSD	10,820MUSD	30,366MUSD	41,270MUSD
	Vulnerability for Fuel Cost	Fuel Inflation in India		None	
(3) Environmental and Social considerations	Natural and Social Impacts	Relatively small		Intermediate	Large
	Cumulated CO_2 Emissions (million ton)	69.1 million ton	52.4 million ton	39.5 million ton	44.5 million ton
	CO_2 Emissions Rate (g-CO_2 /kWh)	172.5 g-CO_2/kWh	111.4 g-CO_2/kWh	27.0 g-CO_2/kWh	25.0 g-CO_2/kWh
	Cumulated Reduction of CO_2 Emissions by Power Export (million ton)	169.1 million ton	205.7 million ton	505.7 million ton	684.3 million ton
Policy	Target of 15000MW in 2030	Not achieved		Achieved	
	Introduction of ARE	Achieved			

Source: JICA Study Team

7. FORMULATION OF THE OPTIMUM SCENARIO

7.1 UPDATE FOR THE FORMULATION OF THE OPTIMUM SCENARIO

This section updates Scenario 3: Hydropower Middle which is selected as the Optimum Scenario and formulates the PGDP, PSP, SEA, economic and financial analysis, financing and utilization of surplus energy in IPSDP. The Optimum Scenario analysis reflects the following updates of two input conditions:

- Power Demand Forecast (Update the input conditions from 2021 to 2023)
- Generation Project List (Update DoED List from May, 2021 to March 2023 and execution of screening of hydropower projects)
- CO_2 Emission Factor of India in Power Trade (820g-CO_2/kWh→716 g-CO_2/kWh)

7.2 POWER GENERATION DEVELOPMENT PLANNING

7.2.1 Screening of Hydropower Projects

This section presents the results of the screening for hydropower projects, which will be applied for the formulation of the Optimum Scenarios demonstrated in the subsequent sections. Screening of hydropower projects were carried out in order to prioritize and select hydropower projects for Optimum Scenario by uniform evaluation in same criteria. Total 865 hydropower projects listed in DoED Project List were assessed based on salient features collected and GIS (Geographic Information System) data.

Evaluation criteria are (1) economy, (2) policy, (3) hydrology, (4) seismic, (5) environment and (6) progress of the projects. Based on each point, hydropower projects are classified into four (4) grade of “High”, “Moderate”, “Fair” and “Low”. Target of screening shall be hydropower project of Survey License, Application for Survey License and GoN. Existing plants and committed projects with Construction License and Application for Construction License are also evaluated but excluded from the screening.

Table 7.2-1 Evaluation Items for Screening

Category	No.	Item	Remarks
1. Economy	1)	Capacity [MW]	Contribution to supply for peak demand
	2)	Dry Energy [%]	Contribution to dry season when electricity supply decreases
	3)	LCOE [cents/kWh]	Economic efficiency of the project
	4)	Assumed COD	When to start for supplying energy
	5)	Transmission Line length [km]	Distance from the nearest substation to the project site
2. Policy	6)	Generation type	STO (storage type) is highly valued because of regulating and supplying in dry season
3. Hydrology	7)	GLOF (Geographic Information System) Risk	Risk of natural disaster (GLOF as hydrological risk)
4. Seismic	8)	PGA [gals]	Risk of natural disaster (PGA as seismic risk)
5. Environment	9)	Protected Area [%]	Impact / Risk for natural environment
	10)	Conservation Area [%]	Impact / Risk for natural environment
	11)	KBA [%]	KBA (Key Bio-diversity Area)
	12)	Forest Area [%]	Impact / Risk for natural environment
	13)	Cropland Area [%]	Impact / Risk for social environment
	14)	Buildup area [km2]	Impact / Risk for social environment
6. Progress	15)	Progress of Project	Reliability of the project is evaluated by its progress
7.Uncertainty	16)	Resettlement	In case of large resettlement occurs, the rating will be reduced
	17)	Political	In case of political issue occurs, the rating will be reduced
	18)	Other critical issues	If other critical issues (Indigenous people, Water use, Cultural heritage) are to occur, the rating will be reduced

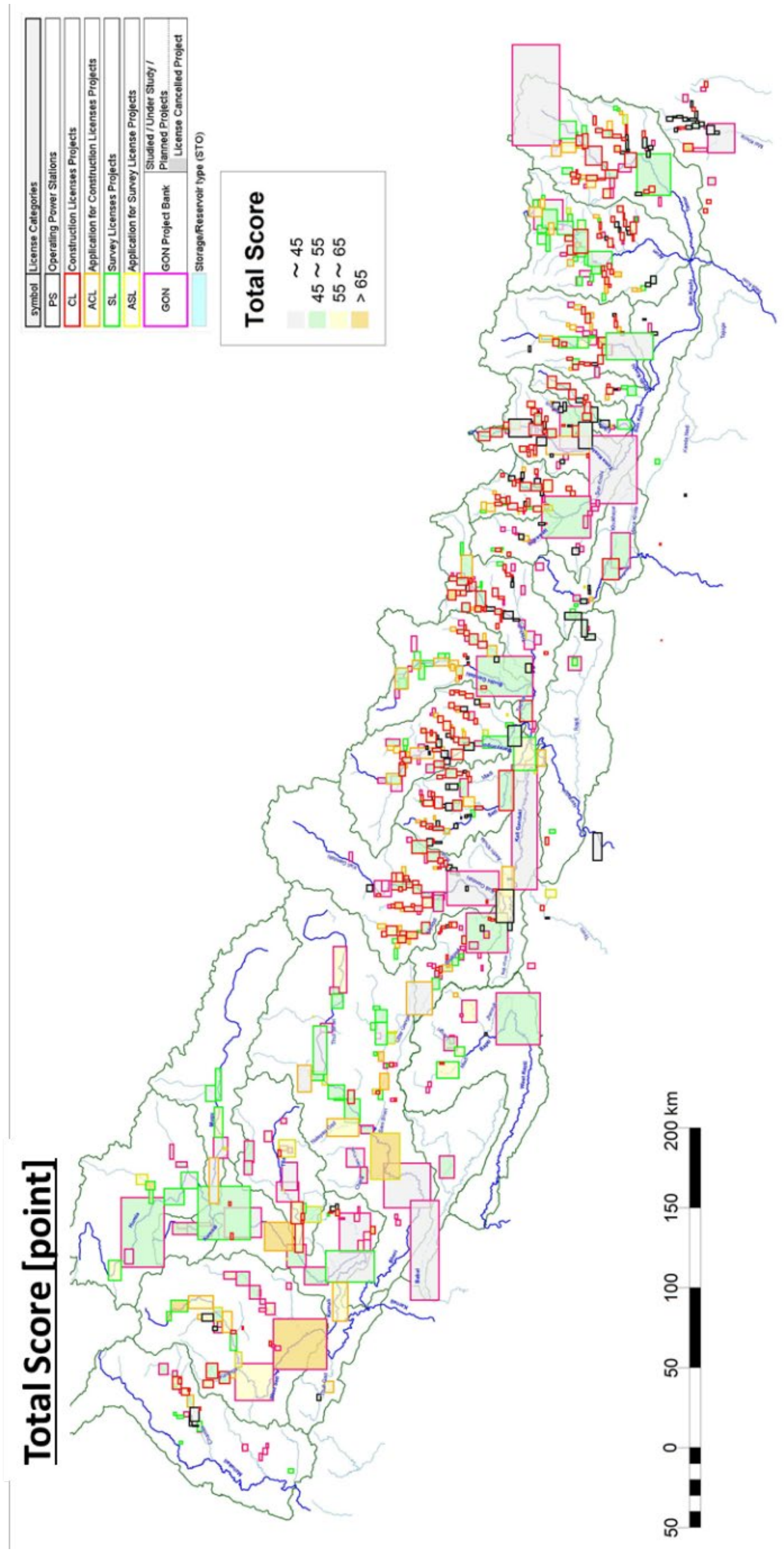
Source: JICA Study Team

Table 7.2-2 Evaluation Score for Screening

Category		Item	Max	Score								
1. Economy	1)	Capacity [MW]	5	A	[5]	>= 100	B	[2]	30-100MW	C	[0]	<30MW
	2)	Dry Energy [%]	10	A	[10]	40%	B	[5]	30-40%	C	[0]	>= 30 %
	3)	LCOE [cents/kWh]	10	A	[10]	< 4	B	[5]	4 - 8	C	[0]	>= 8
	4)	Assumed COD	5	A	[5]	2022-2030	B	[3]	2030-2035	C	[0]	>2035
	5)	Transmission Line Length [km]	5	A	[5]	< 10	B	[3]	5 – 10	C	[0]	>= 20
2. Policy	5)	Generation type	5	A	[5]	STO	B	[3]	PROR	C	[1]	ROR
3. Hydrology	6)	GLOF Risk	5	A	[5]	very low	B	[3]	Low / moderate	C	[0]	High / very high
4. Seismic	7)	PGA [gals]	5	A	[5]	< 200	B	[3]	200-300	C	[0]	>= 300
5. Environment	8)	Protected Area [%]	6	A	[6]	0%	B	[3]	0-10%	C	[0]	>= 10 %
	9)	Conservation Area [%]	6	A	[6]	0%	B	[3]	0-10%	C	[0]	>= 10 %
	10)	KBA [%]	6	A	[6]	0%	B	[3]	0-10%	C	[0]	>= 10 %
	11)	Forest Area [%]	6	A	[6]	0%	B	[3]	0-10%	C	[0]	>= 10 %
	12)	Cropland Area [%]	6	A	[6]	0%	B	[3]	0-10%	C	[0]	>= 10 %
	13)	Buildup area [km^2]	20	A	[20]	< 0.01	B	[10]	0.01-0.5	C	[0]	>= 0.5
6. Progress	14)	Progress of Project	5	A	[5]	Studied	B	[5]	Under-study	C	[5]	Others
7. Uncertainty		Resettlement	In case large resettlement occurs, the rating will be reduced									
		Political	In case of political issue occurs, the rating will be reduced									
		Other critical issues	Indigenous people, Water use, Cultural heritage, etc.									

Source: JICA Study Team

Above results are summarized as Figure 7.2-1 and Table 7.2-3.



Source: JICA Study Team

Figure 7.2-1 Evaluation Results of Screening: Total Score

Table 7.2-3 Summary of Evaluation Results of Screening

Score	Number of Site			Capacity (MW)		
	ROR	PROR	STO	ROR	PROR	STO
0 - 10	4	0	0	11	0	0
10 - 20	6	0	0	3	0	0
20 - 30	6	2	4	151	493	2,403
30 - 40	52	5	1	1,934	2,401	1,116
40 - 50	209	18	6	6,869	4,016	2,074
50 - 60	343	31	10	5,984	3,747	4,699
60 - 70	133	15	13	1,925	1,891	2,513
70 - 80	3	3	0	144	373	0
80 - 90	0	0	0	0	0	0
90 - 100	0	0	0	0	0	0
Sub Total	761	70	756	74	34	17,021
Total	865			42,935		

Source: JICA Study Team

The screening in this study targets all hydropower projects listed in the DoED, evaluated uniformly based on the multi criteria. Evaluation is based on the specific items in the database organized in this Project and the GIS data collected in the SEA. This approach allows for the uniform evaluation of hydropower projects based on the same criteria. The screening enables the prioritization of hydropower projects.

On the other hand, it should be noted that the accuracy of the evaluation is not high and the screening results do not reflect the specific circumstances of individual projects in detail. For example, "residential areas" indicates that there are large differences between target area of screening which is approved boundary by DoED and actual effected area, resulting the trend to lowering the score of large STO projects. Therefore, the evaluation of specific individual projects should be based on the F/S, ESIA (Environmental Impact Assessments), and DPR (Detailed Project Report) of each project.

7.2.2 Input Projects for the Optimum Scenario

The projects to be introduced in the Optimum Scenario are set as follows:

(1) Hydropower Projects

The hydropower projects to be introduced in the Optimum Scenario are 643 sites with a rating of 45 points or more and a total capacity of 32,189.2 MW based on the hydropower screening results as shown in Table 7.2-4.

Table 7.2-4 Hydropower Projects to be introduced in the Optimum Scenario

Category	Status	DOED Status	ROR		PROR		STO		Subtotal	
			Site	Installed Capacity (MW)	Site	Installed Capacity (MW)	Site	Installed Capacity (MW)	Site	Installed Capacity (MW)
a) Existing	PS	(1)Existing Power Plants	135	1,394.9	4	720.0	1	14.0	140	2,128.9
b) Committed	CL	(2)Construction License	233	5,314.5	21	2,887.8	2	153.0	256	8,355.3
	ACL	(3)Application for Construction License	71	1,848.6	18	3,654.8	6	1,584.6	95	7,088.0
c) Screened	SL	(4)Survey License	78	2,065.6	20	2,881.6	6	2,887.0	104	7,834.2
	ASL	(5)Application for Survey License	34	671.8	0	0.0	1	271.4	35	943.2
	GON	(6)GON Reserved Projects	2	534.0	2	785.8	9	4,519.9	13	5,839.7
Total		-	553	11,829.4	65	10,930.0	25	9,429.9	643	32,189.2

Source: JICA Study Team

This screening is a consistent evaluation using GIS on the same criteria and is superior for assessing many sites in similar manners. However, the accuracy is rough, and it should be noted that decisions of individual projects must be carried out based on F/S and ESIA stages.

From this perspective, this examination is based on a list of individual sites for analysis and shows the scale of power generation capacity for the target year. However, it should be noted that the results don't intend to indicate the project-wise feasibility and to recommend the implementation of individual sites.

(2) Renewable Energy

Regarding the introduction of renewable energy in the Optimum Scenario, it was pointed out in evaluation of "Scenario 2: Renewable" with 25% introduction of renewable energy against domestic demand (GWh) that power supply in Nepal is occupied with a significant portion of clean energy by hydropower and the impact on power system stability is more concerning than CO_2 reduction.

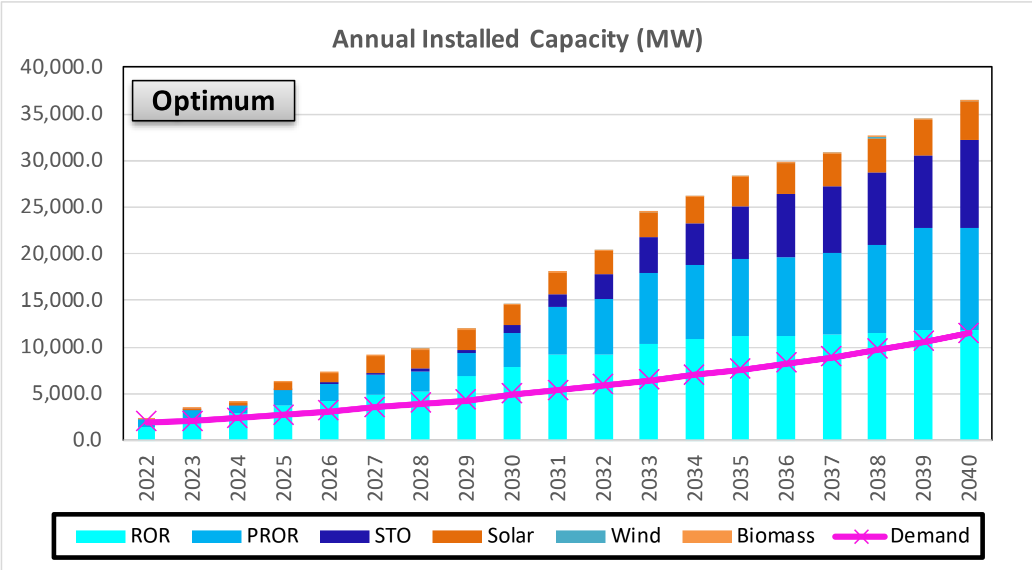
Therefore, 10% against domestic power demand after 2030 is applied as an introduction target for renewable energy which corresponds to phase 2 of IEA's VRE introduction. In this case, the renewable energy capacity in 2040 will be 4,135 MW.

7.2.3 Analysis Results of the Optimum Scenario

(1) Installed Capacity (MW)

The transition of installed capacity and demand in the Optimum Scenario and the generation mix in 2025, 2030, 2035, and 2040 are shown in Figure 7.2-2 and Figure 7.2-3 respectively.

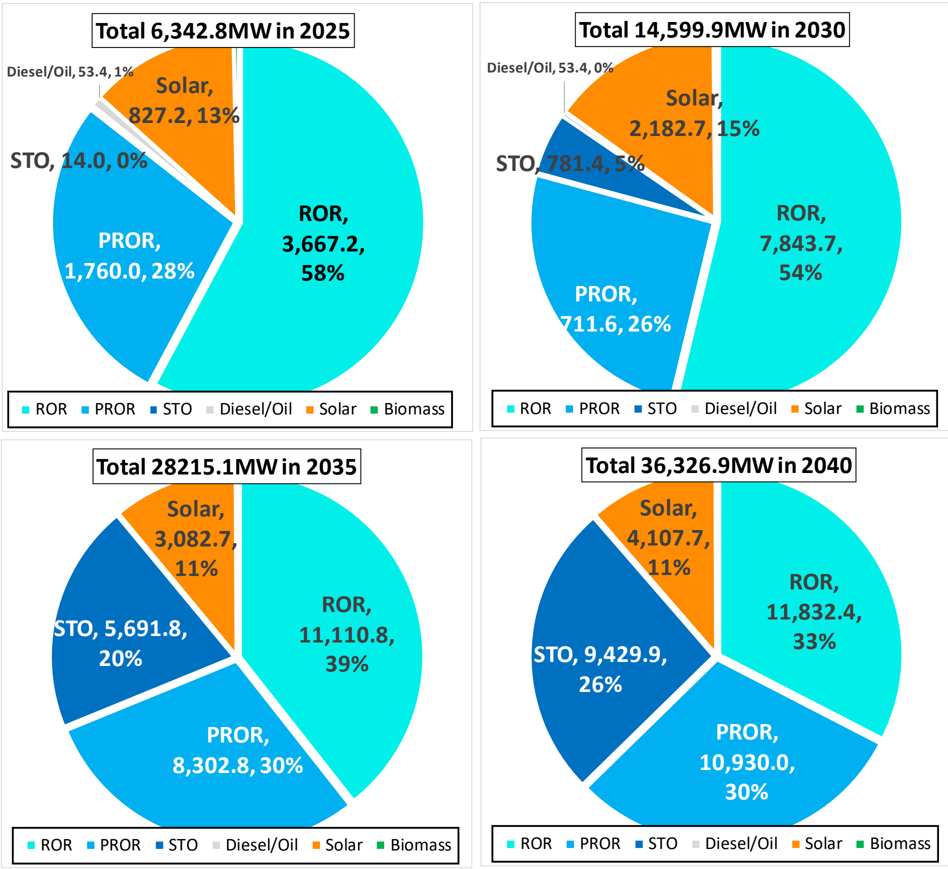
The total capacity in 2040 will be 36,327 MW, with the breakdown being ROR 11,832.4 MW (33%), PROR 10,930.0 MW (30%), STO 9,429.7 MW (26%), solar power 4,107.7 MW (11%), wind power 6 MW and biomass 21 MW.



Year	Hydro			RE			Total
	ROR	PROR	STO	Solar	Wind	Biomass	
2022	1,486.1	747.6	14.0	45.0	0.0	3.0	2,296
2023	2,430.8	787.6	14.0	145.0	0.0	3.0	3,380
2024	2,917.8	840.0	14.0	322.2	0.0	6.0	4,100
2025	3,667.2	1,760.0	14.0	827.2	0.0	21.0	6,289
2026	4,274.9	1,851.2	154.0	927.2	0.0	21.0	7,228
2027	4,884.7	2,145.1	154.0	1,782.2	0.0	21.0	8,987
2028	5,247.1	2,195.1	310.0	1,982.7	6.0	21.0	9,762
2029	6,865.1	2,560.1	310.0	2,082.7	6.0	21.0	11,845
2030	7,843.7	3,711.6	781.4	2,182.7	6.0	21.0	14,546
2031	9,188.2	5,091.4	1,426.3	2,282.7	6.0	21.0	18,016
2032	9,245.1	5,841.4	2,671.3	2,482.7	6.0	21.0	20,267
2033	10,427.9	7,552.4	3,730.3	2,682.7	6.0	21.0	24,420
2034	10,822.8	8,040.4	4,365.3	2,882.7	6.0	21.0	26,138
2035	11,110.8	8,302.8	5,691.8	3,082.7	6.0	21.0	28,215
2036	11,110.8	8,454.0	6,891.8	3,282.7	6.0	21.0	29,766
2037	11,354.8	8,784.3	7,109.8	3,492.7	6.0	21.0	30,769
2038	11,511.6	9,466.3	7,759.9	3,697.7	6.0	21.0	32,463
2039	11,815.6	10,930.0	7,759.9	3,907.7	6.0	21.0	34,440
2040	11,832.4	10,930.0	9,429.9	4,107.7	6.0	21.0	36,327

Source: JICA Study Team

Figure 7.2-2 Installed Capacity (MW) of the Optimum Scenario



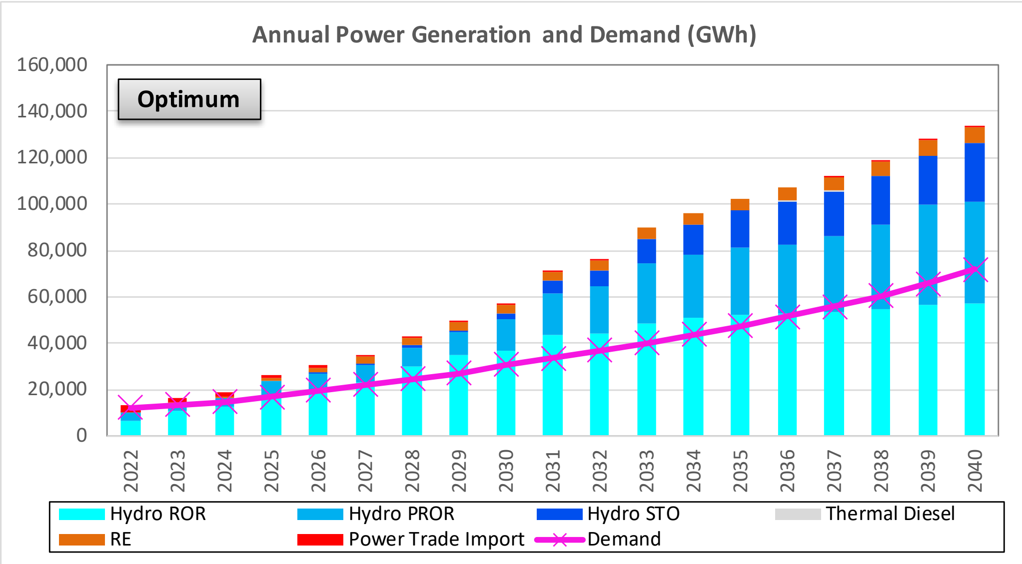
Source: JICA Study Team

Figure 7.2-3 Installed Capacity in 2025, 2030, 2035 and 2040

(2) Power Generation (GWh)

The transition of power generation and demand (GWh) until 2040 is shown in Figure 7.2-4 and the monthly power generation (GWh) for 2025, 2030, 2035, and 2040 is shown in Figure 7.2-5.

In the Optimum Scenario, power exports will exceed imports in 2025, achieving net zero in power trade. Power generation projects currently under Survey License will begin to commence in 2027 and power generation development will accelerate from 2028. Operations of GoN sites will begin in 2031 and annual self-sufficiency in power supply will be achieved in 2033. Finally, the government's targets in roadmap for installed capacity and power generation will be achieved in 2035.

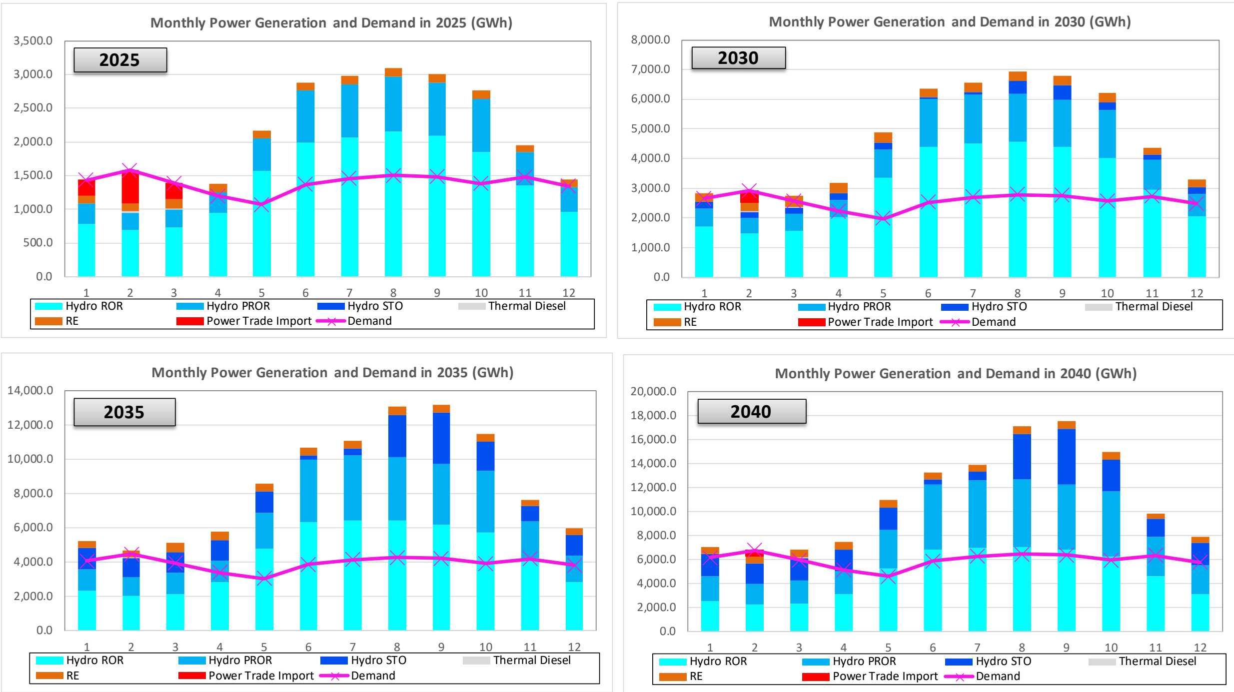


Year	Hydro			Thermal			RE	Total	Demand	Power Trade		Self Sufficient Rate (%)
	ROR	PROR	STO	Gas	Coal	Diesel				Import	Export	
2022	6,669	3,555	0	0	0	81	81	10,387	12,042	2,654	999	86.3%
2023	10,543	3,390	0	0	0	80	250	14,263	13,296	2,080	3,047	107.3%
2024	12,791	3,467	0	0	0	82	555	16,894	14,600	1,976	4,270	115.7%
2025	17,194	6,427	0	0	0	45	1,434	25,100	16,690	975	9,385	150.4%
2026	20,215	6,775	419	0	0	81	1,603	29,094	19,604	1,229	10,719	148.4%
2027	23,267	7,352	399	0	0	83	3,049	34,149	21,969	1,009	13,190	155.4%
2028	29,752	8,505	866	0	0	82	3,399	42,602	24,402	586	18,786	174.6%
2029	34,700	9,862	827	0	0	81	3,568	49,038	26,942	418	22,514	182.0%
2030	37,031	13,079	2,808	0	0	82	3,737	56,737	30,879	394	26,252	183.7%
2031	43,687	17,807	5,487	0	0	58	3,906	70,945	33,480	255	37,720	211.9%
2032	44,322	19,996	7,199	0	0	59	4,244	75,820	37,043	229	39,006	204.7%
2033	48,482	25,921	10,691	0	0	34	4,582	89,710	40,163	0	49,547	223.4%
2034	50,679	27,297	13,199	0	0	34	4,921	96,130	43,619	0	52,510	220.4%
2035	52,220	28,977	16,038	0	0	34	5,259	102,527	47,294	0	55,233	216.8%
2036	52,960	29,745	18,631	0	0	34	5,597	106,968	51,369	0	55,599	208.2%
2037	53,627	32,434	19,588	0	0	88	5,952	111,689	55,705	98	56,082	200.5%
2038	54,986	36,078	20,885	0	0	92	6,299	118,339	60,509	204	58,034	195.6%
2039	56,345	43,739	20,718	0	0	94	6,654	127,549	65,657	313	62,205	194.3%
2040	57,189	44,143	24,772	0	0	88	6,992	133,185	71,815	573	61,943	185.5%

Source: JICA Study Team

Figure 7.2-4 Power Generation of the Optimum Scenario (GWh)

The annual power generation in 2040 will be 133,185 GWh with power imports at 573 GWh and exports at 61,943 GWh. The monthly power generation will peak in September at 17,538.0 GWh and be lowest in February at 6,236.2 GWh. Seasonal difference of monthly power generation is about one-third, at 35.5% from the maximum to minimum months. The annual power generation will exceed demand even in drought years, allowing power exports.



Source: JICA Study Team

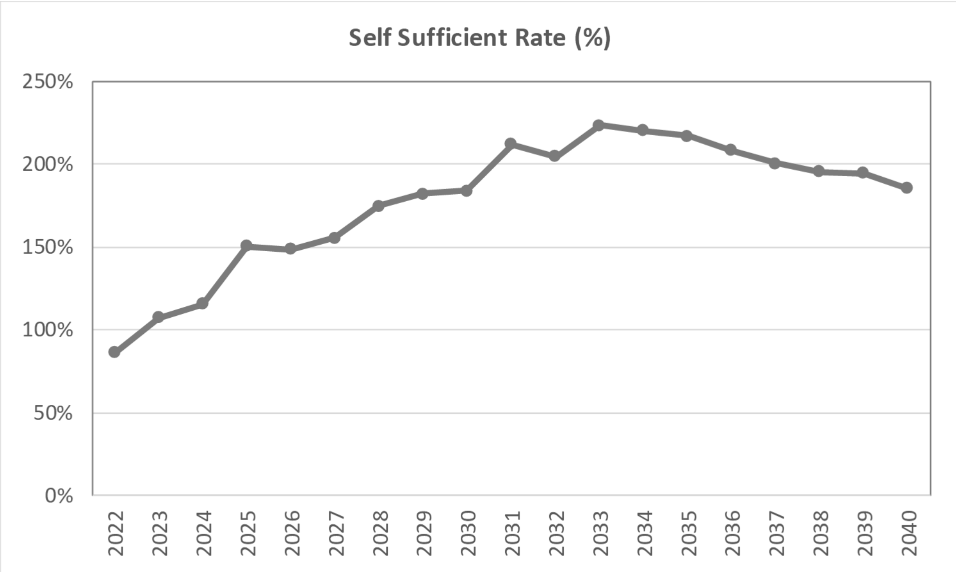
Figure 7.2-5　Monthly Power Generation and Demand (GWh) in 2025, 2030, 2035 and 2040

The operation in February when power generation drops the most is optimized to import a small amount of electricity particularly during peak times from 2037 onwards. For example, it plans to import 573.4 GWh (about 8.4%) against a power demand of 6,786 GWh in February, 2040. It becomes more economical to use export sources to meet the marginal demand increase in February than to introduce new power plants after 2035.

(3) Self Sufficient Rate and CO_2 Emissions

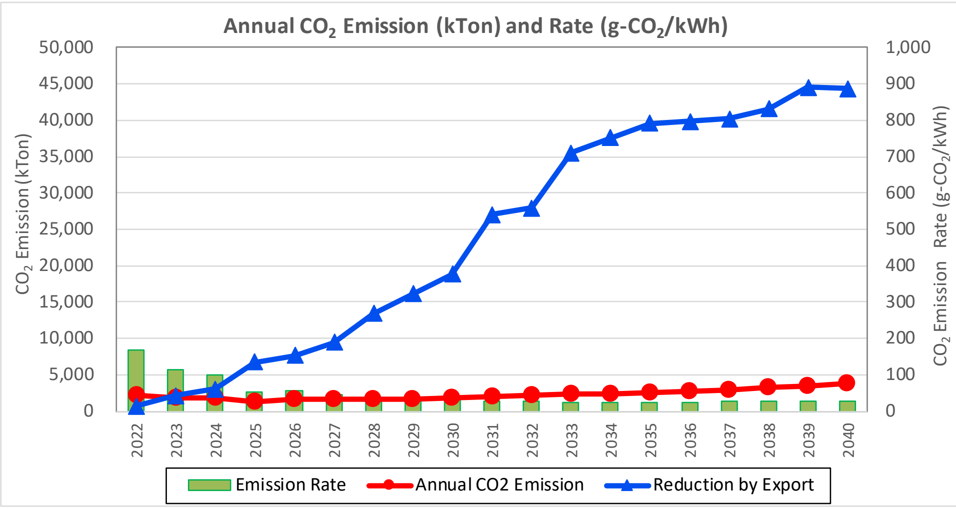
Figure 7.2-6 and Figure 7.2-7 show the self-sufficiency rate of power and CO_2 emissions. The energy self-sufficiency rate increases as hydropower development progresses. It will exceed domestic power demand significantly after 2029, reaching 223.4% in 2032 when the development of c) Survey and d) GoN peaks. It gradually decreases as new hydropower operations start to decline, reaching 185.5% by 2040.

Regarding CO_2 emissions, as hydropower (24 g-CO_2/kWh) increases and electricity imports from India (716 g-CO_2/kWh) decrease, the annual average CO_2 emissions per kWh and total emissions decrease. Rate per kWh moves towards hydropower equivalent emissions after 2029. Also, the amount of CO_2 reduction due to electricity exports increases, contributing to a reduction of 44,351 thousand tons by 2040.



Source: JICA Study Team

Figure 7.2-6 Self-Sufficiency Rate of Power Generation in the Optimum Scenario (%)

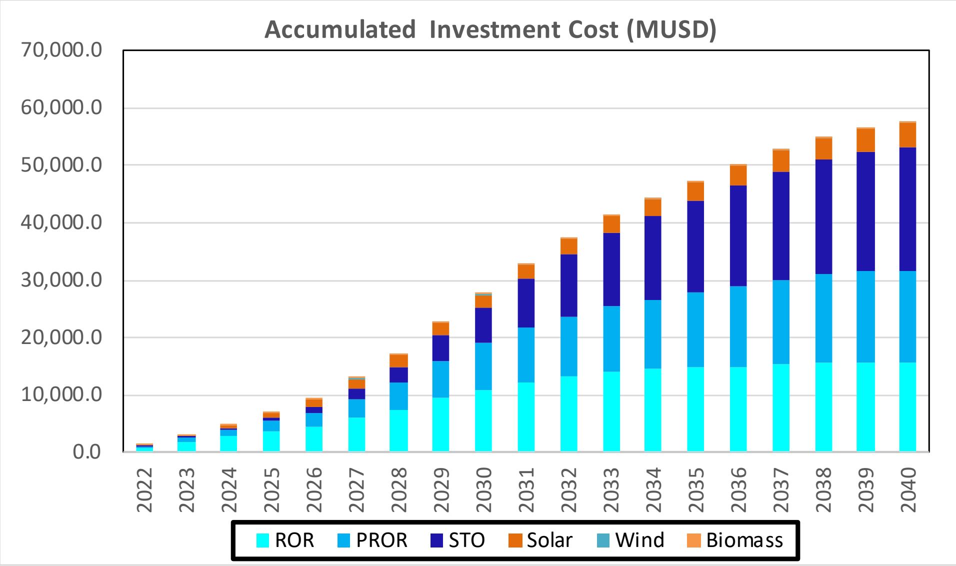


Source: JICA Study Team

Figure 7.2-7 CO2 Emissions (kTon) and Rate per kWh (g-CO2/kWh) in the Optimum Scenario

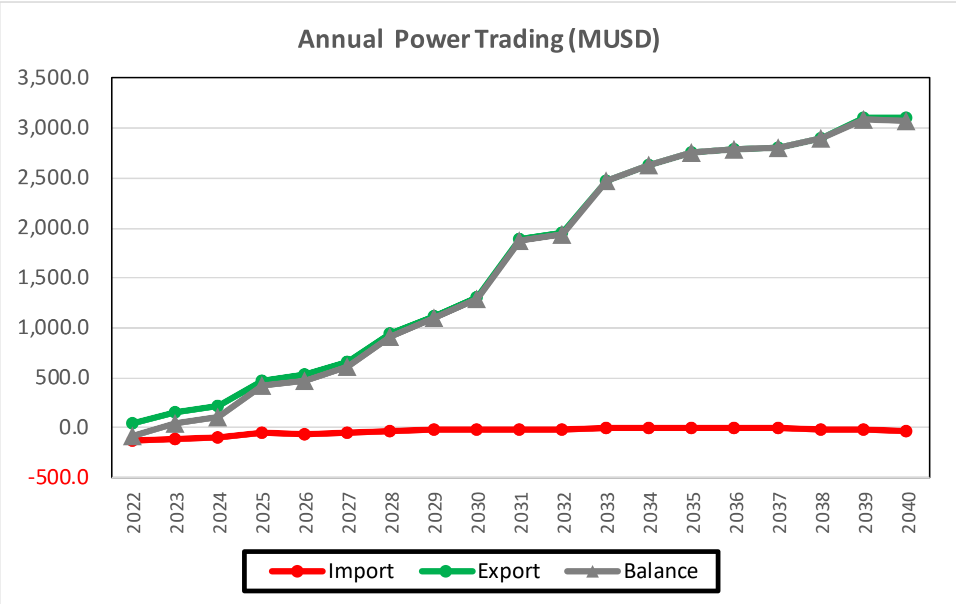
(4) Investment Costs (MUSD)

Figure 7.2-8 and Figure 7.2-9 show the cumulative investment costs and the balance of power trade. The total investment required by 2040 is 57,384 MUSD with an annual average of 3,020 MUSD. Regarding power trade, exports exceed imports after 2023, reaching 1,873 MUSD/year by 2031 and 3,069 MUSD/year by 2040.



Source: JICA Study Team

Figure 7.2-8 Cumulative Investment of the Optimum Scenario (MUSD)



Source: JICA Study Team

Figure 7.2-9 Annual Balance of Power Trade for the Optimum Scenario (MUSD)

7.2.4 Hydropower Priority Projects and Strategic Initiatives by MoEWRI

(1) Hydropower Priority Projects

1) Selection of Hydropower Priority Projects

This section selects priority projects from among the hydropower development sites introduced in the Optimum Scenario to accelerate future hydropower development. The selection criteria for priority projects are shown in Table 7.2-5.

Table 7.2-5 Evaluation Criteria for the Selection of Hydropower Priority Project

Item	Points	
Installed capacity over 100MW	Over 100MW 30 MW~100MW	: +2 point : +1 point
Generation type	STO PROR	: +2 point : +1 point
Governmental developers	GoN Entities	: +1 point
Contribution to cascade operation	STO PROR	: +2 point : +1 point
Score of screening	Over 65 score 55 – 65 score 45 – 55 score	: +3 point : +2 point : +1 point
Consistency with MoEWRI Energy Development Roadmap and Work Plan	Listed	: +1 point
Assistance of Development Partners	Supported	: +1 point
Power Trade Projects	Export Project	: +1 point
Negative impacts on environment due to the large scale reservoirs	Serious Impacts	: -2 point

Source: JICA Study Team

The list of hydropower priority projects is shown in Table 7.2-6. Out of the 643 sites to be elaborated in Optimum Scenario excluding 140 existing power plants, 503 sites were scored using the above selection criteria. Analysis results were confirmed between Nepalese side and JICA Study Team. As a result, the top 26 sites with scores of 5 or higher were selected as priority hydropower projects. It should be noted that projects in this list are selected within the scope of this study and the possibility of each site must be ultimately determined through F/S and ESIA. In particular, ESIA requires comprehensive studies for individual site conditions and this report does not guarantee the implementation of each site.

Furthermore, the list includes sites where development rights are held by government entities such as NEA and VUCL, as well as those held by private companies, considering all as important projects regardless of the developer's attributes.

2) Considerations on Hydropower Priority Projects

Trends in Project Selection

The selection results highlight a preference for large sites in relatively undeveloped river systems such as the Karnali, Bheri, West Seti, and Arun. While there have been more existing hydropower plants with medium to small scale in Gandaki and Trishuli river systems, future development is expected to shift towards these less developed river systems. Despite their abundant hydropower potential, these systems have lagged in development due to reasons such as their relatively small domestic demand scale, distance from the main grid, and difficult access. However, pathway to electricity exports to India and Bangladesh is now open, it is important to proceed the development in these river systems.

Consideration by Progress Status

Progress status and required assistance is discussed based on the project progress status listed in the DoED list. It's important to note that the progress of individual projects may not always reflect the categories in the list and actual assistance measures need to be considered for each site, highlighting a general policy direction. Among the sites listed as Construction, Tanahu and Arun 3 are already under construction. These sites are critical as they are the first HPP (Hydro Power Plant) in the country to have large reservoirs and are significant scale for power exports to India. It is necessary for them to support smooth implementation in construction works. Other sites are held by IPPs but have not yet started construction. Various options including the expiry of development rights for these sites must be considered along with complex factors like finance shortages, access roads, and transmission line to promote development.

Table 7.2-6 List of Hydropower Priority Projects

Status in DoED List	Commis-sioning	Name	River System	Generation Scheme	Installed Capacity (MW)	Annual Power Generation (GWh)
Construction	2026	Tanahu HEP	Trishuli	STO	140	503
	2025	Arun 3	Arun	PROR	900	3,466
	2030	Tila-1 Hydropower Project	Karnali	PROR	299	
	2030	Tila-2 Hydropower Project	Karnali	PROR	297	
	2030	Upper Marsyangdi 1	Trishuli	PROR	102	587
Application for Construction License	2029	Budhi Gandaki Ka	Trishuli	PROR	226	641
	2038	Adhikhola Storage HEP	Kaligandaki	STO	180	693
	2038	Betan Karnali HEP	Karnali	PROR	442	2,319
	2032	Phukot Karnali HEP	Karnali	PROR	480	2,448
	2034	Chainpur Seti HEP	Karnali	PROR	210	1,158
	2039	Kimathanka Arun HEP	Arun	PROR	450	2,558
	2035	Begnas- Rupa Storage HEP	Trishuli	STO	150	206
	2032	Nalsyau Gad Storage HEP	Karnali	STO	417	1,232
Survey	2030	Tamor Storage	Tamor	STO	200	1,079
	2030	Jagdulla HEP	Karnali	PROR	106	615
	2031	Lower Seti (Tanahu) HEP	Trishuli	STO	126	521
	2037	Bajhang Upper Seti HEP	Karnali	PROR	216	1,245
	2034	Dudhkoshi Storage HEP	Sunkoshi	STO	635	3,362
	2028	Madi Storage HEP	Others	STO	156	456
	2033	Upper Arun HEP	Arun	PROR	1,061	4,478
	2035	Kulekhani Sisneri Pumped Storage HEP	Others	STO	100	317
	2031	Budhi Gandaki Prok-1 HEP	Trishuli	PROR	103	
Application for Survey License	2030	Bheri 4 HEP	Bheri	STO	271	1,593
GoN Projects	2038	Bharbung HEP	Bheri	STO	470	1,339
	2033	SR-06 Storage	Karnali	STO	309	1,684
	2035	Sunkoshi 3	Sunkoshi	STO	680	2,300
	2033	West Seti Storage HPP	Karnali	STO	750	2,876

Source: JICA Study Team

There are several HPPs by government entities under Application for Construction License without financing. Phukot Karnali (Karnali), Chainpur Seti (West Seti) and Nalsyau Gad Storage (a tributary of Bheri) are promising sites in the underdeveloped Karnali system and are important for accelerating development in this system.

Survey sites vary widely in progress. Projects like Upper Arun supported by WB and multiple development partners, Dudhokoshi Storage supported by ADB, Tamor Storage and Lower Seti to be developed by NEA are notable. Dudhokoshi Storage is a key site for the development of large reservoirs with ODA (Official Development Assistance) finance model.

For Application for Survey License and GoN Projects, progress varies by sites. NHPC (National Hydroelectric Power Corporation), Indian governmental hydropower developer, show interest to develop West Seti and SR-6. Participation by Indian and Bangladeshi companies is expected to accelerate hydropower development in Nepal. For instance, NHPC have developed a lot of hydropower projects in India involving financial support from development partners such as JICA and ADB and it is also expected for them to utilize their lending capacity to develop hydropower projects in Nepal. Sunkoshi 3 is planned as tri-nation interconnection through Nepal, India and Bangladesh and NEA is implementing consultant bidding for DPR. This project could serve as a pilot for power export projects.

Begnas-Rupa and Kulekhani Sisneri are planned to be developed as pumped storage and under NEA reviews. There are several challenges in economics, operation, and environmental impact but pumped storage are promising regulating function for power system operation and expected to be studied more. Exploring additional pumped storage options is also important.

(2) MoEWRI's Strategic Projects and Large Reservoir Hydropower

Table 7.2-7 presents MoEWRI's strategic projects and large reservoir hydropower as listed in the Energy Development Roadmap and Work Plan until 2035. The plan mentions Dudhokoshi Storage, Budhi Gandaki Storage, Nalsyau Gad Storage, Naumure Multipurpose, Jadulla PRoR, and Upper Arun as national strategic projects. Additionally, large reservoir hydropower projects planned in the lower reaches of major rivers, such as Saptakoshi, Pancheshwor, and Karnali Chisapani Multipurpose, are also referenced.

These sites have broad social and ecological environmental impacts due to large reservoirs. It is crucial to evaluate the validity of project implementation by F/S and ESIA respectively.

Table 7.2-7 MoEWRI's Strategic Hydropower Projects and Large Reservoir Projects

SN	Program	Deadline	Main Responsible body	Assisted by	Remarks
49	To declare as national priority projects and accelerate construction of Dudhkoshi storage project, BudhiGandaki Storage project, Nalgad storage project, Naumure Multipurpose project, Jagadulla PRoR and Upper Arun	continuous	Organizations related to project development.	MoEWRI, Ministry of finance.	To start the construction within 2 years.
68	To complete the study of SaptaKoshi Multipurpose HPP and develop in joint venture with India Nepal cooperation	continuous	Nepal government, MoEWRI	DoED	These programs are to be continued and implemented even after 2035
69	To complete the detail design study of Pancheshwor multipurpose project and develop in joint venture with India Nepal cooperation	continuous	Nepal government, MoEWRI	Pancheshwor Development Authority	
70	To update the study of Karnali Chisapani Multipurpose HPP and accelerate the construction by fixing the development modality	continuous	Nepal government, MoEWRI	NEA	

Source :Energy Development Roadmap and Workplan, MoEWRI

7.3 Power System Development Plan

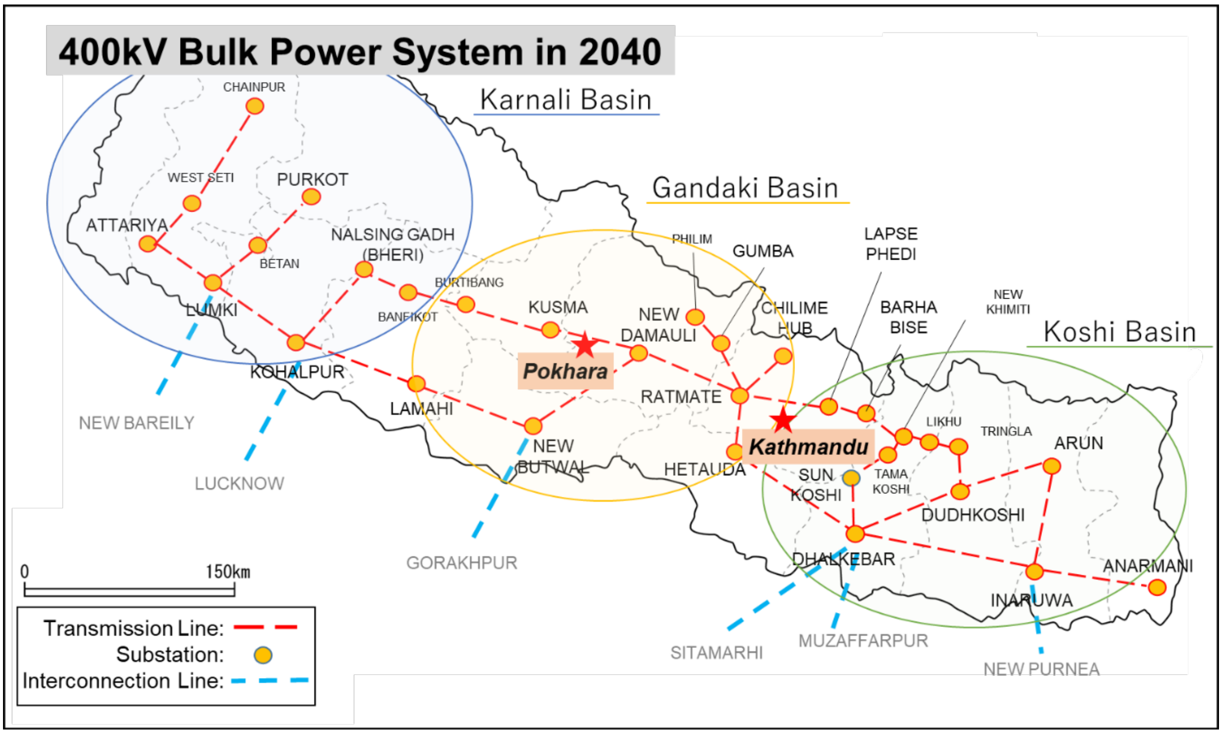
As stated in Section 6.4, the validity of the system plan was confirmed for all scenarios. Based on the results of system planning, power development planning, economic and financial analysis, and environmental and social considerations, Scenario 3 was determined to be the Optimum Scenario (hereinafter referred to as the "optimal scenario").

For the Optimum Scenario, a system analysis will be conducted to confirm the validity of the power system plan for optimization for the target year of 2040. During the 8th site survey (December 2023), the priority project list for power development plan and the power demand forecast were finalized. Therefore, the verification will be based on the new demand forecast and power generation list. The verification items for the power system analysis are the same as those in Section 6.4

7.3.1 Precondition of Power System Analysis in Optimal Scenario

(1) 400 kV bulk power system

The system diagram of the 400kV bulk power system as of 2040, the target year for the Optimum Scenario development, is shown below. It should be noted that there have been no changes to the system diagram since the scenario-specific considerations.

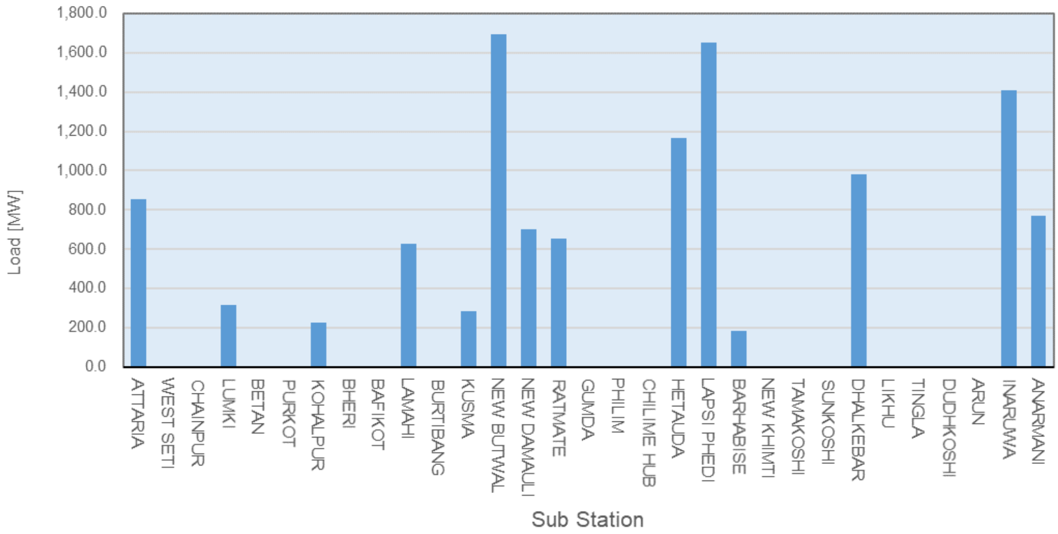


Source: JICA Study Team based on NEA Year Book 2022/2023

Figure 7.3-1 400kV Bulk Power System (as of 2040 year)

(2) Load allocation

The calculation method utilized the actual load data from existing substations (based on data from 2022). As a result, the peak demand for the 400kV substation in the Optimum Scenario for the year 2040 was determined to be 11,510MW. The result is shown in Figure 7.3-2.

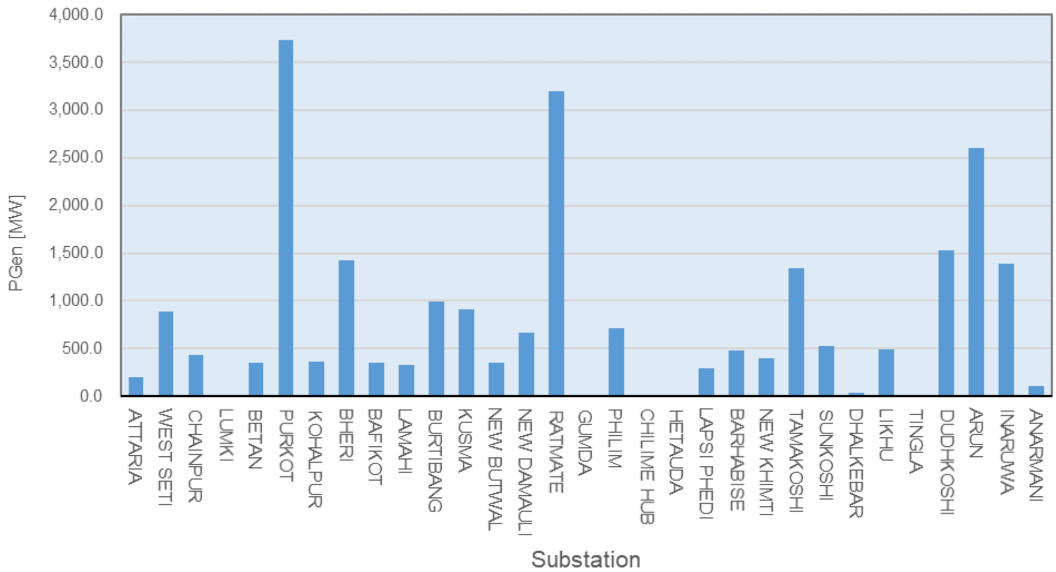


Source: JICA Study Team

Figure 7.3-2 Load Allocation of 400kV System in Optimal Scenario (Rainy Peak)

(3) Power generation allocation

The power generation for optimal scenario is shown below. The power generation was applied during the rainy season in August.



Source: JICA Study Team

Figure 7.3-3 Power Generation Allocation of 400kV System in Optimal Scenario (Rainy Peak)

7.3.2 Power System Analysis Results in Optimal Scenario

(1) Study case for the year 2040

Based on the premise conditions mentioned in the previous section, system analysis was conducted for the following cases of the Optimum Scenario. The power flow, voltage, short circuit current, and system stability were examined, and the results are presented in after sections.

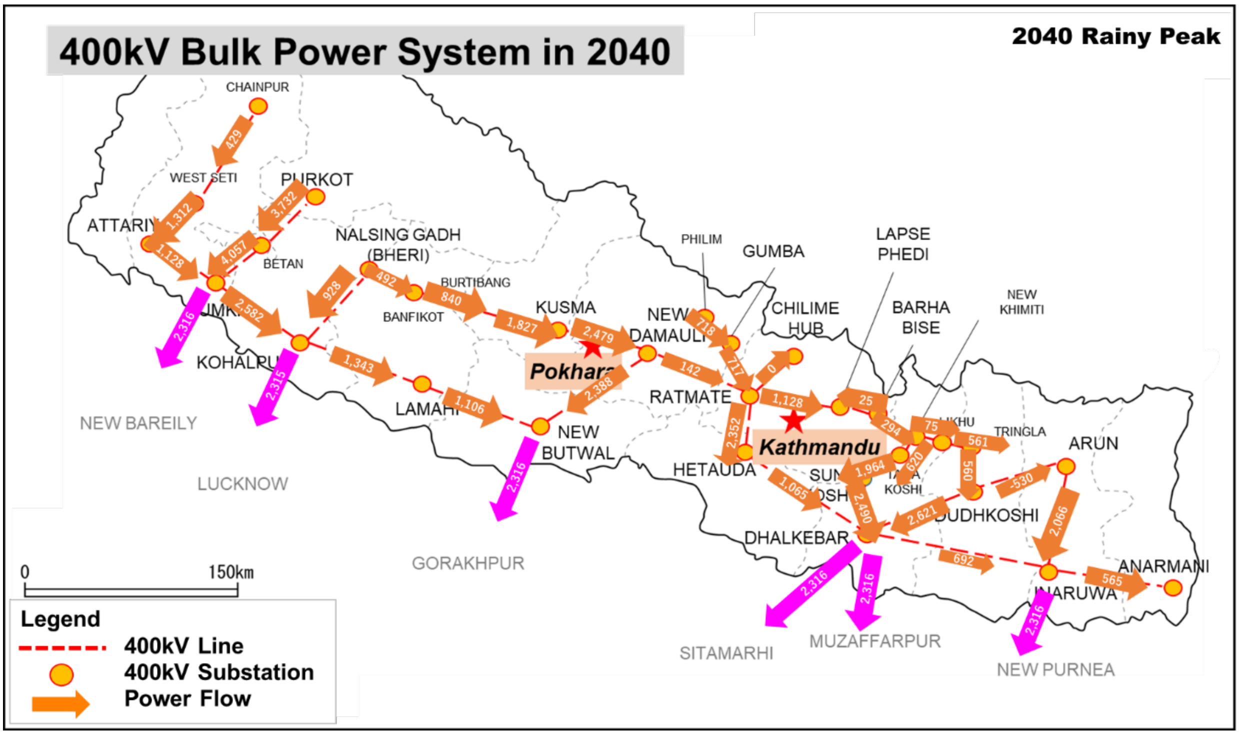
Table 7.3-1 The Study Cases in Optimal Scenario

Targets year of 2040			
No	Case	Conditions of consideration	Direct export
1	2040 Rainy Peak	Maximum power generation during the rainy season Cross section of maximum power demand	3 points
2	2040 Rainy Off Peak	Maximum power generation during the rainy season Cross section of minimum power demand	1 point

Source: JICA Study Team

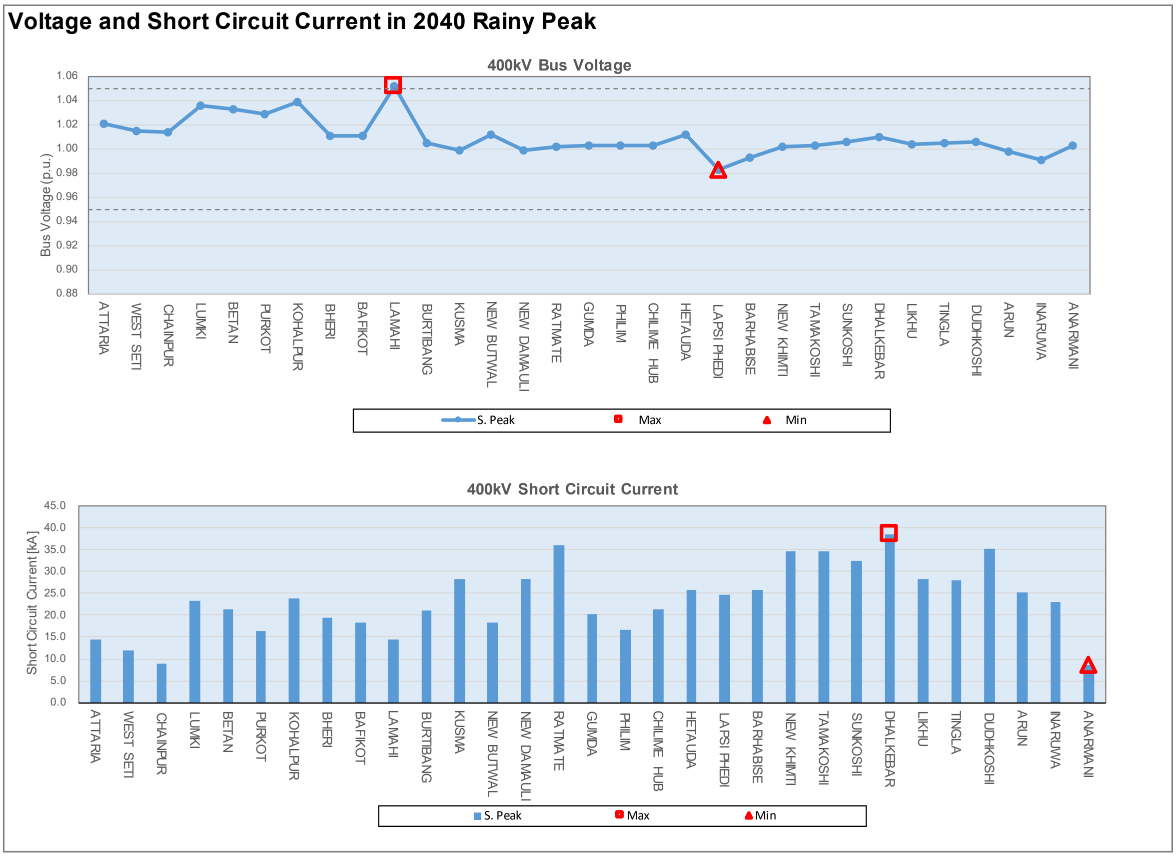
1) 2040 Rainy Peak

The results of the power flow, voltage, short circuit current, and system stability analysis are shown in Figure 7.3-4 to Figure 7.3-6. The interconnection lines are configured to export approximately 2,300 MW of power per location, with direct exports from the Purkot, Betan, Ratmate, and Arun substations. The voltage and short circuit current remained within specified limits, and direct exports contributed to maintaining system stability.



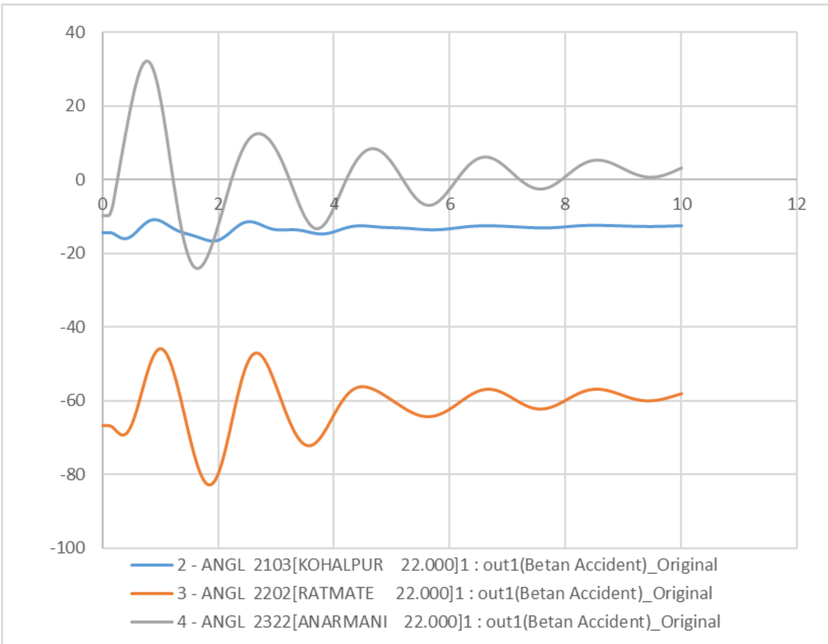
Source: JICA Study Team

Figure 7.3-4 2040 Rainy Peak (power flow)



Source: JICA Study Team

Figure 7.3-5 2040 Rainy Peak (voltage, short circuit current)



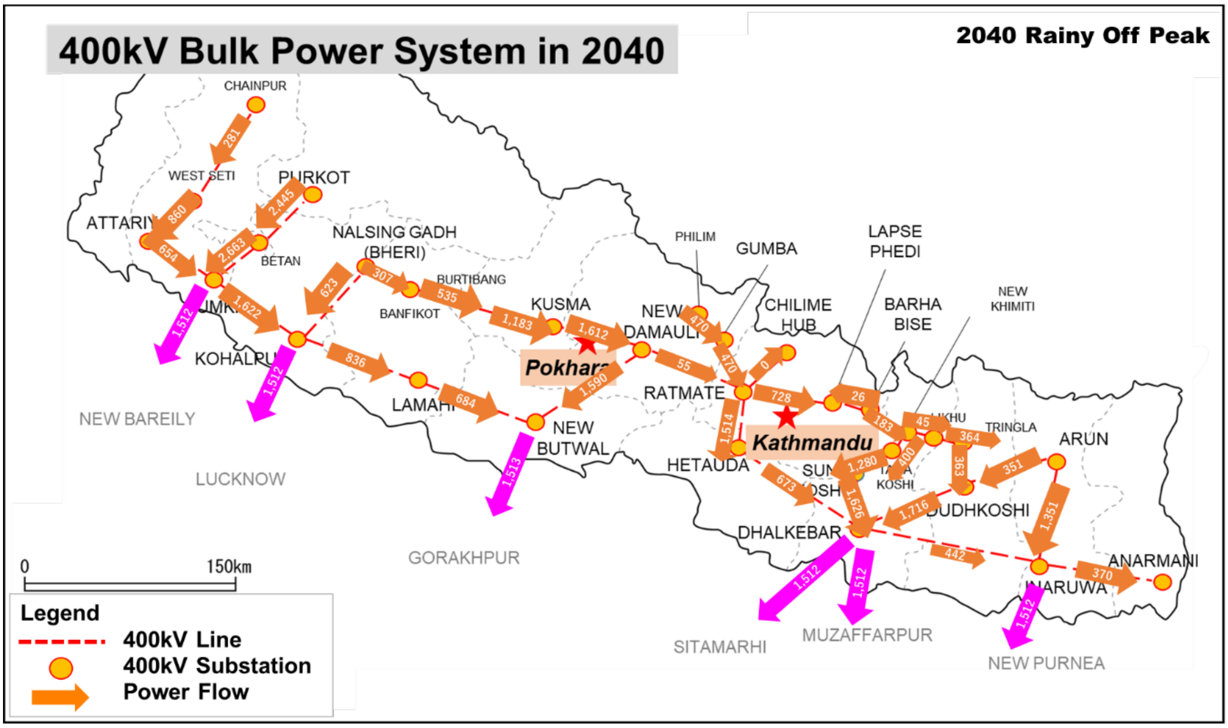
New Damauli – New Butwal (max power flow point), New Damauli side, 5cycle accident
(Direct Export: 7.28GW (Purkot, Betan, Ratmate))

Source: JICA Study Team

Figure 7.3-6 2040 Rainy Peak (system stability)

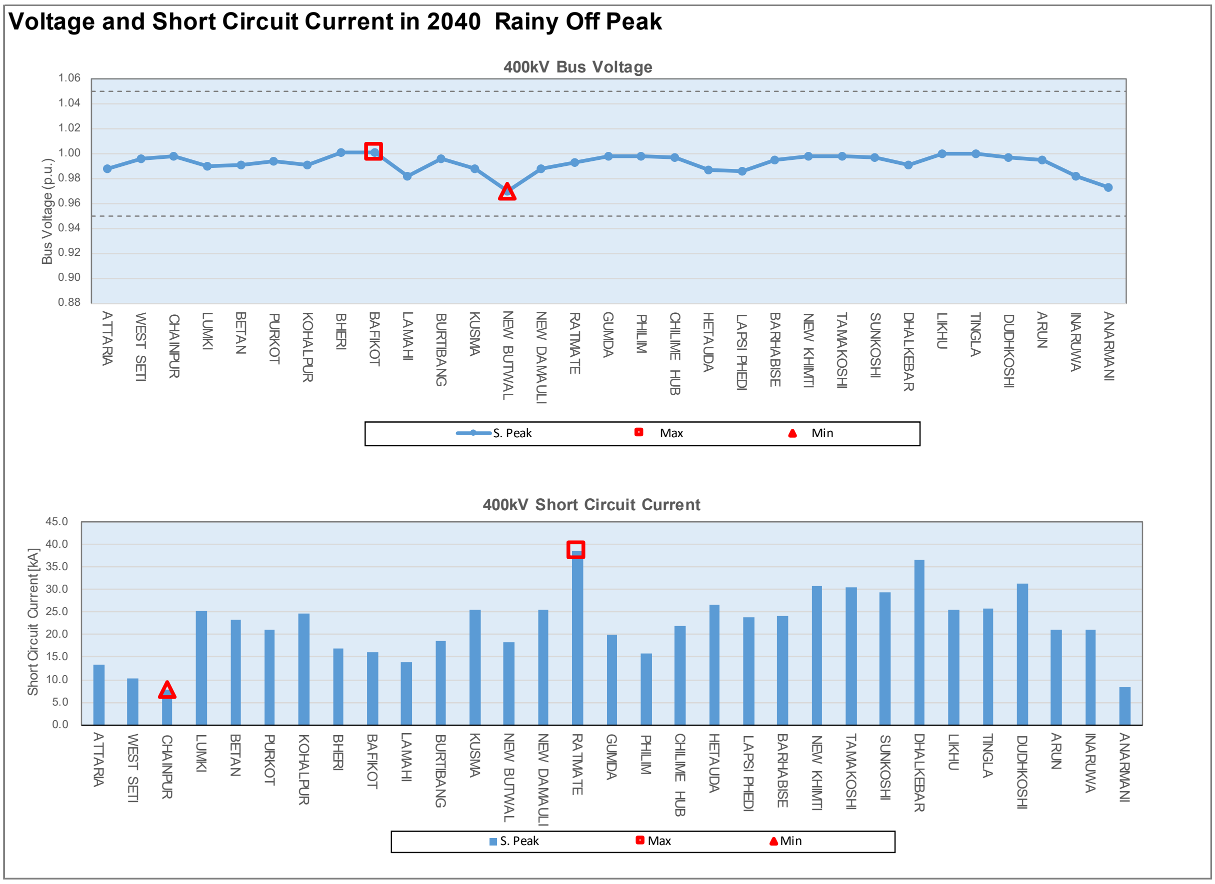
2) 2040 Rainy Off Peak

The results of the power flow, voltage, short circuit current, and system stability analysis are shown in Figure 7.3-7 to Figure 7.3-9. The interconnection lines are configured to export approximately 1,500 MW of power per location, with direct exports from the Purkot, Betan, Ratmate, and Arun substations. The voltage and short circuit current remained within specified limits, and direct exports contributed to maintaining system stability.



Source: JICA Study Team

Figure 7.3-7 2040 Rainy Off Peak (power flow)



Source: JICA Study Team

Figure 7.3-8 Rainy Off Peak (voltage, short circuit current)

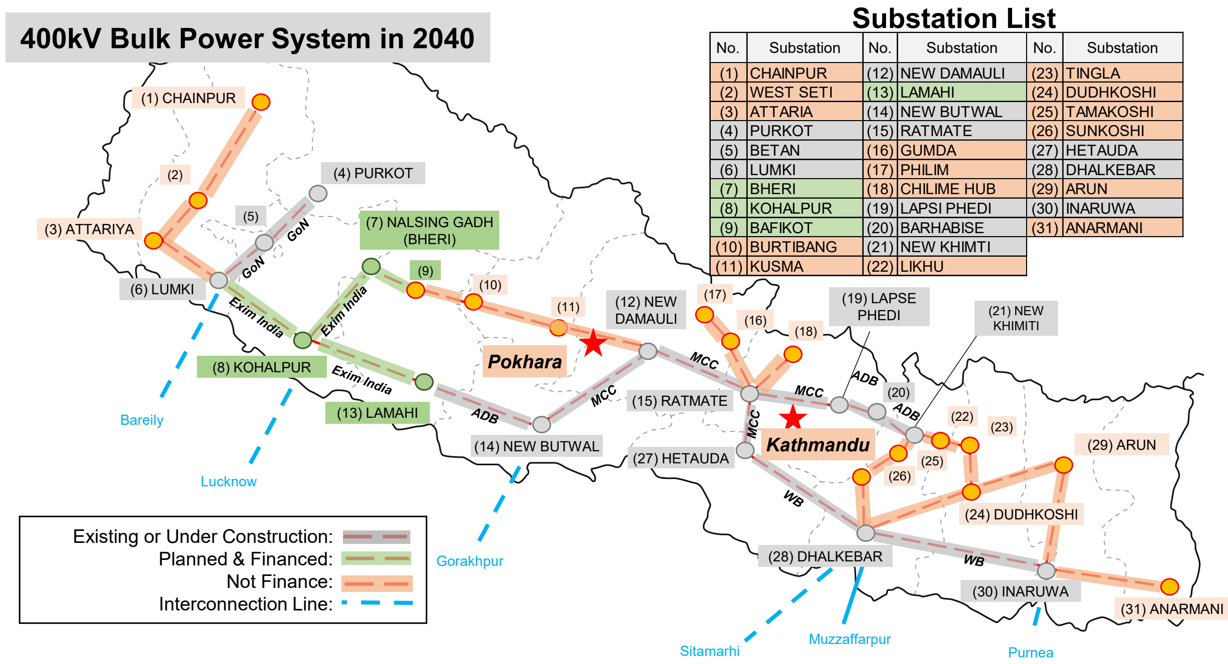
New Damauli – New Butwal T/L (max power flow point), New Damauli side, 5cycle accident
(Direct Export: 2.44GW (Purkot))

Source: JICA Study Team

Figure 7.3-9 Rainy Off Peak (system stability)

7.3.3 Progress of Development for 400kV Power System

Figure 7.3-10, Table 7.3-2, and Table 7.3-3 summarize the development status of the 400 kV domestic grid. With the support of MCC, WB, ADB, etc., the 400 kV domestic grid is under construction or planned for most of the major cities in the country, including Kathmandu and Pokhara. As for the interconnection lines, the existing Dhalkebar-Muzzaffapur interconnection line and the New Butwal-Gorakhpur interconnection line under construction are capable of handling power imports to major cities in the country and hydropower exports in the Gandaki water system and western Koshi water system, both of which are already under construction.



No.	Substation	No.	Substation	No.	Substation
(1)	CHAINPUR	(12)	NEW DAMAULI	(23)	TINGLA
(2)	WEST SETI	(13)	LAMAHI	(24)	DUDHKOSHI
(3)	ATTARIA	(14)	NEW BUTWAL	(25)	TAMAKOSHI
(4)	PURKOT	(15)	RATMATE	(26)	SUNKOSHI
(5)	BETAN	(16)	GUMDA	(27)	HETAUDA
(6)	LUMKI	(17)	PHILIM	(28)	DHALKEBAR
(7)	BHERI	(18)	CHILIME HUB	(29)	ARUN
(8)	KOHALPUR	(19)	LAPSI PHEDI	(30)	INARUWA
(9)	BAFIKOT	(20)	BARHABISE	(31)	ANARMANI
(10)	BURTIBANG	(21)	NEW KHIMTI		
(11)	KUSMA	(22)	LIKHU		

Source: JICA Study Team

Figure 7.3-10 Current status of development plans for 400kV grid and interconnection lines

Table 7.3-2 Current status of development plans for 400kV substation

No.	Substation	State	Developer	Finance
(1)	CHAINPUR	Plan	-	-
(2)	WEST SETI	Plan	RPGCL	-
(3)	ATTARIA	Plan	-	-
(4)	PURKOT	Under Construction	RPGCL	GoN
(5)	BETAN	Under Construction	RPGCL	GoN
(6)	LUMKI	Under Construction	RPGCL	GoN
(7)	BHERI	Plan	-	Exim India
(8)	KOHALPUR	Plan	NEA	Exim India
(9)	BAFIKOT	Plan	NEA	Exim India
(10)	BURTIBANG	Plan	NEA	-
(11)	KUSMA	Plan	NEA	-
(12)	NEW DAMAULI	Under Construction	NEA	MCC
(13)	LAMAHI	Plan	NEA	Exim India
(14)	NEW BUTWAL	Under Construction	NEA	ADB
(15)	RATMATE	Under Construction	NEA	MCC
(16)	GUMDA	Plan	NEA	-
(17)	PHILIM	Plan	NEA	-
(18)	CHILIME HUB	Plan	-	-
(19)	LAPSI PHEDI	Under Construction	NEA	MCC
(20)	BARHABISE	Under Construction	NEA	ADB
(21)	NEW KHIMTI	Under Construction	NEA	ADB
(22)	LIKHU	Plan	NEA	-
(23)	TINGLA	Plan	NEA	-
(24)	DUDHKOSHI	Plan	NEA	-
(25)	TAMAKOSHI	Plan	NEA	-
(26)	SUNKOSHI	Plan	NEA	-
(27)	HETAUDA	Under Construction	NEA	MCC
(28)	DHALKEBAR	Existing	NEA	WB
(29)	ARUN	Plan	NEA	-
(30)	INARUWA	Under Construction	NEA	WB
(31)	ANARMANI	Plan	NEA	-

Source: JICA Study Team

Table 7.3-3 Current status of development plans for 400kV transmission line

Substation From	Substation To	State	Developer	Finance
(1) CHAINPUR	(2) WEST SETI	Plan	-	-
(2) WEST SETI	(3) ATTARIA	Plan	RPGCL	-
(3) ATTARIA	(6) LUMKI	Plan	NEA	-
(4) PURKOT	(5) BETAN	Under Construction	RPGCL	GoN
(5) BETAN	(6) LUMKI	Under Construction	RPGCL	GoN
(6) LUMKI	(8) KOHALPUR	Plan	NEA	Exim India
(7) BHERI	(8) KOHALPUR	Plan	-	Exim India
(7) BHERI	(9) BAFIKOT	Plan	-	Exim India
(8) KOHALPUR	(13) LAMAHI	Plan	NEA	Exim India
(9) BAFIKOT	(10) BURTIBANG	Plan	NEA	-
(10) BURTIBANG	(11) KUSMA	Plan	NEA	-
(11) KUSMA	(12) NEW DAMAULI	Plan	NEA	-
(12) NEW DAMAULI	(14) NEW BUTWAL	Plan	NEA	MCC
(12) NEW DAMAULI	(15) RATMATE	Plan	NEA	MCC
(13) LAMAHI	(14) NEW BUTWAL	Under Construction	NEA	ADB
(15) RATMATE	(16) GUMDA	Plan	NEA	-
(15) RATMATE	(18) CHILIME HUB	Plan	-	-
(16) GUMDA	(17) PHILIM	Plan	NEA	-
(15) RATMATE	(19) LAPSI PHEDI	Plan	NEA	MCC
(15) RATMATE	(27) HETAUDA	Plan	NEA	MCC
(19) LAPSI PHEDI	(20) BARHABISE	Under Construction	NEA	ADB
(20) BARHABISE	(21) NEW KHIMTI	Under Construction	NEA	ADB
(21) NEW KHIMTI	(22) LIKHU	Plan	NEA	-
(21) NEW KHIMTI	(25) TAMAKOSHI	Plan	NEA	-
(22) LIKHU	(23) TINGLA	Plan	NEA	-
(23) TINGLA	(24) DUDHKOSHI	Plan	NEA	-
(24) DUDHKOSHI	(28) DHALKEBAR	Plan	NEA	-
(24) DUDHKOSHI	(29) ARUN	Plan	NEA	-
(25) TAMAKOSHI	(26) SUNKOSHI	Plan	NEA	-
(26) SUNKOSHI	(28) DHALKEBAR	Plan	NEA	-
(27) HETAUDA	(28) DHALKEBAR	Under Construction	NEA	WB
(28) DHALKEBAR	(30) INARUWA	Existing	NEA	WB
(29) ARUN	(30) INARUWA	Plan	NEA	-
(30) INARUWA	(31) ANARMANI	Plan	NEA	-

Source: JICA Study Team

On the other hand, in consideration of future export expansion, it will be necessary to develop 400 kV domestic grids and interconnection lines for water systems that will be developed in the future, such as the West Seti, Karnali, Bheri, Dudhokoshi, Arun, and Tamor water systems. Based on this recognition, the issues of grid development for power export are summarized.

Table 7.3-4 Future 400kV interconnection line and target water system

400kV Interconnection line	400kV Nepal grid	Target water system	Operators
Lumki – Bareily	Chaipur Seti – West Seti – Attariya	West Seti	RPGCL (Only West Seti – Attariya)
	Phurkot – Betan – Lumki	Karnali	RPGCL
Kohalpur – Lucknow	Bheri – Kohalpur	Bheri	NEA
Dhalkebar – Sitamarhi	New-Khimti – Tamakoshi – Sunkoshi – Dalkebar	Sunkoshi, Tamakoshi, Dudhokoshi	NEA
Inaruwa – Purnea	Arun – Inaruwa	Arun, Tamor	NEA, RPGCL

Source: JICA Study Team

These domestic and interconnection lines will be developed in a north-south direction, connecting each water system to India rather than building a conventional east-west grid connecting domestic demand centers. It is also important to promote the development of power sources and systems from the perspective of integrated development of water systems, regarding the future development of power transmission lines as a single package.

7.3.4 Construction Cost of 400kV Bulk Power System (domestic system)

Table 7.3-5 shows the estimated construction cost of the 400kV bulk power system (domestic system). The total cost of transmission facilities and substations is 4,440 million USD, and if sub-systems of 220 kV or less (including the construction costs of distribution system) are included, the total construction cost of transmission and substation facilities is expected to be about 9.5 billion USD.

Table 7.3-5 Construction Cost of 400kV Bulk Power System (domestic system)

Year	Substation		Transmission		Distribution[57]	Total
	400kV	Others[58]	400kV	Others		
2022	115.8	45.6	69.3	31.6	142.3	404
2023	115.8	45.6	69.3	31.6	142.3	404
2024	115.8	45.6	69.3	31.6	142.3	404
2025	115.8	45.6	69.3	31.6	142.3	404
2026	154.3	60.8	92.3	42.1	203.4	553
2027	154.3	60.8	92.3	42.1	203.4	553
2028	154.3	60.8	92.3	42.1	203.4	553
2029	154.3	60.8	92.3	42.1	203.4	553
2030	154.3	60.8	92.3	42.1	203.4	553
2031	154.3	60.8	92.3	42.1	129.8	479
2032	154.3	60.8	92.3	42.1	129.8	479
2033	154.3	60.8	92.3	42.1	129.8	479
2034	154.3	60.8	92.3	42.1	129.8	479
2035	154.3	60.8	92.3	42.1	129.8	479
2036	154.3	60.8	92.3	42.1	193.8	543
2037	154.3	60.8	92.3	42.1	193.8	543
2038	154.3	60.8	92.3	42.1	193.8	543
2039	154.3	60.8	92.3	42.1	193.8	543
2040	154.3	60.8	92.3	42.1	193.8	543

Source: JICA Study Team

7.3.5 Summary of Power System Development Plan

Based on the results of computational simulations and power system analysis, it has been confirmed that our proposed Nepal's backbone system can operate stably in the event of accidents in all cases. Additionally, while direct power export to India may be necessary in the future, the proposed 400kV bulk power system within Nepal for the year 2040, presented in this power system master plan, has been confirmed to be reasonable and valid. The validity of the system plan for the intermediate section and the nearby lower subsystems was confirmed, and a consistent system development plan until 2040 was formulated.

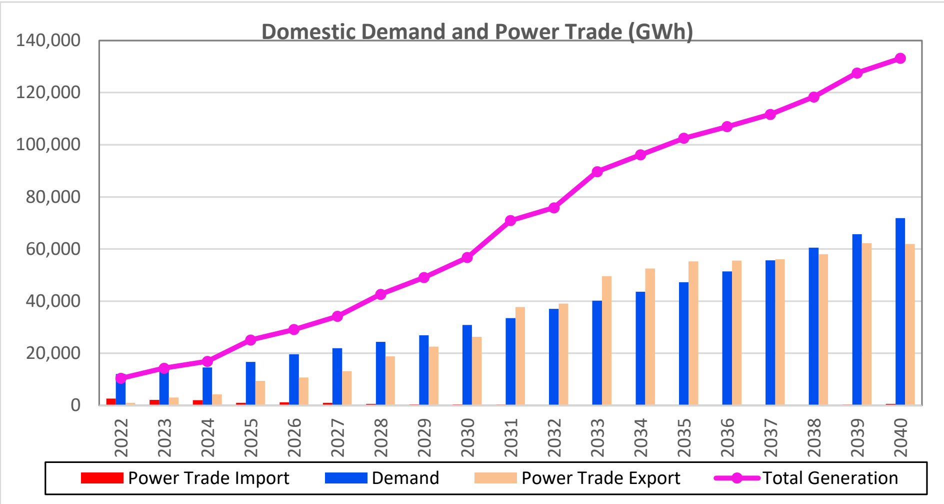
Regarding development costs, it is estimated that a total of approximately 9.5 billion USD will be required for the transmission and distribution systems. Details on funding methods, economic and financial analysis, and environmental and social considerations related to the construction of transmission line will be described in a separate section. IPSDP will create power generation and power system plans based on power demand forecasts and ensure a consistent system development plan in the power sector by integrating economic and financial aspects, governance, and environmental considerations.

[57] Distribution system of 33 kV or less
[58] 220 kV and 132 kV transmission systems

7.4 ASSUMPTION OF THE AMOUNT OF ELECTRICITY THAT CAN BE EXPORTED

As described in Chapter 7, future development will be based on the Optimum Scenario, which is based on Scenario 3: Hydro Middle. Figure 7.4-1 shows the annual power generation and demand forecast under the optimal scenario. The peach line represents total power generation, the blue bars represent estimated demand, the orange bars represent possible exports volume, and the red bars represent import requirements volume.

Scenarios 3 results in a large surplus of electricity toward 2040, which is assumed to provide more opportunities to export electricity to neighboring countries. Table 7.4-1 shows the peak demand for each country and Nepal's generation capacity through 2040. India's peak demand is assumed to be about 50 times Nepal's peak demand and Bangladesh's peak demand is assumed to be more than 4 times Nepal's peak demand as of 2040.



Source : JICA Study Team

Figure 7.4-1 Forecasted Annual Power Generation and Demand (Scenario 3)

Table 7.4-1 Peak demand in each country and Nepal's generation capacity by 2040

	Installed capacity in Nepal	Peak demand in Nepal	Peak demand In India	Peak demand In Bangladesh
2025	6,343 MW	2,675 MW	260,118 MW	22,883 MW
2030	14,600 MW	4,949 MW	350,670 MW	31,910 MW
2035	28,215 MW	7,581 MW	465,531 MW	41,050 MW
2040	36,327 MW	11,510 MW	574,689 MW	50,253 MW

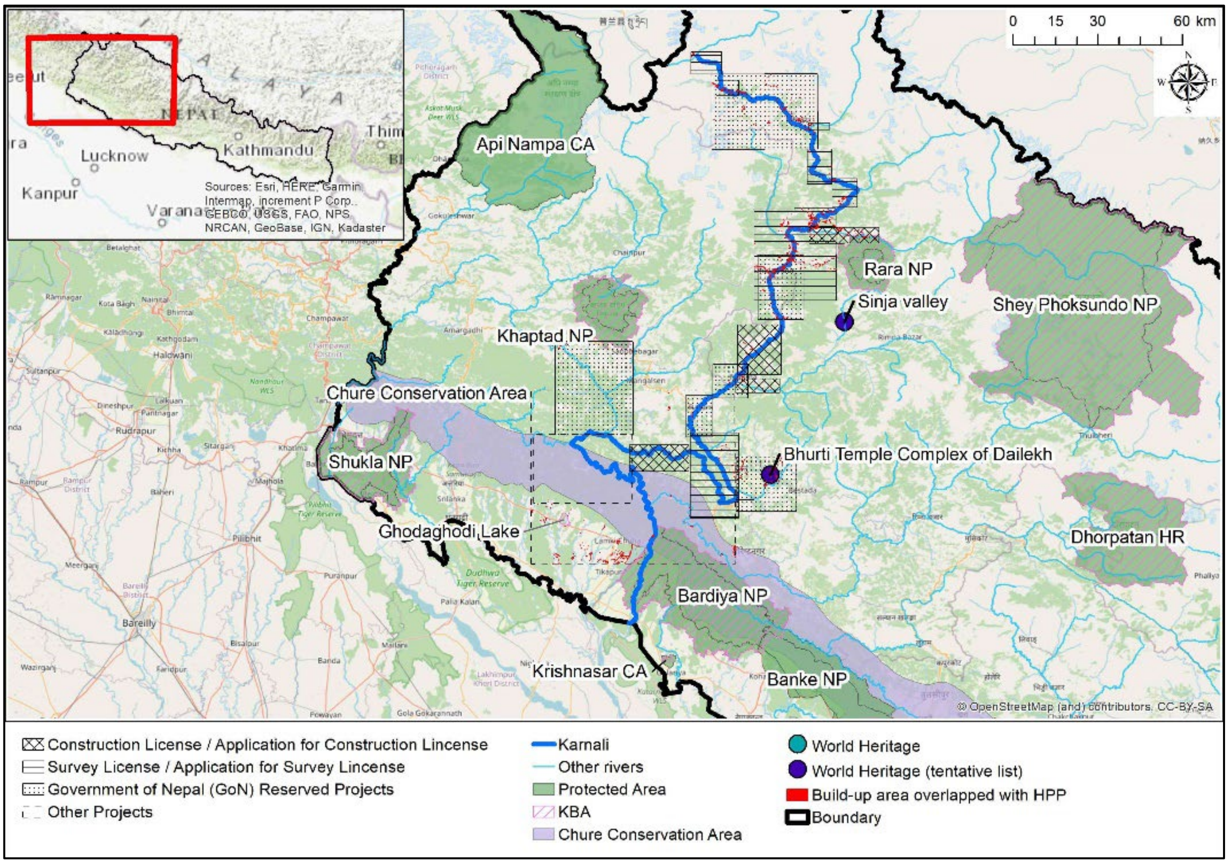
Source: JICA Study Team

In neighboring countries, India and Bangladesh, the power demand will increase in the future, and they make policies that they will not only develop own power sources but also export power from their neighboring countries. In addition to it, Nepal is expected to be able to contribute to decarbonizing and the power supply by exporting power to neighboring countries because Nepal has a potential of hydropower generations and generators without emitting CO_2 have been focused on by a trend of decarbonizing.

In the future, Nepal will have a high expectation because the amount of generation exceed to domestic demand and they can export to neighboring countries in not only the rainy season but also the dry season. In January 2024, a long-term electricity export agreement was signed between India and Nepal. As part of this agreement, both parties have agreed that the amount of electricity exported from Nepal to India will be 10,000MW over the next 10 years, and the amount of electricity exported to India is expected to increase. The long constant supply and profit will be expected by power trade with IEX more and if bilateral agreements including PPA (Power Purchase Agreement) contracts can be conducted. With considering that India has mainly coal-typed thermal power generations, Nepal will be able to contribute to power supply for India and to decarbonizing by exporting power generated by the renewable energy, hydro-powers, of Nepal.

7.5 Environmental and Social Considerations

The Optimum Scenario selected in IPSDP was evaluated from an environmental and social perspective. The points such as cumulative impacts by hydropower projects along each river basin were examined; the impacts on protected areas (national parks, KBAs, IBAs[59], etc.), ecosystems (rivers and land areas, especially migratory fish species and rare species registered in the IUCN (International Union for Conservation of Nature and Natural Resources) Red List), cultural heritage, etc. were analyzed; and the mitigation measures and monitoring methods for the expected impacts were considered.



Source: JICA Study Team

Figure 7.5-1 Analysis of Optimum Scenario along Karnali River (Example)

It is recommended to avoid as much as possible environmental and social impacts of hydropower projects in accordance with mitigation hierarchy; and then consider measures to minimize, reduce, and mitigate those that cannot be avoided. In the process, it is important to provide opportunities

59 IBA (Important Bird and Biodiversity Areas)

for stakeholders such as the central government, provincial governments and affected people to express their opinions and to hold meaningful consultations. In addition, appropriate monitoring should be carried out. If any concerns are identified during monitoring, corrective measures should be taken. The main points to keep in mind are as follows:

1) Basin-wide cumulative impact assessment / Cooperation and collaboration between project developers

In Nepal, the progress of development plans varies from river basin to river basin and cumulative impacts can be significant in some river basins due to multiple hydropower projects; therefore, it is necessary to evaluate the cumulative impacts for each river basin and consider appropriate mitigation measures from the perspective of river basin management. In particular, in river basins where development plans would be concentrated, such as the Gandaki River basin (where many existing power plants are located near demand areas and development is progressing), it is recommended to carry out development that takes cumulative impacts into account at an early stage. In addition, it is recommended that Nepal strategically consider free-flowing rivers in order to avoid significant cumulative impacts on each river system and to conserve the flow rate and continuity of the river basins.

Environmental management is also sometimes not properly implemented from the perspective of watershed management in Nepal; and there are cases that environmental measures (such as the installation of fish passages to allow migratory fish to move around) are not carried out effectively in multiple hydropower projects located along the same river basin. It is recommended that cooperation and collaboration among project developers along the basin, including private hydropower developers, be promoted in order to properly conduct river basin management.

2) E flow

Hydropower projects may affect environmental flow (E flow), including minimum water flow, and may cause changes in the flow rate of the entire river and downstream areas, as well as habitat fragmentation. If adverse effects are anticipated by hydropower development, it is advisable to refer to guidelines such as "IFC Good practice handbook - Environmental flows for hydropower projects (2018)" and to develop and implement an E flow management plan based on evaluation of E flows.

3) Protected areas

When developing a project within a protected area (national park, wildlife sanctuary, hunting reserve, conservation area, and buffer zone) defined in the local country's National Parks and Wildlife Conservation Act (2029/1973), permission from the authorities must be obtained prior to development. Damming or modifying the flow of rivers is prohibited, and restrictions such as maintenance flow are required for hydropower development. In addition, when implementing within a Ramsar site based on an international treaty, the project must be carried out in accordance with the management plan of each Ramsar site. It is advisable to plan and implement the project in accordance with the mitigation hierarchy.

4) Ecosystem / Forest

Water intake, storage, and discharge associated with hydroelectric power generation projects may change river flow rates and water levels, potentially affecting ecosystems such as aquatic organisms and waterfowl. There is also a concern that the construction of dams and intake weirs could cut off river channels and impede the upstream migration of migratory fish. When such impacts are anticipated, it is necessary to evaluate the impact on E flow and aquatic ecosystems and reflect them in environmental management plans and monitoring plans.

In addition, deforestation due to hydroelectric development is expected to have permanent or temporary effects on flora and fauna. In particular, when a project is planned within a KBA or critical habitat is identified, the consideration should be given to minimizing the impact in the layout of the project plan, including access roads and other ancillary facilities. In addition, when local residents rely on forest use for timber and NTFPs (Non-timber Forest Products) as a source of income and adverse effects from the project are expected, it is recommended that livelihood restoration plans be formulated and implemented based on discussions with affected people.

5) Appropriate compensation for land acquisition, involuntary resettlement, and loss of livelihood, distribution of benefits, etc.

One of the challenges facing hydropower development in Nepal is compensation for projects involving resettlement and land acquisition, which has led to criticism from NGOs (Non-Governmental Organizations) and complaints from residents. It is desirable to formulate and implement a resettlement action plan that includes payment of compensation at replacement cost. In particular, when large-scale resettlement is required for reservoir-type hydroelectric power plants or power transmission lines, it is important to secure sufficient budgets and implementation systems.

In addition to physical resettlement, if economic resettlement such as loss of livelihood occurs, it is recommended that livelihood restoration plans be formulated and implemented in accordance with procedures stipulated in local national laws (Land Acquisition Act (2034/1977), Real Estate Expropriation Act (2013/1956)), and with reference to good practices of hydropower projects in Nepal undertaken by the WB and other international donors.

Looking at the country as a whole, the benefits of power development are concentrated in the urban areas of Kathmandu and Pokhara, while the areas directly affected by the development are those surrounding the site. It is desirable to consider correcting these disparities in benefits.

6) Indigenous Peoples

The National Foundation for Development of Indigenous Nationalities Act defines 59 ethnic groups as indigenous peoples, and they are widely distributed in the mountainous areas where hydroelectric power projects are planned. In addition, Nepal has ratified the ILO Convention on Indigenous and Tribal Peoples in Independent Countries (No. 169). If adverse effects on indigenous peoples are anticipated, it is recommended that meaningful consultations be held with indigenous peoples affected by the projects from an early planning stage and that their consent be obtained based on the principle of FPIC (Free, Prior and Informed Consent). In addition, if indigenous peoples are included among the affected peoples, it is advisable to formulate an IPP (Indigenous Peoples Plan) and implement measures accordingly.

7) Natural hazards

Natural disasters in Nepal include landslides caused by heavy rains during the monsoon season. In addition, projects may suffer significant physical damage due to GLOFs (Glacial Lake Outburst Flood). When selecting project sites, it is advisable to avoid areas with high disaster risks such as landslides and GLOFs, and to develop emergency response plans in the event of a disasters etc.

8) Climate change

Nepal has formulated policies such as the National Climate Change Policy (2076/2019), and hydropower is considered to be a desirable form of power generation in terms of greenhouse gas emissions. However, as mentioned above, it is recommended to evaluate physical risks associated with climate change in relation to the risks of GLOFs, etc., and to consider alternatives and incorporate them into the design.

7.6 ECONOMIC AND FINANCIAL ANALYSIS

7.6.1 Purpose of Economic and Financial Analysis

(1) Purpose of Economic and Financial Analysis

Conventional economic and financial analyses in the power sector use the IRR (Internal Rate of Return) as an indicator to evaluate the adequacy of projects and to evaluate LRMC (Long-Run Marginal Cost), which is commonly used to examine the electricity price level. IRR is calculated only with cash flow information generated from projects and is used as an index to measure the profitability of the project. LRMC refers to the additional cost (marginal cost) required to produce one unit of goods, which is also calculated from the amount of expenditure. In the case of power generation projects, the cost of generating electricity required to produce one additional unit of electricity is determined, and this is used as the basis for examining the electricity price level. In the study of economic and financial analyses in conventional development plans, the emphasis has been on how future electricity prices can fluctuate, referring to LRMC.

However, since the IRR and LRMC are calculated only on the basis of future expenditures and do not consider the income and expenditure and financial status of the implementing entity of the plan, the financial situation and the impact on the fiscal and macroeconomic effects of the target country are not taken into account in the analysis. Since these items are considered to be important points in the analysis of IPSDP, how to incorporate them into the analysis matters.

Significant investment is required to implement IPSDP. Therefore, in the financial analysis, we firstly prepare a cash flow table for the IPSDP period with the government-related organization that promotes the IPSDP as the implementing entity to be analyzed, and analyze the procurement of funds necessary for investment. Subsequently, the level of electricity charges, which has often been examined using the LRMC, will be examined using the financial statements of the implementing entity. In addition, given the amount of funds required for investment and the expected increase in exports, the implementation of the IPSDP is expected to have a significant impact on the macroeconomy of Nepal. Therefore, we will also try to analyze the impact on the macroeconomy based on the results of the financial analysis. Since a cost-benefit analysis using IRR can be applied to this project as an index to measure the economic benefits of the I PSDP, it is adopted in the economic analysis section of this chapter.

(2) Structure of this chapter

First of all, basic information related to the subsequent analysis is organized. This information includes the compilation of basic data on Nepal's economy and finances, the establishment of basic financial flows and assumptions, and the estimation of the amount of various expenses.

In order to verify whether the implementation of the IPSDP will bring economic benefits to Nepal, the EIRR (Economic Internal Rate of Return) is calculated. The analysis is carried out using the financial statements of the IPSDP implementing entity. Finally, macroeconomics and the impact of the financing required for investment on Nepal's finances (external debt and foreign exchange reserves) is analyzed, as well as the impact of electricity exports expected to increase by IPSDP (the trade balance and GDP growth). In addition, the new job creation effects that the implementation of IPSDP can create is analyzed.

7.6.2 Basic Information and Preparation for Analysis

(1) Basic Data on Nepal's Economy and Public Finance

We will summarize the basic data on Nepal's economy and finance as a basis for analyses.

Nepal's economy over the past decade has generally shown positive growth. The average real GDP growth rate for the 10 years from 2012 to 2021 was 4.5%.[60] In 2020, the real GDP growth rate fell to minus 2.4% due to the impact of the global pandemic but recovered to 4.2% in 2022. Agriculture accounted for 25.8% of GDP by industry, followed by wholesale trade at 15.7%, real estate at 9.4%, and education at 8.0%. There has been no significant change in the ratio of GDP by industry over the past 10 years. Focusing on the power sector, electricity sales are estimated to account for about 1.4% of GDP[61]. In relation to the IPSDP, it is important to increase the contribution of the power sector to the Nepal economy (contribution to Nepal GDP) by increasing electricity exports, based on the Nepal government's policy of making the power sector a growth industry.

Looking at trade, Nepal's main export items are clothing and agricultural products, and high-priced items such as industrial products and medical equipment are the main import items. As for the trade balance, the trade deficit continues. As for the import and export of electricity, as of 2020/2021, the export value was 316 million rupees (about 370 million yen) and the import value was 21,821 million rupees (about 25,530.57 million yen), and the power sector is also in a trade deficit[62]. As with the real GDP growth rate mentioned above, another important point to check is how the implementation of the IPSDP may affect the improvement of the trade balance of Nepal as a whole.

The following table summarizes the main data on the macroeconomy of Nepal.

Table 7.6-1 Key Figures for Macroeconomy in Nepal[63]

Sections	Number Value	
	2020/2021	2021/2022
Real GDP	31.1 billion dollars (approx. 4.66 trillion yen)	33 billion dollars (approx. 4.95 trillion yen)
Real GDP Growth Rate	4.2%	5.6%
balance of trade	▲1.355 trillion rupees (▲1.585 trillion yen)	▲1.661 trillion rupees (▲1.943 trillion yen)
Amount of electricity exports*1	316 million rupees (approx. 369 million yen)	3.884 billion rupees (approx. 45.44 billion yen)
Amount of electricity imports*2	21.821 billion rupees (approx. 25.531 billion yen)	15.466 billion rupees (approx. 180.95 billion yen)
Unemployment rate*3	13.12%	10.9%

*1 Revenue from NEA's international sales
*2 NEA's Electricity Purchase Costs from India
*3 Share of total working population (total working population is approximately 8.9 million (2022/2023))

Source: Nepal Economy 2024 (Embassy of Japan in Nepal), Current Macroeconomic and Financial Situation (Nepal Rastra Bank), World Development Indicators (WB)

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60 For real GDP growth figures, see IMF "World Economic Outlook Databases (April 2024)"
61 According to the NEA's financial statements, the amount of domestic electricity sales was 70,543 million rupees (about 82.53 billion,5.31 million yen), electricity export value of 316 million rupees (about 369.72 million yen). This was taken into account by adding the 2020/2021 GDP of 3.69 billion dollars.
62 Figures for imports and exports of electricity are based on NEA's financial statements (2020/2021)
63 When converting Nepalese rupees to dollars, the conversion rate was 1 rupee = 0.0075 dollars. The same applies below.

Next, the main data on the finances of the Nepalese government are summarized in the following table.

Table 7.6-2 Data on the finances of the Government of Nepal

item	numeric value	remarks
Government Budget	1.632 trillion rupees (1.909 trillion yen)	2022/2023
Budget Revenue Breakdown	Tax and non-tax income (69.1%) Domestic borrowings (14.3%) Loans from foreign countries (13.5%) Grant Aid from Foreign Countries (3.1%)	2022/2023
External debt as a percentage of GDP	21.7%	2022/2023
Percentage of budget allocation to MoEWRI	2.8% of budget appropriations	2021/2022
Foreign exchange reserves	11.74 billion dollars (approx. 1.76 trillion yen)	2022/2023

Source: Nepal Economy 2024 (Embassy of Nepal), Current Macroeconomic and Financial Situation (Nepal Rastra Bank), and World Development Indicators (WB)

Nepal's external debt risk at present is considered to be low[64]. In addition, the amount of foreign exchange reserves is equivalent to 10 months' worth of imports[65], which implies that foreign currency reserves are not considered to be insufficient according to the criteria.

(2) Basic funding flows and assumptions

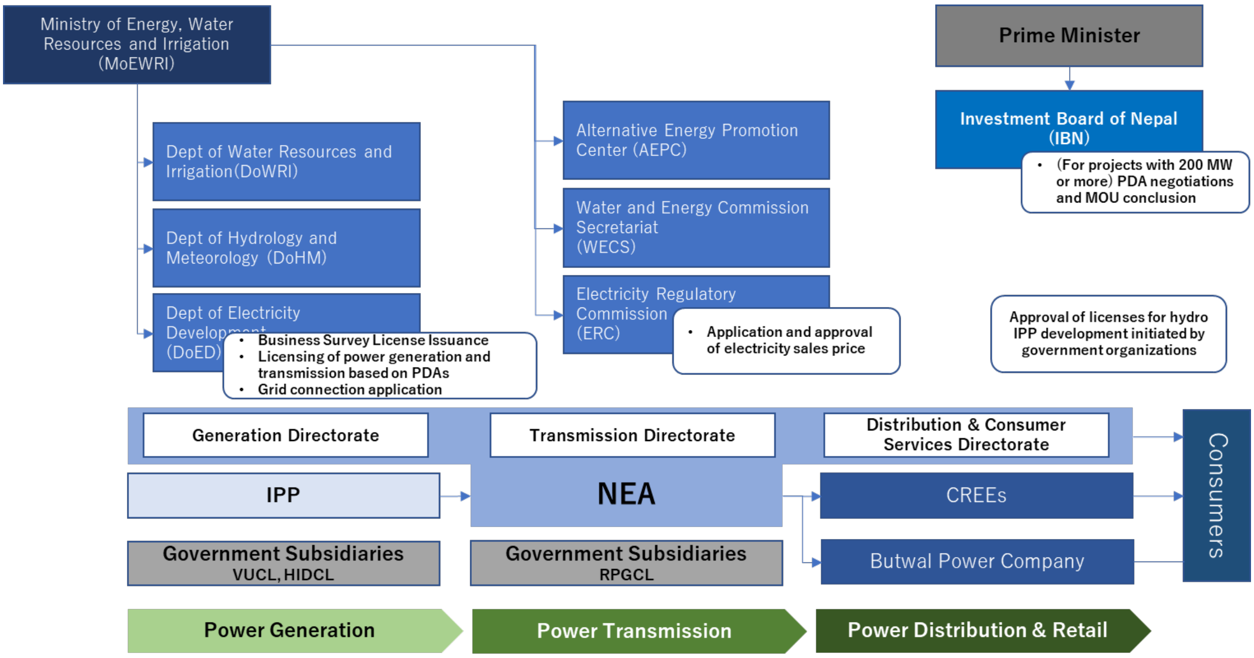
In this section, we will summarize the basic financial flows in Nepal's power sector, which are the prerequisites for conducting economic and financial analysis.

1) Sector-Related Organizations

The government organizations involved in hydropower generation in Nepal can be roughly organized as shown in Figure 7.6-1.

40% of the grid-connected power plants (based on 2023 output) are owned and operated by NEA or a subsidiary of NEA. In terms of installed capacity, NEA owns 1,135.1 MW of hydroelectric power plants, 53.4 MW of diesel power plants, and 25 MW of solar power. Most of the hydroelectric power generation development by IPPs is small and medium-sized projects with a capacity of 30 MW or less, but as of 2023, IPPs have an installed capacity of 1,544.5 MW. As of June 2024, the separation of transmission and distribution (unbundling) is being discussed in connection with the revision of the Electricity Law, but the government is expected to take the lead in developing the power sector in Nepal, especially large-scale projects that require a lot of funding[66]. In this sense, the current structure and financial flows are expected to continue for the time being.

64 According to the World Bank Group and IMF Joint World Bank IMF Debt Sustainability analysis (2022).
65 According to Nepal Rastra Bank "Current Macroeconomic and Financial Situation (2022/23)".
66 With regard to the discussion of unbundling of the NEA, VUCL has already been established in the power generation sector and RPGCL in the transmission sector as a receptacle after unbundling. However, it has not yet been decided how it will be integrated with these organizations.



Source: JICA Study Team

Figure 7.6-1 Organizations Related to the Power Sector in Nepal

The NEA seeks funding for the development of power sources, mainly from revenues from the sale of electricity and the export of electricity. However, its income and equity (capital and retained earnings) are not enough to finance development, so it borrows. The lenders are the Ministry of Finance of the Government of Nepal, and the borrowings from the Government of Nepal include the subleasing of funds loaned to the Government of Nepal by donors. Investment targets basically include power generation facilities, transmission and distribution facilities, and substations. The main expenditures include the maintenance and management of the facility, the purchase of electricity from domestic IPPs, and the import of electricity from India. A part of NEA's business profit is expected to be dividends to shareholders, but at the time of the survey, NEA did not pay dividends and reinvested profits for the purpose of investment.

In addition to the NEA, VUCL is responsible for the development of hydroelectric power sources. RPGCL is responsible for the development of transmission. However, since it is not clear which institution will be responsible for the development of which power source in the future, the implementing entity that integrates NEA, VUCL, and RPGCL will be set as the target of the analysis.

2) Development status of government entities

The financial flow of the public electric power company assumed in financial analysis is the following flow chart.

Figure 7.6-2 summarizes the financial flow diagram focusing on the major business entities in Nepal's power sector, NEA, VUCL, and RPGCL.

Supplementary explanations regarding the main items shown in the above figure are as follows.

- "Income" refers to cash-in from the proceeds of domestic electricity sales and electricity exports. Currently, in Nepal, the NEA is centrally responsible for the sale of electricity. Based on this, it is assumed that public electric power companies will continue to be centrally responsible for the sale of electricity in the future.

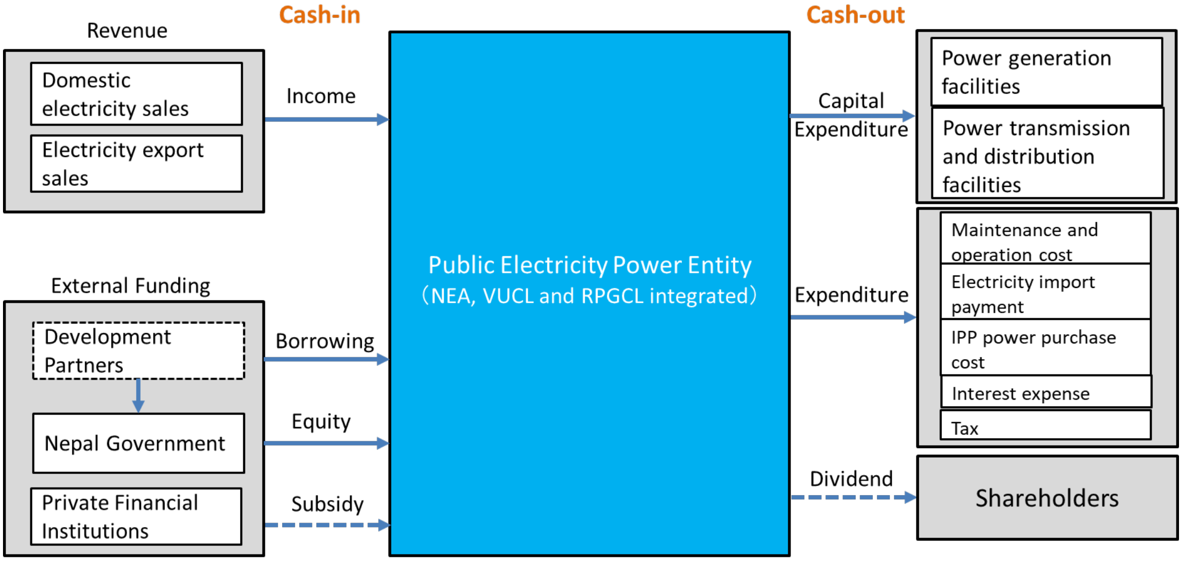
- With regard to "Borrowing", as will be described later, capital investment is required for the implementation of the IPSDP. When the public power utility cannot cover the capital investment fund with its cash reserves, it will need to borrow from the Nepalese government or private financial institutions.

- With regard to "Equity", it is expected that shareholders will increase their capital in order to cover the expenditures necessary for capital investment. This analysis is based on the premise that the necessary funds will be procured through borrowings or capital increases by shareholders (the ratio is borrowing: capital increase = 7:3, which is commonly used in project finance in Nepal), from the perspective of implementing the IPSDP in a sound financial position by the electric power sector.

- "Capital Expenditure" refers to expenditure for capital investment (power generation facilities, transmission and distribution facilities) required for the implementation of the IPSDP. As in the case of borrowing, the funds for capital investment will be allocated to shareholders (currently assumed to be the Nepalese government).

- "Expenditure" are costs for items that are mainly recorded as expenses for accounting purposes, assuming operation and maintenance expenses, payments for electricity imports, costs for purchasing electricity from IPPs, interest expenses on borrowings, and tax.

- "Subsidy" and "Dividend" are not directly taken into account in financial analysis but can be assumed as financial flows. Subsidies are the same as investment in that the government provides funds to public power companies without the premise of repayment, but the government of Nepal gains the status of a shareholder of a public power company by providing funds through equity investment. With regard to dividends, NEA is currently reinvesting the profits earned without paying dividends, and since the investment funds for the IPSDP are large, the financial analysis follows the method of reinvesting the funds without paying dividends.



Source: JICA Study Team

Figure 7.6-2 Basic Funding Flows in Nepal's Electricity Sector

The above is the premise of the financial flow of the financial analysis, and in this section, we will also summarize the current funding sources of NEA, VUCL, and RPGCL, which make up the public electricity power entity. As mentioned above, NEA is reinvesting its profits, while VUCL and RPGCL are investing by raising funds by equity because they do not have income from the sale of electricity. In the financial analysis, it is assumed that the investment comes from the Nepal government, but VUCL currently gains investment from some non-government agencies. In addition, although the two institutions do not borrow at this time, it was stated in the interview with VUCL that there is a possibility of borrowing in the future. Therefore, in the financial analysis, the premise of financing by borrowing is also placed as described above.

Table 7.6-3 The source of finance (NEA, VUCL and RPGCL)

Procurement Agencies	Procurement Methods	Main Suppliers
NEA[67]	Borrowing	Donor Agencies Government of Nepal
	Equity investment	Government of Nepal
VUCL[68]	Borrowing	NA
	Equity investment[69]	MoEWRI (Ministry of Energy, Water Resources and Irrigation) (20%), General Public (17%), NEA (10%), Employees' Provident Fund (10%), Nepal Doorsanchar Company Limited (10%), Residents of the project area (10%), Ministry of Finance (5%), Department of Justice (5%), Citizen Investment Trust (5%), etc.
RPGCL	Borrowing	NA
	Equity investment[70]	MoEWRI (46.01%), Ministry of Finance (21.03%), etc.

Source: JICA Study Team based on the annual reports of each institution

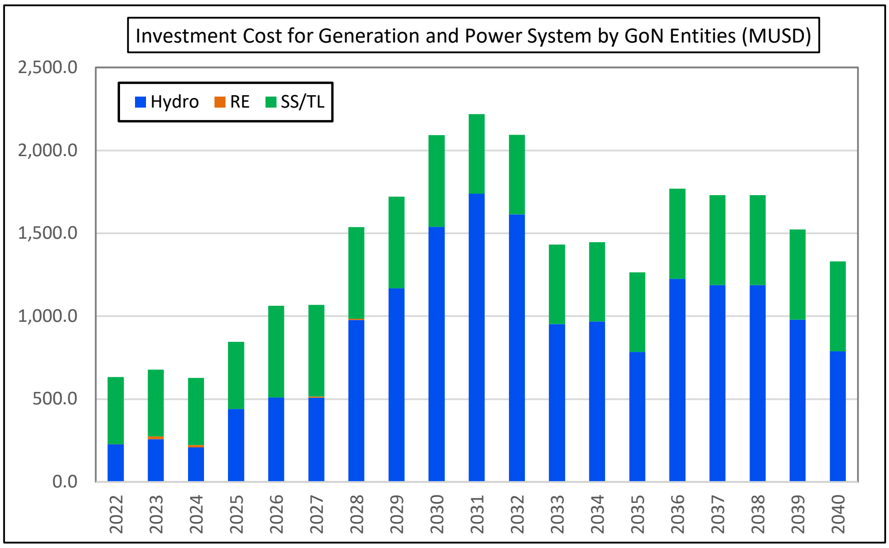
(3) Calculation of various expenses and income, etc.

The following table shows the results of calculations for various types of capital investment and income, which are the basic inputs for conducting various analyses. In the following, the estimation method for each item is shown. The numbers set are based on the optimal scenario.

1) Amount of capital investment

Capital investment costs are set in accordance with the optimal scenario. The following figure shows the annual change in capital investment over the 19-year period covered by the simulation. The total amount of renewal investments during the period covered is 26,804 million dollars, with a maximum of 2,218 million dollars (2031) and an average of 1,411 million dollars.

[67] The NEA did not provide a detailed breakdown of borrowers and investors in its report.
[68] The most recent available report is as of 2021.
[69] Investment ratio in parentheses
[70] ditto

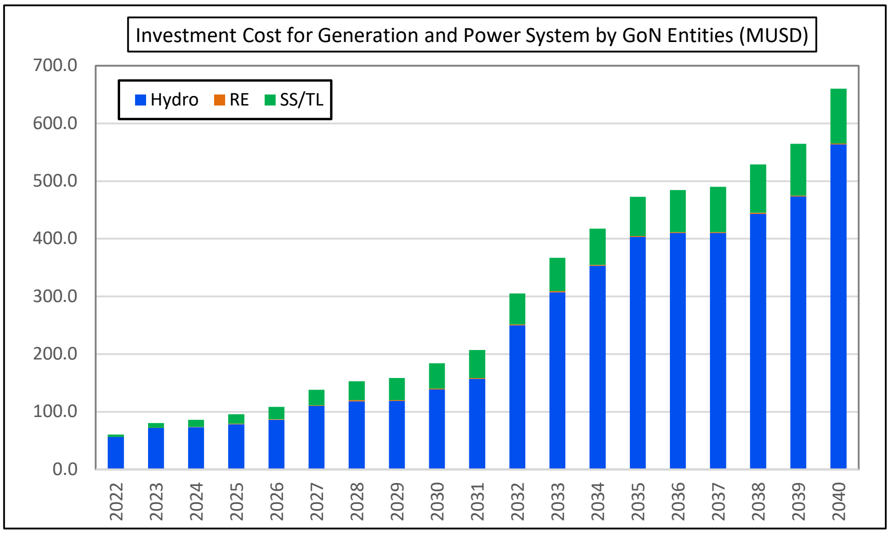


Source: JICA Study Team

Figure 7.6-3 Changes in capital expenditure over time

2) Operation and maintenance costs

Operation and maintenance costs were calculated based on past results and maintenance costs per kilowatt of new power plants under the assumption of 54 dollars/kW per year for hydropower and 14.4 dollars/kW for solar power. The total operation and maintenance costs during the period covered are expected to be 5,563 million dollars, with a maximum of 660.1 million dollars (2040) and an average of 293 million dollars.

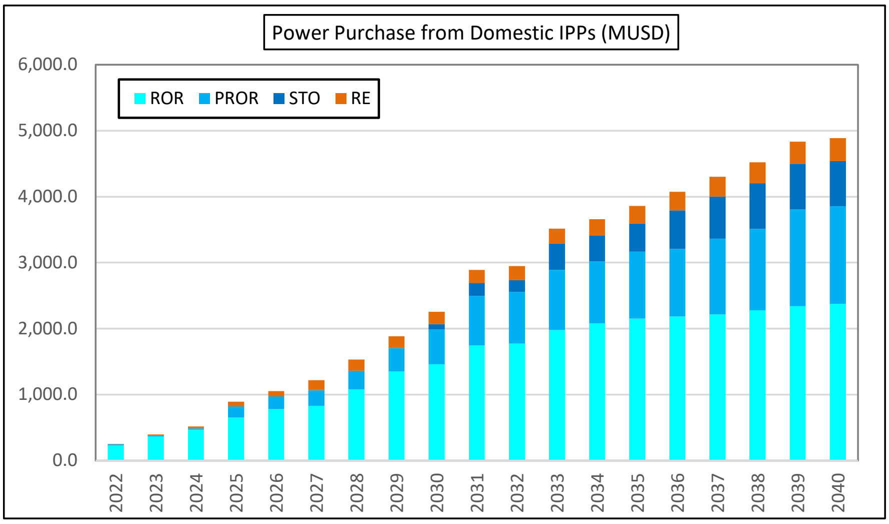


Source: JICA Study Team

Figure 7.6-4 Changes in maintenance and management costs over time

3) Cost of purchasing electricity from IPP

The cost of purchasing electricity from IPPs was determined by multiplying the existing power generation facilities operated by IPPs in Nepal and the amount of electricity to be developed by IPPs in the future, by the unit price set for each power supply configuration. Although it is assumed that the unit price of electricity purchased will fluctuate in the future, since the purpose of this simulation is to evaluate the degree of impact of IPSDP, it is assumed that the unit price of electricity purchased will remain constant over the period covered by the simulation. The unit price per power supply configuration is 0.050 dollars/kWh for ROR, 0.060 dollars/kWh for PROR, 0.080 dollars/kWh for STO, and 0.060 dollars/kWh for solar. The total cost of purchasing electricity from IPPs during the period covered is 49,496 million, with a maximum of 4,890 million dollars (2040). In addition, the change over time in the cost of purchasing electricity from IPP is shown in the following figure.

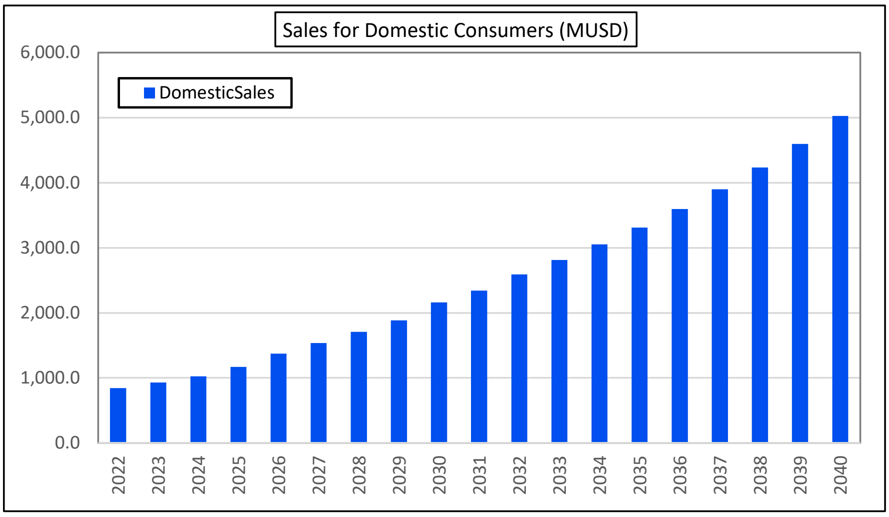


Source: JICA Study Team

Figure 7.6-5 Purchase of electricity for each power supply configuration cost

4) Domestic electricity sales

Domestic electricity sales are set based on the optimal scenario. Since fluctuations in future demand and policies are expected, the unit price of electricity sold is set within the range of the unit price used in the sensitivity analysis described later. The total domestic electricity sales during the period covered by the target period were 48,096 million dollars, with a maximum of 5,027 million dollars (2040).

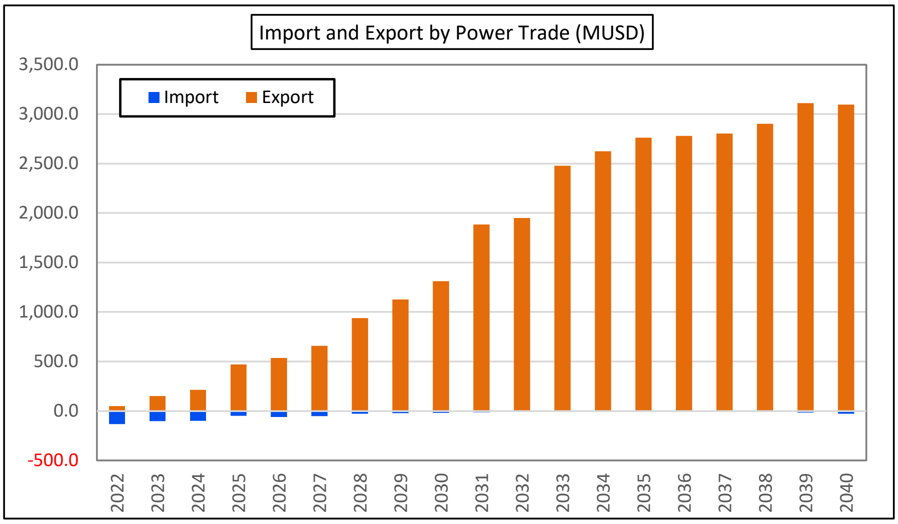


Source: JICA Study Team

Figure 7.6-6 Changes in domestic electricity sales over time

5) Cost of power interchange

Electricity export sales are set based on the import and export plan for power interchange to neighboring countries. Although the unit price of electricity sold for export is expected to fluctuate in the future, the purpose of this simulations to evaluate the degree of impact of the IPSDP. As of 2024, most of Nepal's electricity exports are carried out through IEX (Indian Energy Exchange Limited), so this price will be used as a reference for the electricity sales price of electricity exports. Here, the unit price of electricity for the 2023 IEX was kept constant at 0.070 dollars/kWh. In addition, financial analysis includes sensitivity analysis of the selling price of electricity exports to analyze the financial impact on the public electricity power company when the price fluctuates. The total cost of importing electricity during the period covered will be 650 million dollars. On the other hand, the total export sales are 31,852 million dollars, with a maximum of 3,097 million dollars (2040).



Source: JICA Study Team

Figure 7.6-7 Changes in electricity export sales over time

7.6.3 Economic Analysis

(1) Objectives, methods and evaluation indicators of economic analysis

The economic analysis will determine whether the implementation of the IPSDP will bring economic benefits to the Nepalese economy. As a method, we will use the cost-benefit analysis method, which is widely used in this type of analysis. The EIRR is used as an analytical indicator[71]. This is an indicator of the extent of the impact of the IPSDP on the national economy.

As a specific method of economic analysis, the annual cash flow is calculated for the difference between the case where the plan is implemented (hereinafter referred to as the "with case") and when it is not implemented (hereinafter referred to as the "without case"). The discount rate is determined with which the present value of the net benefit obtained by subtracting the cash flow related to the cost from the cash flow related to the benefit is zero.

If the calculated EIRR exceeds the "hurdle rate", we judge that the IPSDP will have a positive impact (i.e., the IPSDP investment is justified). In this analysis, the hurdle rate is set at 9%. This

[71] The economic internal rate of return is often denoted as EIRR. The study later identified the Equity IRR. In order to avoid confusion between the two companies, the former is "Economic IRR", the latter "EIRR".

is the rate commonly used by ADB for evaluation using the EIRR, which is also used by ADB in power projects in Nepal and will be used in this analysis[72].

The items of costs and benefits subject to this economic analysis and the calculation method are shown below.

1) Cost

The cost consists of capital investment costs and maintenance and management costs. The cash flow figures for each year are given in Table 7.6-4 and are higher than those given in 7.6.2 because they include development by private IPPs. Economic analysis takes into account all relevant costs and benefits occurring within a country.

Capital Expenditure Cost

This is the amount of capital investment required by the implementation of the with case, which is the cost of the construction of the power plant, power transmission and distribution network (However, in accordance with the general method for calculating the EIRR, the standard conversion factor is considered for capital investment that is expected to be procured in Nepal[73]. Conversion factor for this analysis is 0.93, according to the number used by ADB). In addition, if depreciation has not been completed in the last year of the analysis period and there is the residual value, it will be considered as a benefit (negative cost). This suggests that the facility will be used beyond the analysis period and economic benefits will be generated.

Operation and Maintenance Cost

It includes labour costs and repair costs necessary for the maintenance and management of equipment.

2) Benefit

The benefits consist of reducing electricity imports, electricity exports, and greenhouse gas reductions.

Reduction of Electricity Import

Compared to the without case, the with case reduces the dependence on imports of electricity and can be expected to reduce the cost of imports. This import reduction will be evaluated at 0.070 dollars/kWh, which is set with reference to the 2023 IEX electricity unit price, and the amount of the benefit of reducing electricity imports will be calculated.

Electricity Export

Compared to the without case, it is assumed that the with case will promote the export of electricity to neighbouring countries. The amount of the increase in electricity exports is evaluated at 0.070 dollars/kWh, which is the same as the benefit of reducing electricity imports, and the amount of the benefit from electricity exports is calculated.

[72] This hurdle rate is used in an ADB-supported power project in Nepal. For instance “Electric Grid Modernization Project (PPR NEP 54107)”In the economic analysis of 9%The discount rate is used. (https://www.adb.org/sites/default/files/linked-documents/54107-001-ea.pdf)

[73] This is a coefficient for correcting the price of domestically procured goods from the international level of prices by assuming that they are distorted from the international level by tariffs, subsidies, etc., and correcting the distortion and converting it to the international level price.

Reduction of Greenhouse Gas Emissions

In the with case, the development of hydropower-derived electricity can be expected to reduce greenhouse gas emissions in neighbouring countries that import electricity from Nepal. This effect is measured by using a carbon price of 40 dollars/tCO2eq (estimated as a carbon price in developing countries that declare net zero) estimated by International Energy Agency.

(2) Results of economic analysis

As a result of the economic analysis, the calculated EIRR was 10.1%, which exceeded the hurdle rate. The cash flows of costs and benefits used in calculating the EIRR are shown in Table 7.6-4.

As mentioned above, the calculated EIRR exceeds the hurdle rate, and in that sense, the implementation of the IPSDP can be justified from an economic point of view. If we look at the cash flow table in detail, we can see that there is a volume zone of capital expenditure in the middle of the analysis period (around 2030). While the costs will outweigh the benefits until 2032, the benefits will not exceed the costs until 2033 or later.

In addition, although the end year of this economic analysis is 2040, the benefits of investing in IPSDP are expected to continue after 2040. This is reflected in the fact that there is about 50 billion dollars of residual value left on capital expenditures as of 2040, and it is expected that benefits will be expected after 2040, using the equipment invested by 2040. In other words, the benefits of IPSDP can be enjoyed over a long period of time, looking ahead to 2040.

Table 7.6-4 Cash Flows of Costs and Benefits and Calculated EIRR

Unit: Millions of dollars

Year	Economic Cost				Economic Benefit				Net Benefit
	Capital Expenditure Cost	Opearation and Maintenance Cost	Residual Value	Total Cost	Reduction of Electricity	Electricity Export	Reduction of Greenhouse Gas Emissions	Total Benefit	
2022	1,925	0	0	1,925	0	0	0	0	-1,925
2023	2,427	59	0	2,486	58	213	100	371	-2,114
2024	2,519	98	0	2,618	157	299	140	596	-2,022
2025	2,728	217	0	2,945	373	657	308	1,338	-1,608
2026	3,260	270	0	3,530	559	750	352	1,661	-1,869
2027	4,767	367	0	5,133	740	923	433	2,096	-3,037
2028	5,433	410	0	5,843	940	1,315	616	2,871	-2,972
2029	7,042	525	0	7,567	1,130	1,576	738	3,444	-4,123
2030	6,488	673	0	7,160	1,407	1,838	861	4,106	-3,055
2031	6,563	861	0	7,424	1,599	2,640	1,237	5,476	-1,948
2032	5,708	980	0	6,689	1,850	2,730	1,279	5,860	-829
2033	5,180	1,202	0	6,382	2,084	3,468	1,625	7,178	795
2034	3,957	1,292	0	5,249	2,326	3,676	1,722	7,724	2,475
2035	3,866	1,402	0	5,268	2,584	3,866	1,812	8,261	2,993
2036	4,062	1,484	0	5,546	2,869	3,892	1,824	8,584	3,038
2037	3,582	1,537	0	5,118	3,165	3,926	1,840	8,931	3,812
2038	3,181	1,626	0	4,807	3,494	4,062	1,904	9,460	4,653
2039	2,473	1,731	0	4,204	3,847	4,354	2,040	10,242	6,038
2040	1,582	1,831	-51,112	-47,699	4,260	4,336	2,032	10,628	58,326

EIRR 10.1%

Source: JICA Study Team

7.6.4 Financial Analysis

In this section, we conduct a financial analysis focusing on fund raising, electricity tariffs and export prices setting to examine the financial feasibility of IPSDP.

Regarding the former, it is assumed that the implementation of IPSDP will lead to new capital investment. If the public electricity power company itself does not have enough investment funds for the capital investment, it will need to borrow funds or accept investment from outside, which will increase the public utility's debt burden, especially in the case of borrowing. In addition, accepting loans or investment from the government will have an impact on the government's finances. For this reason, it is useful to examine the amount of necessary fund raising and cash flow over the analysis period (2022 to 2040). Based on this analysis, the impact on the finances of the Nepalese government is considered.

Regarding the latter, the setting of electricity tariffs is directly linked to the burden on the people, and if it is high, it puts pressure on the people's lives, while if it is low, the power utility's income will decrease, and its financial situation will worsen. Consideration of appropriate electricity tariff levels in mid- to long-term power development is an important evaluation indicator for the plan and is worthy of consideration in the financial analysis of public power subsidiaries. In addition, as the revenue from electricity export has a significant impact on the financial status of the public electric power company, the prices of electricity export is also a target of analysis.

Here, we prepare cash flow statements for the public electricity power company during the IPSDP analysis period and analyze cash flows based on fundraising for capital investment and electricity tariff settings. First, we analyze cash flows if the current basic conditions of the power sector are followed and capture the cash situation of the public electric power company over the analysis period. Next, we conduct sensitivity analysis using the cash position and borrowing interest rates of the public power company as variables, and sensitivity analysis of electricity export prices and consider the setting of electricity tariffs and the electricity export prices, from the perspective of cash flows.

(1) Analysis of financing for investment

1) Purpose of the analysis

Since the implementation of the IPSDP is expected to lead to new capital investment, and the amount of funds required for capital investment is large. It is useful to examine how the necessary funds can be procured over the course of the year. Therefore, the financial analysis begins with the preparation of a future cash flow of the public electric power company for financing for capital investment and analyzes them.

2) Assumption about funding

The premise for analysis is as follows.

- First of all, income obtained from business activities, which is the amount after repayment of interest and borrowings is a source of investment in the following years. This is based on the premise that NEA is currently reinvesting the profits earned.
- If the funds are insufficient for the amount required for investment, the funds required for investment will be covered by borrowing and shareholder contributions. The ratio of borrowings to shareholder contributions is 7:3.

3) Financial statement items required for the preparation of the cash flow

The cash flow is prepared by the indirect method based on the balance sheet and income statement. The following is a list of items in the balance sheet and income statement of public electric power company that have been calculated with following assumptions.

[Balance Sheet Items]

Asset

New Facilities for IPSDP
They are facilities with new investments for the implementation of the IPSDP, and the amount of expenditure on capital expenditure for each year is depreciated on a straight-line method of 30 years.

Facilities at the end of 2021
Revenue has been generated since 2022, the first year of the IPSDP, which also comes from the use of equipment invested before 2021. Therefore, the facilities of NEA, VUCL and RPGCL at the end of 2021 are taken into account on the balance sheet[74], which is depreciated (straight-line method) in the analysis period.

Assets at the end of 2021
Balance of assets at the end of 2021 other than capital expenditures will be taken into account, and balances on the balance sheet will be matched. With the exception of investments in subsidiaries and affiliates, the majority of the funds are liquid assets and loans, which are expected to be converted into cash during the analysis period.

Liabilities

New Borrowing for IPSDP
As per the financing assumptions, the public electricity power company uses borrowing for capital investments. Here, the calculation is based on the borrowing rate currently used by NEA at 5%. The repayment period shall be 30 years (of which the deferral period is 10 years[75]).

Borrowing at the end of 2021
As liabilities, the balance of borrowings at the end of 2021 is considered. Suppose that this will be repaid over a period of 20 years.

Equity

Other than equity investment and retained earnings by IPSDP, equity at the end of 2021 will also be taken into account.

[Profit and Loss Statement Items]

The revenue and expense items used are domestic electricity sales (0.070 dollars/kWh), electricity export sales (0.070 dollars/kWh), operation and maintenance costs, payments for electricity imports (0.070 dollars/kWh), and electricity purchase costs from IPPs (ROR: 0.050 dollars/kWh, PROR: 0.060 dollars/kWh, STO: 0.080 dollars/kWh, and solar: 0.060

[74] It is set up simply for the purpose of preparing the financial statements of a hypothetical public electric power company for this financial analysis, and does not prepare strict consolidated financial statements.
[75] Referring to the repayment period of yen loans, we heard that the average period of time close to the same assumption was used for ADB.

dollars/kWh). Domestic electricity tariff levels are calculated based on the cash position and borrowing interest rate but as mentioned above, a benchmark of 0.070 dollars/kWh is used to create the cash flow statement. A corporate tax rate of 20% is applied.

In addition, inflation of 3.0% per annum will be taken into account in the financial analysis of new capital investments, domestic electricity sales, electricity export sales, operation and maintenance costs, payments for electricity imports, and payment for IPP[76].

4) Results of the analysis on financing

As can be seen from the cash flow statement, until around 2034, it will be necessary to cover the funds necessary for capital investment through borrowings and shareholder contributions in addition to the funds held on hand from business activities. On the other hand, from 2035 onwards, capital investment will be possible without raising funds from outside the public power utility.

Looking at the average rate of ROE (Return On Equity) and ROA (Return On Asset) over the analysis period of public electric power entity, ROE is about 10% and ROA is about 5%. This is close to the profit margin calculated with reference to the most recent NEA financial statements (9% for ROE and 4% for ROA).[77] Also from the viewpoint of profit margin, the model calculated here is used as a benchmark model.

[76] Apply the same inflation rate as the IRR calculation for individual projects in Chapter 12.

[77] This is the profit margin calculated by the JICA study team based on the items in the balance sheet and income statement described in the assumptions from the NEA's financial statements. We also received feedback from N EA and donors that it is appropriate to set ROE of 10% and ROA of 5% as the basis for profit margins.

Table 7.6-5 Cash Flow Statement

(million dollars)

(Year)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cash flows from operating activities																			
Profit before income tax	165	238	266	391	449	566	770	769	760	942	1,087	1,392	1,753	2,037	2,078	2,191	2,492	2,966	3,450
Depreciation	144	169	193	228	273	319	390	472	577	692	804	881	962	1,033	1,138	1,243	1,351	1,449	1,536
Loan interest	87	102	113	132	156	178	220	265	328	396	448	454	452	444	436	426	414	400	382
Income tax paid	-33	-48	-53	-78	-90	-113	-154	-154	-152	-188	-217	-278	-351	-407	-416	-438	-498	-593	-690
Loan interest paid	-68	-65	-61	-58	-55	-51	-48	-44	-41	-38	-35	-34	-33	-33	-35	-38	-43	-50	-61
Total	294	397	457	615	734	898	1,179	1,308	1,472	1,805	2,088	2,415	2,783	3,074	3,202	3,384	3,716	4,171	4,616
Cash flows from investing activities																			
Payment for new facilities for IPSDP	-690	-765	-721	-1,044	-1,339	-1,386	-2,127	-2,476	-3,136	-3,461	-3,356	-2,312	-2,408	-2,146	-3,140	-3,159	-3,254	-2,921	-2,601
Total	-690	-765	-721	-1,044	-1,339	-1,386	-2,127	-2,476	-3,136	-3,461	-3,356	-2,312	-2,408	-2,146	-3,140	-3,159	-3,254	-2,921	-2,601
Cash flows from financing activities																			
New borrowings for IPSDP	372	377	275	458	554	504	908	956	1,328	1,440	1,134	218	69	0	0	0	0	0	0
Repayment of borrowings for IPSDP	0	0	0	0	0	0	0	0	0	0	-19	-37	-51	-74	-102	-127	-172	-220	-287
Repayment of borrowings residual at 2021	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68
Equity by shareholders	159	162	118	196	238	216	389	410	569	617	486	93	30	0	0	0	0	0	0
Total	463	471	324	586	724	652	1,229	1,297	1,828	1,989	1,533	206	-21	-142	-170	-195	-241	-288	-355
Net increase in cash																			
Total	68	103	60	158	119	165	280	129	164	333	264	309	354	786	-108	30	222	961	1,661
Cash at end of year by IPSDP																			
Total	68	171	231	389	508	672	952	1,082	1,246	1,579	1,843	2,152	2,506	3,292	3,183	3,214	3,436	4,397	6,058

Source: JICA Study Team

(2) Analysis of Domestic Electricity Tariffs

1) Purpose of the analysis

In this section, we calculate the level of electricity tariffs for domestic consumers based on the cash position of the public electricity power company and consider the level of electricity tariffs taking into account fundraising.

2) Cases of the cash position to be analyzed

We will move domestic electricity prices and consider the electricity price levels in the following two cases. Case 1 is a case where cash is shorted, making it difficult to operate a sound business from a financial perspective. Case 2 can be regarded as a case where there is a margin of income in running a business. It is assumed that the electricity tariff will be applied consistently throughout the analysis period.

Case 1: Domestic electricity tariff levels that will result in a negative cash balance of public power utilities from 2023[78] onwards. This is the level of electricity prices when cash shortages occur even if the funds necessary for investment are procured through borrowing and investment.

Case 2: The level of domestic electricity prices at which the funds retained by business activities during the analysis period exceed the funds required for investment. In this case, all of the funds required for capital investment can be covered by the income from the business.

In addition to setting up Case 1 and Case 2, we will also conduct a sensitivity analysis based on borrowing rates. The setting width of the variable is 5.0% to 10.0%[79].

3) The level of electricity tariffs according to each case

Based on the above case settings, the level of domestic electricity charges was calculated to be 0.055 dollars/kWh (Case 1) and 0.130 dollars/kWh (Case 2). If the domestic electricity price level calculated in Case 1 and Case 2 is taken as the threshold, the level of domestic electricity prices can be set between 0.055 dollars and 0.130 dollars per kWh, although it is considered only from the cash position. The profit margins of Case 1 and Case 2 are ROE of 3.0% (Case 1) and ROE of 18.0% (Case 2), respectively.

Table 7.6-6 The level of electricity tariffs

Electricity Tariffs and Profit Level		Interest Rate (%)	
		5.0%	10.0%
Case	Case 1	0.054 dollars/kWh (ROE:3.0% ROA:1.0%)	0.058 dollars/kWh (ROE:2.0% ROA:0.0%)
	Benchmark Case[80]	0.070 dollars/kWh (ROE:10.0% ROA:5.0%)	0.070 dollars/kWh (ROE:8.0% ROA:4.0%)
	Case 2	0.130 dollars/kWh (ROE:18.0% ROA:15.0%)	0,132 dollars/kWh (ROE:18.0% ROA:15.0%)

Source: JICA Study Team

78 For the convenience of calculation, the amount of investment by the electric power business entity in 2022 is based on the estimated business income from the actual value in 2021, and does not fluctuate according to the electricity rates based on this analysis.

79 The interest rate of 10% is the interest rate that will be applied when assuming borrowing from a commercial bank in Nepal, and the interest rate for borrowing from a commercial bank is also set at 10% when calculating the IRR of individual projects. The analysis here assumes that the interest rate of government loans will rise to the same level as that of loans from commercial banks.

80 In the cash flow analysis in the previous section, an interest rate of 5.0% is used as the benchmark case.

(3) Sensitivity analysis of electricity export sales prices

In addition to examining domestic electricity rates, we will also examine the selling price of electricity exports. In Nepal's power sector, the proportion of sales from electricity exports is expected to fluctuate between 37% and 55% after 2027 as power source development progresses. As described previously, the selling price for electricity exports is determined not only by the Nepalese side but also by the demand of neighboring countries such as India and Bangladesh, so the selling price is set at 0.070 dollars/kWh based on IEX's track record. However, since this price setting is expected to have a significant impact on the business operations of the power sector, we will consider the impact on the profit margins and financial status of public power utilities if this price were to fall.

The analysis uses 0.030 dollars/kWh, 0.040 dollars/kWh, 0.050 dollars/kWh, and 0.060 dollars/kWh to set prices that have fallen from 0.070 dollars/kWh. The smallest price of 0.030 dollars/kWh was set based on the 2020 IEX annual average trading fee of 0.031 dollars/kWh, assuming that the selling price of electricity exports falls to this level. Note that conditions other than the selling price of electricity exports are the same as those used in the benchmark case. The results calculated using the above variable settings are shown in the table below.

Table 7.6-7 Result of sensitivity analysis of electricity export sales prices

Result of Analysis		Electricity Export Sales Prices（dollars/kWh）				
		0.030 dollars/kWh	0.040 dollars/kWh	0.050 dollars/kWh	0.060 dollars/kWh	0.070 dollars/kWh
Profit Level	ROE	-39.0%	-4.0%	4.0%	7.0%	10.0%
	ROA	-3.0%	0.0%	2.0%	4.0%	5.0%
Financial Status	Cash Short	No	No	No	No	No
	Insolvency	Yes	No	No	No	No

Source: JICA Study Team

From the results of this calculation, even if the selling price of electricity exports falls to 0.030 dollars/kWh, there will be not cash shortfall, but the deficit will accumulate, resulting in a negative net asset and insolvency. Since the public power utility will have a significant cash shortfall, it will need to raise more external funds (borrowings and shareholder contributions) than in the benchmark case for capital investment, and the Nepalese government's capital contributions will also increase, which could ultimately lead to the public power utility going bankrupt due to insolvency (profit margins: ROE -39.0% and ROA -3.0%). To secure a profit margin similar to the baseline (ROE 10.0%) and to utilize a significant amount of the public power utility's own funds for capital investment, it will be necessary to set domestic electricity tariffs at the level of 0.101 dollars/kWh, which would increase the burden on the public.

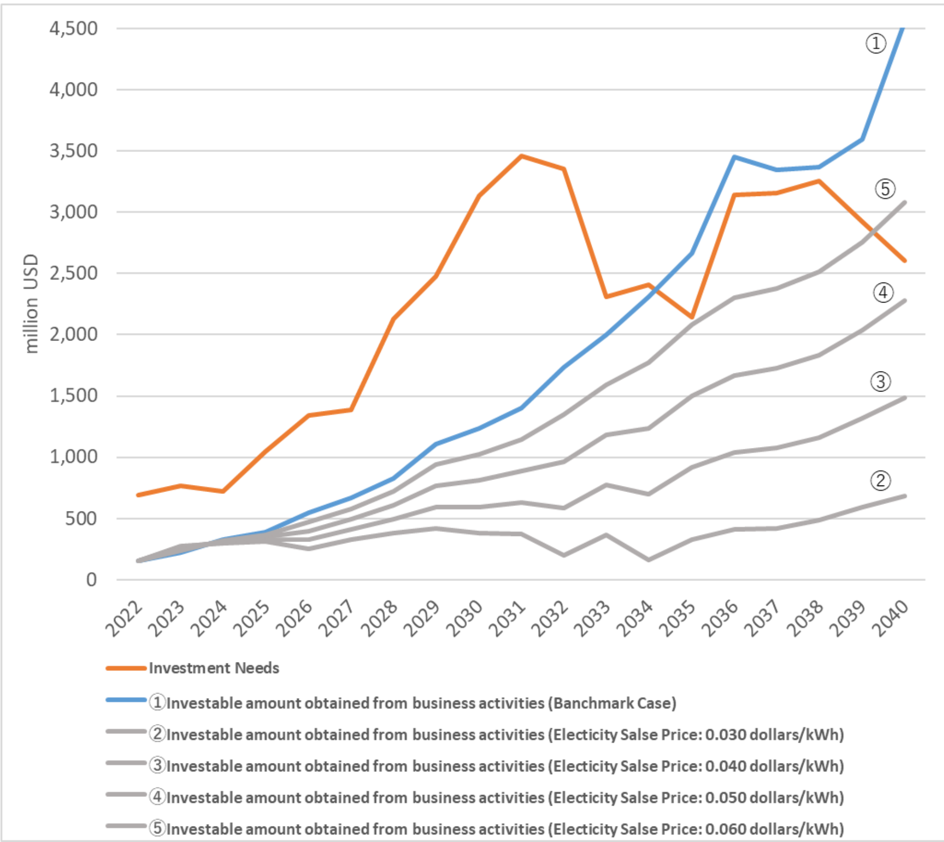
In this case, it may be necessary to consider measures such as suspending unprofitable businesses through a thorough review of current businesses, improving project profitability by reviewing costs for new businesses, and increasing the added value of electricity sales. However, there are limits to reviewing business profitability, and in reality, if the selling price of electricity exports falls to a level where ROE and ROA become negative (below 0.050 dollars/kWh), it is expected that a review of the development plan itself will be necessary.

(4) The Summary of Financial Analysis

Based on the above analysis, from the perspective of cash position alone, there is room to lower the electricity tariff to around 0.055 dollars/kWh. However, in this case, the need for external fundraising will increase, raising the uncertainty of procurement, and potentially increasing the government's financial burden. On the other hand, if all capital investment funds are to be covered by the revenues of public electric power utilities, electricity tariffs would have to be raised by around double the current level, which would increase the burden on citizens. If IPSPD is implemented based on the current electricity tariff level of 0.070 dollars/kWh, capital investment can be promoted using the revenues of the public electricity power company in combination with borrowing and investment, and an increase in the burden on citizens due to a significant increase in electricity tariffs can be avoided.

The results of the study on the selling price of electricity exports suggest that if the situation in potential export destinations, India and Bangladesh, changes significantly in the future and the selling price for electricity exports falls to 0.030 dollars/kWh, public power utilities may become insolvent. Even in the case of other selling prices, the dependency on external funds such as borrowing and shareholder contributions increases compared to the benchmark case, increasing the uncertainty of fund raising possibilities.

One possible way to make up for the loss of revenue from electricity exports would be to raise domestic electricity tariffs, but this would increase the burden on the public. Therefore, if the selling price of electricity exports falls, it may become necessary to reconsider the plans envisaged in the IPSDP by taking measures such as discontinuing unprofitable projects through careful review of the projects, improving the profitability of projects by reviewing the costs of new projects, and increasing the added value of electricity sales. However, there are limits to how much a business profitability can be reviewed, and in reality, if the selling price of electricity exports falls to a level where ROE and ROA become negative (below 0.050 dollars/kWh), it is expected that a review of the development plan itself will be necessary.



Source: JICA Study Team

Figure 7.6-8 Relationship between available investment amount from cash on hand and capital investment amount

Considering the current electricity situation in neighboring countries, it is thought that the electricity export selling price set at 0.070 dollars/kWh will not deviate significantly, but a medium to long term plan such as IPSDP will need to be updated periodically to reflect the surrounding environment of the electricity sector. The figure below shows the relationship between the amount of investment available in the funds reserved by the public electricity power company and the amount of capital investment required to implement the IPSDP for each electricity selling price.

7.6.5 Analysis of Impact on Nepal Macro Economy

(1) Objectives, Methods and Prerequisites for Nepal's Macroeconomic Impact Analysis

In the previous section, we conducted a financial analysis focusing on public electric power companies. This section examines the macroeconomic impact of IPSDP on Nepal. Specifically, the impact on external debt, foreign exchange reserves, the impact of electricity exports on the trade balance, the impact of electricity exports on the GDP, and the impact on employment.

Figures used in this analysis are the same as the previous paragraph (domestic electricity sales charges: 0.070 dollars/kWh, borrowing rate: 5.0%). However, since the growth rate of GDP below is assumed to be real GDP, the inflation rate of 3.0% is not considered.

1) Assumptions for the analysis of GDP

The baseline GDP is set as follows.

- GDP for each year is firstly calculated at 8% per annum (the reason for setting the growth rate is below), and then adding the income from electricity export sales on top of it.
- The growth rate is referred to that of Power Demand forecast, with the growth rate of Middle case, industrial (10.14%), Commercial (7.71%) and others (7.12%).
- Revenue from electricity export sales for each year of financial analysis is added to the GDP set in this way to form the baseline GDP[81]. Electricity exports are expected to be accelerated by the implementation of the IPSDP and are assumed to be generated exogenously by the implementation of the IPSDP.

(2) Analysis of the impact on external debt

1) Objectives, methods and prerequisites for the analysis of the impact on external debt

Baseline external debt

Looking at Nepal's external debt over the past 10 years, it has hovered around 20% of GDP, so the baseline external debt is assumed to be 20% of GDP set in this analysis (of which 3.0%[82] is assumed to be originally allocated to the electricity budget and is excluded to avoid duplication with the borrowing of external debt due to the implementation of the IPSDP).

External debt by IPSDP

If the public electricity power company receives a loan and shareholder contribution, it is assumed that it will be funded from the government budget of Nepal. When the debt is injected

[81] Electricity export revenues for each year are the same as electricity export revenues used in financial analysis.
[82] As described in Chapter 2, since 2.8% of Nepal's budget is allocated to the MoEWRI, which has jurisdiction over the electricity sector, it is assumed that 3% of the external debt will also be allocated to the electricity budget.

from the government budget, the following two cases are assumed to be used in the analysis of external debt. In both cases, the balance of external debt is calculated taking into account the repayment period of 30 years (10 years is a grace period).

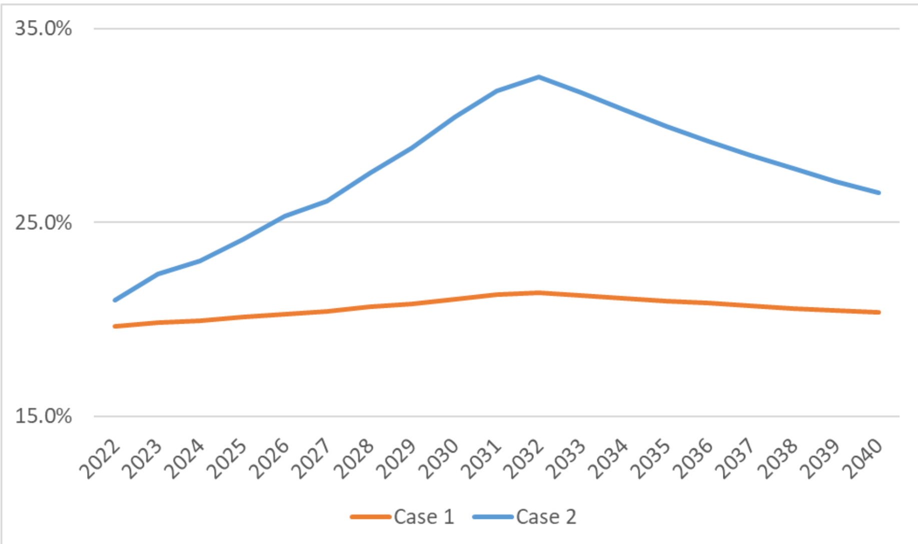
Case 1: The government budget to be input refers to the current budget structure of the Nepal government and consists of "tax and non-tax revenues: external debt: domestic borrowings = 70 : 15 : 15". This means 15% of the loans and shareholder contributions will come from external debt.

Case 2: A case in which all of the government budget is financed by external debt. In this case, 100% of the loans and shareholder contributions are derived from external debt.

The external debt under the IPSDP is added to the baseline external debt in 1) above, resulting in the balance of external debt for each year.

2) Results of the Impact Analysis on External Debt

External debt per GDP ratio is Figure 7.6-9. In both cases, the external debt will be increased around 2031-2032, when the demand for funds by the public electricity power company is high. The ratio will increase up to 21.4% (Case 1), up to 32.5% (Case 2), respectively. For reference, even among developing countries in Asia with higher income levels than Nepal, such as Viet Nam (36.1%), Philippines (28.7%), Thailand (38.4%), the ratio is about 30% to 40%. Since the other factors are fixed and external debt that takes into account only the financing of electricity development, it is not possible to make a general comparison, but it is not an exceptionally high figure compared to the external debt of these countries.



Source: JICA Study Team

Figure 7.6-9 External Debt as a Percentage of GDP

(3) Analysis of the impact on foreign exchange reserves

1) Objectives, methods and prerequisites for the analysis of the impact on foreign exchange reserves

Foreign exchange reserves serve as reserve assets in the event that it becomes difficult to repay external debts or settle import payments. Therefore, in analyzing foreign exchange reserves, the ratio of foreign exchange reserves to external debt is calculated[83]. At the same time, in order to see how much room there is to pay for imports, we also estimate how many months of foreign exchange reserves are equivalent to the value of imports.

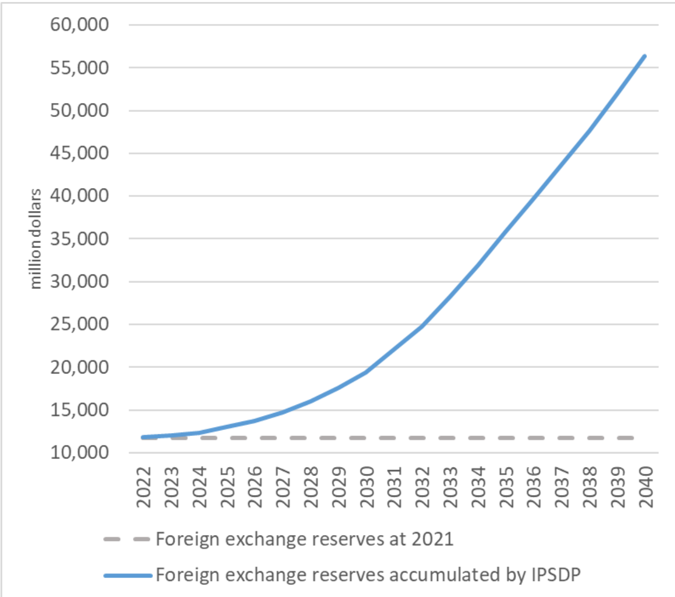
In analyzing the impact on foreign exchange reserves, the following assumptions are made:

a. Foreign exchange reserves are formed by adding imports from electricity export sales from the IPSDP each year to the 2021 foreign exchange reserve of 11.7 billion dollars.

b. The value of imports for each year refers to the average ratio of imports to GDP over the past five years, which is 35% of the baseline GDP.

2) Results of the Analysis on Foreign Exchange Reserves

Calculated according to the assumptions, the foreign exchange reserves, which take into account the income from electricity export sales by the IPSDP, accumulate as shown in the graph below.



Source: JICA Study Team

Figure 7.6-10 Changes in Foreign Exchange Reserves

Although the level of 1.0 is sometimes used as a measure of foreign exchange reserves for short-term external debt balance[84], the current analysis assumes that the external debt to be procured to be used in the power sector is a concessional fund with a long repayment period. If it is more than 1.0 times, it is considered to have exceeded this level. From the calculation results, even when the ratio was minimal, it was 1.44 times (Case 1 of the analysis of external debt) or 1.01 times (Case 2 of the analysis of external debt), so it exceeded 1.0 in both cases.

As for the value of imports, it was estimated that foreign exchange reserves worth at least 10 months of imports would be secured over the analysis period. The three-month level[85] is

[83] However, bearing in mind that India is the main market for electricity exports, and that future electricity exports are expected to be denominated in India rupees, in such cases they differ from borrowed currencies (yen, dollars, etc.), and that while foreign exchange reserves are generally used as an indicator of safety in relation to short-term external debt, the external debt assumed in this analysis has a long repayment period, The ratio is only a guideline.
[84] Nomura Asset Management's "Economic Words for Investment" Vol.2 Foreign Exchange Reserves
[85] ditto

sometimes used as a measure of foreign exchange reserves relative to the value of imports, but the results of this analysis show that the level of foreign exchange reserves equivalent to one year of imports is secured, so the level of this guideline is exceeded.

(4) Analysis of the impact of electricity exports on the trade balance

1) Objectives, methods and prerequisites for the analysis of the impact of electricity exports on the trade balance

Nepal has a trade deficit. The implementation of the IPSDP is expected to improve the trade deficit by promoting electricity exports to neighboring countries. Therefore, we will analyze the expected benefits from electricity exports from the implementation of the IPSDP from the perspective of improving the trade deficit.

The assumptions used in the analysis are as follows.

GDP
The GDP estimated in this section is calculated by subtracting the following revenues from electricity export sales from the baseline GDP.

Baseline trade deficit
Over the past 10 years, the trade deficit has averaged 32% of GDP. Therefore, the amount of the baseline trade deficit will be 32% of GDP for each year, and this trade deficit will be improved by electricity exports.

Income from electricity export sales
Electricity export sales used in financial analysis are used.

2) Results of Analysis of the Impact of Electricity Exports on the Trade Balance

Baseline trade deficit, electricity exports were estimated to improve the trade deficit by up to 14%.

Source: JICA Study Team

Figure 7.6-11 Reduction of trade deficit

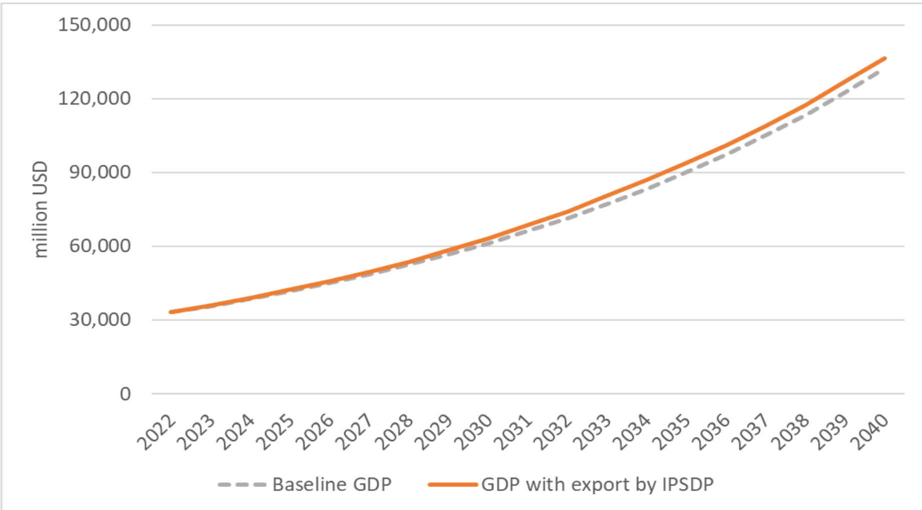
(5) Analysis of the impact of electricity exports on GDP

1) Objectives, methods and prerequisites for the analysis of the impact of electricity exports on GDP

In order to analyze the expected benefits from electricity exports from the implementation of the IPSDP from the perspective of GDP, we estimate the extent to which GDP will be boosted by revenues from electricity export sales. The GDP and electricity export revenues used in the analysis are those used in the previous analysis. At the same time, the contribution of electricity exports to GDP is also estimated.

2) Results of Analysis of the Impact of Electricity Exports on GDP

The GDP, which takes into account revenues from electricity export sales changes as shown in the graph below. It was estimated that the amount of income from electricity export sales would increase year by year, and that the maximum GDP would be increased by about 5% compared to the absence of IPSDP exports. Compared to the previous fiscal year, the GDP growth rate is about 8%.



Source: JICA Study Team

Figure 7.6-12 Trends in GDP taking into account income from electricity export sales

(6) Analysis of Job Creation Effects

1) Objectives, methods and prerequisites for the analysis of the effect of job creation

The implementation of the IPSDP is expected to create jobs associated with the construction of power generation facilities. In this analysis, we analyze the benefits of the development of integrated power systems from the perspective of job creation. MoEWRI's Energy Development Roadmap and Action Plan estimates the number of people employed to build a 1,000 MW hydropower plant as follows:

In analyzing the effects of the IPSDP on job creation, we will try to estimate the number of personnel required to construct a 1,000 MW hydroelectric power plant, using the capital investment costs and installed capacity estimated by the JICA study team. Since detailed analysis of each occupation is not the purpose of macroeconomic analysis, the average labor cost is used to estimate the number of people equivalent to the total number of people estimated by MoEWRI.

Table 7.6-8 MoEWRI Estimation of the number of personnel required to build a 1,000 MW hydroelectric power plant

Occupation of personnel	Number of people
Manager	50-60
Engineer	500-600
Workplace leadership personnel, such as directors and foremen	1,500-2,000
Skilled workers with a variety of skills and abilities	5,000-6,000
General Workers	20,000-25,000
sum	27,050-33,600

Source: JICA Study Team with reference to the Energy Development Roadmap and Action Plan (MoEWRI)

The following figures are used for estimation.

Table 7.6-9 Figures used to estimate employment

item	numeric value
Installed Capacity	Of the increase in installed capacity from 2026 to 2040 in the optimal scenario described, 26,876 MW related to hydropower generation will be used.
Amount of capital investment	Of the cumulative investment in the optimal scenario described, 47,262.4 million dollars will be used for hydropower generated from 2026 to 2040.
Ratio of labor costs to capital investment	As for available data, the Ministry of Health, Labour and Welfare of Japan has set the labor cost rate for the construction of hydroelectric power generation facilities at 19%. In addition, when ADB conducted an economic analysis of the Tanahu development in Nepal, the ratio of labor costs to construction costs was 42 percent. Therefore, in this analysis, it is assumed that labor costs account for 20%-40% of capital investment.
Labor cost	According to the 2018 census conducted by the Nepali government, the annual salary per employee in the electricity, gas and heat supply industry was 770,000 rupees. In addition, according to the salary index of the Central Bank of Nepal, the salary level of workers in the industrial sector has increased by 1.43 times from 2018/2019 to 2022/23. Based on the above, the annual labor cost per employee is 8,258 dollars/year, which is converted at 1 rupee = 0.0075 dollars.

Source: JICA Study Team

Using the above figures, the number of employees per year was first calculated from the amount of capital investment and labor costs, and then the number of employees for the construction of a hydroelectric power plant of 1,000 MW was calculated from the calculated number of people and the installed capacity.

[Calculation formula used for estimation]

$$① \quad \frac{\text{Labor costs in capital expenditure (per year)}}{\text{Labor cost per capita (per year)}} = \text{Number of employees (per employee)}$$

$$② \quad \frac{\text{Number of employees (per year)}}{\text{Increase in installed capacity (MW) (per year)}} = \text{Number of employees (per 1,000 MW)}$$

2) Results of Analysis of Job Creation Effects

The following table compares the number of employees employed per 1,000 MW estimated by the JICA study team with the estimates of MoEWRI [86].

[86] MoEWRI's estimates were included in “Energy Development Road Map”.

Table 7.6-10 Comparison of the estimates of MoEWRI with that of the JICA Study Team

	Estimation of MoEWRI	Estimates by JICA Study Team	Assumptions about the JICA Study Team's estimates
lower limit	27,050 people/ 1,000MW	42,765 people/ 1,000MW	Assuming that labor costs account for 20% of capital investment expenses
upper limit	33,600 people/ 1,000MW	85,530 people/ 1,000MW	Assuming that labor costs account for 40% of capital investment expenses

Source: JICA Study Team

Since the estimates differ depending on how labor and labor costs are taken, the estimates of the JICA study team are higher than the estimates of MoEWRI, but in all estimates, the effect of job creation per 1,000 MW of hydroelectric power plants is expected to be tens of thousands of workers.

Using the figures for the labor force and unemployment rate previously shown in the table, the number of unemployed people in 2022/2023 is estimated to be about 980,000. If about 27,000 workers are employed per 1,000 MW hydropower plant, as in the lower end of MoEWRI's estimate, this will have the effect of reducing the number of unemployed people by about 3%, and if about 85,000 workers are employed per 1,000 MW hydropower plant, which is the upper end of the study team's estimate, this will have the effect of reducing the number of unemployed people by about 9%.

7.6.6 Conclusion of Economic and Financial Analysis

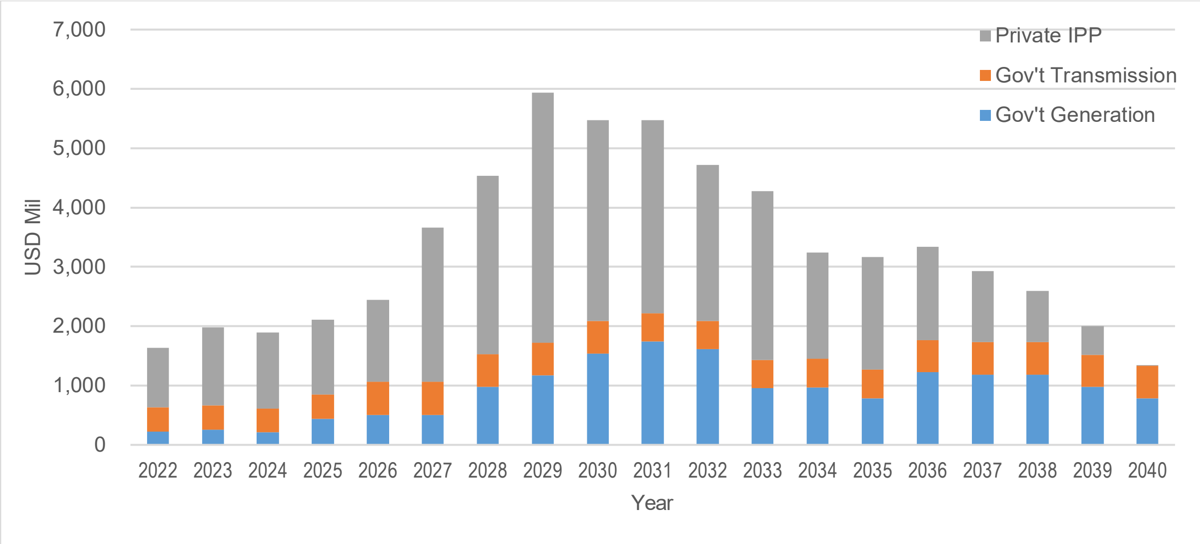
In light of the objectives set forth at the beginning of this chapter, the results of analyses and studies conducted and the suggestions obtained are summarized below.

- In the economic analysis, it was confirmed that the EIRR exceeds the social discount rate (hurdle rate). In this sense, investments under the IPSDP are justified.
- In the financial analysis, with regard to the benchmark case, it was confirmed that in the first half of the analysis period, it was likely that it would be difficult to secure the necessary funds for IPSDP investment without the use of borrowings and shareholder contributions, but in the second half of the analysis period, it was confirmed that the funds held on hand by business activities may exceed the funds required for investment.
- From 2022 to 2032, an increase in the government's external debt is inevitable as it will cover the funds needed for investment, but it is expected that it will not put extreme pressure on public finances.
- In terms of foreign exchange reserves, trade balance, GDP and job creation, the IPSDP is expected to have a positive impact on macroeconomic indicators. IPSDP can benefit Nepal in terms of economic growth and international trade.

Thus, in the analysis conducted in this chapter, positive results were obtained. However, the above analysis is one of the results of the analysis based on many assumptions, and the results are not guaranteed. In this sense, it is important to appropriately monitor the implementation status of the IPSDP, review assumptions and figures as necessary.

7.7 FINANCING OF IPSDP

A large amount of funds needs to be raised to realize the IPSDP. As calculated in 7.6, IPSDP requires 62,756 Mil USD between 2022 and 2040. It was confirmed that the GoN can afford to cover the costs from a fiscal perspective. However, the methodologies of fundraising remain to be assessed by GoN. As for the private sector investment, how to attract such a large amount of capital remains a critical issue.



Note: The classification of government (estimated)/private (estimated) was made by the JICA study team after confirming the proponents of each target project. Projects that were clearly being promoted by the GoN were classified as "Investment by the GoN (estimated)," while other projects were classified as "Investment by the private sector (estimated)." PPPs were classified as the latter.

Source: JICA Study Team

Figure 7.7-1 Investment Plans and Capital Demand in IPSDP

Regarding the use of private funds, it is impossible to cover the capital demand with the financial capabilities of domestic business companies and financial institutions alone, and in that sense, foreign investment and financing is essential. For hydroelectric power generation projects, which require large investment amounts, it is common to solicit investment and financing not only from general investors but also from international development financial institutions to execute project, as seen in examples from other Asian countries. In an environment where there is a clear demand for renewable energy sourced electricity in India and Bangladesh, it is expected that investment and finance sourced from these countries could accelerate power development and realize electricity exports. This chapter will assess options based on these understanding.

The section aims to analyze how to raise the aforementioned huge amount of development funds to realize the IPSDP. The study summarizes the current financing methods of hydroelectric power generation projects in Nepal, followed by the financing methods of the main project operators, the suppliers of project funds, and the current state of project financing. The section also assesses the basic concepts and options for project financing to realize the IPSDP, and analyze the effectiveness of using concessional funding as a source of finance. Finally, we present a plan for raising the funds required to realize the IPSDP.

7.7.1 Status of Financing Nepal's Hydropower Projects

(1) Financing of major hydro power projects

Major operators of hydroelectric power generation (power generation and transmission) in Nepal are public entities, such as NEA, VUCL, RPGCL, and HIDCL. Most of the public entities rely on borrowing from the Nepalese government, and even when they seek investment, MoEWRI or NEA is the investor and invests in VUCL and RPGCL.

Meanwhile, fund raising by private businesses can be broadly divided into PPP cases involving government agencies and cases promoted solely by private businesses. There are no records of private businesses participating in power transmission and distribution businesses, and private businesses have not yet reached the stage of considering concrete investment. Fund raising by private businesses (related to investment in power generation businesses), particularly in terms of debt, has been conducted in the form of loans, and there has been no confirmed case of fund raising through bonds. Fund raising methods through loans can be categorized by local and foreign companies as shown in the table below.

Table 7.7-1 Use of financing by private businesses (loans)

	Commercial Banks	Policy banks/development banks/ export-import banks, etc.
Local Business	○	△
Foreign companies	○	○

Legend ○: Frequently used △: Used Source: JICA Study Team

Many listed companies raise funds from commercial banks, and few borrow from policy banks. The reason for this is that domestic financial institutions have not yet fully developed. On the other hand, foreign companies (for example, Indian companies) actively utilize funds from commercial banks and policy banks. As for financing methods, Upper Trishuli-1 (216MW) is an example of a project in which a foreign company participates, and an SPC (Special Purpose Company) led by Korea Electric Power Corporation received PPP funds from ADB and IFC (International Finance Corporation), using project finance. Although it is unconfirmed about projects in which other foreign companies have invested, corporate finance is used for projects in which local companies have invested and borrowed, and no cases of project finance being used have been confirmed.

The current fundraising methods for the above five organizations (or classifications) have been summarized, and the results are summarized in the following table.

Table 7.7-2 Summary of current fund-raising status of major business entities

	Business Field	Government Borrowing	Commercial banks, etc.	Policy banks, etc.
NEA	Power generation and transmission	○	○	-
VUCL	Power Generation	○	-	-
RPGCL	Power Transmission	○	-	-
HIDCL	Power Generation	○	○	-
Private businesses (local)	Power Generation	-	○	△
Private business operators (overseas)	Power Generation	-	○	○

Legend: ○: Frequently used △: Used —: Unconfirmed (N/A) Source: JICA Study Team

(2) Supply-side information: Suppliers of business capital

This section summarizes information of the supply side of project finance in terms of debt and equity.

1) Equity finance suppliers in Nepal

Equity finance are provided by Nepal's domestic institutional investors, general public and public entities outside of Nepal.

Table 7.7-3 shows an example of institutional investors' investment in Nepal. There is also a mechanism under which up to 10% of issued shares can be issued to residents in areas where hydropower projects are located (Securities Issue and Allotment Directive, 2017, 2074 4-(2)). Some public entities outside of Nepal also considers investment in hydropower project in Nepal to recognize the project as a source of energy to attain carbon neutral movements, such as in India.

Table 7.7-3 Hydropower-related investments by major institutional investors in Nepal

Institutional investor name	Examples of involvement in hydroelectric power generation-related businesses
EPF (Employee Provident Fund)	Betan Karnali Upper Tamakoshi Tamakoshi V Investment in VUCL and HIDCL
CIT (Citizen Investment Trust)	Sanigad Hydro (guarantee) Investment in VUCL and HIDCL
RBS (Rastriya Beema Sansthan)	Investment in VUCL and HIDCL

Source: Company websites and HIDCL website

2) Debt finance suppliers

Local financial institutions and domestic development financial institutions in Nepal are the main suppliers of debt. Local financial institutions are responsible for lending debt to small to medium-sized businesses, but they do not have a sufficient capacity to provide long-term financing for large scale hydro power projects.

Many international development financial institutions also provide loans. The main ones are as follows:

- The WB and UK Department for International Development reviewed and assisted IBN in negotiating PDAs for large-scale hydropower projects with the intent of exporting electricity, which resulted in the development of two sites: Upper Karnali and Arun 3.
- The WB is providing USD 20 million for technical design and bidding assistance for the Upper Arun project with multiple developing partners, and ADB has agreed to provide USD 60 million PPP loan for Trishuli (216 MW), co-financed the 144 MW Kali Gandaki " A " hydropower project with JICA in 2002 , and implemented the 140 MW Tanahu hydropower project, a reservoir-type hydropower plant, co-financed by JICA, EIB (European Infrastructure Bank) , and the Abu Dhabi Fund for Development in 2013 .
- EIB is providing a grant aid of EUR 5.5 million for the Tanahu project to cover the

construction of the power plant, and is also providing € 25 Mil loan funding for development studies for the Chilime-Trishuli transmission line project with KfW (€14 Mil Grant)[87].

- USAID has no history of directly investing in hydroelectric power generation projects, but its Nepal Energy Program includes providing advisory services on deregulation aimed at sector reform, strengthening the capabilities of the private sector, and improving systems for electricity imports and exports.

(3) Situation of Project Finance in Nepal

This part summarizes the information collected regarding the current state of financing for hydroelectric power generation projects in Nepal by key elsewhere.

1) Financing Methods

It is difficult to gather information on the specific financing methods for individual cases (because of commercial confidence), but based on interviews with private organizations such as IPPAN and international organizations such as the WB and ADB, it can be assumed that, at least for local companies, corporate financing is the most common financing method currently used. The reasons for this are thought to be as follows:

- The investment scale is not large enough to formulate project financing.
- Local companies have limited knowledge or experience regarding project finance.
- Local financial institutions have limited knowledge and experience in project finance.

2) Debt-Equity Ratio

The debt-to-equity ratio (hereinafter referred to as the "D/E ratio") that is considered when raising funds for hydroelectric power generation projects is generally around 20:80 to 40:60 worldwide. According to the survey conducted this time, it appears that in Nepal, the ratio of 70:30 is often applied[88].

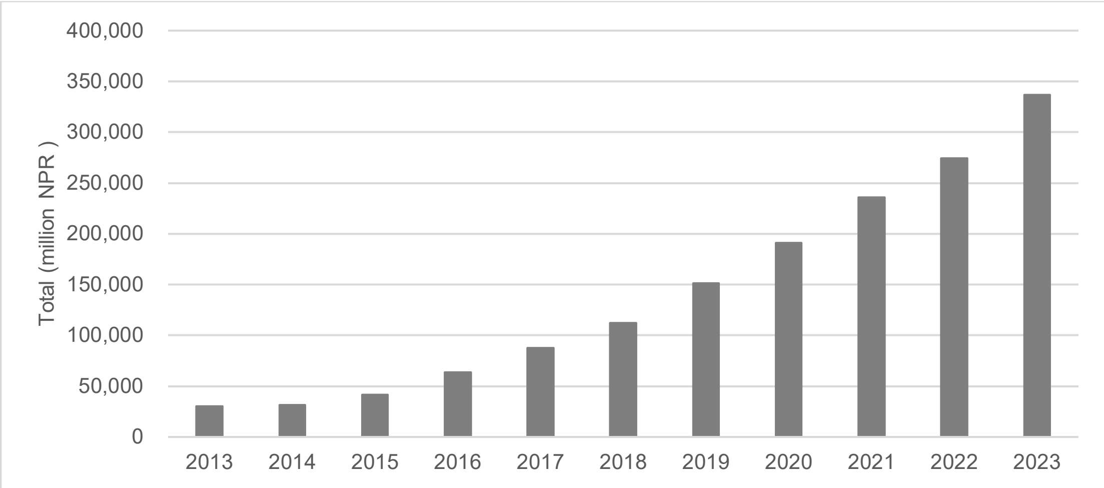
For equity investment, investors in large projects can choose from government organizations or neighboring power companies that will purchase electricity. For medium-sized and larger projects with excellent profitability, investment is often sought from investors in India, China, etc. As a result, domestic investors are focusing on the possibility of investing in small to medium-sized businesses, due in part to limited investment capital.

Regarding debt, local Nepalese financial institutions have limited capacity to lend long-term funds, making it difficult for them to lend to medium-sized or larger projects, and therefore local financial institutions are limited to minority participation in medium-sized or larger projects. Lenders for medium-sized or larger projects are limited to international commercial banks and international development financial institutions. Furthermore, some ECA[89] providers, such as the Exim Bank of India, have provided institutional loans through credit guarantee schemes.

[87] " Global Gateway: EU and Nepal launch new flagship to support electrification of rural areas", 17 May 2024, European Commission
[88] This is based on various literature surveys and interviews with private business operators, including IPPAN. In addition, the financial analysis in Chapter 11 is based on these survey results and assumes that the business operator's debt/equity ratio is 70:30.
[89] Export Credit Agency

3) Lending capacity of local financial institutions

In Nepal, commercial banks and development banks are actively lending to hydropower projects. The following figure shows the [90]lending trends of commercial financial institutions to the infrastructure sector, including the energy sector, and the past lending trends to the sector have exceeded the overall increase in lending amount of these financial institutions. NRB is calling for a gradual increase in the proportion of lending to the power, gas and water sector, which remains at 5.45% of the total lending amount as of 2021, to more than 10% by 2023/24. [91] The figure below shows that the lending capacity of local financial institutions is on the rise.



Source: "Quarterly Economic Bulletin Mid-Oct 2023", Nepal Rastra Bank

Figure 7.7-2 Lending trends from commercial financial institutions

(4) Laws and regulations related to Power Development

Key laws and regulations related to hydropower project financing in Nepal are as follows;

- Private Finance in Build and Operation of Infrastructure Act, 2063
- The Public Private Partnership and Investment Act 2019
- Hedging Related Regulations, 2075 (as amended in 2076)
- The Foreign Investment and Technology Transfer Act 2075
- Foreign Exchange (Regulation) Act 2019

7.7.2 Basic Consideration on Financing Method of IPSDP

(1) Overall IPSDP investment plan, capital needs and business financing options

Major financing methods applies in power generation and transmission projects are summarized[92]. The following discussion will be based on this table.

[90] In addition to the energy sector, this includes transport, communications and public services.
[91] Nepal Rastra Bank " Financial Stability Report 2019/20 "
[92] The word "general" here means that it can be used not only in Nepal but in developing countries in general.

Table 7.7-4 Major Financing options in developing nations' power projects

Business Classification	Government/ Private Sector	Major Classification	Remarks
Power Generation Business	Government funding	- Domestic budget (Tax & Non-tax revenue, domestic borrowing) - Foreign borrowing	It is often used in projects with huge construction costs or low profitability.
	Private funding (PPP/IPP)	Equity Debt	It can be applied if the conditions are met in terms of business scale, risk, profitability, finance, etc.
Power Transmission Business	Government Business	- Domestic budget (Tax & Non-tax revenue, domestic borrowing) - Foreign borrowing	Generally, transmission projects are implemented as government projects.
	Private funding (PPP)	Equity Debt	Limited cases of application due to factors such as construction costs, land acquisition, and exclusivity.

Source: JICA Study Team

(2) Considerations regarding financing for power generation projects

Power development projects are likely to have different investors and lenders depending on the scale of the project, profitability, and the composition of the participating parties. In hydroelectric power projects, the scale of the project determines the development period and required investment amount, so the composition of investors and lenders varies.

Small-scale usually refers to projects of less than 1MW, but in this section, investor procurement is set at 50MW, which is completed by investors (including state power companies, etc.) within Nepal or neighboring countries such as India. Medium scale refers broadly to projects up to 200MW that do not require IBN investment permission. Since hydroelectric power plants over 200MW in size are subject to IBN approval, in such cases, it can be interpreted that the GoN is determining investor eligibility through IBN approval.

The financing methods for hydroelectric power generation projects of each scale can be summarized as shown in the following table, considering the actual situation in Nepal and the experience of other countries.

Table 7.7-5 Fund Raising Methods of Hydropower projects

Capacity	Fund raising methods
Small projects (less than 50MW)	- Corporate Finance
Medium-sized projects (50-200MW)	- Corporate Finance - Project Finance - Public support, including the use of ODA
Large-scale projects (over 200MW)	- Project Finance - Public support, including the use of ODA

Source: JICA Study Team

(3) Considerations regarding Financing of power distribution businesses

Unlike power generation businesses, power transmission and distribution businesses must be operated as an entire power system, not as individual project development, and profitability varies project by project. In addition, because it is a business with a high degree of public interest, namely a stable supply of electricity to the people of Nepal, financing for the construction/operation of transmission lines tends to be primarily through public funds. The construction of the 132kV system, which RPGCL began, is being carried out with funds from the GoN. Using funds obtained from the WB, ADB, and AIIB (Asian Infrastructure Investment Bank), NEA is working on the construction of transmission lines and substation facilities, as shown in the following table.

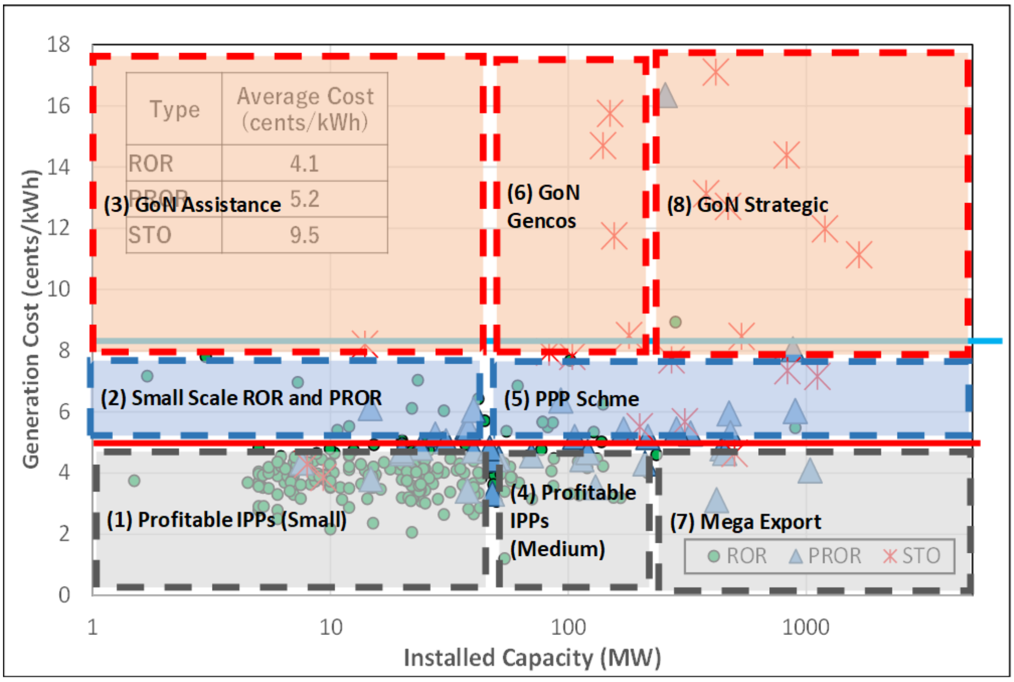
Table 7.7-6 NEA projects assisted by Development partners.

Development partners	NEA Business
ADB	Rehabilitation of Sundarijal HEP as part of support for the maintenance of power plants with a generating capacity of less than 30MW
WB	Hetauda Dhalkebar Inaruwa 400kV Transmission Line Project
AIIB/EIB	Power distribution system renewal plan
EIB	Marsyangdi Corridor 220kV Transmission Line Project
ADB	Tanahu region electrification, network improvement
ADB	Strengthening of electricity distribution network in suburban areas of Lalitpur and Bhaktapur
ADB	Substation Automation
ADB	132kV Keraun Substation Project
Export-Import Bank of India	Raghuganga Hydropower
JICA	Urban Power Transmission and Distribution Network Development Project

Source: NEA Annual Report

(4) Basic considerations for realizing IPSDP financing

In this study, hydropower projects that were deemed to be given priority for development in the IPSDP were evaluated based on the axes of power generation cost and project scale (installed capacity) and were classified into eight categories as illustrated. Followings are salient features of projects of each category.



Source: JICA Study Team

Figure 7.7-3 Priority Development Projects

<Project categories with relatively high profitability>

(1) For profitable IPPs (small) development is likely to proceed, if financing is possible within Nepal and the surrounding environment, such as access roads and grid connections, is in place. On the other hand, considering the implementation of appropriate approval processes by the government, it is not desirable to spend time and money on formulating and supporting projects for each development sites. For this reason, it is expected that the lending capacity of HIDCL, an organization supporting development, will be strengthened, new funds will be established to provide financing for multiple projects, and a bank specializing in small and medium-sized hydropower will be established or supported. Such support will likely include TSL (Two Step Loan) and policy loans, which provide large amounts of capital to banks and government-affiliated funds.

(4) The situations are similar to for profitable IPPs (medium), but the number of businesses that can implement projects with a development scale of over USD 100 million in Nepal is limited due to financial scale. For this reason, measures are needed to encourage matching with domestic and foreign investors and businesses for projects that have been granted development rights but are not progressing. Financial support will include a mix of corporate finance and project finance, and investment and financing for private entities is also expected.

(7) Mega Export is a large-scale, highly profitable project and an attractive investment opportunity. However, as it is a massive project worth over USD 400 million, the expected participants will be limited to an SPC consisting of government-affiliated businesses such as the NEA, major domestic conglomerates, major international development businesses, and Indian power companies.

<Moderate profitability project category>[93]

(2) There are many small-scale ROR and PROR projects, but because the fixed costs are too large to be implemented through project financing like medium to large scale projects, it is expected that lump sum support will be provided through funds, or that government-affiliated businesses such as HIDCL will join in the support. In terms of the order of hydropower development, development of (1) will take priority, but it is expected that support will be necessary in the future.

(5) The PPP Scheme will be a joint support method for medium to large-scale projects. In addition to the various power generation formats of ROR, PROR, and STO, a variety of players are expected to participate in the development process, including medium to large-scale domestic and foreign developers, government-affiliated businesses, and Indian power companies. Since it is necessary to consider the composition of each project and the support methods are expected to be diverse, it is necessary to consider a flexible composition that combines support measures applicable to each player.

<Project categories with lower profitability>[94]

Projects with generating costs above approximately 8 cents/kWh fall into this category.

There are few projects below 50 MW that fall under this category. Projects aimed at rural

[93] For projects with medium profitability that are difficult to ensure profitability with the interest rates of Nepalese commercial banks (approximately 10-12%), it is necessary to supplement credit and ensure business viability through the provision of public funds and joint ventures with government-affiliated businesses.

[94] Low-profit projects include regulated power sources such as STO. The business value of STO power sources is difficult to evaluate based on hourly value such as LCOE alone, and many locations do not show business feasibility or profitability through financial analysis, so development by government-affiliated businesses or joint development with IPPs is expected.

electrification or rural development, or projects developed without regard for profitability to utilize remaining head differentials, fall under (3) GoN Assistance. This is hardly the case for the IPSDP candidate projects. Examples of projects that are expected to be implemented include projects aimed at rural electrification or its development, and projects that utilize remaining head. Although the number of such projects is small overall, if the necessity of the project is recognized, it is expected that the project will be implemented using the government budget or support from various development aid agencies.

(6) GoN PROR/STO Projects envision the development of regulated power sources by government-affiliated companies in Nepal. Because project will be classified as a regulated power source, the scale of business development will be moderate, at 50 to 200 MW. However, because it will be a regulated power source, its operation will not be constant, making it less profitable, and it will be necessary to utilize loans from development aid agencies, such as ODA.

(8) The GoN Strategic Project is similar, but due to the large scale of development and mostly designed for export-oriented, project will be necessary to utilize funds not only from government-affiliated companies in Nepal, but also from overseas power companies, etc. In addition to utilizing support schemes such as EBF (Equity Backed Finance) and investment and loans for private entities, it will also be important to utilize ODA budgets not only for Nepal, but also for neighboring countries that are potential destinations for the electricity.

(5) Basic principles regarding financing for power generation projects

Based on the discussion in the previous section, the basic principles of financing for power generation projects have been summarized in the Table 7.7-7. These principles will serve as the basis for the discussion in the following sections.

Table 7.7-7 Basic Concepts of Project Categories and Financing Methods in IPSDP

Relative profitability	Categories	Expected main financing entities	
		government	private
High	(1) Profitable IPPs (Small)	-	◎
	(4) Profitable IPPs (Medium)	△	◎
	(7) Mega Export	○	◎
Moderate	(2) Small Scale ROR and PROR	△	○
	(5) PPP Scheme	○	○
Low	(3) GoN Assistance	○	△
	(6) GoN PROR/STO Projects	◎	-
	(8) GoN Strategic Project	◎	-

Legend: ◎: Consider as a prerequisite ○: Consider as a priority △: Consider necessity and possibility —: Not applicable

Source: JICA Study Team

(6) Considerations regarding financing for power transmission business

At present, the legal basis for private participation in the power transmission business (including substation business) is unclear, and there is no prospect of this being realized. Therefore, the financing method for the power transmission business will be based on the following ideas.

- As the revised Electricity Act has not yet been enacted, it is assumed that financing for the electricity transmission business will be provided by the government.
- On the other hand, we cannot rule out the possibility that private participation in power

transmission projects will be legally recognized in the future. There are plans to utilize private funds in the development of power transmission networks for international power exchange as an idea. Therefore, we reserve the option of utilizing private funds depending on the situation and developments.

7.7.3 Analysis of the Effectiveness of Concessional Funding

There are 750 hydroelectric power projects expected to be developed under the IPSDP, with large-scale projects including large-scale developments with an average investment exceeding USD 1,000 million. It seems difficult for the GoN, IPP operators, and Nepalese financial institutions to conclude the financing of such a large-scale hydroelectric power development project alone. International development financial institutions have participated to date and have provided grant and loan assistance and credit enhancement to make this possible.

This section analyzes the effectiveness of applying concessional funds from international development financial institutions, taking into account the characteristics of projects expected to be prioritized for development in the IPSDP. Concessional funds are loans in which the loan conditions (interest rates, repayment period, etc.) are set favorably for the recipient country. In this section, the study examines the cases in which sovereign loans, investment loans for private entities, and EBF are applied to the projects and verify the effect of introducing concessional funds. Furthermore, since hydroelectric power development is being carried out in Nepal in anticipation of electricity exports, the study analyzes the possibility of development and fundraising by utilizing the creditworthiness of India, Bangladesh, and other countries that will be the destinations for electricity exports. Projects analyzed were selecting projects for which the results of feasibility studies necessary for financial analysis were available, and by setting scoring criteria to determine the projects. The study excluding projects that have high profitability given consider the nature of concessional loan's additionality. These projects are enabled to be developed with private funds, and projects that are too small in scale to require concessional loans from donors and therefore are unlikely to produce support or development effects. Note that while this section will examine the feasibility of projects using concessional funds, it is not premised on support from JICA.

(1) Selection of target projects

Here, we will select projects to analyze through the following three steps.

- Step 1: Consideration of categories for which concessional financing is desirable
- Step 2: Selection process for projects to be analyzed and setting criteria
- Step 3: Selection of projects to be analyzed.

1) Step 1: Consideration of categories for which concessional loans are desirable

Hydropower priority projects mapped into the eight categories shown in Figure 7.6-2 were examined. After examining each category, it was found that projects classified as (1) and (4) Profitable IPPs, which have lower power generation costs, and (7) Mega Export, do not require the application of concessional loans because the projects are sufficiently viable. In addition, (2) Small Scale ROR/PROR is excluded from consideration because its development impact is limited, and there are few projects classified as (3), so it will not be considered. Projects that are expected to promote hydropower projects through the application of concessional loans are those located in the quadrants of (5) PPP Scheme, (6) GoN Gencos, and (8) GoN Strategic.

2) Step 2: Selection process for projects to be analyzed and setting of criteria

Based on the analysis in the preceding paragraphs, for projects for which it was deemed appropriate to analyze the effects of introducing concessional loans, since it would be difficult to obtain comprehensive business feasibility studies from the perspective of confidentiality of individual projects, projects for which specific analysis work would be carried out were screened and selected based on certain conditions.

Table 7.7-8 Evaluation criterion of projects applying concessional fund

Criterion	Specific evaluation methods and criteria
Business scale	● In cases where large-scale investments are required and it is difficult for the private sector alone to raise business funds, it is effective to utilize concessional loans. ● We highly value projects with large total investment amounts.
Economic efficiency	● By providing concessional loans to projects with low feasibility, it is expected that economic viability will be improved, and development will be promoted and implemented. ● Projects with an LCOE exceeding 7.0 cents compared to the NEA's wholesale unit price for consumers (7.0 cents/kWh) are less economical, so there is rationality in introducing concessional financing.
Ease of implementation	● When formulating projects and considering the provision of concessional loans, it is easier to support projects being developed by GoN entities than projects being developed solely by private sector entities. ● Projects where the implementing entity is the GoN or a government agency such as VUCL will be highly evaluated.
Involvement of other donors	● In cases where assistance is already being considered by other donors, it is assumed that additional concessional loans will be received, so a high rating is given to projects where there is no visible donor involvement, and a low rating is given to projects where there is no sign of donor involvement.

Source: JICA Study Team

3) Step 3: Selection of businesses to be analysed

Based on the above evaluation, the 26 projects listed as priority projects were evaluated. Among 26 projects, 9 projects scores more than 5 points out of 8 full points. Within these 9 projects, 5 projects’ financial performance data are available for the study. Given considerations of data availability, the study chooses 2 projects (i.e. Sunkoshi 3 and Lower Seti) which are not negatively evaluated with respect to the “Economic Efficiency” and “Implementation”. Phukot Karnali project added to the evaluation as power export is an important goals of Nepalese hydro project development.

At present, Upper Arun is not included in the analysis because it is deemed that there is little need for concessional financing as sufficient economic viability is foreseen. In terms of type classification, Upper Arun is classified as the (7) Mega Export quadrant. In terms of type classification, Lower Seti is classified as (5) PPP Scheme, but in terms of business feasibility it is closer to the (6) GoN Gencos classification, and it was determined that there is value in verifying the effects of concessional financing. In addition, Sunkoshi 3 is classified as (8) GoN Strategic (a project that is meaningful for the GoN to undertake strategically) in terms of type classification, and since it is premised on cross-border exports to India and Bangladesh, the development effect of concessional financing is high, and it was deemed that there is value in analyzing and verifying.

Table 7.7-9 Screening evaluation results of priority projects

Project Note：＊ represents PROR type	Name of Developer	FS Availability		Total Score	Business Scale	Economic Efficiency	Implementation	Other Donor's involvement
Sunkoshi 3	NEA	○		7	○	○	○	△
Dudhkoshi	NEA	○		7	○	△	○	○
Upper Arun*	Upper Arun Hydro Electric Ltd.	○		6	○	×	○	○
Lower Seti	Tanahu Hydropower Ltd.	○		5	△	△	○	△
Tanahu	Tanahu Hydropower Ltd.	○		4	○	○	–	–
Nalsyau gad	Nalgad Hydropower Co., Ltd	△		5	○	○	△	×
Bharbung	Not decided	△		4	○	○	×	×
Phukot karnali*	VUCL／NHPC India	△		4	○	△	△	×
Tila-1	S C Power Co. Ltd	×		5	△	○	×	○

Evaluate listed projects with respect to Business Scale, Economic Efficiency, implementation and Other Donor's Involvement were scored with ○: 2points, △: 1points, ×: 0opints
Critically negative aspects are highlighted with yellow
Nominated 3 projects for detailed analysis are highlights with red bold

Source: JICA Study Team

(2) Considerations of analytical methods and indicators

1) Summary review of concessional funding methods

The quantitative analysis of the project aimed to quantitatively grasp the improvement in profitability for investors by utilizing concessional funds from the perspective of promoting the introduction of private funds. For this analysis, a sensitivity analysis was conducted on the variables set using the equity IRR as an indicator. The types of concessional funds that could be applied to the projects analyzed are as shown in the table below. However, since the Lower Seti project, which is the subject of this calculation, assumes a concessional sovereign loan, the analysis of debt assumes direct financing of the project using concessional funds. On the other hand, in the analysis of Sunkoshi 3, a model was constructed that allows calculations assuming financing using investment loans for private entities. Regarding the analysis of equity, application of EBF was examined to the Lower Seti project to evaluate quantitative impacts of concessional loan application.

Table 7.7-10 Types of concessional funds used in the analysis

Type	Overview
Direct project financing	Concessional funds such as yen loans are provided directly to projects.
Private-sector investment and financing	In order to promote development in developing countries through the private sector, funds are provided in the form of investments and loans to development projects implemented by private companies and others.
EBF Loans	We will provide loans to developing country governments to cover capital investment in infrastructure development projects, etc., and promote PPP infrastructure development projects.
Two Step Loan	In order to provide funds to the private end beneficiaries, the necessary funds are provided through a development bank (in the case of Nepal, this would be HIDCL, etc.).

Source: JICA Study Team

2) Indicators used in the analysis

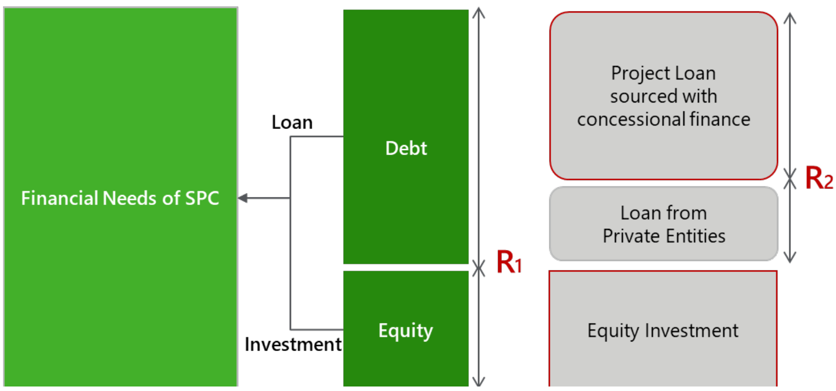
This analysis conducted a sensitivity analysis of the equity IRR by changing conditions to see how the concessional financing would affect investor profitability.

3) Schemes assessed

The analysis was conducted assuming a scheme in which concessional funds could be applied to both the debt and equity portions of the loan.

a. Scheme for applying sovereign loan to debt portion

Sensitivity analysis of shareholder profitability conducts when concessional funds are injected into debt (in this analysis, direct lending of concessional funds is assumed). We assume that the interest rate of loans funded by concessional funds is 5% and that of commercial banks is 10% (Sunkoshi3 also assumes loans funded by investment and loans for private entities (interest rate 7%)) and use the D/E ratio (R1 in the figure below) and the interest rate determined by the funds injected into debt (R2 in the figure below) as variables.

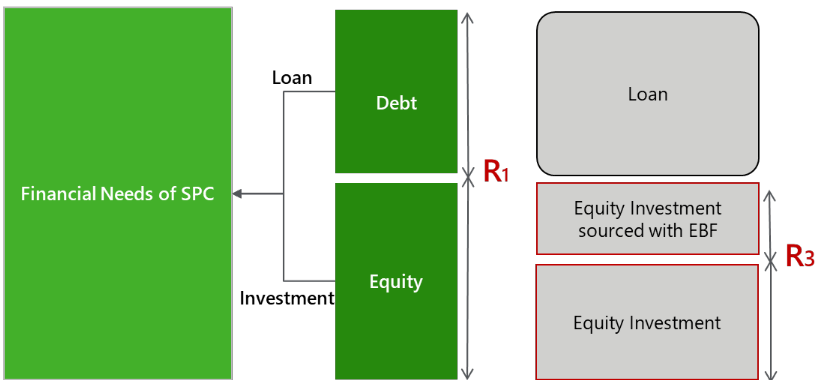


Source: JICA Study Team

Figure 7.7-4 Cases where sovereign loans are applied to debt portion

b. EBF application for equity portion

Sensitivity analysis of the profitability of private investors when concessional funds (EBF) are injected into equity. The variables used are the D/E ratio (R1 in the figure below) and the proportion of EBF funds to concessional loans and equity (R3 in the figure below).



Source: JICA Study Team

Figure 7.7-5 Cases where EBF is applied to equity portion

c. How to proceed with the analysis

In this analysis, the study first perform a basic analysis: 1) 2) Sovereign loan application scheme for debt portion (R1 × R2) We will analyse the EBF application scheme (R1 x R3) for the equity portion and consider the appropriate development scheme and EBF applicability for the target business based on profitability.

Based on the results of the fundamental analysis, an IRR analysis will be carried out for a business structure assuming a specific equity developer and debt provider.

(3) Analysis of the effectiveness of the Lower Seti concessional fund application

1) Fundamental Analysis of Lower Seti

The assumptions for analysis of Lower Seti are as follows:

Table 7.7-11 Assumptions for Lower Seti Analysis

Index	Assumptions
Period	- Construction period: 5 years, operation period: 30 years
Revenues and expenses for calculating equity IRR	- Dividends paid to private shareholders are used as income for the purposes of calculating the IRR. - Contributions from private shareholders are treated as expenditures for the purpose of calculating the IRR. - If the EBF is included in the investment, the dividend ratio between the EBF's original funds and the private investment will be determined so as to provide favorable dividends to private shareholders (in this calculation, the ratio of EBF's original funds: private investment is assumed to be 2:3).
Debt Interest Rate	- The interest rate for concessional sovereign loans is assumed to be 5%, and that of commercial banks is assumed to be 10%. (Figures from the IPSDP financial analysis are used.) The repayment period for concessional loans was set to 30 years (with a grace period of 10 years) while the period for commercial bank loans was set to 12 years (with a grace period of 5 years).
Power plant construction costs	- USD224M
Amount of electricity sold and unit price	- The amount of electricity sold is 520.78GWh/year, and the unit price is USD 0.060/kWh - (All based on F/S reports)

Source: JICA Study Team

■ Analysis 1: Effects of applying sovereign loans

From the following table, we can see that the equity IRR will increase by increasing the proportion of debt in the R1 ratio, and by increasing the proportion of concessional funds within that. If borrowing from a commercial bank is assumed, the repayment of principal and interest will be large, there will be periods when the cash balance will be negative, and it will be difficult to operate the business (marked with an "×" in the table). If the hurdle rate for the equity IRR is set at 9.0% from the perspective of the expected return of private investors, the only time the equity IRR will exceed this rate is when the interest rate is further lowered to 3.0% and the D/E ratio is set to 80:20.

Table 7.7-12 Effects of sovereign loan application in Lower Seti (results of sensitivity analysis)

		R1（Debt/Equity Ratio）	
		80:20	70:30
R2（Deb Interest）	Concessional Loan (Interest 3.0%)	13.3%	10.9%
	Concessional Loan (Interest 5.0%)	10.0%	8.8%
	Commercial Bank (Interest 10.0%)	×	×

Source: JICA Study Team

■ Analysis 2: Effects of applying EBF

If concessional funds with an interest rate of 5.0% and borrowing from commercial banks are assumed, a business plan using EBF would not be viable. This is because the project's profitability is low, and dividends to the NEA would not be sufficient, and the NEA would not be able to meet the EBF repayment schedule. If interest rates were further reduced and it were possible to borrow concessional funds with an interest rate of 3.0%, dividends would be possible to meet the EBF repayment schedule, and an equity IRR of over 9.0%, which was assumed as the hurdle rate, would be calculated.

Table 7.7-13 Effect of EBF application in Lower Seti (results of sensitivity analysis)

Debt Interest：3.0%		R1（Debt/Equity Ratio）	
		80:20	70:30
R3 (Percentage of EBF in Equity)	80%	15.7%	13.1%
	60%	15.0%	12.5%
	40%	14.4%	×
	20%	13.8%	×

Source: JICA Study Team

2) Detailed analysis of Lower Seti

The Lower Seti project is located downstream of the Tanahu HEP (under construction, scheduled to start operation in 2026, STO 140MW), for which JICA provided financing together with ADB, and is expected to provide adjustment during the dry season through cascade operation. The access roads are also well developed, and there are few environmental issues. The three patterns were analyzed for the application of concessional loans, including methods involving an IPO (Initial Public Offering) for residents.

Table 7.7-14 Conditions of Lower Seti project assessment

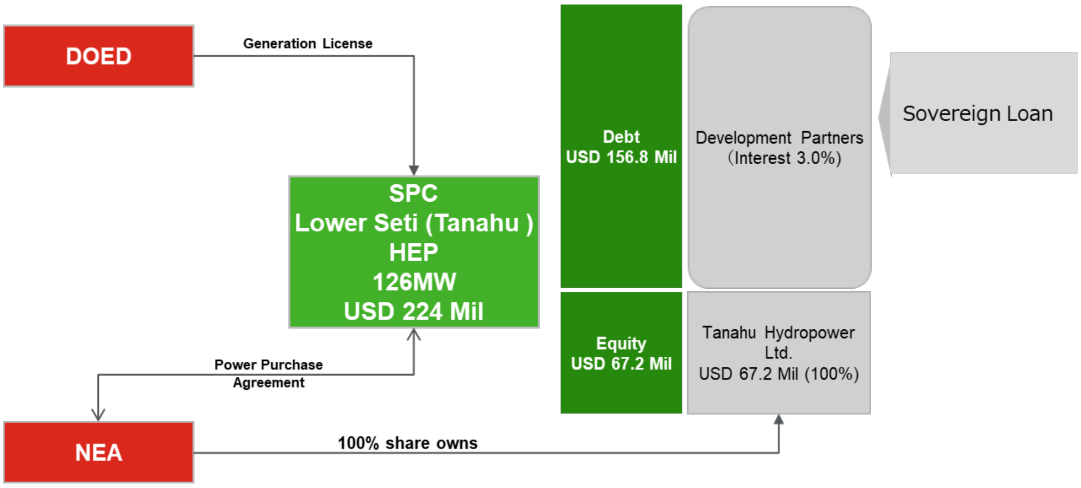
Case	Overview	Conditions	IRR	
Case A-1	Implementation as a concessional sovereign loan project by a public institution	Interest rate 3.0%, D/E ratio 70:30	Project IRR Equity IRR	8.0% 10.9%
Case A-2	Case A plus an IPO for residents	Ibid.	Project IRR Equity IRR	8.0% 10.9%
Case B	Utilizing private funds through EBF	Interest rate 3.0%, D/E ratio 80:20, EBF equity ratio 40%	Project IRR Equity IRR	8.0% 14.4%

Source: JICA Study Team

Result of the analysis suggests ensuring the feasibility of the Lower Seti project application of concessional funds is vital. However, if profits were distributed using EBF via a public institution, it would be possible to achieve the equity IRR expected by private investors, leading to the attraction of private investment. The results of each analysis are shown below.

Case A-1: Implementation as a concessional loan project by a public institution

It is assumed that the project will be funded by a Japanese ODA loan through investment by Tanahu Hydropower Ltd., a wholly owned subsidiary of NEA. The interest rate conditions applied are 3.0% and D/E ratio is 70:30. In accordance with this scheme, the project IRR will reach 8.0% and the equity IRR will reach 10.9%. This is an established financing scheme; it is important to implement the project as quickly as possible.



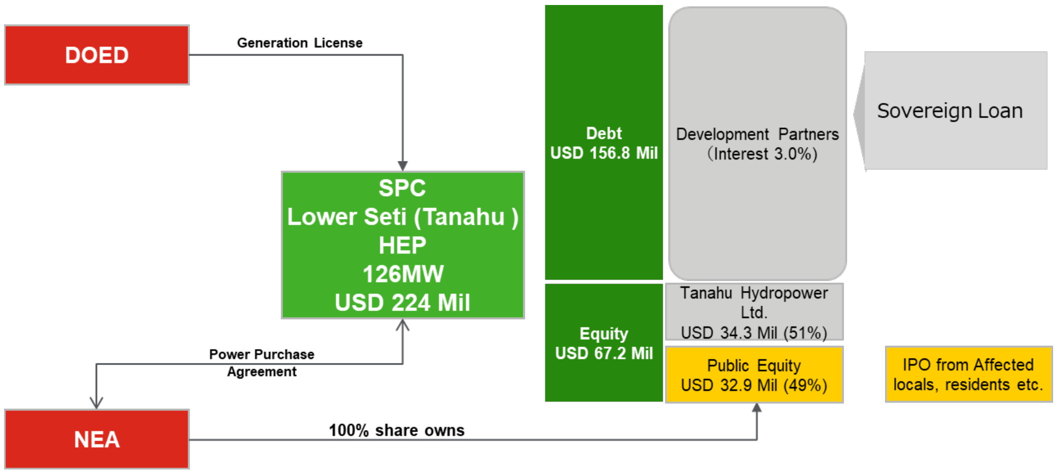
Source: JICA Study Team

Figure 7.7-6 Lower Seti Project Case A-1 Scheme diagram

[Reference] Case A-2: Public institutions provide concessional loans and implement an IPO for residents

Tanahu Hydropower Ltd will invest 51% and will conduct an IPO to allocate 49% of the shares to residents who will be affected around the project site. The D/E ratio will be 70:30, and the interest rate conditions of the sovereign loan used for the debt portion will be 3.0%. Applying this condition, the project IRR will be 8.0% and the equity IRR will be 10.9%, the same figures as Case A-1.

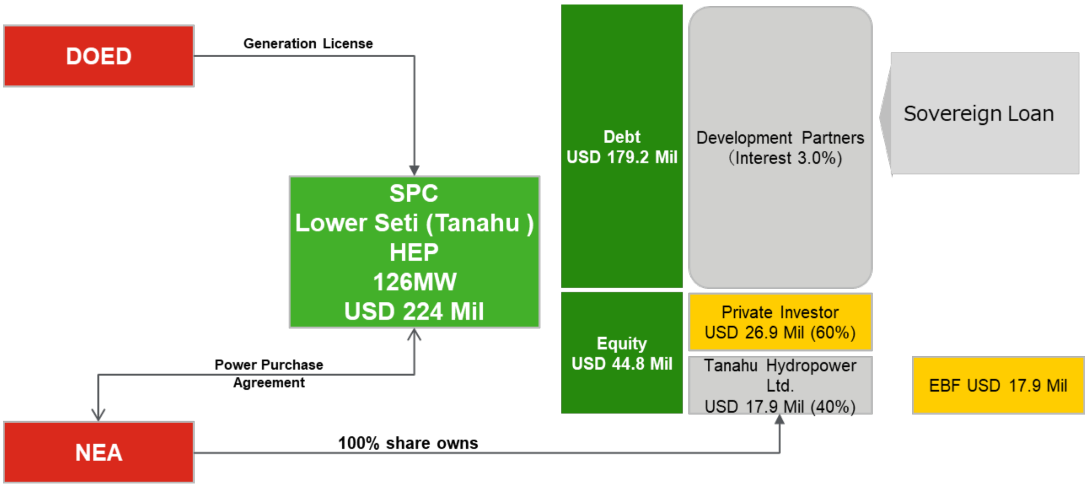
The resident IPO, also referred to as public equity, is a system established by the Securities Registration and Issue Rules enacted in 2016 and the Securities Registration, Issue and Allotment Rules and Regulations enacted in 2017, and is used in the Upper Tamakoshi project, aiming to compensating local communities through hydroelectric power generation projects. This system allows private funds to be introduced into projects and also makes it possible to distribute dividends to meet the level required for an IPO. It should be noted that, there are mixed opinions on the Nepalese side regarding the effectiveness of the resident IPO system in accelerating hydroelectric power development projects, and careful consideration is needed.



Source: JICA Study Team

Figure 7.7-7 Lower Seti Project Case A-2 Scheme diagram

Case B: Utilizing private funds through EBF



Source: JICA Study Team

Figure 7.7-8 Lower Seti Project Case B Scheme diagram

The debt-to-equity ratio is set at 70:30, and a sovereign loan (USD 179.2M) with an interest rate of 3.0% is applied to the debt side, while 40% of the equity (USD 17.9M) is injected as EBF to Tanahu Hydropower. As a result, the equity IRR reaches 14.4%, making it possible to utilize private funds. In this case, although the public institution does not contribute its own funds, there is no business profit, and Tanahu Hydropower Ltd must carefully consider whether it can accept investment. In addition, injecting 87.9% of concessional funds into a project with a project IRR of 8.0% and deliberately encouraging private companies to participate is not an efficient way of utilizing concessional funds, and therefore EBF is not appropriate for this project.

(4) Analysis of the effectiveness of Sunkoshi 3 concessional funding

1) Fundamental Analysis of Sunkoshi 3

Assumptions applied for analysis of Sunkoshi 3 are as follows:

Table 7.7-15 Sunkoshi 3 Analysis Assumptions

Index	Assumptions
period	・Construction period: 7 years, operation period: 30 years
Revenues and expenses for calculating equity IRR	・Dividends paid to private shareholders are used as income for the purposes of calculating the IRR. ・Contributions from private shareholders are treated as expenditures for the purpose of calculating the IRR. ・If the EBF is included in the investment, the dividend ratio between the EBF's original funds and the private investment will be determined so as to provide favorable dividends to private shareholders (in this calculation, we have assumed a ratio of EBF's original funds: private investment = 2:3).
Debt Interest Rate	・The interest rate for concessional financing (yen loans, etc.) is assumed to be 5%, and the repayment period is assumed to be 30 years (including a 10-year grace period). ・The interest rate on investment loans for private entities is assumed to be 10%, with a repayment period of 20 years (including a grace period of 7 years during the construction period). ・The interest rate on borrowing from commercial banks was assumed to be 10%, with a repayment period of 15 years (including a grace period of 7 years during the construction period).
EBF Repayment Terms	・Assume that the original capital is 5% interest, and the repayment period is 30 years (10 of which is a grace period). The repayment is conducted with dividends from the project.
Power plant construction costs	・USD1,331M (based on F/S report)
Amount of electricity sold and unit price	・The amount of electricity sold is 2,356.27GWh/year, and the unit price is USD 0.060/kWh ・(All based on F/S reports)

Source: JICA Study Team

The details of the analysis results are presented below.

■ Analysis 1: Effects of applying sovereign loans

Table 7.7-16 Sovereign Loan Application in Sunkoshi 3 (Sensitivity Analysis Results)

		R1（Debt/Equity Ratio）	
		80:20	70:30
R2（Debt Interest）	Concessional Loan（5.0%）	7.5%	6.9%
	Oversea Investment Loan（10.0%）	×	×
	Commercial Bank（10.0%）	×	×

Source: JICA Study Team

The D/E ratio of 70:30, which is prevalently used for hydroelectric power generation projects in Nepal, is used to calculate Equity IRR this time. In addition to 70:30, the ratio of 80:20 is also applied. The project is not profitable (project IRR is 6.0%), and the amount of cash that can be obtained from business activities is small to begin with. The repayment of principal and interest will result in a negative cash balance, so it is difficult to borrow and repay with a D/E ratio of 70:30 when the loan is based on oversea investment loans or commercial bank loans with an interest rate of 10%. If concessional funds with an interest rate of 5% are used, borrowing and repayment with a D/E ratio of 70:30 becomes possible, and the equity IRR reaches 6.9%. However, if the hurdle rate for the equity IRR is set at 9% from the perspective of the expected return of private investors, none of the calculated equity IRRs reach that level.

■ Analysis 2: Effects of applying EBF

Because the dividend resources obtained from business activities are small, even if concessional funds are used for 100% of the debt, the repayment conditions cannot be met and a business using EBF is difficult to implement. Although there was limited room for the use of EBF in Lower Seti, in the case of Sunkoshi 3, even if concessional funds (interest rates of 5%) were used for 100% of the debt, a business using EBF would be difficult, and the business plan was not viable.

2) Detailed analysis of Sunkoshi 3

Basic analysis results of the Sunkoshi 3 projects

Sunkoshi 3 is a site planned for exporting electricity to India and Bangladesh, and is a reservoir-type hydroelectric power plant that is relatively economical and close to the main grid. In January 2024, NEA issued an EOI for D/D[95] consulting for development. Although the design needs to be reviewed, the project is highly important as a trilateral project between Nepal, India, and Bangladesh, and is expected to be a development site that would be meaningful for support from development financial institutions, including JICA.

After obtaining the Sunkoshi 3 F/S documents and analyzing the D/E ratio, we obtained the following results. The project IRR for the Sunkoshi 3 project is 6.0%, and if concessional financing (D/E ratio 80:20, interest rate 5.0%) is used for this, the equity IRR will be 7.5%, which is below the target of 9%. In addition, even if part of the equity is planned as public funds using EBF, it is found that the business plan is not viable because the repayment conditions cannot be met.

As a result of the above fundamental analysis, it was realized that in order to make the Sunkoshi 3 project a reality, it was necessary to find ways to improve profitability other than through a financing scheme. For this reason, we conducted a more detailed analysis of the electricity export pattern envisaged by the Sunkoshi 3 project and explored the possibility of improving profitability.

Projects that are already seeking funding seek concessional financing because the use of concessional financing by project investors or project promoters has the following effects:

First, the use of concessional financing is expected to complement private financing in terms of risk reduction, making it easier to carry out projects, including infrastructure development, in the business environments of emerging countries, which are generally considered to be high-risk.

Second, the addition of development financial institutions and development aid agencies that provide concessional financing signals to investors that project risks have eased, and they will be more proactive in considering lending. An increase in the number of fund providers means that fundraising conditions will be relaxed for business operators planning projects, and it will also serve as a catalyst for an increase in business operators working on similar projects.

Third, the provision of concessional financing for social infrastructure development in developing countries, where it is difficult to expect development to proceed autonomously through economic efficiency alone, is expected to encourage appropriate fiscal discipline management through monitoring opportunities from the loan provider side. Without concessional financing, developing country governments would refrain from excessive

[95] Due Diligence

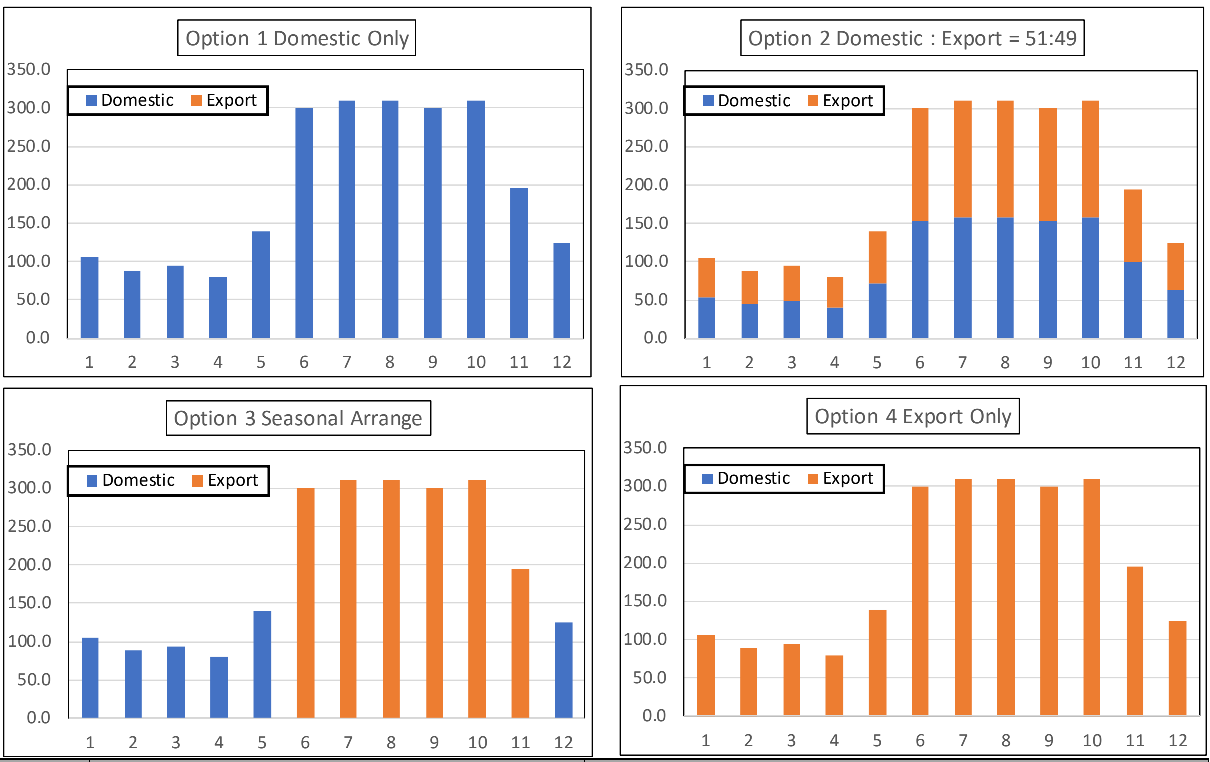
infrastructure spending that disrupts fiscal discipline, and miss opportunities for economic development, so it can be said that concessional financing is effective in achieving economic development while maintaining fiscal balance.

Even with the above-mentioned effects of concessional financing in mind, it is still important to improve the profitability of the project, so we conducted a more detailed analysis of the electricity export pattern planned by the Sunkoshi 3 project to explore possibilities for improving profitability.

Measures to improve profitability of Sunkoshi 3 projects through electricity exports.

The Sunkoshi 3 project plans to export electricity and intends to sell it across borders to India and Bangladesh in addition to domestically (NEA). Therefore, if electricity is exported, it is expected that profits will improve, and the application of concessional funds will improve profits. Based on this assumption, the variations of electricity export can be assumed as shown below. We assumed that electricity would be sold domestically (NEA) and for export (India, Bangladesh), and for electricity prices, we took into account the price difference due to the season (rainy season/dry season) and the difference between peak and off-peak, and set the peak operation time to 6 hours (off-peak time is 18 hours).

Table 7.7-17 Sunkoshi 3 business analysis



Option	overview	Conditions
1	Domestic sales only	No exports
2	Domestic and exports equally	Equal exports regardless of season (domestic: export = 51%:49%)
3	Exports (the tariff of domestic electricity sales is based on seasonal considerations)	Dry season (January to May, December), Rainy season (June to November) (domestic: export = 51%:49%)
4	Export only	Export all

Source: JICA Study Team

The electricity prices for this analysis are set as shown in the table below.

Table 7.7-18 Prices used in the analysis of profitability improvement

dry season	Peak	10.6 NPR/kWh
	Off-peak	8.4NPR/kWh
rainy season	Peak/off-peak	4.8NPR/kWh
See NEA PROR peak operation tariffs		
export	- Calculated based on IEX electricity market performance in 2023 - Based on the data on the average electricity selling price for each region for the year, the electricity selling price for each month (Ave. 8.80NPR/kWh) and the peak (Ave. 12.70 NPR/kWh) and off-peak prices (Ave. 7.60 NPR/kWh) are calculated (Table)	

Source: JICA Study Team

When looking at the seasonality of the electricity supply and demand relationship between Nepal and the assumed export destinations, India and Bangladesh, securing supply capacity is important in Nepal during the dry season when hydroelectric power output is low, whereas in India and Bangladesh demand increases during the rainy season when temperatures rise, and electricity demand expands. As a result, a mutually complementary relationship is established in the electricity demand between Nepal and India/Bangladesh and selecting the optimal electricity sales destination between Nepal and export destinations while taking seasonality into consideration will be beneficial for both Nepal and India/Bangladesh.

In the following analysis, we analyzed the contribution of the application of concessional funds to improving profitability in Option 3 (Exports (the tariff of domestic electricity sales is based on seasonal considerations)): whether or not to distinguish between peak and off-peak periods for exports (taking into account seasonality).

Fundamental analysis showed that the Sunkoshi 3 project would be more profitable if electricity exports were taken into consideration, and that the introduction of concessional financing would increase the project's feasibility.

In Case D analyzed below (electricity export considering seasonality), if peak and off-peak are distinguished, and if a concessional loan with an interest rate of 5.0% is applied with a D/E ratio of 70:30, the equity IRR will reach 11.9% This exceeds the hurdle rate (9.0%) set in this analysis from the perspective of private investors' expected returns. However, since the interest rate of 5.0% on the concessional funds at this time is only applicable to operators in Nepal, it will be difficult to utilize concessional funds if the three countries including India and Bangladesh are included.

Based on the above analysis, the following three concessional funding application schemes were considered.

Table 7.7-19 Conditions of Sunkoshi 3 project assessment

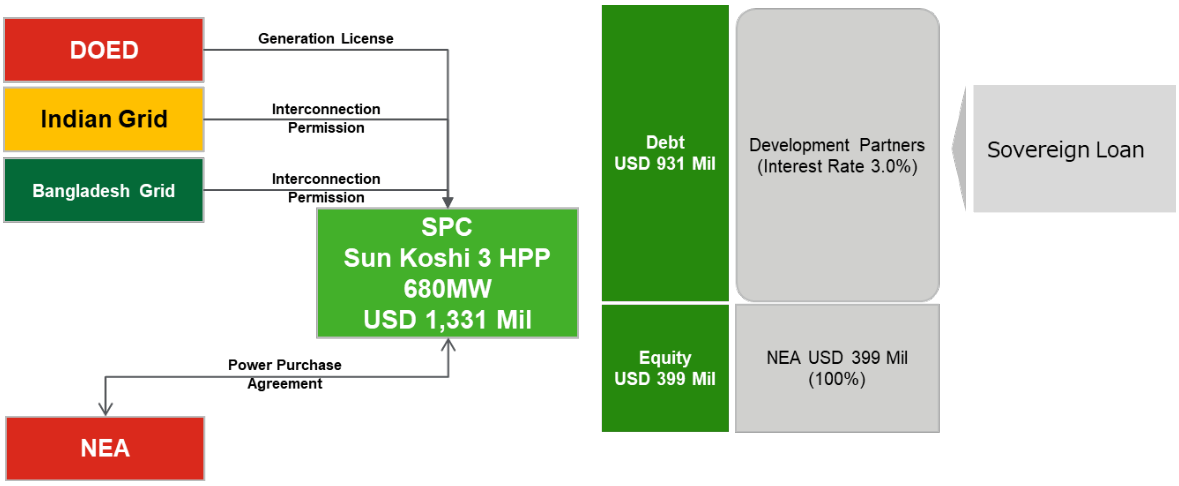
Case	Overview	Conditions	IRR
Case C	Implementation as a loan project by a public institution	Interest rate 5.0%, D/E ratio 70:30	Project IRR 6.0% Equity IRR 6.9%
Case D	Implementation as a loan project by a public institution with electricity export	Interest rate 5.0%, D/E ratio 70:30 Power export	Project IRR 8.5% Equity IRR 11.2%
Case E	Using investment and financing for loans for private entities by public institutions involving electricity exports	Interest rate 3.0% (concessional loan) and 7.0 (investment loan for private entities), D/E ratio 80:20, EBF equity ratio 29% Power export	Project IRR 8.5% Equity IRR 12.4%

Source: JICA Study Team

Case C: Implementation as a concessional loan project by a public institution

Although a sovereign loan will be injected into the debt portion, the equity IRR will remain at 6.9%, below the hurdle rate. In order to secure the debt portion equivalent to USD 931 million (70% of the total cost), financial assistance will be required from multiple development aid agencies, and NEA will also need to secure USD 339 million (30% of the total cost) of its own funds for the equity portion.

In this case, Project IRR and Equity IRR remain at 6.0% and 6.9%, respectively.

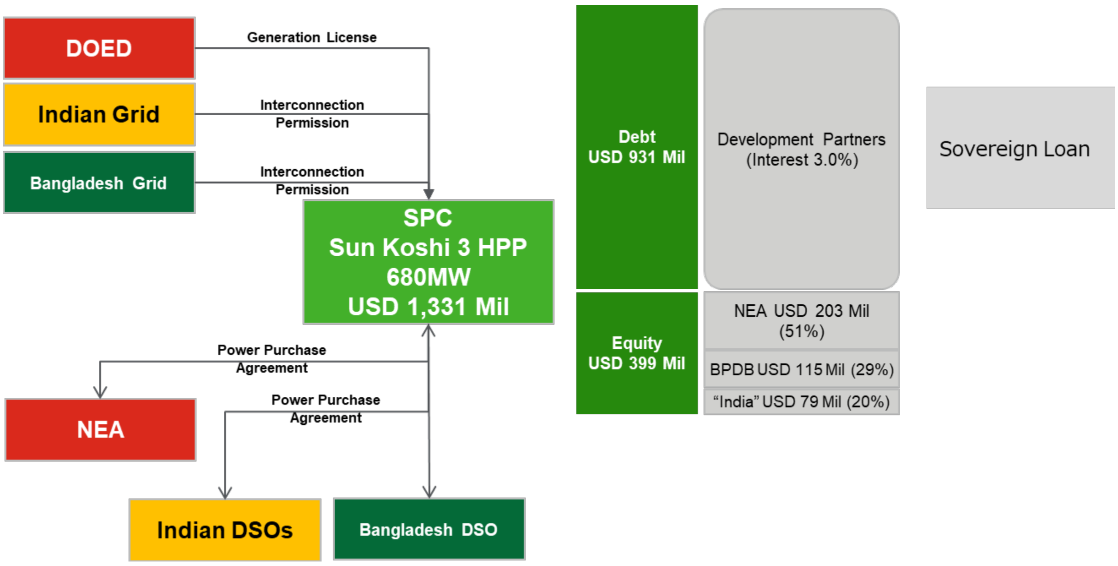


Source: JICA Study Team

Figure 7.7-9 Sunkoshi 3 Project: Case C Scheme Diagram

Case D: Implementation as a concessional loan project by a public institution with electricity export

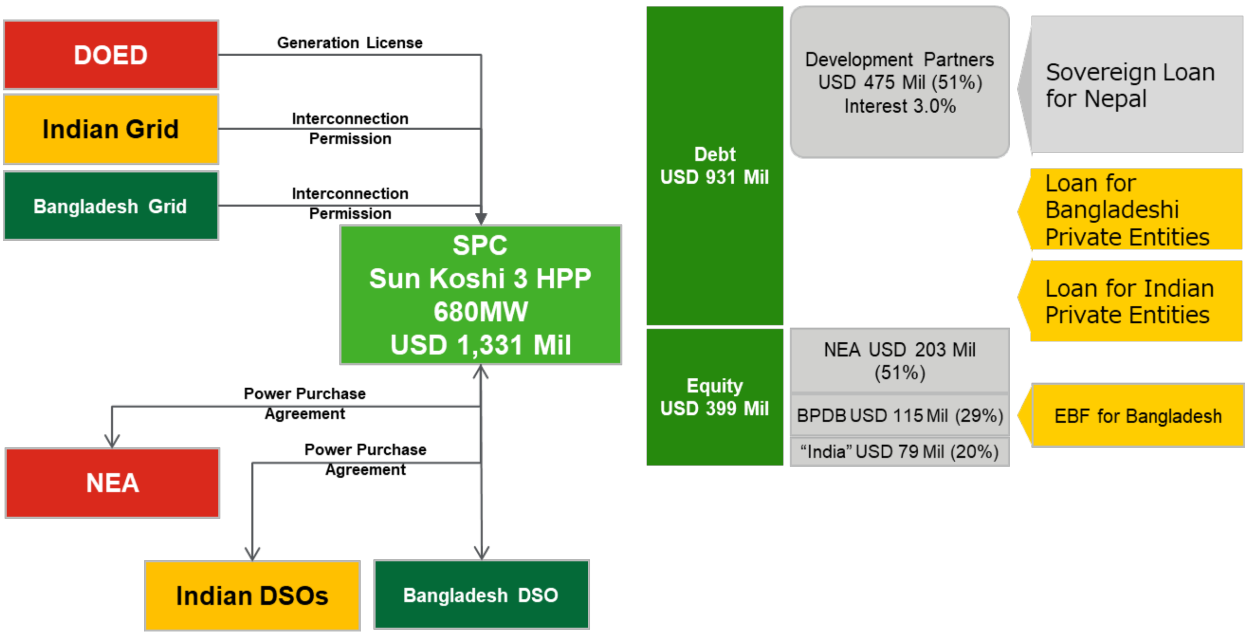
By providing a sovereign loan and exporting electricity, it is possible to create a business with an equity IRR of 11.9%, which exceeds the hurdle rate of 9.0%. However, it is difficult for Nepal alone to secure a sovereign loan of USD 931 million, and fundraising will need to be conducted through multiple development aid agencies.



Source: JICA Study Team

Figure 7.7-10 Sunkoshi 3 Project: Case D Scheme Diagram

Case E: Private Sector Investment Finance was applied to concessional loans provided by public institutions with electricity exports



Source: JICA Study Team

Figure 7.7-11 Sunkoshi 3 Project: Case E Scheme Diagram

If the interest rate for concessional funds is 5.0% and the interest rate for investment loans for private entities is 10.0%, the burden of interest payments is heavy, making it difficult to use EBF. If the interest rates were lowered to 3.0% for concessional funds (the same applies to loans made from concessional funds that are the basis of EBF) and 7.0% for investment loans for private entities, and this scheme was used with the assumption of issuing common stocks without preferential dividends while using EBF, the equity IRR improved to 12.4%, exceeding the hurdle rate.

In addition to sovereign loans, we will utilize the investment and financing for private entities framework for India and Bangladesh, which are the destinations for electricity exports, and provide EBF to the Bangladesh Power Development Board (BPDB), an organization responsible for power development in Bangladesh, as an investor. We assume that investment and financing for Bangladeshi private entities will be equivalent to 29% of the debt (USD 270 million), and investment and financing for Indian private entities will be 20% (USD 186 million), and the analysis was conducted using the prescribed interest rate for investment and financing for private entities of 7.0%. By utilizing the financing framework for both India and Bangladesh, we can avoid placing an excessive burden on the financing framework for Nepal.

On the other hand, commercial terms of electricity sales to India and Bangladesh, such as applied currency of the PPA are unknown. If it is difficult to settle the condition with US dollars, Nepalese party should have support for negotiating on the terms of the PPA. Currency hedging schemes in Nepal is other contentious issue. Foreign investors are seeking usable hedging scheme in Nepal to mitigate exchange risks.

(5) Analysis of the effectiveness of Phukot Karnali concessional funding

1) Fundamental Analysis of Phukot Karnali

Assumptions applied for analysis of Phukot Karnali are as follows:

Table 7.7-20 Phukot Karnali Analysis Assumptions

Index	Assumptions
period	・ Construction period: 7 years, operation period: 30 years
Revenues and expenses for calculating equity IRR	・ Dividends paid to private shareholders are used as income for the purposes of calculating the IRR. ・ Contributions from private shareholders are treated as expenditures for the purpose of calculating the IRR. ・ If the EBF is included in the investment, the dividend ratio between the EBF's original funds and the private investment will be determined so as to provide favorable dividends to private shareholders (in this calculation, we have assumed a ratio of EBF's original funds: private investment = 2:3). ・ When concessional funds are invested in the equity portion, if the investors are public institutions, there is no dividend priority and the dividend ratio is 1:1.
Debt Interest Rate	・ The interest rate for concessional financing (yen loans, etc.) is assumed to be 5%, and the repayment period is assumed to be 30 years (including a 10-year grace period). ・ The interest rate on investment loans for private entities is assumed to be 10%, with a repayment period of 20 years (including a grace period of 7 years during the construction period). ・ The interest rate on borrowing from commercial banks was assumed to be 10%, with a repayment period of 15 years (including a grace period of 7 years during the construction period).
EBF Repayment Terms	・ Assume that the original capital is 5% interest, and the repayment period is 30 years (10 of which is a grace period). The repayment is conducted with dividends from the project.
Power plant construction costs	・ USD617M (based on F/S report)
Amount of electricity sold and unit price	・ The amount of electricity sold is 2,447.88GWh/year, and the unit price is USD 0.050/kWh ・ (All based on F/S reports)

Source: JICA Study Team

The details of the analysis results are presented below.

■ Analysis 1: Effects of applying sovereign loans

Because the project itself is highly profitable, unless borrowing from a commercial bank with a D/E ratio of 80:20, the company will not run out of cash even after repaying the principal and interest, and will be able to enjoy the leverage effect of borrowing.

Table 7.7-21 Sovereign Loan Application in Phukot Karnali (Sensitivity Analysis Results)

		R1（Debt/Equity Ratio）	
		80:20	70:30
R2（Debt Interest）	Concessional Loan（5.0%）	23.9%	19.8%
	Oversea Investment Loan（10.0%）	19.0%	16.7%
	Commercial Bank（10.0%）	×	15.6%

Source: JICA Study Team

■ Analysis 2: Effects of applying EBF

Because the project itself is highly profitable, unlike Sunkoshi 3, a financing plan combining overseas investment financing for private entities and EBF is possible (the dividend ratio is calculated as public institution investment: private investment = 2:3).

Table 7.7-22 Effect of EBF application in Phukot Karnali (results of sensitivity analysis)

Debt Interest：10.0% (Overseas Investment Loan)		R1（Debt/Equity Ratio）	
		80:20	70:30
R3（Percentage of EBF in Equity)	80%	22.0%	19.5%
	60%	21.1%	18.7%
	40%	20.3%	18.0%
	20%	19.6%	17.3%

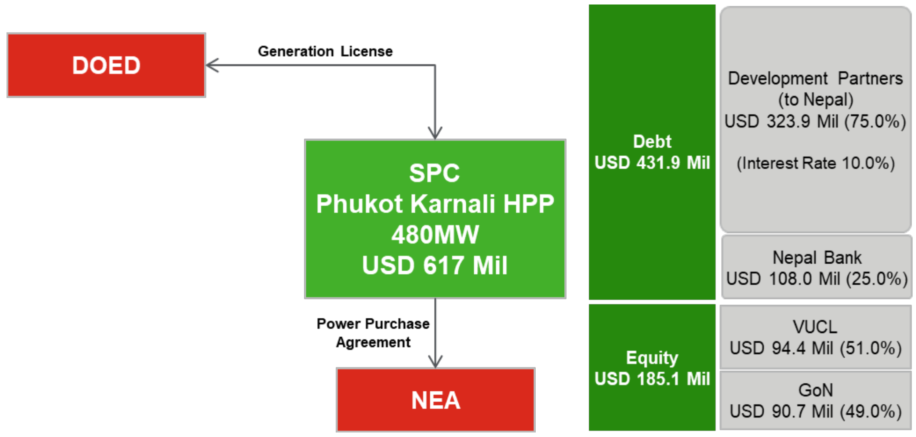
Source: JICA Study Team

2) Detailed analysis of Phukot Karnali

Based on the results of the fundamental analysis of Phukot Karnali, we present possible financing schemes. As mentioned above, NHPC, an Indian government-affiliated operator, is considered to participate in Phukot Karnali with a capital ratio of 51% or more, and we will examine a scheme for foreign capital participation using concessional funds. Below, we will first consider a conventional scheme carried out by a single country (Case F), in which VUCL and the Nepalese government are the development implementation bodies. Next, we will consider an export-oriented scheme led by NHPC (Case G). Note that for Case G, we will also consider EBF support for VUCL, which is short of its own funds.

Case F: Investment loans for private entities and commercial bank loans are combined

Based on the results of the fundamental analysis, it is believed possible to construct a financing scheme that is profitable for investors through investment loans for private entities and loans from commercial banks, without using concessional funds with an interest rate of 5.0%. The figure below shows a financing scheme using investment loans for private entities and loans from commercial banks, and the equity IRR calculated based on this scheme is 16.6%, which exceeds the expected rate of return of 9.0%.



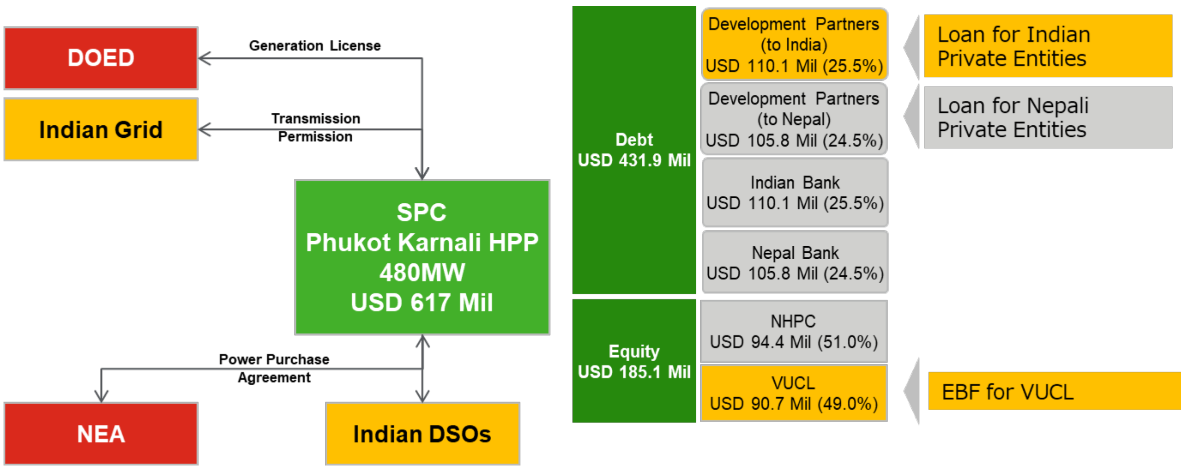
Source: JICA Study Team

Figure 7.7-12 Phukot Karnali Project: Case F Scheme Diagram

Case G: Investment Loans for Private Entities, Commercial Bank Loans, and EBF are combined

We present a financing scheme that incorporates NHPC's involvement in Phukot Karnali. In this case, we assume that investment loans for private entities will be utilized not only for Nepal but also for India, in addition to loans from commercial banks. In addition, to supplement the investment capital, VUCL will invest in equity using EBF as capital. Note that NHPC is also a state-owned enterprise, and the dividend ratio is set at 1:1, with no difference in dividends to VUCL and NHPC. The above assumptions are illustrated in the figure below, and the equity IRR in this case is 16.3%. This case also exceeds the expected rate of return of 9.0%.

In this scheme, the debt burden on the Nepalese side is reduced through the participation of NHPC, and the use of EBF also contributes to solving VUCL's fundraising issues.



Source: JICA Study Team

Figure 7.7-13 Phukot Karnali Project: Case G Scheme Diagram

(6) Implications from the analysis

Through the analysis of the above two projects, the following observations were made:

- In particular, in the case of Sunkoshi 3, there is a high possibility that the repayment of principal and interest will result in a cash flow shortfall . Even if low-interest concessional loans are used, it is desirable to reduce the reliance on loans and increase investment from investors' own capital, etc. to avoiding shortage of finance..

- In particular, in the case of Sunkoshi 3, both the project IRR and equity IRR are low, and rather than relying on private investment, from the perspective of prioritizing public interest, having a public institution provide capital as the main investor will increase the feasibility of the project and fundraising.

Next, the following points can be noted as suggestions obtained from a somewhat generalized perspective of introducing concessional financing into power generation projects.

- Assuming that dividends are paid in line with the repayment schedule, if dividends to EBFs cannot be paid due to low profits caused by cash outflows for repayment of borrowing principal and interest, or the burden of interest payments and depreciation expenses, then business consideration using EBFs would not be viable. Therefore, if it were permitted to set a longer grace period, such as freezing EBF dividends during the borrowing principal and interest repayment period, the feasibility of using EBFs would be enhanced.

- When investing in concessional funds in debt, the lower the interest rate of the concessional loan, the more profits that can be distributed to investors, making it a desirable condition for private investors. Therefore, when financing the project itself, it is important to consider to what extent "concessionality" can be maintained, such as how low the interest rate spread can be kept when sub-lending to the SPC.

- It was found that while it is possible to improve the equity IRR and increase the profitability of private investors by injecting concessional funds, if the profitability of the project itself is low, there is a limit to how much concessional funds can be used to increase the profitability of private investors. In the case of a highly profitable project like Phukot Karnali, it is possible to implement the project even with the borrowing conditions of a commercial bank. On the other hand, considering the amount of debt procurement in Nepal and the amount of equity that developers can invest, as mentioned in Section 7.6.3, the participation of foreign companies is necessary for projects above a certain size. In this case, it is expected that the use of concessional funds with favorable borrowing conditions will improve the profitability of the project and the reliability will be improved through the involvement of donors. It is expected that this will attract investment from foreign companies and promote the development of projects that would be difficult to implement on a scale by Nepal alone.

7.7.4 Funding plan for IPSDP implementation

This section examines the outlook for financing for projects designated as priority projects under the IPSDP based on the characteristics of the projects and the characteristics of the lenders, and shows the outlook for capital needs and financing during the IPSDP period.

(1) Methodology

Based on the distribution and characteristics of the projects shown in Figure 7.7-3 and Table 7.7-7, a model of the investor and lender for the project was assumed, and the investor and lender were allocated based on the model. In this case, the debt/equity ratio was set at 70:30. In addition, when considering the investor and lender, the investor and lender were considered based on the considerations in Table 7.7-23 and Table 7.7-24. The investment and lending ratio for each classification is as shown in Table 7.7-23, which is the premise of the procurement ratio from each organization at the time of fundraising.

Based on the investment and lending ratio assumed for each investor attribute, the required amount for each classification per year was calculated. The calculation results were summed up for each organization, and the amount required over the IPSDP planning period from 2022 to 2040 was tabulated to give Table 7.7-24, the IPSDP Funding Plan by Funding Source (draft).

Table 7.7-23 Funding assumption for each category and source of finance

	Country	Organization	(1) Profitable IPPs (Small)	(2) Small Scale ROR and PROR	(3) GoN Assistance Projects	(4) Profitable IPPs (Medium)	(5) PPP Scheme	(6) GoN PROR/STO Projects	(7) Mega Export Project	(8) GoN Strategic Projects	(9) Others	(10) Power System
Equity	Nepal	Gov't & SOE			100%		30%	80%	30%	50%		100%
		Gov't Fin. Instititions										
		Private IPP	50%	100%		40%	20%		5%		100%	
	Neighboring Countries	Gov't & SOE					30%	20%	30%	40%		
		Gov't Fin. Instititions										
		Private IPP	40%			40%	10%		15%			
	Dev't Partners											
	Private Co.	MNEs	10%			20%	10%		20%			
		Int'l Inv. Banks										
Debt	Nepal	Sovereign					20%	60%	10%	40%		80%
		PPP					10%		15%			
		Two Step Loan										
		Gov't Fin. Instititions	20%	50%	100%	20%	20%	20%	5%	10%	20%	20%
		Private Fin. Institutions	30%	50%		20%			5%		80%	
	Neighboring Countries	Sovereign							5%			
		PPP					30%	15%	25%	40%		
		Two Step Loan										
		Gov't Fin. Instititions	20%			20%	10%	5%	10%	10%		
		Private Fin. Institutions	20%			20%			5%			
	Global	PPP				20%	10%		10%			
		Int'l Inv. Banks	10%						10%			

Source: JICA Study Team

Table 7.7-24 IPSDP Funding Plan by source

	Country	Organization	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
		Equity+Debt	1,699	2,137	2,249	2,417	2,918	4,195	4,691	6,035	5,569	5,628	4,918	4,474	3,444	3,368	3,544	3,141	2,804	2,208	1,440
Equity	Nepal	Govertment & SOE	184	194	222	244	298	351	450	544	575	594	557	471	451	445	497	433	411	341	281
		Gov't Finance Instititions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Privaet IPP	154	208	237	226	291	427	349	415	315	316	280	291	163	144	127	123	103	89	31
	India	Govertment & SOE	31	39	53	67	74	106	185	254	273	300	292	225	213	214	248	195	178	134	94
		Gov't Finance Instititions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Privaet IPP	89	124	97	102	112	214	236	303	221	220	156	172	81	76	59	59	37	21	1
	Bangradesh	Govertment & SOE	12	16	17	25	28	40	61	98	105	103	94	76	61	63	73	62	57	43	24
		Gov't Finance Instititions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Privaet IPP	0	2	2	5	6	9	6	12	13	10	4	5	5	7	7	9	8	5	0
	Development Partners		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	MNE	MNEs	39	58	47	57	67	112	120	184	169	145	92	101	58	62	54	62	47	30	0
		Int'l Investment Banks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Year Total		510	641	675	725	876	1,258	1,407	1,811	1,671	1,688	1,475	1,342	1,033	1,010	1,063	942	841	662	432
Debt	Nepal	Soveerign	327	336	388	410	502	566	762	879	932	984	963	801	792	774	872	738	704	595	525
		PPP	29	42	36	59	69	98	97	196	216	169	115	112	63	71	71	88	80	57	0
		TSL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Gov't Finance Instititions	255	294	302	305	371	528	576	722	639	637	570	536	362	335	338	299	266	221	147
		Private Commercial Banks	178	267	345	323	432	621	429	440	288	333	305	329	218	194	175	173	149	128	58
	India	Soveerign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		PPP	69	87	108	142	157	224	364	529	570	598	565	444	398	402	461	375	342	258	165
		TSL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Gov't Finance Instititions	122	162	140	147	161	290	369	474	386	409	343	321	206	198	197	161	129	92	56
		Private Commercial Banks	90	130	102	105	117	233	250	298	196	208	138	163	81	76	56	56	32	12	1
	Bangradesh	Soveerign	0	4	4	11	13	21	15	28	31	24	9	12	12	15	15	21	19	11	0
		PPP	29	34	36	47	52	73	127	200	215	216	211	166	130	133	154	123	113	90	55
		TSL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		Gov't Finance Instititions	0	4	4	11	13	21	15	28	31	24	9	12	12	15	15	21	19	11	0
		Private Commercial Banks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Global	PPP	63	90	74	79	101	147	183	309	316	251	158	175	103	111	95	101	73	46	0
		Int'l Investment Banks	28	45	37	53	56	113	97	121	78	86	57	62	33	33	31	43	38	23	1
	Year Total		1,189	1,496	1,574	1,692	2,043	2,936	3,284	4,225	3,898	3,940	3,443	3,132	2,411	2,358	2,481	2,199	1,963	1,545	1,008

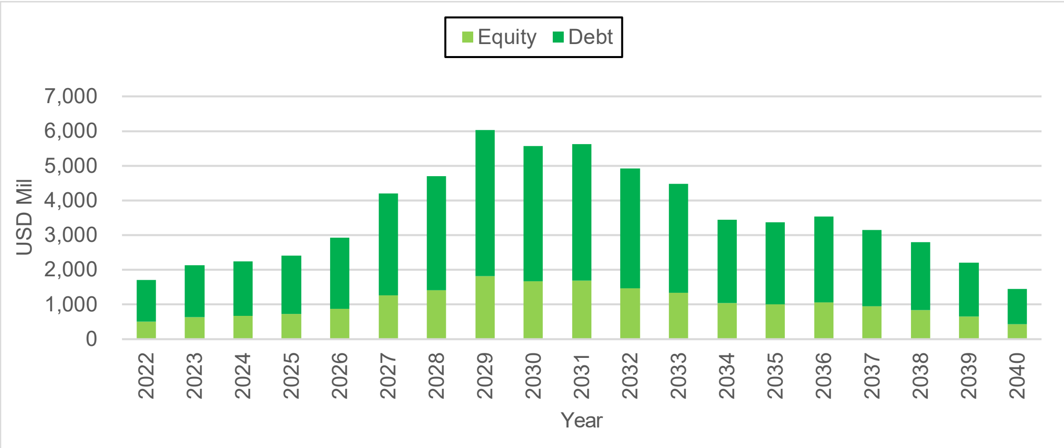
Source: JICA Study Team

(2) Analysis

The trend of debt and equity procurement by country and organization during the period is illustrated in Figure 7.6-14 capital demand will peak in 2029 (USD 6,035 million in total debt and equity), then gradually decrease, reaching around USD 3,500 million per year from 2034 to 2036, after which it will begin to decline. Note that while this study includes demand for development up to 2040, it does not include the cost of power plants scheduled to start operation after 2041.

During this period, Nepal will bear 53-72% of the equity investment by government organizations and private developers in total (see Figure 7.6-14). However, the equity investment ratio by government organizations and private developers in Nepal will fall to about 53% of the total equity investment from 2029 to 2031, when the total equity demand will peak. This is because, in addition to increased investment from India and Bangladesh, increased investment from international developers is expected.

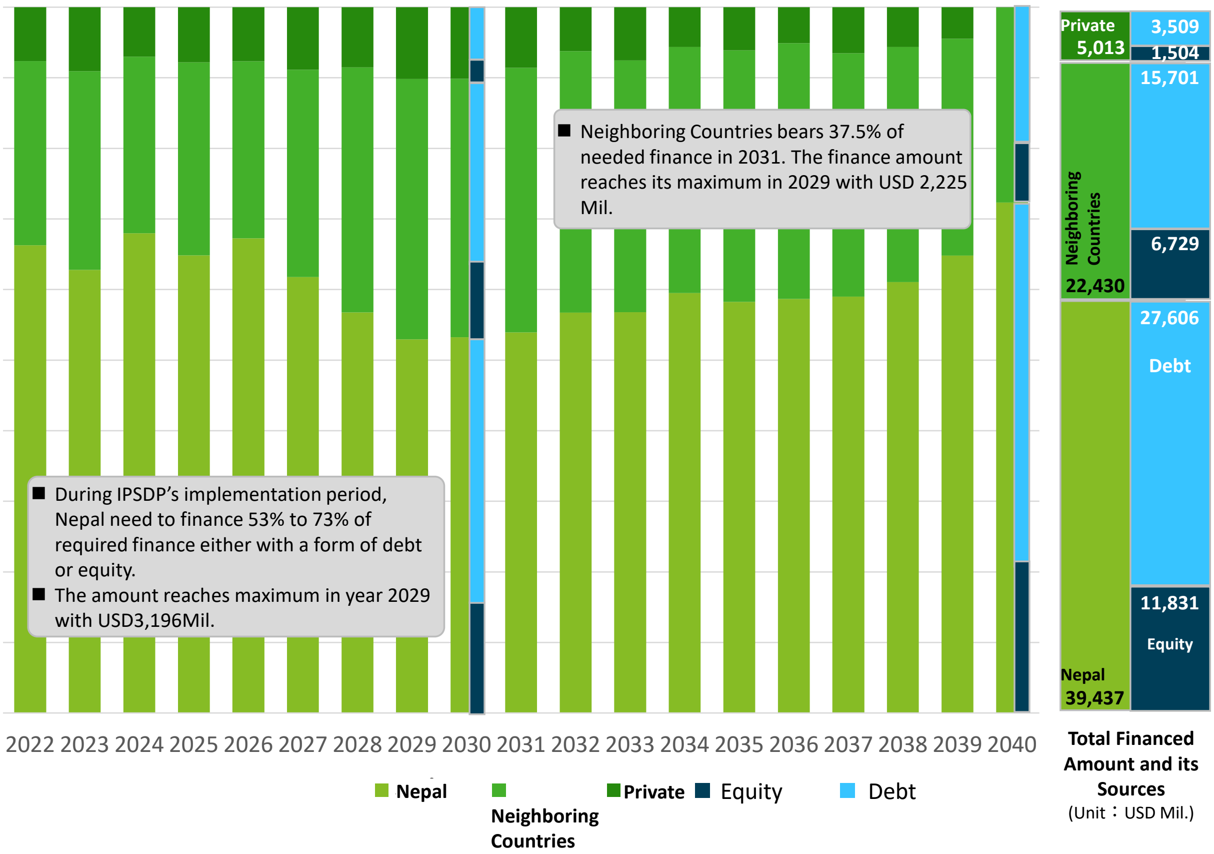
Debt will also peak at USD 4,225 million in 2029, then decrease to USD 2,411 million by 2034, increase to USD 2,481 million in 2036, and gradually decrease thereafter (see Figure 7.6-14). The proportion of total debt borne by the Nepalese government, government-affiliated financial institutions, private banks, and PPP schemes will trend at a similar rate to equity. Nepal's share will also decline from 2029 to 2031 and will remain at 57-72% from 2032 onwards.



Source: JICA Study Team

Figure 7.7-14 Capital Demand Forecast

As shown in Figure 7.7-15 and Table 7.7-25, capital demand during the IPSDP period will peak between 2029 and 2032, when construction of many projects will be concentrated, and then gradually decline. This forecast covers hydropower projects currently captured in the IPSDP, and it is expected that trends up to around 2030 will attract private sector investment. It should be noted that this figure does not show the inflow of private sector investment outside of the IPSDP plan. There are also areas that need improvement in order to more smoothly invest in hydropower projects in Nepal, and these are discussed in Chapter 9.



Source: JICA Study Team

Figure 7.7-15 Proportional trend and Source of Finance

Table 7.7-25 Trend of Finances by Sources during IPSDP period

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Nepal	5,194	5,992	6,185	6,498	7,427	9,785	10,675	13,207	12,353	12,405	11,077	10,286	8,314	8,166	8,470	7,763	7,151	6,070	4,635
Neighboring Countries	978	1,381	1,371	1,562	1,833	2,914	3,362	4,651	4,271	4,248	3,524	3,222	2,348	2,357	2,451	2,185	1,873	1,363	678
Private	217	301	251	267	295	549	639	805	617	645	497	501	307	296	277	245	186	123	480

(Unit : USD Mil)

Source: JICA Study Team

7.8 CONSIDERATIONS ON UTILIZATION OF SURPLUS ELECTRICITY

This Section examines the feasibility of introducing CN (Carbon-Neutral) fuels, particularly green hydrogen produced from renewable energy, from the perspective of utilizing surplus electricity in PGDP as a consideration for energy transition.

7.8.1 Initiatives related to Energy Transition in Nepal

(1) Lessons from Previous Studies

Regarding the legal system related to energy transition in Nepal, although the Environmental Protection Rules (EPR 2020) and the National Climate Change Policy, 2020, formulated in 2020, mention green hydrogen, no policy with specific guidelines or strategies had been established. In

February 2024, MoEWRI formulated the Green Hydrogen Policy, which outlines long-term guidelines and goals after organizing the situation surrounding green hydrogen in Nepal, stating five objectives and seven strategies to achieve them. Outline of this policy is shown in Table 7.8-1 and recent studies and researches are summarized in Table 7.8-2.

Table 7.8-1 Outline of Green Hydrogen Policy

Item	Contents
Long term vision	Economic prosperity by the use of green hydrogen that has been produced from the utilization of renewable energy sources where hydrogen is used alternative to existing energy sources that will help to achieve carbon neutral state with energy security and sustainable economic development.
Goal	To make country's economy viable, secured and independent by promoting the production and use hydrogen through renewable energy sources.
Objectives	1. To minimize the effects of climate change by promoting the production and use of hydrogen that will be produced by renewable energy sources including hydropower. 2. To create an economy that is carbon neutral and reduce dependency on petroleum products 3. To make provision for the use and storage of green hydrogen and its sub products 4. To promote industrialization inside country and production of chemical fertilizer by using green hydrogen and its sub products 5. To promote research and studies for the commercial use of green hydrogen and its sub products
Strategy	i. Necessary law will be made for production of green hydrogen and its sub products ii. To make special provision in relevant laws to provide concession facility based on necessity and relevance to attract investment in industries that are based on green hydrogen and its sub-products. iii. To promote carbon trade by minimizing carbon emission from the use of green hydrogen and its sub products iv. To construct environment friendly infrastructure for the production, storage, transport and use of green hydrogen v. To establish and promote plant to produce chemical fertilizer by using green hydrogen and its sub products vi. To construct and promote relevant and necessary infrastructure necessary for the use of green hydrogen or its sub products vii. To promote research and studies for the use and application of green hydrogen and its sub products.

Source :Prepared Based on Green Hydrogen Policy, MoEWRI

Table 7.8-2 Studies and Research related to Green Hydrogen in Nepal

Item	Agency	Year
Hydrogen and Sub-products Generation from Hydropower	Tribhuvan University and Western Michigan University	2009
Study on the Possibility of Producing Hydrogen in Nepal Using Hydropower	Asian Development Bank	2021
Report on the Production and Use of Green Hydrogen in Nepal	WECS	2022
Expert Group Report on the Potential for Chemical Fertilizer Production Using Green Hydrogen in Nepal	MoEWRI	2022
Data collection survey for energy transition and carbon neutral society	JICA	2022
Green Hydrogen for Development in Nepal	Kathmandu University	2023

Source: Prepared Based on Green Hydrogen Policy, MoEWRI

Past research and studies have explored the potential for hydrogen production in Nepal using multiple approaches. The lessons learned from these initiatives, considering the situation in Nepal as of February 2024, are organized below:

- The production of green hydrogen in Nepal is expected to leverage the country's abundant untapped hydropower, especially the surplus electricity during the rainy season that was subject to output curtailment.

- Possible applications for green hydrogen include the production of green ammonia, fuel cells in the transportation sector, thermal use in the industrial sector, and seasonal adjustment of electricity supply through hydrogen storage and generation. The possibility of manufacturing essential chemical fertilizers for the country's key industry, agriculture, is particularly anticipated.

- The costs for green ammonia and fertilizer production in pilot projects are estimated at $750/ton and $637/ton, respectively, assuming an electricity rate of 3 NPR/kWh. However, the import prices for these products in the fiscal year 2021/2022 were $390.8/ton and $361.3/ton, respectively, indicating a price gap.

- The significance of producing green hydrogen in Nepal includes not only achieving carbon neutrality but also improving energy and food security by reducing reliance on imported fossil fuels and fertilizers.

- Currently, the use of hydrogen in Nepal is limited, necessitating the need to stimulate demand. Moreover, a complete supply chain from infrastructure development for hydrogen production to distribution needs to be established.

- A systematic legal framework encompassing hydrogen storage, transport, business licensing, and retail is lacking. In particular, establishing rules for the technically challenging aspects of storage and transport is crucial for commercialization.

(2) Considerations for Future Energy Transition

Based on the lessons learned from previous initiatives, two key considerations for the energy transition are outlined:

1) The change in added value of surplus electricity during the rainy season.
2) The available output (MW) and the electricity generation (GWh).

Change in the Added Value of Surplus Electricity during the Rainy Season

Although the lessons mentioned in the previous section are assumed to remain key points of focus going forward, it's important to recognize that the premise regarding the utilization of surplus electricity during the rainy season has significantly changed as of 2024. Initially, the surplus electricity during the rainy season, explored in studies prior to 2022, was not guaranteed for export to India, and considerations were made for handling this surplus through output curtailment. Hence, the utilization of green hydrogen focused on how to utilize this surplus electricity, which, under the assumption, had no wholesale buyers and was considered low-value electricity.

However, with the cooperation between the governments of Nepal and India, avenues for exporting electricity to India and Bangladesh during the rainy season are opening, and from 2022 to 2023, NEA has been profiting from electricity exports. Thus, the surplus electricity during the rainy season, previously considered of low value, has started to generate value, albeit market-dependent, for exports to India at 6 – 8 cents/kWh. This development suggests a need to reconsider the narrative of utilizing surplus electricity without buyers during the rainy season.

Specifically, it's necessary to evaluate the economics of green hydrogen production, which previously assumed production costs electricity as no value or cheap, compared to the export rates to India of 6 – 8 cents/kWh. If the electricity cost is to be kept low, it essentially represents a form of subsidy by setting the value obtained lower than potential.

It is also crucial to understand that this value exchange is merely a transfer of goods within Nepal and does not diminish the economic value of the country as a whole. Nepal's reliance on imports from India for fossil fuels and chemical fertilizers represented a transfer of goods that led to an outflow of foreign currency. However, the domestic production and consumption of green hydrogen would be a local transaction, potentially preventing foreign currency outflow and contributing to enhanced security. It's important to note that the manufacturing of green hydrogen should be evaluated not only for its financial viability but also for its contribution to economic value in terms of enhancing security.

Available Output (MW) and Electricity Generation (GWh)

The consideration of surplus electricity in past studies was not based on the power development plan, and thus, the seasonal availability of power (MW) and electricity generation (GWh) were not taken into account. These pieces of information are crucial input conditions for assuming the scale and operation rate of hydrogen production plants. The IPSDP power development plan also organizes the foundation data for considering green hydrogen, making it possible to examine the available surplus electricity on a monthly and annual basis.

7.8.2 Estimation of Surplus Electricity and Potential of Green Hydrogen Production upto 2040

This section estimates the monthly available surplus power (MW) and electricity generation (GWh) up to 2040, based on the results of the power development plan analysis. The surplus electricity is accounted for by subtracting domestic demand (GWh) from the total generated electricity (GWh).

As the methods for utilizing surplus electricity, such as electricity export, heat or hydrogen production, vary in demand each month, supply must be adjusted according to demand. While green hydrogen can also be stored, its production quantity depends on the supply capacity of surplus electricity. However, as is known, Nepal mainly relies on hydropower, leading to a significant difference between the dry and rainy seasons. According to the power development plan results, the total electricity generated during the dry season tends to drop to about one-third of that during the rainy season, leading to an even smaller surplus. Therefore, when considering the utilization of surplus electricity, it is important to estimate the base supply available throughout the year and the peak outputs and electricity quantities focused on the rainy season.

The forecast of surplus electricity will serve as foundational information for future considerations of electricity export, electrification, and CN fuels centered on green hydrogen. Specifically, in green hydrogen production, the electricity cost constitutes a significant portion of the expenses. Additionally, the capacity (MW) and operational rate (%) of water electrolysis plants have a considerable impact on the costs. The operational rate is calculated based on the relationship between capacity (MW) and the amount of electricity supplied (GWh), making the available surplus electricity's output (MW) and quantity (GWh) crucial for evaluating the manufacturing cost of green hydrogen.

(1) Monthly Average Available Output and Electricity Generation

Table 7.8-3 shows the average available output (MW) and electricity generation (GWh) for each month, calculated based on the performance data from 2022 and 2023, as well as the results of the power development plan. This average available output assumes a 24-hour supply capability, with the potential for increased output during peak operation.

Until 2028, surplus electricity will not occur during the dry season, as the supply capacity falls below domestic demand, necessitating electricity imports. From 2029 onwards, surplus electricity is generally expected to occur throughout the year, except in February. Between 2033 and 2036, surplus electricity is anticipated to be available throughout the year, achieving self-sufficiency in electricity. It should be noted that from 2037 onwards, minimal imports during the daytime peak in February will be the most cost-effective operation. From 2039 to 2040, due to limited hydropower development capacity compared to the growth in demand, surplus electricity will slightly decrease, but for the rest of the period, surplus electricity is expected to increase annually.

(2) Utilization of Surplus Electricity Based on Output and Electricity Generation

Based on the estimation results of surplus electricity supply in the previous section, this part discusses the utilization policy based on output and electricity generation. The results from Table 7.8-3 can be categorized into the following two options:

Option 1: Electricity that can be supplied as a base throughout the year, tailored to the dry season
Option 2: Electricity matching the peak during the rainy season

Here, the output and electricity generation for Option 1 (Base), Option 2 (Peak), and the total up to 2040 are calculated. The average possible output for Option 1 is based on March, as the output in February, being the lowest, results in a very low value. Option 2 assumes that all surplus electricity is utilized. The total is accounted for by adding Option 1 and Option 2. These estimated results are shown in Table 7.8-4.

Table 7.8-3 Monthly Available Surplus Output (MW) and Power Generation (GWh) until 2040

Year	Item	1	2	3	4	5	6	7	8	9	10	11	12	Total
2022	Exp. (GWh)	0	0	0	0	91	207	210	202	164	122	1	1	999
	Imp. (GWh)	-514	-674	-520	-322	0	0	0	0	0	0	-249	-374	-2,654
	Cap. (MW)	0	0	0	0	125	284	288	277	224	167	1	1	-
2023	Exp. (GWh)	0	0	0	5	386	568	571	559	517	438	1	1	3,047
	Imp. (GWh)	-456	-643	-461	-189	0	0	0	0	0	0	-71	-260	-2,080
	Cap. (MW)	0	0	0	7	529	778	782	766	708	600	2	2	-
2024	Exp. (GWh)	0	0	0	15	550	770	789	774	728	634	5	5	4,270
	Imp. (GWh)	-462	-673	-463	-143	0	0	0	0	0	0	0	-234	-1,976
	Cap. (MW)	0	0	0	20	753	1,055	1,081	1,061	998	869	6	6	-
2025	Exp. (GWh)	2	0	9	186	1,104	1,509	1,518	1,591	1,525	1,376	468	98	9,385
	Imp. (GWh)	-241	-491	-243	0	0	0	0	0	0	0	0	0	-975
	Cap. (MW)	3	0	13	254	1,512	2,067	2,079	2,179	2,088	1,885	641	135	-
2026	Exp. (GWh)	0	0	0	209	1,290	1,767	1,762	1,826	1,757	1,570	481	58	10,719
	Imp. (GWh)	-306	-623	-301	0	0	0	0	0	0	0	0	0	-1,229
	Cap. (MW)	0	0	0	286	1,767	2,421	2,413	2,501	2,407	2,151	659	80	-
2027	Exp. (GWh)	0	0	0	370	1,586	2,118	2,118	2,187	2,107	1,877	651	176	13,190
	Imp. (GWh)	-226	-588	-195	0	0	0	0	0	0	0	0	0	-1,009
	Cap. (MW)	0	0	0	507	2,172	2,902	2,902	2,995	2,886	2,571	892	242	-
2028	Exp. (GWh)	142	0	4	589	2,051	2,912	2,930	3,001	2,892	2,657	1,124	484	18,786
	Imp. (GWh)	-143	-443	0	0	0	0	0	0	0	0	0	0	-586
	Cap. (MW)	195	0	5	807	2,810	3,989	4,013	4,111	3,961	3,639	1,540	664	-
2029	Exp. (GWh)	83	0	74	771	2,485	3,462	3,472	3,548	3,422	3,131	1,421	645	22,514
	Imp. (GWh)	0	-418	0	0	0	0	0	0	0	0	0	0	-418
	Cap. (MW)	114	0	101	1,056	3,403	4,743	4,756	4,861	4,688	4,289	1,947	884	-
2030	Exp. (GWh)	187	0	181	962	2,892	3,836	3,864	4,157	4,050	3,662	1,642	818	26,252
	Imp. (GWh)	0	-394	0	0	0	0	0	0	0	0	0	0	-394
	Cap. (MW)	257	0	248	1,318	3,961	5,255	5,293	5,695	5,548	5,016	2,250	1,121	-
2031	Exp. (GWh)	629	201	588	1,486	3,884	5,134	5,203	5,808	5,724	5,119	2,530	1,412	37,720
	Imp. (GWh)	0	-255	0	0	0	0	0	0	0	0	0	0	-255
	Cap. (MW)	862	276	806	2,036	5,320	7,033	7,127	7,956	7,841	7,013	3,466	1,934	-
2032	Exp. (GWh)	641	122	601	1,528	4,042	5,277	5,351	6,068	6,004	5,339	2,562	1,471	39,006
	Imp. (GWh)	0	-229	0	0	0	0	0	0	0	0	0	0	-229
	Cap. (MW)	878	167	823	2,093	5,537	7,229	7,331	8,312	8,225	7,314	3,510	2,015	-
2033	Exp. (GWh)	1,062	232	1,030	2,075	4,922	6,373	6,503	7,710	7,797	6,678	3,184	1,981	49,547
	Imp. (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Cap. (MW)	1,455	318	1,411	2,843	6,742	8,730	8,908	10,562	10,681	9,148	4,361	2,714	-
2034	Exp. (GWh)	1,115	230	1,111	2,265	5,285	6,593	6,746	8,259	8,343	7,155	3,320	2,089	52,510
	Imp. (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Cap. (MW)	1,528	314	1,521	3,103	7,239	9,031	9,242	11,313	11,429	9,802	4,548	2,861	-
2035	Exp. (GWh)	1,168	213	1,170	2,392	5,563	6,793	6,968	8,815	8,972	7,545	3,444	2,189	55,233
	Imp. (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Cap. (MW)	1,600	292	1,603	3,276	7,620	9,305	9,546	12,076	12,291	10,336	4,718	2,999	-
2036	Exp. (GWh)	1,108	93	1,124	2,386	5,626	6,665	6,866	9,123	9,388	7,694	3,363	2,163	55,599
	Imp. (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
	Cap. (MW)	1,518	127	1,540	3,269	7,707	9,131	9,405	12,497	12,860	10,539	4,607	2,963	-
2037	Exp. (GWh)	1,015	7	1,044	2,372	5,788	6,780	6,972	9,308	9,590	7,824	3,286	2,095	56,082
	Imp. (GWh)	0	-98	0	0	0	0	0	0	0	0	0	0	-98
	Cap. (MW)	1,391	10	1,430	3,249	7,929	9,288	9,551	12,751	13,137	10,718	4,501	2,870	-
2038	Exp. (GWh)	994	0	1,019	2,381	5,971	7,068	7,260	9,591	9,946	8,206	3,455	2,141	58,034
	Imp. (GWh)	0	-204	0	0	0	0	0	0	0	0	0	0	-204
	Cap. (MW)	1,362	0	1,395	3,261	8,180	9,683	9,945	13,139	13,625	11,241	4,733	2,933	-
2039	Exp. (GWh)	999	0	1,007	2,420	6,360	7,747	7,948	10,268	10,592	8,907	3,703	2,255	62,205
	Imp. (GWh)	0	-313	0	0	0	0	0	0	0	0	0	0	-313
	Cap. (MW)	1,368	0	1,380	3,315	8,712	10,612	10,887	14,066	14,510	12,201	5,072	3,089	-
2040	Exp. (GWh)	844	23	874	2,354	6,365	7,403	7,640	10,638	11,147	9,016	3,496	2,142	61,943
	Imp. (GWh)	0	-573	0	0	0	0	0	0	0	0	0	0	-573
	Cap. (MW)	1,156	32	1,197	3,225	8,719	10,141	10,466	14,573	15,269	12,351	4,789	2,934	-

Source: JICA Study Team

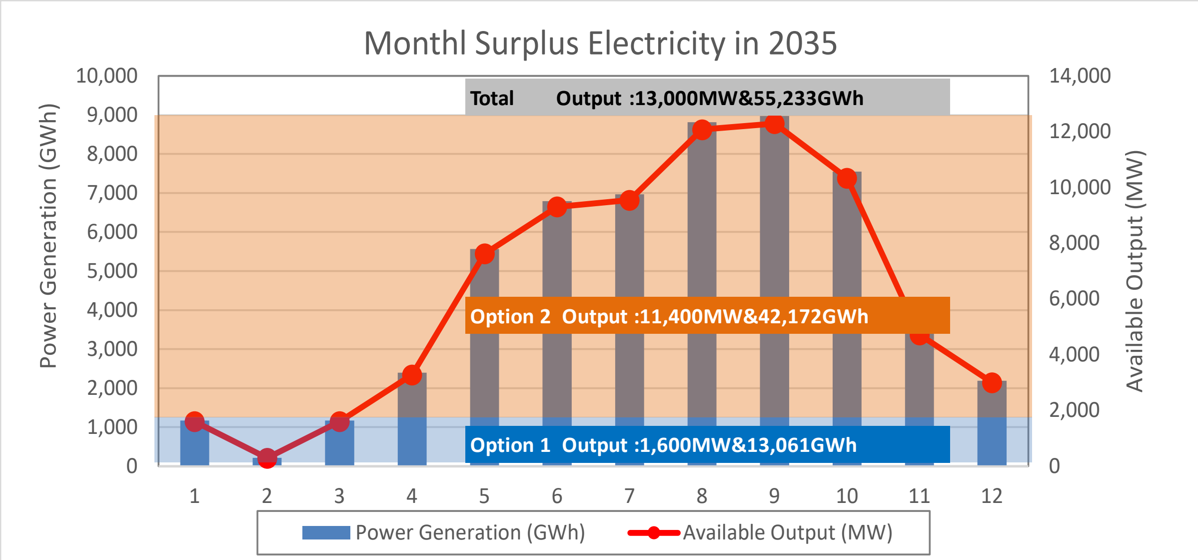
Table 7.8-4 Available Output (MW) and Power Generation (GWh) in Base and Peak

Year	Option	Output (MW)	Surplus Generation (GWh)												Total	Usage Factor (%)
			1	2	3	4	5	6	7	8	9	10	11	12		
2022	Option 1: Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Option 2 :Peak	1,000	0	0	0	0	91	207	210	202	164	122	1	1	999	11.4%
	Total	1,000	0	0	0	0	91	207	210	202	164	122	1	1	999	11.4%
2023	Option 1: Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Option 2 :Peak	1,000	0	0	0	5	386	568	571	559	517	438	1	1	3,047	34.8%
	Total	1,000	0	0	0	5	386	568	571	559	517	438	1	1	3,047	34.8%
2024	Option 1: Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Option 2 :Peak	2,000	0	0	0	15	550	770	789	774	728	634	5	5	4,270	24.4%
	Total	2,000	0	0	0	15	550	770	789	774	728	634	5	5	4,270	24.4%
2025	Option 1: Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Option 2 :Peak	3,000	2	0	9	186	1,104	1,509	1,518	1,591	1,525	1,376	468	98	9,385	35.7%
	Total	3,000	2	0	9	186	1,104	1,509	1,518	1,591	1,525	1,376	468	98	9,385	35.7%
2026	Option 1: Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Option 2 :Peak	3,000	0	0	0	209	1,290	1,767	1,762	1,826	1,757	1,570	481	58	10,719	40.8%
	Total	3,000	0	0	0	209	1,290	1,767	1,762	1,826	1,757	1,570	481	58	10,719	40.8%
2027	Option 1: Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Option 2 :Peak	3,000	0	0	0	370	1,586	2,118	2,118	2,187	2,107	1,877	651	176	13,190	50.2%
	Total	3,000	0	0	0	370	1,586	2,118	2,118	2,187	2,107	1,877	651	176	13,190	50.2%
2028	Option 1: Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
	Option 2 :Peak	5,000	142	0	4	589	2,051	2,912	2,930	3,001	2,892	2,657	1,124	484	18,786	42.9%
	Total	5,000	142	0	4	589	2,051	2,912	2,930	3,001	2,892	2,657	1,124	484	18,786	42.9%
2029	Option 1: Base	100	73	0	73	73	73	73	73	73	73	73	73	73	803	91.7%
	Option 2 :Peak	4,900	10	0	1	698	2,412	3,389	3,399	3,475	3,349	3,058	1,348	572	21,711	50.6%
	Total	5,000	83	0	74	771	2,485	3,462	3,472	3,548	3,422	3,131	1,421	645	22,514	51.4%
2030	Option 1: Base	200	146	0	146	146	146	146	146	146	146	146	146	146	1,606	91.7%
	Option 2 :Peak	5,800	41	0	35	816	2,746	3,690	3,718	4,011	3,904	3,516	1,496	672	24,646	48.5%
	Total	6,000	187	0	181	962	2,892	3,836	3,864	4,157	4,050	3,662	1,642	818	26,252	49.9%
2031	Option 1: Base	800	584	201	584	584	584	584	584	584	584	584	584	584	6,625	94.5%
	Option 2 :Peak	7,200	45	0	4	902	3,300	4,550	4,619	5,224	5,140	4,535	1,946	828	31,094	49.3%
	Total	8,000	629	201	588	1,486	3,884	5,134	5,203	5,808	5,724	5,119	2,530	1,412	37,720	53.8%
2032	Option 1: Base	800	584	122	584	584	584	584	584	584	584	584	584	584	6,546	93.4%
	Option 2 :Peak	8,200	57	0	17	944	3,458	4,693	4,767	5,484	5,420	4,755	1,978	887	32,460	45.2%
	Total	9,000	641	122	601	1,528	4,042	5,277	5,351	6,068	6,004	5,339	2,562	1,471	39,006	49.5%
2033	Option 1: Base	1,400	1,022	232	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	11,474	93.6%
	Option 2 :Peak	9,600	40	0	8	1,053	3,900	5,351	5,481	6,688	6,775	5,656	2,162	959	38,073	45.3%
	Total	11,000	1,062	232	1,030	2,075	4,922	6,373	6,503	7,710	7,797	6,678	3,184	1,981	49,547	51.4%
2034	Option 1: Base	1,500	1,095	230	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	12,275	93.4%
	Option 2 :Peak	10,500	20	0	16	1,170	4,190	5,498	5,651	7,164	7,248	6,060	2,225	994	40,236	43.7%
	Total	12,000	1,115	230	1,111	2,265	5,285	6,593	6,746	8,259	8,343	7,155	3,320	2,089	52,510	50.0%
2035	Option 1: Base	1,600	1,168	213	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168	1,168	13,061	93.2%
	Option 2 :Peak	11,400	0	0	2	1,224	4,395	5,625	5,800	7,647	7,804	6,377	2,276	1,021	42,172	42.2%
	Total	13,000	1,168	213	1,170	2,392	5,563	6,793	6,968	8,815	8,972	7,545	3,444	2,189	55,233	48.5%
2036	Option 1: Base	1,500	1,095	93	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	12,138	92.4%
	Option 2 :Peak	11,500	13	0	29	1,291	4,531	5,570	5,771	8,028	8,293	6,599	2,268	1,068	43,462	43.1%
	Total	13,000	1,108	93	1,124	2,386	5,626	6,665	6,866	9,123	9,388	7,694	3,363	2,163	55,599	48.8%
2037	Option 1: Base	1,400	1,015	7	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	11,243	91.7%
	Option 2 :Peak	12,600	0	0	22	1,350	4,766	5,758	5,950	8,286	8,568	6,802	2,264	1,073	44,840	40.6%
	Total	14,000	1,015	7	1,044	2,372	5,788	6,780	6,972	9,308	9,590	7,824	3,286	2,095	56,082	45.7%
2038	Option 1: Base	1,400	994	0	1,019	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	11,211	91.4%
	Option 2 :Peak	12,600	0	0	0	1,359	4,949	6,046	6,238	8,569	8,924	7,184	2,433	1,119	46,823	42.4%
	Total	14,000	994	0	1,019	2,381	5,971	7,068	7,260	9,591	9,946	8,206	3,455	2,141	58,034	47.3%
2039	Option 1: Base	1,400	999	0	1,007	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	11,204	91.4%
	Option 2 :Peak	13,600	0	0	0	1,398	5,338	6,725	6,926	9,246	9,570	7,885	2,681	1,233	51,001	42.8%
	Total	15,000	999	0	1,007	2,420	6,360	7,747	7,948	10,268	10,592	8,907	3,703	2,255	62,205	47.3%
2040	Option 1: Base	1,200	844	23	874	876	876	876	876	876	876	876	876	876	9,625	91.6%
	Option 2 :Peak	14,800	0	0	0	1,478	5,489	6,527	6,764	9,762	10,271	8,140	2,620	1,266	52,318	40.4%
	Total	16,000	844	23	874	2,354	6,365	7,403	7,640	10,638	11,147	9,016	3,496	2,142	61,943	44.2%

Source: JICA Study Team

For the base usage in Option 1, 100MW becomes available in 2029, 200MW in 2030, 800MW from 2031 to 2032, and then fluctuates between 1,200MW and 1,600MW from 2033 onwards. For the peak usage in Option 2, the capacity gradually increases in line with hydropower development: 3,000MW in 2025, 5,800MW in 2030, 11,400MW in 2035, and 14,800MW in 2040.

A capacity setting example for 2035, the target year of the MoEWRI's energy development roadmap and work plan, is illustrated in Figure 7.8-1.



Source: JICA Study Team

Figure 7.8-1 Example of Available Output and Generation in 2035

For Option 1, the supply capability is 1,600MW with a surplus electricity generation of 13,061GWh, and for Option 2, the figures are 11,400MW and 42,172GWh, respectively. The total supply capacity is 13,000MW and 55,233GWh. The annual utilization rate for these surplus electricity is 93.2% for Option 1, 42.2% for Option 2, and 48.5% overall.

Considering the estimated results of surplus electricity, there are two suggested directions for its utilization: focusing on the base throughout the year and emphasizing the peak during the rainy season. As of 2024, all surplus electricity is utilized for electricity exports to India, which can be considered a strategy focusing on the peak as per Option 2. The production of green hydrogen, as shown in Nepal's previous initiatives, fundamentally aligns with this concept.

Once surplus electricity begins to emerge even during the dry season from 2029 onwards, its use as a base in Option 1 becomes feasible. In this case, options such as promoting new year-round electrification demands with heat pumps or stable green hydrogen production throughout the year become viable.

(3) Potential for Heat Demand and Hydrogen Production Utilizing Surplus Electricity

This section discusses the conversion of the surplus electricity available until 2040 into heat demand (GJ) and hydrogen production (million Ton), examining the maximum amounts that can be produced and realistically supplied. The potentials are calculated under the following conditions:

- Heat potential and hydrogen production potential are calculated based on Table 7.8-3.
- Alkaline water electrolysis is assumed for the conversion from electricity to hydrogen, with a conversion efficiency of 52.40kWh/kg.
- The calorific value of hydrogen is based on the LHV (Lower Heating Value) standard at 120MJ/kg.
- The heat efficiency from electricity is set at 3600kJ/kWh.
- The heat potential (GJ), hydrogen production potential (million Ton), and heat potential converted to hydrogen for each month until 2040 are presented in Table 7.8-5.

Table 7.8-5 Potential for Surplus Electricity, Heat, and Green Hydrogen Production until 2040

Year	Power Generation (GWh)			Electification (PJ)			Green Hydrogen (Thousand Ton)			Green Hydrogen (PJ)		
	Option 1 (Base)	Option 2 (Peak)	Total	Option 1 (Base)	Option 2 (Peak)	Total	Option 1 (Base)	Option 2 (Peak)	Total	Option 1 (Base)	Option 2 (Peak)	Total
2022	0.0	998.8	998.8	0.0	3.6	3.6	0.0	20.0	20.0	0.0	2.4	2.4
2023	0.0	3,047.0	3,047.0	0.0	11.0	11.0	0.0	60.9	60.9	0.0	7.3	7.3
2024	0.0	4,270.0	4,270.0	0.0	15.4	15.4	0.0	85.4	85.4	0.0	10.2	10.2
2025	0.0	9,385.3	9,385.3	0.0	33.8	33.8	0.0	187.7	187.7	0.0	22.5	22.5
2026	0.0	10,719.1	10,719.1	0.0	38.6	38.6	0.0	214.4	214.4	0.0	25.7	25.7
2027	0.0	13,189.8	13,189.8	0.0	47.5	47.5	0.0	263.8	263.8	0.0	31.7	31.7
2028	0.0	18,786.2	18,786.2	0.0	67.6	67.6	0.0	375.7	375.7	0.0	45.1	45.1
2029	803.0	21,711.1	22,514.1	2.9	78.2	81.1	16.1	434.2	450.3	1.9	52.1	54.0
2030	1,606.0	24,646.2	26,252.2	5.8	88.7	94.5	32.1	492.9	525.0	3.9	59.2	63.0
2031	6,625.3	31,094.3	37,719.6	23.9	111.9	135.8	132.5	621.9	754.4	15.9	74.6	90.5
2032	6,545.6	32,460.5	39,006.1	23.6	116.9	140.4	130.9	649.2	780.1	15.7	77.9	93.6
2033	11,474.2	38,072.8	49,547.0	41.3	137.1	178.4	229.5	761.5	990.9	27.5	91.4	118.9
2034	12,274.5	40,235.9	52,510.4	44.2	144.8	189.0	245.5	804.7	1,050.2	29.5	96.6	126.0
2035	13,061.0	42,171.8	55,232.8	47.0	151.8	198.8	261.2	843.4	1,104.7	31.3	101.2	132.6
2036	12,137.5	43,461.7	55,599.2	43.7	156.5	200.2	242.8	869.2	1,112.0	29.1	104.3	133.4
2037	11,242.5	44,840.0	56,082.5	40.5	161.4	201.9	224.9	896.8	1,121.6	27.0	107.6	134.6
2038	11,211.1	46,823.0	58,034.1	40.4	168.6	208.9	224.2	936.5	1,160.7	26.9	112.4	139.3
2039	11,203.8	51,001.0	62,204.8	40.3	183.6	223.9	224.1	1,020.0	1,244.1	26.9	122.4	149.3
2040	9,625.3	52,317.8	61,943.1	34.7	188.3	223.0	192.5	1,046.4	1,238.9	23.1	125.6	148.7

Source: JICA Study Team

The utilization of surplus electricity is expected to focus mainly on peak-oriented Option 2 until 2028. From 2029 onwards, if surplus electricity becomes available even during the dry season, it will be possible to utilize the base of Option 1, which aims to meet year-round demand. In this case, options such as meeting new electrification demand with heat pumps throughout the year or stable green hydrogen production throughout the year become viable options.

7.8.3 Considerations for a Carbon-neutral Approach Utilizing Surplus Electricity in Nepal

(1) Comparison with Nepal's Primary Energy Consumption in 2022/23

Primary energy consumption in Nepal in 2022/23 was 640.0 PJ, with the composition being Traditional at 410.1 PJ (64.2%), Commercial at 181.4 PJ (28.4%), System Power at 31.8 PJ (4.9%), and Renewables at 16.1 PJ (2.5%). Of these, Traditional, mainly biomass for cooking, is not the main target of the energy transition. The main focus is assumed to be on the Commercial heat demand of 181.4 PJ, of which coal accounts for 58.1 PJ, gasoline 24.7 PJ, diesel 66.1 PJ, kerosene 0.6 PJ, LPG (Liquefied Petroleum Gas) 24.6 PJ, and other 7.2 PJ.

The total calorific value converted from surplus electricity for electrification or hydrogen production is estimated to be 33.8 PJ and 22.5 PJ in 2025, 94.5 PJ and 63.0 PJ in 2030, 198.8 PJ and 132.8 PJ in 2035, and 223.0 PJ and 148.7 PJ in 2040, respectively. For example, the calorific value of hydrogen in 2040, at 148.7 PJ, corresponds to about 82% of the Commercial primary energy in 2023, allowing for the substitution equivalent to coal, diesel, and LPG in terms of calorific value.

Although these utilizations need to be decided based on a comprehensive assessment of the economics compared to existing energy and the cost of establishing hydrogen infrastructure, there is a potential of a certain scale from a simple energy generation perspective.

(2) Comparison with Green Hydrogen Demand in Previous Studies

The demand for green hydrogen in previous studies is summarized in Table 7.8-6. It should be noted that the values for the annual hydrogen demand are reference figures estimated by the JICA Study Team.

Table 7.8-6 Green Hydrogen Demand in Previous Studies

Application		Annual Demand of Hydrogen (Thousand Ton)	References
Green Ammonia	Demonstration Plant	0.29	Ammonia production: 5 ton/day, Fertilizer factory annual: 198,000 ton
	Pilot Project	20.07	Urea production: 600 ton/day, Electrolysis: 400MW
	Potential Demand (2020)	81.09	Urea production: 2,424 ton/day, Electrolysis: 1,616MW
Industry*2	Cement, Bricks, Concrete Manufacturing	77.5 (2030) 201.4 (2035) 419.3 (2040)	
	Chemical Products, Rubber, Glass, Plastic Manufacturing	15.5 (2030) 39.75 (2035) 81.75 (2040)	
Transportation*3	Cars	23.16 (2018)	FCEV fuel efficiency 0.01kgH2/km, 154,433 cars and 15,000km/year
	Buses	30.28 (2018)	FCEV fuel efficiency 0.08kgH2/km, 12,617 cars and 30,000km/year

*1: Green Hydrogen for Development in Nepal, Kathmandu University,
*2: Report on the Production and Use of Green Hydrogen in Nepal, WECS,
*3: Study on the Possibility of Producing Hydrogen in Nepal Using Hydropower, ADB

Source: JICA Study Team

Regarding the demand for green hydrogen in “Green Hydrogen for Development in Nepal”, the hydrogen demand for an ammonia demonstration plant is very small, with a negligible amount of required electricity generation (GWh), which is assumed not to impact supply and demand. The demand for a fertilizer plant pilot project is 20.07 thousand ton, which can be supplied by the base surplus electricity from 2030 onward. Similarly, the potential demand for fertilizer within Nepal, estimated at 800,000 ton/year, requires approximately 81.09 thousand ton of hydrogen, which can be supplied by the base from 2031 onward. Utilizing the peak during the rainy season, if storage is possible, early supply by advancing production is feasible for ammonia and fertilizers.

For the use in boilers for cement, brick, and concrete production, supply is possible on the base from 2033 to 2035, but in other years, peak hydrogen production is also needed. However, by 2040, with a demand of 419.3 thousand ton and a hydrogen production potential of 1,238.9 thousand ton, year-round supply is feasible. Chemical products, rubber, glass, and plastic manufacturing are within the range that can be supplied by the base from 2030 onward.

Hydrogen demand for the transport sector is an estimate based on the number of vehicles in 2018, but passenger cars and buses together can be supplied by the base from 2031 onward. FCVs (Fuel Cell Vehicle) are assumed to store hydrogen over a period due to their usage pattern, peak utilization is also possible.

(3) Considerations on the Utilization of Surplus Electricity in Nepal

This section examines the potential for surplus electricity, heat, and green hydrogen production in the IPSDP's power development plan, as well as the energy consumption and hydrogen demand in Nepal from previous studies. Key findings include:

- Until 2028, the utilization of surplus electricity, heat, and green hydrogen will mainly occur during peaks, but from 2029 onwards the base supply gradually increase, and from 2031 onward, it will be possible to meet both base and peak demand.

- It is estimated that surplus of electricity, heat, and green hydrogen in Nepal can enable a significant energy transition compared to primary energy consumption.

- The potential is sufficient when compared to future hydrogen demand in previous studies.

On the other hand, when considering the kWh value of these surplus electricity sources, the value of electrifying heat demand followed by exporting electricity to India is high. As of 2024, the business feasibility of green hydrogen in Nepal without subsidies or carbon credits has not been reached. Therefore, it is essential to enhance the financial value of green hydrogen through an increase in the market value of green hydrogen, establishment of various preferential systems, and reduction in manufacturing costs through the development of new technology.

From an energy efficiency perspective, the most efficient utilization of electricity is for direct use as a power source for EVs, E-cooking, and heat demand. As already mentioned in Chapter 3, the Nepal government has set ambitious targets for EV and E-cooking. It is therefore important to promote these existing initiatives and stimulate new demand through heat pumps is considered important.

Exporting electricity also contributes to the energy transition from the perspective of CO_2 reduction in neighboring countries and is assumed to be a necessary measure for Nepal to earn valuable foreign exchange. It is therefore important to focus on electrification and electricity exports, which offer superior financial value.

While the practical use of CN fuels, including green hydrogen, is advancing in some developed countries, the full-scale social implementation is still at the exploratory stage worldwide, and it is assumed that Nepal is no exception. Therefore, for the time being, it is important to prioritize domestic economic value from the perspectives of technology dissemination, establishment of related systems, energy and food security, and preventing the outflow of foreign currency.

In particular, there is a clear market demand for ammonia produced from green hydrogen as fertilizer for agriculture in Nepal. Although it is less competitive in price than fertilizers imported from India, which are made from natural gas, it is preferable to proceed from the perspectives of a stable supply of fertilizers and food security. Furthermore, using CO_2 emitted from cement clinker production as a raw material for urea production can contribute to reducing emissions in carbon neutrality. However, the business is likely to be rely on subsidies. In the short term. Therefore, it is advisable to carefully consider the production scale to avoid impacting the finances of related businesses and the GoN.

7.9 ANALYSIS RESULTS AND EVALUATION OF THE OPTIMUM SCENARIO

7.9.1 Analysis Results of the Optimum Scenario

Analysis results of the Optimum Scenario is summarized in Figure 7.9-1.

(1) Power Demand Forecast

Based on various policies interventions such as EVs, E-cooking, and SEZ (Special Economic Zone), power demand forecast estimates that power demand (GWh) and peak demand (MW) will grow from 7,102 GWh and 1,482 MW in 2021 to 62,390 GWh (8.8 times) and 11,510 MW (7.8 times) in 2040, respectively. Per capita electricity consumption is expected to grow from 242 kWh/capita in 2021 to 1,779 kWh/capita in 2040. Although the growth rate indicates a significant increase, the demand forecast results are not excessive and are generally reasonable compared to the world average of 3,265 kWh/capita and other South and Southeast Asian countries. Continuous demand stimulation such as industrial development and energy transition is also motivated.

(2) Power Generation Development Plan

Power generation development plan focuses on developing clean energy based on hydropower. The potential of hydropower in various domestic rivers is organized and the necessary development capacity for both the rainy and dry seasons is considered. The installed capacity of 2,684 MW in 2023 is expected to reach the development target of 28,000 MW in 2035 as indicated in the Energy Development Roadmap and Workplan by MoEWRI Plan and further increase to 35,591 MW by 2040. Generation mix in 2040 will be ROR: 13,264 MW (37%), PROR: 10,060 MW (28%), STO: 8,079 MW (23%), and renewable energy: 4,108 MW (12%). Power generation is expected to increase from 10,693 GWh in 2023 to 133,185 GWh by 2040.

(3) Power System Development Plan

Power System Development Plan analyze the 400kV bulk power system, 400kV interconnections to India and sub-systems around major cities. The 400kV backbone system is expected to grow from 78 km of transmission lines and 945 MVA of transformer capacity in 2023 to 2,487 km and 20,475 MVA by 2040, organizing a network of two east-west routes and north-south routes along major rivers. The urban power system of 220kV/132kV/66kV will also be reinforced in Kathmandu, Pokhara, Butwal, and other cities.

(4) Economic and Financial Analysis

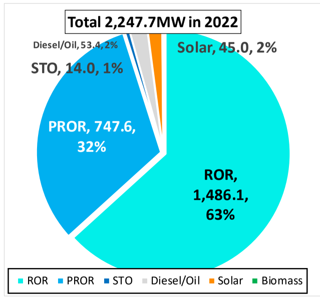
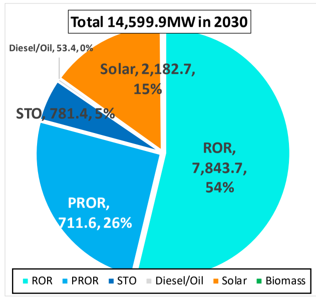
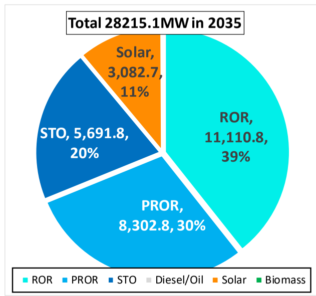
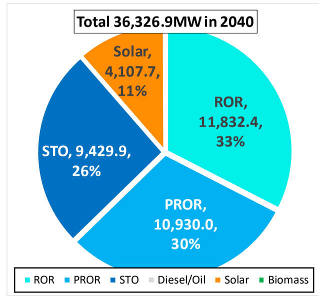
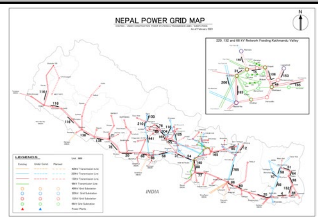
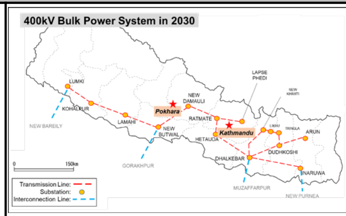
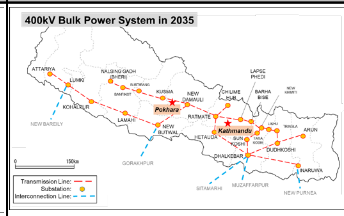
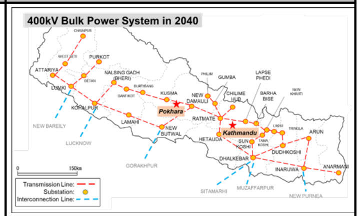
The economic and financial analysis calculated the revenue from power sales to consumers and neighboring countries and the expenses including capital investment, O&M and power purchase from IPPs and India. The viability while maintaining financial health in power sector is assessed. The required capital investment by 2040 is estimated to be $53,063 million (annual $3,121 million) for the Power Generation Development Plan and $8,687 million (annual $511 million) for the Power System Development Plan. The expansion of Clean Export is expected to impact with power export revenue increasing from $80.4 million in 2022/23 to $3,069 million by 2040, providing valuable foreign currency earnings for Nepal.

(5) Strategic Environmental Assessment

SEA aimed to minimize negative impacts and maximize positive impacts, considering appropriate management, monitoring, and mitigation measures for unavoidable negative impacts. The cumulative impacts on river basins due to hydropower development are particularly assessed and the results are reflected in mitigation measures. Sufficient consideration and measures for environmental flow, protected areas, ecosystems/forests, indigenous peoples, natural disasters and climate change are necessary for future power development, making Safeguard Policy and individual project ESIA essential for each river basin.

(6) Power Trade

Expanding Clean Export is a crucial strategy for Nepal's export and economic growth. Nepal primary power export destinations are India and Bangladesh where rely heavily on thermal power. Hydropower development in Nepal can contribute to stabilizing power supply and reducing CO_2 emissions in these countries. Nepal can export clean energy equivalent to twice its domestic demand, mainly during the rainy season, contributing to 61,370 GWh and reducing CO_2 emissions by 44,531 thousand tons in 2040. Power trade with neighboring countries will be implemented through India, with six planned 400kV international interconnection routes. Direct export through interconnection lines is also necessary for stable and efficient system operation for development sites post-2035. Besides infrastructure development, it is also important to establish direct trade between IPPs and power companies/consumers in India and Bangladesh, organize the interconnection application to their system and obtain incentives for clean energy.

Item	2022/23	2030	2035	2040
Power Demand Forecast				
Power Consumption (GWh)	9,347GWh	24,737GWh	39,638GWh	62,390GWh
Power Demand (MW)	1,986W	4,949MW	7,581MW	11,510MW
Energy Consumption Per capita	320.5kWh/capita	774kWh/capita	1,184kWh/capita	1,779kWh/capita
Power Generation Development Planning				
Installed Capacity				
Annual Power Generation (Power Trade)	10,693GWh (-521GWh)	56,737GWh (25,859GWh)	102,527GWh (55,233GWh)	133,185GWh (61,370GWh)
Self Sufficient Rate	86.3%	183.7%	216.8%	185.5%
CO2 Emission	128.3kg-CO_2/kWh	31.8kg-CO_2/kWh	25.4kg-CO_2/kWh	29.0kg-CO_2/kWh
Power System Planning				
Power System				
Total Length of Transmission Line	400kV 78 km and 220&132kV 4,068km	400kV 1,149 km and 220&132kV 4,988km	400kV 1,818km and 220&132kV 5,563km	400kV 2,487 km and 220&132kV 6,138 km
Total Capacity of Transformer	400kV 945 MVA / 220&132kV 4,917 MVA	400kV 9,625 MVA / 220&132kV 13,317 MVA	400kV 15,050 MVA / 220&132kV 18,567 MVA	400kV 20,475 MVA / 220&132kV 23,817 MVA
Economic and Financial Analysis				
Accumulated Investment (Generation)	-	23,207MUSD	42,642MUSD	53,063MUSD
Accumulated Investment (Transmission)	-	3,573MUSD	5,970MUSD	8,687MUSD
Total Cost	-	26,780MUSD	48,612MUSD	61,750MUSD

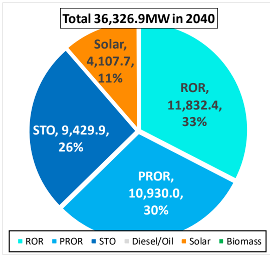
Source: JICA Study Team

Figure 7.9-1 Summary of IPSDP

7.9.2 Evaluation of the Optimum Scenario from 3E + Policy

The evaluation of the analysis results of the Optimum Scenario is shown in Table 7.9-1 based on the 3E + Policy framework.

Table 7.9-1 Evaluation of the Optimum Scenario according to 3E + Policy

<table>
<tr><th colspan="2">Evaluation Items</th><th>Optimum Scenario</th></tr>
<tr><td colspan="2" rowspan="2">Generation Mix in 2040</td><td>
</td></tr>
<tr><td>36,327MW</td></tr>
<tr><td rowspan="3">(1) Energy Security</td><td>Self Sufficiency Rate of Power Generation (%)</td><td>185.5%</td></tr>
<tr><td>International Issues</td><td>Interruption of power exports</td></tr>
<tr><td>Grid Stability</td><td>None</td></tr>
<tr><td rowspan="3">(2) Economy</td><td>Cumulated Investment Cost</td><td>57,384 MUSD
(3,020MUSD/year)</td></tr>
<tr><td>Cumulated Balance of Power Trade</td><td>31,202MUSD</td></tr>
<tr><td>Vulnerability for Fuel Cost</td><td>None</td></tr>
<tr><td rowspan="4">(3) Environmental and Social considerations</td><td>Natural and Social Impacts</td><td>Intermediate</td></tr>
<tr><td>Cumulated CO_2 Emissions (million ton)</td><td>44.6 million ton</td></tr>
<tr><td>CO_2 Emissions Rate (g-CO_2 /kWh)</td><td>29.0 g-CO_2/kWh</td></tr>
<tr><td>Cumulated Reduction of CO_2 Emissions by Power Export (million ton)</td><td>522.4 million ton</td></tr>
<tr><td rowspan="2">Policy</td><td>28000MW in 2035</td><td>Achieved</td></tr>
<tr><td>Introduction of RE</td><td>Achieved</td></tr>
</table>

Source: JICA Study Team

From the perspective of energy security, the self-sufficiency rate of energy will be 185.5% in 2040.It is possible to complete self-sufficiency in electricity supply including the dry season. However, it is necessary to consider events of unfavourable issues with neighboring countries. Although domestic power supply is possible, it is difficult to sell electricity to them. This interruption could make investment recovery for new power plants difficult. Therefore, it is crucial to establish a mutual relationship with neighbouring countries by promoting projects and investment participation from them and ensuring the continuation of power trade even in such kind of affairs. Additionally, energy transition could be risk hedge to mitigate effect of unselling surplus energy. Further promotion of electrification policies and enhancement of energy self-sufficiency should be considered.

The trade-off between reducing financial burden and economic growth through power exports exists with the capacity of hydropower development. The Optimum Scenario requires significant development of power sector than the current scale. Regarding the power sector's financial balance, if power export is realized, the cumulative balance of power trade will be significantly in surplus. Regarding vulnerability to fuel inflation, domestic power self-sufficiency minimizes the impact even if global fuel inflation occurs as in the first half of 2022. Therefore, the power sector needs to scrutinize whether this scale of development is feasible, verified through economic and financial analysis shown in Section 7.5.

Concerning environmental and social considerations, the Optimum Scenario includes many STO site developments, potentially increasing impacts on the natural and social environment. Mitigation measures presented in Section 7.4 need to be implemented to achieve acceptable development for socio-ecological environment.

From the perspective of climate change measures, hydropower development will contribute to reduction of regional CO_2 emission through electricity exports to neighboring countries which are mainly depended on thermal power plants. Additionally, incentives resulting from these reductions can be anticipated in the future.

Regarding the alignment with Nepal's power policy, the development target of 28,000 MW by 2035 shown in the Energy Development Roadmap and Work Plan will be achieved and the introduction of renewable and alternative energy meeting 10% of domestic demand is also secured.

8. STRENGTHENING POWER SECTOR GOVERNANCE MECHANISM

8.1 NECESSITY OF ESTABLISHING VISIONS IN POWER SECTOR

The JICA study team believes that it is important to set the following vision as a prerequisite for improving governance in Nepal's power sector:

- First, promote industry through appropriate collaboration between ministries and agencies within the country, generate electricity demand, and build a power supply system to meet that demand.
- Second, export surplus electricity to neighboring countries, bringing about a positive impact on the country's trade balance and national finances.

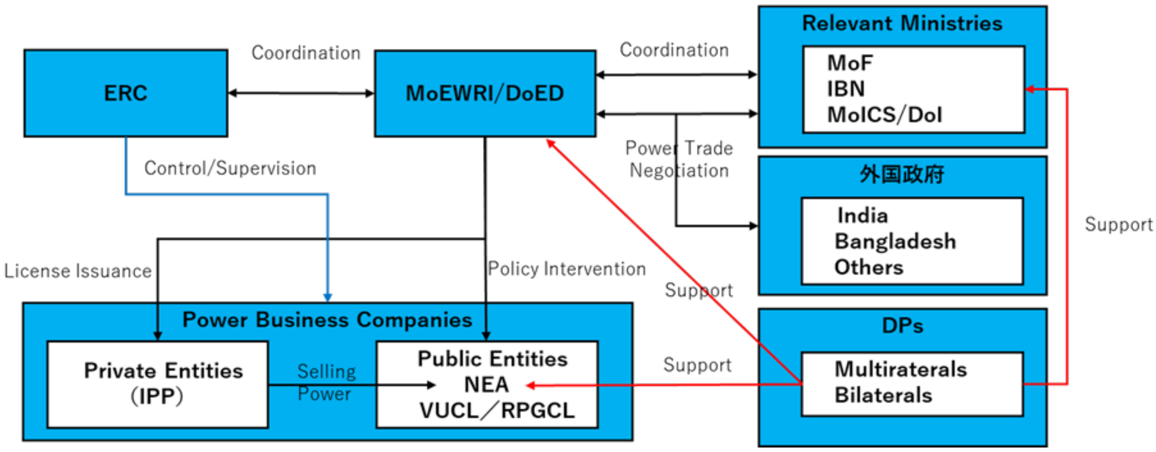
Through exchanges of opinions with relevant stakeholders, the following four points were identified as the main points (mainly, but not limited to, governance-related) that require capacity building in the future. These points will also be useful for development partners such as JICA to consider future support measures for Nepal.

- Capacity to implement IPSDP: Ability to position IPSDP as a practical master plan and realize its contents
- Capacity to form and implement power projects: Ability to carry out project operations such as issuing licenses[96] for power generation projects and setting and changing tariffs[97] for power generation, transmission, and distribution
- Capacity to manage the grid: Ability to appropriately manage the grid under the expected future introduction of a domestic wheeling system and expansion of power exchange with neighboring countries[98]
- Capacity to coordinate among ministries: To realize the contents of IPSDP, DoED needs to collaborate with multiple ministries and local governments such as the Ministry of Finance, IBN, and the Ministry of Industry, but it has the ability to coordinate them[99]

Based on the above, the following sections will present the results of the survey and examination of the main issues in the power sector of Nepal identified through this survey and the measures to alleviate and resolve them.

The current status and the associated issues of power sector governance in Nepal is summarized in the following figure.

96 For more information on licensing issues, see Chapter 2, Section 2.2.5, "IPP Permitting and Approval Processes."
97 For more details on issues relating to setting and changing tariffs, see Chapter 2, Section 2.4.2, "Electricity Tariff System."
98 For more details on the challenges of grid management, see the section on the Asian Development Bank in Chapter 2, Section 2.7, "Assistance of Development Assistance Agencies in the Power Sector."
99 For more information on the major players in the power sector, see Chapter 2, Section 2.1, "Institutional Structure of the Power S



Source: JICA Study Team

Figure 8.1-1 Summary of Power Sector Governance and Related Issues

8.2 ISSUES RELATING TO THE CURRENT GOVERNANCE MECHANISM AND CONSIDERATIONS ON THEIR MITIGATION AND RESOLUTION

8.2.1 Development of Interorganizational Communication Platform and Protocol

Currently, it can be observed that the policies and measures implemented in Nepal's power sector have been strictly limited to the sector. In order to achieve the IPSDP based on the visions outlined above, collaboration with the departments and ministries listed below is essential from the perspective of industrial development and promotion of private investment. However, the current status suggests that governance in this area is not effective.

- Ministry of Finance, IBN: procurement of funding for power plants and transmission and distribution grids as well as related discussions and assessments
- Ministry of Industry, Commerce, and Supplies: assessment and discussion concerning industrial development policy (particularly from the perspective of electricity supply)
- Private entities: exchange of information and ideas with investors who in particular develop power plants as IPP, private proprietors and business owners, and commercial banks
- Local governments assessment and discussion on land purchase and the maintenance and operation of transmission and distribution lines

It is important to clarify communication protocol to ensure unimpeded communication between ministries and departments and strengthen governance for inter-ministerial collaboration. The items below may be considered as what may be done specifically for this.

- Creation of a communication platform (conference) and secretariat
- Holding periodic and ad hoc meetings
- Communication methods (face-to-face meetings, online meetings, etc.)
- Planning and holding regular events
- Preparation of manuals and guidelines concerning the above

8.2.2 Investment Climate Improvement

Generally, the conditions listed below are needed to attract investment from countries and firms; however, attracting investment to Nepal have been made challenging by certain issues that counter each of those conditions.

- Government stability (ministerial and departmental leadership): changes in positions held by high-ranking officials is frequent, resulting in the lack of clarity in leadership and responsibility.[100]
- The state of legal system and process development: the amended Electricity Act is pending, and existing administrative and legal processes are subject to frequent changes[101].
- Risk sharing when making contracts: The contents of contracts, particularly for IPP, may be difficult to agree to from the perspective of foreign investors.
- Foreign investors may be feeling that they cannot cover every possible risk owing to the insufficient in development legal systems that would ensure the protection of their rights.[102]
- Procurement of business finance: It is difficult, at least in Nepal, to procure finance at competitive conditions from public or urban financial institutions, which necessitates foreign investors to turn to foreign financial institutions for funding. Naturally, foreign financial institutions are also wary of financing projects in Nepal.

Although the items above are all crucial, there are not many courses of action available for line ministries involved in the power sector, particularly the DoED. Consequently, these are issues that must be addressed by the GoN as part of its national policy, led as an initiative from the top and put into action with collaboration between relevant ministries such as the Ministry of Finance and IBN.

8.2.3 Clarification of Processes concerning License Issuance for IPP and Screening Standards, and Discussions with the Private Sector

In the implementation phase of this study, USAID, which supports Nepal in the energy sector, pointed out that the acquisition of land and application for licenses and approvals were labor intensive and time consuming[103], while IPPAN also identified the complexity and high cost of processes, especially in consideration of climate-friendly societies, as being issues[104]. Additionally, private businesses found it burdensome how laws, regulations, and processes frequently change and how regulations differ between ministries due to the lack of collaboration[105].

Moreover, IPPAN and other parties have also pointed out that the standard used for the issuance of licenses to investors is unclear. In fact, as discussed in chapter 2 “2.2.5 IPP licensing and approval process” of this report, they noted that many construction projects seemed to never begin even though years had passed since their licenses had been issued. Some attribute this situation to the substandard screening during the license application process (uncontrolled and haphazard issuance of construction licensing for IPP) rather than delays to construction caused by problems that arose after the issuance of the license. Regardless of the validity of this viewpoint, the fact that such opinions exist suggest that it may cause significant setback to promoting investment from private entities, including foreign investors.

Based on the above, it is necessary to again review and clarify processes and screening standards concerning the issuance of licenses. In doing so, the burden felt by private firms may be lessened.

[100] Political instability was also pointed out at length at the aforementioned Nepal Investment Summit 2024.
[101] For an overview of the amended Electricity Act and its current status, refer to Chapter 2 “2.2.1 Legal system concerning the entire power industry” of this report.
[102] This may require the credit guarantee of NEA as an off-taker.
[103] Based on hearing conducted with USAID (March 2022)
[104] Based on hearing conducted with IPPAN (June 2022)
[105] Based on hearing conducted with IPPAN (June 2022)

At the same time, more private investment may be raised by improving the transparency of processes and evaluation standard. Additionally, in making these improvements, it is also vital to hold discussions as needed with private entities, heed their opinions, and incorporate them as needed into plans and actions.

8.2.4 New Electricity Act and the Unbundling of the NEA

As stated in Chapter 2 of this report, the amended Electricity Act, 2075 was submitted to Congress in July 2020. However, the amended law has not passed as of October 2024, and there is no prospect of this happening. A scanning of the amendment bill reveals that it includes the unbundling of the NEA, the introduction of the competitive principle to the implementation of government-led projects, introduction of a consignment system domestically, open access to the grid, participation of private entities to transmission and distributions projects, and other crucial elements. Nonetheless, any concrete discourse on such matters would not occur unless the amendment passes.

Similarly, the unbundling of the NEA did not reach any meaningful discussions during the meetings with members from the GoN, at least during the implementation of this project. Looking at similar examples in other countries, the separation of generation and transmission/distribution may be one example to refer to. However, in identifying a model that suits Nepal’s power sector the best, the country’s needs and situation should be discussed independently from cases used by other countries. In particular, Nepal has existing public organizations such as the VUCL and RPGCL, and the demarcation between the NEA and their functions would also need to be considered at some point.

As for the governance relating to the passage of the amendment, this is an issue that stems from the Nepali Congress and government and thus cannot be said to be an issue stemming from the individual ministries. Consequently, this study also concludes that providing comments and advice to specific ministries is not feasible. In any case, it is a fact that the structural reform (or preliminary discussions for this) of Nepal’s power sector have been halted or delayed as a result of the unbundling of the NEA put on hold for a number of years, and thus it must be stressed again that this is a key issue that needs to be addressed.

8.2.5 Strengthening Collaboration between Donors

As discussed in “2.7 Aid from development agencies for the power sector” of this report, international organizations such as the WB, ADB, and AIIB and many other bilateral development agencies have designed and implemented projects in Nepal’s power sector (or energy sector). The aid provided are not necessarily coordinated and, on the surface, seem to overlap in places. The following items are of particular importance.

- Electricity demand forecast in Nepal
- Assessment concerning power trade with neighboring countries
- Assessment concerning the state of SEA
- Assessment concerning the promotion of private funding utilization

With regard to these overlapping areas, although a certain degree of overlap (based on cursory review) in some areas may be unavoidable, some risks may arise that any discrepancy or contradiction would not be properly managed and dealt with should they arise between donors. To prevent this, coordination between donors is important.

8.2.6 Summary of Key Issues on Power Sector Governance of Nepal

Based on the above, the JICA study team's comments (which, in this chapter, are limited to items relating to governance) can be summarized as follows.

- The action plans are very comprehensive and agrees with the contents of the IPSDP.

- If actions to be taken by the DoED and NEA were to be added to the action plans, they would pertain to matters such as the development of a SOP (Standard Operation Procedure) for both intra- and inter-ministerial applications and communication. In particular, considering the limitations in staffing (in terms of number) in the GoN, the development of an SOP, guideline, or manual would be conducive to effectively conducting administrative functions.

- While the action plans mention using IPP and strengthening the collaboration with private entities, it should also incorporate actions pertaining to the government increasing opportunities for discussion, thus deepening understanding between both parties, and taking necessary measures to promote private investment. Additionally, strengthening finance is to be the purview of the MoF (Ministry of Finance) and IBN, and ensuring their capacity for implementation is key.

- The plans acknowledge that the current IPP is done basically on a non-competitive basis (based on proposals from private entities). However, there is need to consciously introduce the competitive principle for large-scale projects and IPP. Actions for this may be incorporated into the plans. In line with this, it is also vital to prepare RFP (Request for Proposal) and PPA templates according to international standards.

- It is somewhat disappointing that the action plans hardly mention industrial development and power generation development. As mentioned previously in this chapter, industrial development in Nepal is a matter of utmost importance, and there should be discussions on whether the issue can be approached by addressing the power sector, the result of which should be reflected in specific actions to be taken.

- The action plans do not mention anything about ODA donors. The inclusion of donors is important (in a sense vital), whether through financial aid such as loans and grants, technical assistance, supply of investment funds to businesses (non-sovereign base). The action plans would benefit from mentioning specific actions pertaining to the effective utilization of aid and coordination mechanism to prevent aid from overlapping or contradicting.

8.3 POSSIBLE SUPPORT BY DEVELOPMENT PARTNERS

Based on the above considerations and observations, the JICA study teams proposes the followings as possible support that development partners (which include JICA and other partners) may consider.

- Capacity Building to implement and realize IPSDP: DPs may provide capacity building to successful implementation of IPSDP (*Target organizations may include, DoED, NEA, VUCL, RPGCL, and VUCL)

- Financing the IPSDP projects: Donors may provide sovereign and non-sovereign finance (debt/equity) to independent projects listed in IPSDP

- Development of RFP / PPA template according to international standards: DPs may support GoN to prepare model RFP/PPA of international standard to attract more foreign investors.

- Provision of TAS (Transaction Advisory Service): DPs may provide TAS, which may include feasibility study, preparation of RFP, bidder selection, and contract negotiation.

- Supporting the development and implementation of an electricity export strategy: DPs may support GoN to develop power export strategy to support successful negotiation and agreement of power trading with neighboring countries.

9. MILESTONES AND FUTURE OUTLOOK FOR THE POWER SECTOR TOWARDS THE REALIZATION OF IPSDP

In order to achieve the development sector outlined in IPSDP, it is crucial for Nepal to transform the power sector itself significantly in power infrastructure, business structures, power trade, finance and legal frameworks. These elements are closely related among various fields such as power generation, power system, environment and finance. Thus, it is necessary to involve diverse stakeholders and to proceed the development from comprehensive perspective. This Chapter organizes the results from Chapters 1 to 8 cross-sectionally, presents the milestones and pathway towards realizing IPSDP and indicates the necessary transformations and future outlook of power sector. Finally, challenges and recommendations to carry out IPSDP are summarized.

9.1 DEVELOPMENT MILESTONES AND PATHWAYS TOWARDS 2040 IN IPSDP

Table 9.1-1 and Figure 9.1-1 summarize the installed capacity, domestic demand, power trade and major milestones towards 2040 in IPSDP. Development milestones of IPSDP are; achieving net-zero in power trade (2025), commencement of operation of power generation projects currently under survey (2027), achieving self-sufficiency through a year (2033), meeting government targets in roadmap (2035) and contributing to stable power supply to domestic and neighboring countries (2040).

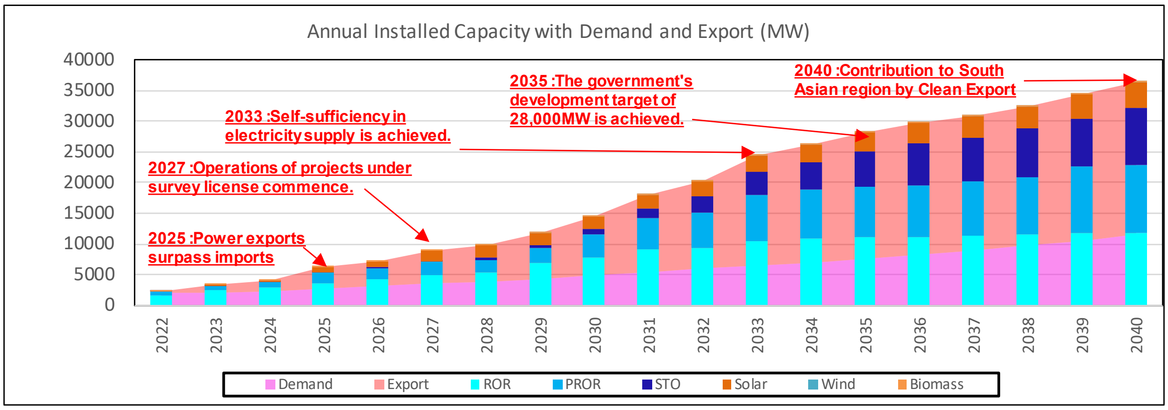
Table 9.1-1 Milestones towards 2040

Year	Milestone
2025	Power exports surpass imports.
2027	Commencement of operation of currently surveyed power projects, accelerating power exports.
2033	Achieving power self-sufficiency including the dry season and advancing energy transition.
2035	Commencement of large scale STO HPPs, achieving the energy development roadmap target of 28,000 MW.
2040	Contributing to stable power supply to Nepal and neighboring countries.

Source: JICA Study Team

9.1.1 Development Milestones in IPSDP

From 2023 to 2025, 4,110.2MW of installed capacity will have been developed. It is important to steadily implement the projects currently under construction that have already obtained a Construction License. This requires proper and smooth monitoring, quick reviews and approval of necessary permits and interconnection between power system and plants. Hydropower development includes projects such as Rasuwagadhi and Madhya Bhotekoshi by NEA subsidiaries and large IPP projects like Upper Trishuli-1 and Arun 3. Development of power system focuses on 400kV interconnection line at New Butwal and 400kV backbone system connecting major domestic cities from New Butwal to Ratmate, Hetauda and Dhalkebar.



Item			～2025	2026 -2030	2031 - 2035	2036 - 2040
Generation	Hydro	GoN Entities	Rasuwagadhi (111MW), Sanjen (42.5MW), Upper Modi A (42MW), Rahughat (40MW), Upper Trishuli 3B (37MW), Madhya Bhotekoshi (102MW)	Tanahu HEP (140MW), Tamor Storage (200MW), Madi Storage HEP (156MW)	Lower Seti(126MW), Uttarganga STO (828MW), Phukot Karnali (480MW), Nalsyau Gad STO (417MW), Upper Arun (1061MW), Chainpur Seti (210MW), Dudhkoshi STO (635MW), Sunkoshi 3 STO (680MW)	Betan Karnali (442MW) Kimathanka Arun (450MW), Bharbung (470MW), Mugu Karnali STO (1670MW)
			408MW (509MUSD)	**1113MW (2216MUSD)**	**4900MW (8558MUSD)**	**2969MW (6130MUSD)**
		IPPs	Upper Trishuli-1 (216MW), Arun 3 (900MW)	Manang Marsyangdi (282MW), Budhi Gandaki Ka (226MW), Bheri 4 HEP (271MW), Tila-1 (299MW), Tila-2 (297MW)	Lower Badigad STO (380MW), Budhi Gandaki (340MW), Upper Marsyangdi -2 (327MW), Dudh Koshi-IV (350MW), Upper Tamor (285MW), Bheri-2 (270MW), West Seti STO (750MW), SR-06 STO (309MW) Tamakoshi 3 (650MW), Khimti Shivalaya STO (396MW)	Bajhang Upper Seti (216MW), Naumure STO (218MW), Upper Mugu Karnali (240MW), Bheri-1 (270MW), Humla Karnali-Cascade (637MW)
			2902MW (4267MUSD)	**5782MW (9661MUSD)**	**7869MW (14776MUSD)**	**4118MW (7963MUSD)**
	RE		**800.2MW (823MUSD)**	**1355.6MW (1363MUSD)**	**900MW (950MUSD)**	**1025MW (925MUSD)**
	Technical Studies		Planning for Cascade Operation utilizing STO Considerations of access road for hydropower corridors	Introduction of pumped storage Innovation of generation planning considering export		
	Construction		**1) HPPs in Construction Licenses**	**2) HPPs in Survey Licenses**	**3) HPPs in GoN categories**	
Power System	400kV Bulk Power System		NEW BUTWAL - NEW DAMAULI - RATMATE - LAPSI PHEDI, RATMATE – HETAUDA – DHALKEBAR – INARUWA	LUMKI – KOHALPUR – LAMAHI - NEW BUTWAL, DHALKEBAR - NEW KHIMTI - DUDHKOSHI, DHALKEBAR – DUDHKOSHI – ARUN	ATTARIA - LUMKI, NALSING GADH - NEW DAMAULI, LAPSI PHEDI - NEW KHIMTI	CHAINPUR - ATTARIA, PURKOT - LUMKI, NALSING GADH - KOHALPUR, PHILIM – RATMATE - CHILIME HUB, ARUN – INARUWA - ANARMANI
	Interconnection Lines		NEW BUTWAL - GORAKHPUR	LUMKI - BAREILY, INARUWA - PURNEA	DHALKEBAR 2 - MUZAFFARPUR	KOHALPUR - LUCKNOW
	Major Cities Demand		Kathmandu 506 MW (LAPSI PHEDI, RATMATE) Birgunj 302 MW (HETAUDA) Pokhara 195 MW (NEW DAMAULI) Dhalkebar 126 MW (DHALKEBAR)	Kathmandu 935 MW (LAPSI PHEDI, RATMATE) Birgunj 570 MW (HETAUDA) Pokhara 371 MW (NEW DAMAULI) Dhalkebar 368 MW (DHALKEBAR) Lumbini 637 MW (NEW BUTWAL)	Kathmandu 1,329 MW (LAPSI PHEDI, RATMATE) Birgunj 873 MW (HETAUDA) Pokhara 403 MW (NEW DAMAULI) Dhalkebar 564 MW (DHALKEBAR) Lumbini 975 MW (NEW BUTWAL)	Kathmandu 2,017 MW (LAPSI PHEDI, RATMATE) Birgunj 1,326 MW (HETAUDA) Pokhara 612 MW (NEW DAMAULI) Dhalkebar 856MW (DHALKEBAR) Lumbini 1,481 MW (NEW BUTWAL)
	Cost		**1213MUSD**	**2765MUSD**	**2397MUSD**	**2717MUSD**
	Technical Studies		Power system operation planning with power trade Interconnection studies with neighboring countries	Harmonization between power system and VRE Power System Planning for Western Province		
	Construction		**Reinforcement of Interconnection Lines and Domestic Bulk Power System**	**Establishment of 400kV Bulk Power System**		**Operation of Transmission Lines for Direct Export**
Developer			Matching between domestic HPPs and potential developers Facilitation of involvement of foreign developers	Establishment of SPCs		
Finance			Enhancing the finance capacity of domestic finance	Involvement of Indian/Bangladesh Investors Utilization of Sovereign or PPP loans for Nepal, India and Bangladesh		
Rule & Regulation			Establishment of modality of power trade in PPA, grid interconnection and related regulations			
Capacity Development			Restructuring the Power Sector	Scale-up of governmental entities in quantity and quality		
Energy Transition			Facilitation of electrification by EV, E-cooking or Heat pumps Research and development for green hydrogen or ammonia		Energy transition by utilizing surplus electricity	

Source: JICA Study Team

Figure 9.1-1 Development Milestones and Pathways in IPSDP

From 2026 to 2030, 8,250.6MW of installed capacity will have been developed. The projects currently under construction are expected to commence operations between 2026 and 2027. From 2028 onwards, projects currently with a Survey License or identified by GoN will also start operations. Hydropower development will focus on medium and small-scale projects up to 200MW such as Tanahu STO in this period. Although scale of individual HPPs are not huge, total amount of capacity addition is a significant increase. Solar projects around Terai plains are also expected to be developed by mainly IPPs. As power exports increase owed to rapid capacity addition, power system will also be developed in new 400kV interconnection lines at Lumki and Inaruwa, as well as the 400kV backbone system connecting western regions to New Butwal and Koshi basin to Dhalkebar. Active participation from international developers, investors, and banks including those from India and Bangladesh is facilitated.

From 2031 to 2035, 13,669.0MW of installed capacity will have been developed. Development will shift from small and medium ROR to large-scale PROR and STO projects over 200MW. In this period, commencement of major projects under Survey License will reach the peak of development, achieving power self-sufficiency including the dry season by 2033. Hydropower development will focus on new river basins such as Karnali, Bheri, Kaligandaki, and Tamor. The power system development will extend the 400kV backbone system in the far west and develop the 2nd eastern-western backbone along the northern route. As surplus electricity is available through the year after 2030, energy transition initiatives will advance the utilization of low-carbon fuels like hydrogen and ammonia. These continuous efforts will lead the achievement of development target indicated in the Energy Development Roadmap and Work Plan 2035.

From 2036 to 2040, 8,112.0MW of installed capacity will have been developed. Large-scale STO HPPs and development of upstream areas in each river basin will progress. As domestic power supply is stable year-round, new power sources will be developed for direct export to neighboring countries.

9.1.2 Pathways to IPSDP

Achieving the milestones shown in the previous section requires the implementation of various measures, including technical considerations, finance, institutional and regulatory frameworks, and human resource development. Considering the timeline and the progress of each project, it is assumed that projects currently under construction with a Construction License will be required to commence operations by 2027. Ensuring the steady execution and progress monitoring of these projects is essential.

Conversely, numerous projects with a Survey License and GoN projects need to be proceeded towards commercialization. To achieve the MoEWRI development target of 28GW by 2035, these projects need to commence operations between 2031 and 2035. Therefore, construction works of them are required to start by 2026-2030. This means that it is necessary to complete organization of SPC, financing, PPA negotiations and obtaining Construction License by 2026-2030. Similarly, preparation for the development of international interconnection lines and domestic backbone systems targeting 2031-2035 is necessary.

Various tasks are addressed including technical considerations for power generation and system operation aimed at the power trade, financing for each project, establishing a mechanism of Clean Export, enhancing safeguards and strengthening the power sector's capacity. These are urgent issues to be carried out involving not only the power sector but also other sectors.

9.2 CHALLENGES OF IPSDP

To realize IPSDP, it is crucial to steadily execute the currently ongoing projects by 2026. From 2027 onwards, it will be necessary to develop the currently surveyed projects. Many of these new developments lack established implementation structures and financing. Feedback from local private and government operators indicates that it is difficult for individual license-holding developers to undertake large-scale projects alone. Meanwhile, domestic resources are already being utilized, making the promotion of participation by foreign developers, investors, banks, and development aid agencies an urgent task. To achieve development post-2027, issues such as integrated river basin development, access road development, securing transmission routes, and promoting power trade must be addressed. Additionally, enhancing the capacity of government organizations and the entire power sector is also necessary.

Many of these challenges need to be addressed promptly to achieve development post-2028. However, as the various fields are closely related, it is difficult to solve them through the efforts of individual government organizations alone. Inter-organizational cooperation is crucial. For instance, while NEA's risk in expanding power trade does not directly affect the technical considerations of power sources and systems as an electrical phenomenon, it is closely related to financial aspects, such as who bears the financial risk in power trade, institutional aspects, such as whether organizations other than NEA will be involved in the power trade, and governance aspects, such as adjusting interests among various stakeholders, including neighboring countries.

This section organizes the major challenges, summarizing knowledge and experiences of JICA Study Team through IPSDP studies and comments obtained from various stakeholders. Although issues of power sector are closely related each other, these are classified into the following five categories;

(1) Clean export
(2) Expansion of the Nepal power system
(3) Business structure of power sector
(4) Finance / Private Investment
(5) Energy Transition

Major topics and relation with generation, power system, finance, legal framework and governance are integrated in Table 9.2-1.

Table 9.2-1 Challenges in the Five Necessary Transformations in the Nepalese Power Sector

Item	Generation	Power System	Finance	Institutional / Legal	Governance
1.Clean Export					
Concentration of risks on NEA for expansion of clean export	✓	✓	✓	✓	✓
Securement of power supply reliability for domestic demand	✓	✓		✓	✓
Technical issues on expansion of power trade		✓			
Development scheme on interconnection lines		✓		✓	✓
Issues on legal framework for power trade	✓	✓		✓	
Insufficient experiences on export oriented hydropower projects by Nepalese developers	✓	✓	✓	✓	
2.Expansion of the Nepal Power System					
Necessary adaptation measures against climate change risks.	✓	✓		✓	
Necessity of integrated river basin development	✓			✓	✓
Capacity development on tunnel design and construction	✓			✓	
Need to improve system planning capabilities.		✓		✓	
Interconnection of VRE		✓		✓	
Mitigation of environmental and social impacts	✓	✓	✓	✓	
3.Business Structure of Power Sector					
Necessity of capacity development of GoN	✓	✓		✓	
Clarification of role of government organizations and sector reforms.	✓	✓		✓	✓
Shortage of domestic contractors	✓	✓		✓	
Necessity of international standard PPA	✓			✓	✓
4.Finance/Private Investment					
Finance from domestic investors or lenders	✓	✓	✓	✓	
Necessity of promotion of FDI	✓	✓	✓	✓	
Enhancement of assistance by development partners	✓	✓	✓	✓	
5.Energy Transition					
Promotion of electrification	✓	✓	✓	✓	
Establishment of legal framework and supply chain in Green Hydrogen	✓	✓	✓	✓	

Source: JICA Study Team

9.2.1 Clean Export

(1) NEA's Risk in Expanding Power Trade

Regarding power exports to India, there has been progress in negotiations since 2023, with India setting exchange volumes and purchase periods of 5-10 years, but long-term prospects remain uncertain. When NEA, as a single buyer, purchases power from IPPs and trades it with India, the lack of long-term guaranteed buyers can pose significant financial risks. Additionally, while Bangladesh has started receiving 40MW and future expansion is expected, transmission is primarily via the Indian grid, raising concerns about country risk if relations with India deteriorate.

Under the current business structure, NEA bears all risks related to power trade. To mitigate these risks, establishing a business model where power plants directly wholesale to distribution companies or large consumers in other countries or the Exchange Market, bypassing NEA, is necessary. This direct transaction model is expected to involve developers or financiers from India and Bangladesh, contributing to stable power supply in the South Asian region, with each stakeholder benefiting from Clean Export.

(2) Ensuring Domestic Supply Capacity in Nepal

The examination of power development plans and the utilization of surplus power includes considerations of power exports, electrification of heat demand, and the production of green hydrogen and ammonia. From 2029 onwards, surplus power is expected even during the dry season, which could drive Nepal's economic growth. When considering the utilization of surplus power, the government and NEA's role in the power sector is to ensure stable domestic power supply first. However, as demand and economic viability for export power and green hydrogen grow, there is a concern that private operators might focus on overseas projects, potentially jeopardizing domestic supply.

Currently, NEA handles domestic power supply, but as power exports expand, it is crucial to establish mechanisms to ensure domestic demand-supply balance. Particularly, it is important to establish the operational systems that flexibly combine exports and imports utilizing allocation of electricity supply from export to domestic demand or procurement from IEX in case of shortage for supply capacity to domestic demand.

(3) Technical Challenges in Expanding Power Trade

1) Technical Considerations for International Interconnection Lines

Future power trade with India, particularly for international interconnection lines beyond New Butwal, such as Lumki, Koharpur, and Inaruwa, will require considerations for optimizing transmission capacity, controlling power flow and faults on the interconnection lines, frequency adjustment, synchronization, interconnection regulations, and connection points to the Indian backbone system. These considerations will primarily be addressed within the existing framework of the Joint Technical Study Team. However, NEA also needs to enhance its capability to carry out these technical studies, necessitating capacity building in the Power System Department.

2) Understanding the Power Trade Volume in Power Supply-Demand Operation

Power licenses need to be granted in alignment with the progress of transmission line development, but there are frequent comments about the lack of coordination between power and transmission line developers. Specific issues include scenarios where transmission line development is ahead but power generation is delayed, or vice versa. Coordination is principally managed by NEA's Generation Control Department, which needs to collaborate with DoED and hydropower developers. However, there are also comments about insufficient coordination and frequent plan changes. Both NEA and DoED recognize these coordination and project management issues, emphasizing the need for smooth project advancement.

In the coming years, NEA will continue commissioning its hydropower plants, and power trade volumes with India are expected to increase. If NEA fails to control power trade volumes as per the contracts, it will incur penalties under the Deviation Settlement Mechanism with India. Therefore, enhancing NEA's supply-demand adjustment capabilities is also crucial as power trade volumes increase.

3) Seasonal Discrepancies in Generation and Optimization of Generation Plans for Power Export

Nepal's power generation primarily relies on hydropower, excluding some thermal and renewable energy sources. Consequently, there is a significant seasonal variation in power generation, with high output during the rainy season (May to October) and low output during the dry season (November to April). This necessitates power imports from India during the dry season despite ample generation during the rainy season. Nepal is addressing this seasonal generation discrepancy through the development of reservoir-based hydropower plants, but only the Tanahu Hydropower Project is in the construction stage. Even with the development of reservoir-based hydropower, seasonal discrepancies will persist.

Existing project plans primarily focus on domestic supply, with generation plans targeting high purchase rates during the dry season. However, as power exports to overseas markets increase, generation plans must also consider the high power demand period in India and Bangladesh, which corresponds to rainy season in Nepal. These export-oriented generation plans require optimization of supply-demand operation plans and individual generation plans for exportable power across the entire system.

4) Steady implementation of grid development

In order to realize the expansion of electricity exports through hydropower development after 2030, it is necessary to also realize the operation of the domestic grid and interconnection lines. On the other hand, interviews with various stakeholders also raised concerns about the progress of transmission line development.

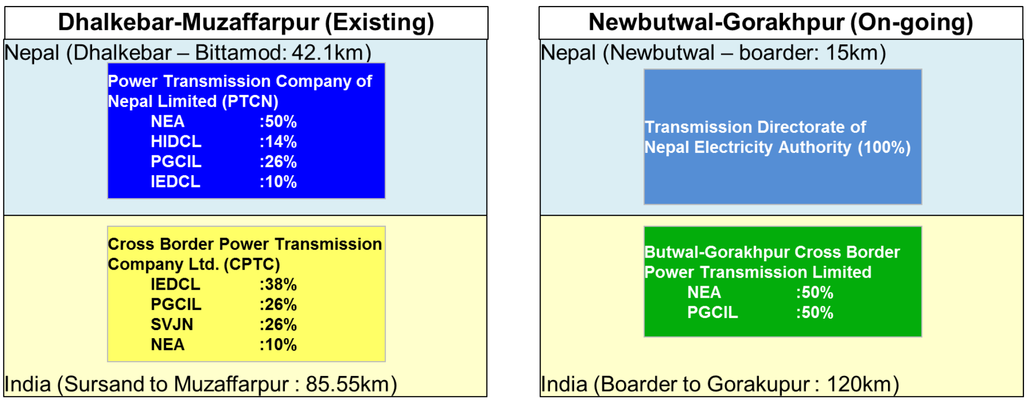
The lead time for the development of the transmission and substation facilities is expected to be about 6 years in total: 2 years for investigation, 1 year for bidding, and 3 years for construction. If the power plant is to be partially put into operation in 2030, it will not be ready in time if the survey is not started at this point. Even if the target year is 2033, when the power plant will be in peak operation, the survey should be started in 2027.

As for the sections that currently have no development prospects, the domestic system is mainly a north-south transmission line along the rivers connecting the West Seti, Sunkoshi, and Arun water systems, and the Bheri - New Damauli transmission line. For the international interconnection lines, future development will be required for the Dodohara (Lumki) - Bareily, Kohalpur - Lucknow, Inaruwa - Purnea, and Dhalkebar - Sitamarhi interconnection lines.

For electricity exports to India and Bangladesh, delays in the operation of power plants or transmission lines are assumed to be compensable, and it is important that grid development is also carried out on schedule.

(4) Development Schemes for International Interconnection Lines for Power Trade

While NEA and RPGCL are expected to be the implementing entities for the 400 kV domestic grid, the international interconnection line will be a joint project with India, so coordination between the two countries, including the project implementation structure, will be important. The development of the interconnector is assumed to be done by dividing the operating companies (Dhalkebar-Muzaffarpur) and by transmission companies (New Butwal-Gorakhpur). Figure 9.2-1 shows this project structure.



(Left: Dividing operating companies, Right: Transmission companies)

Figure 9.2-1 Project development structure for interconnection line

The existing Dhalkebar - Muzaffarpur transmission line was constructed and operated through the establishment of a special purpose company (SPC) in Nepal and India.

For New Butwal-Gorakhpur, which is under construction, the Nepal side is being built by NEA, while the Indian side is being built by an SPC half owned by the PGCIL (Power Grid Corporation of India) and NEA. As with the “400 kV Dhalkebar - Muzaffarpur Transmission Line,” NEA will pay the full development cost of the transmission line as a capacity charge, regardless of the actual amount of power transmission.

In interviews with NEA regarding future development, the Indian side has commented that they would like the structure same as existing Dhalkebar - Muzaffarpur project to be split into separate operating companies. If the division of the project company is assumed, PTCL, which will be the operator of the Nepalese side, will be responsible for completing the development of the Nepalese side. If the development lead time is 6 years, the project will not be operational until 2030 even if it is started now, so it is necessary to coordinate with the Indian side and implement the project promptly.

(5) Institutional Challenges in Expanding Power Trade

1) Restrictions on power plants for export

A condition for exporting electricity to India is that an export permit must be obtained on a power plant-by-power plant basis. To obtain this export permit, a country must conclude a “Bilateral agreement on power sector cooperation” with India, and power from power plants related to countries that have not concluded such an agreement cannot be exported to India. In addition, electricity to be exported to Bangladesh also passes through India, so only power plants that have been approved by India can export electricity.

Since export approvals for each power plant must be applied for annually, there is a risk that NEA will not be able to establish a medium-term outlook for power exports.

2) Open access to Nepalese grid

The Nepalese grid is not open access, and IPPs cannot freely use the grid in Nepal. As a result, IPPs will not be able to trade directly with trading companies in Nepal or with consumers in neighboring countries even if NEA's obligation to purchase the entire amount of electricity is removed. Therefore, it is necessary to establish an open access mechanism for Nepal's domestic grid.

3) Improve commercial and legal capabilities

In addition to the development of hardware, procedures such as the establishment of SPCs by operators in Nepal, neighboring countries, and third countries, PPAs with neighboring countries, setting of transmission tariff, and application for grid connection are necessary to promote export expansion. The only project that has made concrete progress in 2024 is Arun 3, but since this site is being developed by SJVN, an Indian company, there are no particular obstacles to the application of these procedures. On the other hand, in the case of a project led by a Nepalese company, the executing entity must take the lead in these procedures, consultations and negotiations with partners and related organizations in each country.

(6) Results of Nepal-led power generation projects for export

Table 9.2-2 summarizes the current status of export projects for each type of power producer in the future expansion of electricity exports.

Table 9.2-2 Current status of export projects by type of power producer

Item	1) Foreign producers	2) JV between Nepal and overseas producers	3) Nepal producers
Development site	(1) West Seti, (2) SR6, (3) GMR, (6) Lower Arun, (8) Arun 3	(4) Phurkot Karnali, (5) Sunkoshi 3, (7) Lower Arun	N/A
Power Purchaser	Large overseas consumers, trading companies	NEA, large overseas consumers, trading companies	NEA, large overseas consumers, trading companies
Nepal Grid	Individual project will be developed as needed, but in principle, existing facilities are used.		
Interconnection line	Existing facilities utilization		

Source: JICA Study Team

As for the cases of power producers, 1) Only foreign operators accounted for 5 out of 8 cases, and there are no cases of independent development of individual power export projects only Nepal, including NEA. As mentioned in Arun 3, even if an only foreign operators develop a project, it can gain benefits such as free power, regional development, and employment expansion, but its contribution to Nepal's assets and development experience will be small. Therefore, in the future, the 2) model, in which the Nepalese side is also involved, will be increased, and it will be necessary for Nepal company to acquire knowledge and experience in technical studies, finance, commercial affairs, and legal affairs. In the future, it is also expected that Nepal companies will be able to implement projects for export independently in 3).

9.2.2 Expansion of Nepal Power System

(1) Development of Access Roads and Transmission Lines in Major River Basins

1) Cost Burden of Access Road Construction

In the development of hydropower and transmission lines within Nepal, the construction of access roads to project sites is crucial. Hydropower development requires roads capable of transporting heavy equipment, such as construction machinery, turbines, and transformers. These routes often run along river valleys, characterized by steep slopes prone to landslides, and are frequently remote and lengthy. Considering the needs and safety of local residents, multiple routes may be necessary. The costs of these constructions are often borne by the developers of the leading projects in each river basin, which can be a heavy financial burden when considering the project's individual profitability.

2) Securing Transmission Line Routes

For transmission line development in Nepal, lines connecting hydropower plants to the backbone system are often built along north-south routes following the rivers. As with access roads, these river valleys are steep, limiting suitable locations for constructing transmission lines. If these locations are occupied by lines from smaller, easier-to-develop hydropower plants, securing routes for future 400kV, 220kV, and 132kV transmission lines becomes challenging. To avoid overlapping transmission routes, a transmission plan considering the integrated development of river basins is necessary.

3) Development of Access Roads and Transmission Line Routes by the Public Sector

In river basins where development is currently concentrated, such as the Trishuli, Marshyangdi, Likhu, and Bhotekoshi rivers, existing hydropower plants have ensured the necessary road and transmission line routes. However, securing access roads and transmission line routes remains a common challenge in river basins with abundant hydropower potential but less development, such as the West Seti, Karnali, Bheri, Kaligandaki, Dudhkoshi, and Tamor rivers.

The construction of access roads and transmission lines in major river basins also has public works aspects, contributing to regional development. Therefore, measures such as preferential treatment for pioneering developers, incorporation of costs into tariffs, or development by the public sector are necessary.

(2) Need for Integrated River Basin Development**

1) Application of the Integrated River Basin Development Concept

Nepal's rivers originate from the Himalayas and flow into the Terai plains. These lower basins are expected to develop into granaries but also frequently experience flooding. Integrated river basin development is crucial in water resource development and management plans to maximize societal benefits from power generation, water use, and irrigation. However, single-project developments tend to decide project scale and generation plans based on individual site economics. Integrated river basin development, which maximizes each river's hydropower potential through coordinated operation, such as cascade operation contributing to peak generation, is necessary. Additionally, sedimentation and flood control are critical issues in dam and reservoir operations.

In this context, the WECS, with WB support, is formulating "Preparation of River Basin Plans and Hydropower Development Master Plans and Strategic Environmental and Social Assessment." It is desirable to pursue integrated river basin development based on such comprehensive plans.

2) Acquisition Status of Development Licenses

Small-scale hydropower developments sometimes hinder reservoir-based hydropower projects. For example, the Tamor Storage Project (762MW) in the Tamor River basin is impeded by earlier developments like Lower Hewa (7.3MW) and Kabeli A (37.6MW), which affect reservoir capacity. There are concerns about the licensing issue, where promising sites are preemptively occupied through survey licenses. Although measures like license expiration are in place, an integrated river basin development plan is needed.

3) Sedimentation Issues

Sedimentation is a significant challenge in hydropower development in Nepal. Despite steep river slopes, many riverbeds have thick sediment layers. Sedimentation increases construction costs due to higher excavation volumes and dam heights, reduces effective reservoir capacity, decreases generated power, and raises maintenance costs due to turbine wear. Sedimentation management, including annual desilting, is particularly crucial for smaller reservoir-based plants. However, there is insufficient research on sedimentation volume and monitoring, and the status of reservoir sedimentation in existing plants is not well understood. Analyzing landslide potential and sediment sources in watersheds is also lacking. These sedimentation issues require integrated watershed management, including soil conservation and coordinated desilting, which is currently not adequately analyzed.

4) Climate Change Measures in Hydropower Development

Nepalese rivers originate from Himalayan glaciers, with ICIMOD (International Centre for Integrated Mountain Development) highlighting the risks of glacier melt due to climate change. In February 2021, a flood in the Dhauliganga River, attributed to glacier melt, resulted in 200 deaths. Nepal lacks a technical committee to address such development risks related to climate change, necessitating assessments like GLOF and Dam Break Analysis in hydropower projects.

Climate change also impacts snowmelt and precipitation patterns, affecting river flow and reducing power generation during droughts. These risks should be considered on a river basin level rather than individual projects.

(3) Enhancing Tunnel Planning, Design, and Construction Capabilities

Many ROR and PROR projects in Nepal involve constructing water conveyance tunnels, given the high-altitude, steep river sites. Additionally, projects like the Dudhkoshi Storage HEP and Bharbhung HEP plan to secure head using diversion tunnels. However, as previously mentioned, Nepal's mountainous geology includes weak layers, making tunnel construction challenging. Besides water tunnels, access road tunnels are also necessary in mountainous terrain.

Enhancing "quality" and "quantity" capabilities in planning, designing, and constructing tunnels is essential.

(4) Enhancing System Planning Capabilities

Nepal's hydropower plants are distributed across various river basins, while major demand centers like Kathmandu, Pokhara, and New Butwal are centrally located, causing voltage rise at power generation points. Future plans include a grid of east-west 400kV transmission routes and north-south routes in each river basin, necessitating phased voltage increase operation considerations. Some northern routes and 400kV substations might become redundant. One example is the potential reduction in the transmission capacity from remote areas to demand centers such as Kathmandu, due to changes in the power generation development situation. The roles of 220kV (power lines) and 132kV (current backbone system) voltage levels need reevaluation. For example, regarding the demand system, the voltage levels will be structured in three stages: 400 kV / 132 kV / 33 kV or 11 kV, and the existing 220 kV and 66 kV will not be increased beyond the current levels. This approach will reduce the number of transformers needed and help stabilize the voltage. Urban centers with high demand, like Kathmandu, require individual system planning.

(5) Integration of Renewable Energy into the Grid

The development of renewable energy in Nepal is concentrated in the southern Terai plains, with significant progress expected post-2023. These areas currently have 132kV or 66kV systems, and solar power plants are expected to connect to these systems. However, there are concerns about local grid instability due to the rapid output fluctuations of solar power in some concentrated development areas. Future system planning must consider these impacts and implement appropriate measures.

(6) Need for Mitigation Measures for Environmental and Social Impacts Accompanying Development

At the stages following the F/S, it is desirable to appropriately conduct environmental and social considerations in accordance with local laws such as EPA 2019, EPR 2020, and good practices, taking into account the following points:

1) Cumulative Impact Assessment for the Entire Basin

Since the current local laws and regulations in Nepal (EPA 2019, EPR 2020, etc.) do not specifically require cumulative impact assessment, there are cases that cumulative impacts from the entire watersheds' viewpoints are not taken into account during impact assessments and mitigation measures development. Due to the varying progress of development plans in each river basin in Nepal, it is necessary to evaluate cumulative impacts[106] in each basin and consider appropriate mitigation measures from a watershed management perspective. This is especially important in basins with concentrated development plans, such as the Gandaki River Basin, which has many existing power plants and is close to demand centers. Early-stage development considering cumulative impacts is desirable.

2) Impact on Ecosystems

Hydropower projects can alter river flow and water levels due to water intake, storage, and release, potentially affecting aquatic life and waterbirds. The construction of dams and intake weirs can also disrupt river continuity, hindering the migration of fish species, which are the issues in Nepal. Where these impacts are expected, it is necessary to assess the effects on environmental flow and ecosystems and incorporate them into environmental management and monitoring plans. Additionally, it is essential to recognize and plan for risks associated with climate change, such as GLOF.

3) Appropriate Compensation and Benefit Distribution for Land Acquisition and Resettlement

One of the challenges in hydropower development in Nepal is the compensation and benefit-sharing for land acquisition and resettlement, which has occasionally led to criticism from NGOs and complaints from residents. It is desirable to develop and implement a resettlement plan, including compensation payments based on the reacquisition price. Particularly in projects involving significant resettlement due to reservoir-based hydropower plants or transmission lines, sufficient budget and implementation systems must be secured. Moreover, benefits from power development, such as those from power projects and power trade with neighboring countries, often concentrate in urban areas like Kathmandu and Pokhara, while the directly impacted areas are around the project sites. It is also important to consider correcting these benefit disparities.

4) Consideration for Indigenous Peoples

The "National Foundation for Development of Indigenous Nationalities Act" in Nepal designates 59 ethnic groups as indigenous peoples, with many residing in mountainous areas where hydropower projects are planned. Nepal has also ratified the International Labour Organization's Indigenous and Tribal Peoples Convention, 1989 (No. 169). However, there are still few cases where the FPIC are obtained in the planning of hydropower projects. It is recommended to conduct meaningful consultations with the affected indigenous peoples from the early stages of planning and obtain agreement based on the principles of FPIC.

[106] Impacts caused by concentration of multiple similar projects in a certain area. For example, cumulative impact of multiple hydropower projects being developed in the same river basin should be evaluated from the perspective of river basin management; and the impacts on river flow and migratory fish should be appropriately managed and monitored.

9.2.3 Business Structure of Power Sector

(1) Strengthening Government Organizational Structure in the Power Sector

Nepal's total installed capacity was 2,684 MW as of 2023 but is expected to reach 35,591 MW by 2040. Progresses in power source and system development are anticipated from 2025 upto 2030, calls for efficient conduct of surveys, design, and construction. The Nepalese government need to handle approvals, control progress management, and execute administrative processes for power development in efficient manner. Human resource development within government organizations involved in power development is therefore an urgent topic. The following describes the specific needs for NEA, VUCL, and other institutions:

1) NEA

NEA owns development rights of projects like Lower Seti (126 MW), Dudhkoshi Storage HEP (835 MW), Uttarganga Storage HEP (828 MW), and Chainpur Seti HEP (210 MW) in addition to several ongoing projects such as Upper Trishuli 3B (37 MW) and Tanahu (140 MW) with its subsidiaries. Additionally, new developments like Sunkoshi 3 HEP (680 MW) and Syarpu Lake Pump Storage (334 MW) are under discussion.

System development requires the establishment of 400 kV, 220 kV, and 132 kV backbone systems and distribution networks. International interconnection for power trade will also be integral. NEA needs the capability to execute these projects without fail.

2) VUCL

VUCL is progressing with the development of projects like Phukot Karnali, Mugu Karnali, Nalgad, and Jagdulla. However, VUCL heavily relies on external consultants for F/S implementation. VUCL is a relatively new organization compared to NEA, with few experienced engineers for projects in the construction phase, which is a concern.

3) Other Institutions

Other than developers, institutions like DoED, managing licenses, and ERC, overseeing legal frameworks including PPAs, are in need to fortify staff when power and system development expands. Strengthening capabilities in technical fields such as hydropower and transmission, as well as in financial and legal fields related to PPAs and contractor agreements, is an essential.

(2) Clarifying Roles and Restructuring Government Enterprises

Several organizations within the government, such as MoEWRI (including DoED and ERC) and IBN, and power generation companies like NEA and VUCL, and transmission companies like NEA and RPGCL, are overlapping their roles and results in inefficiencies. The 2019 PPP Investment Act designates IBN as the primary interface for projects over 200 MW, but IBN faces a shortage of technical staff involved in power development hence requires collaboration with MoEWRI. However, the specifics of this collaboration are unclear. Similarly, the role demarcation between NEA and VUCL/RPGCL is not well-defined, often decided on a case-by-case basis.

The revised Electricity Act, currently under parliamentary review, includes provisions for the separation of NEA's transmission and distribution functions. Following the enactment of this law, once it happens, discussions on the separation or integration of NEA, VUCL, and RPGCL are expected to accelerate. On the other hand, the role distribution and collaboration between MoEWRI and IBN are not currently under consideration, possibly due to the lack of relevant projects. Implementing pilot projects defining respective roles and collaboration methods between these organizations might be a viable approach.

(3) Shortage of Private Sector Developers in the Power Sector

1) Hydropower Developers

The shortage of private developers investing in hydropower projects is a concern, particularly for mid-to-large-scale projects requiring strong financing partners. While existing projects under construction or under survey have developers, finding local or attractive international partners for new large-scale projects remains challenging. Local private companies are already involved in various projects, making additional investments difficult, while local government companies face uncertainties in role distribution with NEA. Attracting international developers, especially for export-focused projects, requires creating and improving a conducive investment environment.

2) Contractors

A shortage of contractors is also anticipated. It is expected that the shortage of construction companies, as well as financial institutions and hydropower developers, will become apparent in the future. The construction industry's share of the total GDP will remain at around 5.1% as of fiscal 2021, which is somewhat lower than in other countries. However, the development costs expected for power development in Nepal are expected to be at the same scale as they are now. Meeting construction demand of power project, project developer needs to secure a large sum of workforce, from skilled to general laborers, with improved wages and working conditions.

(4) Need for PPA Development

Hydropower development requires significant investment, making it difficult for the Nepalese government alone to secure the necessary funds, highlighting the need for private investment. Efforts to attract private investment include the revision of NEA’s PPA standards in 2017 and the establishment of new PPA conditions by ERC in October 2019. However, risks from the perspective of international investors remain, hindering significant growth in hydropower investments. These risks include:

- Uncertainty in the legal framework
- Mechanisms for determining and revising purchase prices
- Implementation of take-or-pay provisions (and government guarantees for purchases)
- Protection of foreign investors’ rights (development rights, land use rights, access to various infrastructures, collateral rights, etc.)

Additionally, the 2019 PPP Investment Act designates IBN as the point of contact for IPP development rights over 200 MW, adopting a bidding method based on developer proposals (Swiss Challenge). This increases the risk of losing bids for developers, reducing development incentives. Although a currency hedge method was implemented in 2022, it has seen limited application.

Alongside these general IPP-related legal risks, the development of reservoir-based hydropower projects by private investment also poses specific risks. Reservoir-based projects capable of annual adjustment require NEA, as the system operator, to direct power generation based on supply-demand balance. However, private developers cannot guarantee their generation volume, making it difficult to secure a stable financial base. To promote private investment, introducing payment methods based on capacity (kW) rather than energy (kWh) is desirable. Additionally, given the large total project costs for reservoir-based hydropower, considering development schemes like the vertical separation model proposed in previous PPP studies is necessary.

9.2.4 Finance / Private Investment

(1) Domestic Fundraising

The required investment amounts (CAPEX (Capital Expenditure) and OPEX (Operating Expense)) for realizing IPSDP are estimated as follows:

Table 9.2-3 Required Investment Amount for Realizing IPSDP

Category	Total	Government	Private
CAPEX	USD 80,195 Mil.	USD 31,119 Mil.	USD 49,076 Mil.
OPEX	USD 18,998 Mil.	USD 5,563 Mil.	USD 13,435 Mil

Source: JICA Study Team

Funding for the realization of the IPSDP based on the above table is being undertaken both domestically and internationally. The following describes the challenges each of these efforts faces, from the perspective of domestic and international fundraising, and assistance from development aid agencies.

Nepal has 20 commercial banks (Class A) and 17 development banks (Class B), but current credit capacity of these banks, cannot cover the required amounts. Although development licenses have been granted for many projects, many of them have been unable to raise funds and are effectively stranded. If lending to IPPs is based on project finance basis, the number of financial institutions executing these roles is limited. Hence, enhancing the capacity of local financial institutions to supply funding to projects are essential to realize IPSDP.

In addition, hydropower development in Nepal relies heavily on imports for civil engineering materials and equipment such as concrete and construction machinery, in addition to electrical equipment. Even in development funded by IPPs, the power purchase fee for the foreign currency investment must be paid in foreign currency. For this reason, in order to realize the IPSDP scenario, it is necessary to secure sufficient foreign currency to cover these payments. This issue involves a result-oriented or project-environment oriented issues. Given Nepal's limited foreign currency reserves, a practical approach in the short term is to leverage international aid (sovereign and non-sovereign loans) while promoting power exports and foreign currency acquisition.

(2) Need to Promote Overseas Financing

As noted, the primary requirement for realizing IPSDP is to increase business investment by local companies and enhance domestic fundraising capabilities. However, the annual investment required for IPSDP is more than three folds of current levels (2022-2023), making it practically impossible to meet these needs domestically. Therefore, attracting foreign investors is critically important for realizing IPSDP.

As of 2024, most development rights for hydropower are held by Nepalese developers, with a few Indian companies. Projects over 50 MW require at least USD 80 million, and many are stalled due to financing issues. Major infrastructure development groups in Nepal can raise substantial funds, but overall financing is still insufficient.

Challenges for foreign investors and financial institutions considering investments in Nepal's power sector include:

- Political Stability
  Frequent changes in senior officials make leadership and accountability unclear.

- Legal and Procedural Frameworks
  The pending revised Electricity Act and frequent changes to procedures lack clarity and transparency.

- Contractual Risk Allocation
  IPP contract terms may be unacceptable from the perspective of foreign investors.

- Protection of Foreign Investors
  Insufficient legal frameworks to protect the rights of foreign investors, including development rights, land use rights, and access to infrastructure.

- Project Financing
  Nepalese financial institutions struggle to offer competitive financing, forcing foreign investors to rely on international financial institutions, which are cautious about lending to Nepalese projects.

To accelerate foreign investment, it is essential to address listed issues individually and improve the investment environment.

(3) Support from Development Aid Agencies

Collaboration with development aid agencies is crucial for realizing IPSDP. Nepal's power sector already receives support from multiple agencies such as JICA, WB, ADB, and USAID. Effective utilization of these supports to enhance funding capabilities and develop government officials' skills is essential. The support includes:

- Financial Cooperation: Program loans, project loans, and two-step loans.
- Investment and Lending for Private Entities: Investments without government guarantees for private companies and financial institutions.
- Technical Cooperation: Execution support for IPSDP, capacity building, and transaction advisory.
- Expert Dispatch: Providing advice to MoEWRI, NEA, and IBN.

It is vital to avoid inefficiencies or contradictions caused by overlapping support from different international agencies. Thus, active involvement and comprehensive management by the Nepalese government, along with strengthened information sharing and coordination among development aid agencies, are critical.

9.2.5 Energy Transition

(1) Promoting Domestic Electrification

The power demand forecast in IPSDP includes policies for electrification such as EVs and E-cooking, presenting achievable figures. Given the characteristics of hydropower, the development capacity significantly exceeds demand, planning for export. Further demand stimulation, such as industrial promotion utilizing cheap electricity, is desirable.

Table 9.2-4 Power Demand Forecast for EV and E-Cooking

Policy / Year	2025	2030	2035	2040
EV[GWh]	190	724	1,464	2,233
Electric cooking[GWh]	904	2,649	3,146	3,649

Source: JICA Study Team

By 2040, power demand from EVs and E-cooking will reach 2,233 GWh (3.6% of total) and 3,649 GWh (5.8% of total) respectively, which is significant. Promoting electrification reduces fossil fuel consumption, contributing to CO_2 reduction, improving energy self-sufficiency, and preventing foreign currency outflows.

The primary energy supply in 2021, excluding traditional biomass, consisted of hydropower at 34,321 TJ (16%), renewable energy at 5,403 TJ (3%), coal at 49,970 TJ (23%), and petroleum products at 122,738 TJ (58%). More than 98% of the coal and all petroleum products were supplied through imports from India.

For Nepal, which relies on India for fossil fuel procurement, promoting electrification, including replacing boiler-based heat demand with heat pumps, is crucial.

(2) Legal Framework and Supply Chain for Green Hydrogen Production

Nepal has significant potential for producing green hydrogen and other carbon-neutral fuels due to its abundant hydropower resources. However, a supply chain for hydrogen use is not yet established. Although MoEWRI formulated a Green Hydrogen Policy in 2024, preferential measures are yet to be developed. Further examination of these measures is necessary.

9.3 REQUIRED TRANSFORMATIONS AND FUTURE OUTLOOK FOR IPSDP

This Section clarify the current business structure of power sector based on recognition of challenges and considers required transformations and future outlook for IPSDP.

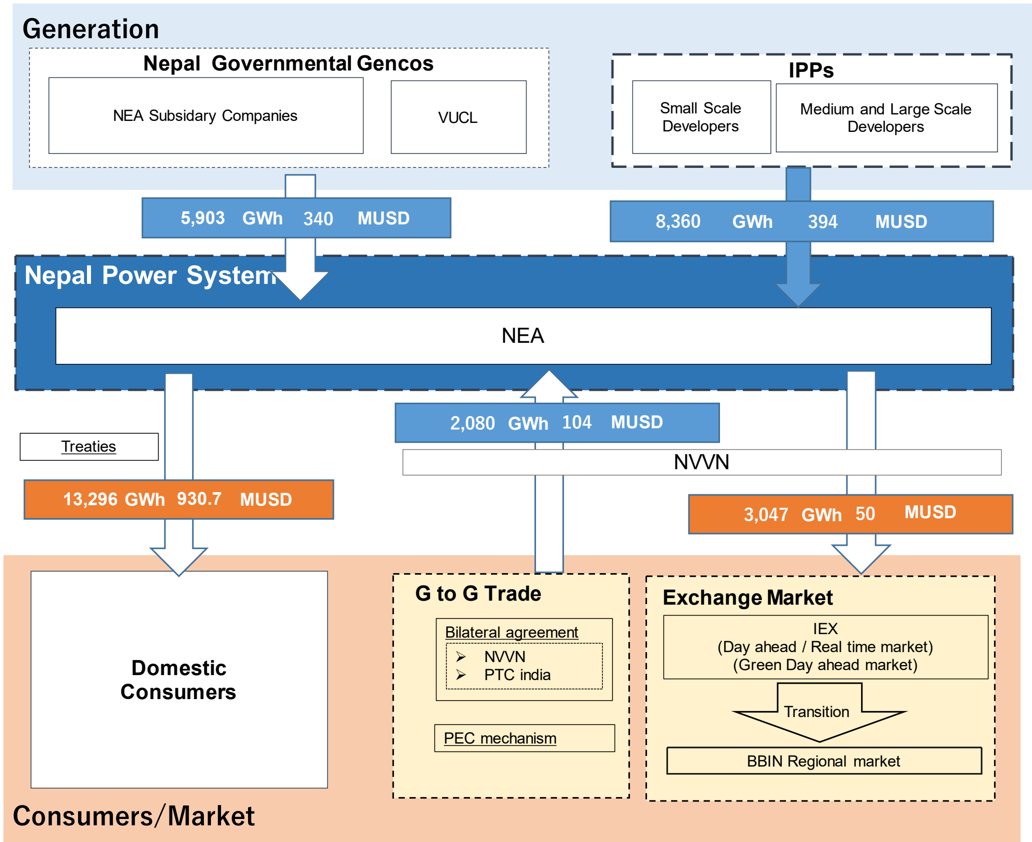
9.3.1 Current Power Business Structure

Figure 9.3-1 illustrates the current business structure of power sector in 2023. NEA, the vertically integrated power company, functions as a single buyer, purchases power from generation companies and handles domestic and export power sales.

Based on challenges described in previous section, the vulnerabilities of this business structure are consolidated below;

- Financial risk is concentrated in NEA, as it functions as the single buyer.
- NEA's dual roles in generation and transmission/distribution lack transparency in decision-making processes and financial performance.
- There is unclear role distribution between NEA and historical public power entities like VUCL and RPGCL, potentially leading to operational inefficiencies.
- NEA's near-monopoly in transmission/distribution results in a lack of competition, potentially increasing costs.

- With anticipated activation of power trade with India and Bangladesh, a strategic and speedy decision-making organizational structure is required.



Source: JICA Study Team

Figure 9.3-1 Business Structure of the Power Sector in 2023

9.3.2 Five Transformations Needed for IPSDP

As of 2024, the power sector has achieved stable power supply and better financial conditions owed to development over the past decade. However, to achieve the development outlined in IPSDP, it is necessary to solve issues shown in previous section. Following five transformations are proposed for realization of IPSDP:

(1) Expansion of Clean Export
(2) Significant Scale Expansion of the Power System
(3) Reform of the Power Sector
(4) Expansion of Finance/Private Investment
(5) Energy Transition

(1) Expansion of Clean Export

As a nature of outputs from hydropower, surplus electricity during the rainy season is unavoidable. By 2030, approximately half of the annual generated power will be supplied for domestic demand and the other half for export. Hence, development of power sector is synonymous with expansion of Clean Export. The MoEWRI Roadmap and Workplan targets 15GW of exports by 2035.

The current business structure concentrates power purchases in NEA which contains various risks related to export expansion. Reduction of these risks involves establishing commercial flow through NPTCL and allowing IPPs to engage in PPAs with distribution companies or consumers in India and Bangladesh to sell electricity to them directly. NEA can collect wheeling charges for transmission lines which can recover investment costs of power system while avoiding purchase risks. Such direct trade would also attract new players, increase foreign currency inflows and contribute to expand the business in power sector.

(2) Significant Scale Expansion of the Power System

Between 2023 and 2040, the power system in Nepal will achieve significant expansion. Domestic power demand (GWh) will increase 6.7 times, generation capacity (MW); 16.2 times, and the length of 400kV backbone transmission lines (km); 262.5 times. Cumulative investment in the power system will reach 61,750MUSD by 2040 with an annual average of 3,632MUSD.

Developing the power system will promote economic growth and navigate Clean Export to a pillar of the export industry. As it is insufficient not only to utilized existing resources but also to strong initiatives as the growing industry of Nepal and attraction of vast foreign investment.

(3) Reform of the Power Sector

To implement IPSDP and achieve its goals, power sector reform is essential. Specific considerations include:

- Strengthening ERC functions
- Unbundling NEA's generation, transmission, and distribution functions and introducing competition
- Determining the structure of public entities like VUCL and RPGCL post-NEA unbundling
- Segregating NEA's generation business from private IPPs
- Introducing open access and transmission systems in transmission business
- Operationalizing NPTCL for domestic and international power trade

These reforms require further capacity development of government officials.

(4) Expansion of Finance/Private Investment**

Sustainable development of Nepal's power sector requires robust foreign investment and financing. Hydropower development as per IPSDP involves substantial capital, necessitating active attraction of foreign investors. Potential sources include loans from international aid agencies like ADB and investments from private investors.

Essential conditions for attracting private investment include:

- Stability of government finances and macroeconomics
- Legal frameworks
- Protection of foreign investors' rights
- Standardized RFPs and PPAs
- Enhanced financing options for private developers
- Strengthened project formation and implementation capabilities of government officials
- Ensuring competitiveness, transparency, and fairness

Government efforts to create a conducive investment environment, coupled with seed projects led by international aid agencies, will foster private investment, realizing large-scale hydropower development as envisioned in IPSDP.

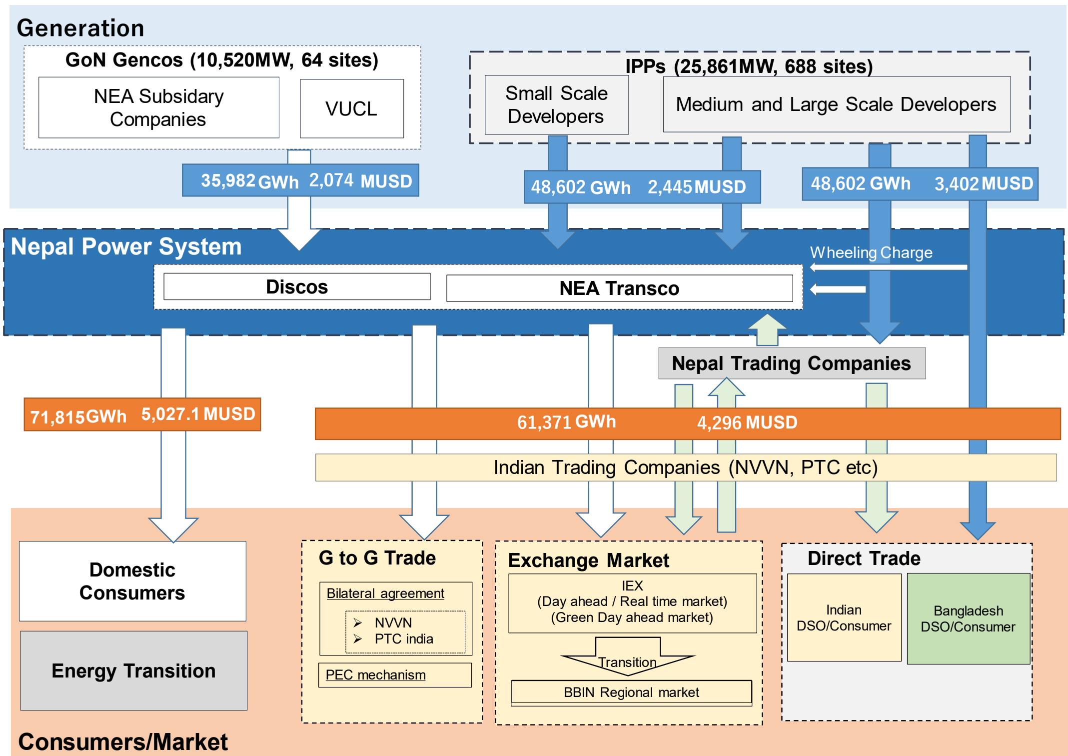
(5) Energy Transition

Achieving Net Zero 2045 is an important mission for the power sector. Nepal has significant potential to contribute to CO_2 reduction domestically and in neighboring countries with its abundant hydropower resources. Promoting electrification policies, such as EV and E-Cooking, and utilizing carbon-neutral fuels like hydrogen is essential.

Reducing fossil fuel use will enhance energy security by decreasing dependency on primary energy from India. Production of carbon-neutral fuels like green ammonia offer potential for fertilizer procurement and exports to India for combustion of thermal power plants. It is important to utilize surplus electricity for carbon-neutral purposes by 2040.

9.3.3 Future Business Structure of the Power Sector

Figure 9.3-2 illustrates the envisioned business structure of the power sector in 2035, reflecting the five required transformations.



Source: JICA Study Team

Figure 9.3-2 Future Outlook for the Power Sector in 2035

In 2035, power sector in Nepal will see dramatic expansion in terms of supply-demand scale, clean export, institutional structure and cash flow. The installed capacity and number of power plant sites will be 7,497 MW and 58 sites for government entities such as NEA and VUCL, and 20,718 MW and 654 sites for IPPs. The power system will have a 400 kV backbone transmission lines from east to west across the country with a total length of 1,818 km and six 400 kV international interconnection lines.

The amount of power market business and sales revenue will also increase significantly. Domestic consumption will be 39,966 GWh (44.3%) with a revenue of 3,311 MUSD and Clean Export will be 50,259 GWh (55.7%) with a revenue of 3,518 MUSD, out of the total sales volume of 90,224

GWh. Clean Export will particularly account for 6% of the national GDP, developing into an export industry that would earn foreign currency. The institutional structure of power sector will also be significantly transformed with the establishment of power trading companies alongside the unbundling of generation, transmission, and distribution.

Nepal has substantial potential for energy transition including CO_2 reduction in neighboring countries through Clean Export. It is also expected to promote electrification of energy derived from fossil fuels and the utilization of green hydrogen and ammonia.

9.4 RECOMMENDATIONS FOR IPSDP

This Section propose recommendations for power sector in short and middle terms.

The milestones and pathways presented in Section 9.1 suggest that technical studies for Clean Export, strengthening and attracting IPPs, securing domestic and international financing, power system planning and capacity development of human resources must be completed within the next few years to achieve large-scale development beyond 2030. In other words, immediate actions are required to realize massive expansion of power sector. It is critical to deal with these issues but these tasks involve various fields and domestic and international agencies, making it challenging to achieve solely through the activities of individual agencies and requiring various adjustments.

Considering the limited resources of relevant agencies such as MoEWRI, DoED, ERC, NEA, and development partners, it is also important to focus on priority issues that Nepal must address urgently. As comprehensive topics have been covered by “Energy Development Roadmap and Work Plan in 2035 (MoEWRI)”, important issues are highlighted in recommendations for IPSDP.

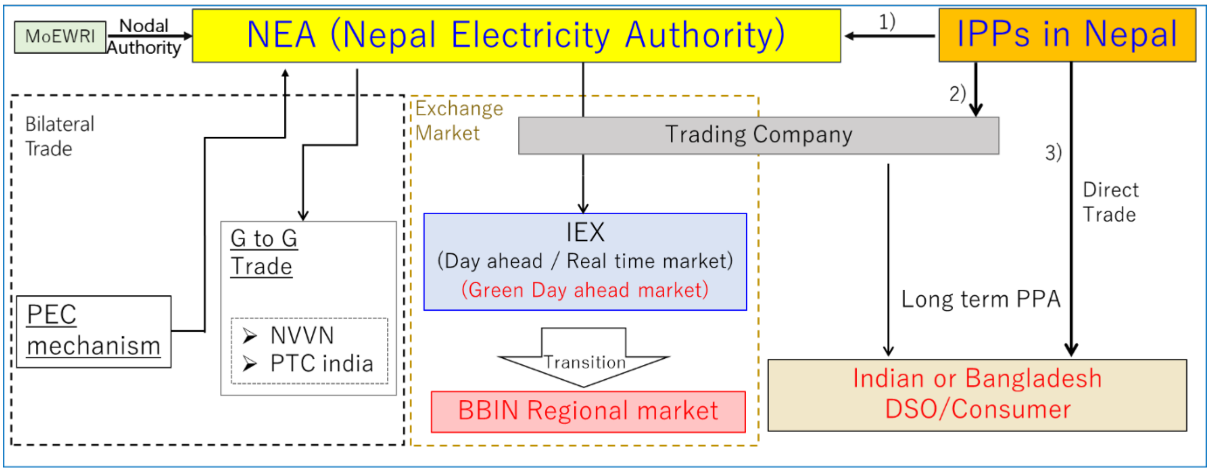
9.4.1 Power Trade

Extensive concentration of sales and purchase trade on NEA is a significant issue for IPSDP because NEA is forced to shoulder a lot of risks in power trade. It is also important to establish institutional arrangements such as establishing distribution channel between power trading companies and IPPs and power companies/customers in India and Bangladesh, granting preferential treatment for clean energy, and applying for power grid connection in each country in order to mitigate the concentration of wholesale to NEA.

(1) Diversification of power trade

Currently, NEA acts as a single buyer, purchasing all electricity generated in Nepal and then exporting the electricity to India. Considering that the amount of electricity traded will expand in the future, there are concerns that the risks (business partners, trading price) of NEA purchasing all electricity domestically will become too large. And in order to promote power development through IPPs, etc., options that do not rely on PPAs (Power Purchase Agreement) with NEA are necessary. As an option that does not rely on PPA with NEA, we think it will be necessary to introduce a system where IPPs in Nepal can directly conduct bilateral agreements with IEX and customers. Possible future trading schemes are shown in Figure 9.4-1.

IEX also has a Green Market that traded electricity derived from renewable energy sources, which is traded 10% higher than the regular market. As mentioned above, India plans to continue to increase its procurement of electricity derived from renewable energy sources, and future market expansion can be expected. In addition to IEX, it will be necessary to conclude long-term contracts (PPAs) with power distribution companies and large customers in India and Bangladesh in order to secure long-term stable power export.



Source: JICA Study Team

Figure 9.4-1 Trading scheme in the future

Regarding trade with Bangladesh, there are plans to build a direct interconnection line between Nepal and Bangladesh. And considering that IEX is expected to be operated as a wide-area power exchange in South Asia, the idea of Bangladesh joining IEX will contribute to an increase in the volume of electricity trading between Nepal and Bangladesh, albeit indirectly. Even if Bangladesh participates in IEX, the existing transmission lines will not have available capacity, so the transmission line between India and Bangladesh will need to be expanded.

When looking at electricity trading from the perspective of a power generators, the supplier and the price at which electricity is sold are important factors to consider when examining business feasibility. Currently, PPAs sell electricity price to NEA domestic customers at an average of about 5.0 cents/kWh in 2022/23, and to exporters at 7.0 cents/kWh, the latter being the higher price.

Power generators need to consider both domestic trading and electricity exporting as wholesale customers. We propose the following three specific schemes of electricity wholesale customers.

1) is conventional trading, and 2) and 3) are new forms of trading that assume electricity export.

1) NEA
2) Power Trading Companies
3) Direct to DISCO (Distribution Company)/customer in India/Bangladesh

1) is a conventional scheme of trading that is completed through domestic transactions with NEA. Since NEA distributes the purchased power to the domestic retail market and the surplus to India, the generators are not directly involved in power trade.

Although the purchase price will be lower for the generator, it is assumed that this will continue to be the mainstream scheme for small and medium-sized power generation projects in Nepal, as it does not require any administrative procedures such as grid connection applications or PPAs with customers in other countries.

2) is a scheme through power trading companies. In the future, Nepal's Electricity Act will be amended to allow power trading business, and it is expected that the function of power distribution, which NEA is responsible for, will be partially transferred to Nepal Trading Companies. NEA has established NPTCL, the first trading company in Nepal, in 2021, and NPTCL is expected to operate this trading business for the time being. The power generation companies will be able to choose whether to use the PPA with the power trading companies as the price at which they sell electricity,

or whether the price will be linked to the market.

3) is a scheme in which power generation companies deal directly with power distribution companies and major customers in India and Bangladesh, and it offers economies of scale in structuring project financing with the participation of investors from various countries.

There is no restriction that only one scheme of trading should be selected for each project, but flexible combinations are expected to be possible. For example, during the dry season, electricity could be sold to Nepal through NEA in the scheme of 1), and during the rainy season, electricity could be sold to India and Bangladesh in the scheme of 2) and 3). If this scheme of trade is possible, the power generation plans required, especially for medium to large scale projects, are expected to change.

Table 9.4-1 Comparison by Electricity Supplier

Scheme	1) NEA	2) Trading Company	3) Direct Trade
Purchaser	NEA	Trading Company	Large consumers in overseas
Selling Price	PPA with NEA	PPA with Trading Company Market Price	PPA with Consumers
Pros	- Purchase volume and price are secured. - There are transmission costs only within Nepal.	[PPA] - Purchase volume and price are secured. [Market] - Electricity can be sold when surplus power is generated.	- Purchase volume and price are secured. - IPP can choose the customer with the best contract conditions by themselves.
Cons	Limited amount of NEA purchases.	The purpose and function of the Trading Company has not yet been determined.	- IPPs need to secure their own customers - Transmission costs are incurred outside of the Nepal in addition to that of within Nepal

Source: JICA Study Team

(2) Guarantee of domestic electricity supply

In order to ensure the supply of electricity to the domestic demand, it will be necessary to require a certain amount of domestic supply throughout the year when granting a license to each power producer.

At the time of construction of the power plant, the amount of supply required for domestic use will be taken into consideration based on the projected future domestic demand in Nepal. By requiring a certain amount of domestic supply throughout the year, including the dry season, it will be possible to ensure a stable supply of electricity even if domestic demand increases in Nepal in the future. Electricity in excess of a certain amount of domestic supply can be traded directly with trading companies and distribution companies/larger customers in India/Bangladesh.

For this mechanism to work, close coordination between DoED (Department of Electricity Development), which grants licenses to power generators, and NEA, which is in charge of supply and demand planning in Nepal, is necessary to determine which licenses to grant, but currently there is no good coordination between DoED and NEA. In addition to this, it is necessary for NEA to appropriately formulate medium- and long-term supply and demand plans. Currently, NEA's capacity to formulate supply and demand plans is low, so it is necessary to improve NEA's supply and demand planning capacity.

The role of the Trading Company will mainly be to purchase surplus power from NEA and IPPs and sell it to IEX and other markets, but if domestic supply cannot be secured, a mechanism to procure power via the Trading Company can be secured to ensure stable domestic supply capacity.

9.4.2 Promotion of Pioneer of Hydropower Project in River Basin

This Section suggests the promotion of future development of hydropower projects from the aspect of progress of implementation in each river basin.

(1) Organization of Hydropower Development Sites and Progress in IPSDP

Table 9.4-2 organizes the installed capacity and progress of hydropower development sites in each river basins listed in IPSDP. Status is categorized based on DoED classifications into: a) Operation, b) Construction (Construction License, Application for Construction License), c) Survey (Survey License, Application for Survey License), and d) GoN. The gray hatch indicates over 50% completion in categories a) + b), highlighting river systems with substantial progress in operation and construction. It shall be noted that Tila Nadi in the Karnali basin and Tamor in the Koshi basin have seen no actual progress due to the expiration of Construction Licenses or project suspensions.

Table 9.4-2 Capacity of Hydropower Development Sites by River System and Progress in IPSDP (MW)

River		a) Existing (Operation)		b) Committed (Construction)		c) Prioritized (Survery)		d) Optimized (GON)		Total
Karnali	Karnali	11.9	0.2%	1,068.4	22.3%	2,888.5	60.3%	821.1	17.1%	4,789.9
	Tiala Nadi	0.0	0.0%	621.7	83.1%	126.6	16.9%	0.0	0.0%	748.3
	Seti	12.0	0.7%	385.5	22.8%	236.4	14.0%	1,059.0	62.6%	1,692.9
	Bheri	0.0	0.0%	644.3	22.7%	1,569.1	55.4%	618.8	21.8%	2,832.1
Gandaki	Kali Gandaki	217.5	20.8%	819.0	78.5%	6.7	0.6%	0.0	0.0%	1,043.2
	Modi Khola	45.0	20.1%	175.0	78.2%	3.8	1.7%	0.0	0.0%	223.8
	Badigad Khola	7.5	0.6%	898.1	68.0%	35.0	2.7%	380.3	28.8%	1,321.0
	Myagdi Khola	0.0	0.0%	250.7	86.1%	40.4	13.9%	0.0	0.0%	291.0
	Seti Gandaki	94.5	10.0%	621.5	66.0%	225.1	23.9%	0.0	0.0%	941.1
	Marshandi	255.3	13.4%	1,509.8	79.3%	139.7	7.3%	0.0	0.0%	1,904.8
	Budhi Gandaki	13.5	0.6%	950.4	40.6%	174.6	7.5%	1,200.0	51.3%	2,338.4
	Trishuli	134.5	10.1%	1,075.0	80.6%	123.5	9.3%	0.0	0.0%	1,333.0
	Other Tributaries	76.4	76.2%	7.0	7.0%	16.8	16.8%	0.0	0.0%	100.2
Koshi	Sun Koshi	17.5	2.3%	38.5	5.1%	19.3	2.6%	680.0	90.0%	755.3
	Indrawati Nadi	10.5	20.8%	29.1	57.6%	10.9	21.6%	0.0	0.0%	50.4
	Balephi Khola	4.2	1.2%	307.7	89.8%	30.8	9.0%	0.0	0.0%	342.7
	Bhote Koshi	89.3	27.3%	233.4	71.5%	3.7	1.1%	0.0	0.0%	326.3
	Likhu Khola	131.8	33.9%	239.0	61.5%	18.0	4.6%	0.0	0.0%	388.8
	Tama Koshi	603.4	26.2%	1,249.2	54.3%	51.0	2.2%	396.5	17.2%	2,300.0
	Dudh Koshi	27.1	1.2%	857.8	38.9%	971.1	44.0%	350.0	15.9%	2,206.0
	Arun	33.2	1.0%	1,915.9	55.1%	1,525.9	43.9%	0.0	0.0%	3,475.1
	Tamor	95.3	5.2%	1,331.9	73.2%	392.9	21.6%	0.0	0.0%	1,820.2
	Koshi DS	155.5	28.3%	59.3	10.8%	335.0	60.9%	0.0	0.0%	549.8
Other Rivers		173.6	9.1%	309.7	16.3%	1,088.6	57.1%	334.0	17.5%	1,905.9
Total		2,209.5	6.6%	15,597.8	46.3%	10,033.4	29.8%	5,839.7	17.3%	33,680.4

Source: JICA Study Team

Among the three major rivers, development have been relatively advanced in Gandaki and Koshi rivers. Particularly, Gandaki River with Seti, Marshandi, and Trishuli has many sites under construction. Conversely, there are many river systems undeveloped such as Karnali River, West Seti River, Bheri River, Dudhkoshi River and Tamor River despite having abundant hydropower potential. These underdeveloped river basin account for 53% of the total development capacity and it is an important and urgent issue to realize the development outlined in IPSDP.

(2) Development of Pioneer of Hydropower Projects in River Basin

The main reasons for the lack of development in these river basins are assumed to be supply risk and insufficient related infrastructure.

For the former, potential sites in these river basins are relatively larger in scale compared to domestic power demand, raising concerns about supply risk during the rainy season when power generation may exceed domestic power demand. In fact, without secured power export to India, medium- to large-scale hydropower projects have not been well progressed except for Arun 3 and Upper Karnali involving Indian developers. However, India is positive to import electricity from Nepal now and it is also possible to select the option to export electricity to India via interconnections in case of delays in developing domestic 400kV power system. Mitigation of this risk is expected to motivate IPPs to develop hydropower potentials in these undeveloped river basins.

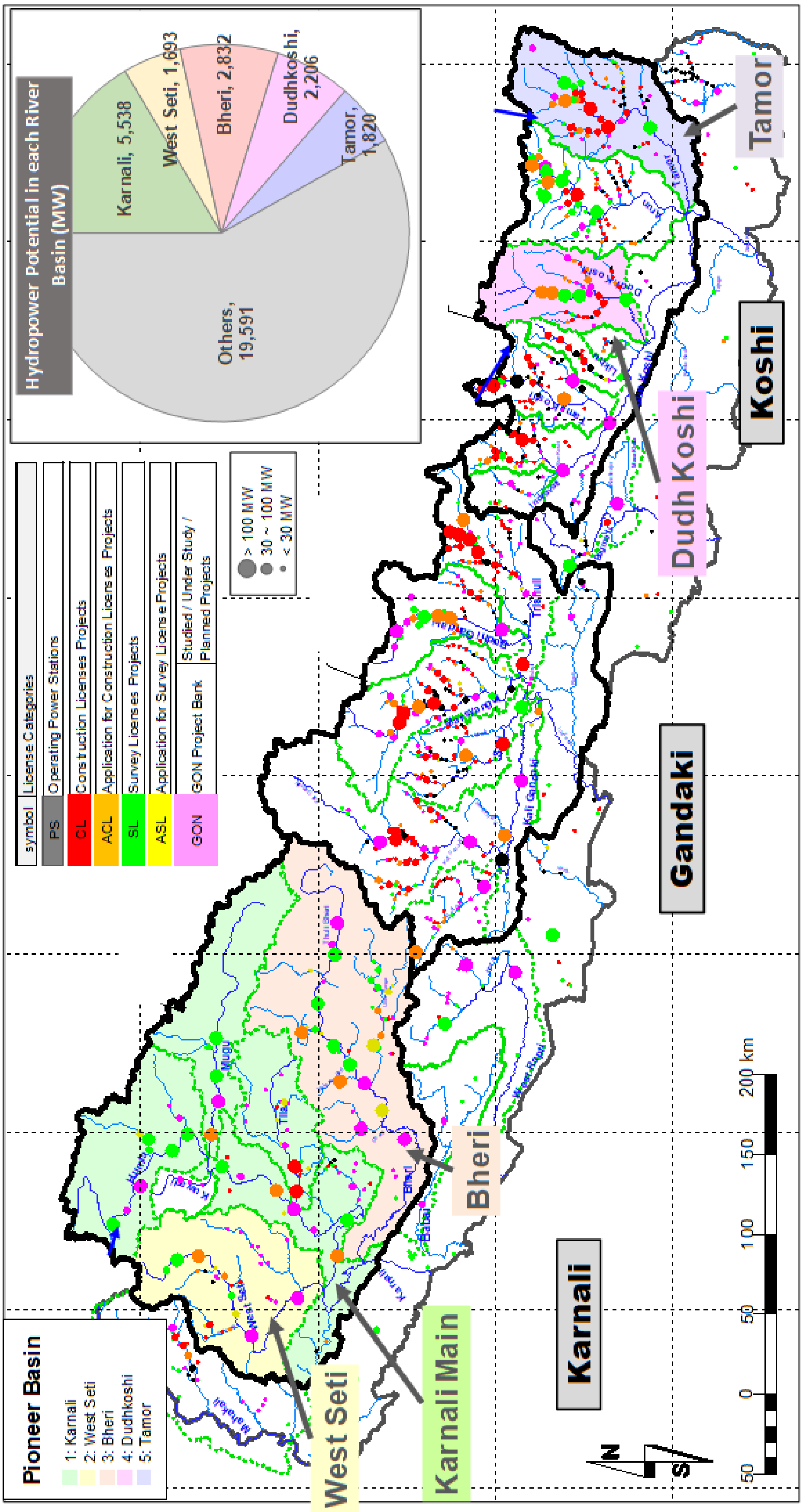
Considering the current situation, the main issues in undeveloped river basins are assumed to be the lack of access road and transmission lines. Development of related infrastructure and interconnection to power system is shouldered by first developers in the river basin who need to be responsible for the costs and various procedural applications. It becomes big burdens for developers to hesitate accelerating the development. On the other hand, examples from rivers like Tamakoshi, Arun, Likhu, and Solu suggest that once one project advances, subsequent projects are accelerated. Thus, developing access roads and transmission lines and ensuring grid interconnection can promote hydropower development in each river system. Based on this understanding, IPSDP proposes the Pioneer of Hydropower Project in River Basin as a hydropower development promotion plan. The candidate river basins and projects are summarized in Table 9.4-3 and Figure 9.4-2.

Table 9.4-3 Candidate Sites for Pioneer of Hydropower Project in River Basin

River Basin	Major River	Installed Capacity	Candidates for Pioneer
Karnali Basin	Karnali, Humla Karnali and Tila	5,538 MW	Phukot Karnali
West Seti Basin	Seti	1,693 MW	Chainpur Seti, West Seti, SR6
Bheri Basins	Bheri, Sano Bheri, Nalgad and Jadulla	2,832 MW	Nasyaugad、Jadulla PRoR
Dudhokoshi Basins	Dudhokoshi	2,206 MW	Dudhokoshi STO
Tamor Basins	Tamor and Kabeli	1,820 MW	Tamor Storage

Source: JICA Study Team

As previously mentioned, constructing access roads and transmission lines also serves as public works. Therefore, the development of these projects is desirable through GoN entities with support from development partners such as JICA, WB, and ADB or by utilizing PPP scheme. For this reason, priority is put on hydropower projects which licenses are handled by NEA and VUCL and which progress are relatively advanced. Finally, candidate sites for pioneer are selected in each river basin.



Source: JICA Study Team

Figure 9.4-2 Location of Undeveloped River Basins

9.4.3 Scaling Up the Power Sector Industry

Steady implementation of IPSDP needs to be supported by power sector with an appropriate industry scale. Nepal's power industry should have its blueprint for power infrastructure developments, which includes power plants, transmission/substation facilities, and distribution facilities. Industry also equip with an organizational strengthening and human resource development to realize IPSDP.

From an organizational perspective, the strengthening private sector is important in addition to capacity enhancement of government and related departments. During the plant construction, supporting services, such as survey companies, design firms, consultants, service contractors, and equipment and material suppliers are important. Of its operational phase, companies operating the plants and catering operation and maintenance capabilities are in need. In case projects are implemented as private IPP projects, the engineering consultancy, legal, and financial professionals in addition to financial institutions that provide loans to projects, are essential.

As many of the projects will be implemented in rural areas in the future, there will be a need to ensure the supply capacity of organizations and human resources to provide these services and technologies. Impact of these change will extend beyond urban areas such as Kathmandu. The direct effects of developing and operating project facilities are significant, and the expansion of supporting infrastructure (roads, electricity, water, and housing) is also necessary. As a result, scaling up of the power sector will significantly impact rural areas in terms of employment and capacity development.

As mentioned above, in order to develop the power sector as an industry, it is necessary for MoEWRI to strengthen collaboration with other government ministries and agencies (e.g. MoF, DoI (Department of Industry), IBN, public financial institutions, etc.) and local governments. It is also expected that there will be dialogue with the private sector (for example, the Nepal Chamber of Commerce) and that various policies will be developed based on this dialogue. Furthermore, in order to strengthen human resources, in addition to the Nepalese government's own efforts, it is also possible to consider utilizing international development aid agencies to dispatch experts and provide technical cooperation.

9.4.4 Matching the Demand and Needs for Project Financing

The scale and participation methods of power development projects will likely vary depending on the characteristics of investors.

(1) Improvement of the investment environment

Foreign investors participating in hydroelectric power projects in Nepal are mostly from India and China, and there is a lack of expansion. The biggest obstacle is that payments to the NEA, the off taker for the time being, are limited to Nepalese rupees. With the revision of the hedging-related regulations of the PPP/Investment Act in 2019, foreign investors are required to hedge their exchange rate risk in accordance with the mechanism set by the GoN, but discussions are ongoing regarding the detailed methodology. For this reason, Indian and Chinese investors are currently investing on the premise that they will accept the exchange rate risk.

Requesting international development financial institutions to cover the exchange risk of the Nepalese rupee is considered to be an essential measure from the perspective of reducing business risks, but it is urgently necessary for the GoN to establish a specific mechanism for reducing exchange risk. If the off taker is an Indian electricity consumer, it may be possible to consider structuring the business in a currency with many established hedging methods, such as making payments from India in Indian rupees.

(2) Negotiating electricity sales amounts and terms with off-takers in neighboring countries

Nepal's hydroelectric power generation projects are planned with the sale of electricity not only in the domestic market but also in the markets of neighboring countries such as India. In this case, the following three mechanisms are considered: 1) the NEA becomes the electricity buyer (off-taker), 2) a PPA is concluded with overseas consumers, or 3) the electricity is sold through a market mechanism such as IEX. On the other hand, if price fluctuations at IEX are taken into account when developing the project, option 3 is the option, but electricity that is price-competitive enough to be sold across borders to India will require a certain degree of business scale, and it is expected that price fluctuations will be suppressed in terms of fundraising, and stable income will be obtained. Therefore, from the perspective of reducing risk, direct sales to market mechanisms may be difficult.

As a result, PPAs will be concluded with NEAs or overseas consumers. In such cases, care must be taken to ensure that PPA terms are not significantly subordinated. The price of renewable energy-derived electricity currently used as a benchmark in the Indian market (approximately NPR 5.00) may fall further in the future as renewable energy sources become more widespread.

In India, the main export destination of Nepal's hydroelectric power generation, the SERC (State Electricity Regulatory Commission) of each state imposes a RPO (Renewable Energy Purchase Obligation) on power companies. The RPO came into force in 2016 and made the purchase of renewable energy, including wind and solar power, mandatory, but a review in 2018 showed that actual purchases did not reach the target, and each state is setting higher introduction targets.

In order to accelerate the development of hydroelectric power generation projects, it is necessary to develop exchange rate risk hedging methods as part of the improvement of the investment environment in Nepal, with the aim of inviting the participation of private funds or IPP operators. At the same time, considering that the development of hydroelectric power generation projects based on the premise of electricity export will be the main focus in the future, it is desirable from the perspective of improving the investment environment for operators and investors for the GoN to take the lead in establishing a certain degree of standards for the electricity sales conditions and prices exchanged between Nepalese operators and export destinations.

(3) Strengthening the capacity of local financial institutions

It is expected that the project development will be promoted by improving the lending capacity of local Nepalese financial institutions, which are currently only involved in small to medium-sized hydropower projects. In terms of financing, it is expected that leading banks will be selected from among the Nepalese financial institutions that rely on short-term loans, and their lending capacity will be strengthened by providing TSL. At the same time, it is necessary to develop the lending capacity of financial institutions so that they can lend to corporate or project loans, instead of lending to individuals at present. In the short and medium term, it is necessary to provide support to local financial institutions and develop their appraisal capacity for corporate loans, while cultivating the appraisal capacity for project financing for hydropower projects, which is the target.

9.4.5 Energy Transition

Until 2028, the surplus electricity will mainly be available during rainy season but the base supply in dry season gradually increase from 2029 onwards and it will be possible to meet both rainy and dry season from 2031 onward.

On the other hand, when considering the kWh value of these surplus electricity sources, the value of electrifying heat demand followed by exporting electricity to India is high. As of 2024, the business feasibility of green hydrogen in Nepal without subsidies or carbon credits has not been reached. Therefore, it is essential to enhance the financial value of green hydrogen through an increase in the market value of green hydrogen, establishment of various preferential systems, and reduction in manufacturing costs through the development of new technology.

From an energy efficiency perspective, the most efficient utilization of electricity is for direct use as a power source for EVs, E-cooking, and heat demand. As already mentioned in Chapter 5, the Nepal government has set ambitious targets for EV and E-cooking. It is therefore important to promote these existing initiatives and stimulate new demand through heat pumps is considerably important.

Exporting electricity also contributes to the energy transition from the perspective of CO_2 reduction in neighboring countries and is assumed to be a necessary measure for Nepal to earn valuable foreign exchange. It is therefore important to focus on electrification and electricity exports, which offer superior financial value.

While the practical use of CN fuels, including green hydrogen, is advancing in some developed countries, the full-scale social implementation is still at the exploratory stage worldwide, and it is assumed that Nepal is no exception. Therefore, for the time being, it is important to prioritize domestic economic value from the perspectives of technology dissemination, establishment of related systems, energy and food security, and preventing the outflow of foreign currency.

In particular, there is a clear market demand for ammonia produced from green hydrogen as fertilizer for agriculture in Nepal. Although it is less competitive in price than fertilizers imported from India, which are made from natural gas, it is preferable to proceed from the perspectives of a stable supply of fertilizers and food security. Furthermore, using CO_2 emitted from cement clinker production as a raw material for urea production can contribute to reducing emissions in carbon neutrality. However, the business is likely to be rely on subsidies in the short term. Therefore, it is advisable to carefully consider the production scale to avoid impacting the finances of related businesses and the GoN.

9.5 PROPOSAL OF PILOT PROJECTS FOR IPSDP

It is critical to carry out recommendations and to deal with challenges but these tasks involve various fields and domestic stakeholders and international agencies. It seems to be challenging to achieve solely through the activities of individual agencies and requiring various adjustments.

To resolve these situations, implementation of pilot projects is expected to be effective, encompassing many of the identified key issues. Once pilot projects indicate solution of these issues such as PPA, interconnection with foreign grid, setting of transmission wheeling charge or physical infrastructure development, these could be good benchmarks for subsequent projects. As these pilot projects are required to explore various new fields with a lot of issues or unforeseeable risks, it supposed to be challenging for IPPs or private sector to deal with these pilot projects. Therefore, it might be reasonable to select GoN entities such as NEA or VUCL as implementing agencies and to execute these pilot projects under the assistance from GoN and development partners.

Based on this understandings, following five (5) pilot projects which can be the key driver for further development are proposed.

- Sunkoshi-3 HPP
- Phukot Karnali HPP
- Transaction Advisory Service
- Two Step Loan through HIDCL
- Promotion of Pilot Projects for Energy Transition

Based on understandings above, issues and recommendation of pilot projects are summarized in Table 9.5-1.

Table 9.5-1 Issues and Recommendations on IPSDP

Item	Sunkoshi-3 HPP	Phukot Karnali HPP	Transactionary Advisory Service	Enhancemen of HIDCL	Energy Transition
1.Expansion of Clean Export					
Concentration of risks on NEA for expansion of clean export	Establish direct trade scheme with India and BPDB				
Securement of power supply reliability for domestic demand	Improve dry season supply capacity	Improve dry season supply capacity			
Technical issues on expansion of power trade	Review and establish generation plans considering three-country interconnection	Promote development of Lumki-Bareily interconnection line			
Development scheme on interconnection lines	Establish and operate three-country interconnection				
Issues on legal framework for power trade	Facilitate smooth expansion of power trade by involving India and BPDB				
Insufficient experiences on export oriented hydropower projects by Nepalese developers	Project implementation by NEA	Participation of VUCL	Advisory support for NEA and/or VUCL		
2.Significant Expansion of the Nepalese Power System,					
Necessary adaptation measures against climate change risks.	Develop 400kV substations and transmission lines in Sunkoshi basin	Develop access roads in Surkhet to Karnali basin Phukot - Lumki 400kV T/L			
Necessity of integrated river basin development		Promote development of Karnali main river and Tila river basin			
Capacity development on tunnel design and construction		Undertake the first large-scale tunnel construction in Karnali basins			
Need to improve system planning capabilities.	Develop three-country interconnection plan	Develop power system plan for western area			
Interconnection of VRE					
Mitigation of environmental and social impacts	Implement study of international standards including transmission lines	Implement study of international standards including transmission lines			
3.Reforming the Electricity Sector					
Necessity of capacity development of GoN	Improve NEA's capabilities	Improve VUCL's capabilities	Strengthen organizational structure of the power sector and coordination with other ministries		
Clarification of role of government organizations and sector reforms.			Promote organizational restructuring along with power law revision		
Shortage of domestic contractors	Involve Indian developers and BPDB	Involve NHPC	Expand the sector to include contractors, equipment suppliers, construction consultants, legal advisors		
Necessity of international standard PPA	Consider PPAs with India and Bangladesh	Consider PPAs with India			
4.Expanding Finance/Private Investment					
Finance from domestic investors or lenders				Strengthen HIDCL and private banks	
Necessity of promotion of FDI	Encourage entry of developers and financial institutions from India and Bangladesh	Promote financing by NHPC		Matchmaking between foreign and domestic businesses on India and Bangladesh Expand clean energy use in energy-intensive industries	
Enhancement of assistance by development partners	Ensure cross-regional involvement of development partners including India and Bangladesh	Support VUCL		Propose finance promotion measures such as loans, PPPs, sector loans, TSLs"	
5.Energy Transition					
Promotion of electrification					Propose new electrification promotion measures such as heat pumps
Establishment of legal framework and supply chain in Green Hydrogen					Propose pilot projects for green hydrogen and ammonia

Source: JICA Study Team

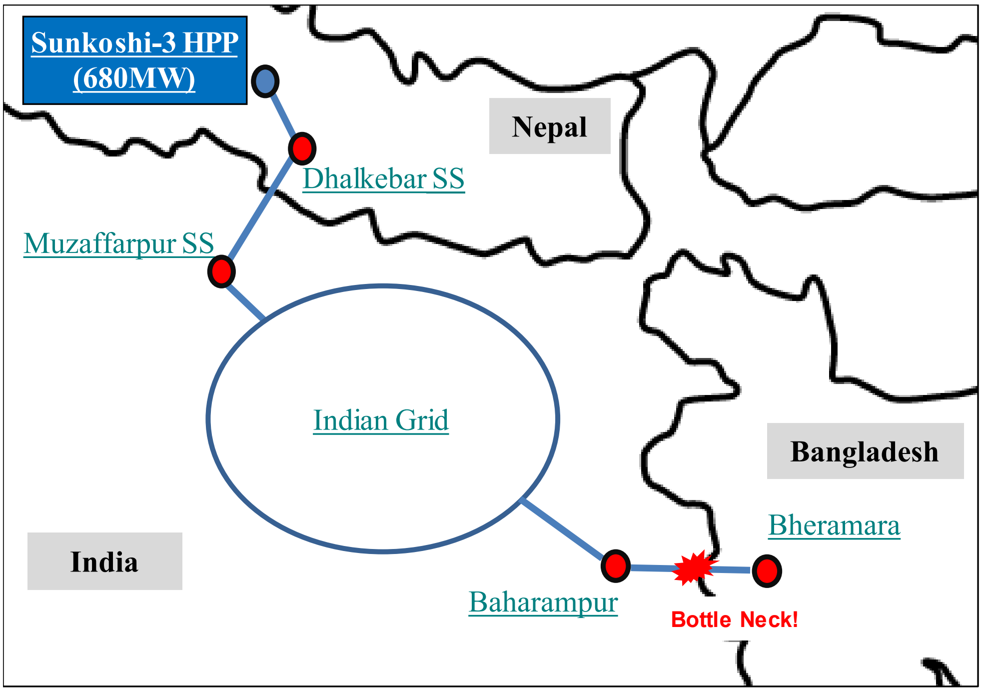
9.5.1 Sunkoshi 3 HPP

While expanding Clean Export is essential for the future development of the power sector, it is necessary to resolve various issues such as legal frameworks, development schemes, financing, and the construction of physical infrastructures. As these issues are related each other and difficult to solve by only one organization, it is effective to deal with these issues through the implementation for pilot projects under the mutual collaboration with related agencies and development partners.

Under this recognition, IPSDP proposes Sunkoshi 3 Hydropower Project (680MW) agreed for development between Nepal and Bangladesh as a pilot project to accelerate Clean Export expansion. This site is planned to be developed by a JV between NEA and BPDB, with the prospect of attracting Indian developers as well.

(1) Interconnection of Sunkoshi 3 HPP through Three Countries

The concept of interconnection from Sunkoshi 3 to India and Bangladesh is show in Figure 9.5-1.



Source: JICA Study Team

Figure 9.5-1 International Interconnection from Sunkoshi 3 to India and Bangladesh

The "Guidelines for Import Export Cross Border of Electricity 2018 India" formulated in 2018 allows for power trade to third countries via the Indian grid. Therefore, it is envisaged that Sunkoshi 3 will connect to the Indian grid.

Electricity generated at Sunkoshi 3 will be transmitted to Dhalkebar substation in Nepal by domestic power system. Then, it will be transmitted to Muzaffarpur via 400kV interconnection line with India. Although India and Bangladesh are also interconnected by a 400kV HVDC (High Voltage Direct Current) line, the available capacity of this transmission line is almost fully utilized. It is necessary to develop a new transmission line between India and Bangladesh. The cost burden of this transmission line needs to be monitored through the pilot project.

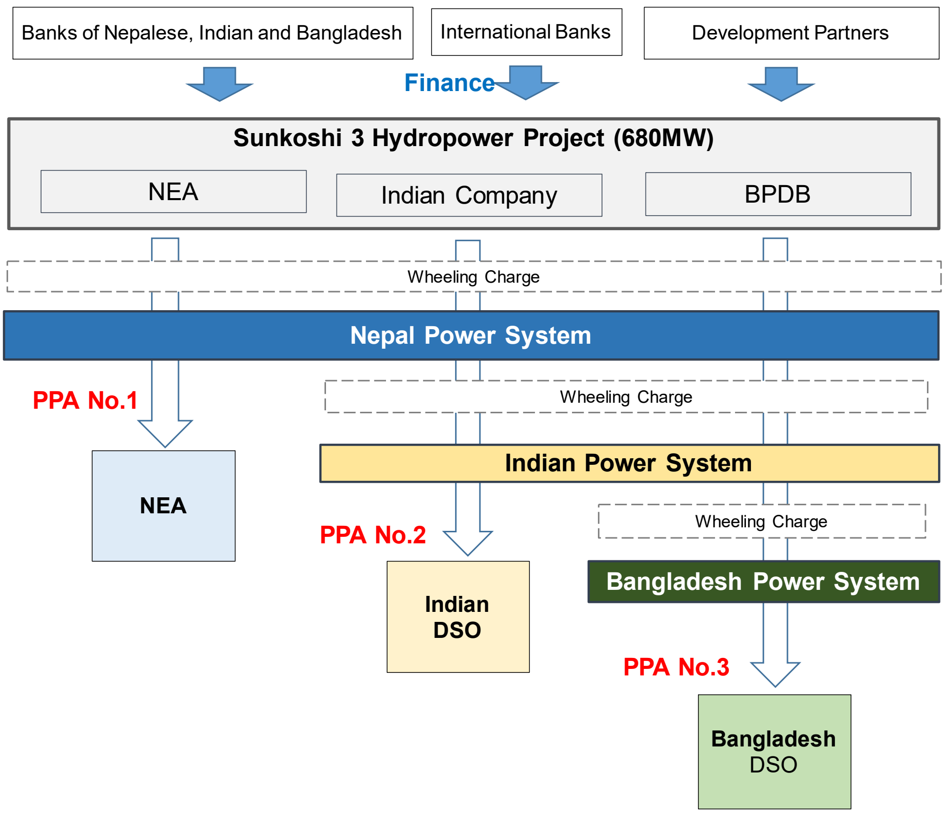
(2) Effectiveness of Promotion of Sunkoshi 3 HPP

The commercial flow and finance scheme for Sunkoshi 3 HPP are described in Figure 9.5-2 and Figure 9.5-3. Through the pilot project of Sunkoshi 3, it is expected to establish good practices in the following areas necessary for power trade to India and Bangladesh:

- Application of necessary legal frameworks for project implementation
- Application for interconnection among the three countries
- Consideration of wheeling charges for transmission and interconnections in each country
- Establishment of SPC and shareholder agreements by developers in each country
- Conclusion of PPAs with off-takers in each country
- Utilization of Indian and Bangladeshi funds in project finance

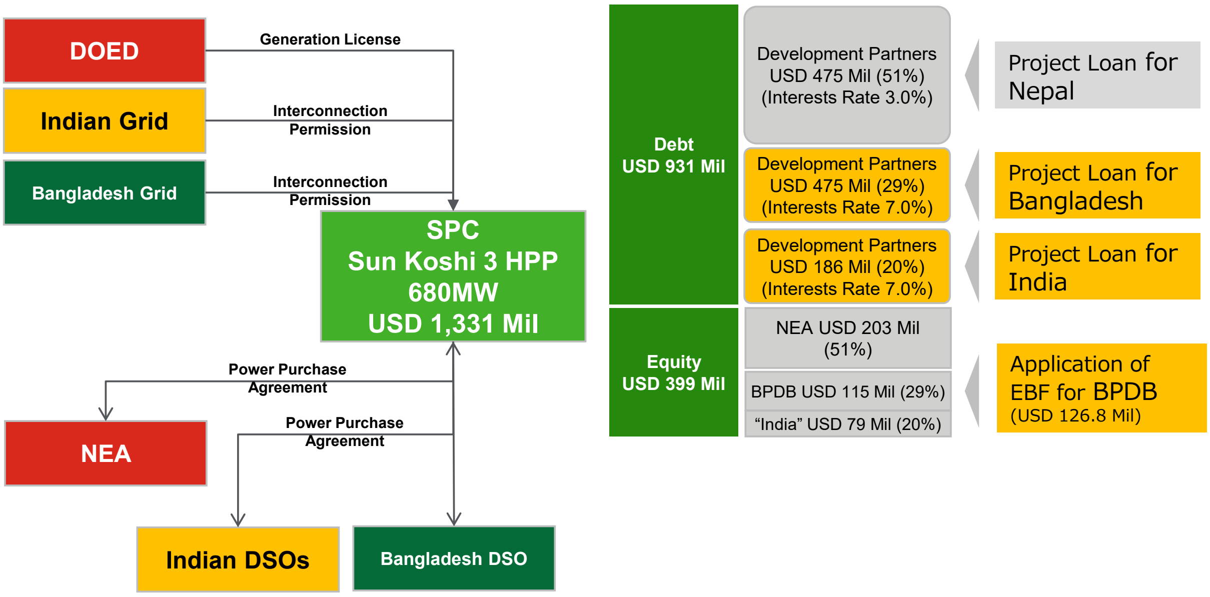
To facilitate the application of PPAs, interconnection applications to power system and the setting of wheeling charges for transmission lines in three countries, the participation of experienced power companies from each country is desirable. Therefore, participation from India is also assumed to involve experienced power utility companies.

It is necessary to maximize the use of financing not only from Nepal but also from India and Bangladesh to efficiently develop hydropower potential in Nepal. As Sunkoshi 3 is not a profitable projects, it is favorable to utilize advantageous financing from development partners such as sovereign loan or PPP loan. It shall be noted that the allocation of equity and debt for each country's developers is just an assumption and required to be revised in accordance with mutual discussion among related stakeholders.



Source: JICA Study Team

Figure 9.5-2 Commercial Flow of Sunkoshi 3 HPP



Source: JICA Study Team

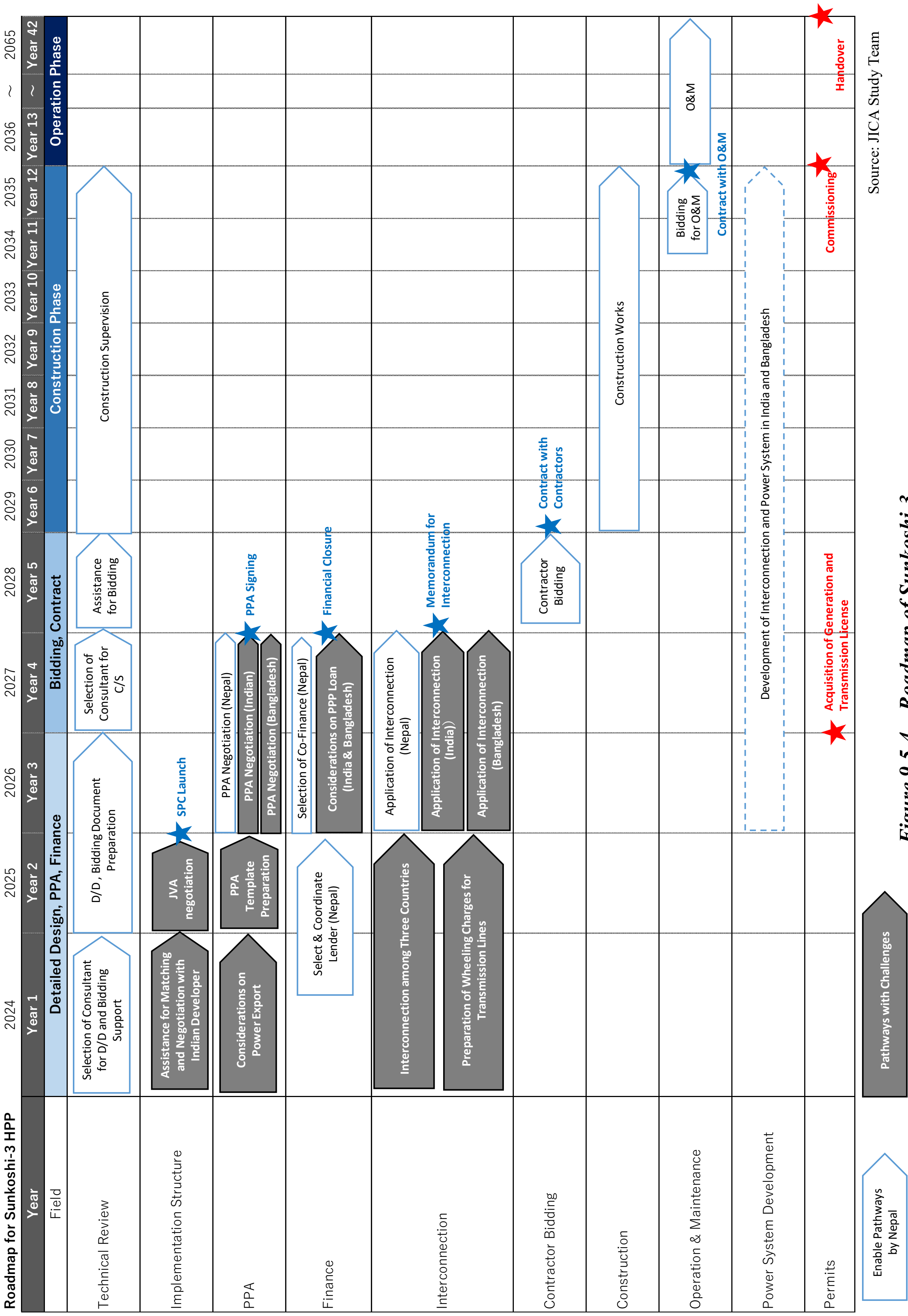
Figure 9.5-3 Financing Scheme of Sunkoshi 3

(3) Action Plan for the Development of Sunkoshi 3 HPP

Based on the understanding presented in this section, the schedule and roadmap for issues for the development of Sunkoshi 3 HPP are illustrated in Figure 9.5-4 and Table 9.5-2.

The proposed schedule for Sunkoshi 3 HPP includes establishing an SPC in 2025, signing the PPA in 2027, achieving financial close, signing a memorandum of understanding for interconnection, starting construction in 2029, and commencing operations in 2035. Immediate actions required include selecting a development partner on the Indian side, which is a critical path in the project formulation stage and must be promptly initiated. Concurrently, it is desirable to promptly start examining the supply allocation to Nepal, India, and Bangladesh necessary for PPA considerations, and the system plan necessary for transmission charge considerations. These examinations require coordination among the three countries, and a framework where all stakeholders can collaborate for the project's success needs to be established. In addition to technical aspects such as international interconnection and SPC establishment, PPA, and system interconnection agreements across three countries, ongoing support from development aid agencies in coordinating stakeholders is also considered crucial.

The development of Sunkoshi 3 for Clean Export expansion encompasses many of the critical tasks needed for India's and Bangladesh's participation in PPA, finance, and interconnection. Immediate actions include attracting Indian developers, supporting the formation of SPCs, optimizing the generation plan considering power exports, and securing interconnection among the three countries. Subsequently, SPC establishment, PPA conclusion, and interconnection applications in each country need to be carried out. These are common issues for other projects, and realizing this project as a good practice would enable horizontal expansion, making it a priority project to promote.



Source: JICA Study Team

Figure 9.5-4 Roadmap of Sunkoshi-3

Table 9.5-2 Action Plan for Sunkoshi-3 HPP

Item	Issue	Solution	Policy Action	Outcome Indicator	Implementing Agency	Support Needs	MoEWRI Work Plan Consistency
Implementation Structure	Indian partner is not decided	Select hydropower developers with hydropower development and grid interconnection experience in India such as SVJN, NHPC	Year 1: Support formatching and discussions with Indian companies	Joint venture partner for Sunkoshi-3 is selected	NEA	Support for discussions with Indian side	
	JVA for SPC jointly funded by three countries is not prepared	Prepare JVA template	Year 1: Pprepare JVA template	JVA template is prepared	NEA, ERC	Continuous technical cooperation	No.50
	NEA doesn't have experience in establishing SPC jointly funded by three countries	Support negotiations for establishing SPC	Year 2: Support for establishing SPC	SPC is established	NEA	Continuous technical cooperation	
PPA	Optimization for power generation planning involving power export and project benefit are not studied	Optimize power generation plans and project benefits	Year 1: Review optimization of power generation plans formulated by NHPC	Power generation plans are optimized	NEA	Support for technical review	
	Allocation of domestic supply and power export are not reviewed	Determine allocation ratio of domestic and export supply based on power generation plans		Allocation of domestic and export supply are determined			
	There is no examples of wholesale prices for three-country sales	Set wholesale prices	Year 2: Prepare PPA template and support for negotiations	PPA template is prepared	ERC, NEA	Continuous technical cooperation	No.18
	No PPA template for selling power to three countries	Prepare PPA template					
	NEA doesn't have experinces of PPA negotiations with Indian DSO	Assign roles for PPA negotiations with Indian developers Collaborate with Indian developers	Year 3: Support for PPA negotiations	PPA with Indian DSO is signed	NEA	Support for discussions with Indian developers	No.18
	NEA doesn't have experinces of PPA negotiations with Bangladesh DSO	Assign roles for PPA negotiations with BPDB Collaborate with BPDB	Year 3: Support for PPA negotiations	PPA with Bangladeshi DSO is signed	NEA	Support for discussions with BPDB	No.18
Finance	No experience in foreign investment applications for Indian and Bangladeshi developers hydropower projects in Nepal	Support Indian developers and BPDB to process foreign investment applications	Year 3: Support for foreign investment applications	Indian developers and BPDB achieve financial close for foreign investments	Indian developers, BPDB	Support for discussions with Indian developers and BPDB	No.27
Interconnection	Power system planning including interconnection for three countries is not considered	Conduct Evacuation Route Study	Year 2: Support for D/D	Evacuation Route Study is prepared	NEA	Review D/D components	No.18
	Capacity of international interconnection lines between India and Bangladesh is insufficient	Develop 765kV international interconnection line from Katihal (India) to Parbotipur (Bangladesh)	Year 3 onward: Monitor the progress	Interconnection line between India and Bangladesh is developed	India, Bangladesh	Monitor progress of interconnection line development	
	Wheeling charges for transmission lines are not prepared for Nepal, India, and Bangladesh power systems	Prepare wheeling charges for transmission lines Negotiate wheeling charges with TSOs of each country	Year 2: Prepare wheeling charges Year 3: Negotiate with TSOs	Wheeling charges for transmission lines in three-countries are set	NEA	Continuous technical cooperation	No.18, No.25
	There is no experiences in application of interconnection with Indian TSO	Assign roles for interconnection applications to Indian developers Support Indian developers	Year 3: Support for interconnection applications	Interconnection with Indian TSO is approved	NEA	Support for discussions with Indian developers	No.18
	There is no experiences in application of interconnection with Bangladesh TSO	Assign roles for interconnection applications to Indian developers Support BPDB	Year 3: Support for interconnection applications	Interconnection with Bangladeshi TSO is approved	NEA	Support for discussions with BPDB	No.18
Grid Development	400kV transmission lines and substation needs to be developed	Sunkoshi-Dhalkebar 400kV transmission line	-	Transmission system will be developed by commissioning	NEA	Various supports	No.54, No.62, No.80, No.81

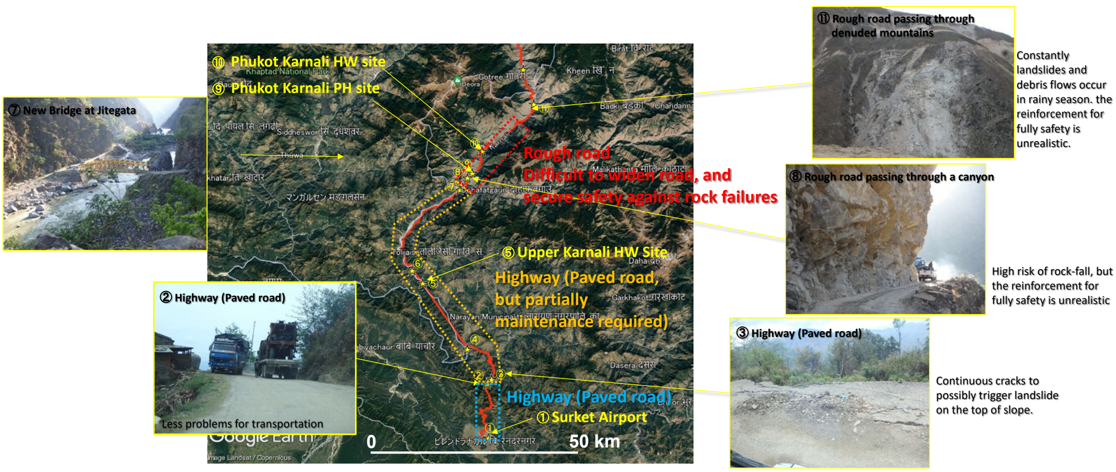
Source: JICA Study Team

9.5.2 Phukot Karnali HPP

As a case example of pioneer of Karnali River Basin, this section focuses on the Phukot Karnali HPP in Karnali River. Phukot Karnali is a PROR type hydropower plant with an output of 480MW owned by VUCL, currently applying for a Construction License. It is located at midstream of Karnali River which has abundant hydropower potential but have been not developed and planned to be co-developed with India's state-owned hydropower developer NHPC.

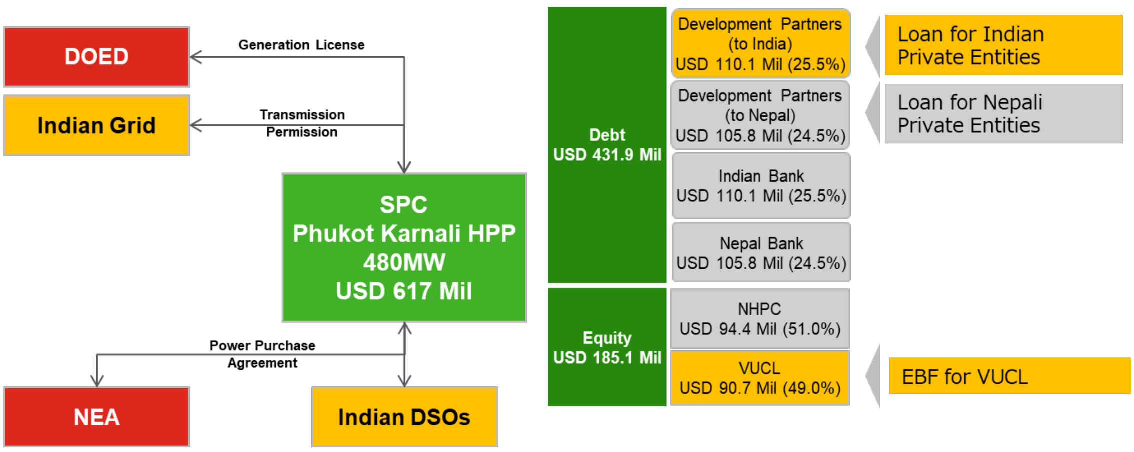
(1) Effectiveness of Promotion of Phukot Karnali HPP

Karnali River has large-scale planned sites like Upper Karnali and Betan Karnali and Mugu Karnali Storage but progress has not been seen in construction stage. Various equipment and materials are expected to be procured from India. Paved road are available from India to Birendranagar, the provincial capital of Surkhet. The mountain road from Birendranagar to the confluence of the Karnali River is asphalted but necessitating major repairs to ensure the slope stability and to expand the width of road for heavy machineries access. Currently, 132kV transmission line is connected at Koharpur, but a 400kV western transmission line (New Butwal to Lumki) and a 400kV transmission line along the Karnali River (Lumki to Phukot) need to be developed for power system.



Source: JICA Study Team

Figure 9.5-5 Access to Phukot Karnali HPP



Source: JICA Study Team

Figure 9.5-6 Assumption of Finance Scheme for Phukot Karnali HPP

The development of Phukot Karnali HPP is expected to bring the following benefits to the river basins:

- Promotion of regional development through improved logistics in the upstream area of Karnali river
- Access to Betan Karnali, Upper Karnali, Mugu Karnali Storage, Tila-1 and Tila-2
- Development of Phukot Karnali 400kV substation as a key substation
- Power export to India via Lumki interconnection line
- Implementation of the project as a JV between NHPC and VUCL

Although installed capacity of Phukot Karnali is 480MW, the total potential in Karnali and Tila rivers is 5,538MW, suggesting significant benefits beyond the development of the individual site. The development of Karnali river basins is significantly essential for achieving MoEWRI's target in 2035. Phukot Karnali has completed Detailed Project Report and is progressing towards obtaining Construction License, considering a highly important and effective for accelerating the development of Karnali basin.

(2) Roadmap and Action Plan for the Development of Phukot Karnali HPP

Based on the understanding presented in this section, the roadmap and action plan for addressing issues for the development of Phukot Karnali HPP are illustrated in Figure 9.5-7 and Table 9.5-3.

As of June 2024, the implementation structure for Phukot Karnali is not yet determined but the investment ratio is assumed to be 51% for NHPC and 49% for VUCL based on current discussions. The roadmap is prepared on the premise that NHPC will take the lead, and the action plan considers necessary measures from VUCL's standpoint.

The schedule for the Phukot Karnali HPP assumes the establishment of the SPC in 2024, the signing of the PPA, financial closure, and the signing of the memorandum of understanding for system interconnection in 2026, the start of construction in 2027, and the commencement of operations in 2032.

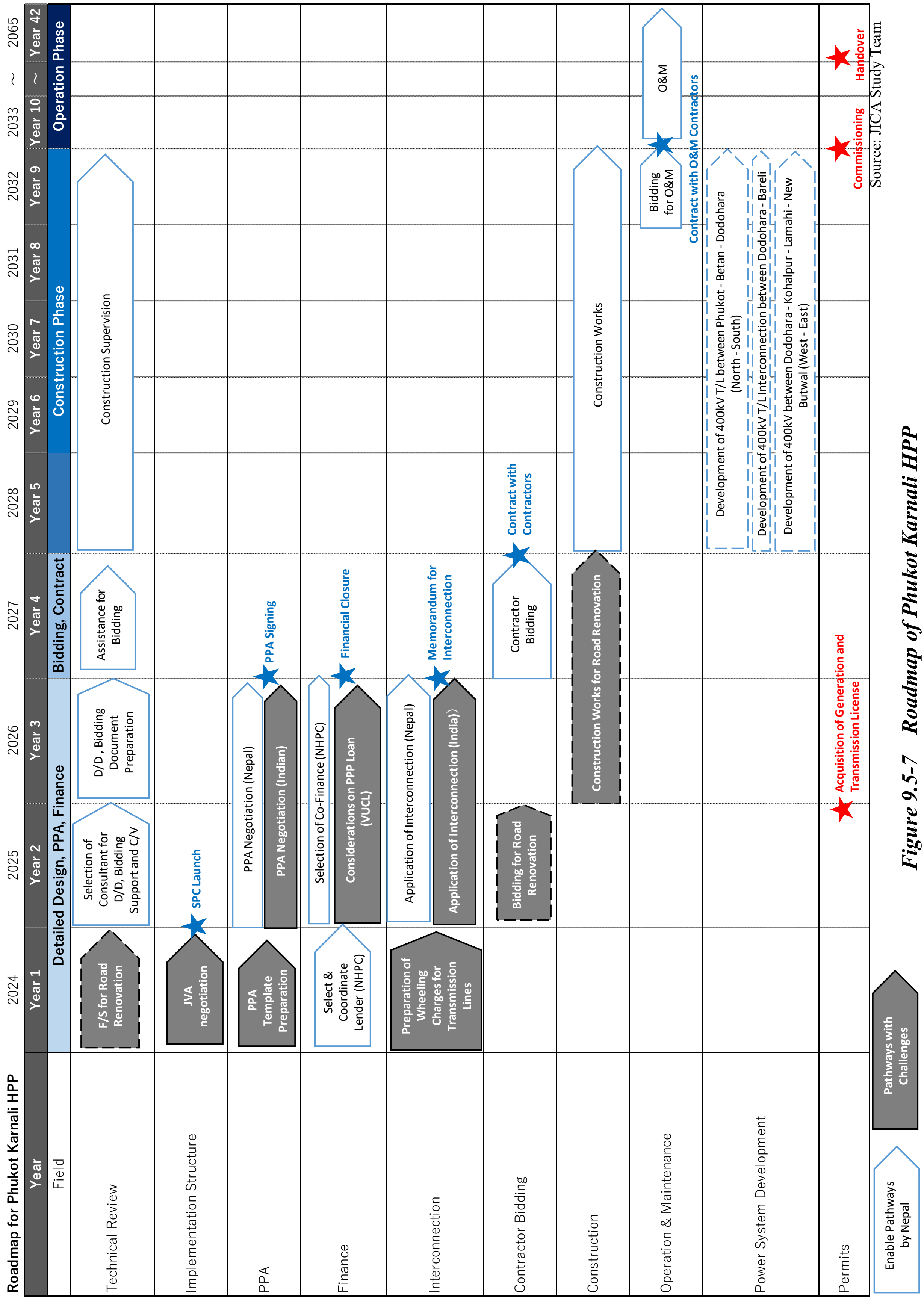
As previously mentioned, NHPC is assumed to hold the majority stake in this project and it is expected to take the lead in organization of SPC, negotiation of PPA and applying for grid interconnection. NHPC has extensive experience in hydropower projects both within India and in Bhutan and is considered to have the necessary experience and capabilities as an implementing agency. On the other hand, VUCL is a relatively newly established organization with no projects currently in the construction phase. It is assumed that VUCL will need support in negotiations with NHPC and in considering funding through PPP and other means. Additionally, since the PPA involves ERC and NEA and the grid interconnection also involves NEA. These aspects are assumed to be considered as well.

Regarding the operation commencement schedule, VUCL has already applied for a Construction License. Based on progress and timing, construction commencement in 2027 does not appear to be an unrealistic schedule. However, as indicated in the previous section, the Karnali river basin may face bottlenecks due to the renovation of existing roads. It is necessary to consider the period required for the basic design, budget securing and implementation of these construction works. Although which agencies are responsible for implementation these works are not decided, the coordination is supposed to be required for Nepalese side. Early commencement of this examination is necessary.

Additionally, regarding the related power system development, NEA or RPGCL are assumed to be the implementing agencies and some of the 400kV backbone systems are expected to be implemented by IPPs. Considering the support from development partners, starting from the F/S stage will not allow for a relaxed schedule. It is also necessary to monitor this consideration.

The pilot project of the Phukot Karnali HPP is expected to promote the development of hydropower in Karnali river, which has the largest capacity among the undeveloped river basins. Similarly, selecting and prioritizing the first pioneer development projects for rivers like the West Seti, Bheri, Dudhokoshi, and Tamor is considered as effective solutions to accelerate the development.

Furthermore, the Phukot Karnali HPP is expected to serve as a model case for project implementation with a majority stake held by an Indian public company. In this regard, the project is also considered one that anticipates support from development partners.



Source: JICA Study Team

Figure 9.5-7 Roadmap of Phukot Karnali HPP

Table 9.5-3 Action Plan for Phukot Karnali HPP

Item	Issue	Solution	Policy Action	Outcome Indicator	Implementing Agency	Support Needs	MoEWRI Work Plan Item
Technical Review	Implementing agency for existing road renovations is not decided	Decide the implementing agencies	Year 1: Coordination with relevant agencies	The implementing agency for existing road renovations is decided	GoN	Coordination with relevant agencies	No.31
Technical Review	Basic design and bidding documents for road renovations are needed	Carry out F/S and prepare bidding documents	Year 1: Hire a consultant	F/S and bidding documents are prepared	GoN	Support for basic road design in mountainous areas	No.31
Implementation Structures	VUCL lacks knowledge on forming SPC with foreign companies	Enhance capabilities related to JVA negotiations	Year 1: Support for JVA negotiations	SPC is formed	VUCL and ERC	Capacity building for VUCL	
PPA	Optimization for power generation planning involving power export and project benefit are not studied	Optimize power generation plans and project benefits	Year 1: Review optimization of power generation plans formulated by NHPC	Power generation plans are optimized	VUCL	Capacity building for VUCL	
PPA	Allocation of domestic supply and power export are not reviewed	Determine allocation ratio of domestic and export supply based on power generation plans	Year 1: Review optimization of power generation plans formulated by NHPC	Allocation of domestic and export supply are determined	VUCL	Capacity building for VUCL	
PPA	No examples of setting wholesale prices assuming export to Indian DSO	Set wholesale prices	Year 1: Create PPA template and support negotiations with Indian DSO	PPA template is prepared	ERC, NEA, VUCL	Support for negotiations with NHPC	No.18
PPA	No PPA template for selling power to Indian DSO	Prepare PPA template	Year 1: Create PPA template and support negotiations with Indian DSO	PPA template is prepared	ERC, NEA, VUCL	Support for negotiations with NHPC	No.18
PPA	VUCL has less experiences in PPA negotiations with NEA and ERC	Enhance VUCL's negotiation capabilities	Year 2: Support for PPA negotiations	PPA with NEA is signed	VUCL	Capacity building for VUCL	
Finance	VUCL lacks experience to obtain foreign finance	Enhance VUCL's capabilities for application of PPP loan	Year 2-3: Support for applications of PPP loan	VUCL achieves financial close	VUCL	Capacity building for VUCL	No.27
Interconnection	Wheeling charges for transmission lines are not prepared between Nepal-Indian power system	Prepare wheeling charges for transmission lines and negotiate with NEA and Indian TSO	Year 2: Set and negotiate wheeling charges for transmission lines	Wheeling charges for transmission lines are set between Nepal and Indian power systems	NEA, VUCL	Support for negotiations with NHPC	No.18, No.25
Contractor Bidding	Bidding for road renovation are not planned	Implement bidding for existing road renovations	Year 2	Road renovation contractors are selected	GoN	Support for bidding	No.31
Construction	Budget for road renovations is not secured	Allocate budget for road renovation works	Year 3	Road renovations are budgeted	GoN	Project financing	No.31
Power System	400kV transmission lines and substation needs to be developed	- Phukot - Betan - Betan 400kV transmission line - Dodohara - Bareli 400kV international interconnection line - Dodohara - Kohalpur - Lamahi - New Butwal 400kV transmission line"	-	Transmission system will be developed by commissioning	NEA, RPGCL	Various supports	No.54, No.62, No.80

Source: JICA Study Team

9.5.3 Transaction Advisory Service

When the GoN develops new projects (mainly power generation projects) using PPPs or ODA, they have to select operators through public procurement. However, at present, it cannot be said that MoEWRI and other government agencies already have sufficient experience or know-how. TAS are a support menu provided by development partners to complement such aspects.

TAS is one kind of TA (Technical Assistance) in which development partners support a series of procedures (transactions) for a fee or free of charge when a government agency conducts public procurement for a specific project. In the power sector, IFC and ADB have provided TAS to many other countries. JICA has also provided TAS for a waste-to-energy project in Indonesia in cooperation with IFC.

The support items included in TAS are selected on a tailor-made basis for each individual project, but the scope of coverage includes the following:

- ✓ Support for preparation of feasibility studies (including demand forecasts and financial analysis)
- ✓ Support for implementation of market soundings (prior dialogue with private companies)
- ✓ Support for preparation of RFPs and PPAs
- ✓ Evaluation of proposals submitted by private companies and selection of preferred negotiators
- ✓ Support for contract negotiations

For GoN, receiving TAS has the advantages in terms of increasing the likelihood of successful procurement of a specific project, or strengthening institutional and human capacity through OJT, which can be utilized for future procurement of similar projects.

As mentioned above, TAS is provided for procurement of individual projects, but the following projects are considered to be included to the candidates for target projects.

- ✓ Sunkoshi 3 HPP (Utilization of ODA funds)
- ✓ Phukot Karnali HPP (Utilization of PPP)

9.5.4 Strengthening the Financing Capacity of HIDCL and Domestic Financial Institutions

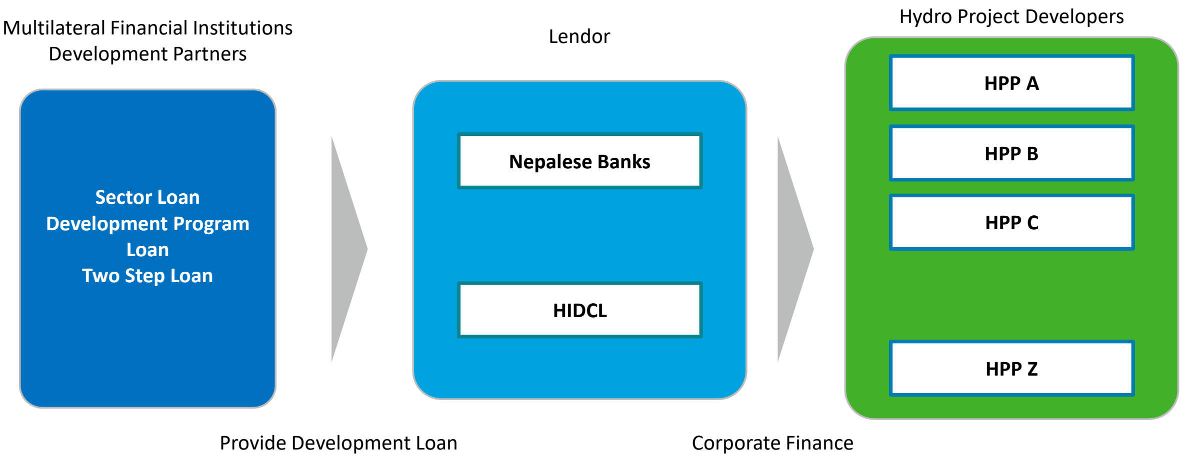
The application of sovereign loans for the Sunkoshi 3 HPP is proposed in Section 9.5.1 and finance scheme for Phukot Karnali HPP through private investment is proposed in Section 9.5.2. It presents a project finance model for large-scale hydropower aiming at Clean Export. This Section proposes strengthening the financing capacity of domestic financial institutions to support small and medium-sized hydropower development which constitutes the majority of the sites in terms of number.

(1) Strengthening of financing functions and capabilities, and strengthening of project development capabilities

In order to promote hydroelectric development in Nepal, it is hoped that the challenges facing the financial sector in terms of lending capacity and appraisal capacity will be resolved.

Nepal's private financial institutions are relatively small in scale, have a high loan-to-deposit ratio, and may not have the capacity to lend long-term funds such as project loans. Loans to small-scale hydropower projects and IPPs are made against the personal guarantees of project owners, and local financial institutions have not developed the capacity to provide project finance that evaluates the feasibility of hydropower projects, or to assess the credit of companies developing such hydropower projects.

One possibility is for international development financial institutions to provide loans in the form of TSL to local financial institutions interested in hydropower project development, which in turn provide loans to individual development companies or projects. HIDCL, which is involved in hydropower projects of over 25MW, has traditionally provided loans and advisory services to projects, and strengthening its lending capacity is believed to contribute to promoting the development of hydropower projects.



Source: JICA Study Team

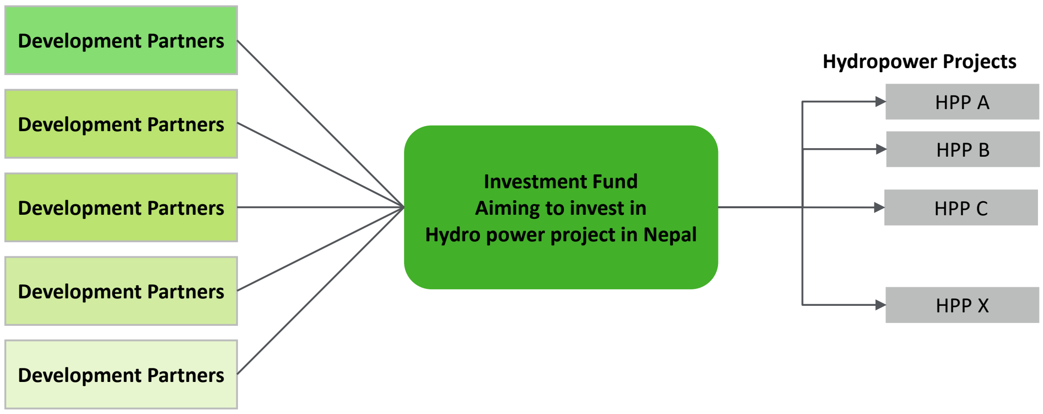
Figure 9.5-8 Efforts to strengthen the capacity of local financial institutions

This initiative requires that financial institutions be provided with loans to increase their lending capacity, as well as technical support for capacity building and advisory service support. The development financial institutions providing the loans will need to reduce the initial burden on local financial institutions by, for example, taking on the responsibility of evaluating and screening business risks. The GoN has set a goal of increasing the ratio of lending to the energy sector by local financial institutions, and this will also contribute to achieving this goal.

(2) Establishment of a fund for hydroelectric power generation projects

There are numerous hydroelectric power projects in Nepal, and in order to overcome the current situation where each project is individually trying to raise funds, we propose forming a fund for the purpose of investing in hydroelectric power in Nepal, and soliciting investments from IFC, development aid agencies, commercial financial institutions, and general investors.

The challenge with fund-based fundraising is that if the fundraising period does not match the fundraising activities of individual projects, businesses cannot join the fund as target projects. In addition, by incorporating the individual circumstances surrounding hydroelectric power generation projects into a fund, the fund is expected to have a risk hedging function, but as economically superior projects can raise funds without joining the fund, the projects that join the fund bear high risks and there is a possibility that the fund will be biased towards less economical projects. If the profitability of the fund declines, it will become difficult to attract investors, so it will be necessary to devise ways to achieve economic viability by incorporating economically superior projects to a certain extent into the fund.



Source: JICA Study Team

Figure 9.5-9 Concept diagram of Hydropower Development Fund

9.5.5 Implementation of Pilot Projects for Energy Transition

Nepal, with its abundant hydropower potential, generates surplus electricity mainly during the rainy season, which is used for Clean Export to neighboring countries. Currently, surplus electricity is limited to the rainy season and Nepal imports electricity from India during the dry season. However, power generation is expected to exceed demand even during the dry season from 2029 onwards allowing for year-round utilization of surplus electricity.

In addition to power exports, further electrification and the introduction of CN fuels such as green hydrogen or ammonia are expected to be additional solutions for utilizing surplus electricity. IPSDP proposes the following two key measures for utilizing surplus electricity as part of the energy transition:

1. Promoting electrification in the buildings sector
2. Promoting research and pilot projects for green ammonia

(1) Promoting Electrification in the Buildings Sector

The "Net Zero by 2050 Roadmap for the Global Energy Sector" formulated by the IEA in 2021 outlines recommendations and priority measures to achieve carbon neutral by 2050, keeping the temperature rise due to climate change within 1.5°C. The roadmap for the buildings sector is shown in Table 9.5-4.

In Nepal, various measures focusing on E-cooking, conversion from biomass to electricity are already being promoted and implemented. IPSDP proposes the introduction of energy-efficient electric products such as heat pumps, ZEBs (Zero Energy Building), inverter air conditioners and refrigerators. In particular, heat pumps are considered to be promoted drastically in building sector. It is highly efficient and multi-purpose equipment for heating, cooling, and drying across a wide temperature range (-100°C to 100°C) and their widespread introduction is highly desirable.

Table 9.5-4 Roadmap for Net Zero Emissions in the Buildings Sector by 2050

Category	
New buildings	• From 2030: all new buildings are zero-carbon-ready.
Existing buildings	• From 2030: 2.5% of buildings are retrofitted to be zero-carbon-ready each year.

Category	2020	2030	2050
Buildings			
Share of existing buildings retrofitted to the zero-carbon-ready level	<1%	20%	>85%
Share of zero-carbon-ready new buildings construction	5%	100%	100%
Heating and cooling			
Stock of heat pumps (million units)	180	600	1 800
Million dwellings using solar thermal	250	400	1 200
Avoided residential energy demand from behaviour	n.a.	12%	14%
Appliances and lighting			
Appliances: unit energy consumption (index 2020=100)	100	75	60
Lighting: share of LED in sales	50%	100%	100%
Energy access			
Population with access to electricity (billion people)	7.0	8.5	9.7
Population with access to clean cooking (billion people)	5.1	8.5	9.7
Energy infrastructure in buildings			
Distributed solar PV generation (TWh)	320	2 200	7 500
EV private chargers (million units)	270	1 400	3 500

Source: IEA: Net Zero by 2050 Roadmap for the Global Energy Sector_

(2) Promoting Research and Pilot Projects for Green Ammonia

Regarding the use of CN fuels, green ammonia is assumed to be a focal point in Nepal. MoEWRI and Kathmandu University are advancing various policy considerations and research studies. The "Green Hydrogen for Development in Nepal" by Kathmandu University's Green Hydrogen Lab proposes pilot projects for green ammonia production and commercial-scale fertilizer manufacturing using green ammonia.

Future utilization of green ammonia in Nepal envisions two directions: i) short- to mid-term fertilizer manufacturing and ii) mid- to long-term export of green ammonia. The former can mitigate the dependence of food security to India because almost full of fertilizer is imported from India and green ammonia may be one solution to reduce this dependency. On the other hand, there are several challenges to move on commercial scale which will require project finance, technical and legal framework improvements and subsidy considerations. The latter anticipates supplying green ammonia for coal co-firing and marine fuel applications as CN fuels in India or other countries. Global researches are ongoing in this field and the economic viability of green ammonia production be proven in future. At that time, green ammonia could become a new form of Clean Export following power exports.