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Report No: PAD1565

INTERNATIONAL DEVELOPMENT ASSOCIATION

PROJECT APPRAISAL DOCUMENT

ON

PROPOSED CREDITS

IN THE AMOUNT OF
US$169.135 MILLION

AND

A PROPOSED GRANT

IN THE AMOUNT OF
US$56.565 MILLION EQUIVALENT

TO THE

REPUBLIC OF TAJIKISTAN

FOR A

NUREK HYDROPOWER REHABILITATION PROJECT - PHASE I

ENERGY AND EXTRACTIVES GLOBAL PRACTICE
EUROPE AND CENTRAL ASIA REGION

CURRENCY EQUIVALENTS

(Exchange Rate Effective February 28, 2017)

Currency Unit	=	Tajik Somoni (TJS)
TJS7.88	=	US$1
US$1	=	SDR0.73

FISCAL YEAR

January 1 – December 31

ABBREVIATIONS AND ACRONYMS

ACF	Average Capacity Factor
ACG	Arab Coordination Group
ADB	Asian Development Bank
AIIB	Asian Infrastructure Investment Bank
AMC	Anti-Monopoly Commission
a.s.l	Above see level
BoP	Balance of Plant
BT	Barqi Tojik
CAPS	Central Asia Power System
CASA	Central Asia South Asia
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CPS	Country Partnership Strategy
CRI	Corporate Results Indicators
CSO	Civil Society Organization
DA	Designated Account
DC	Direct Contracting
DCC	Development Coordination Council
DPL	Development Policy Loan
EBRD	European Bank for Reconstruction and Development
EBITDA	Earnings before Interest, Taxes, Depreciation, and Amortization
ECA	Europe and Central Asia
EDB	Eurasian Development Bank
EC	European Commission
EIB	European Investment Bank
EIRR	Economic Internal Rate of Return
EPC	Engineering, Procurement, and Construction
EPP	Emergency Preparedness Plan
IMF	International Monetary Fund
IPP	Independent Power Producer
ISA	International Standards on Auditing
IsDB	Islamic Development Bank
KfW	Kreditanstalt fur Wiederaufbau
kV	Kilovolt
kWh	Kilowatt-hour
LC	Letter of Credit
LEC	Levelized Energy Cost
LV	Low Voltage
MEWR	Ministry of Energy and Water Resources
MIV	Main Inlet Valve
mln	Million
MMBtu	Million British Thermal Units
MOEDT	Ministry of Economic Development and Trade
MOF	Ministry of Finance
MOJ	Ministry of Justice
MV	Medium Voltage
NGO	Non-Government Organization
NPV	Net Present Value
OBE	Operating Basis Earthquake
O&M	Operation and Maintenance
OP	Operational Policy
OPEC	The Organization of Petroleum Exporting Countries
PFMA	Possible Failure Mode Analysis
PMC	Project Management Consultant
PMT	Proxy Means Testing
PoE	Panel of Experts

ESIA	Environmental and Social Impact Assessment	POM	Project Operational Manual
ESMAP	Energy Sector Management Assistance Program	PPA	Power Purchase Agreement
ESMP	Environmental and Social Management Plan	PPSD	Project Procurement Strategy Document
EU	European Union	PRG	Project Realization Group
EXIM	Exports and Imports	PSDI	Plant Supply, Design, and Installation
FIRR	Financial Internal Rate of Return	QCBS	Quality and Cost Based Selection
FM	Financial Management	RFB	Request for Bids
FMM	Financial Management Manual	SCADA	Supervisory Control and Data Acquisition
GBAO	Gorno-Badakhshan Autonomous Oblast	SEE	Safety Evaluation Earthquake
GDP	Gross Domestic Product	SEP	Social Engagement Plan
GHG	Greenhouse Gas	SOE	State-owned Enterprise
GRM	Grievance Redress Mechanism	SSS	Single-Source Selection
GRS	Grievance Redress Service	TA	Technical Assistance
GWh	Gigawatt-hour	TALCO	Tajik Aluminum Company
HAP	Hydropower Advancement Project	TPP	Thermal Power Plant
HPP	Hydropower plant	TSA	Targeted Social Assistance
ICB	International Competitive Bidding		
IDC	Interest During Construction	UN	United Nations
IFAC	International Federation of Accountants	UNDP	United Nations Development Program
IFI	International Financial Institution	USAID	United States Agency for International Development
IFR	Intermediate un-audited Financial Report	VECs	Valued Environmental and Social Components
IFRS	International Financial Reporting Standards		

Regional Vice President:	Cyril Muller
Country Director:	Lilia Burunciuc
Senior Global Practice Director:	Riccardo Puliti
Practice Manager:	Ranjit Lamech
Task Team Leaders:	Artur Kochnakyan, Takhmina Mukhamedova

REPUBLIC OF TAJIKISTAN
Nurek Hydropower Rehabilitation Project, Phase I

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Republic of Tajikistan

Nurek Hydropower Rehabilitation Project Phase I (P150816)

PROJECT APPRAISAL DOCUMENT

EUROPE AND CENTRAL ASIA REGION

ENERGY AND EXTRACTIVES GLOBAL PRACTICE

Report No.: PAD1565

Basic Information

Project ID	EA Category	Team Leader(s)
P150816	B - Partial Assessment	Artur Kochnakyan, Takhmina Mukhamedova

Lending Instrument	Fragile and/or Capacity Constraints [ ]
Investment Project Financing	Financial Intermediaries [ ]
	Series of Projects [X]
Project Implementation Start Date	Project Implementation End Date
May 4, 2017	31-Dec-2023
Expected Effectiveness Date	Expected Closing Date
01-Nov-2017	31-Dec-2023
Joint IFC	
No	

Practice Manager	Senior Global Practice Director	Country Director	Regional Vice President
Ranjit J. Lamech	Riccardo Puliti	Lilia Burunciuc	Cyril E Muller

Recipient: Republic of Tajikistan

Responsible Agency: Ministry of Energy and Water Resources

Contact:	Usmonali Usmonzoda	Title:	Minister
Telephone No.:	99237-235-35-66	Email:	uusmanov@gmail.com

Responsible Agency: OJSHC Barqi Tojik

Contact:	Mirzo Ismoilzoda	Title:	Chairman
Telephone No.:	99237-235-87-66	Email:	barki_tojik@tajnet.com

Project Financing Data(in USD Million)

[ ]	Loan	[X]	IDA Grant	[ ]	Guarantee
[X]	Credit	[ ]	Grant	[X]	Other

Total Project Cost:	350.00	Total Bank Financing:	225.7
Other Financing:	100.00		
Financing Gap:	24.30		

Financing Source	**Amount**
International Development Association (IDA)	169.135
IDA Grant	56.565
Asian Infrastructure Investment Bank (AIIB)	60.00
Eurasian Development Bank	40.00
Total	325.70

Expected Disbursements (in USD Million)

Fiscal Year	2018	2019	2020	2021	2022	2023	2024	
Annual	2.00	36.00	22.00	50.00	60.00	40.00	15.70	
Cumulative	2.00	38.00	60.00	110.00	170.00	210.00	225.70	

Institutional Data

Practice Area (Lead)

Energy & Extractives

Contributing Practice Areas

Trade & Competitiveness, Water

Proposed Development Objective(s)

The project development objectives are to rehabilitate and restore the generating capacity of three power generating units of Nurek hydropower plant, improve their efficiency, and strengthen the safety of the Nurek dam.

Components

Component Name	**Cost (USD Millions)**
Rehabilitation of the three generating units, the key infrastructural components of the plant, and replacement of auto-transformers	310.00
Enhancement of dam safety	30.00
Technical assistance (TA)	10.00

Systematic Operations Risk- Rating Tool (SORT)

Risk Category	**Rating**
1. Political and Governance	High

2. Macroeconomic	High
3. Sector Strategies and Policies	High
4. Technical Design of Project or Program	Substantial
5. Institutional Capacity for Implementation and Sustainability	Substantial
6. Fiduciary	High
7. Environment and Social	Moderate
8. Stakeholders	Substantial
9. Financing	Substantial
10. Climate Change Related Disaster	Low
OVERALL	Substantial

Compliance

Policy

Does the project depart from the CAS in content or in other significant respects?	Yes [ ]	No [X]
Does the project require any waivers of Bank policies?	Yes [ ]	No [X]
Have these been approved by Bank management?	Yes [ ]	No [X]
Is approval for any policy waiver sought from the Board?	Yes [ ]	No [X]
Does the project meet the Regional criteria for readiness for implementation?	Yes [X]	No [ ]

Safeguard Policies Triggered by the Project	**Yes**	**No**
Environmental Assessment OP/BP 4.01	**X**	
Natural Habitats OP/BP 4.04		**X**
Forests OP/BP 4.36		**X**
Pest Management OP 4.09		**X**
Physical Cultural Resources OP/BP 4.11		**X**
Indigenous Peoples OP/BP 4.10		**X**
Involuntary Resettlement OP/BP 4.12		**X**
Safety of Dams OP/BP 4.37	**X**	
Projects on International Waterways OP/BP 7.50	**X**	
Projects in Disputed Areas OP/BP 7.60		**X**

Legal Covenants

Name	**Recurrent**	**Due Date**	**Frequency**
Legislation Related to BT	**X**		CONTINUOUS

Description of Covenant

The Project Implementing Entity’s Legislation has been amended, suspended, abrogated, repealed or waived so as to affect materially and adversely the ability of the Project Implementing Entity to perform any of its obligations under the Project Agreement.

Name	**Recurrent**	**Due Date**	**Frequency**
Channeling of Project Funds	**X**		CONTINUOUS
Description of Covenant To facilitate the carrying out of the Project, the Recipient shall make the proceeds of the Financing available to the Project Implementing Entity under the financing terms, including Front-end Fee, the Commitment Charge, Service Charge, Interest Charge and repayment schedule applicable to the respective parts of the Financing, as set forth in Article II of the Financing Agreement.			
Name	**Recurrent**	**Due Date**	**Frequency**
Changes to the Subsidiary Agreement	**X**		CONTINUOUS
Description of Covenant The Recipient shall exercise its rights under the Subsidiary Agreement in such manner as to protect the interests of the Recipient and the Association and to accomplish the purposes of the Financing. Except as the Association shall otherwise agree, the Recipient shall not assign, amend, abrogate or waive the Subsidiary Agreement or any of its provisions.			
Name	**Recurrent**	**Due Date**	**Frequency**
Safeguards Compliance	**X**		CONTINUOUS
Description of Covenant The Recipient shall cause the Project Implementing Entity to implement the Project in accordance with the Environmental and Social Impact Assessment, the Environmental and Social Management Plan, the Stakeholder Engagement Plan, the Dam Operation and Maintenance Plan and the Emergency Preparedness Plan.			
Name	**Recurrent**	**Due Date**	**Frequency**
Average Electricity Tariff Increase	**X**		CONTINUOUS
Description of Covenant The Recipient shall gradually increase the average electricity tariff annually during the Project implementation period to reach cost-recovery tariff level by December 31, 2021.			
Name	**Recurrent**	**Due Date**	**Frequency**
Project Operational Manual	**X**		CONTINUOUS
Description of Covenant The Project Implementing Entity shall carry out the project in accordance with the Project Operational Manual and not amend, suspend, repeal or waive any of the provisions of the Project Operational Manual without the Association’s prior written agreement. In case of any discrepancy between the provisions of the Project Operational Manual and those of the Project Agreement, the provisions of the Project Agreement shall prevail.			
Name	**Recurrent**	**Due Date**	**Frequency**
Project Management Consultant	**X**		CONTINUOUS

Description of Covenant			
The Project Implementing Entity shall maintain, during the entire period of project implementation, unless otherwise agreed with the Association, the Project Management Consultant, with the experience, competence and terms of reference satisfactory to the Association, to assist with the detailed design of the rehabilitation and dam safety works, the tendering processes, and the supervision of the works.			
Name	**Recurrent**	**Due Date**	**Frequency**
Dam Safety Panel	X		CONTINUOUS
Description of Covenant			
The Project Implementing Entity shall maintain, during the entire period of the project implementation, the Dam Safety Panel, which shall include international experts with the experience, competence and terms of reference satisfactory to the Association, to provide independent review and expert advice on dam safety and other technical aspects of the project.			
Name	**Recurrent**	**Due Date**	**Frequency**
Project Realization Group	X		CONTINUOUS
Description of Covenant			
The Project Implementing Entity shall maintain, during the entire period of project implementation, the Project Realization Group with functions, terms of reference and resources satisfactory to the Association for the purposes of day-to-day Project management, monitoring and evaluation.			
Name	**Recurrent**	**Due Date**	**Frequency**
Long term Debt of BT	X		CONTINUOUS
Description of Covenant			
The Recipient shall cause the Project Implementing to, except as the Association shall otherwise agree, not incur any long-term debt unless a reasonable forecast of its revenues and expenditures shows that its estimated net revenues for each fiscal year during the term of the debt to be incurred shall be equal to at least the estimated long-term debt service requirements in such year on all debt of the Project Implementing Entity, including the debt to be incurred.			
Name	**Recurrent**	**Due Date**	**Frequency**
Short term Debt of BT	X		CONTINUOUS
Description of Covenant			
The Project Implementing Entity shall, except as the Association shall otherwise agree, maintain the ratio of its operating cash flows to short-term debt service requirement not be less than 0.08 for the Recipient's fiscal year 2017; 0.15 for fiscal year 2018; 0.20 for fiscal year 2019; 0.25 for fiscal year 2020; 0.31 for fiscal year 2021; and 0.52 for fiscal year 2022.			
Name	**Recurrent**	**Due Date**	**Frequency**
Collection Rates for Billed Electricity	X		CONTINUOUS
Description of Covenant			
The Project Implementing Entity shall reach 88 percent average collection rate for billed electricity sold domestically in 2017 and 90 percent in 2018, and not to reduce such rate below 90 percent until the Project Closing Date.			

Conditions

Source Of Fund	Name	Type
IDA	Subsidiary Agreement of BT	Effectiveness

Description of Condition

The Subsidiary Agreement has been executed on behalf of the Recipient and the Project Implementing Entity.

Source Of Fund	Name	Type
IDA	Financing Agreement with AIIB	Effectiveness

Description of Condition

The Co-financing Agreement has been executed and delivered and all conditions precedent to its effectiveness or to the right of the Recipient to make withdrawals under it (other than the effectiveness of the Financing Agreement) have been fulfilled.

Source Of Fund	Name	Type
IDA	Project Operational Manual	Effectiveness

Description of Condition

The Project Operational Manual, satisfactory to the Association, has been adopted by the Project Implementing Entity.

Team Composition

Bank Staff

Name	Role	Title	Specialization	Unit
Artur Kochnakyan	Team Leader (ADM Responsible)	Senior Energy Specialist	Task management and economic analyses	GEE03
Takhmina Mukhamedova	Team Leader	Energy Specialist	Task management	GEE03
Dilshod Karimova	Procurement Specialist (ADM Responsible)	Procurement Specialist	Procurement	GGO03
Ahmed Merzouk	Team Member	Lead Procurement Specialist	Procurement	GGO03
Niso Bazidova	Financial Management Specialist	Financial Management Analyst	Financial Management	GGO21
Eric Ranjeva	Team Member	Finance Officer	Disbursements	WFALN
Angela Nyawira Khaminwa	Safeguards Specialist	Senior Social Development Specialist	Social Issues	GSU03
Dung Kim Le	Team Member	Program Assistant	Operational support	GEE03
Emil Zalinyan	Team Member	Energy Specialist	Financial analyses	GEE03
Farangis Dakhte	Team Member	Program Assistant	Program support	ECCTJ
Garik Sergeyan	Team Member	Senior Financial	Financial	GGO21

		Management Specialist	management	
Hiwote Tadesse	Team Member	Operations Analyst	Operations	GEE03
Husam Mohamed Beides	Team Member	Lead Energy Specialist	Technical and operational advice	GEE03
Imtiaz Hizkil	Team Member	Consultant	Engineering	GEE03
Javaid Afzal	Safeguards Specialist	Senior Environmental Specialist	Environment	GEN03
Juliana Victor	Team Member	Senior M&E Specialist	Monitoring and Evaluation	GEESO
Majed El-Bayya	Team Member	Lead Procurement Specialist	Procurement	GGO03
Moses Sabuni Wasike	Team Member	Senior Financial Management Specialist	Financial Management	GGO21
Nikolai Soubbotin	Counsel	Lead Counsel	Legal	LEGLE
Paivi Koljonen	Team Member	Lead Energy Specialist	Technical	GEE03
Satoru Ueda	Team Member	Lead Dam Specialist	Dam specialist	GWASO

Extended Team

Name	Title	Office Phone	Location
Iftikhar Khalil	Energy Advisor		
Federico Ciampitti	Hydro-mechanical consultant		

Locations

Country	First Administrative Division	Location	Planned	Actual	Comments
Tajikistan	Viloyati Khatlon	Nurek	X		

Consultants (Will be disclosed in the Monthly Operational Summary)

Consultants Required? Consultants will be required

I. STRATEGIC CONTEXT

A. Country Context

1. **Tajikistan is a landlocked country located in southeast Central Asia. It has a population of 8.5 million and a Gross National Income per capita of US$1,240 (2015)**. Tajikistan is one of the poorest countries in the Europe and Central Asia (ECA) Region. Since 2000, the economy grew strongly for 17 years, at 7.8 percent on average per annum driven by the rapid increase of remittances and the subsequent expansion of services, public investments, and construction. The spillover effects of the regional recession slowed the economic growth from 7.4 percent in 2013 to 6.9 percent in 2014 and then to 6.0 percent in 2015, mirroring the steep decline in remittances and weakened export proceeds. In 2016, the economic growth recovered to 6.9 percent as foreign-financed investments and improvement in the net export position more than offset the continued decline in remittances.

2. **Despite regional headwinds, Tajikistan's economy grew by a robust 6.9 percent, year-on-year (y/y), in 2016, supported by an increase in foreign-financed public and private investments**. Higher economic activity was largely driven by industry and construction, while the contribution of agriculture sector was relatively modest. A sharp increase in foreign-financed public investments coupled with underperforming external revenue collections, widened the fiscal deficit from 1.9 percent of Gross Domestic Product (GDP) in 2015 to 4.0 percent of GDP in 2016. Although, in mid-2016 the government took steps to cut low-priority current and capital outlays, the downward revision of the budget expenditures was not enough to adjust for the unexpectedly high shortfall in revenues. Strategic expenditures, including Rogun Hydropower Plant (HPP) and core social spending, were ring-fenced. The government also honored its postponed commitment to increase public sector wages and pensions, which added an additional strain to the budget envelope.

3. **The continued decline in remittances, which are the major source of foreign exchange income, coupled with governance issues in the banking sector, have exacerbated financial sector vulnerabilities**. The share of nonperforming loans increased dramatically and several systemic banks failed to meet obligations starting in the first half of 2016. This has resulted in the government’s decision to bailout two of the largest banks in the amount of 6.0 percent of GDP at the end 2016, while licenses for two smaller banks were revoked in the beginning of 2017.

4. **The external position significantly improved in light of import contraction and strong foreign-direct investments.** The current account deficit narrowed from 6.0 percent of GDP in 2015 to an estimated 2.5 percent of GDP by end 2016. The protracted decline in real remittances of over 50 percent through 2014-2016 and exchange rate depreciation by another 11.2 percent in 2016, considerably depressed consumer demand. The level of foreign direct investments rose to 6.0 percent of GDP from 3.4 percent of GDP in 2014 and continued to be heavily dominated by China.

5. **To ease inflationary pressures, the Central Bank significantly tightened the monetary policy stance**. It increased the refinancing rate from 8.0 percent at the end of 2015 to

16.0 percent in March 2017, particularly as a response to the liquidity injection resulting from the financial sector bailout. The Central Bank also continued its efforts to build up the country's foreign-exchange reserves, mainly in gold, which increased by over 30 percent in 2016 and reached 2.7 months of imports according to official estimates.

6. **Despite the anticipated improvement of the external environment, risks to growth are tilted to the downside**. Large contingent liabilities among state-owned enterprises (SOEs) and weaknesses in the business climate will continue to slow economy-wide growth, and could add to debt-related risks. Ongoing asset-quality reviews at commercial banks may reveal new capitalization needs and further increase fiscal costs. A weaker-than-expected recovery among regional economies or delays in the expansion of the Targeted Social Assistance program could hinder progress on poverty reduction.

7. **The Government of Tajikistan set ambitious goals to be achieved in its Medium-term Development Strategy 2016-2020 and National Development Strategy 2030**. The main objectives are to reduce poverty to 20 percent by 2020, double the GDP per capita by 2030 and develop into an industrialized economy. In the medium-term, achieving these goals will be subject to prudent fiscal and monetary policy frameworks by addressing vulnerabilities in the financial sector and SOEs. Comprehensive structural reforms will be essential to improve the business climate and to promote private sector-led growth.

B. Sectoral and Institutional Context

Overview

8. **The power sector is comprised of the vertically integrated energy company, Barqi Tojik (BT), two independent power producers (IPPs), Rogun Joint Stock Company, and a concession combining power generation and distribution**. BT owns and operates most of the electricity generating plants and is also responsible for electricity transmission, dispatch, and distribution services. The two IPPs – Sangtuda-1 and Sangtuda-2 HPP – were constructed with foreign direct investments from Russia and Iran, and supply electricity to BT under 20-year power purchase agreements. The Government has started construction of the Rogun HPP through the incorporated Rogun Joint Stock Company, which is legally independent from BT. The Pamir Energy Company generates and supplies electricity to around 30,000 consumers in the Gorno Badakhshan Autonomous Oblast (GBAO), which is in the south eastern part of the country. Access to electricity is universal with all cities and rural areas connected to the distribution network.

9. **The Government initiated unbundling of BT** and plans to complete the functional unbundling of generation, transmission, and distribution services by the end of 2017 and the legal separation of those entities by the end of 2018. BT has already completed functional unbundling at one of the service zones and unbundling is underway in two more service zones.

10. **The power sector is dominated by hydropower plants**. The total installed capacity is 5,400MW and hydropower plants account for 95 percent of that capacity. The Nurek HPP, with a seasonal reservoir, is the largest generating plant. With an installed capacity of 3,000MW, it

generates 70 percent of the total annual energy requirements and is also the balancing plant in the system.

Table 1: Generation Capacity of Main HPPs

Plant	Installed Capacity (MW)
Nurek	3,000
Sangtuda-1	670
Baipasa	600
Golovnaya	240
Sangtuda-2	220
Kairakum	126

11. **Restoration of the generation capacity of Nurek HPP is essential for meeting the domestic demand and improving financial viability of BT.** Only 77 percent of Nurek's installed capacity is operational due to dilapidation and obsolescence of power plant equipment and key infrastructural components. One of the units is off-line due to a major failure of the transformer and the remaining units cannot operate at the rated capacity due to dilapidation of key equipment and infrastructural components of the plant. Nurek HPP is critical for supplying the much needed electricity during the winter when the demand is the highest (given the heating season) and the supply capability is the lowest due to hydrological conditions.

12. **The power system is interconnected with the neighboring countries, but there is limited electricity trade despite significant potential**. Following independence in 1991, Tajikistan continued to be a member of the Integrated Central Asia Power System (CAPS), through which the five Central Asian countries optimized the use of fossil fuel and hydropower resources that are unevenly distributed among those countries. Tajikistan and the Kyrgyz Republic, as the upstream countries of the Amu Darya and Syr Darya river basins, have significant hydropower potential, whereas thermal resources are concentrated in the downstream countries of Uzbekistan, Turkmenistan and Kazakhstan. The coordinated system operated successfully in the initial years of independence. However, differences in national priorities soon put pressure on these arrangements and some of the countries, including Tajikistan, desynchronized their systems. Parts of the transmission interconnections were dismantled.

13. **The Ministry of Energy and Water Resources (MEWR) is responsible for policy-making in the power sector and the Anti-Monopoly Commission (AMC) is responsible for review and approval of tariffs.** The legal and regulatory framework of the sector is governed by the Law on Energy (2000), the Law on Conservation of Energy (2002), Concept for Development of Small Scale Hydropower (2009), and the Law on Alternative Energy Sources (2010). The Law on Energy defines the role of various government bodies and agencies, including MEWR with respect to regulation of the power sector operations, including licensing, and potential incentives that may be provided to promote foreign investments in the sector. The legislation on energy conservation and alternative sources of energy stipulate the strategic objective of ensuring economically efficient consumption of energy and promotion of indigenous renewable energy resources, which consist largely of hydropower. The electricity tariff approval function is with the Anti-Monopoly Commission (AMC) under the Government. The AMC is

responsible for review and approval of tariffs for all natural monopolies, including electricity services.

14. **The National Development Strategy for 2016-2030 prioritizes energy sector development as one of the strategic goals.** The energy sector is considered essential for achievement of the country's long-term development objective to improve the living standards of the population based on sustainable economic development. The Government's energy sector development strategic goal focuses on providing reliable, adequate, and affordable electricity in a socially, economically, and environmentally sustainable manner. The policy aims to: (a) provide access to energy for all; (b) maximize energy savings through efficient use of energy; (c) improve sector performance by commercializing utility operations; (d) attract private investments in the sector; (e) increase electricity exports; and (f) undertake power sector reforms, including strengthening of the capacity and governance of the sector companies.

Power Sector Challenges

15. The power system is currently facing the key challenges below, which need to be addressed to ensure adequate and reliable electricity supply.

16. **Challenge #1: Winter electricity shortages.** Approximately 70 percent of the population suffers from extensive shortages of electricity during the winter. These shortages were estimated at about 2,700 GWh or 25 percent of winter demand in 2013.[1] The economic losses from those shortages were estimated at US$200 million or 3 percent of GDP. The electricity shortages are due to:

(a) *Shortage of firm generation capacity in winter*. Hydropower generation reduces during winter due to seasonal reduction of the flows of the main rivers. Insufficient reservoir capacity and water rights of downstream riparian states limit the ability to offset this seasonal variation. As a result, the country is in the unfortunate situation of having insufficient electricity generation in winter and excess capacity during the summer with limited market opportunities for sales. Eighty percent of urban households rely on electricity-based heating, which contributes to substantial increase of the winter demand given that the existing centralized heating systems are not functional due to severe dilapidation and the absence of gas imports. The winter electricity deficit reduced given the commissioning (in December 2016) of additional 300MW of capacity at Dushanbe-2 Combined Heat and Power Plant (CHP), which will also be supplying heat to the city of Dushanbe.

(b) *Dilapidation of the largest generation plant in the country*. Only 77 percent of the generation capacity of Nurek HPP is operational because generating units require refurbishment given the age and technical condition. The need for rehabilitation was established based on the technical assessment of the condition of the generating units and other infrastructural components of the power plant. The poor technical condition of the plant is due to obsolescence of equipment and lack of major capital repairs since its commissioning.

[1] Tajikistan's Winter Energy Crisis: Electricity Supply and Demand Alternatives, 2012.

17. Overall, O&M practices at Nurek HPP are adequate. The feasibility study for the proposed project confirmed that the power plant was operated without major accidents/issues resulting from incompetence or limited capacity of the staff. Nurek HPP staff maintained the equipment and other infrastructural components in good condition taking into account financing constraints. Planned electricity tariff increases to gradually reach cost-recovery levels by 2022 will allow generating additional financial resources for increased spending on O&M after rehabilitation of the power plant.

18. **Challenge #2: Financial distress**. The power sector is in financial distress due to tariffs lagging the cost-recovery level and sub-optimal financial management of BT. The weighted average tariff is estimated to be 55 percent below the cost-recovery level (computed following the cash needs approach). In 2012-2014, the Government increased the end-user tariffs by 46 percent in nominal terms. However, the tariff increases were not sufficient to allow BT to recover its cash costs, which have significantly increased due to inflation and increasing debt service needs. The debt service costs increased due to depreciation of local currency. Specifically, in 2012-2015, the cumulative inflation was 24.6 percent and the local currency depreciated by 47 percent, which further exacerbated the cash shortage given the need to service US$800 million equivalent of long-term debt (as of end-2015) denominated primarily in US$.

19. **The flaws in the existing tariff-setting methodology exacerbated financial difficulties of BT**. In particular, the existing tariff methodology does not allow servicing the debts and does not contain any provision for pass-through of increasing costs. As a result, BT has not been able to pay in full for energy purchased from IPPs, service its debts and finance the required capital repairs and maintenance. The issue of debt service is particularly acute because BT's total debt, including short-term debt, increased from US$450 million in 2012 to US$950 million in 2015. Out of the total debt, US$800 million are long-term loans from International Financial Institutions (IFIs) and bilaterals for specific investment projects. The remaining US$150 million are short-term and expensive loans in US$ from a local commercial bank. Those loans were taken to make up for the short-fall of working capital due to cash shortage. BT rolls over the short-term commercial loans as it is not able to repay them. It is not able to service the long-term loans either and the Ministry of Finance (MOF) repays the principal due to lenders (e.g. IFIs and bilaterals) and the interest from the state budget. The Government is currently preparing a debt restructuring plan to resolve this unsustainable indebtedness issue.

20. **BT has inefficient management of receivables and inventory, which results in significant amount of cash being tied up for extended periods of time**. The number of days receivables are outstanding was 91 days in 2015 compared to the good-practice industry standard of no more than 45 days. The average annual inventory was 174 days of sales in 2015 compared to the industry benchmark of 60 days. The development partners have already agreed on targets for improvement of the receivables collection and inventory management, which should be implemented by BT in 2017-2018.

21. **Challenge #3: Gaps in billing, accounting and financial reporting of BT**. There is no unified billing system in place. There are donor-financed ongoing initiatives in regional distribution companies of BT. However, those systems will ultimately need to be integrated and

rolled-out to cover all consumers and regions. The existing system of BT does not provide end-to-end data integrity, and its reliance on manual entry of all customer and consumption data at various dispersed entry points significantly increases the risk of error, manipulation and fraud in the critical metering and billing cycle.

22. **BT has made significant progress since 2010 in strengthening its accounting and financial reporting functions**. The auditors of the 2014 and 2015 annual financial statements of BT were able to express an opinion. It was a qualified opinion primarily due to the absence of appropriate procedures for recognition of revenues, accounts receivable and advances received for electricity supply. This is due to deficiencies in the billing system and inability to recognize commercial losses as such. BT is allowed to include into the computation of tariffs a loss provision approved by the Government. If the actual losses exceed the allowed level of provision, then BT treats those unaccounted for electricity as sales. The practice should discontinue and BT should recognize those as commercial and technical losses even if not recovered through tariff. Despite outstanding problems, the qualified audit opinion is a tangible achievement given that auditors of annual financial statements for previous years issued only disclaimer of opinion given lack of appropriate audit evidence to verify the values/amounts of other main line items of the balance sheet and the income statement.

23. **Challenge #4: Increasingly unaffordable electricity tariffs and inadequate social protection of vulnerable consumers**: The energy expenditure burden is high for the poorest parts of the population, especially in rural areas. This suggests that a large share of rural households cannot afford even basic levels of energy consumption. As of 2014, the bottom two quintiles of rural households were estimated to spend 24 and 19 percent of their disposable income on energy during the winter heating season. This is substantially above the 10 percent benchmark, which is often used to define "energy poverty."

24. **The Government is using the Targeted Social Assistance (TSA) benefit program to deliver social assistance to the poor**. The program was introduced after merging the two legacy social assistance programs. The Government adopted a new mechanism for poverty-targeting based on proxy-means testing (PMT), which uses indicators of well-being that are correlated significantly with poverty in the country. The TSA was launched as a pilot in 2011 initially in two districts and expanded to a total of 10 districts in 2013. The early success of the program was recognized in the national poverty reduction strategy, which endorsed the pilot as a basis for establishing a national mechanism for TSA. The program was further expanded to 25 districts in 2014 and rolled out to an additional 15 districts in early 2017, covering two-thirds of the country. In February 2017, the TSA bill was signed into law by the President, laying a solid foundation for the national TSA rollout in 2018. The allocation to the program is not sufficient to adequately protect all the poor, however, given the limited coverage of the program (at the moment, focusing on the extreme poor only, or the bottom 15 percent of the population) due to fiscal constraints of the Government.

Measures Undertaken by the Government to Address the Existing Challenges

25. **Reduction of winter electricity deficit**. The Government has undertaken the following key steps to address the issue of winter electricity deficit.

- In 2014, BT completed the 100MW Phase I of the new Dushanbe-2 Combined Heat and Power (CHP) Project, which is run on domestic coal. Phase II of the Project added another 300MW of capacity, which will increase winter supply by a total of 1,180 GWh, which is 12 percent of the total winter demand.
- The Government started construction of the 3,600MW Rogun HPP. The first two units are expected to start generating electricity from mid-2019. This will increase winter supply by 612 GWh in 2019, which is 6 percent of the total winter demand.
- BT is also currently rehabilitating Golovnaya and Kairakum HPPs with support from the Asian Development Bank (ADB) and the European Bank for Reconstruction and Development (EBRD) respectively to restore and increase generation capacity of those power plants.
- BT requested development partners to finance rehabilitation of Nurek HPP to avoid loss of generation capacity. The total financial cost of rehabilitation of the power plant is estimated at US$700 million (to be financed in two phases), which includes refurbishment of all generating units; key infrastructural components of the plant; replacement of auto-transformers used to evacuate the generated electricity; dam safety enhancement measures; and technical assistance required for implementation of the project.

26. **Improvement of financial standing of BT**. Barqi Tojik and the Government are implementing the Action Plan for Financial Recovery of BT, which was approved by the Deputy Prime Minister on April 5, 2017 (the Action Plan is presented in Annex 6). The key activities include: (a) adoption of a cost-recovery electricity tariff methodology; (b) gradual increase of tariffs to cost-recovery level; (c) increase of cash collection rates, reduction of outstanding days for receivables, and improvement of inventory management efficiency; and (d) repayment of Orienbank loans from additional cash or cost savings generated from implementation of the measures in the Action Plan. Development partners, including the World Bank, EBRD and ADB, have TA programs aimed at helping the Government implement those key measures.

27. The Government with support of development partners has already undertaken some measures to improve operational and financial performance of BT.

a. MEWR prepared a Concept for New Electricity Tariff Policy. The draft of the Concept contains all of the key elements of a robust cost-recovery tariff methodology and a time-bound action plan to complete the preparatory work required for introduction of the new tariff methodology. The Concept is expected to be approved by the end of April 2017, disclosed for public consultations, and transformed into a detailed methodology. The Bank will be supporting the Government under a proposed Energy Sector Management Assistance Program (ESMAP) Grant to prepare the methodology, train the staff to apply it, and conduct public outreach to inform the key stakeholders and raise public awareness around tariff-setting issues.
b. The Government increased the average electricity tariff by approximately 13 percent starting from November 1, 2016.
c. BT will not be required to pay penalties on accumulated overdue tax payments to the Ministry of Finance.

d. BT and Agency on Land Reclamation and Irrigation signed an act on mutual settlement of debts, which will enable BT to remove payables to the Agency of Land Reclamation and Irrigation from BT's accounts.
e. BT's payable to Sangtuda-1 HPP was reduced by TJS12.5 million (President's Decree No. 42, dated January 25, 2017) in exchange for a reduction in the accrued tax liabilities of Sangtuda-1 IPP to the state budget.
f. BT completed functional unbundling into generation, transmission, and distribution business segments.
g. The Ministry of Health and Social Policy and the Ministry of Finance are working to develop social mitigation measures for tariff increases. The Bank is providing advisory and analytical support to the Government to further improve the coverage and targeting of existing benefit programs to deliver the subsidies. Additionally, the Bank intends to provide support to review alternative mechanisms for protection of the poor such as lifeline subsidies.
h. Improvement of financial efficiency indicators of BT. The average collection rate for billed electricity increased from 63 percent in 2013 to 83 percent in 2015, including collections from Tajik Aluminum Company (TALCO). The number of days that receivables are outstanding reduced from 104 days in 2013 to 91 days in 2015 as per International Financial Reporting Standards (IFRS) compliant financial statements.

28. **Improvement of reliability of electricity supply**. BT has recently implemented a number of projects to improve the reliability of electricity supply in the country through the construction of new transmission lines and substations and the rehabilitation of existing obsolete and unreliable transmission and distribution infrastructure. These include construction of the important North-South 500kV transmission interconnection, and the rehabilitation of various substations, including Ravshan and Regar, which are the backbone of the power transmission network.

29. **Reduction of electricity losses and improvement of billing**. BT has implemented investment programs aimed at reduction of commercial electricity losses and improvement of the billing systems. Under the recently completed World Bank financed Energy Loss Reduction Project, BT installed 215,000 new meters for the Dushanbe Electricity Network, which has the largest number of consumers in the country. The project helped to reduce the unaccounted consumption of electricity in the city of Dushanbe from 19 percent in 2011 to 17.5 percent in 2014. BT is implementing a number of projects to introduce commercial billing systems.

30. The Working Group of the Development Coordination Council (DCC), which is comprised of representatives of Asian Development Bank (ADB), Aga Khan Development Network, European Union (EU), European Bank for Reconstruction and Development (EBRD), European Investment Bank (EIB), Islamic Development Bank (IsDB), KfW, United Nations Development Program (UNDP), United States Agency for International Development (USAID), and World Bank, is a coordination platform, which enables all development partners of the Government to better coordinate their efforts in helping the Government address the above power sector challenges.

Table 2: Recently Completed and Ongoing Power Sector Projects

Name of Project	Loan/Project Size	Source of Financing
Rehabilitation of Existing and Construction of New Generation Capacity		
Construction of 3,600MW Rogun HPP	US$3.9 billion	State budget
300MW Phase II of Dushanbe-2 CHP	US$350 million (including US$140 million loan)[2]	EXIM Bank of China
Construction of small and mini hydropower plants in rural areas of Tajikistan	US$15 million	Islamic Development Bank (IsDB) and the Kuwait Fund for Arab Economic Development
Rehabilitation of Kairakum HPP	US$71 million	EBRD
Rehabilitation of Golovnaya HPP	US$136 million	ADB
Rehabilitation of Varzob HPP	US$13 million	
Strengthening of Transmission and Distribution Infrastructure and Loss Reduction		
Wholesale metering and transmission reinforcement project	US$54 million	ADB
Rehabilitation of electricity transmission and distribution facilities in the Khatlon and Dushanbe regions	US$34 million	
Baipaza HPP landslide stabilization project	US$5 million	
Construction of 220 kV double-circuit transmission interconnection between Tajikistan and Afghanistan	US$10 million	IsDB
Rehabilitation of 220kV Ravshan substation	US$13 million	
Central Asia South Asia Electricity Transmission and Trade Project	US$1.0 billion	World Bank, EBRD, IsDB, ACG[3]
Construction of 220 kV double-circuit transmission interconnection between Tajikistan and Afghanistan	US$9 million	OFID
Construction of 220 kV Khujand-Ayni transmission line	US$37 million	Government of China
Construction of 500 kV South-North transmission interconnection	US$318 million	EXIM Bank of China
Rehabilitation of 500kV Regar substation	US$35 million	
Construction of Lolazor-Khatlon 220 kV transmission line	US$55 million	
Reduction of electricity losses in Sughd region	US$30 million	EBRD, EIB, EC

[2] The remaining portion was financed through award of mining rights to Chinese companies.
[3] ACG currently includes: the Saudi Fund for Development, the Kuwait Fund for Arab Economic Development, the Abu Dhabi Fund for Development and the Organization of Petroleum Exporting Countries' (OPEC) Fund for Development.

Name of Project	Loan/Project Size	Source of Financing
Loss Reduction, improvement of BT billing, accounting function, financial management, and regulatory framework		
Phase II Regulatory TA	US$0.5 million	EBRD
Improvement of BT's billing and collection system	US$0.5 million	ADB
Introduction of International Accounting Standards at BT	US$0.5 million	
Strengthening of corporate management of BT	US$1.5 million	
Improvement of accounting and financial management systems of the BT subsidiaries	US$0.4 million	

31. **Elimination of gaps in accounting and financial management**. With support from ADB and EBRD TA projects, BT strengthened the accounting capacity, introduced International Accounting Standards, improved financial management systems, and is planning to further strengthen corporate governance.

C. Higher Level Objectives to which the Project Contributes

32. The project contributes to the key strategic outcomes outlines in the Country Partnership Strategy (CPS) for FY2015-18. In particular, the project supports Pillar 1 of the CPS, "Strengthening the role of the private sector." Specifically, rehabilitation of Nurek HPP will reduce the amount of un-met electricity demand in winter, which will reduce the amount of foregone economic revenue due to power outages, thus, contributing to private sector led economic growth. The project is also aligned with the World Bank Group's Energy Sector Directions Paper and the Sustainable Development Goal No. 7 (Ensuring access to affordable, reliable, sustainable, and modern energy for all).

33. The proposed project supports the World Bank's twin objectives of reducing poverty and promoting shared prosperity. Specifically, the project will:

- *Avoid an increase in poverty due to substantial increase of electricity tariffs, which would have been needed to replace generation from Nurek HPP.* The inability of Nurek to maintain the current levels of generation would lead to an increase in the cost of electricity supply for all consumers because it would need to be replaced by a new thermal power plant with higher electricity costs. Coupled with increases required to bring tariffs to cost-recovery levels, this would have had significant poverty impacts. Therefore, rehabilitation of Nurek HPP contributes to having lower tariff increase compared to a scenario where such rehabilitation is not done and Nurek HPP is replaced by substitute plants.

  The cost of generation from Nurek HPP is negligible given that no fuel or other large expenses are needed. Rehabilitation of the plant will increase the cost of electricity by only 0.5 c/kWh. This is substantially below the cost of electricity from a new gas-fired

thermal power plant, which is estimated at 8.9 c/kWh.[4] In case of loss of generation from Nurek, the end-user tariff would need to increase. Assuming no changes in other factors impacting poverty, such an increase, if it were to materialize, would result in significant increase of poverty. It should be noted that currently households spend up to 16 percent of their disposable income on energy. That proportion is 25 percent for the poorest quintile in rural areas. Thus, the proposed operation would help preclude an increase in poverty due to a substantial hike of electricity tariffs, which would happen if the proposed operation does not support rehabilitation of Nurek HPP.

The World Bank will be providing advisory support to the Government under the recently approved Bank-executed ESMAP grant to develop measures to mitigate the impact of the tariff increases on the poor. This is important in the context of gradual transition to cost-recovery tariffs, which is one of the main pillars of the Action Plan for Financial Recovery of BT.

- *Increase of electricity exports with positive welfare impacts on entire population*. Rehabilitation of Nurek HPP will ensure that Tajikistan is capable of expanding its electricity exports. The export revenues will generate more taxes and require less financial injections from the Government into BT, thus, freeing up resources that can be used for social or other programs and increasing shared prosperity.

II. PROJECT DEVELOPMENT OBJECTIVES

A. PDO

34. The project development objectives are to rehabilitate and restore the generating capacity of three power generating units of Nurek hydropower plant, improve their efficiency, and strengthen the safety of the Nurek dam.

Project Beneficiaries

35. The beneficiaries of the project are all electricity consumers in the country and BT.

36. *Electricity consumers*: The project will contribute to the ongoing efforts of the Government in ensuring adequate and reliable electricity supply. In particular, the project will preclude loss of electricity supply from Nurek HPP, which accounts for 70 percent of winter generation during the time period of October-March when demand is the highest. Thus, the entire 8.3 million population of the country (including 4 million females) will benefit from the project. Moreover, 53,680 legal entities connected to the electricity network will also benefit because the project will help to meet their demand in a reliable manner.

37. *BT*: Rehabilitation of Nurek will allow BT to reduce revenue loss due to equipment failures caused by dilapidation and obsolescence. Those equipment failures lead to electricity under-supply from the power plant, which creates financial loss for BT. In case of disconnection

[4] Gas-fired CCGT plant with estimated levelized cost of energy at 8.9 c/kWh. See Annex on Economic Analysis for details.

of Nurek HPP from the power supply network due to failure of equipment or infrastructural components, the power plant does not supply electricity until the technical issues are fixed.

PDO Level Results Indicators

38. The key outcome indicators include:

Indicator One (CRI): Generation capacity of energy constructed or rehabilitated under the project (MW). This indicator measures the capacity of hydropower constructed or rehabilitated under the project.

Indicator Two (Custom): Estimated annual electricity generation of three units included in the scope of the project (GWh). This indicator measures the amount of electricity supplied by the rehabilitated units of Nurek HPP to the power transmission network.

Indicator Three (Custom): Estimated increase of winter electricity generation of rehabilitated units due to efficiency improvements (GWh). This indicator measures the increase in winter generation of rehabilitated units during the time period of October-March due to minimum weighted average efficiency increase of 2 percent.

Indicator Four (Custom): Improved dam safety against hydrological and geological risks (Yes/No). This indicator measures the improvement of the dam safety from introduction of advanced flood forecasting system and reservoir management rules, rehabilitation of the spillway tunnels, gates and hoisting system, and works to make both sides of the concrete gallery of the dam impermeable.

Indicator Five (CRI): People provided with improved electricity service (Number). The indicator measures the number of people that have received improved electricity service due to the project.

III. PROJECT DESCRIPTION

39. Rehabilitation of Nurek HPP will be conducted in two phases. The phased approach is due to unavailability of the total US$700 million required to complete all rehabilitation works. Thus, US$350 million Phase I will finance rehabilitation of three units, the key infrastructural components of the power plant, replacement of six auto-transformers that are used to evacuate the generated electricity, all of the dam safety enhancement related measures, and technical assistance to BT. The preparation of Phase II of the project will commence in 2017-2018 when the Government of Tajikistan mobilizes the remaining US$350 million required to complete rehabilitation of Nurek HPP. There are no risks to sustainability of rehabilitated units and overall operation of Nurek HPP if Phase II is delayed or does not materialize. Phase I will finance the key infrastructural components of the plant and will strengthen the dam safety. Therefore, even if remaining five units are not rehabilitated on time, safe operation of the plant will not be jeopardized.

A. Project Components for Phase I

40. **Component 1: Rehabilitation of the three generating units, the key infrastructural components of the plant, and replacement of autotransformers (US$310 million, including US$200.7 million from IDA, US$45 million from AIIB, US$40 million from EDB, and US$24.3 financing gap).** This component will consist of two sub-components.

41. *Sub-component 1.1: Replacement and refurbishment of mechanical, electrical, and electromechanical equipment (US$270 million, including US$200.7 million from IDA, US$45 million from AIIB, and a financing gap of US$24.3 million).* This sub-component will finance: (a) rehabilitation of three power generating units (generators, turbines, main inlet valves, and transformers), auxiliary systems and key balance of plant; and (b) providing spare parts, and operations and maintenance equipment.

42. *Sub-component 1.2*: *Replacement of six autotransformers (US$40 million, which will be 100 percent financed by EDB).* This sub-component will finance supply and installation of six autotransformers, replacing the existing autotransformers that are beyond their economic life and are in poor technical condition.

43. Assessment of the scope of the required rehabilitation works for the power plant equipment was based on detailed inspections carried out by the feasibility consultants, supplemented by information from recently performed rehabilitation works and a review of the O&M history of the plant. The recently performed rehabilitation works included replacement of three runners and rehabilitation of two Main Inlet Valves (MIVs).

44. The need for rehabilitation of turbines was determined based on: (a) inspection of the spiral case and stay vanes, stay vanes inlet and outlet profile and visual examination in order to check the possible presence of cracks, corrosion or other defects; as well as inspection of guide vanes (while assembled in the distributor); and (b) inspection of other turbine components such as operating ring, guide vane operating mechanism, turbine bearing and guide vane servomotor while assembled.

45. BT's consultant conducted detailed inspection of the key infrastructural components of the plant (transformers, auxiliary systems, etc.) and review of O&M history to determine the scope of rehabilitation required.

46. **Component 2: Enhancement of dam safety (US$30 million, including US$15 million from IDA and US$15 million from AIIB).** This component will finance activities to improve the safety of the operation of the Nurek HPP. The cost estimate for this component includes a provision for the possible mitigation measures that may be required. The cost of this component was estimated taking into account the maximum scope of activities, which may need to be implemented based on the results from ongoing seismic hazard assessment work. Therefore, the cost estimate includes a margin sufficient to implement all of the dam safety enhancement related activities, which will be required.

(a) Rehabilitation of spillway tunnels, refurbishment of spillway gates/hoisting system, improvement of protection on permeable zone of the embankment dam above the core zone crest, etc.

(b) Implementation of measures to enhance safety against seismic hazards. The scope of those measures will be finalized after completion of the: (i) ongoing seismic hazard assessment and stability analyses of the Nurek dam; and (ii) completion of ongoing geotechnical investigation on the downstream part of the left bank to check the slope stability.

    Probabilistic Seismic Hazard Assessment is being carried out to update the seismic design parameters, defining the Operating Basis Earthquake (OBE) and the Safety Evaluation Earthquake (SEE). Using the updated seismic design parameters, a two-dimensional dynamic analysis of the main embankment dam will be carried out. This will include checking of the condition of the seismic belt, which has been affected by differential settlement over the years. The stability of the triangular block in the left abutment under seismic loads will also be assessed. Based on the assessment results, appropriate measures (if required) to enhance safety will be designed and included in the project.

    The Feasibility Study identified a risk that movement of a 'triangular block' in the downstream part of the left bank could cause shearing of the bottom spillway tunnel, adversely impacting the surface spillway tunnel, and possibly even blocking the tailrace channel. Such an eventuality could render Nurek incapable of safely discharging floods. The initial assessment is that a large-scale sliding movement is unlikely, although gradual minor movements along a fault are to be expected due to the oblique rise of a deep salt/gypsum layer. To confirm the findings, BT is drilling five boreholes and will check the slope stability under various loading conditions to confirm these findings. Regular 3D geodetic monitoring will be undertaken by instruments. Appropriate remedial measures to allow the spillway tunnels to function adequately from a hydraulic and structural perspective will be implemented as part of the project.

(c) Introduction of an advanced flood forecasting/warning system and preparation of optimized reservoir operating rules to enhance the flood-handling capacity of the dam. The analysis indicated that an improved flood forecasting system, combined with delayed reservoir filling for enhanced flood routing during years of expected high floods, can provide safety against a 100,000-year return period flood, significantly higher than the current flood-handling capacity. The possibility of utilizing a concrete gallery located near the top of the dam as an extension of the impervious core is being investigated as a further enhancement of the flood-handling capacity of the dam. Detailed design and execution of required measures, such as advanced flood forecasting system, modified reservoir operation procedure, and possibly some protective measures of the top pervious layer of the embankment body will be further studied to detailed design level and undertaken during project implementation.

(d) Refurbishment and upgrade of monitoring instruments and management system to improve the collection and analysis of the safety monitoring data.

(e) Update of the Nurek HPP Emergency Preparedness Plan (EPP), Dam Operation and Maintenance Plan, and the Instrumentation Plan.

47. **Component 3: Technical assistance (US$10 million, 100 percent of which will be financed by IDA).** This component will support implementation of the project and strengthen the institutional capacity of BT by supporting the following:

(a) Project management consultant (PMC) to assist with the review of designs, bidding, quality control and construction supervision of the project. BT has already signed the US$5.2 million equivalent contract with PMC.
(b) Panel of Experts (PoE) on matters related to dam safety and other critical aspects of the Project.
(c) Technical and other engineering studies, which may be required during project implementation.
(d) Consultant services to support BT with citizen engagement and gender-informed consultative processes during project implementation.
(e) Capacity building for Nurek HPP and BT staff in dam safety, operation and management of hydro facilities, project management, including fiduciary and safeguards aspects of the Project.
(f) Advisory and analytical support aimed at improvement of BT's financial standing.
(g) Project and entity audits.
(h) Incremental operating costs of the project implementing entity.

B. Project Financing

48. The sources of financing for the project are presented below.

- US$225.7 million from IDA, which includes US$100 million from the IDA Scale-Up Facility, and US$69.135 million IDA concessional credit, and US$56.565 million equivalent IDA grant;
- US$60 million from AIIB; and
- US$40 million from EDB.

49. The project has a financing gap of US$24.3 million, which will be filled either by other financiers or additional financing to the project.

50. The Recipient will be the Ministry of Finance on behalf of the Republic of Tajikistan. The Ministry of Finance will on-lend the IFI credits to BT under Subsidiary Agreements under the same terms as borrowed from the respective IFIs. The Grant portion of the financing will be transferred to BT on grant terms.

C. Project Cost and Financing

51. The total cost of Phase I of the project is US$350 million. The cost estimate is based on the detailed techno-economic study conducted by a reputable international firm. The cost estimate includes 5 percent physical contingency and 5 percent price contingency built into the estimates for Components 1 and 2.

Project Components	Project cost (US$ million)	IDA Financing (US$ million)	AIIB financing (US$ million)	EDB financing (US$ million)	IDA Financing as % of Total
Component 1. Rehabilitation of power plant and replacement of autotransformers	310	200.7	45	40	65%
Sub-component 1. Power plant rehabilitation	270	200.7	45	-	74%
Sub-component 2. Replacement of autotransformers	40	-	-	40	0%
Component 2. Enhancement of dam safety	30	15	15	0	50%
Component 3. Technical assistance	10	10	-	-	100%
Total Project Costs	350	225.7	60	40	64%
Total Financing Required	350	250	60	40	64%

52. AIIB will co-finance the following two contracts under the project: (a) plant supply, design, and installation (PSDI) contract for refurbishment of the power plant under Sub-component 1.1, and (b) civil works contract for enhancement of dam safety under Component 2.

53. Under Sub-component 1.1, PSDI contract will include payments for design and model testing of turbines, manufacturing and supply of goods, and installation. As per World Bank's standard bidding documents for PSDI contracts, BT will be required to issue confirmed and irrevocable letter of credit (LC) for the value of goods to be supplied under the contract. It will not be plausible to link the LC with two sources of financing for this contract (World Bank and AIIB), especially considering that this large contract will require use of the World Bank's Special Commitment for the LC. Thus, AIIB will finance design and model testing and installation costs under the PSDI contract, which is estimated at US$45 million.

54. AIIB will also co-finance US$15 million of the total cost of the civil works contracts under Component 2 of the project, which are estimated at US$30 million.

IV. IMPLEMENTATION

A. Institutional and Implementation Arrangements

55. BT will be responsible for implementation of the project. The proposed project's implementation arrangements were developed considering the experience of BT with implementation of IFI-financed projects, including the Energy Emergency Recovery Project and its Additional Financing (World Bank), the Energy Loss Reduction Project and its Additional Financing (World Bank), ongoing Project on Reduction of Electricity Losses in Sughd Region (EBRD) as well as the ongoing Kairakum Hydropower Rehabilitation Project financed (EBRD).

56. The Supervisory Board of BT will be responsible for overall project oversight. The Supervisory Board is chaired by the Prime Minister and includes the Minister of Energy and Water Resources, Minister of Finance, Minister of Economic Development and Trade, Minister of Justice, Chairman of the State Committee on Investments and State Property Management, and the Chairman of BT.

57. **Working Group for the Project**: BT established a Working Group for the project, which will be responsible for: (a) review and acceptance of works of the contractors and outputs of the consultants under the project; and (b) review of justifications for changes in the scope of contracts under the project, including variation orders under construction contracts. The Working Group will be submitting semi-annual project implementation progress reports to the Supervisory Board. The Working Group will implement the above key functions taking into account the advice from PMC and PoE. The Working Group will include representatives from BT, MEWR, and Nurek HPP.

58. **Technical Council of BT**: The Technical Council will be responsible for review and approval of the technical specifications of the bidding documents for all main contracts under the project. The Technical Council includes the heads of all technical departments of BT.

59. PoE and PMC will provide technical advice and implementation support to both Technical Council and the Working Group. Specifically, PoE will provide independent review and expert advice on dam safety issues, including review of all technical reports and specifications in the bidding documents for implementation of activities related to enhancement of the dam safety. BT completed the selection of a PoE, which includes an experienced dam safety specialist, geologist, and an electro-mechanical expert.

60. The support of PMC, which is staffed with relevant technical specialists, will include: (a) preparation of the design and construction plan for the power plant rehabilitation, civil works for the dam safety, rehabilitation of spillway gates, and replacement of autotransformers; (b) preparation of a detailed cost estimate for each of the contract packages in accordance with standard methods of measurement; (c) preparation of the bidding documents for power plant rehabilitation works, replacement of autotransformers and dam safety enhancement works; (d) support to BT with evaluation of bids under the project, including advice on all technical and commercial matters related to the bid; (e) update of the EPP and preparation O&M plan; (f) site handover and preparation; (g) review of contractors' implementation schedules; (h) supervision of the construction works; (i) monitoring of the contractors' compliance with the provisions of ESMP and relevant national legislation; (j) issuing of instructions to the contractors; (k) inspection and testing of works; (l) advising BT on approval of payment certificate; and (m) training of the relevant BT staff and knowledge transfer.

61. **Project Realization Group (PRG) of BT**. PRG at BT will be responsible for procurement, contract administration, and financial management under the project. PRG has experience in implementation of IFI financed projects, including the recently completed World Bank financed Energy Loss Reduction Project and its Additional Financing. Overall, the PRG is adequately staffed with procurement and FM staff with qualifications acceptable to the Bank.

62. In particular, the Central Accountancy of BT and Financial Management department of PRG will be responsible for overall implementation of the financial management (FM) function of the project including, monitoring the flow and accountability of funds, budgeting, accounting, reporting, internal controls and external auditing.

63. PRG under BT has expanded its project management capabilities through implementation of the World Bank and other donor funded projects over the past years. However, implementing a project of the proposed scope and technical complexity will require further strengthening of the implementation capacity and devoting additional resources to support PRG in: (i) preparation and implementation of the technical and dam safety aspects; (ii) planning and implementation of procurement activities; (iii) establishing of a contract management system; and (iv) strengthening a control and coordination arrangement between the PRG and the technical team in the Nurek HPP.

64. BT will further strengthen the capacity of PRG. In particular, BT PRG will hire a new FM/accounting expert/consultant, acceptable to the Bank, to manage the increased work-load. Additionally, BT PRG will hire technical specialists/consultants for the project needs. The cost of additional staff/consultants under the project may be financed from the project funds.

65. **Project implementation timeline**. The project implementation schedule foresees completion by December 31, 2023. According to the schedule, the bid documents for the project's largest component, power plant rehabilitation, will be issued in the first semester of 2017 with contract award expected by the end of 2017. The activity with the longest lead time is rehabilitation of the generating units, which is expected to take 60 months, including the time required for contractor mobilization, detailed design, manufacture, transportation, installation and commissioning.

B. Results Monitoring and Evaluation

66. BT will be responsible for monitoring and evaluating the PDO Level and Intermediate Results Indicators during implementation, and submitting semi-annual implementation progress reports to the Bank. BT will collect the required data from progress reports submitted by PMC, Reports of the UN Population Division, and Nurek HPP (see Annex 3 for details). The baseline values for the results indicators were provided by BT. The target values will be discussed and agreed with BT.

C. Sustainability

67. The sustainability of the investments will be secured through improved financial viability of BT, which, among other things, will require inclusion of the project debt service costs and adequate level of O&M costs in the electricity tariff. Specifically, as part of the Action Plan for Financial Recovery of BT, the Government committed to introduce a new cost-recovery tariff methodology by the end of 2017. This methodology will allow tariffs to be gradually increased to cost-recovery levels. The new tariff framework will allow BT to service the debts using the proceeds from tariffs revenue and will allow allocating sufficient resources to Nurek HPP for O&M. The Bank team will be reviewing the tariff computations during implementation of the

project because cost-recovery tariffs are one of the principal measures in the Action Plan for Financial Recovery of BT.

68. The project's TA component will also strengthen the capacity of Nurek HPP staff in technical matters related to O&M of the plant, including training on any recent advances in operational and maintenance practices of such plants. In addition, Nurek HPP staff will benefit from training and knowledge transfer of PMC. Specifically, PMC will provide training and other capacity building support to relevant staff of Nurek HPP. This will include: (i) transfer of expertise through the work on site with engineers of BT working with the PMC experts; (ii) transfer of expertise by means of training sessions or lectures conducted in Tajikistan by the PMC's engineers on site that would ensure active participation of Nurek HPP's engineers throughout the duration of the project assignment; and (iii) hands-on training/lectures at the PMC's head offices. The above activities will contribute to sustainability of the project.

69. The PSDI contract also envisages supply of spare parts required for the generating units and other infrastructural components of the project. This will contribute to sustainability of the operation of the project after rehabilitation works are completed.

D. Role of Partners

70. AIIB will co-finance the project and EDB will provide parallel financing. Specifically, AIIB will co-finance the main contracts for rehabilitation of power plant equipment, dam safety measures, and the technical assistance. EDB will provide parallel financing for replacement of the six autotransformers. EDB funding will be earmarked and available only for the autotransformers. The execution of financing from AIIB will be a condition for disbursement of IDA funds for Sub-component 1.1, Component 2 and Component 3 of the project.

71. The financiers of the project will coordinate during implementation. A Jointly Agreed Procedures document that describes donor coordination mechanisms and processes with respect to procurement, financial management, safeguards, and project implementation support will be drafted and agreed among financiers. It will be updated during the implementation, as needed.

V. KEY RISKS

A. Overall Risk Rating and Explanation of Key Risks

72. The rating for the overall risk to the project's achievement of the PDO is Substantial. The key risks and mitigating measures during implementation are captured below.

73. **Political and Governance Risk is High**. Although the project has political support and commitment at the highest level, poor quality of data, accountability and transparency issues, and weak civil society oversight, may affect the project. Tajikistan's anti-corruption framework, which includes the Law of the Republic of Tajikistan on Combating Corruption (2008), Anti-Corruption Strategy in the Republic of Tajikistan 2013-2020 (2013), and the Code of Ethics for Civil Servants (2004), will help mitigate governance risks. To increase demand for accountability, the Country Partnership Strategy (CPS) aims to engage civil society in all aspects of the Bank's portfolio, enabling Civil Society Organizations (CSOs) to gain experience in

preparing, implementing and monitoring government programs. The project will provide further mitigation through due diligence on the cost estimates (review by PMC of the cost estimates from the feasibility study) and a robust procurement process.

74. **Macroeconomic Risk is High** given Tajikistan's high vulnerability to external and domestic shocks, low policy buffers, and weak macroeconomic and fiscal frameworks. Domestic risks have been materializing as evidenced by the insolvency of several systemic banks and growing losses in the largest state-owned-enterprises (SOEs). The bailout of the financial sector has narrowed the fiscal space and potential needs for additional bank recapitalization and/or SOE support undermines medium-term fiscal and debt sustainability. Due to inadequate macroeconomic environment and pending amendments to the financial sector supervisory and resolution frameworks, the Development Policy Loan (DPL) was put on hold and conditioned upon an IMF arrangement. The state of negotiations between the government and the IMF has been sluggish, indicating slim chances to reach agreement in the upcoming few months.

75. **Sector Strategies and Policy Risk is High** given inadequacy and year-to-year variability of BT revenues due to non-predictable tariff increases, possible further devaluation of TJS that reduces the cash available to service foreign currency denominated debt, and variability of collection rates for electricity. This may impact the financial sustainability of the project and BT's overall operations. This risk will be mitigated through covenants included into the legal agreements under this project. The Recipient and BT will not be able to comply with those covenants if the measures in the Action Plan for Financial Recovery of BT are not implemented. Moreover, the Bank and other development partners will provide the required advisory and analytical support to implement the key measures of the Action Plan for Financial Recovery of BT. This includes the ongoing Phase II of EBRD's Regulatory Program TA and ADB's ongoing support, and Bank support to introduction the new tariff methodology, improve efficiency of financial management of the company, and improve the accounting and financial reporting functions.

76. **Technical Design Risk is Substantial** given that refurbishments of the power plant may require additional technical works and studies when the works commence and new information becomes available on the condition of some of the assets. Therefore, the project design was based on robust technical and economic assessments, including physical examination of technical condition of key equipment, the balance of the plant, and the dam. The rehabilitation works, including the new equipment such as large generating units, have been successfully operated globally in other large hydropower projects. The project's economic benefits depend on factors under the project implementing entity's control and the cost estimates and assumptions are realistic.

77. **Institutional Capacity for Implementation Risk is Substantial** given lack of experience of BT and Nurek HPP with implementation of similar large-scale rehabilitation projects. There is clear institutional decision-making structure with respect to responsibilities of PRG, the Working Group, Technical Council and the Supervisory Board of BT, however, BT will require significant technical support to successfully implement the project. The Panel of Experts, which has already been selected, will provide the required advice on technical and dam

safety aspects of the project. PMC will conduct technical supervision of the project and will help resolve technical issues.

78. **Fiduciary Risk is High** because the procurement risk is High and the FM risk is Substantial. The project involves large procurement packages that require strong implementation capacity and BT does not have prior experience with procurement of such packages. Therefore, PMC was hired to provide implementation support to BT for procurement and contract management. BT's relevant procurement staff will receive additional training on advanced procurement topics. The FM risk is Substantial due to lack of appropriate policies and procedures for recognition of revenues and receivables for electricity sales and some other issues identified by the auditor of FY2015 financial statements. The FM capacity risks will be mitigated by hiring an experienced consultant to support BT with addressing the short-comings identified by the auditor of the FY2015 financial statements.

79. **Environmental and Social Risks are Moderate** given limited environmental and positive social impacts of the project and arrangements put in place to ensure compliance of project rehabilitation works with requirements of ESMP under the project and the ongoing advisory support on options available to mitigate impacts of tariff increases on the poor. The negative environmental impacts are mainly associated with the asbestos present in the old equipment and infrastructure components, waste to be generated during rehabilitation works, and ensuring on-site workers' and power plant's personnel's health and safety. Those risks will be mitigated by including the ESMP into the bidding documents and requiring the contractors to fulfill the specified requirements. Additionally, PMC has an environmental specialist on the team, which will supervise compliance of power plant rehabilitation and dam safety related works with the requirements of ESMP. PMC will be reporting directly to head of BT's PRG on all safeguards issues and will be submitting recommendations to address them. The environmental risk is rated as Moderate and the social risk is rated as Low, thus, the overall environmental and social risk is Moderate.

80. **Stakeholder Risk is Substantial** given that the project impacts may not be well understood by the riparian countries. Therefore, the World Bank at the request of the Government of Tajikistan notified all of the riparian countries about the proposed project, including description of components, activities and estimated impacts as required under OP7.50. Domestically, the project objectives are well understood and all key stakeholders support the project. BT conducted consultations on the project and the Environmental and Social Impact Assessment (ESIA), and has prepared a Stakeholder Engagement Plan, which is a road map for stakeholder consultations and engagement during implementation of the project.

81. **Financing Risk is Substantial** given financing gap of US$24.3 million for Phase I of the project and no firm financing for Phase II of the project. The financing gap for Phase I will most likely be covered with additional financing to Phase I. The financing package for Phase II will depend on the progress with implementation of financial recovery of BT and other factors such as public debt sustainability. If financing for Phase II does not materialize, it will not have any financial implications on the PSDI contract for three units under Phase I and sustainability of the rehabilitated units and the dam safety.

82. **Climate Change Related Disaster Risk is Low** given that the impact of climate change on the hydrology of the Vakhsh river have been studied. Furthermore, the project will support preparation of an advanced flood forecasting model. The model will allow for more reliable prediction of the flow discharge in order to avoid significant flood underestimation or overestimation. The model will also take into account the climate change driven impacts of snow/glacier melting and flood runoff.

VI. APPRAISAL SUMMARY

A. Economic and Financial Analyses

Economic Analysis of Entire Project

83. The economic analysis of the entire project was done based on the incremental benefits and costs of the project. The economic and financial analyses of the project covers only the investments in rehabilitation of the power plant equipment, replacement of autotransformers and the PMC costs. The investment for the safety component is not included as this would be required even if the rehabilitation was not undertaken. The corresponding benefits of strengthening the safety of the project are also not included.

84. Economic costs: The economic costs include: (a) PSDI costs for electrical, mechanical and electromechanical equipment and the works required for rehabilitation of all nine units and all of the balance of plant; (b) the cost of six autotransformers; (c) PMC costs; and (d) the incremental O&M costs associated with maintenance of the new equipment. The costs are projected according to the years in which they are expected to be incurred during the project construction period.[5]

85. Economic benefits: The main economic benefit is the avoided increase of the cost of electricity supply to consumers during winter time period due to replacement of Nurek HPP with a new generation plant. In case of loss of generation from Nurek HPP, it will be replaced by a gas-fired combined cycle gas turbine (CCGT) plant, which has higher economic cost of supply. The project will also generate global social benefits in form of avoided GHG emissions due to increased gas generation to replace it. Electricity supply from Nurek HPP during summer time period will generate marginal economic benefit because the power system is projected to have significant surplus capacity, which can be used to fill in the gap from the plant's loss at near-zero incremental economic cost. The power system will have shortage of energy for exports starting from 2043. However, those benefits are too distant in the future and, thus, have small value in present terms. See Annex 7 for details.

86. GHG reduction benefits for the entire project: The project will also generate benefits in form of avoided CO2 emissions. The CO2 emission reduction benefits from the project were evaluated following the World Bank's Guidance Note on Greenhouse Gas Accounting for Energy Investment Operations (June 2013). The entire project will lead to 68 million tCO2e reduction in emissions vs. the baseline during economic life of the project. Therefore, the project will generate climate mitigation co-benefits. See Annex 7 for details.

[5] Project construction costs are not levelized over the operating life of the project.

87. Results: The economic analysis of the entire project yielded an economic Net Present Value (NPV) of US$1615 million and Economic Internal Rate of Return (EIRR) of 36 percent exclusive of the social cost of avoided CO2 emission and an economic NPV of US$2077 million and EIRR of 40 percent inclusive of the social cost of avoided CO2 emissions.

88. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated project economic returns to changes in the main evaluation variables. The results of the sensitivity analyses suggest that the project returns are robust even in case of significant variation of main evaluation variables. See Annex 7 for details.

Table 3: Sensitivity Analysis for Economic Evaluation of Entire Project

Exclusive of avoided CO2 emissions	**NPV (million US$)**	**EIRR (%)**
Base-case	**1615**	**36**
a. 20 percent higher investment cost	1,517	32
b. 20 percent lower-than-projected border price of imported gas	1,384	30
c. Loss of generation capacity at a rate of one unit in three years[6]	272	12
d. Combination of a, b, and c	89	11

Economic Analysis of Phase I of the Project

89. The economic analysis of the Phase I of the project was conducted using the cost-benefit approach and using the same methodology as the analysis for the entire project. The differences between the economic analysis of the Phase I and the entire project are the following: (a) lower economic cost due to rehabilitation of only three generating units and key balance of plant; and (b) smaller avoided CCGT generation under "with project" scenario given that the remaining six units, which are not rehabilitated under Phase I, are assumed to completely lose generation by 2028.

90. GHG reduction benefits for the Phase I of the project. The Phase I will generate global environmental benefits in form of net reduction of CO2 emissions. The assessment of net CO2 emission reductions from Phase I of the project was conducted using the same methodology as for entire project. The Phase I of the project will lead to 29 million tCO2e reduction in emissions vs. the baseline during economic life of the project. Therefore, the project will generate climate mitigation co-benefits.

91. Results: The economic analysis of the Phase I yielded an economic NPV of US$713 million and EIRR of 33 percent exclusive of the social cost of avoided GHG emissions and an economic NPV of US$905 million and EIRR of 37 percent inclusive of the social cost of avoided GHG emissions.

92. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Phase I economic returns to changes in the main evaluation variables. The results of

[6] Total loss of generation by 2048 instead of 2028 under base-case.

the sensitivity analysis suggest that the project becomes economically non-viable in cases: (a) when Nurek maintains generation capacity under "without project" scenario until 2048 instead of 2028 under base-case, and (b) investment cost over-run and lower-than-forecast gas prices coupled with 20 years slower loss of generation capacity. Please see Annex 7 for details.

Table 4: Sensitivity Analysis for Economic Evaluation of the Phase I of the Project

Exclusive of avoided CO2 emission costs	NPV (million US$)	EIRR (%)
Base-case	**713**	**33**
a. 20 percent higher investment cost	664	29
b. 20 percent lower-than-projected border price of imported gas	597	27
c. Loss of generation capacity at a rate of one unit in three years[7]	(479)	4
d. Combination of a, b, and c	(505)	3

Financial Analysis of the Entire Project

93. Financial costs of the entire project: The financial costs include: (a) PSDI costs for replacement of electrical, mechanical and electromechanical equipment and the works required for rehabilitation; (b) supply and installation of six autotransformers; (c) dam safety enhancement related measures; (d) PMC, which will be acting as the owner's engineer; and (e) incremental O&M costs. The costs are projected according to the years in which they are expected to be incurred during the project construction period.[8]

94. Financial benefits of the entire project: The financial benefits of the project were estimated as the avoided reduction in revenues from electricity sales when Nurek HPP gradually loses generation capacity. The avoided reduction in revenues was estimated for winter domestic sales, and summer exports. The estimates of avoided revenue reduction take into account electricity losses in the power system and the estimated bill collection rates.

95. Avoided reduction of revenues from domestic sales in winter was computed as the product of reduction in supply from Nurek and forecast average end-user electricity tariffs. The avoided reduction in revenues due to decline of electricity supply is largest during winter months when electricity demand is the highest and there is no spare capacity in the power system. In fact, there is winter energy deficit.

96. Avoided reduction of revenues from summer exports was computed as the product of reduction in supply from Nurek and forecast tariffs under Power Purchase Agreements (PPA), including those signed under CASA-1000. Avoided reduction from summer exports has small impact on financial viability of the project given that the power system has significant surplus energy, which will increase further with commissioning of Rogun HPP. Availability of surplus energy for exports due to loss of generation from Nurek will start reducing revenue from exports only starting from 2046. Taking into account that this will be 19 years from commissioning of

[7] Total loss of generation by 2048 instead of 2028 under base-case.
[8] Project construction costs are not levelized over the operating life of the project.

the completely rehabilitated Nurek project, the present value of avoided reduction in export revenues is small.

97. Results: The financial analysis of the project yielded a financial NPV of US$25,156 million and Financial Internal Rate of Return (FIRR) of 23 percent. This result suggest that the project will have significant impact on precluding significant deterioration of financial viability of BT. Without the project, BT's revenues will significantly reduce exacerbating the financial difficulties of the company.

98. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated project financial returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the financial returns to the project. The results of the sensitivity analysis suggest that the project is financially robust even in case of substantial variation of main variables that affect its viability.

Table 5: Sensitivity Analysis for Financial Evaluation of Entire Project

	NPV (million US$)	**FIRR (%)**
Base-case	**25,156**	**23**
a. 20 percent higher investment cost	24,940	21
a. Financial cost recovery tariff reached by 2029 instead of 2022	14,245	18
b. Loss of generation capacity at a rate of one unit in three years	21,491	14
c. Combination of a, b, and c	11,435	11

Financial Analysis of Phase I of the Project

99. The financial analysis of the Phase I of the project was conducted using the cost-benefit approach and using the same methodology. The base-case of the analysis for Phase I is similar to the base-case for analysis of the entire project. The main difference between the financial analysis of the Phase I and the entire project is the lower financial cost due to rehabilitation of only three generating units.

100. Results: The financial analysis of the Phase I yielded an economic NPV of US$25,979 million and FIRR of 23 percent.

101. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Phase I financial returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the financial returns to Phase I of the project. The results of the sensitivity analysis suggest that the project is financially robust even in case of substantial variation of main variables that affect its viability. The results of the sensitivity analyses are presented in the Table below.

Table 6: Sensitivity Analysis for Financial Evaluation of the Phase I of the Project

	NPV (million US$)	FIRR (%)
Base-case	**25,979**	**23**
a. 20 percent higher investment cost	25,882	22
a. Financial cost recovery tariff reached by 2029 instead of 2022	21,818	21
b. Loss of generation capacity at a rate of one unit in three years	15,557	13
c. Combination of a, b, and c	12,068	11

Assessment of Financial Standing of BT

102. The financial condition of BT continued to deteriorate in the period from 2013 to 2015, due to: (a) unsustainable and increasing debt levels, (b) low cash collections, and (c) below cost recovery end-user electricity tariffs.

103. In 2015, BT earned TJS1548 million (US$252 million) from sales of electricity. The Company supplied 12,817 GWh of electricity to domestic consumers and exported 1,340 GWh to Afghanistan and Kyrgyzstan. The weighted average export tariff was US$0.035/kWh.

104. The collection rate for billed electricity at 83 percent remains below the industry average. BT had 97 days of receivables outstanding. The aluminum producer, TALCO, is the largest debtor to BT with its total debt of TJS412 million (US$59 million).

Table 7: Bill Collection Rates by Customer Categories

Customer category	Bill collection rate (%)
Industry, excl. TALCO	96.0
TALCO	88.4
Utilities, state organizations, transport	76.2
Pumps and water pumping stations	27.6
Residential consumers	78.6
Average	**83.0**

105. As of the end-2015, BT's total liabilities exceeded its total assets. Operating losses persisted in the period of 2013-2015 leading to complete erosion of equity. Accumulated losses of BT reached TJS5300 million (US$758 million). Total liabilities of BT stood at TJS11, 617 million (US$1,662 million), about 55 percent of which were borrowings from IFIs. The ability to sustain those loans was considerably impaired by absence of corresponding revenue allowance in the tariffs and under-collection of receivables. BT failed to make both principal and interest payments on them. In addition, BT has a total of TJS1102 million (US$158 million) expensive short-term dollar denominated commercial debts from a local bank, which costs the company about TJS253 million (US$36 million) per annum in interest expense.

106. The situation with payables deteriorated. In particular, payables for electricity purchases from IPPs - Sangtuda-1 and Sangtuda-2 HPPs (with 2016 tariffs of US$0.023 and US$0.032/kWh respectively) - rose to TJS835 million (US$119 million). BT struggles to make

payments to those IPPs in timely manner because the cost of electricity from those IPPs is higher than the end-user electricity tariff and those IPPs primarily supply electricity during the months of April-October (surplus energy season) when the other lower cost HPPs, owned by BT, can generated at significantly lower cost and spill water given low summer demand and lack of export opportunities.

107. In 2015, total current liabilities of TJS5446 million (US$779 million) accounted for 47 percent of total liabilities. Current assets were only one fifth of that amount. This represented a significant reduction in the liquidity, as measured by the ratio of current assets to current liabilities, which was at 0.39 in 2013.

108. End-user electricity tariffs remain below the cost-recovery levels, which do not allow the company to finance even the required recurrent expenditures. The expected average end-user tariff for 2016 (12.89 diram/kWh)[9] is estimated 55 percent below the cost-recovery level. The cost-recovery tariff was assessed following the cash needs approach. This was done through assessment of the amount of cash revenue that BT requires to fully finance the recognized recurrent expenses (accrual based items in the financial statements), which include the O&M costs, administrative costs, capital repairs from own funds, pension liabilities, debt service, and taxes. It also assumes gradual repayment of accrued liabilities (i.e. interest payables, overdue loans and payables to Sangtuda-1 and Sangtuda-2 HPPs for purchased electricity) over a five-year period starting 2017. It should be noted that concept of cash-based cost of service is different from the concept of economically efficient cost of supply and does not take into account the return on invested capital and investments required to meet the long-run forecast electricity demand.

109. **Forecast of Financial Performance of BT**. Financial performance of BT was forecast for two scenarios. The base-case scenario is based on the agreed-upon targets to be achieved by BT as reflected in the Action Plan for Financial Recovery of BT, including increase of end-user average tariff, improvements in collection rates, and other efficiency improvements. The conservative scenario assumes lower increase in average end-user tariffs, smaller improvements in collection rates and other financial efficiency indicators such as days of receivables outstanding and inventory turnover. The key assumptions for each of the forecast scenarios are presented below.

Base-case Forecast of Financial Performance of BT

110. The base-case forecast was done assuming that BT implements all of the measures mentioned in the Action Plan for Financial Recovery of BT (see Annex 6). Those measures include average annual 15 percent increase of end-user tariffs to reach cost recovery by 2022; improvement of cash collections; improvement of inventory management and collection of receivables, which will increase cash revenues; and increase of exports starting from 2022 when CASA-1000 project is commissioned (see Annex 7 for details).

111. Until 2020, BT will continue to experience deterioration in liquidity and financial leverage due to persisting net losses, slow reduction of accrued liabilities and expected

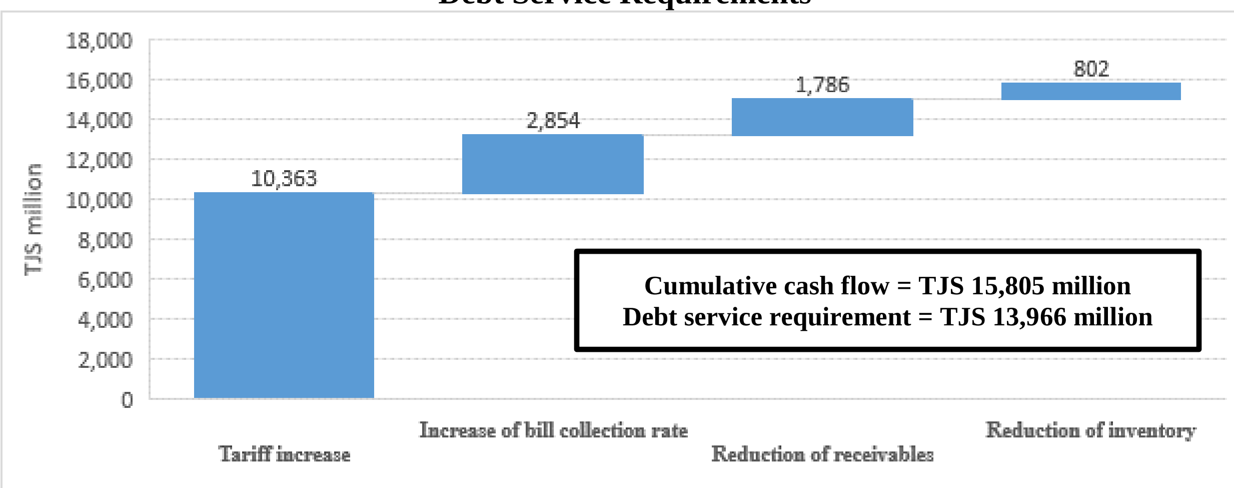
[9] 1TJS = 100 diram.

disbursements under ongoing projects. The ratio of current assets to current liabilities will decrease to 0.08 from 0.20 in 2015, and debt-to-assets ratio will increase to 1.2.

112. At the end of 2016, BT will have accrued liabilities for a total TJS5131 million. Total debt service requirements for the forecast period of 2016-2025, including repayment of accruals, are estimated at TJS13,966 million, as shown on Figure 1 below. During the same period tariff increases, improved collections and working capital management are expected to generate an additional TJS15,805 million in cash. Once target for collection rates and days of receivables outstanding are reached in 2020, available operating cash flow of BT will allow to accelerate repayment of outstanding commercial debt, accrued payables for electricity and debts to international financial institutions. In that year, EBITDA margin will increase to 54 percent, and operating cash flow per unit of sales is expected to increase fivefold to TJS0.50.

113. The Government is currently considering the following option for resolving the short-term indebtedness issue. BT will gradually repay the commercial loans to Orienbank in 2018-2022 using incremental operating cash flows from financial recovery measures. The increase of the incremental cash flows of BT was estimated assuming implementation of the Action Plan for Financial Recovery of BT. It was assumed that the loans will either be rolled over each year on the date of the repayment as was the practice before or will be restructured to long-term loans.

Figure 1: Cumulative Impact of Financial Recovery Measures vs. Debt Service Requirements



114. By 2025 net debt of BT is forecast to decrease to 2 times EBITDA, and by 2023 the debt service coverage ratio will have reverted to a sustainable level of 1.11.

Table 8: Financial Ratios

	2013A	2014A	2015A	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Gross margin	52%	18%	41%	40%	39%	44%	49%	54%	59%	70%	70%	70%	71%
EBITDA margin	2%	12%	25%	28%	29%	37%	44%	50%	49%	62%	63%	63%	63%
OCF/Revenue	3%	16%	10%	38%	40%	47%	48%	50%	43%	51%	52%	51%	51%
Current ratio	0.39	0.29	0.20	0.16	0.14	0.10	0.09	0.08	0.09	0.27	0.56	1.08	1.86
Debt-to-assets	0.60	0.74	1.01	1.14	1.18	1.20	1.20	1.17	1.12	0.96	0.82	0.69	0.58

	2013A	2014A	2015A	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Operating cash flow / short-term debt service	0.05	0.10	0.06	0.11	0.08	0.15	0.20	0.25	0.31	0.52	0.95	1.48	1.95
DSCR	0.02	0.08	0.04	0.13	0.11	0.15	0.20	0.27	0.38	0.82	1.11	1.70	2.42

Conservative Forecast of BT Financial Performance

115. If BT does not fully achieve the targets specified in the Action Plan for Financial Recovery of BT, then the company's financial performance will remain distressed. Specifically, the current assets will not be sufficient to cover the current liabilities even by the end of the forecast period. BT will not be able to repay the short-term commercial debt until 2024 and will only be able to repay portion of the payables to IPPs. The debt service coverage ratio will reach 1.1 by 2025. The details are presented in the Tables below.

Table 9: Financial Ratios under Conservative Scenario

	2013A	2014A	2015A	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Gross margin	52%	18%	41%	40%	38%	42%	45%	48%	51%	65%	65%	65%	64%
EBITDA margin	2%	12%	25%	27%	28%	33%	37%	40%	40%	55%	56%	55%	54%
OCF/Revenue	3%	16%	10%	32%	32%	37%	39%	40%	37%	49%	48%	44%	33%
Current ratio	0.39	0.29	0.20	0.17	0.16	0.15	0.14	0.14	0.15	0.17	0.21	0.29	0.43
Debt-to-assets	0.60	0.74	1.01	1.14	1.18	1.21	1.23	1.23	1.23	1.13	1.03	0.92	0.81
DSCR	0.02	0.08	0.04	0.13	0.11	0.13	0.15	0.17	0.20	0.42	0.52	0.72	1.09

B. Technical

116. The proposed approach to rehabilitation of the power plant and the dam safety measures are based on comprehensive and robust technical and economic assessments, including detailed cost estimate. The feasibility study proposed three options for rehabilitation of Nurek HPP:

- Option 1: Rehabilitation measures urgently required to maintain the power plant's generation capacity and the safety of the power complex. This option covered only the generation units, electrical balance of plant, parts of the mechanical balance of plant, and the SCADA system.
- Option 2: All activities under Option 1 plus additional measures to replace and refurbish the obsolete equipment such as the hydro-mechanical equipment at the power intake and some mechanical auxiliary systems; and
- Option 3: All activities under Option 2 pus all additional measures to ensure complete rehabilitation of the power plant.

117. The project will support complete rehabilitation of the power plant proposed under Option 3. This approach is justified because several of other infrastructural components of the power plant, which would have been left out of Options 1 and 2, are also close to the end of their useful economic life and would require rehabilitation within 5-7 years from now if not rehabilitated under the proposed project.

118. *Dam safety*. The design of the dam safety measures is based on the assessment of the condition of the Nurek dam and associated structures, including a Possible Failure Mode Analysis (PFMA). The ongoing advanced flood forecasting study, ongoing seismic hazard assessment and stability analyses of the Nurek dam; and assessment of the geological structure of the left bank to check the slope stability will be used to finalize the scope of the safety measures to be included in the project. These aspects are covered in Annex 2.

119. *Sedimentation study*. In addition to the dam safety issues, the project's preparation has addressed the issue of sedimentation in the Nurek reservoir and is addressing the issue of the tailrace channel. The Vakhsh River carries a heavy sediment load but the data available on the sediment inflow and the extent of sediment deposition in the Nurek reservoir was considered to be inconsistent, particularly the results of the last bathymetric survey carried out in 2001. A new sedimentation study was therefore undertaken by HR Wallingford Consultants in 2015 to predict future sedimentation in the reservoir under different conditions. The study included a bathymetric survey, a reliability evaluation of hydrometric data from the two existing stations at Darband and Kishrog, and sediment transport modeling.

120. The study found that a 33 percent reduction in Nurek's reservoir capacity has taken place over 43 years. The present storage capacity is 6.976 km^3, with an active storage capacity (above El. 857 m) of 3.885 km^3 and an inactive storage capacity of 3.091 km^3. Total estimated annual average sediment inflow is 93 Mt. The study predicted the storage volume would reduce by 4 percent every 5 years in the absence of an upstream storage. Thus, by 2035, storage volume would have reduced by half from the original volume.

121. However, the start of construction of the Rogun dam upstream of Nurek impacts the deposition of sediment in the Nurek reservoir. The study has shown that, once Rogun dam is built, very little storage is lost in the Nurek reservoir. The numerical model predicts that there will be almost no change in the total storage volume of the Nurek reservoir in the first 90 years after the construction of Rogun dam. These findings have been taken into account in the calculation of the energy generated from Nurek.

122. *Survey of Tailrace Channel*. The possibility of reducing the tailrace water level in order to increase the head is being investigated. The reduction could be possibly achieved by removing the remnants of a cofferdam that have existed from the time of construction of the Nurek dam. A bathymetric survey of the tailrace channel is to be carried out. This information will be used for the design specifications of the new turbines to be procured and installed under the project.

C. Financial Management

123. The financial management arrangements of BT PRG were reviewed in October 2016 as part of financial management assessment for the Project and have been assessed as adequate for the Project’s implementation. The project FM assessment confirmed that: (i) the FM/accounting staff at BT PRG has experience in the Bank-financed projects; (ii) the internal control and filing systems at BT PRG are overall adequate; (iii) results from the latest annual audit of the Bank-financed projects implemented by BT PRG were satisfactory, and (iv) the IFRs on the other Bank-financed projects implemented by BT PRG were mostly received on time and in general found to be acceptable to the Bank. As capacity building actions, it was agreed that within 30

days after project effectiveness, BT PRG will: (a) hire additional FM/accounting staff, acceptable to the Bank, to manage the increased workload, and (b) finalize the upgrade of the accounting system. Additionally, by project effectiveness, BT will develop the FM Manual that is part of Project Operational Manual (POM), acceptable to the Bank, to reflect the FM arrangements and controls under the Project; and.

124. The PRG will prepare and submit to the bank un-audited interim financial reports (IFRs) in form and content satisfactory to the Bank. Such reports will be submitted within 45 days after the end of every quarter.

125. There are no pending audits for the projects implemented by the BT PRG. The auditor issued unmodified (clean) opinions on the financial statements of projects implemented by the BT PRG with no critical recommendations in the management letters. The audit of the project and entity (BT) will be conducted: (i) on an annual basis; (ii) by independent auditors and on terms of reference acceptable to the World Bank; and (iii) according to the International Standards on Auditing (ISA) issued by the International Auditing and Assurance Standards Board of the International Federation of Accountants (IFAC). The terms of reference to be used for the project audit would be prepared by the BT and cleared by the Bank, before contracting the auditor. The annual audited project and entity financial statements would be provided to the World Bank within six months of the end of each fiscal year and also at the closing of the project. In accordance with the World Bank's Access to Information Policy, audited project financial statements shall be made publicly available. Upon receipt of the audited financial management statements, the Bank would also make them publicly available.

126. Disbursement: Disbursements from the IDA accounts will follow the transaction-based method, i.e., traditional Bank procedures: including Direct Payments, Special Commitments and reimbursement (with full documentation and against Statements of Expenditures - SOEs). For payments above the minimum application size, as will be specified in the Disbursement Letter, BT may submit withdrawal applications to the Bank for payments to suppliers and consultants directly from the Credit Account. The Disbursement Letter will be amended to introduce the advance method for disbursement upon resolution of the outstanding country portfolio issue.

D. Procurement

127. BT procurement capacity. The overall procurement risk under the project is currently assessed as High. The Project Procurement Strategy Document (PPSD) has been prepared by BT with support of the Bank's team. The PPSD has identified the key issues and risks concerning procurement including: (i) limited technical/procurement expertise within BT to develop and implement international competitive bidding requirements for complex and high value contracts; thus BT might not be able to provide quality preparation, review and comments on commercial part of the procurement packages; (ii) Procurement in the country has not attracted adequate competition due to unfavorable business environment and slow private sector growth; (iii) the Tender Committee members, which will be involved in project procurement, may not be familiar with international procurement procedures; (iv) Limited contract monitoring and management skills and tools to ensure efficient and timely contract implementation; and (v) Overall high public procurement risk environment. Additional details are contained in the PPSD.

128. Given the above risks and based on the lessons learned from similar experiences, the following measures are proposed to strengthen BT's capacity and ensure effective project implementation:

- Engagement of PMC, which will assist the PRG in the procurement activities;
- Engagement of PoE, which will advise BT on the preparation and implementation of the technical and dam safety aspects of the project;
- Active participation by the Bank Team in assisting the PRG in the planning and implementation of procurement activities; and
- Other measures detailed in the PPSD.

129. Procurement of contracts financed by the World Bank, AIIB, and EDB will be conducted through the procedures as specified in the World Bank's Procurement Regulations for IPF Recipients -Procurement in Investment Project Financing Goods, Works, Non-Consulting and Consulting Services , July 2016 (Procurement Regulations). The procurement approaches for key packages has been determined and agreed in the PPSD as follows.

130. <u>Procurement approach for key consultancy contracts</u>. PMC was selected based on Quality and Cost Base Selection (QCBS) method as advance procurement. The PoE was hired on the basis of Sole-source selection method as advance procurement.

131. <u>Procurement approach for key Plant Design, Supply and Installation (PDSI) and works contracts</u>. To achieve the project's objectives, the key considerations for determining the procurement approach are:

132. *Power plant rehabilitation*. Taking into consideration the nature of the rehabilitation works required for the power plant equipment, the following approach was agreed:

- The rehabilitation will be carried out under design, supply, and installation contract following International Request for Bids (without prequalification).
- The procurement documents will cover rehabilitation of all nine generating units, key auxiliary systems and associated Balance of Plant (BoP). The contract will be awarded only for the Phase I scope and will be extended for the Phase II scope as soon as the required additional financing is secured.

133. *Supply and installation of autotransformers*. Procurement process will follow International Request for Bids (Single stage without prequalification) method and will be conducted following procurement regulations of the World Bank.

134. *Dam safety works and instrumentation*. Taking into consideration the nature of the rehabilitation works required for this component, the following approach is being adopted:

- A Works contract would be used for the civil works and spillway gates rehabilitation included in the dam safety component.
- The upgrading of the dam instrumentation could be a separate contract following International Invitation for Bids (after prequalification).

135. Procurement risks analysis. PPSD identifies the main procurement risks and the proposed mitigation measures. When preparing the PPSD, the Recipient drew upon the experience in preparing and implementing energy projects in Tajikistan. The details on risks are contained in Annex 3 and the PPSD.

136. Market analysis. The major contract will be PDSI contract for the rehabilitation of the power plant equipment. Experience with currently implemented Kairakum Hydropower Rehabilitation Project (total cost of Phases I and II is US$198.5 million) and 3600MW Rogun Hydropower project (US$ 3.9 billion) proves interest from potential bidders to similar projects. Similarly, it is expected that most of the major manufacturers of large hydropower generating units (nine companies were identified by the Recipient in consultation with the Bank team) will be interested in bidding for the contract.

137. Market analysis for autotransformers confirmed that this is a very competitive market with large number of manufacturers and suppliers. BT implemented a large number of power transmission and distribution network expansion/rehabilitation projects financed by various international financial institutions (IFIs) and bilaterals. Those procurements generated good competition with several bidders participating.

138. The package(s) for dam safety works are expected to be of relatively smaller values. Prequalification will be adopted for the package covering the civil works and the rehabilitation of the spillway gates. It is expected that large number of internationally experienced companies specializing in such works would be interested.

139. The awareness of potential bidders about the project was raised through the following two measures: (a) BT issued the GPN for the project in October 2016 and already received expressions of interest from several firms; (b) As per the PPSD recommendations BT held a conference for potential bidders in Istanbul on January 19-20, 2017, to: (i) provide information on the proposed scope of the project; and (ii) seek comments and suggestions from the bidders on the planned procurement approach for the main package. The feedback obtained from this conference will be used to fine-tune the procurement approach and will be reflected in the relevant provisions of the procurement documents (qualification requirements, implementation schedule, etc.).

140. The procurement plan for the project is presented in Annex 3 and PPSD. The PPSD and procurement plan were finalized and agreed by the Bank.

E. Social (including Safeguards)

141. The overall social impact of the project is expected to be positive because it will help avoid increase of the winter electricity shortages. Specifically, if Nurek HPP is not rehabilitated, then electricity supply of this plant, which accounts for 70 percent of the electricity supply in the country, will start reducing due to severe dilapidation of mechanical, electrical and electro-mechanical equipment. Thus, the project will create benefits for all electricity consumers, including vulnerable and impoverished households and will have positive impacts on all consumers across both genders. The project impacts on local jobs and livelihoods are expected

to be minimal given that rehabilitation works primarily require qualified and skilled labor force, which may not be available locally. No significant labor influx is expected during construction or operation of the plant. Thus, risks associated with labor influx are rated as low to minimal. Negative impacts on communities, such as increased traffic, were highlighted in the ESIA with mitigation measures identified.

142. The Government plans to gradually increase the end-user electricity tariffs to cost-recovery levels by 2022. This will have negative social impacts in particular on the poorest segments of the population, many of whom cannot afford the basic level of energy consumption. The World Bank is currently providing advisory support on options available for mitigation of impacts on the poor. Additionally, the Government's action plan of activities related to new tariff policy requires the Ministry of Labor and Employment and the Ministry of Finance to develop mitigation measures by June 2017.

143. Citizen Engagement. BT has undertaken consultations during project preparation and prepared a Stakeholder Engagement Plan (SEP) to guide information sharing and consultations during project implementation. The preparation-stage consultations were based on a stakeholder mapping, which included key stakeholders at the national, regional, and local levels. The consultations provided and will continue to provide an opportunity for stakeholders to be exposed to the project implementation process and to provide feedback and ask questions. The SEP envisions annual consultations during implementation starting from spring 2018. Local authorities will assist with additional consultations and communication with local communities as necessary. A system to integrate feedback to project design and implementation has been included. The SEP also includes a Grievance Redress Mechanism (GRM), which is based on BT's existing GRM with adjustments to ensure that there are uptake points at the local level (through local BT offices and local authorities). Details on the SEP and GRM are included in Annex 4.

144. Social Inclusion. The SEP was prepared keeping in mind approaches needed to ensure the engagement of groups susceptible to exclusion (such as women, the disabled and the elderly). In terms of project impacts, it is expected that the proposed operation is expected to translate into positive impacts for women as they disproportionately carry the responsibility for household related work and are vulnerable to costly and unreliable electricity supply. To that effect, women's questions and complaints related to impacts of the project will be encouraged and monitored through the proposed intermediate results indicator on percent of registered project related grievances (disaggregated by gender) responded to within stipulated service standard for such responses.[10] In addition, noting gender disparities in employment (women are less than half of the total employed in Tajikistan) and in an effort to minimize this gap, the project will encourage recruitment of women through targeted communication and advertisement of job opportunities. This will be done by using local communication channels to disseminate recruitment information and targeting areas where women can access information. The impact of those efforts will be modest. It is expected that the proposed project will create only a hundred direct or indirect jobs during project implementation.

[10] Within 30 days.

145. Involuntary Resettlement**.** The project does not trigger OP4.12 on Involuntary Resettlement. All project works will take place within the existing facilities. The ESIA and technical studies indicate that under the current design, the rehabilitation works will not result in any impacts on total downstream discharge.

146. Consultations. The project design and its potential impacts and mitigation measures were shared with stakeholders identified through stakeholder mapping. Consultations were held in Dushanbe (national), Kurghan Tyube (regional), Nurek City Hall and Puli Sangin (local). Consultations were held June 2016 and were attended by 175 people. Approximately 50 percent of participants were women. Feedback consultations are planned for Spring 2017.

147. Capacity to implement consultations at BT is low and, therefore, the consultation process will be supported by an NGO that BT will hire. To ensure sustainability of community engagement processes, the NGO will work closely with BT, including relevant local BT offices, in planning and implementation of consultations.

F. Environment (including Safeguards)

148. The project will provide significant environmental benefits in the long run by rehabilitating low-carbon renewable energy based generation plant. The proposed rehabilitation works will also restore the power generation capacity of Nurek due to use of modern turbines and generators with improved designs. The project is not expected to have any significant adverse or irreversible environmental impacts. The project impacts are only site-specific, generally limited to construction stage, and are to be mitigated through a well-designed environmental and social management plan (ESMP). The project has therefore been classified as Environmental Category “B”.

149. The Recipient prepared an ESIA report. The majority of the environmental impacts are associated with potential pollution due to hazardous and non-hazardous waste, and risks associated with occupational health and safety. Safe removal and disposal of asbestos and prevention of workers from electrocution and drowning in deep waters will have to be addressed by the contractor(s) through development of appropriate health and safety plans, emergency preparedness plan, good waste (both construction including hazardous and municipal) management plan. The ESMP will be part of project bidding documents and will require BT and its contractors to allocate adequate human and financial resources to comply with requirements of the ESMP during project implementation. The bidding documents for power plant rehabilitation will also contain a requirement for the PSDI contractor to organize the works in a way to ensure health and safety of both the contractors’ and the power plant’s personnel during the rehabilitation works given the parallel activities (rehabilitation and operation) to be carried out within the limited space in the power house.

150. The ESIA also assessed the cumulative impacts of the project as part of the overall Vakhsh basin hydropower development cascade. The incremental impacts resulting from the proposed Nurek hydropower rehabilitation project are minimal as the project does not alter the river hydrology (upstream or downstream), does not add to any further storage, and does not impact water downstream releases either during construction or operation. The project also does

not pose any incremental impact on aquatic life in general or fisheries in particular. No additional impacts are foreseen due to the project on Tigrovaya Balka State National Reserve, which represents unique Tugai system (flood plain habitat dependent on river flooding, groundwater levels in desert like environment).

151. Following consultations with communities, civil society organizations and stakeholders, the final ESIA was revised to adjust feedback/concerns received during the process. The final ESIA report was disclosed in-country and at the World Bank's InfoShop. The executive summary of ESIA report was also translated into Tajik and Russian and made available at locations that are accessible to stakeholders and was also posted on the web-site of BT.

G. Other Safeguards Policies Triggered

152. **Projects on International Waterways**. OP 7.50 is applicable to the project since the Nurek dam is located on the Vakhsh River in western Tajikistan. The Vakhsh River is one of the main tributaries of the Amu Darya River, which is considered an "international waterway" for purposes of the Policy. The other riparian states to the Amu Darya are Afghanistan, Uzbekistan and Turkmenistan, all three being downstream riparians.

153. The policy applies, inter alia, to hydroelectric projects that involve the use or potential pollution of international waterways. Therefore, at the request of the Republic of Tajikistan, the Bank sent a notification letter to riparians. No responses were received by the Bank from the concerned riparian states.

154. **Safety of Dams**. OP 4.37 is applicable to the project as it relies on the performance of an existing dam. As required by the policy, the project: (a) has engaged a PoE to provide independent review and expert advice on dam safety issues and other aspects during both preparation and implementation; (b) will ensure that the works under the project will be designed and supervised by competent professionals. This will be done by the international PMC, who is financed by the project; and (c) prepare and implement the following detailed plans: (i) a plan for construction supervision and quality assurance; (ii) an instrumentation plan; (iii) an O&M plan; and (iv) an EPP. PoE in its first meeting held in October 2016 provided valuable comments and recommendation on ongoing additional dam safety related investigations and analyses conducted by BT's consultant, which will be reflected in the final design of dam safety works.

155. PoE will review the dam safety related aspect of the detailed design, supervision of remedial works, and upgraded dam safety plans during preparation and implementation periods. PoE is expected to meet at least twice per year, but the frequency of site visits will be adjusted depending on the actual design and rehabilitation work progress including possible use of video conferences. More details on these aspects are presented in in Annex 3 of this document.

H. World Bank Grievance Redress

156. Communities and individuals who believe that they are adversely affected by a World Bank (WB) supported project may submit complaints to existing project-level grievance redress mechanisms or the WB's Grievance Redress Service (GRS). The GRS ensures that complaints received are promptly reviewed in order to address project-related concerns. Project affected

communities and individuals may submit their complaint to the WB's independent Inspection Panel which determines whether harm occurred, or could occur, as a result of WB non-compliance with its policies and procedures. Complaints may be submitted at any time after concerns have been brought directly to the World Bank's attention, and Bank Management has been given an opportunity to respond. For information on how to submit complaints to the World Bank's corporate Grievance Redress Service (GRS), please visit http://www.worldbank.org/GRS. For information on how to submit complaints to the World Bank Inspection Panel, please visit www.inspectionpanel.org.

Annex 1: Results Framework and Monitoring

Project Development Objectives	
PDO Statement The project development objectives are to rehabilitate and restore the generating capacity of three power generating units of Nurek hydropower plant, improve their efficiency, and strengthen the safety of the Nurek dam.	
These results are at	Project Level

Project Development Objective Indicators

Indicator Name	**Core**	**Unit of Measure**	**Baseline**[11]	**Cumulative Target Values**						**Frequency**	**Data Source/ Methodology**	**Responsibility for Data Collection**
				YR1	**YR2**	**YR3**	**YR4**	**YR5**	**YR6**			
Indicator One: Generation capacity of energy constructed or rehabilitated under the project	☒	MW	0	0	0	0	335	670	1,005	Annual	BT project implementation progress reports based on inputs from PMC	BT
Indicator Two: Estimated annual electricity generation of three units included in the scope of the project[12]	☐	GWh	At least 3,750	At least 3,750	At least 3,750	At least 2,500	At least 2,511	At least 2,522	At least 3,783	Annual	BT project implementation progress reports based on inputs from PMC	BT
Indicator Three: Estimated increase of winter electricity generation of rehabilitated units due	☐	GWh	0	0	0	0	At least 11	At least 22	At least 33	Annual	BT project implementation progress reports based on inputs from PMC	BT

[11] All baseline values are as of 2015.

[12] The three units to be rehabilitated under Phase I. This indicator was computed based on the assumption that one unit will be taken out of service each year starting from YR3. It is assumed that rehabilitation of one unit will take up to 11 months. After rehabilitation, the annual electricity output from one unit will increase by at least 11 GWh.

to efficiency improvements[13]												
Indicator Four: Improved dam safety against hydrological and geological risks	☐	Text	No	No	No	No	No	Yes	Yes	Annual	BT project implementation progress reports based on inputs from PMC	BT
Indicator Five: People provided with improved electricity service [14]	☒	Number	0	0	0	0	8,276,000[15]	8,276,000	8,276,000	Annual	UN Population Reports / Data and National Statistical Service of Tajikistan	BT
Female beneficiaries	☒	% Sub-Type Supplemental	0%	0%	0%	0%	49.3%[16]	49.3%	49.3%	Annual	UN Population Reports / Data and National Statistical Service of Tajikistan	BT

[13] This is based on the assumption that minimum 2 percent weighted average efficiency improvement will be obtained under water head varying from 75 to 100 percent of the maximum operating head.

[14] The total number of people connected to the central power system. This excludes the population (206,000 as of 2011) of GBAO, which has an autonomous power system. The GBAO population was assumed to remain unchanged during the project implementation period. The baseline of the total population of Tajikistan is based on the UN forecast for 2014.

[15] The baseline is for 2015 and is the annual mid-year interpolated population. The population is conservatively assumed to remain unchanged during the implementation of the project. The population number excludes population of Gorno-Badakhshan region because it is not connected to the central power system of Tajikistan. Source: UN Population Prospects Report, July 2015.

[16] UN World Population Prospects: The 2015 Revision. The share of females in the total population is assumed to remain unchanged.

Intermediate Results Indicators												
				Cumulative Target Values						**Frequency**	**Data Source/ Methodology**	**Responsibility for Data Collection**
Indicator Name	**Core**	**Unit of Measure**	**Baseline**	**YR1**	**YR2**	**YR3**	**YR4**	**YR5**	**YR6**			
Intermediate Result Indicator One: Cumulative number of generating units rehabilitated	☐	Number	0	Contract for rehabilitation is signed and effective	Turbine hydraulic model test is completed	Design for generating units is completed and manufacturing commenced	1	2	3	Semi-annual	BT project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Two: Cumulative number of autotransformers replaced	☐	Number	0	Bidding document is issued and evaluation of bids is completed	Contract for replacement of autotransformers is signed and effective	The supply of autotransformer s is underway	Installation of auto-transformers is underway	6	6	Semi-annual	BT project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Three: Enhanced hydrological safety	☐	Text	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 10,000 years flood	Once in 100,000 years flood	Annual	BT project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Four: Upgrade of the dam monitoring instrumentation completed	☐	Text	No	Bidding document is issued	Contract for upgrade of dam instrumentation is signed and effective	The supply and installation of the dam monitoring instrumentation commenced	The dam monitoring instrumentation is partly operational	The dam monitoring instrumentation is fully operational	-	Semi-annual	BT project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Five: Civil,	☐	Text	No	Bidding document is	Contract for procuremen	The dam safety	The dam safety	Rehabilitation of the	-	Semi-annual	BT project implementation	BT

electrical and mechanical works for improvement of the dam safety completed				issued	t of the dam safety improvement works is signed and effective	improvement works are in progress	improvement works are in progress	spillway tunnel, gates and hoising system is completed			progress reports based on inputs from PMC	
Intermediate Result Indicator Six: Update of EPP and preparation of O&M plans completed	☐	Text	No	Draft updated EPP and O&M plans are reviewed by BT and other relevant state agencies	Final updated EPP and O&M plans are approved by BT and other relevant state agencies	Final updated EPP and O&M plans are effective and implemented	Final updated EPP and O&M plans are effective and implemented	Final updated EPP and O&M plans are effective and implemented	Final updated EPP and O&M plans are effective and implemented	Semi-annual	BT project implementation progress reports based on inputs from PMC	BT
Intermediate Result Indicator Seven: Percent of registered project related grievances (disaggregated by gender) responded to within stipulated service standards for response times[17]	☐	%	0	100	100	100	100	100	100	Semi-annual	GRM reports of BT	BT

[17] Not more than 30 days.

Indicator Description

Program Development Objective Indicators

Indicator Name	Description (indicator definition etc.)
Generation capacity of energy constructed or rehabilitated under the project.	This indicator measures the capacity of hydropower constructed or rehabilitated under the project.
Estimated annual electricity generation of three units included in the scope of the project.	This indicator measures the supply from rehabilitated units. This indicator will be estimated by dividing the total annual electricity generation by the total number of units and considering their efficiency compared to the base-line.
Estimated increase of winter electricity generation of rehabilitated units due to efficiency improvements.	This indicator measures additional winter generation of rehabilitated units during the time period of October-March due to minimum weighted average efficiency increase of 2 percent. The 2 percent increase was assumed under water head varying from 75 to 100 percent of the maximum operating head.
Improved dam safety against hydrological and geological risks.	This indicator measures the improvement of the dam safety from introduction of advanced flood forecasting system and reservoir management rules, rehabilitation of the spillway tunnels, gates and hoising system, and works to make both sides of the concrete gallery of the dam impermeable.
People provided with improved electricity service.	The indicator measures the number of people that have received improved electricity service due to Phase I of the project.

Intermediate Results Indicators

Indicator Name	Description (indicator definition etc.)
Cumulative number of generating units rehabilitated.	This indicator measures the progress with rehabilitation of generating units under the project.
Cumulative number of autotransformers replaced.	This indicator measures the progress with replacement of the six autotransformers.
Enhanced hydrological safety.	This indicator measures ability of the dam to handle large floods.
Upgrade of the dam monitoring instrumentation completed.	The indicator measures the progress with procurement and installation of dam monitoring instrumentation.

Civil, electrical and mechanical works for improvement of the dam safety completed.	This indicator measures the progress with implementation of civil works aimed at improvement of the dam safety.
Update of EPP and preparation of O&M plans completed.	This indicator measures the progress with preparation and introduction of updated EPP and O&M plans.
Percent of registered project related grievances (disaggregated by gender) responded to within stipulated service standards for response times.	This indicator measures the progress with responding to project related grievances related to environmental and social safeguards issues.

Annex 2: Detailed Project Description

1. The project aims to rehabilitate and restore the generating capacity of three power generating units of Nurek hydropower plant, improve their efficiency, and strengthen the safety of the Nurek dam. To that end, the project will support rehabilitation of three generating units and key infrastructural components of the power plant, dam safety improvement measures, and technical assistance to help BT implement the project. The detailed description of the project components and the relevant technical justifications are presented below.

2. **Component 1: Rehabilitation of the three generating units, the key infrastructural components of the plant, and replacement of autotransformers (US$310 million to be financed by the Association and other financiers as described below).** This component will finance the replacement and refurbishment of mechanical, electrical, and electromechanical equipment and works required for rehabilitation of three generating units of the Nurek HPP and replacement of all six autotransformers. Specifically, this component will include the following sub-components.

3. **Sub-component 1.1**: **Replacement and refurbishment of mechanical, electrical, and electromechanical equipment required for the rehabilitation of three generating units of the Nurek HPP (US$270 million, including US$200.7 million from IDA, US$45 million from AIIB, and a financing gap of US$24.3 million).**

4. Assessment of the scope of the required rehabilitation works for the power plant equipment was based on detailed inspections carried out by the feasibility consultants, supplemented by information from recently performed rehabilitation works and a review of the O&M history of the plant. The recently performed rehabilitation works included replacement of three runners and rehabilitation of two MIVs.

5. For the turbines, the inspections carried out during the feasibility study included:

- Inspection of the spiral case and stay vanes, stay vanes inlet and outlet profile and visual examination in order to check the possible presence of cracks, corrosion or other defects; as well as inspection of guide vanes (while assembled in the distributor).
- Inspection of other turbine components such as operating ring, guide vane operating mechanism, turbine bearing and guide vane servomotor while assembled. For one unit, one upper stem bushing and lever were dismantled and examined. The turbine bearing cover on one unit was also dismantled.

6. Evaluation sheets for the inspected components were prepared providing an assessment of the condition of each piece of equipment, through a rating based on the assessment guidelines of the Hydropower Advancement Project (HAP).

7. The technical assessment of the Generator was performed following the HAP Condition Assessment Manual for Generators. The condition assessment was carried out on four units and covered quantitative ratings of installed technology, operation and maintenance history and detailed inspections of the generator components.

8. A similar approach was adopted for the remaining equipment (transformers, auxiliary systems, SCADA, etc.) with detailed inspections being carried out in conjunction with a review of O&M history.

9. Following the technical assessment of the condition of the equipment, different rehabilitation options were considered, ranging from maximum reuse of existing equipment components after refurbishment to a complete rehabilitation of the plant so as to achieve near-new conditions. Based on a comparison of these options, the rehabilitation scope is defined as follows:

(a) <u>Replacement of three turbines</u>. This component will support design, supply and installation of new turbine runners and other turbine components, as well as the refurbishment of the existing embedded components. The technical specifications will require a new hydraulic design for the runner with the possibility of increasing the available generating capacity of each turbine by up to 12 percent over the current level. Replacement of the turbine runners and other turbine components, as well as the refurbishment of the existing embedded components will include:

(i) *Replacement of runners on three units*. The hydraulic design of the existing runners is obsolete and the runner blades show damages at the inlet and outlet. The cavitation damages on the suction side of the blades' inlet are characteristic of high head cavitation. The damages on the outlets of blades were most likely caused by cavitation. A new hydraulic design will be developed to eliminate cavitation and also allow increasing the available generation capacity. Another factor that will need to be taken into account in the design of the runners is the joint operating mode that is to be adopted for the Rogun and Nurek reservoirs after Rogun comes into operation.

(ii) *Refurbishment of spiral cases and stay vanes*. The spiral case and stay ring water passage surface will be sandblasted and the stay vane weld, radius transition zones and other sections of potential damage will undergo non-destructive examination. Refurbishment will include welding and grinding repair of stay vane surface defects, painting of the stay vanes and spiral casing, and correction of the upper faces of stay rings to ensure horizontality of head cover. Additionally, stay vane profile adjustments will be done if cracks or vibration issues are identified.

(iii) *Refurbishment of bottom and discharge rings*. Refurbishment of discharge and bottom rings will include sandblasting, repair of welds, repair of active surface of bolts and painting. The bottom ring will be refurbished and machined at site with a special machine to allow for installation of a new stainless steel wearing plate. Additionally, bottom ring guide vane bushings will be replaced by self-lubricating bushings.

(iv) *Refurbishment of draft tubes*. Refurbishment will include repair of the concrete lining in order to ensure smooth water passage.

(v) *Replacement of turbine head cover*. During the replacement of the runner for Unit 3, ultrasonic examination had revealed cracks in the head cover. There is a significant probability that all head covers (of identical design, manufactured with the same material and manufacturing processes, and subject to the same operating conditions) may suffer (already or in the near future) from similar cracks. Therefore, the head covers on all three turbines, as well as the operating rings, will be replaced. The turbine head cover drainage system will also be changed retaining the same principle of pump or hydro-ejector forced drainage plus gravity drainage.

(vi) *Refurbishment of guide vanes and their operating mechanism*. This will include:

- Replacement of wicket gates/guide vanes to allow for safe and reliable operation of the units for 30 years after completion of the project.
- Replacement of regulating rings, levers and links.
- Use of self-lubricating material for all guide vane bushing, links and lever bearing as well as operating ring guides and supports.
- Supply of new servomotors as part of the new high-pressure governor oil system with the additional possibility of upgrading the rate pressure of the governing system.
- Replacement of turbine shaft and sealing.
- Installation of turbine discharge measurement system.

(vii) *Replacement of turbine governing system*. The electrohydraulic speed governor will be replaced by a modern microprocessor based speed governor. This will allow for safe and reliable operation of the units. Similarly, the instruments and auxiliary components such as electrohydraulic actuators, safety valves, motors and pumps, manual valves and other pieces of equipment will be replaced.

(viii) *Replacement of oil pressure system*, which includes air-oil pressure tanks, air pressure tanks, and oil sumps tanks; and replacement of pumps, safety valves, manual isolating valves, filters and electro-valves of the oil pressure system.

(ix) Refurbishment of penstocks. The penstocks will undergo non-destructive examination. Refurbishment will include welding and grinding repair of surface defects, and painting.

(x) Refurbishment of main inlet valves (MIV). The assessment of the structural and foundation conditions will be carried out, including possible pressure testing of the MIV. Refurbishment will include (as needed): provision of self-lubricated bearings, replacement of trunnion sleeve, replacement of the operation seal ring, replacement of by-pass valve, etc. In addition, the operating principle of the MIV will be modified to have closure by a counter weight, instead of the current closure by oil pressure.

(b) <u>Replacement of generators</u>. All of the water-cooled generators will be replaced. The generators have not undergone any capital repair (installation of new winding or new stator cores). The operation of the generators is constrained by vibration of the shaft line and/or overheating. Thus, the project will finance acquisition of new air-cooled generators for the

three units being rehabilitated, which will allow avoiding operational capacity constraints currently experienced when distilled water system is out of order. Furthermore, the new air-cooled generators will allow increasing the rated capacity of the power plant. The option for generators with higher rated capacity will be specified in the bidding document. The insulated phase bus-bars and generator circuit breakers will also be replaced.

(c) Replacement of generator step-up transformers. The existing step-up transformers are old and have high electrical losses. The risk of sudden failure is high; one transformer suffered a major internal insulation failure in 2014 and could not be repaired, resulting in the generating unit being out of operation since then. The three transformers will be replaced, with the rated power defined in accordance with the new generator rated power and the operating power factor.

(d) Replacement of plant monitoring, control, automation and protection systems. The control, measurement, and monitoring equipment and the protection cubicles based on electro-magnetic relays will be replaced by modern equipment since those have not been changed since commissioning of the plant in 1972-1979. This equipment is obsolete and difficult to maintain given lack of spare parts. The new control system will allow automatic operation of the units.

(e) Replacement of auxiliary electrical systems. These systems will be replaced as they are obsolete and the non-availability of spare parts is a major constraint. This will include:

(i) *Replacement of LV and MV switchboards at the powerhouse, the equipment of the dam and power rings of the underground complex*. This is needed to ensure reliability of the electricity distribution systems and to allow for integration with the new control and monitoring systems.
(ii) *Replacement of the stand-by diesel generator sets*. This will include replacement of the emergency diesel set of the water intake; installation of the new scheme for connection of the back-up generators to relevant switchboards and improvement of the emergency power scheme at the powerhouse through installation of an emergency MV diesel set.
(iii) *Replacement of cables and cable trays*. Most of the power and control cables are old and will be replaced.
(iv) *Improvement of the lighting system in the powerhouse and underground complex*. The indoor regular and emergency lighting systems will be replaced because they are in poor condition and show signs of excessive wear and tear.

(f) Replacement of auxiliary mechanical systems. This will include replacement or refurbishment of cooling water and technical water supply system of the units; cooling system of main power transformers; distilled water system to cool stator windings and rotor core; compressed air systems; drainage systems for the power house and the dam; dewatering system of the units; powerhouse heating, ventilation and air conditioning system; ventilation system of the underground complex; fire-fighting system; sewage system; hoisting equipment and elevators; and oil infrastructure system.

(g) Installation of new Supervisory Control and Data Acquisition System (SCADA). This will include replacement of the existing electromagnetic relays-based control and monitoring system with a new modern SCADA system. The new system will be installed in the existing control room. The architecture based on the redundant real-time server will match the needs of the plant. The control room will be connected to different controllers installed in the power plant through an optical fiber network.

(h) Replacement and refurbishment of hydro-mechanical equipment at the power intake. This will include installation of a head loss measurement system; refurbishment of intake trash racks; replacement of seals on maintenance gates and other refurbishment works; replacement of electrical hoists, lifting cables on intake gates and other refurbishment work.

(i) Replacement of laboratory equipment and purchase of tools. This will include support to replace equipment and purchase tools required for the oil quality analysis laboratory, oil treatment plant, electrical and mechanical workshop, generator workshop, high voltage laboratory, and the instrumentation, control and protection laboratories.

10. **Sub-component 1.2: Replacement of six autotransformers (US$40 million, which will be 100 percent financed by EDB)**. This sub-component will finance the supply and installation of six autotransformers. These 10.5/220/500kV single phase autotransformers are located in the 220kV switchyard. They interconnect the 220 and 500kV networks. These autotransformers are essential for reliable evacuation of electricity generated by Nurek HPP and the auxiliary electricity supply. The age of the autotransformers is around 40 years and their condition creates a risk of malfunction or failure that could result in disconnection of the Nurek HPP from the electricity network.

11. **Component 2: Enhancement of dam safety (US$30 million, including US$15 million from IDA and US$15 million from AIIB)**. This component will finance activities designed to improve the safety of the operation of the Nurek HPP. The Feasibility Study for the project assessed the existing condition of the Nurek dam and associated structures, including a Possible Failure Mode Analysis (PFMA) and made a number of recommendations to improve their safety. The following key safety-related elements are being addressed in the preparation of the project and required measures are being included in the project's design. The scope will be further refined based on the results of ongoing studies and would include the following activities:

(a) Rehabilitation of spillway tunnels, refurbishment of spillway gates/hoisting system, improvement of protection on permeable zone of the embankment dam above the core zone crest, etc.

(b) Implementation of measures to enhance safety against seismic hazards. Those scope of those measures will be finalized after completion of the: (a) ongoing seismic hazard assessment and stability analyses of the Nurek dam; and (b) completion of the drilling of five boreholes on the downstream part of the left bank to check the slope stability.

The original design-stage seismic hazard assessment and stability analysis of the Nurek dam under seismic loading conditions are not available. In 2008, a pseudo static analysis with

peak ground acceleration of 0.37 g was done but without indication of occurrence frequency. Given the 300 m height of the dam and potential hazard, a Probabilistic Seismic Hazard Assessment is being carried out to update the seismic design parameters, defining the Operating Basis Earthquake (OBE) and the Safety Evaluation Earthquake (SEE). Using the updated seismic design parameters, a two-dimensional dynamic analysis of the main embankment dam will be carried out. This will include checking of the condition of the seismic belt, which has been affected by differential settlement over the years. The wedge stability in the left abutment under seismic loads will also be assessed. Based on the assessment results, appropriate measures (if required) to enhance safety will be designed and included in the project.

The Feasibility Study identified a risk that movement of a 'triangular block' wedge in the downstream part of the left bank could cause shearing of the bottom spillway tunnel (2,020 m3/s), adversely impact the surface spillway tunnel (2,020 m3/s), and possibly even block the tailrace channel. Such an eventuality could render Nurek incapable of safely discharging floods. An independent expert geologist, who is familiar with the geological setting of this region, carried out an assessment of the risk of a significant movement of the triangular block wedge. The initial assessment is that a large-scale sliding movement is unlikely, although gradual minor movements along a fault are to be expected due to the oblique rise of a deep salt/gypsum layer. To confirm the findings, a number of boreholes are being drilled and the slope stability will be checked under various loading conditions to confirm these findings. Regular 3D geodetic monitoring will be undertaken by instruments. Appropriate remedial measures to allow the spillway tunnels to function adequately from a hydraulic and structural perspective will be implemented as part of the project.

(c) Update of EPP. A full-fledged EPP will be prepared during project implementation. The EPP will be based on a dam break analysis, including failure mechanism (breach geometry, duration, etc.), downstream topographic survey, and flooding simulation. It will cover risk categorization, roles/responsibilities of key entities, notification/ warning procedures, etc. including the downstream cascade HPPs.

(d) Preparation of the O&M Plan. The Plan will cover the reservoir operation procedure during floods including advanced flood forecasting and downstream warning systems, sedimentation monitoring/management plan, as well as regular surveillance, instrumentation data analysis/reporting, periodic inspection procedure, etc.

(e) Refurbishment and upgrading of monitoring instruments and management system to improve the collection and analysis of the safety monitoring data. The dam is equipped with about 2,800 monitoring instruments to measure seepage volume, piezometric pressure, soil pressure, settlement, displacement, joint opening, seismic acceleration, etc. of the main embankment dam and associated concrete structures. However, around 40 percent of monitoring sensors, cables, and multiplexor boxes have been damaged by aging, corrosion, etc. Some critical instruments need to be repaired or replaced for proper dam safety monitoring. Also, the software for managing measurement data requires updates as it does not allow for: (i) adding new instrument data, (ii) graphical data presentation, and (iii) automatic warning in the case of monitoring data exceeding thresholds. The Feasibility Study prepared an inventory of monitoring instruments and cost estimates for

replacing/upgrading the monitoring system, including new sensors and data management system, which will be covered by the project. An updated Instrumentation Plan including each instrument's reading frequency, warning thresholds, etc. as well as the analytical/reporting procedure using the updated management software will be prepared during project implementation.

(f) Installation of an advanced flood forecasting/warning system. The Nurek dam was designed for a flood of 5,400 cubic meters/second, which was consistent with the design criteria used in the Soviet Union at the time of the construction. This corresponded to a 10,000-year return period flood, evaluated based on the hydrological records available up to that time. The other HPPs of the Vakhsh cascade, which are downstream of Nurek, were also designed for the 10,000-year return period flood. Recent hydrological studies, based on up-to-date hydrological data, have resulted in a 5 percent increase in the peak value of the 10,000-year flood. The under-construction Rogun dam upstream of Nurek will significantly reduce the flood risk because the Rogun dam is designed to attenuate extreme floods (up to the Probable Maximum Flood) so that the discharge downstream of Rogun is limited to the flood-handling capacity of Nurek (5,400 cubic meters/second).

To cover the eventuality that the construction of Rogun is delayed, a number of scenarios were analyzed under the technical studies to assess the safety of the Nurek dam against extreme floods, without taking into account any attenuation at Rogun. The analysis indicated that an improved flood forecasting system, combined with delayed reservoir filling for enhanced flood routing during years of expected high floods, can provide safety against a 100,000-year return period flood, significantly higher than the current flood-handling capacity. The possibility of utilizing a concrete gallery located near the top of the dam as an extension of the impervious core is being investigated as a further enhancement of the flood-handling capacity of the dam. Detailed design and execution of required measures, such as advanced flood forecasting system, modified reservoir operation procedure, and possibly some protective measures of the top pervious layer of the embankment body will be further studied to detailed design level and undertaken during project implementation.

12. **Component 3: Technical assistance (US$10 million, which will be 100 percent financed by the Association and AIIB)**. This component will strengthen the project's management and implementation arrangements as follows:

(a) PMC to assist with the design, bidding, quality control and construction supervision of the project. BT has already signed US$5.2 million equivalent contract with PMC, which mobilized in January 2017.
(b) Panel of Experts (PoE) on matters related to dam safety and other critical aspects of the Project, including matters relating to dam safety, its appurtenant structures, the catchment area, the area surrounding the reservoir and downstream areas, and other important matters.
(c) Additional technical and engineering studies, which may be required during the project implementation.
(d) Expert assistance for operations and maintenance, procurement and financial management, environmental and social risk management and monitoring.

(e) Capacity building for Nurek HPP and BT staff, including in project management, dam safety, operation and management of hydro facilities, financial management and safeguards aspects of hydropower projects.
(f) Support to BT in implementation of key measures aimed at improvement of financial standing of the company.
(g) Implementation of the Stakeholder Engagement Plan (SEP).
(h) Project and entity audits.
(i) Incremental operating costs of the project implementing entity.

Annex 3: Implementation Arrangements

Project Institutional and Implementation Arrangements

1. BT will be responsible for implementation of the project. BT, the state-owned open joint stock holding company, was established in 1999 and is responsible for generation, transmission, and distribution of electricity and heat in the Republic of Tajikistan. The proposed project implementation arrangements were developed considering the experience of BT with implementation of the IFI financed projects, including Energy Emergency Project and its Additional Financing (World Bank), Energy Loss Reduction Project and its Additional financing (World Bank), ongoing Project on Reduction of Electricity Losses in Sughd Region (EBRD) as well as the ongoing Kairakum Hydropower Rehabilitation Project financed (EBRD).

2. The Supervisory Board of BT will be responsible for overall project oversight. The Supervisory Board is chaired by the Prime Minister and includes the Minister of Energy and Water Resources, Minister of Finance, Minister of Economic Development and Trade, Minister of Justice, Chairman of the State Committee on Investments and State Property Management, and the Chairman of BT. The Working Group will be submitting semi-annual project implementation progress reports to the Supervisory Board.

3. **Working Group for the Project**: BT established a Working Group for the project by February 2017, which will be responsible for: (a) review and acceptance of works of the contractors and outputs of the consultants under the project; and (b) review of justifications for changes in the scope of contracts under the project, including variation orders under construction contracts. The Working Group will implement the above key functions taking into account the advice from PMC and PoE. The Working Group includes representatives from BT, MEWR, and Nurek HPP.

4. **Technical Council of BT**: The Technical Council is a functioning body within BT, which will be responsible for review and approval of the technical specifications of the bidding documents for all main contracts under the project. The Technical Council includes the heads of all technical departments of BT. Review and approval of bidding documents is typically done by the Working Group, however, given the strategic importance of the project, it will be conducted by the Technical Council. Specifically, the bidding documents for PSDI contract for power plant rehabilitation; supply and installation of autotransformers; and dam safety enhancement civil works will be reviewed and approved by the Technical Council.

5. PoE and PMC will provide technical advice and implementation support to both Technical Council and the Working Group. Specifically, PoE will provide independent review and expert advice on dam safety issues, including review of all technical reports and specifications in the procurement documents for implementation of activities related to enhancement of the dam safety. BT completed selection of PoE, which includes an experienced dam safety specialist, geologist, and an electro-mechanical expert. PoE had the first meeting at the dam site in October 2016. PoE provided valuable comments and recommendation on ongoing additional dam safety related investigations and analyses conducted by BT's consultant and other dam safety aspects, which will be reflected in the final design of dam safety works.

6. The support of PMC, which is staffed with relevant technical specialists, will include:

(a) Preparation of the design and construction plan for the power plant rehabilitation, civil works for the dam safety, rehabilitation of spillway gates, and rehabilitation of switchyard equipment.
(b) Preparation of a detailed cost estimate for each of the contract packages in accordance with standard methods of measurement.
(c) Preparation of the procurement documents for power plant rehabilitation works, replacement of autotransformers and dam safety enhancement works. The Consultant shall prepare all the required documents for the required works and equipment in accordance with the appropriate version of the project financiers' procurement guidelines. This will include description of the project, all technical specifications, design drawings and bill of quantities as required for each package.
(d) Support BT with evaluation of bids under the project, including advice on all technical and commercial matters related to the bid.
(e) Preparation of the EPP based on a dam break analysis, including failure mechanism (breach geometry, duration, etc.), downstream topographic survey, and flooding simulation. The EPP will cover risk categorization, roles/responsibilities of key entities, notification/ warning procedures, etc. including the downstream Vakhsh cascade.
(f) Preparation of the O&M plan. The O&M Plan will cover the O&M procedure, reservoir operation rules, as well as instrumentation monitoring, reporting, analyses, regular surveillance, periodic inspection, etc. In addition, the Consultant shall provide detailed O&M Manuals for the newly installed electro-mechanical equipment as it reviews and approves, if appropriate, the O&M Manuals provided by the manufacturers of the hydro-mechanical equipment and shall ensure that these are provided in good time prior to re-commissioning of the rehabilitated generating units.
(g) Site handover and preparation, including: issuance of handover notice of the site to the contractors as per the general conditions of contract; checking and approval of the contractors' construction / shop drawings; review and approval of the construction layout plan; preparation of a Construction Supervision and Quality Control Plan for BT's approval; review and preparation of the Health & Safety Plan; attendance of Factory Acceptance Tests.
(h) Review of contractors' implementation schedules.
(i) Supervision of the construction works. The Consultant will supervise the implementation of the project on behalf of BT and ensure that the contractors carry out all works in a proper workmanship and expeditious manner and in accordance with the contract documents. The Consultant will, in coordination with BT, check, approve, reject and record, as per the technical specifications, as the case may be, inter alia, the following: contractors' construction plant and equipment; materials of construction; testing procedures and results; construction of site works; manufacturing, installation, tests, initial operation and preparation for the commissioning of hydro-electrical and mechanical equipment. The PMC will also review and approve all submittals, including method statements, construction / shop drawings, etc. submitted by the contractors/suppliers for permanent and temporary works, formwork, etc. to ensure conformity with construction contracts and that the work can be carried out safely and in

accordance with recognized and accepted practices. The PMC will assess any design modifications that may become necessary during contracts execution, and propose technically acceptable modifications, or assess and approve contractors / suppliers proposals in consultation with BT.

(j) Monitoring of the contractors' compliance with the provisions of ESMP, Occupational Health and Safety provisions, relevant national legal obligations.
(k) Issuing of instructions to the contractors.
(l) Inspection and testing of works.
(m) Advising BT on approval of payment certificate.
(n) Training of the relevant BT and Nurek HPP staff to strengthen its capacity.

7. **Project Realization Group of BT**. PRG at BT will be responsible for procurement, contract administration, and financial management under the project. PRG has extensive experience in implementation of IFI financed projects, including the recently completed World Bank financed Energy Loss Reduction Project and its Additional financing. Overall, the PRG is adequately staffed with procurement and FM staff with qualifications acceptable to the Bank.

8. In particular, the Central Accountancy of BT and Financial Management department of PRG will be responsible for overall implementation of the financial management (FM) function of the project including, monitoring the flow and accountability of funds, budgeting, accounting, reporting, internal controls and external auditing.

9. As concluded by the PPSD, PRG under BT has expanded its project management capabilities through implementation of the World Bank and other donor funded projects over the past years. However, implementing a project of the proposed scope and technical complexity will require further strengthening of the implementation capacity and devoting additional resources to support PRG in: (i) preparation and implementation of the technical and dam safety aspects; (ii) planning and implementation of procurement activities; (iii) establishing a contract management system; and (iv) strengthening a control and coordination arrangement between the PRG and the technical team in the Nurek HPP.

10. BT will further strengthen the capacity of PRG. In particular, BT PRG will hire a new FM/accounting expert/consultant, acceptable to the Bank, to manage the increased work-load. Additionally, BT PRG will hire technical specialists/consultants for the project needs. The cost of additional staff/consultants under the project may be financed from the project funds.

11. **Project implementation timeline**. The project's implementation schedule foresees completion by December 31, 2023. According to this schedule, the bid documents for the project's largest component, power plant rehabilitation, will be issued in the first semester of 2017 with contract award by the end of 2017. The construction time for the project, including contractor mobilization, detailed design, manufacture, transportation, and installation is expected to be 60 months and the commissioning of the project is therefore projected to take place in 2022.

Financial Management, Disbursements and Procurement

Financial Management

12. The FM arrangements of BT PRG were reviewed as part of financial management assessment for the project and have been assessed as acceptable for the project's implementation. The project FM assessment undertaken in October 2016 confirmed that: (i) the FM/accounting staff at BT PRG has experience in the Bank-financed projects; (ii) the internal control and filing systems in place at BT PRG are overall adequate; (iii) results from the latest annual audit of the Bank-financed projects implemented by BT PRG were satisfactory, and (iv) the IFRs on the other Bank-financed projects implemented by BT PRG were mostly received on time and in general found to be acceptable to the Bank. Nevertheless, the following action plan, was agreed with the BT PRG, and will need to be implemented to incorporate additional financial management requirements for the proposed project. The agreed plan consists of capacity building actions that have to be in place before project implementation starts.

Action	Responsibility	Deadline
Hire additional FM/accounting staff, acceptable to the Bank, to manage the increased workload.	BT	Within 30 days after project effectiveness
Develop the FM Manual that is part of Project Operational Manual (POM), acceptable to the Bank, to reflect the FM arrangements and controls under the Project.	BT	By effectiveness
Finalize the upgrade of the existing accounting system.	BT	Within 30 days after project effectiveness

13. The overall FM risk for the proposed project is Substantial before mitigation and Moderate after mitigation of above-mentioned measures.

14. The BT PRG is capable to prepare relevant budgets. The project plans and budgets are developed in close collaboration between the Government representatives and PRG management. The final plans and budgets are submitted to the BT for approval. The annual budget is based on the procurement plan, which is regularly updated by the procurement specialist. All changes in procurement plan are reviewed by the BT Chairman agreed in advance with the Bank, and only then the changes are incorporated in the annual budget. Once reviewed and endorsed by the MOF, the project budget is included into the State Budget.

15. For financial reporting purposes, the BT uses cash basis IPSAS (for the project reporting) and IFRS (for the entity reporting). The chart of accounts used for the ongoing project can be adapted to be used for this project. The accounting policies and procedures are documented for the ongoing Bank-financed project. BT PRG will develop an FM Manual, which will be part of the POM (by project effectiveness). The accounting at BT is automated, using 1C accounting software. Following the recommendations of Accounting and Auditing ROSC, the Accounting Law was amended in 2011 to require all Public Interest Entities to apply International Financial Reporting Standards (IFRS).

16. BT uses the 1C accounting software (version 8.2) and both project and entity accounting are tracked in this program. The software has the capability to produce interim financial reports in accordance with formats to be agreed with the Bank. All transactions recorded on a cash basis of accounting and the supporting documentation will be maintained in files for ready access by auditors and during implementation support missions of the World Bank. The Chart of Accounts for the project is based on the Chart of Accounts developed by the MOF, and modified to allow tracking of project transactions and reporting by source of financing, project components, and type and category of expenditure. The system was used for the previous Bank-financed projects, and is used for the on-going Bank-financed project and is considered adequate. Given recently increased multi-donor portfolio of BT PRG, it will finalize the upgrade of the accounting system to meet the requirements for multi-donor reporting, which needs to be completed before the project implementation (within 30 days after project effectiveness).

17. BT PRG has overall adequate internal control system in place for implementation of the project, including adequate segregation of duties among the FM/accounting staff. It was agreed that within 30 days after project effectiveness, BT PRG will develop FM Manual that is part of POM, and will reflect the FM arrangements and controls under the project.

18. BT PRG has access to the Bank Client Connection and downloads disbursement data from the system for reconciliation purposes. The reconciliation of the project accounts with the Bank Client Connection system is done after each withdrawal application is sent/funds received. The backup of the accounting data is done on every week on an external hard disk.

19. Project management-oriented Interim Un-audited Financial Reports (IFRs) will be used for the project monitoring and supervision. BT PRG has significant experience in IFR preparation, and the IFRs of projects implemented by PRG were always received on time and found to be in general acceptable to the Bank. The format of the IFRs has been confirmed during assessment and includes: (i) Project Sources and Uses of Funds, (ii) Uses of Funds by Project Activity, (iii) A Statement of the Financial Position, and (iv) SOE Withdrawal Schedule. These financial reports will be submitted to the World Bank within 45 days of the end of each quarter, with the first reports under the proposed Project being submitted after the end of the first quarter of initial disbursement.

20. BT’s current auditing arrangements are satisfactory to the Bank (there are no pending audits for the projects implemented by BT PRG, and no major issues have arisen in the latest audit of the project implemented by BT PRG), and it has, thus, been agreed that similar audit arrangements will be adopted for the project to cover the project financial statements. The audit of the entity (BT) and the project will be conducted: (i) by independent private auditors acceptable to the Bank, on terms of reference (TOR) acceptable to the Bank and procured by the BT, and (ii) according to the International Standards on Auditing (ISA) issued by the International Auditing and Assurance Standards Board of the International Federation of Accountants (IFAC).

21. The annual audits of the entity and the project financial statements will be provided to the Bank within six months since the end of each fiscal year; and for the project also at the project closing. If the period from the date of effectiveness of the loan to the end of the Recipient’s fiscal

year is no more than six months, the first audit report may cover financial statements for the period from effectiveness to the end of the second fiscal year. The Recipient has agreed to disclose the audit reports for the project and the entity within one month of their receipt from the auditors and acceptance by the Bank, by posting the reports on its official web site. Following the Bank's formal receipt of these reports from the Recipient, the Bank will make them publicly available according to World Bank Policy on Access to Information. The cost of the audit will be financed from the proceeds of the project.

Disbursement

22. The FM/accounting staff of BT PRG is well aware of the Bank disbursement policies and procedures. Project funds will flow from the Bank on the basis of direct payment withdrawal applications and/or special commitments, received from the BT PRG. The following disbursement methods may be used under the Project: Reimbursement, Direct payment and Special Commitment. The DA's ceiling is proposed to be established at US$4,000,000, which will be finalized and reflected in the Disbursement Letter. Detailed instructions on withdrawal of loan proceeds are provided in the Disbursement Letter.

23. The following table specifies the categories of Eligible Expenditures that may be financed out of the proceeds of Credits and the Grant ("Category"), the allocation of the amounts of Credits and Grant to each Category, and the percentage of expenditures to be financed for Eligible Expenditures in each Category.

Category	**Amount of Portion A of the Credit Allocated (expressed in USD)**	**Amount of Portion B of the Credit Allocated (expressed in USD)**	**Amount of the Grant Allocated (expressed in SDR)**	**Percentage of Expenditures to be Financed (exclusive of VAT and customs taxes, including imposts, levies, fees and duties of any nature, whether in effect at the date of the Financing Agreement or imposed after that date)**
(1) Goods, works, non-consulting services, consulting services, Training and Incremental Operating Costs for the Project	64,135,000	99,750,000	41,800,000	100%
(2) Refund of Preparation Advance	5,000,000			Amount payable pursuant to Section 2.07 (a) of the General Conditions

(3) Front-end Fee		250,000		Amount payable pursuant to Section 2.03 of this Agreement in accordance with Section 3.01 (a) of the General Conditions
TOTAL AMOUNT	**69,135,000**	**100,000,000**	**41,800,000**	

24. Project funds would be transferred electronically to a Transit Account opened at the same commercial bank/financial institution for immediate payments in local currency, based on expenditures already incurred or immediately to be incurred. All payment orders would be approved by the BT Chairman, or its designate, and the Chief Accountant after being verified by the FM consultant.

25. Payments in foreign currency would be made directly from the Credit Account as Direct Payment depending on the threshold for such payments, as would be determined in the Disbursement Letter. Withdrawal applications for Direct Payments would be submitted directly to the MoF where they would be reviewed and forwarded to the person authorized to sign withdrawal applications on behalf of the Recipient. Disbursement Letter will be amended to introduce the advance method for disbursement upon resolution of the outstanding country portfolio issue.

Procurement

26. BT's PRG was involved in implementation of the Energy Loss Reduction Project and its Additional Financing (World Bank), Energy Emergency Recovery Project and its Additional Financing (World Bank) the Tajikistan Advisory Support for the Regional Trade Initiatives Project (TF016252), and the two ongoing energy projects funded by EBRD.

27. The overall procurement risk under the project is currently assessed as High. The PPSD has been prepared by BT with support of the Bank's team. The PPSD has identified the key issues and risks concerning procurement including: (i) limited technical/procurement expertise within the BT to develop and implement international competitive bidding requirements for complex and high value contracts; the BT might not be able to provide quality preparation, review and comments on commercial part of the procurement packages; (ii) Procurement in the country has not attracted adequate competition due to unfavorable business environment and slow private sector growth; (iii) the Tender Committee members, which will be involved in project procurement through tender committees, may not be familiar with international procurement procedures; (iv) Limited contract monitoring and management skills and tools to ensure efficient and timely contract implementation; and (v) Overall high public procurement risk environment.

28. Given the above risks and based on the lessons learned from the similar experience the below measures are proposed to strengthen BT's capacity and ensure effective project implementation:

- Engagement of PMC, which will assist the PRG in the procurement activities;
- Engagement of a Panel of Experts, which will advise BT on the preparation and implementation of the technical and dam safety aspects of the project;
- Active participation by the Bank Team in assisting the PRG in the planning and implementation of procurement activities;
- Training to the PRG and the Nurek HPP team in appropriate areas related to procurement, contract management and coordination, and contract management of large and complex projects. In particular, the Bank will finance technical assistance to support and provide the Recipient with the modern tools for procurement development, design and contract management;
- Strengthening the control and coordination arrangement between the PRG and the technical team at Nurek HPP in order ensure well-coordinated implementation.

29. Procurement of contracts financed by the World Bank and AIIB will be conducted through the procedures as specified in the World Bank's Procurement Regulations for IPF Recipients - Procurement in Investment Project Financing Goods, Works, Non-consulting and Consulting Services (July 2016) (Procurement Regulations). The procurement approaches for key packages has been determined in the PPSD as follows.

30. **Procurement approach for key consultancy contracts**. BT contracted an engineering firm to carry out the techno-economic studies for the project, and a specialized firm for the sedimentation studies. BT has subsequently contracted a consulting firm under a Single-Source Selection (SSS) to undertake additional follow-up studies and investigations on the Nurek HPP. BT completed selection of PMC to provide support during implementation of the project based on QCBS method as advance procurement.

31. PoE was hired by BT on the basis of Sole-source selection method, also through advance procurement.

32. **Procurement approach for key PDSI and works contracts**. To achieve the project's objectives, the key considerations for determining of the procurement approach are:

- A competent and experienced consulting firm has been contracted as advance procurement and started preparation of the procurement documents.
- The number of contracts should be kept to a reasonable minimum so as to minimize the coordination requirements and reduce the likelihood for disputes, claims and eventually time and cost overruns.
- Due to the limited space available in the powerhouse for dismantling and assembly of the major equipment, a single contractor should be responsible for installation, testing and commissioning of the power plant equipment (turbines, generators, main inlet valves, transformers, auxiliary systems and Balance of Plant - BoP).

- Having a single contractor responsible for installation, testing and commissioning of the power plant equipment would also limit contractor interface issues, and thereby reduce potential claims and delays.
- In order to reduce the implementation period, avoid additional design and manufacturing costs, and minimize subsequent O&M difficulties, it would be preferable to have the same contractor for both phases of the power plant rehabilitation.

33. Based on the project's technical requirements, the procurement approach to be adopted for the key PDSI and works contracts was discussed with the Government, BT, the Bank team, TEAS consultant and PMC. Following these discussions, the approach adopted is described hereunder.

34. Power plant rehabilitation. Taking into consideration the nature of the rehabilitation works required for the power plant equipment, the following approach was agreed:

- The rehabilitation would be carried out under PDSI contract following International Request for Bids (without prequalification);
- Detailed implementation schedules were prepared for two options: adopting prequalification versus adopting post-qualification. The first option resulted in a significantly longer project implementation schedule that was not compatible with the agreed project processing schedule. Given that post-qualification for the contracts for the power plant rehabilitation is a viable alternative, the procurement approach developed for the project is based on post-qualification for the rehabilitation of the power plant equipment.
- Regarding the scope to be covered by the procurement documents for the Phase I rehabilitation, two options were considered. The first option was to have the procurement documents cover only the rehabilitation foreseen under Phase I (i.e. the rehabilitation of three generating units, key auxiliary systems and associated BoP), with a separate bidding process to be adopted using a new bidding package at a subsequent date for the Phase II rehabilitation (i.e. the rehabilitation of six generating units and the remaining BoP). The second option was to have the initial procurement documents cover the entire power plant rehabilitation (all nine generating units, auxiliary systems and entire balance of plant), with the initial PDSI contract being awarded for the Phase I scope and the contract extended to include the Phase II scope as soon as the required additional financing was arranged. The contract extension to cover the Phase II works could be done with an appropriate overlap with the first phase.
- A review of these two approaches led to the conclusion that the first approach of having separate bidding processes for the two phases would result in several significant disadvantages, including:

    - Different manufacturers for the Phase I and Phase II equipment leading to subsequent operation and maintenance difficulties.
    - Significant additional costs and additional time associated with the Phase II Contractor also having to carry out design work, model testing and establishment of manufacturing arrangements; these would be avoided if both the Phase I and Phase II contracts were with the same Contractor. It is estimated that adopting a separate

procurement process for the Phase II rehabilitation could add between 2 to 3 years to the implementation of the total rehabilitation project. Furthermore, additional costs could be in the range of US$10 to 20 million.

- Based on the above considerations, the second approach is being adopted for the rehabilitation of the power plant equipment. The procurement documents will cover the entire power plant rehabilitation (all nine generating units, auxiliary systems and entire balance of plant), with the initial PDSI contract being awarded for the Phase I scope and the contract extended to include the Phase II scope as soon as the required additional financing was arranged. If the necessary financing cannot be mobilized within the stipulated period (say within 2 years after award of Phase I contract), the contract will not be extended to cover Phase 2, with no financial or sustainability implications for the project.

35. Supply and installation of autotransformers. EBD will require BT to use International Request for Bids (Single stage without prequalification) method and will be conducted following procurement regulations of the World Bank.

36. Dam safety works and instrumentation. Taking into consideration the nature of the rehabilitation works required for this component, the following approach is being adopted:

- A Works contract would be used for the civil works and gates rehabilitation included in the dam safety component.
- The upgrading of the dam instrumentation could be a separate contract following International Request for Bids (after prequalification).

37. **Procurement risks analysis**. The Bank supported the Recipient in developing the PPSD. Thus, the Recipient benefited from Bank's experience in involvement in energy sector projects in Tajikistan and the good understanding of the capacity and constraints that exist. The PPSD and procurement plan were finalized and agreed by the Bank.

38. Considering the nature of the rehabilitation works, the main risks associated with implementation of the project and the proposed mitigation measures are described in the risk management plan below.

Procurement Risk Management Plan

Identified Risk	Risk Description	Likelihood Rating	Impact Rating	Overall Risk	Description of proposed mitigation through the procurement process	Risk owner	Procurement Process stage
		A	B	A*B			
Financing shortfalls	As the financing requirements are significant, there is a risk that sufficient financing may not be readily available for the rehabilitation works.	4	3	12	This aspect is being partly mitigated by the decision to undertake the implementation in phases, thereby reducing the financing required to initiate the rehabilitation works. Furthermore, the scope of the Phase I rehabilitation to be undertaken under the project can be adjusted to match the available financing. For example, the autotransformer component (estimated cost US$40 million) could be shifted to Phase II of the rehabilitation without impacting the effectiveness of the remaining rehabilitation being carried out under Phase I. Another possibility would be to shift the rehabilitation of some non-critical Balance of Plant items to Phase II. Project preparation will be linked to satisfactory commitments on the availability of the balance financing from other donors. Similarly, Phase II will be undertaken only when sufficient financing commitments become available.	Recipient	Planning /packaging

Identified Risk	Risk Description	Likelihood Rating	Impact Rating	Overall Risk	Description of proposed mitigation through the procurement process	Risk owner	Procurement Process stage
Insufficient interest by bidders	The procurement opportunities under the proposed project may not attract sufficient number of bidders considering that bids will be invited for nine generating units and the initial contract will be signed for three units only with a trigger condition to execute the other six units once the funding is secured for phase II.	3	4	12	Market analysis revealed the availability of a relatively large number of potential bidders. Furthermore, BT organized a conference for potential bidders on January 19-20, 2017 (Istanbul, Turkey) to provide information on the proposed scope of the project; and to seek comments and suggestions from the bidders on the planned procurement approach for the main package. The feedback obtained from this conference should be used to fine-tune the procurement approach and to be reflected in the relevant provisions of the bidding documents (qualification requirements, implementation schedule, etc.)	Recipient	Planning /preparation of bidding documents/ launching of bidding process.
Evaluated prices of bids exceeding the estimate	Recent trends are for bids to come in at levels lower than the feasibility estimates, partly due to the fall in material prices. Nevertheless, there is a risk that the evaluated prices of bids are higher than the existing estimates.	3	3	9	5 percent physical and 5 percent price contingencies were incorporated within the components of the project covering power plant rehabilitation and dam safety measures. A further mitigation measure that can be considered for the key PDSI contract for the rehabilitation of the power plant equipment is to create a separate lot for the rehabilitation activities that could be postponed. The bidders will submit bids for this lot but, if the lowest evaluated bid exceeds the available financing, this lot could be excluded from the Phase I contract award. In such an eventuality, these rehabilitation activities would be	Recipient	Planning/ packaging/bid evaluation

Identified Risk	Risk Description	Likelihood Rating	Impact Rating	Overall Risk	Description of proposed mitigation through the procurement process	Risk owner	Procurement Process stage
					included in the Phase II award.		
Cost overrun	Given the nature of the rehabilitation work and the relatively long duration over which the works are to be carried out, there is a risk that cost overruns will materialize. There could also be significant increases resulting from price escalation.	3	3	9	5 percent physical contingency and 5 percent price contingency is included in the cost estimate for the component on power plant rehabilitation and dame safety. This level of contingency will be sufficient given that this is a rehabilitation project and not a green-field investment. If contingency provisions are insufficient to cover these additional costs, additional financing will need to be raised.	Recipient	Contract management stage
Procurement and implementation delays	The risks of procurement and implementation delays are present in the proposed project but can be manageable through various proper mitigation measures.	4	4	16	The major measures envisaged to reduce these risks are the following: -The feasibility study was carried out by internationally recognized consulting firm. The study carried out a detailed assessment of the rehabilitation and safety-enhancement needs, and considered various technical options for defining the rehabilitation scope. Procurement packaging is based on this detailed study. -Active and close supervision and involvement of the Recipient as well as the Bank team in project planning and implementation activities. -Appointment of a competent and experienced consulting firm to review	Recipient	Preparation of bidding document, bid evaluation and contract management

Identified Risk	Risk Description	Likelihood Rating	Impact Rating	Overall Risk	Description of proposed mitigation through the procurement process	Risk owner	Procurement Process stage
					previous studies, prepare the bidding documents, assist BT in the various procurement processes, and supervise the performance of the contractors during the implementation phase. -Undertaking procurement activities in parallel with project preparation activities in order to allow early start on the critical rehabilitation works. -Involvement of an independent PoE in the review of the design and implementation activities.		
Currency exchange rate fluctuations	Local currency expenditures are expected to be very low, and, thus, further devaluations of TJS will not directly impact the project.	2	2	4	If the currencies of major expenditures under the bid are significantly different from the currencies in which the financing is provided, the impact of currency fluctuations will need to be managed by the Government, as is the norm.	Recipient	Bid evaluation and contract management.
Payment delays resulting in implementation delays	Given the overall macroeconomic trends and distress of the financial sector, there may be delays with executing payments to contractors.	2	2	4	To mitigate this risk, Letter of Credits (LC) with World Bank's Specialist Commitment mechanism will be used by the Recipient to pay for imported goods. The Special Commitment will allow paying the contractors for supplied goods through wire transfers from the World Bank's Treasury in HQ, thus, minimizing the payment risks.	Recipient/ Bank	Bid document preparation stage
Disruption in upstream supply chain	Transportation of goods and services from their source to final destination is	3	3	9	Undertake market engagement with potential bidders/suppliers to understand how supply chain operates in the market	Recipient	Contract management stage

Identified Risk	Risk Description	Likelihood Rating	Impact Rating	Overall Risk	Description of proposed mitigation through the procurement process	Risk owner	Procurement Process stage
	difficult because Tajikistan is a land-locked country with limited regional connectivity and under-developed domestic transport network.				or in the region.		
Non-compatibility of power plant equipment procured under Phase I and II of the project, and O&M difficulties	Different manufacturers for the Phase I and Phase II equipment leading to subsequent O&M difficulties.	3	3	9	Bids will be invited for all nine generating units to avoid compatibility issues.	Recipient	Planning/Bidding documents preparation

39. **Market analysis**. The major contract will be PDSI contract for the rehabilitation of the power plant equipment. Experience with currently implemented Kairakum Hydropower Rehabilitation Project (KHPP) with total cost of US$198.5 million and 3600MW Rogun Hydropower project (US$ 3.9 billion) proves interest from potential bidders to similar projects. Similarly, it is expected that most of the major manufacturers of large hydropower generating units (nine companies were identified by the Recipient in consultation with the Bank team) will be interested in bidding for the contract.

40. Market analysis for autotransformers confirmed that this is a very competitive market with large number of manufacturers and suppliers. BT implemented a large number of power transmission and distribution network expansion/rehabilitation projects financed by various international financial institutions (IFIs) and bilaterals. Those procurements generated good competition with several bidders participating.

41. The package(s) for dam safety works are expected to be of relatively smaller values. Prequalification will be adopted for the package covering the civil works and the rehabilitation of the spillway. It is expected that a large number of internationally experienced companies specializing in such works would be interested.

42. The awareness of potential bidders about the project was raised through the following two measures:

- BT issued GPN for the project in October 2016 and received expression of interest from several firms.
- As per PPSD recommendation, BT held a conference for potential bidders in Istanbul on January19-20, 2017 to: (i) provide information on the proposed scope of the project; and (ii) seek comments and suggestions from the bidders on the planned procurement approach for the main package. The feedback obtained from this conference will be used to fine-tune the procurement approach and will be reflected in the relevant provisions of the bidding documents (qualification requirements, implementation schedule, etc.).

43. **Procurement plan**. The recommended procurement plan for the project is given in the Table below. The PPSD and procurement plan was finalized and agreed by the Bank during the project negotiations.

Summary Procurement Plan

Sl. No.	Component	Estimated Cost (US$ million)	Financing Source	Procurement Method
1	Package 1. PSDI contract covering supply, erection and commissioning of nine units along with auxiliary systems and key components of the balance of plant (Phase I and II), out of which: *Phase I - for three units along with auxiliary systems and key components of the balance of plant;* *Phase II – for remaining six units*	620.0 270.0 350.0	IDA, AIIB IDA, AIIB TBD	Request for Bids (RFB) RFB

Sl. No.	Component	Estimated Cost (US$ million)	Financing Source	Procurement Method
2	Package 2. Supply, erection and commissioning of six autotransformers.	40.0	EDB	RFB
3	Package 3. Dam safety works: Rehabilitation of spillway tunnels, rehabilitation of spillway gates, dam monitoring instrumentation	30.0	IDA, AIIB	RFB
4	PMC	5.2	IDA	QCBS
5	Dam Safety PoE	1.0	IDA	Direct Contracting (DC)
6	Other technical assistance	3.8	IDA	TBD

Environmental and Social (including safeguards)

44. Environmental: The project will provide significant environmental benefits in the long run by preserving low-carbon renewable energy based generation plant. The proposed rehabilitation works will also increase the power generation capacity of Nurek due to use of modern turbines with improved hydraulic design. The project is not expected to have any significant adverse or irreversible environmental impacts, majority of which are only site-specific, generally limited to construction stage and can be mitigated through a well-designed environmental and social management plan (ESMP). The project has therefore been classified as Environmental Category "B".

45. The Recipient prepared an Environmental and Social Impact Assessment (ESIA) report. In order to avoid impacts on downstream releases and water uses, the project will replace one turbine at a time. The other alternative was to replaced two turbines at a time; this alternative was discarded due to technical reasons. This approach to rehabilitation enables to avoid unnecessary environmental and social issues downstream. Majority of the environmental impacts are associated with pollution due to hazardous and non-hazardous waste, and risks associated with occupational health and safety. Safe removal and disposal of asbestos and prevention of workers from electrocution and drowning in deep waters will have to be addressed by the contractor(s) through development of appropriate health and safety plans, emergency preparedness plan, good waste (both construction and municipal) management plan. The ESMP will be part of project bidding documents and will require BT and its contractors to allocate adequate human resource to comply with requirements of the ESMP during project implementation. The bidding documents for power plant rehabilitation will also contain a requirement for the PDSI contractor to organize the works in a way to ensure health and safety of both the contractors' and the power plant's personnel during the rehabilitation works given the parallel activities (rehabilitation and operation) to be carried out within the limited space in the power house.

46. The ESIA also assessed the cumulative impacts of the project as part of the overall Vakhsh basin hydropower development cascade. The incremental impacts resulting from the proposed Nurek hydropower rehabilitation project are minimal as the project does not alter the river hydrology (upstream or downstream), does not add to any further storage, does not impact water quality (upstream or downstream in anyway) and does not impact water downstream releases either during construction or operation. The project also does not pose any incremental

impacts on aquatic life in general or fisheries in particular. Fisheries, downstream water uses and safety of communities downstream are some of the valued environmental and social components (VECs). An assessment of environmental flows presented in the ESIA report also suggests no changes in the downstream releases during construction or operation of the project. The project does not present additional impacts in any way Tigrovaya Balka State National Reserve, which represents unique Tugai system (flood plain habitat dependent on river flooding, groundwater levels in desert like environment).

47. Following consultations with communities, civil society organizations and stakeholders, the final ESIA was revised to adjust feedback/concerns received during the process. The final ESIA report was disclosed in-country and at the World Bank's InfoShop. The executive summary of ESIA report was also translated into Tajik and Russian and made available at locations that are accessible to stakeholders and was also posted on the web-site of BT.

48. Social: The overall social impact of the project is expected to be positive because it will help avoid increase of the winter electricity shortages. Specifically, if Nurek HPP is not rehabilitated, then electricity supply of this plant, which accounts for 70 percent of the electricity supply in the country, will start reducing due to severe dilapidation of mechanical, electrical and electro-mechanical equipment. Thus, the project will create benefits for all electricity consumers, including vulnerable and impoverished households and will have positive impacts on all consumers across both genders. It should be noted that adequate and reliable electricity supply is especially beneficial for people who spend most of their time at home such as the elderly, children and women. The project impacts on local jobs and livelihoods are expected to be minimal given that rehabilitation works primarily require qualified and skilled labor force, which may not be available locally. No significant labor influx is expected during construction or operation of the plant. Thus, risks associated with labor influx are rated as low to minimal. Negative impacts on communities, such as increased traffic, were highlighted in the ESIA with mitigation measures identified.

49. The Government plans to gradually increase the end-user electricity tariffs to cost-recovery levels by 2022. This will have negative social impacts in particular on the poorest segments of the population, many of whom cannot afford the basic level of energy consumption. The World Bank is currently providing advisory support on options available for mitigation of impacts on the poor. Additionally, the Government's action plan of activities related to new tariff policy requires the Ministry of Labor and Employment and the Ministry of Finance to develop mitigation measures by June 2017.

50. *Citizen Engagement.* BT conducted consultations during project preparation and prepared a SEP to guide information sharing and consultations during project implementation. The preparation-stage consultations were based on a stakeholder mapping, which included key stakeholders at the national, regional, and local levels. The consultations provided and will continue to provide an opportunity for stakeholders to be exposed to the project implementation process and to provide feedback and ask questions. The SEP envisions annual consultations during implementation starting in spring 2018. Accommodation has been made for additional consultations and communications with local communities through local authorities when necessary. Consultations will be documented and the reports will detail issues raised and

responses provided and recommendations to project implementation. These reports will also provide a plan for providing feedback to participating communities. The SEP will be a living document with revisions made as necessary depending on the evolution of the project, new stakeholders, and potential new issues that may arise.

51. The SEP also includes a GRM, which is based on BT's existing GRM with adjustments to ensure that there are uptake points at the local level (through local BT offices and local authorities). The GRM includes uptake points at BT in Dushanbe, local BT offices, local authorities, and the Project Management Consultant. Complainants will be able to make complaints in writing, email, or in person. The GRM references the coordination of registration and response of complaints between local and central levels with local BT offices playing a key part. Information on the GRM will be made available through local-level disclosure of the SEP and outreach during the consultations. Reporting on GRM implementation will be made periodically to the World Bank.

52. *Social Inclusion.* The SEP was prepared keeping in mind approaches needed to ensure the engagement of groups susceptible to exclusion (such as women, the disabled and the elderly). In addition, the project will encourage recruitment of the local population and women through targeted communication and advertisement of job opportunities. This will be done by using local communication channels to disseminate recruitment information and targeting areas where women can access information to advertise for job openings. However, as noted above, it is expected that new direct or indirect jobs created by the proposed project will be modest (approximately 100 skilled jobs during project implementation). The attention to women's recruitment responds to the gender disparities in employment - women are less than half of the total employed in Tajikistan.

53. In terms of project impacts, it is expected that the proposed operation is expected to translate into positive impacts for women as they disproportionately carry the responsibility for household related work and are vulnerable to costly and unreliable electricity supply. To that effect, women's questions and complaints related to impacts of the project will be encouraged and monitored through the proposed intermediate results indicator on percent of registered project related grievances (disaggregated by gender) responded to within stipulated service standard for such responses.

54. *Involuntary Resettlement.* The project does not trigger OP4.12 on Involuntary Resettlement. All project works will take place within the existing facilities. The ESIA and technical studies indicate that under the current design, the rehabilitation works will not result in any impacts on total downstream discharge.

55. *Consultations.* The project design and its potential impacts and mitigation measures were shared with stakeholders identified through stakeholder mapping. Consultations were held in Dushanbe (national), Kurghan Tyube (regional), Nurek City Hall and Puli Sangin (local). Consultations were held June 2016 and were attended by 175 people. Approximately 50 percent of participants were women. The main issues raised at consultations include: concerns about employment opportunities, perceptions of health risks related to Nurek, transport through Nurek city, concerns about water discharge and impacts on communities, and the participation of

women in activities related to project implementation. Where relevant, the ESIA was revised to reflect issues raised in the consultations; for example, concerns about impacts on electromagnetic fields. Some concerns related to the traffic management plan, alternatives to proposed access roads, and some other issues left unresolved/unclarified during the consultations, will be responded to during feedback consultations scheduled for Spring 2017.

56. Capacity to implement consultations at BT is low and, therefore, the consultation process will be supported by an NGO that BT will hire. To ensure sustainability of community engagement processes, the NGO will work closely with BT, including relevant local BT offices, in planning and implementation of consultations.

Other Safeguards Policies Triggered

57. **Projects on International Waterways**. OP 7.50 is applicable to the project since the Nurek Dam is located on the Vaksh River in western Tajikistan. The Vaksh River is one of the main tributaries of the Amu Darya River, which is considered an “international waterway” for purposes of the Policy. The other riparian states to the Amu Darya are Afghanistan, Uzbekistan and Turkmenistan, all three being downstream riparians.

58. The policy applies, inter alia, to hydroelectric projects that involve the use or potential pollution of international waterways. Therefore, at the request of the Recipient, the Bank notified the riparian countries about the proposed project. The notification letters, dated December 8, 2016, were sent to riparians. No responses were received by the Bank from the concerned riparian states.

59. **Safety of Dams**. OP 4.37 is applicable to the project as it relies on the performance of an existing dam. As required by the policy, the project will:

- Engage a PoE to provide independent review and expert advice on dam safety issues and other aspects during both preparation and implementation. In particular, the experts will (i) inspect and evaluate the safety status of the existing dam, its appurtenances, and its performance history; (ii) review and evaluate the owner's operation and maintenance procedures; and (iii) provide written reports of findings and recommendations for any remedial work or safety-related measures over the course of the project's preparation and implementation. The Recipient completed selection of the PoE, which includes an experienced dam safety specialist, geologist, and an electro-mechanical expert. The PoE had the first meeting at the dam site on October 15-20, 2016. The PoE provided valuable comments and recommendation on ongoing additional dam safety related investigations and analyses conducted by BT’s consultant and other dam safety aspects, which will be reflected in the final design of dam safety works. BT will also hire a hydraulic expert for the PoE if the inspection result of the surface spillway tunnel proves the hydraulic design of the remedial works as critical and complicated.

  PoE will review the dam safety related aspect of the detailed design, supervision of remedial works, and upgraded dam safety plans during preparation and implementation periods. PoE is expected to meet at least twice per year, but the frequency of site visits

will be adjusted depending on the actual design and rehabilitation work progress including possible use of video conferences.

The dam safety related aspect of the electro-mechanical aspects have been reviewed during the first PoE meeting including redundancy of the spillway gates operation system, which will be reflected in the safety improvement package. As the inspection of spillway gates is undertaken, the PoE will review the inspection result and advice on any remedial measures as well as the refurbishment design of electro-mechanical works.

- Will ensure that the works under the project will be designed and supervised by competent professionals. This will be done by PMC to be financed by the project and for which the selection process is ongoing; and

- Prepare and implement the following detailed plans: (i) for construction supervision and quality assurance; (ii) instrumentation plan; (iii) O&M plan; and (iv) EPP.

Monitoring & Evaluation

60. BT will be responsible for monitoring and evaluating the PDO Level and Intermediate Results Indicators during implementation, and submitting semi-annual implementation progress reports to the Bank. BT will collect the required data to monitor the progress towards achievement of the PDO Level and Intermediate Results Indicators from progress reports submitted by PMC, Reports of the UN Population Division, and Nurek HPP. The baseline values for the results indicators were provided by BT. The target values were discussed and agreed with BT. In particular, the data and information on results indicators will came from the following sources.

- PMC will be providing monthly reports to BT on progress with power plant rehabilitation works and dam safety improvement related activities. Those reports will allow BT to track progress with PDO Level Results Indicators 1 and 2 as well as Intermediate Results Indicators related to Components 1 and 2 of the project.
- BT will obtain the data on PDO Level Result Indicator 3 (Direct Project Beneficiaries) from UN Global Population Prospect Reports, which are publicly available.
- The GRM system at BT will allow generating the data on percentage of registered grievances received and responded to within stipulated service standards. BT and its regional branches will register all the grievances received from various individuals and other stakeholders. The reports to be submitted to the Bank will include gender-disaggregated data on grievances to allow tracking percent of grievances from females.

Role of Partners

61. AIIB will co-finance the project and EDB will provide parallel financing. Specifically, AIIB will provide the co-financing through separate designated account and the resources will be made available to BT, which can use the funds to co-finance all of the project activities except for sub-component 1.2. The main contracts for rehabilitation of power plant equipment, dam safety measures, and the technical assistance will be co-financed by AIIB. EDB will provide

parallel financing for replacement of the six autotransformers. EDB funding will be earmarked and available only for the autotransformers. The execution of financing from AIIB will be a condition for disbursement of IDA funds for Sub-component 1.1, Component 2 and Component 3 of the project.

62. Approval of AIIB and EDB financing by their respective Boards is expected to take place on various dates between May 2016 and September 2016. Therefore, it is justified to have effectiveness of loan agreement signed with AIIB as disbursement condition for IDA financing for the following reason. The PDSI contract for rehabilitation of three units is expected to be signed in November 2017 and all of the financing for this contract should be available by then.

63. The financiers of the project will coordinate during implementation. A Jointly Agreed Procedures document that describes donor coordination mechanisms and processes with respect to procurement, financial management, safeguards, and project implementation support will be drafted and agreed among financiers. It will be updated during the implementation as needed.

Annex 4: Implementation Support Plan

1. The implementation support strategy was developed considering the risks identified in the SORT and targets provision of flexible and efficient implementation support to the client.

- Technical: The Bank team will provide just-in-time implementation support to BT on: (i) technical aspects of power plant equipment rehabilitation and dam safety measures, including review of the technical specifications for bidding documents; and (ii) resolving issues that may arise during installation of the power plant equipment, replacement of autotransformers, and implementation of dam safety measures.

- Procurement**:** The procurement related implementation support will include: (i) timely advice on various procurement related issues and guidance on the Bank's Procurement Framework to be applicable to the project financed activities; (ii) technical support in reviewing the bidding documents, Request for Proposals, amendments, evaluation reports and other procurement-related documents; (iii) monitoring of procurement progress against the procurement plan; and (iv) post review of contracts.

- Financial management: As part of its project implementation support and supervision missions, the Bank will conduct risk-based financial management implementation support and supervisions within a year from the Project effectiveness, and then at appropriate intervals. During the Project implementation, the Bank will supervise the Project's financial management arrangements in the following ways: (a) review the Project's semi-annual IFRs as well as the entities' and the Project's annual audited financial statements and auditor's management letters and remedial actions recommended in the auditor's management letters; and (b) during the Bank's on-site missions, review the following key areas (i) project accounting and internal control systems; (ii) budgeting and financial planning arrangements; (iii) disbursement arrangements and financial flows, including counterpart funds, as applicable; and (iv) any incidences of corrupt practices involving project resources. As required, a Bank-accredited Financial Management Specialist will participate in the implementation support and supervision process.

- Environmental and social safeguards: The Bank's environmental and social specialists will provide regular support to BT in ensuring compliance with ESMP under the project, timely resolution of safeguards issues, timely response and clarifications on safeguards related questions and issues, and implementation of SEP.

- Financial standing of BT: The Bank's financial specialists will provide the required advisory support to BT and clarify questions related with implementation of key measures aimed improving financial standing of BT.

Time	Focus	Skills Needed	Resource Estimate (staff weeks (SW)
First twelve months	Task management	Sr. Energy economist and Energy Specialist	5 SWs
	Technical review of the electro-mechanical aspects of bidding documents; support with review of detailed designs; and supervision of rehabilitation of target infrastructure; and construction of new infrastructure	Electro-mechanical Engineer	4 SWs
	Technical review of hydropower-specific and dam safety related aspects of bidding documents; support with review of detailed designs; and supervision of rehabilitation of target infrastructure	Hydropower Specialist	5 SWs
	Procurement review of the bidding documents	Procurement Specialist	4 SWs
	Financial management	Financial Management Specialist	2 SWs
	Progress with implementation of key measures to improve financial standing of BT	Financial Specialist	3 SWs
	Support with review of detailed designs; and supervision of rehabilitation of target infrastructure; and construction of new infrastructure	Power Engineer	4 SWs
	Environmental safeguards supervision	Sr. Environmental specialist	2 SWs
	Stakeholder engagement plan	Sr. Social specialist	2 SWs
13-72 months	Task management	Sr. Energy Economist and Energy Specialist	25 SWs
	Review of procurement documents, and procurement guidance	Procurement Specialist	10 SWs
	Financial management and disbursements	Financial Management Specialist	10 SWs
	Progress with implementation of key measures to improve financial standing of BT	Financial Specialist	12 SWs
	Guidance and implementation support on power engineering issues	Electro-mechanical Engineer	12 SWs
	Guidance on hydropower-specific technical issues	Hydropower Consultant	25 SWs
	Environmental supervision	Environmental specialist	5 SWs
	Stakeholder engagement plan	Social development specialist	4 SWs

2. The staff skill mix and focus in terms of implementation support is summarized in the tables below.

Skills Mix Required

Skills Needed	Number of Staff Weeks	Number of Trips	Comments
Task team leader	30	Field trips as required	Country office based and HQ based
Hydropower specialist	30	Field trips as required	Based in the region
Procurement specialist	14	Field trips as required	Country office based
Financial management specialist	12	Field trips as required	County office based
Electro-mechanical engineer	17	6-8	HQ based
Environmental specialist	7	7	HQ based
Social specialist	6	6	Vienna based

Partners

Name	Institution/Country	Role
Energy specialist and task team leader	AIIB	Coordination and implementation support during project implementation
Procurement specialist	AIIB	Procurement review of bidding documents
Safeguards specialist	AIIB	Supervision over compliance of the project with safeguards requirements
Energy specialist and task team leader	EDB	Coordination and implementation support during project implementation

Annex 5: Systematic Operations Risk Rating Tool (SORT)

Risk Category	**Rating**
1. Political and Governance	High
2. Macroeconomic	High
3. Sector Strategies and Policies	High
4. Technical Design of Project or Program	Substantial
5. Institutional Capacity for Implementation and Sustainability	Substantial
6. Fiduciary	High
7. Environment and Social	Moderate
8. Stakeholders	Substantial
9. Financing	Substantial
10. Climate Change Related Disaster	Low
OVERALL	Substantial

Annex 6: Action Plan for Financial Recovery of BT

No.	Activities	Responsible Agencies	Deadlines	Activity Results
1.	Adopt the Concept of New Tariff Policy and develop and approve a cost recovery tariff methodology by the end of 2017.	MEWR, MOF, Ministry of Justice (MOJ), Ministry of Economic Development and Trade (MOEDT), Antimonopoly Service, BT	2017-2018	The Concept of New Tariff Policy includes the foundations of norms for calculation of tariffs and provides the methodology for tariff calculation to cover all production costs, including generation, transmission, distribution of electricity, operational cost, repair and equipment maintenance cost, administrative costs, salaries, capital costs, debt service and tax liabilities.
2.	Gradual increase of electricity tariff by 2022 to a full cost recovery level.	MEWR, MOEDT, MOF, MOJ, Antimonopoly Service, BT	2018-2022	Increase of BT revenues from electricity sales to domestic consumers.
3.	Improve tariff collection rate for billed electricity and reach 95% collection rate by 2021	BT	On regular basis	Increase of BT revenues from electricity sales to domestic consumers.
4.	Ensure gradual collection of old receivables for billed electricity sales in the past and achieve a minimal level of receivables by 2022	BT	2018-2022	Increase of liquid assets, reduction of losses due to exchange rate differences and contribution to strengthened balance sheet of BT.
5.	Increase efficiency of inventory management at BT and purchase only necessary materials	BT	On regular basis	Improvement of cash conversion cycle, which will reduce the costs. Besides, it will have positive impact on the procurement discipline and policy of BT.
6.	Reduce receivables from current sales of energy	BT	On regular basis	Reduction of time period between billing and collection of funds will have positive impact on the cash conversion cycle and ensure increase in operating cash. At present, the time period covers from 20 to 60 days.

No.	Activities	Responsible Agencies	Deadlines	Activity Results
7.	Determine actual level of electricity losses (commercial losses in particular) according to the requirements of international financial institutions.	MEWR, BT	On regular basis	Actual losses and key sources will be determined and accounting of actual balance will be ensured.
8.	Further reduction of technical losses.	BT	On a regular basis	Given winter energy deficit, reduction of technical losses will allow to increase supply of electricity during winter period.
9.	Fully abandon subsidization of separate groups of electricity consumers.	MOF, MOJ, MOEDT, MEWR, Antimonopoly service, BT	On a regular basis	Losses will be reduced and revenues of BT will increase.
10.	Ensure mandatory payments to IPPs and annual offset of BT liabilities to OJSC “Sangtuda-1” at the expense of tax liabilities of the latter.	MOF, MEWR, Antimonopoly service, BT	On a regular basis	Increased ability to meet obligations to OJSC “Sangtuda-1”.
11.	Write-off of non-performing loans of the bankrupt companies and residents.	MEWR, BT	February, 2017	Improved accuracy of balance sheet, which will help to improve the financial situation of BT.
12.	Develop and submit recommendations on improving the debt situation of BT.	MOF, MOJ, MEWR, BT	On regular basis	Revisiting some of the financial obligations of BT to the MOF will allow to improve the financial situation of BT.

No.	Activities	Responsible Agencies	Deadlines	Activity Results
13.	Gradual repayment of the outstanding principal amount of short-term commercial debt of BT from additional funds generated as a result of implementation of above-mentioned measures.	BT	On a regular basis	Implementation of all measures specified in this Action Plan will increase cash revenues and improve the ability of BT to repay the principle amount of debt.
14.	Taking urgent and efficient measures in installation of the energy billing system at all billing points.	MEWR, BT	2018-2020	Increase of electricity sales and reduction of losses; increase in cash collections.
15.	Increasing efficiency in collecting the debts from consumers by full execution of decisions taken by the economic court and formalized claims.	BT	On regular basis	BT will receive additional revenues.
16.	Ensure full and timely payment of bills for electricity used by TALCO.	Ministry of Industry and New Technologies, MEWR, TALCO, BT	On regular basis	BT will receive additional revenues.
17.	Payment of the bills by the state budget financed organizations based on the actual use of energy.	MOF, MOEDT, BT	On regular basis	The amount of receivables of BT will reduce and cash conversion cycle will improve.

Results Matrix of Potential Impact from Implementation of the Action Plan for Financial Recovery of BT

	Financial Recovery Measures	Target and Unit	2017	2018	2019	2020	2021	2022	TOTAL
1	Increase the average tariff	Percent (%)	15	15	15	15	15	15	
		Additional revenue, million TJS	167	390	651	925	1,225	1,412	**4,771**
2	Increase the collection rate for billed electricity	Percent (%)	88	90	93	94	95	95	
		Additional revenue, million TJS	53	102	189	247	319	369	**1,279**
3	Gradual collection of old receivables for billed electricity	Additional revenue, million TJS	37	37	37	37	37	37	**222**
4	Reduce receivables due to current sale of energy	Additional revenue, million TJS	80	158	213	276	333	175	**1,235**
5	Increase efficiency of inventory management at BT	Additional revenue, million TJS	50	50	50	50	50	50	**300**
6	Reduce technical losses by 0.5 percent per annum	Additional revenue, million TJS	4	11	21	28	42	59	**165**
	RESULTS								
7	Forecast revenues without implementation of recovery measures	Million TJS	2,162	2,404	2,670	2,992	3,348	4,881	**18,457**
8	Forecast operating costs of BT taking into consideration fulfilment of financial obligations (except for the credit agreements and full payment of interests to commercial banks)	Million TJS	2,241	2,338	2,672	3,112	3,560	4,390	**18,313**

	Financial Recovery Measures	Target and Unit	2017	2018	2019	2020	2021	2022	TOTAL
9	Free cash flow without implementation of recovery measures (difference between items 7 and 8)	Million TJS	-79	66	-2	-120	-212	491	**144**
10	Free cash flow for fulfillment of financial obligations (total of items 1-6 and 9)	Million TJS	312	814	1,159	1,443	1,794	2,593	**8,115**
11	Ensure payment of long-term debts (interests + principal amount), including payment of interests to the local commercial banks (calculated based on the requirements of agreements)	Million TJS	756	784	876	935	929	975	**5,255**
12	Remaining funds for fulfillment of other financial obligations (difference between items 10 and 11)	Million TJS	-444	30	283	508	865	1,618	**2,880**
13	Debt to Sangtuda-1	Million TJS	-	-	-	-	-	-	**654**
14	Debt to Sangtuda-2	Million TJS	-	-	-	-	-	-	**458**
15	Interest paid under long-term loans	Million TJS	-	-	-	-	-	-	**1,156**
16	Principal amount not paid under long-term loans	Million TJS	-	-	-	-	-	-	**1,508**
17	Debt to Orienbank	Million TJS	-	-	-	-	-	-	**1,347**
18	Deficit	Million TJS	-	-	-	-	-	-	**-2,263**
19	Additional liquidity injection into BT, including grants and concessional loans from international financial	Million TJS	-	-	-	-	-	-	**2,263**

	Financial Recovery Measures	Target and Unit	2017	2018	2019	2020	2021	2022	TOTAL
	institutions								
20	**Deficit**	**Million TJS**	**-**	**-**	**-**	**-**	**-**	**-**	**0**

Annex 7: Economic and Financial Analyses

1. This Annex contains economic analysis of the entire project (i.e. rehabilitation of all facets of the project, including all nine generating units), economic analysis of the Phase I, financial analysis of the entire project, financial analysis of the Phase I, and analyses and forecast of financial standing of BT.

Economic Analysis of the Entire Project

2. The economic analysis discusses the rationale for public financing of the project, the valued added from the Bank support and description of the analysis of the project's development impact in terms of expected benefits and costs. The cost-benefit analyses were conducted for both Phase I of the project and the entire project.

3. Rationale for public sector provision/financing: The project warrants public intervention given its economic viability and the fact that private sector financing and provision is not plausible due to:

a. *Limited domestic capital markets:* Domestic private capital market in Tajikistan lacks the breadth and depth to mobilize the financing required for such a large infrastructure project.

b. *Prohibitively high private capital cost due to scarce capital and risks:* Costs for private capital are significantly higher than for public debt given the macro and project-specific risks involved. Thus, in case of private financing, the end-users of electricity would benefit less.

c. *Limited ability of BT to borrow on commercial terms*: BT would not be able to borrow on commercial terms even if sufficient financing was available from local capital markets. This is due to challenging financial condition of BT.

4. Thus, given the risks involved and significant social benefits of the project, the public financing is justified.

5. Value added of the Bank's support. BT has limited capacity to prepare and implement the project given the complexity of overall project management, technical, and fiduciary aspects. Thus, the Bank's additional value added will arise from the technical inputs of the staff in helping the Recipient to identify and address in a timely manner all project implementation issues related to technical aspects, procurement and financial management.

6. The economic viability of the project was assessed through cost-benefit analysis and was determined through assessment of the expected economic returns, which were evaluated in terms of the NPV and EIRR from total economic costs and benefits attributable to this component.

- The economic costs and benefits are expressed in US$2015 real price terms that are based on average exchange rates for 2015. The economic analysis is based on estimated real

prices/costs and is exclusive of any taxes and duties that might be applicable to the project inputs and outputs. The costs do not include Interest During Construction (IDC) or any contingencies for expected price inflation. The evaluation does not incorporate any relative movements in exchange rates over the project evaluation period. The other important inputs and assumptions are discussed below.

- *Under "without project" scenario the available capacity of the plant will reduce to 0MW by 2028*. Regular maintenance will help to continue running the plant for some time. However, given that useful economic life of electro-mechanical equipment is 30 to 35 years and most of the equipment at Nurek HPP is beyond that age, the likelihood of major equipment failures that will result in loss of generating units is significant. Under the base-case, it was assumed that starting from 2019 the power plant will lose one generating unit per year. This assumption is based on the assessment of the technical condition of the generating units.

Reduction of Available Capacity under "No Project" Scenario

Nurek Capacity Without Project	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Unit 2	270	270	270	-	-	-	-	-	-	-	-	-
Unit 5	280	280	280	280	-	-	-	-	-	-	-	-
Unit 7	300	300	300	300	300	-	-	-	-	-	-	-
Unit 1	270	270	270	270	270	270	-	-	-	-	-	-
Unit 3	300	300	300	300	300	300	300	-	-	-	-	-
Unit 4	300	300	300	300	300	300	300	300	-	-	-	-
Unit 6	300	300	300	300	300	300	300	300	300	-	-	-
Unit 8	0	0	340	340	340	340	340	340	340	340	340	-
Unit 9	300	300	300	300	300	300	300	300	300	300	-	-
Total	**2320**	**2320**	**2660**	**2390**	**2110**	**1810**	**1540**	**1240**	**940**	**640**	**340**	**-**

Source: Bank team assumptions.

- *Replacement of one unit requires 11 months and only one unit is replaced at a time*. The generation of the plant during the project implementation was forecast taking this into account. This means that there are eight units generally available, except for routine maintenance and outages. This means that during erection works electricity generation from the plant will reduce only by the amount equivalent to the generation of one unit, which will be taken out of service for 11 months. No other impacts are anticipated on total energy generation of the plant during rehabilitation works.

- *The available generation capacity of the plant will increase from the current level of 2320MW to 3214MW*. This will be achieved due to the higher operating capacity of the new turbines and generators to be installed. For the base-case, an 8 percent capacity increase was assumed for the new units. The total available generating capacity for the plant under "with project" scenario was estimated assuming that after rehabilitation Units 3 and 8 would have a nominal capacity of 340MW each and the remaining units will have

a capacity of 362MW each. Unit 8 is expected to be brought back into operation in 2019 under both “with” and “without project” scenarios because the major components have either already been rehabilitated or are being replaced with financing by BT.

- *400MW Dushanbe-2 CHP and 3600MW Rogun HPP were included in the estimate of winter electricity supply*. Dushanbe-2 CHP was commissioned in December 2016. It will be supplying 300MW of electricity and 270Gcal of heat. Dushanbe-2 CHP is assumed to operate primarily in October-March with total estimated average generation of 1,180 GWh. Construction of Rogun HPP is underway and the first two generating units are expected to come online by the end of 2018. Rogun HPP will start supplying electricity in winter and summer, however, the amount of supply will increase as construction of the dam progresses and the reservoir level increases. The winter and summer electricity supply estimates are based on the Techno-Economic Assessment Studies for Rogun HPP (August 2014). The electricity generation from Rogun HPP, which is used in this analysis, is based on the assumption of 1,290 m a.s.l dam and 3600MW of installed capacity.

- *Average winter and summer generation levels were derived based on the simulation of the Nurek reservoir operation*. Based on the 2013 Nurek data, the following computation was carried out. The reservoir was emptied to the Minimum Operating Level in winter and filled up to the Fully Supply Level in summer. The simulation was carried out on the available historical daily inflows in Nurek over the period of 1972-2013. The powerhouse limitations in terms of head, turbine discharge, and generation capacity were taken into account. The simulated averages were very close to actual generation numbers for the period of 2007-2013 for which data is available. Specifically, there was 2.6 percent difference between historical and simulated long term average values, primarily due to the fact that actual generation figures are lower due to summer spillages caused by supply exceeding domestic demand.

- *The average winter and summer generation levels were estimated taking into account the current state of sedimentation and commissioning of Rogun HPP*. The base-case is based on the assumption that average winter generation during the time period of October-March will be 4,680 GWh and the average summer generation will reach 7,800 GWh. The current summer generation is on average 6,600 GWh and corresponds to summer electricity demand and the water is spilled. Those numbers will change after Rogun HPP starts generating at full estimated capacity because the current level of sedimentation of Nurek reservoir will be maintained for another 80 years (i.e. up to the end of the simulation period for the sedimentation studies).

- *Real PPA tariffs*. The weighted average PPA tariff was used to evaluate the economic benefits of the project during summer months in form of avoided reduction in export revenues. The weighted average PPA tariff was estimated taking into account the current PPA tariff with Afghanistan using existing interconnections, agreed-upon PPA tariffs under CASA-1000 with Pakistan and Afghanistan, and the relevant shares of exports in the total exports. The escalation of PPA tariffs is not relevant for economic analysis of the project.

- *Stochastic Dual Dynamic Programming tool was used to simulate the average maximum summer electricity supply capability of existing HPPs*. This assessment was needed to derive the surplus electricity supply capability in order to determine whether gradual reduction of supply from Nurek HPP under "No Rogun" scenario can be replaced by surplus from other generating plants, including 600MW Baipaza HPP, 670MW Sangtuda-1 HPP, 220MW Sangtuda-2 HPP, 240MW Golovnaya HPP, 30MW Perepadnaya HPP, and 15MW Centralnaya HPP. The simulations were done considering the historical sequence of inflows to Nurek (Tajikistan) reservoirs. The simulations were run for the period of 2016-2035. The surplus power for 2036-2071 was estimated by extrapolating the pattern of variation in hydro generation derived by SDDP simulations. The simulated supply under base-case does not assume construction of any other new power plants during the project evaluation period.

7. The base-case for economic analysis is formed from expected values for the main evaluation variables, namely: (a) the base-case forecasts of winter and summer electricity demand and supply in Tajikistan; (b) entire project rehabilitation cost and in-service date; (b) amount of electricity supplied under the project based on simulated results of generation by Nurek HPP during winter and summer seasons,[18] and (c) the forecast costs of fuels under the project counterfactual, i.e. construction of a gas-fired thermal power plant to replace generation from Nurek HPP assuming it is not rehabilitated, which leads to reduction of supply.

8. Under the base-case, the stream of economic costs and benefits was discounted at the social opportunity cost of the capital, which was assumed to equal 10 percent. The choice of the discount rate is driven by the conservative assumption that the average real GDP will grow at an average annual rate of 5 percent during the useful economic life of the project. The economic life of the replaced units is assumed to be 35 years from the date of commissioning of each of the refurbished units.

9. Economic costs of the project: The economic costs include: (a) Engineering, Procurement, and Construction (EPC) costs for refurbishment of electrical, mechanical and electromechanical equipment and the works required for rehabilitation; (b) the cost of six autotransformers; (c) PMC, which will be acting as the owner's engineer; and (d) the incremental O&M costs. The costs are projected according to the years in which they are expected to be incurred during the project construction period.[19] The cost of the dam safety component is excluded from the economic analyses because those costs will need to be incurred irrespective of the power plant refurbishment (Component 1).

10. Economic benefits of the project: The main economic benefit is the avoided increase of the cost of electricity supply to consumers due to replacement of Nurek HPP with new supply sources. The evaluation of avoided increase in economic cost of supply was conducted taking into account the role of the project in winter electricity supply, and the incremental supply costs associated with substituting the generation from Nurek HPP. The plant accounts for a large share

[18] For the purposes of this analyses, winter includes generation during the months of October-March and summer includes generation during the months of April-September.
[19] Project construction costs are not levelized over the operating life of the project.

of total winter electricity supply. Specifically, the plant currently generates on average 4,700 GWh of electricity, which is 70 percent of the total winter generation during the time period of October-March and 47 percent of total unconstrained demand, inclusive of un-met demand. Therefore, under “no-project” scenario, gradual loss of electricity output from Nurek HPP during economic evaluation time horizon will need to be filled by an alternative supply source. The project will also generate global social benefits in form of avoided GHG emissions due to increased gas generation to replace Nurek under project counterfactual. The benefits of avoided GHG emissions were estimated based on the incremental gas-fired electricity supply to the grid and the forecast social cost of carbon (the World Bank Guidance on Social Value of Carbon in Project Appraisal, Sep. 2014).

11. Electricity from Dushanbe-2 CHP starting from December 2016 and from early generation at Rogun HPP starting from 2019 will not be sufficient to fully replace the loss of generation Nurek HPP given the estimated 2,700GWh of un-met winter electricity demand (2014) and the forecast increase of demand. Dushanbe-2 CHP is estimated to generate 1,180 GWh during winter and Rogun HPP at full capacity will be able to supply around 5,600 GWh of winter electricity, which will be sufficient to replace Nurek HPP, but will not be sufficient to meet the forecast electricity demand, which also includes the un-met electricity demand of 2,700 GWh as of 2014.

12. **Winter supply and demand balance**: Assessment of the economic benefits from rehabilitation of the project will require forecast of the winter electricity supply and demand balance during the time period of October-March. This is needed to determine whether the power system will experience electricity shortages in case Nurek HPP is not rehabilitated.

Installed Capacities of Power Plants

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Available Installed Capacity "without project" in MW												
Rogun HPP	0	0	812	812	812	812	812	1200	3,600	3600	3600	3600
Nurek	2660	2660	2660	2390	2110	1810	1540	1240	940	640	340	340
Sangtuda-1	670	670	670	670	670	670	670	670	670	670	670	670
Baipasinskaya	600	600	600	600	600	600	600	600	600	600	600	600
Golovnaya	240	240	240	252	252	252	252	252	252	252	252	252
Sangtuda-2	220	220	220	220	220	220	220	220	220	220	220	220
Kairakum	126	126	174	174	174	174	174	174	174	174	174	174
Perepadnaya	30	30	30	30	30	30	30	30	30	30	30	30
Varzob cascade	25	25	25	25	25	25	25	25	25	25	25	25
Other SHPPs	15	15	15	15	15	15	15	15	15	15	15	15
Centralnaya	15	15	15	15	15	15	15	15	15	15	15	15
Pamir-1	14	14	14	14	14	14	14	14	14	14	14	14
Dushanbe-2 TPP[20]	300	300	300	300	300	300	300	300	300	300	300	300

[20] In both electricity and heat supply regime.

13. Winter supply from existing and committed generation plants was estimated based on their average capacity factors (ACFs) during the winter time and their available installed capacities. For Rogun HPP, the numbers were taken from Techno-Economic Studies of Rogun HPP (August 2014).

Winter ACFs of Main Power Plants

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter ACF "without project"												
Nurek	42.8%	42.8%	42.8%	47.2%	52.1%	58.8%	66.7%	80.2%	90.8%	94.8%	94.8%	94.8%
Sangtuda-1	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Baipasinskaya	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%	46.0%
Golovnaya	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%
Sangtuda-2	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
Kairakum	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Perepadnaya	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%	58.0%
Varzob cascade	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%
Other SHPPs	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%
Centralnaya	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Pamir-1	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%
Dushanbe-2 TPP	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%

14. **Forecast of electricity demand**. The forecast winter and summer electricity demand was derived drawing upon the base-case total electricity demand forecast for Tajikistan. Demand projections are developed in two steps: unconstrained demand and economically efficient demand. The projections cover residential and non-residential demand, but exclude TALCO's demand, which is assumed to remain constant. The forecast of electricity demand used for this analysis reflects the demand for electricity that is consistent with economic efficiency principles. In principle, this demand is the estimated quantity of electricity that consumers would consume if they had to pay a price that fully covers the economic cost of supplying that amount of electricity. The forecast real GDP growth was used as the proxy of the growth in real income to derive the demand projection.

Key Assumptions of the Electricity Demand Forecast

	2017	2018	2019	2020	2025	2030	2035	2040	2045	2050
Change of real electricity price[21]	9.2%	13.1	13.1%	13.1%	2%[22]	2.0%	2.0%	2.0%	2.0%	2.0%
Real GDP growth rate[23]	6%	4.5%	4.5%	4.5%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

[21] The nominal increase will be 17% per year in 2018-2021.
[22] 6% nominal increase was used in financial forecast.
[23] Real GDP forecast is based on IMF's forecasts from World Economic Outlook Report, Oct. 2016.

15. The base-case forecast electricity demand assumed that the current average retail tariff will be increasing to the level of cost recovery by 2022 (US$0.04/kWh)[24] and then continue increasing at an annual rate of 2 percent.

16. To estimate economically efficient demand, the unconstrained demand projection was modified to incorporate the conserving effect of price, specifically, a price that reflects the economic cost of supplying power to meet the forecast consumers' demand for electricity. Conventionally in the derivation of electricity demand forecasts, this price signal assumes that the electricity price is increased incrementally to fully cover costs of supply. This approach broadly satisfies the requirement for economic efficiency, although in practice it recognizes that consumers need time to adjust their electricity usage to price increases without undue disruption.

Box 1. Electricity demand growth model

The methodology for deriving a forecast of the economically efficient level of demand for electricity over the long-term is based on the following relationship between electricity demand growth, and real income growth and real electricity price growth, assuming a constant elasticity power demand function: The rate of growth of demand is equal to the rate of growth of prices times the price elasticity plus the rate of growth of income times the income elasticity. This is expressed formally as:

$d = p*b + g*a$

where:

d = average rate of growth of demand between successive forecast periods
a = income elasticity (positive)
g = growth of real income between successive forecast periods
b = price elasticity of demand (negative)
p = change of real electricity prices between successive forecast periods.

The demand for electricity derived with this model is the forecast unconstrained end use consumption without reduction of losses from the present level. This forecast end use consumption is then transposed into the gross energy sent out to the power network from power generation plants needed to supply forecast unconstrained end use consumption.

17. The sensitivity of demand to GDP growth and economic price of electricity was assumed for each main group of consumers. The assumptions for elasticity are based on observed elasticities derived from historical data.

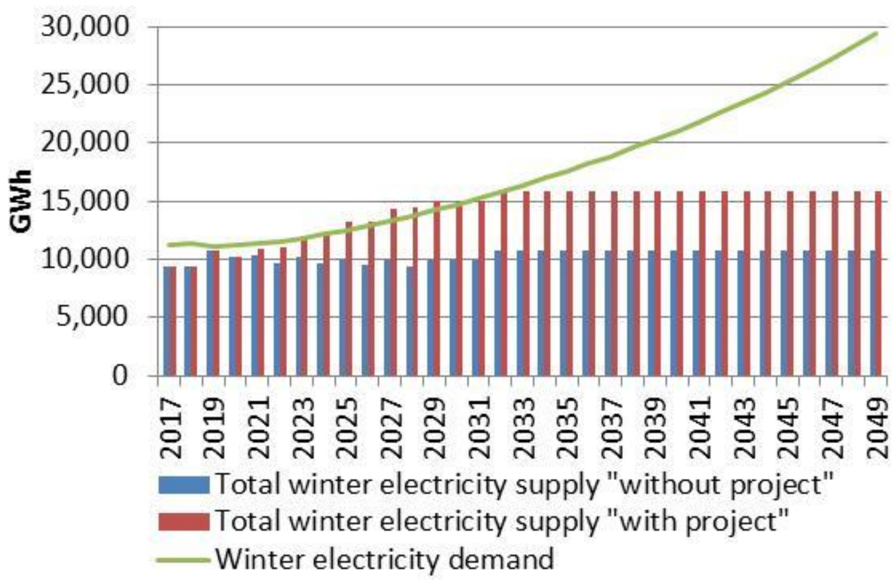
Income and Price Elasticity Assumptions in Electricity Demand Forecast

	GDP growth elasticity	Price elasticity
Industry	0.9	0.0
Pumping irrigation	0.5	-0.15
Agriculture	0.5	-0.15
State-budget financed organizations	0.7	-0.30
Residential	0.9	-0.20
Other	0.8	-0.15

[24] World Bank team estimate.

18. The forecast of winter electricity demand and demand at generation level suggests that Tajikistan will experience winter electricity deficit if Nurek HPP is not rehabilitated. The existing and committed generation capacity (Rogun HPP) will not be able to substitute the loss of generation from Nurek HPP. Therefore, the Government will need to identify new supply sources to substitute the loss of generation from Nurek HPP.

Figure 2: **Forecast of Winter Electricity Supply and Demand Balance**



Source: Bank team estimates.

19. Determination of the alternative supply source or the project counterfactual is needed to evaluate the economic benefit in the form of avoided increase in the cost of supply. The project counterfactual ("no project" scenario) is the construction of combined cycle gas turbine (CCGT) power plants run on imported natural gas if Nurek HPP is not rehabilitated and its generation starts decreasing. The gas-fired generation is assumed to be the project counterfactual because: (a) there is no spare existing generation capacity during winter to replace the supply from Nurek HPP; (b) only CCGTs offer the operational flexibility offered by Nurek HPP and supply the daily and seasonal load during winter period because Nurek HPP is a load-following plant; and (c) the updated results of the power supply options for Tajikistan suggest that it is the lowest-cost new supply option to replace the generation from Nurek HPP. Thus, the economic benefit of avoided increase of power supply costs due to rehabilitation of Nurek HPP was compared to the cost of constructing new gas-fired CCGT units to replace the decreasing generation from Nurek if it is not rehabilitated.

20. The levelized energy cost (LEC) of gas-fired generation is estimated at US$0.084/kWh taking into account the plant-gate costs for imported natural gas. The plant-gate cost of natural gas was computed as the sum of the:

(a) Estimated border price of imported natural gas, which was derived based on the average sales price of Turkmen gas to Russia and China under long-term contracts with long-term

price forecast of US$6.4/MMBtu, including premium for winter supply only. The year-on-year changes of real border gas price were assumed to reflect the changes in the forecast European market prices as reflected in the World Bank's Commodity Price Forecast dated July 26, 2016.

(b) Levelized cost of a new 700km gas transmission pipeline from Turkmenistan. The pipeline cost was assumed to be US$1,300,000 per km and sufficient to supply the amount of gas required for 1200MW CCGT plant to replace Nurek HPP. The cost of the pipeline was assumed to be amortized over 30 years. This adds additional US$2.6/MMBtu to the price of imported natural gas.

(c) Domestic transmission and distribution margin is estimated at US$1/MMBtu.

(d) The forecast of the plant-gate prices for imported natural gas is presented below.

Forecast of Plant-gate prices for Natural Gas in Tajikistan

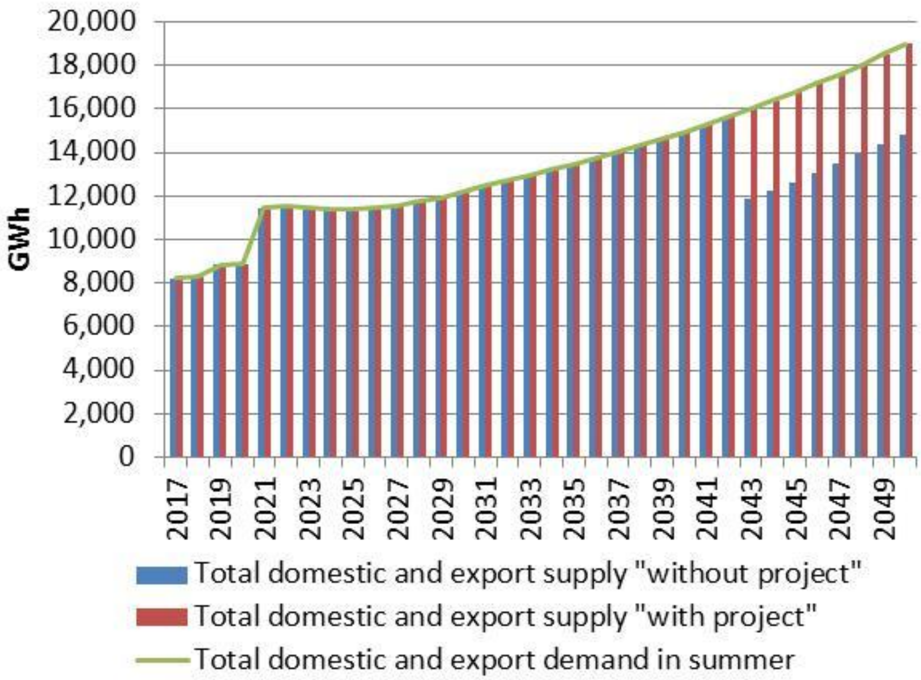
	2020f	**20251f**	**2030f**	**2035f**	**2040f**	**2045f**	**2050f**
Border price of imported natural gas	5.3	6.6	6.6	6.6	6.6	6.6	6.6
New transmission pipeline cost	2.6	2.6	2.6	2.6	2.6	2.6	2.6
T&D margin	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Plant-gate price of natural gas	8.9	10.2	10.2	10.2	10.2	10.2	10.2

21. Rehabilitation of Nurek HPP will not generate any economic benefits for domestic supply during summer period. This is due to the large summer supply potential of Rogun HPP. Once this plant is commissioned, then economic cost of incremental electricity to replace Nurek HPP will be close to zero. With the commissioning of the Rogun HPP, the power system will be able to fully meet the forecast demand in summer even in case of full loss of generation from Nurek HPP. Therefore, electricity from Nurek HPP for domestic market during the summer period has no economic value from the perspective of the project.

22. Nevertheless, the project will generate marginal summer benefits taking into account export demand, which consists of around 1,350 GWh of annual exports to Afghanistan as well as – 640 GWh to Afghanistan and around 2,140 GWh to Pakistan committed under CASA-1000 project. For the purposes of the economic and financial analyses of Nurek rehabilitation project, we conservatively assumed that exports will remain at the above level during the entire period for economic evaluation of the Nurek rehabilitation project.

23. The power system will experience energy shortage for exports starting from 2046 given forecast increase of domestic demand in summer, which will eliminate the energy surplus on the system. Therefore, without Nurek HPP, there will be no electricity available for exports starting from 2043, which will result in foregone economic revenues. Those revenues were computed at the average real PPA tariffs. Given that this will be almost 20 years from completion of the project, the economic benefits discounted at social opportunity cost of capital are small.

Figure 3: Forecast of Summer Electricity Demand and Supply



Source: Bank team estimate.

24. **GHG reduction benefits for entire project**: The project will also generate global environmental benefits in form of net reduction of CO2 emissions. The CO2 emission reduction benefits from the project were evaluated following the World Bank's Guidance Note on Greenhouse Gas Accounting for Energy Investment Operations (June 2013). Specifically, the net emissions were estimated using the following approach:

- Net emissions = Project emissions – (improved performance baseline emissions + life extension baseline emissions).
- Project emissions = annual electricity output x emissions factor for construction x economic life of the project
- Improved performance baseline emissions = incremental generation capacity x emission factor for the country's grid x remaining life of the plant before rehabilitation
- Life extension baseline emissions included emissions from CCGT to supply electricity to make up for loss of generation from Nurek and construction emissions for CCGT plant.

Assumptions underlying GHG Accounting for the Entire Project

Items	Units
Emission factor for rehabilitation of Nurek	0.001kg/kWh
Emission factor for Tajik power grid	0.009kg/kWh
Emissions from CCGT	0.362kg/kWh
Emissions factor for construction of CCGT	0.503kg/kW of installed capacity

Source: Bank team GHG Guidance Note and team assumptions.

25. The entire project will lead to 68 million tCO2e reduction in emissions vs. the baseline during economic life of the project. Therefore, the project will generate climate mitigation co-benefits.

26. Results: The economic analysis of the entire project yielded an economic NPV of US$1,615 million and EIRR of 36 percent exclusive of the social cost of avoided CO2 emission and an economic NPV of US$2,077 million and EIRR of 40 percent inclusive of the social cost of avoided CO2 emissions.

27. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated project economic returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the economic returns to the project. The results of the sensitivity analyses are presented in the Table below.

a. 20 percent lower forecast border price of imported natural gas with the expected base-case values for all other variables.
b. 20 percent higher investment cost with the expected base-case values for all other variables.
c. Loss of generating units at the rate of one unit in three years (instead of the base-case assumption of one unit each year) with expected base-case values for all other variables.
d. Combination of the above cases.

Sensitivity Analysis for Economic Evaluation of Entire Project

Exclusive of avoided CO2 emissions	NPV (million US$)	EIRR (%)
Base-case	**1615**	**36**
a. 20 percent higher investment cost	1517	32
b. 20 percent lower-than-projected border price of imported gas	1384	30
c. Loss of generation capacity at a rate of one unit in three years[25]	272	12
d. Combination of a, b, and c	89	11

28. The results of the sensitivity analysis suggest that the project is economically robust even in case of substantial variation of main variables that affect its viability.

29. It should be noted that delays with commissioning of Rogun HPP will increase the economic benefits for the project because Rogun will not be able to substitute the loss of generation from Rogun HPP and the gap will have to be filled with expensive gas-fired CCGT. With assumed delays in commissioning, all remaining major milestones (commissioning of remaining five units) are assumed to be delayed as well. The capital costs for Rogun HPP are sunk costs from perspective of economic evaluation of the project and only variable costs matter, which are very small for hydropower plants. In case Rogun HPP is not constructed at all, then returns to the project would be even bigger because all of the generation loss from Nurek would have to be replaced by CCGT. If Rogun is not constructed, then generation from Nurek will also

[25] Total loss of generation by 2048 instead of 2028 under base-case.

reduce, but that will have less impact on economic returns compared to the cost of energy from gas-fired CCGT under the project counterfactual.

Economic Analyses of Phase I of the Project

30. The economic analyses of the Phase I of the project was conducted using the cost-benefit approach and using the same methodology. The base-case of the analyses for Phase I is similar to the base-case for analyses of the entire project. The differences between the economic analyses of the Phase I and the entire project are the following: (a) lower economic cost due to rehabilitation of only three generating units; and (b) smaller avoided CCGT generation under "with project" scenario given that the remaining six units, which are not rehabilitated under Phase I, are assumed to completely lose generation by 2028.

31. **GHG reduction benefits for Phase I of the project**. The Phase I will generate global environmental benefits in form of net reduction of CO2 emissions. The assessment of net CO2 emission reductions from Phase I of the project was conducted using the same methodology as for entire project. The Phase I of the project will lead to 29 million tCO2e reduction in emissions vs. the baseline during economic life of the project. Therefore, the project will generate climate mitigation co-benefits.

32. Results: The economic analysis of the Phase I yielded an economic NPV of US$713 million and EIRR of 33 percent exclusive of the social cost of avoided GHG emissions and an economic NPV of US$905 million and EIRR of 37 percent inclusive of the social cost of avoided GHG emissions.

33. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Phase I economic returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the economic returns to Phase I of the project. The results of the sensitivity analyses are presented in the Table below. The results of the sensitivity analysis suggest that the project becomes economically non-viable in cases: (a) when Nurek maintains generation capacity under "without project" scenario until 2048 instead of 2028 under base-case, and (b) investment cost over-run and lower-than-forecast gas prices coupled with 20 years slower loss of generation capacity.

Sensitivity Analysis for Economic Evaluation of the Phase I of the Project

Exclusive of avoided CO2 emission costs	NPV (million US$)	EIRR (%)
Base-case	**713**	**33**
a. 20 percent higher investment cost	664	29
b. 20 percent lower-than-projected border price of imported gas	597	27
c. Loss of generation capacity at a rate of one unit in three years[26]	(479)	4
d. Combination of a, b, and c	(505)	3

[26] Total loss of generation by 2048 instead of 2028 under base-case.

Financial Analysis of Entire Project

34. Financial analyses of the entire project and Phase I of the project was conducted from the perspective of BT, which is the entity to incur the financial costs associated with the projects and to receive the financial benefits. Most of the key assumptions underlying the economic analyses are also applicable to the financial analyses. The following additional assumptions and inputs are worth highlighting for the financial analyses, which are different from the economic analysis.

- *Financial costs and prices*. Financial analysis was conducted inclusive of applicable taxes and duties on equipment, works and revenues. Given that projects financed through sovereign loans and approved by the Parliament are exempt from import duties and taxes, those will not have any implications on the cost estimates. Direct taxes such as profit and income taxes do not directly impact the costs of the inputs and works. The financial analysis was done based on nominal costs, prices and the discount rate.

- *Price and physical contingencies are included into the financial analysis*. The total economic cost of the project was revised to include price contingency of 5 percent, which is computed on the estimated cost of power plant rehabilitation, replacement of autotransformers and PMC.

- *Exchange rate and inflation*. The average annual exchange rate was assumed to remain unchanged at TJS7.88 per US$1 during the entire evaluation period. The inflation, as measured by consumer price index (CPI) was assumed to equal 6.3 percent in 2016, 7.3 percent in 2017 and 6 percent for subsequent years drawing upon the forecast of the IMF World Economic Outlook (October 2016).

- *Average domestic tariff for electricity*. The average billed tariff is assumed to increase at an annual rate of 15 percent in 2017-2021. Starting from 2022, the nominal tariff increase is assumed at 6% per year to compensate for inflation of costs.

- *Collection rates*. The annual increases of electricity bill collection rates for 2016-2018 were assumed to equal the targets specified in the Action Plan as presented in Annex 6. Specifically, the collection rates were assumed to increase from 85 percent in 2015 to 90 percent in 2018, and then to 95 percent by 2022 and remain at that level afterwards.

Required Tariff Increase to Reach Cost Recovery by 2022

		2016	2017	2018	2019	2020	2021
Cost-recovery tariff with repayment of payables and the principals of expensive commercial loans over 5 years	Diram/ kWh	12.79	14.48	16.95	19.85	23.25	27.22
Average annual nominal increase[27]	%	2%[28]	13.2%	17.1%	17.1%	17.1%	17.1%

- *Electricity export tariffs*. Currently, Afghanistan accounts for the bulk of electricity exports. 1,350 GWh of annual exports to Afghanistan over existing 220kV interconnection were assumed to continue during the economic life of the project. The 2016 export tariff of US$0.037/kWh was assumed to escalate at annual rate of 2.5 percent. Electricity exports will increase starting from 2022 when CASA-1000 project is operational. The estimated additional exports to Afghanistan and Pakistan over CASA transmission facilities were reflected in the financial analyses of the project based on the negotiated PPA quantities and tariffs. The duration of PPAs is 15 years. Therefore, for the purposes of the financial analyses, it was conservatively assumed that exports over CASA line will continue at the same quantity after expiration of PPAs under CASA.

Electricity Export Tariffs

		2017	2020	2022	2025	2028	2031	2034	2036
Energy tariff for CASA exports to Afghanistan	US$/ kWh	0	0	0.051	0.055	0.059	0.064	0.069	0.072
Energy tariff for CASA exports to Pakistan	US$/ kWh	0	0	0.052	0.055	0.060	0.064	0.069	0.073
Energy tariff for exports to Afghanistan	US$/ kWh	0.037	0.040	0.042	0.045	0.049	0.052	0.056	0.059
Annual escalation of export tariff to Afghanistan and CASA tariffs	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Weighted average export tariff	US$/ kWh	0.037	0.040	0.048	0.052	0.056	0.060	0.065	0.068

- *Transmission and distribution losses*: Transmission and distribution losses impact the amount of electricity sold to end-users. The transmission losses were assumed to remain at 3.7% of the energy input into transmission. The distribution losses were assumed to remain at 13.6% of input into distribution grid. BT was assumed to receive 12% loss allowance through the tariff.

35. The base-case for financial analysis is formed from expected values for the main evaluation variables, namely: (a) the base-case forecasts of winter and summer electricity demand and supply in Tajikistan; (b) financial costs of the rehabilitation, including dam safety enhancement related costs, and in-service date; (b) amount of electricity supplied under the project based on simulated results of generation by Nurek HPP during winter and summer

[27] Important note: The electricity demand forecast is based on real price increase, i.e. adjusted for forecast inflation.
[28] The 12 percent average tariff increase became effective on November 1, 2016. Thus, it translates only to 2 percent increase if spread over the entire year.

seasons;29 (c) average domestic tariffs and export tariffs as presented above, (d) electricity bill collection rates as presented above and (e) transmission and distribution losses as discussed above.

36. Under the base-case, the incremental cash inflows and outflows were discounted at the estimated cost of the debt to the project, which was estimated 1.37% (see Table below). The financial discount rate for the entire project was assumed to be the same as for Phase I. At this stage, the cost of debt for entire project cannot be determined given the uncertainty with future financing envelope. Therefore, the average cost of debt for Phase I was assumed to apply both for the entire project and the Phase I. There will be no equity financing for the project and it was assumed that the MOF will on-lend the project funds to BT at the same terms and conditions as stipulated in the legal agreements signed with financiers.

Financing Structure for Phase I

	Unit	IDA Grant	IDA concessional credit	IDA Scale-up facility	AIIB	EDB
Credit/Grant amount	million	$45.00	$55.00	$100.00	$60.00	$40.00
Grant element	%	100.0%	53.6%	22.8%	25.4%	39.8%
Grant element	million	$31.00	$20.92	$22.78	$15.27	$15.94
Maturity	years		38	30	20	20
Grace period	years		6	9	5	8
Lending spread/fixed rate			0.75%	3.12%	0.90%	1.00%
	%	-	-	-	-	-
Front-end fee	%	-	-	-	0.25%	-
Commitment fee	%	-	-	-	0.25%	-
Service fee	%	-	-	-	-	-
Discounting rate	%	-	5%	5%	5%	5%
6-Month LIBOR rate	1.25%	-	-	-	-	-

37. Financial costs of the project. The financial costs include: (a) EPC costs for replacement of electrical, mechanical and electromechanical equipment and the works required for rehabilitation; (b) supply and installation of six autotransformers; (c) dam safety enhancement related measures; (d) PMC, which will be acting as the owner's engineer; and (e) incremental O&M costs. The costs are projected according to the years in which they are expected to be incurred during the project construction period.[30]

38. Financial benefits of the project. The financial benefits of the project were estimated as the avoided reduction in revenues from electricity sales when Nurek HPP gradually loses generation capacity. The avoided reduction in revenues was estimated for winter domestic sales, and summer exports. The estimates of avoided revenue reduction take into account electricity losses in the power system and the estimated bill collection rates.

[29] For the purposes of this analyses, winter includes generation during the months of October-March and summer includes generation during the months of April-September.

[30] Project construction costs are not levelized over the operating life of the project.

- Avoided reduction of revenues from domestic sales in winter was computed as the product of reduction in supply from Nurek and forecast average end-user electricity tariffs. The avoided reduction in revenues due to decline of electricity supply is largest during winter months when electricity demand is the highest and there is no spare capacity in the power system. In fact, there is winter energy deficit.
- Avoided reduction of revenues from summer exports was computed as the product of reduction in supply from Nurek and forecast PPA tariffs, including those signed under CASA. Avoided reduction from summer exports has small impact on financial viability of the project given that the power system has significant surplus energy, which will increase further with commissioning of Dushanbe-2 TPP and Rogun HPP. Availability of surplus energy for exports due to loss of generation from Nurek will start reducing revenue from exports only starting from 2046. Taking into account that this will be 19 years from commissioning of rehabilitated Nurek project, the present value of avoided reduction in export revenues is small.
- There is no financial cost to BT during summer months if Nurek HPP starts losing generation. As explained above, this is due to significant energy surplus during summer months given hydrology and new generation projects. Specifically, Dushanbe-2 CHP and Rogun HPP will be capable of supplying around 10,000 GWh in summer, which exceeds the maximum average 7,700 GWh supply from Nurek.

39. Results: The financial analysis of the project yielded a financial NPV of US$25,156 million and FIRR of 23 percent. This result suggest that the project will have significant impact on precluding significant deterioration of financial viability of BT. Without the project, BT's revenues will significantly reduce exacerbating the financial difficulties of the company.

40. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated project financial returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the financial returns to the project. The results of the sensitivity analyses are presented in the Table below.

- 20 percent higher investment cost with the expected base-case values for all other variables.
- Loss of generation capacity at a rate of one unit in three years with the expected base-case values for all other variables.[31]
- Financial cost recovery tariff reached by 2029 instead of 2022 with the expected base-case values for all other variables.
- Combination of the above cases.

Sensitivity Analysis for Financial Evaluation of Entire Project

	NPV (million US$)	**FIRR (%)**
Base-case	**25,156**	**23**
a. 20 percent higher investment cost	24,940	21
b. Financial cost recovery tariff reached by 2029 instead of	14,245	18

[31] Total loss of generation by 2048 instead of 2028 under base-case.

2022		
c. Loss of generation capacity at a rate of one unit in three years	21,491	14
d. Combination of a, b, and c	11,435	11

41. The results of the sensitivity analysis suggest that the project is financially robust even in case of substantial variation of main variables that affect its viability.

Financial Analysis of Phase I of the Project

42. The financial analysis of the Phase I of the project was conducted using the cost-benefit approach and using the same methodology. The base-case of the analysis for Phase I is similar to the base-case for analysis of the entire project. The main difference between the financial analysis of the Phase I and the entire project is the lower financial cost due to rehabilitation of only three generating units.

43. Results: The financial analysis of the Phase I yielded an economic NPV of US$25,979 million and FIRR of 23 percent.

44. Sensitivity analysis: Sensitivity analysis was conducted to assess the robustness of the estimated Phase I financial returns to changes in the main evaluation variables. Sensitivity analysis covers the following cases that in turn stress test the financial returns to Phase I of the project. The results of the sensitivity analyses are presented in the Table below.

Sensitivity Analysis for Financial Evaluation of the Phase I of the Project

	NPV (million US$)	**FIRR (%)**
Base-case	**25,979**	**23**
a. 20 percent higher investment cost	25,882	22
b. Financial cost recovery tariff reached by 2029 instead of 2022	21,818	21
c. Loss of generation capacity at a rate of one unit in three years	15,557	13
d. Combination of a, b, and c	12,068	11

Analysis of Financial Performance of BT

45. The assessment of the financial performance of BT is based on: (a) the audited financial statements for 2013-2015; (b) information and data on tariffs, debts, and projected electricity generation and sales by BT; and (c) the information obtained during the discussions with the management of BT and the World Bank staff.

46. The financial condition of BT continued to deteriorate in the period from 2013 to 2015, due to (a) unsustainable and increasing debt levels, (b) low cash collections, and (c) below cost recovery end-user electricity tariffs.

47. As of the end-2015, BT's total liabilities exceeded its total assets. Operating losses persisted in the period of 2013-2015 leading to complete erosion of equity. Accumulated losses

of the BT reached TJS5300 million (US$758 million). In 2015 alone, total liabilities of BT increased by 1.5 times, mainly due to more than 30 percent depreciation of the domestic currency.

48. As of the end-2015, total liabilities of BT stood at TJS11,617 million (US$1,662m), about 55% of which were borrowings from IFIs. The ability to sustain those loans was considerably impaired by absence of corresponding revenue allowance in the tariffs and under-collection of receivables. BT failed to make both principal and interest payments on them. By the end of 2015, it had already accrued TJS1156 million (US$165 million) of interest payable and incurred penalties for delinquency in total amount of TJS1133 million (US$162 million). In addition, BT has TJS1102 million (US$158 million) very expensive short-term dollar denominated commercial debt from a local bank, which costs the company about TJS253 million (US$36 million) per annum in interest expense.

49. The situation with payables deteriorated. In particular, payables for electricity purchases from IPPs - Sangtuda-1 and Sangtuda-2 HPPs (with 2016 tariffs of US$0.023 and US$0.032/kWh respectively) - rose to TJS835 million (US$119 million). BT struggles to make payments to those IPPs in timely manner because the cost of electricity from those IPPs is higher than the end-user electricity tariff and those IPPs primarily supply electricity during the months of April-October (surplus energy season) when the other lower cost HPPs, owned by BT, can generated at significantly lower cost and spill water given low summer demand and lack of export opportunities.

50. In 2015 total current liabilities of TJS5446 million (US$779 million) accounted for 47 percent of total liabilities. Current assets were only one fifth of that amount. This represented a significant reduction in the liquidity, as measured by the ratio of current assets to current liabilities, which was at 0.39 in 2013.

51. Nonetheless, the relative stability of operating costs before depreciation and 11% average annual growth of sales revenue, driven by end-user tariff increases, lead to substantial improvement of EBITDA margin (25 percent in 2015 vs. 2 percent in 2013) and net debt[32]-to-EBITDA ratio of the company; albeit well above acceptable levels, net debt decreased from 222 times EBITDA in 2013 to 30 times EBITDA in 2015.

52. End-user electricity tariffs remain below the cost-recovery levels, which do not allow the company to finance even the required recurrent expenditures. The expected average end-user tariff for 2016 (12.89 diram/kWh) is estimated 55 percent below the cost-recovery level. The cost-recovery tariff was assessed following the cash needs approach. This was done through assessment of the amount of cash revenue that BT requires to fully finance the recognized recurrent expenses (accrual based items in the financial statements), which include the O&M costs, administrative costs, capital repairs from own funds, pension liabilities, debt service, and taxes. It also assumes gradual repayment of accrued liabilities (i.e. interest payables, overdue loans and payables to Sangtuda-1 and Sangtuda-2 HPPs for purchased electricity) over a five-year period starting 2017. It should be noted that concept of cash-based cost of service is different from the concept of economically efficient cost of supply and does not take into

[32] Net debt = total liabilities – cash and cash equivalents.

account the return on invested capital and investments required to meet the long-run forecast electricity demand.

Cost-recovery Tariff Calculation

TJS million	2016F	2017F	2018F	2019F	2020F	2021F
[+] Cash cost of sales	**837**	**993**	**1,036**	**1,081**	**1,128**	**1,177**
Cost of purchased electricity	514	537	560	584	610	636
Cost of inventory used	160	184	195	206	219	232
Salary expenses	87	94	100	106	112	119
Taxes	34	34	34	34	34	34
Direct OPEX of Dushanbe-2 CHP	-	100	100	100	100	100
Other expenses	41	44	47	50	53	56
[+] Cash selling expenses	**320**	**353**	**374**	**397**	**420**	**446**
[+] Cash admin expenses	**79**	**83**	**86**	**89**	**92**	**95**
[+] Financing costs	**558**	**1,734**	**1,771**	**1,790**	**1,882**	**1,897**
Interest payments on IFI loans	242	275	288	299	309	302
Principal repayment on IFI loans	316	422	446	454	536	558
Payables for electricity purchase to Sangtuda-1	-	114	114	114	114	114
Payables for electricity purchase to Sangtuda-2	-	74	74	74	74	74
Interest payables on IFI loans	-	261	261	261	261	261
Overdues on IFI loans	-	340	340	340	340	340
Orienbank loans	-	248	248	248	248	248
[+] Profit	**-**	**-**	**-**	**-**	**-**	**-**
[=] Revenue requirement	**1,794**	**3,163**	**3,267**	**3,356**	**3,522**	**3,616**
Revenue from export	376	376	376	376	376	376
Revenue from domestic sales	1,419	2,787	2,891	2,980	3,146	3,240
Electricity dispatched to domestic consumers (million kWh)	**12,900**	**13,567**	**13,567**	**13,567**	**13,567**	**13,567**
Cost recovery tariff incl. VAT (Diram/kWh)	**12.98**	**24.24**	**25.15**	**25.92**	**27.36**	**28.18**
Proposed tariff increase schedule (Diram/kWh)	**12.79**	**14.48**	**16.95**	**19.85**	**23.25**	**27.22**

53. In 2015, BT earned TJS1548 million (US$252 million) from sales of electricity. The Company supplied 12,817 GWh of electricity to domestic consumers and exported 1,340 GWh to Afghanistan and Kyrgyzstan. The weighted average export price of electricity was US$0.035/kWh.

54. The collection rate for billed electricity was still below the industry average, at around 83 percent. As of the end of 2015, the Company had 97 days receivables outstanding. The aluminum producer, TALCO, is the largest debtor to BT with its total debt of TJS412 million (US$59 million).

Bill Collection Rates by Customer Categories

Customer category	Bill collection rate (%)
Industry, excl. TALCO	96.0
TALCO	88.4
Utilities, state organizations, transport	76.2
Pumps and water pumping stations	27.6

Customer category	Bill collection rate (%)
Residential consumers	78.6
Average	**83.0**

55. **Forecast of Financial Performance of BT**. Financial performance of BT was forecast for two scenarios. The base-case scenario is based on the agreed-upon targets to be achieved by BT as reflected in the Action Plan for Financial Recovery of BT, including increase of end-user average tariff, improvements in collection rates, and other efficiency improvements. The conservative scenario assumes lower increase in average end-user tariffs, smaller improvements in collection rates and other financial efficiency indicators such as days of receivables outstanding and inventory turnover. The key assumptions for each of the forecast scenarios are presented below.

Key Assumptions underlying Forecast of Financial Performance

Base-Case Scenario	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Increase of average end-user tariff	13%	15%	15%	15%	15%	15%	6%	6%	6%
Electricity bill collection rates	88%	90%	93%	95%	95%	95%	95%	95%	95%
Days receivables outstanding	82	68	49	30	30	30	30	30	30
Inventory as days of sales	121	65	65	65	65	65	65	65	65
Conservative Scenario	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Increase of average end-user tariff	12%	12%	12%	12%	12%	11%	4%	4%	4%
Electricity bill collection rates	87%	89%	90%	90%	90%	90%	90%	90%	90%
Days receivables outstanding	88	80	69	60	60	60	60	60	60
Inventory as days of sales	178	150	150	150	150	150	150	150	150

Base-Case Forecast of Financial Performance of BT

56. The projected financial performance of BT takes into account the targets specified in the Action Plan for Financial Recovery of BT and expected increase in export revenues starting from 2022 when CASA-1000 project is commissioned. In particular, projections of financial performance of BT were made on assumptions that:

(a) End-user electricity tariffs will converge to their cost-recovery levels by 2022, which implies an average annual tariff increase of 15 percent; from 2022 onward end-user electricity tariff is assumed to increase at the nominal rate of 6 percent.
(b) Total power generation and domestic supply will increase by about 5 percent in 2017 upon completion of the Second Phase of construction of Dushanbe-2 CHP.

(c) Exports are forecast to increase by 2,800 GWh starting from 2022, when cross-border transmission facilities with Afghanistan and Pakistan under CASA-1000 project become operational.
(d) Power purchase prices under PPAs with Afghanistan and Pakistan are assumed to be US0.051/kWh and US$0.0515/kWh respectively.
(e) Prices of electricity purchased from Sangtuda-1 and Sangtuda-2 will growth at annual rate of 4 percent and 5 percent respectively.
(f) Bill collection rate will improve by 2 percent per year to reach 95 percent over a five-year period.
(g) Receivables will reduce from 85 to 45 days of sale by 2020.
(h) Inventory will reduce from 233 to 65 days of cost of sales by 2018; and
(i) From 2016 onward the exchange rate of TJS against US dollar will be at TJS7.88 per US dollar.

57. Until 2020, BT will continue to experience deterioration in liquidity and financial leverage due to persisting net losses, slow reduction of accrued liabilities and expected disbursements under ongoing projects. The ratio of current assets to current liabilities will decrease to 0.08 from 0.20 in 2015, and debt-to-assets ratio will increase to 1.2.

58. At the end of 2016, BT will have accrued liabilities for a total TJS5131 million. Total debt service requirements for the forecast period of 2016-2025, including repayment of accruals, are estimated at TJS13,966 million, as shown on Figure 1 below. During the same period tariff increases, improved collections and working capital management are expected generate an additional TJS15,805 million in cash. Once target collection rates and days receivables are reached in 2020, available operating cash flow of BT will allow to accelerate repayment of outstanding commercial debt, accrued payables for electricity and debts to international financial institutions. In that year EBITDA margin will increase to 54 percent, and operating cash flow per unit of sales is expected to increase fivefold to TJS0.50.

59. Commencement of electricity exports under CASA-1000 project will also significantly contribute to improvement of financial standing of BT starting from 2022. The exports will increase from current level of 1,340 GWh to more than 4,100 GWh per year, including the existing exports to Afghanistan. Specifically, exports under CASA-1000 project are expected to generate additional US$150 million of income per year.

60. The Government is currently considering the following option for resolving the short-term indebtedness issue. BT will gradually repay the commercial loans to Orienbank in 2018-2021 using incremental operating cash flows from financial recovery measures. The increase of the incremental cash flows of BT was estimated assuming implementation of the Action Plan for Financial Recovery of BT. It was assumed that the loans will either be rolled over each year on the date of the repayment as was the practice before or will be restructured to long-term loans.

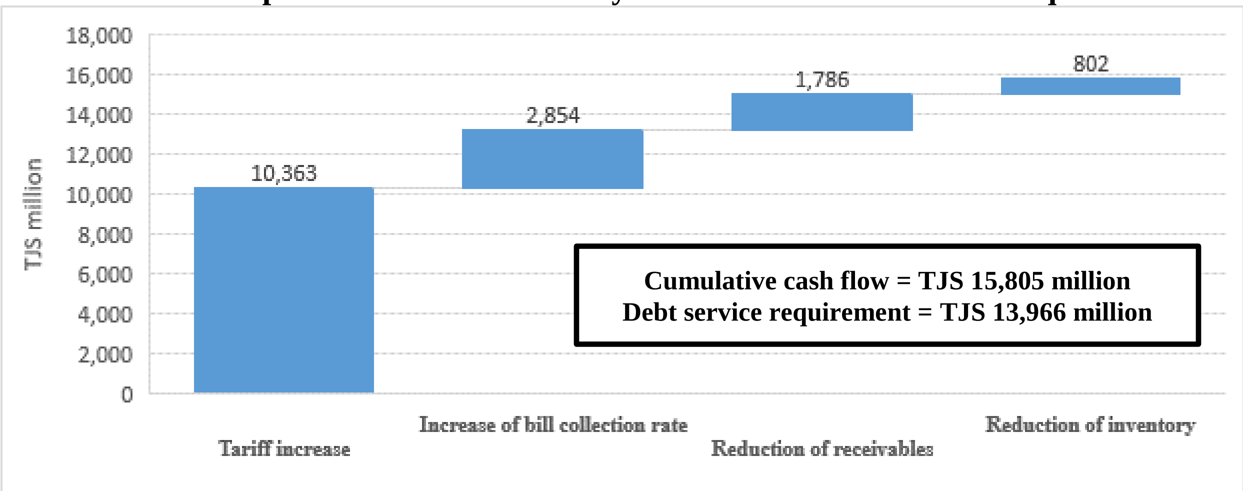
Impact of Financial Recovery Measures

	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Additional cash flow, mln TJS	20.3	168.7	397.5	670.1	981.6	1,287.0	1,461.6	1,631.1	1,789.0	1,956.3
Additional cash flow, mln TJS	33.6	79.9	140.3	219.1	295.2	345.7	397.7	421.6	446.9	473.7
Additional cash flow, mln TJS	149.3	200.3	268.0	357.4	334.6	73.8	86.4	99.4	105.4	111.7
Additional cash flow, mln TJS	164.4	219.1	214.6	22.5	25.1	23.2	52.3	26.5	26.2	28.0
Total cash flow	**367.6**	**667.9**	**1,020.4**	**1,269.0**	**1,636.5**	**1,729.7**	**1,998.1**	**2,178.7**	**2,367.5**	**2,569.7**
Cumulative cash flow	**367.6**	**1,035.5**	**2,055.9**	**3,325.0**	**4,961.4**	**6,691.1**	**8,689.2**	**10,867.9**	**13,235.4**	**15,805.1**

Debt Repayment Schedule under Base-Case Scenario

TSJ million	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Principal payment on IFI loans	217	252	446	454	536	558	613	605	605	605
Interest payment on IFI loans	242	268	277	285	289	277	260	236	212	189
Interest payment on Orienbank loan	253	286	286	268	211	106	-	-	-	-
Repayment of Orienbank loans	-	-	75	248	459	459	-	-	-	-
Repayment of payables to Sangtuda-1 & Sangtuda-2	-	-	-	-	44	62	160	177	222	222
Repayment of arrears on IFI loans	-	-	-	-	-	85	340	425	425	425
Repayment of interest payables	-	-	-	-	-	-	586	586	130	-
Total debt service requirement	**713**	**805**	**1,083**	**1,256**	**1,540**	**1,547**	**1,960**	**2,029**	**1,594**	**1,440**
Cash available for debt service	**729**	**827**	**1,111**	**1,293**	**1,596**	**1,629**	**2,862**	**3,978**	**5,070**	**6,708**

Cumulative Impact of Financial Recovery Measures vs. Debt Service Requirements



61. By 2025, net debt of BT is forecast to decrease to 2 times EBITDA, and by 2023 the debt service coverage ratio will have reverted to a sustainable level of 1.11, as shown in Table 13 below. Detailed debt repayment schedule is presented in Table below.

Financial Ratios under Base-Case Scenario

	2013A	2014A	2015A	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Gross margin	52%	18%	41%	40%	39%	44%	49%	54%	59%	70%	70%	70%	71%
EBITDA margin	2%	12%	25%	28%	29%	37%	44%	50%	49%	62%	63%	63%	63%
OCF/Revenue	3%	16%	10%	38%	40%	47%	48%	50%	43%	51%	52%	51%	51%
Current ratio	0.39	0.29	0.20	0.16	0.14	0.10	0.09	0.08	0.09	0.27	0.56	1.08	1.86
Debt-to-assets	0.60	0.74	1.01	1.14	1.18	1.20	1.20	1.17	1.12	0.96	0.82	0.69	0.58
Operating cash flow / short-term debt service	0.05	0.10	0.06	0.11	0.08	0.15	0.20	0.25	0.31	0.52	0.95	1.48	1.95
DSCR	0.02	0.08	0.04	0.13	0.11	0.15	0.20	0.27	0.38	0.82	1.11	1.70	2.42

Conservative Forecast of BT Financial Performance

62. If BT does not fully achieve the targets specified in the Action Plan for Financial Recovery of BT, then the company's financial performance will remain distressed. Specifically, the current assets will not be sufficient to cover the current liabilities even by the end of the forecast period. BT will not be able to repay the short-term commercial debt until 2024 and will only be able to repay portion of the payables to IPPs. The debt service coverage ratio will reach 1.1 by 2025. The details are presented in the Tables below.

Debt Repayment Schedule under Conservative Scenario

TSJ million	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Principal payment on IFI loans	121	82	246	360	499	521	613	605	605	605
Interest payment on IFI loans	242	268	277	285	289	277	260	236	212	189
Interest payment on Orienbank loan	253	286	286	286	286	286	286	-	-	-
Repayment of Orienbank loans	-	-	-	-	-	-	993	248	-	-
Repayment of payables to Sangtuda-1 & Sangtuda-2	-	-	-	-	-	-	-	44	177	666
Repayment of arrears on IFI loans	-	-	-	-	-	-	-	1,020	680	-
Repayment of interest payables	-	-	-	-	-	-	-	-	573	730
Total debt service requirement	**617**	**635**	**809**	**931**	**1,073**	**1,083**	**2,153**	**2,153**	**2,248**	**2,188**
Cash available for debt service	**620**	**646**	**836**	**969**	**1,129**	**1,163**	**2,282**	**2,410**	**2,542**	**2,594**

Financial Ratios under Conservative Scenario

	2013A	2014A	2015A	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2023F	2024F	2025F
Gross margin	52%	18%	41%	40%	38%	42%	45%	48%	51%	65%	65%	65%	64%
EBITDA margin	2%	12%	25%	27%	28%	33%	37%	40%	40%	55%	56%	55%	54%
OCF/Revenue	3%	16%	10%	32%	32%	37%	39%	40%	37%	49%	48%	44%	33%
Current ratio	0.39	0.29	0.20	0.17	0.16	0.15	0.14	0.14	0.15	0.17	0.21	0.29	0.43
Debt-to-assets	0.60	0.74	1.01	1.14	1.18	1.21	1.23	1.23	1.23	1.13	1.03	0.92	0.81
DSCR	0.02	0.08	0.04	0.13	0.11	0.13	0.15	0.17	0.20	0.42	0.52	0.72	1.09

Streams of Economic Costs and Benefits for Entire Project

ECONOMIC ANALYSIS FOR ENTIRE PROJECT		2017	2018	2019	2023	2027	2031	2035	2039	2043	2047	2051	2055	2059	2063
EPC costs	MUS$	51.7	5.2	5.2	75.3	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs of autotransformers	MUS$	7.7	15.3	11.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMC costs	MUS$	0.1	0.2	1.1	1.4	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Incremental O&M	MUS$	0.0	0.0	0.0	2.9	6.9	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Total incremental economic cost	**MUS$**	**59.4**	**20.7**	**17.8**	**79.7**	**41.0**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**
Winter supply to domestic market under "without project"	GWh	9,365	9,365	10,696	10,186	9,967	9,890	10,752	10,752	10,752	10,752	10,752	10,752	10,752	10,752
Winter supply to domestic market "with project"	GWh	9,365	9,365	10,696	12,051	14,318	14,972	15,834	15,834	15,834	15,834	15,834	15,834	15,834	15,834
Winter electricity deficit "without project"	GWh	1,824	1,999	425	1,664	3,290	5,351	6,815	9,541	12,737	16,485	20,881	24,564	24,147	23,737
Winter electricity deficit "with project"	GWh	1,824	1,999	425	0	0	270	1,734	4,460	7,656	11,404	15,800	19,483	19,066	18,656
Avoided CCGT generation to replace Nurek in winter	GWh	0	0	0	1,664	3,290	5,081	5,081	5,081	5,081	5,081	5,081	5,081	5,081	5,081
Avoided economic cost of generation to replace Nurek in winter	MUS$	0	0	0	148	293	452	452	452	452	452	452	452	452	452
Summer supply to domestic market "without project"	GWh	6,858	6,943	7,468	7,313	7,499	8,329	9,328	10,497	11,868	13,467	15,333	15,962	15,962	15,962
Summer supply to domestic market "with project"	GWh	6,858	6,943	7,468	7,313	7,499	8,329	9,328	10,497	11,868	13,467	15,333	16,890	16,706	16,525
Avoided CCGT generation to replace Nurek in summer	GWh	0	0	0	0	0	0	0	0	0	0	0	928	744	563
Avoided economic cost of generation to replace Nurek in summer	MUS$	0	0	0	0	0	0	0	0	0	0	0	83	66	50
Summer electricity exports "without project"	GWh	1,353	1,353	1,353	4,167	4,047	4,137	4,137	4,137	0	0	0	0	0	0
Summer electricity exports "with project"	GWh	1,353	1,353	1,353	4,167	4,047	4,137	4,137	4,137	4,137	4,137	4,137	4,137	4,137	4,137
Avoided reduction in exports	GWh	0	0	0	0	0	0	0	0	4,137	4,137	4,137	4,137	4,137	4,137
Avoided revenue loss due to reduction in exports	MUS$	0	0	0	0	0	0	0	0	193	193	193	193	193	193
Net economic benefits exclusive of CO2 reduction	**MUS$**	**-59**	**-21**	**-18**	**68**	**252**	**443**	**443**	**443**	**637**	**637**	**637**	**719**	**703**	**687**

ECONOMIC ANALYSIS FOR ENTIRE PROJECT		2017	2018	2019	2023	2027	2031	2035	2039	2043	2047	2051	2055	2059	2063
benefits															
NPV exclusive of CO2 reduction benefits	**MUS$**	**$1,615**													
EIRR exclusive of CO2 reduction benefits	**%**	**36%**													
Project emissions	tCO2e	11,286	11,286	12,940	12,345	12,977	13,016	13,016	13,016	13,016	13,016	13,016	13,016	13,016	13,016
Baseline operational emissions	tCO2e	0	0	0	602,401	1,190,908	1,839,429	1,839,429	1,839,429	1,839,429	1,839,429	1,839,429	2,175,407	2,108,894	2,043,395
Baseline construction emissions	tCO2e	0	0	0	100,600	0	0	0	0	0	0	0	0	0	0
Avoided CO2 emissions	tCO2e	-11,286	-11,286	-12,940	690,657	1,177,931	1,826,412	1,826,412	1,826,412	1,826,412	1,826,412	1,826,412	2,162,391	2,095,878	2,030,379
Social cost of avoided CO2 emissions	MUS$	-0.4	-0.4	-0.4	27.3	53.6	94.1	105.0	116.0	126.9	137.9	146.1	173.0	167.7	162.4
Net economic inclusive of CO2 reduction benefits	MUS$	-60	-21	-18	96	305	537	548	559	763	774	783	892	870	849
NPV inclusive of CO2 reduction benefits	**MUS$**	**$2,077**													
EIRR inclusive of CO2 reduction benefits	**%**	**40%**													

Streams of Economic Costs and Benefits for Phase I of the Project

ECONOMIC ANALYSIS FOR PHASE I		2017	2018	2019	2023	2027	2031	2035	2039	2043	2047	2051	2055	2059	2063
EPC costs	MUS$	51.7	5.2	5.2	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs of autotransformers	MUS$	7.7	15.3	11.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMC costs	MUS$	0.1	0.2	1.1	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Incremental O&M	MUS$	0	0.0	0.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total incremental economic cost	MUS$	**59.4**	**20.7**	**17.8**	**29.6**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**
Winter supply to domestic market under "without project"	GWh	9,365	9,365	10,696	10,186	9,967	9,890	10,752	10,752	10,752	10,752	10,752	10,752	10,752	10,752
Winter supply to domestic market "with project"	GWh	9,365	9,365	10,696	12,051	11,832	11,560	12,422	12,422	12,422	12,422	12,422	12,422	12,422	12,422

ECONOMIC ANALYSIS FOR PHASE I		**2017**	**2018**	**2019**	**2023**	**2027**	**2031**	**2035**	**2039**	**2043**	**2047**	**2051**	**2055**	**2059**	**2063**
Winter electricity deficit "without project"	GWh	1,824	1,999	425	1,664	3,290	5,351	6,815	9,541	12,737	16,485	20,881	24,564	24,147	23,737
Winter electricity deficit "with project"	MUS$	1,824	1,999	425	0	1,425	3,681	5,145	7,871	11,067	14,815	19,211	22,894	22,477	22,067
Avoided CCGT generation to replace Nurek in winter	GWh	0	0	0	1,664	1,865	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Avoided economic cost of generation to replace Nurek in winter	MUS$	0	0	0	148	166	149	149	149	149	149	149	149	149	149
Summer supply to domestic market "without project"	GWh	6,858	6,943	7,468	7,313	7,499	8,329	9,328	10,497	11,868	13,467	15,333	15,962	15,962	15,962
Summer supply to domestic market "with project"	GWh	6,858	6,943	7,468	7,313	7,499	8,329	9,328	10,497	11,868	13,467	15,333	16,890	16,706	16,525
Avoided CCGT generation to replace Nurek in summer	GWh	0	0	0	0	0	0	0	0	0	0	0	928	744	563
Avoided economic cost of generation to replace Nurek in summer	MUS$	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Summer electricity exports "without project"	GWh	1,353	1,353	1,353	4,167	4,047	4,137	4,137	4,137	0	0	0	0	0	0
Summer electricity exports "with project"	GWh	1,353	1,353	1,353	4,167	4,047	4,137	4,137	4,137	4,137	4,137	0	0	0	0
Avoided revenue loss due to reduction in exports	MUS$	0	0	0	0	0	0	0	0	193	193	0	0	0	0
Net economic benefits exclusive of CO2 reduction benefits	**MUS$**	**-59**	**-21**	**-18**	**119**	**163**	**146**	**146**	**146**	**339**	**339**	**146**	**146**	**146**	**146**
NPV exclusive of CO2 reduction benefits	**MUS$**	**$713**													
EIRR exclusive of CO2 reduction benefits	**%**	**33%**													
Project emissions	tCO2e	11,248	11,248	12,897	12,303	6,485	4,314	4,314	4,314	4,314	4,314	4,314	4,314	4,314	4,314
Baseline construction emissions	tCO2e	0	0	0	602,401	675,069	604,538	604,538	604,538	604,538	604,538	604,538	940,517	874,004	808,505
Baseline construction emissions	tCO2e	**0**	0	0	50,300										
Avoided CO2 emissions	tCO2e	-11,248	-11,248	-12,897	640,398	668,584	600,225	600,225	600,225	600,225	600,225	600,225	936,203	869,691	804,191

ECONOMIC ANALYSIS FOR PHASE I		2017	2018	2019	2023	2027	2031	2035	2039	2043	2047	2051	2055	2059	2063
Social cost of avoided CO2 emissions	MUS$	-0.4	-0.4	-0.4	25.3	30.4	30.9	34.5	38.1	41.7	45.3	48.0	74.9	69.6	64.3
Net economic benefits inclusive of CO2 reduction benefits	**MUS$**	**-60**	**-21**	**-18**	**144**	**193**	**177**	**180**	**184**	**381**	**384**	**194**	**221**	**215**	**210**
NPV inclusive of CO2 reduction benefits	**MUS$**	**$914**													
EIRR inclusive of CO2 reduction benefits	**%**	**37%**													

Streams of Financial Costs and Benefits for Entire Project

FINANCIAL ANALYSIS FOR ENTIRE PROJECT		2017	2018	2019	2023	2027	2031	2035	2039	2043	2047	2051	2055	2059	2063
EPC costs	MUS$	54.2	5.4	5.4	79.0	34.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs of autotransformers	MUS$	8.0	16.1	12.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dam safety	MUS$	6.0	12.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMC costs	MUS$	0.1	0.2	1.1	1.5	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Incremental O&M	MUS$	0.00	0.00	0.00	2.94	6.86	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82
Total incremental cash outflows	**MUS$**	**68.4**	**33.7**	**27.7**	**83.5**	**42.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**	**8.8**
Winter electricity sales "without project"	GWh	8,691	8,691	9,926	9,453	9,249	9,178	9,978	9,978	9,978	9,978	9,978	9,978	9,978	9,978
Cash collections for winter electricity sales "without project"	US$	141	168	230	390	482	604	829	1,047	1,322	1,669	2,107	2,660	3,358	4,239
Winter electricity sales "with project"	GWh	8,691	8,691	9,926	11,183	13,287	13,894	14,694	14,694	14,694	14,694	14,694	14,694	14,694	14,694
Cash collections for winter electricity sales "with project"	MUS$	141	168	230	462	693	915	1,221	1,542	1,947	2,457	3,103	3,917	4,945	6,243
Avoided loss of cash from winter electricity sales	MUS$	0	0	0	71	211	310	392	495	625	789	996	1,257	1,587	2,003
Summer electricity sales "without project	GWh	6,364	6,443	6,931	6,786	6,959	7,730	8,656	9,741	11,013	12,497	14,229	14,812	14,812	14,812
Summer electricity sales "with project"	GWh	6,364	6,443	6,931	6,786	6,959	7,730	8,656	9,741	11,013	12,497	14,229	15,674	15,503	15,335
Cash collections from summer electricity sales "without project"	MUS$	103	125	161	280	363	509	719	1,022	1,459	2,090	3,005	3,949	4,985	6,293

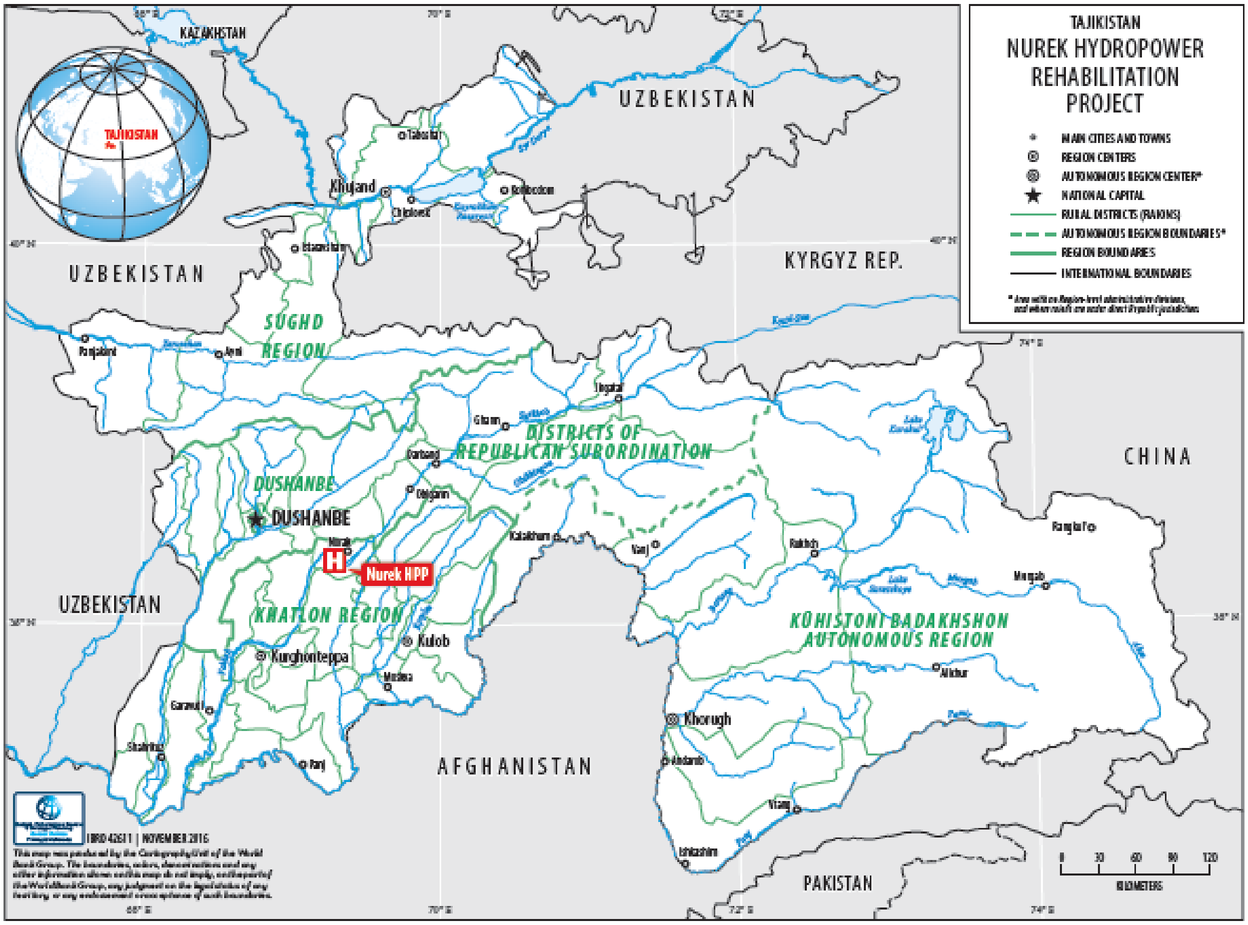
Cash collections from summer electricity sales "with project"	MUS$	103	125	161	280	363	509	719	1,022	1,459	2,090	3,005	4,178	5,217	6,516
Avoided loss of cash from summer electricity sales		0	0	0	0	0	0	0	0	0	0	0	230	232	222
Summer electricity exports "without project"	GWh	1,304	1,304	1,304	4,017	3,901	3,988	3,988	3,988	0	0	0	0	0	0
Summer electricity exports "with project"	GWh	1,304	1,304	1,304	4,017	3,901	3,988	3,988	3,988	3,988	3,988	3,988	3,988	3,988	3,988
Avoided loss of cash from summer electricity exports	MUS$	0	0	0	0	0	0	0	0	323	357	394	435	480	530
Net financial benefits	**MUS$**	**-68**	**-34**	**-28**	**-12**	**168**	**302**	**383**	**486**	**939**	**1,137**	**1,381**	**1,913**	**2,291**	**2,747**
NPV	**MUS$**	**$25,156**													
FIRR	**%**	**22.9%**													

Streams of Financial Costs and Benefits for Phase I of the Project

FINANCIAL ANALYSIS FOR PHASE I		**2017**	**2018**	**2019**	**2023**	**2027**	**2031**	**2035**	**2039**	**2043**	**2047**	**2051**	**2055**	**2059**	**2063**
EPC costs	MUS$	54.2	5.4	5.4	27.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Costs of auto-transformers	MUS$	8.0	16.1	12.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dam safety	MUS$	6.0	12.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMC costs	MUS$	0.1	0.2	1.1	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Incremental O&M	MUS$	0.0	0.0	0.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total incremental cash outflows	**MUS$**	**68.4**	**33.7**	**27.7**	**30.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**	**2.9**
Winter electricity sales "without project"	GWh	8,691	8,691	9,926	9,453	9,249	9,178	9,978	9,978	9,978	9,978	9,978	9,978	9,978	9,978
Cash collections for winter electricity sales "without project"	MUS$	141	168	230	390	482	604	829	1,047	1,322	1,669	2,107	2,660	3,358	4,239
Winter electricity sales "with project"	GWh	8,691	8,691	9,926	11,183	10,980	10,728	11,528	11,528	11,528	11,528	11,528	11,528	11,528	11,528
Cash collections for winter electricity sales "with project"	MUS$	141	168	230	462	573	706	958	1,210	1,527	1,928	2,434	3,073	3,880	4,898
Avoided loss of cash from winter electricity sales	MUS$	0	0	0	71	90	102	129	163	205	259	327	413	522	658
Summer electricity sales "without project	GWh	6,364	6,443	6,931	6,786	6,959	7,730	8,656	9,741	11,013	12,497	14,229	14,812	14,812	14,812

Summer electricity sales "with project"	GWh	6,364	6,443	6,931	6,786	6,959	7,730	8,656	9,741	11,013	12,497	14,229	15,674	15,503	15,335
Cash collections from summer electricity sales "without project"	MUS$	103	125	161	280	363	509	719	1,022	1,459	2,090	3,005	3,949	4,985	6,293
Cash collections from summer electricity sales "with project"	MUS$	103	125	161	280	363	509	719	1,022	1,459	2,090	3,005	4,178	5,217	6,516
Avoided loss of cash from summer electricity sales	MUS$	0	0	0	0	0	0	0	0	0	0	0	230	232	222
Summer electricity exports "without project"	GWh	1,304	1,304	1,304	4,017	3,901	3,988	3,988	3,988	0	0	0	0	0	0
Summer electricity exports "with project"	GWh	1,304	1,304	1,304	4,017	3,901	3,988	3,988	3,988	3,988	3,988	0	0	0	0
Avoided loss of cash from summer electricity exports	MUS$	0	0	0	0	0	0	0	0	3,988	3,988	0	0	0	0
Net financial benefits	**MUS$**	**-68**	**-34**	**-28**	**41**	**87**	**99**	**126**	**160**	**4,190**	**4,244**	**324**	**640**	**751**	**878**
NPV	**MUS$**	**$25,979**													
FIRR	**%**	**23.1%**													

MAP


TAJIKISTAN
NURÉK HYDROPOWER REHABILITATION PROJECT
MAIN CITIES AND TOWNS
REGION CENTERS
AUTONOMOUS REGION CENTER*
NATIONAL CAPITAL
RURAL DISTRICTS (RAIONS)
AUTONOMOUS REGION BOUNDARIES*
REGION BOUNDARIES
INTERNATIONAL BOUNDARIES
KAZAKHSTAN
UZBEKISTAN
KYRGYZ REP.
CHINA
AFGHANISTAN
PAKISTAN
SUGHD REGION
DISTRICTS OF REPUBLICAN SUBORDINATION
DUSHANBE
KHATLON REGION
KŪHISTONI BADAKHSHON AUTONOMOUS REGION
Khujand
DUSHANBE
Nurek HPP
Kulob
Kurghonteppa
Khorugh
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