The World Bank

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Report No: 71622-VN

PROJECT APPRAISAL DOCUMENT

ON A

PROPOSED CREDIT
IN THE AMOUNT OF SDR297.7 MILLION (US$448.9 MILLION EQUIVALENT)

AND A
PROPOSED LOAN FROM THE CLEAN TECHNOLOGY FUND
IN THE AMOUNT OF US$30 MILLION

TO THE

SOCIALIST REPUBLIC OF VIETNAM

FOR A

DISTRIBUTION EFFICIENCY PROJECT

August 14, 2012

Vietnam Sustainable Development Unit
Sustainable Development Department
East Asia and Pacific Region

CURRENCY EQUIVALENTS

(Exchange Rate Effective as of July 31, 2012)

Currency Unit

US$1.00 VND 20,870

SDR1.00 US$1.51

VIETNAM – GOVERNMENT FISCAL YEAR

January 1 – December 31

ABBREVIATIONS AND ACRONYMS

AusAID	Australian Agency for International Development	kV	Kilovolt
AMI	Advanced metering infrastructure	kVA	Kilovolt- Ampere
AUD	Australian Dollar		
BAU	Business as usual	kWh	Kilowatt hour
BST	Bulk Supply Tariff	LDU	Local Distribution Utility
CO_2	Carbon dioxide	LV	Low Voltage
CPS	Country Partnership Strategy	M&E	Monitoring and Evaluation
CPC	Central Power Corporation	MoF	Ministry of Finance
CTF	Clean Technology Fund	MoIT	Ministry of Industry and Trade
DMS	Detailed Measurement Survey	MONRE	Ministry of Natural Resources & Environment
DA	Designated Account	MPI	Ministry of Planning and Investment
DER	Debt to equity ratio	MV	Medium Voltage
DP	Displaced Person	MW	Megawatt
DSCR	Debt Service Coverage Ratio	NPC	Northern Power Corporation
EA	Environmental Assessment	PC	Power Corporation
ECOP	Environmental Codes of Practice	PCom	Power Company subsidiary of a PC
EIRR	Economic Internal Rate of Return	PFRP	Policy Framework for Resettlement Plans
EMF	Environmental Management Framework	POM	Project Operations Manual
EMDP	Ethnic Minority Development Plan	PDMP7	Power Development Master Plan 7
EMP	Environmental Management Plan	PMU	Project Management Unit
ERAV	Electricity Regulatory Authority of Vietnam	RE	Renewable energy generation
EVN	Vietnam Electricity	ROW	Right of Way
FMR	Financial Monitoring Report	RP	Resettlement Plan
FIRR	Financial Internal Rate of Return	SBV	State Bank of Vietnam
GOV	Government of Vietnam	SCADA	Supervisory Control and Data Acquisition
GDP	Gross domestic product	SEDP	Socio-Economic Development Plan
GHG	Greenhouse gas	SEM	Strategy for Ethnic Minorities
HCM PC	HCM City Power Corporation	SFR	Self Financing Ratio
HNPC	Hanoi City Power Corporation	SB	Single Buyer
IAS	International Accounting Standards	SPC	Southern Power Corporation
ICB	International Competitive Bidding	TA	Technical Assistance
ICM	International Creditors' Model	TOR	Terms of Reference
IDA	International Development Association	TWh	Terawatt hours (1TWh= 1 billion kWh)
IDC	Interest During Construction	VAS	Vietnam Accounting Standards
IPP	Independent Power Producer	VND	Vietnam Dong

PROJECT ABBREVIATIONS

CPEE	GEF Clean Production and Energy Efficiency Project (GEF TF099859)
PSRDPO1	First Power Sector Reform Development Policy Operation (Loan 7868 and Cr 4711)
PSRDPO2	Second Power Sector Reform Development Policy Operation (Loan 8147 and Cr 5082)
REDP	Renewable Energy Development Project (Cr. 4564)
RD	Rural Distribution Project (Cr. 4444 and AusAID grant TF080590)
RE2	Second Rural Energy Project (Cr. 4000 and GEF TF054464)
SEIER	System Efficiency Improvement, Equitization and Renewables Project (Cr. 3680 and GEF TF051229)
SEIER AF	System Efficiency Improvement, Equitization and Renewables Project - Additional Financing (Cr. 4781)
TD2	Second Transmission and Distribution Project (Cr. 4107)
TD2 AF	Second Transmission and Distribution Project – Additional Financing (Ln 8026)

Regional Vice President:	Pamela Cox
Country Director:	Victoria Kwakwa
Sector Director:	John A. Roome
Sector Manager:	Jennifer Sara
Task Team Leaders:	Hung Tien Van and Beatriz Arizu de Jablonski

VIETNAM
Distribution Efficiency Project

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PAD DATA SHEET

Vietnam

Distribution Efficiency Project

PROJECT APPRAISAL DOCUMENT

East Asia and Pacific

EASVS

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Basic Information	
Date: August 14, 2012	Sectors: Energy (100%)
Country Director: Victoria Kwakwa	Themes: Rural services and infrastructure (P)
Sector Manager/Director: Jennifer Sara/John Roome	EA Category: B
Project ID: P125996	
Lending Instrument: SIL	
Team Leaders: Hung Tien Van; Beatriz Arizu de Jablonski	
Does the project include any CDD component? No	
Joint IFC: No	

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Borrower: Socialist Republic of Vietnam			
Responsible Agency: Ministry of Industry and Trade and Vietnam Electricity (EVN)			
Contact:	Pham Le Thanh	Title:	President, EVN
Telephone No.:	84-4220139	Email:	GIANGNTL@EVN.COM.VN

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Project Implementation Period: 2012- 2018	Start Date: October 22, 2012	End Date: June 30, 2018
Expected Effectiveness Date: 15 January 2013		
Expected Closing Date: December 31, 2018		

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Project Financing Data(US$M)					
[ ]	Loans	[ ]	Grant	[x]	Other: CTF loan AusAID
[x]	Credit	[ ]	Guarantee		

For Loans/Credits/Others

Total Project Cost :	800.4	Total Bank Financing :	448.9

Total Cofinancing :	38.0	Financing Gap :	

Financing Source	Amount (US$M)
BORROWER/RECIPIENT	313.5
IBRD	0.0
IDA: New	448.9
IDA: Recommitted	
Others:	
Clean Technology Fund (CTF)	30.0
AusAID Trust Fund[1]	8.0
Financing Gap	
Total	800.4

Expected Disbursements (in USD Million)

Fiscal Year	2013	2014	2015	2016	2017	2018	2019		
Annual	10.0	40.0	110.0	150.0	120.0	40.0	8.9		
Cumulative	10.0	50.0	160.0	310.0	430.0	470.0	478.9		

Project Development Objective(s)

The project development objectives are to improve the performance of Vietnam's Power Corporations in providing quality and reliable electricity services, and to reduce greenhouse gas emissions through demand side response and efficiency gains.

Components

Component Name	Cost (USD) Millions)
Component (A): System Expansion and Reinforcement	621.7
Component (B): Introduction of Smart Grid Technologies in Distribution	92.8
Component (C): Technical Assistance and Capacity Building	10.5

Compliance

Policy

Does the project depart from the CPS in content or in other significant respects?	Yes [ ] No [x]

[1] *Note: (1) AusAID grant will be AUD 7.6 million. For the purpose of this Data Sheet, an indicative US$ equivalent of US$ 8 million is reflected, based on exchange rate on the last day of the month preceding negotiations (July 31,2012)(same date used to calculate IDA SDR amount)*

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Does the project require any exceptions from Bank policies?	Yes [ ]	No [x]
Have these been approved by Bank management?	Yes [ ]	No [ ]
Is approval for any policy exception sought from the Board?	Yes [ ]	No [x]
Does the project meet the Regional criteria for readiness for implementation?	Yes [x]	No [ ]

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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 Waters OP/BP 7.50		X
Projects in Disputed Areas OP/BP 7.60		X

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Legal Covenants

Name : *Subprojects*	**Recurrent**	**Due Date**	**Frequency**
IDA PA, Schedule, Section I.E.2,	yes	15 January 2015	

Description of Covenants
Not later than twenty-four (24) months after the Effective Date, identify and prepare all Phase 2 Sub-projects, and have such Sub-projects approved and cleared by the relevant authorities of the Recipient and appraised by the Association

Name *Financial model*	**Recurrent**	**Due Date**	**Frequency**
IDA PA, Schedule, Section II.4).	yes	15 January 2014	

Description of Covenants
The Power Corporations shall, not later than twelve (12) months after the Effective Date: (i) adopt a financial model, including an operational manual, in form and substance satisfactory to the Association, for the carrying out of financial analysis and planning and the establishment of key financial performance indicators; and (ii) carry out training of their core financial staff in relation to such model in a manner satisfactory to the Association.

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Team Composition

Bank Staff

Name	**Title**	**Specialization**	**Unit**	**UPI**
Hung Tien Van	Senior Energy Specialist	Task Team Leader	EASVS	
Beatriz Arizu de Jablonski	Senior Energy Specialist	*Co-TTL, Regulations and energy sector specialist*	EASWE	

Pedro Antmann	Senior Energy Specialist	*Metering, distribution utility and tariff specialist*	SEGEN	
Makoto Takeuchi	Senior Energy Specialist	*Smart Grid specialist*	EASWE	
Hung Tan Tran	Power Engineer	*Project Procurement Specialist/ Power Engineer*	EASVS	
Defne Gencer	Energy Specialist	*Energy Specialist*	EASWE	
Franz Gerner	Lead Energy Specialist	*Energy Coordinator*	EASVS	
Nghi Quy Nguyen	Social Specialist	*Social Safeguards*	EASVS	
Son Van Nguyen	Environmental Specialist	*Environmental Safeguard*	EASVS	
Vanessa Lopes Janik	Operational Analyst	*Gender*	SEGES	
Hanh Huu Nguyen	Financial Management Specialist	*Financial Management*	EAPFM	
Mai Thi Phuong Tran	Financial Management Specialist	*Financial Management*	EAPFM	
Miguel-Santiago Oliveira	Senior Finance Officer	*Disbursement*	CTRLN	
Thao Thi Do	Finance Analyst	*Disbursement*	CTRLN	
Sameena Dost	Senior Counsel	*Country Lawyer*	LEGES	
Ninh Quang Nguyen	Disbursement Specialist	*Disbursement*	EACVF	
Joel J. Maweni	Operations Adviser	*Corporate finance*	EASSD	
Teresita G. Velilla	Program Assistant	*Project Assistance*	EASIN	
Cristina Hernandez	Program Assistant	*Project Assistance*	EASWE	
Dung Kim Le	Team Assistant	*Project Assistance*	EASVS	
Lien Thi Bich Nguyen	Program Assistant	*Project Assistance*	EASVS	
Richard J. Spencer	Country Sector Coordinator	*Peer Reviewer*	SASDE	
Leopoldo Montanez	Senior Energy Specialist	*Peer Reviewer*	LCSEG	
Ashish Khanna	Senior Energy Specialist	*Peer Reviewer*	SASDE	

Non Bank Staff

Name	Title	Office Phone	City
Rafael Cueto Stefani	AMI external reviewer	(809) 519-9171	Santo Domingo, Dominican Republic
Dan O'Hearn	Financial Consultant	66 (0) 2618-8800	Bangkok, Thailand

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Locations

Country	First Administrative Division	Location	Planned	Actual	Comments
National	National	Country wide	Country wide		

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I. STRATEGIC CONTEXT

A. Country Context

1. **Recent Economic Trends.** After a period of heightened turbulence, Vietnam's economy is gradually entering a more stable macroeconomic environment. Between 2007 and 2010, partial adjustments to a series of shocks, including a surge in capital flows, resulted in rising macroeconomic vulnerabilities evidenced by higher inflation, falling reserves, an increase in public and external deficits, and weaknesses in the banking and corporate sectors. The situation, however, begun to reverse after the Government introduced measures to stabilize the economy and to ensure social stability (Resolution 11, February 2011).

2. **Achieving macroeconomic stability remains the Government's key priority and the economy has begun to stabilize, after a significant tightening of macroeconomic policies over the course of 2011**. Real GDP growth decelerated in 2011 to 5.9 percent from 6.8 percent in 2010, as domestic demand slowed, affecting construction, services and utilities. Inflation declined to 5.4 percent year-on-year (y/y) in July 2012 from a peak of 23 percent (y/y) in August 2011. The current account deficit is estimated to have declined to 0.5 percent of GDP in 2011, from 4.1 percent in 2010, mainly due to a broad-based rebound in exports. The fiscal deficit (international definition) is estimated to have declined to 2.7 percent of GDP in 2011, down from 5.2 percent in 2010, which is lower than the budgeted 6.5 percent deficit due to higher-than-expected revenue performance and some adjustment to capital spending. After the 8.5 percent currency devaluation in February 2011, the unofficial exchange rate has remained close to the lower edge of the ±1 percent band around the central rate. Increased supply of US dollars has enabled the State Bank of Vietnam (SBV) to replenish foreign exchange reserves in the first two months of calendar year 2012, which reportedly is enough to finance nearly 10 weeks of imports.

3. **Credit growth has slowed markedly**, from 32.4 percent (y/y) at end-2010 to 14.3 percent (y/y) at end-2011. However, asset quality has deteriorated in part due to rapid credit growth before 2011. Official non-performing loans (NPL) have increased from 2.2 percent of assets at end-2010 to 8.6 percent in June 2012, but are likely to be higher if measured based on international standards. Monetary tightening has also added liquidity stress in some smaller banks. In response, the authorities have provided liquidity and other support to ailing banks, and issued a credit institution restructuring plan for 2011-2015 (Decision 254, February 2012). In 2012, economic growth is expected to be 5.7 percent and year-end inflation is forecasted to decline to below 10 percent.

4. **The Government is planning to step up restructuring efforts in state owned enterprises (SOEs), public investment and the financial sector,** to achieve greater efficiency and productivity to drive medium and longer term growth. Within the power sector, SOE restructuring is currently targeting the equitization of power generation and the creation of Generation Corporations consolidating the portfolio of power plants currently owned by Vietnam Electricity.

B. Sectoral and Institutional Context

5. ***General Background.*** Over the past decades, Vietnam has transformed from a primarily agricultural economy with a rural population to a mixed economy with substantial development of commercial and industrial activities and an urbanizing population that has increasing access to modern energy. Rapid urbanization, fast and sustained increase in energy consumption driven by the success of the electricity access program (leading to growing demand and productive uses in rural areas, which has contributed to poverty reduction), improvements in living standards and growing industrialization are at the core of Vietnam's development challenges in achieving energy security and sustainable growth in the power sector. At the same time, climate change represents a significant threat to economic and human development, and greenhouse gas (GHG) emissions have more than doubled over the past decade. Industry, power and transport sectors are projected to account for the bulk of future increases in GHG emissions. A number of Bank operations are providing support for energy efficiency to mitigate climate change, including the Vietnam Climate Change Development Policy Operation programmatic series and the Clean Production and Energy Efficiency GEF project.

6. ***Power sector structure.*** Vietnam Electricity (EVN), directly and through its subsidiaries, has played a dominant role in the power sector. EVN, which is organized as a holding company, is active in all electricity activities, and is the single wholesale purchaser from power generation. As of 2011, EVN held majority ownership of around 70 percent of installed generating capacity directly (e.g. strategic multi-purpose hydropower plants) and through its subsidiaries. Others, mainly Vietnamese SOEs and local private investors, own around 17 percent of power generation capacity as independent power producers (IPPs), and foreign-invested build-own-transfer (BOT) power plants around 13 percent of generating capacity. Transmission of electricity at 500 kV and 220 kV is under the ownership and responsibility of the National Power Transmission Corporation (NPT), an EVN subsidiary which was formed in July 2008.

7. Five EVN subsidiary Power Corporations (PCs) are responsible for electricity distribution and retail supply services within their franchise areas, at voltage levels of 110 kV and below, and purchase energy generated by power plants with capacity not greater than 30 MW. The PCs were established in early 2010 out of the existing 11 power companies, as part of the power sector restructuring objective to increase the scale and strengthen financial and corporate management capacity of the power distribution sub-sector. The five PCs are Hanoi Power Corporation (HNPC), Northern Power Corporation (NPC), Central Power Corporation (CPC), Southern Power Corporation (SPC), and Ho Chi Minh City Power Corporation (HCMPC). The PCs' subsidiary Power Companies (PComs) own and operate the medium-voltage (MV) and low-voltage (LV) distribution systems, which include urban and rural areas. As of 2011, about 75 percent of distribution networks supplying rural households are under PCs.

8. In the remaining rural areas, LV distribution and retail supply services are undertaken by local distribution units (LDUs), which purchase from PComs at regulated wholesale tariffs. The rural networks of financially weak LDUs are being transferred to PCs to rehabilitate and upgrade the distribution system and provide reliable and quality supply to improve living standards and support local economic development.

9. ***Electricity demand and supply.*** By the end of 2010, the total generation capacity in Vietnam's interconnected power system was 19.74 GW. Between 1995 and 2010, household electricity access rate increased from 50 percent to over 96 percent; and annual per capita electricity consumption increased from 156 kilowatt hours (kWh) to about 983 kWh. Industrial consumption is growing at a faster rate than the national average, and residential customers with rising disposable incomes are increasing consumption due to electrical appliance ownership. Investments in the power sector have been unable to keep up with demand growth to maintain adequate network capacity and generation reserve levels, leading to load curtailment, in particular during dry hydrology and high peak demand periods.

10. ***Supplying projected electricity demand growth.*** Electricity demand has grown fast, at an average annual rate of around 15 percent, between 2008 and 2010. The national Power Development Master Plan 7 (PDMP7), approved by the Prime Minister in 2011, projects a similar annual demand growth rate from 2011 to 2015, although consumption slowed down in 2011 to about 9 percent due to the macroeconomic situation. Supplying the projected electricity demand growth would require large volume of investments and would increase dependency on coal fired power generation. Consequently, electricity tariffs would require high increases and GHG emissions from power generation are expected to more than double. The power sector is facing the challenge of moving from quantity to quality of electricity access, securing sustainable and reliable electricity supply at competitive costs to support economic growth and poverty reduction, modernization and enhancement of power system efficiency and reliability, and promoting efficient use of electricity by customers to reduce investment needs and projected growth in GHG emission from the power sector.

11. ***Power sector reform.*** The Government of Vietnam's (GOV) power sector reform program was initiated by the Electricity Law, the power market roadmap approved by the Prime Minister and the creation of the Electricity Regulatory Authority of Vietnam (ERAV). Prime Minister Decision 21, issued in 2009, initiated electricity tariff reform, which lays out the regulatory framework for the determination of retail electricity tariffs based on (i) the unbundling of cost components, with tariff regulations dedicated to each component of the supply chain, incorporating efficiency and performance incentives and market based mechanisms to achieve cost reflective tariffs; (ii) better targeting of subsidies for the poor; and (iii) promoting demand side efficient use of electricity. In particular, the Vietnam Distribution Code issued in 2010 governs the connection, planning and operation procedures and performance standards for PCs' distribution and retail services, and the standards, rights and obligations for customers or distribution network users of PCs. Additionally, the Government has established a special regulatory framework for small renewable energy (RE) generation, whereby PCs are mandated to provide priority dispatch and purchase electricity from RE at a regulated avoided cost tariff and under a standard power purchase agreement. The Bank is supporting these GOV policy initiatives and regulations through the ongoing Power Sector Reform Development Policy Operation series and the Renewable Energy Development Project, combined with an active policy dialogue.

12. ***Institutional setting.*** The Ministry of Industry and Trade (MoIT) is the line ministry for the power sector.

(a) Within MoIT and directly under its Minister, since 2006, ERAV has been responsible for licensing; development of and monitoring compliance with technical codes and performance standards for distribution and transmission, electricity tariff regulations, the electricity market rules, as well as measures for supply security, including demand response.

(b) MoIT was restructured in 2011 to create the General Directorate of Energy (GDE), combining all state management functions for the energy sector, including an energy efficiency department and a renewable energy department.

13. ***Efficient use of electricity and demand side response.*** Demand-Side Management (DSM) and Energy Efficiency (EE) activities were initiated in Vietnam in 1997, when EVN, with the Bank assistance, commissioned the "Demand-Side Management Assessment for Vietnam". This Assessment concluded that DSM could play a significant role in managing the growth of electricity demand in Vietnam. Since 2006, ERAV has taken the lead on load research and demand side activities in the power sector. ERAV has also been assigned the responsibility to develop the overall smart grid program for Vietnam, to increase efficiency in the power sector, and implement efficient pricing in electricity tariffs and demand response programs. The adoption of demand response programs and the reduction of electricity demand elasticity coefficient[2] from the current 2.0 to 1.0 by 2020 are specific targets in PDMP7.

14. ***Enhancing efficiency and modernization in electricity distribution.*** Historically, PCs' efforts have focused on rural electrification and the rehabilitation and upgrading of distribution systems to eliminate bottlenecks, reduce high technical losses in rural areas, and improve reliability and quality of service. Reported average annual total distribution losses at the end of 2010 were 8.08 percent for HNPC, 6.03 percent for HCMPC, 6.03 percent for NPC, 7.1 percent for CPC, and 6.04 percent for SPC. However, the PCs' average losses are increasing, in particular with the absorption of previously LDU-owned LV networks which are in need of rehabilitation. The challenge facing PCs is shifting from connecting as many consumers as possible, to ensuring good quality supply through modern and efficient investment and operation of existing infrastructure, and promotion of efficient use of electricity.

15. The GOV recognizes that there is a need for modernization of the power system to support achieving energy security and power sector efficiency. The Law on Energy Efficiency and Conservation (EE&C Law) calls for energy savings in all economic sectors and requires the power sector to develop programs, plans and roadmaps to reduce electricity losses and improve efficiency in distribution systems.

16. PDMP7, which identifies power sector investments required for the next five to 10 years for reliable supply, instructed the development of a smart grid roadmap for transmission and distribution. Upgrading and expansion of the distribution system, combined with modernization

[2] Similar to practices in other power sectors, PDMP7 longer term demand projections are based on elasticity coefficients which relate electricity consumption to GDP growth rate. Historically, elasticity coefficients for electricity consumption have been significantly higher than 1.

and enhancing planning and operation of PCs' systems, are critical for achieving sustainable and secure electricity supply at the lowest possible costs. The demonstration of quantified contributions to energy security, cost reductions and avoided GHG emissions, which will be achieved by the modernization of PCs' systems and operations, and development of power sector regulations for smart grids, efficient pricing and demand response programs, would have a transformational impact on the future of Vietnam's power sector. This impact will be particularly significant in terms of the future investments to be made in the sector, the efficiency with which end users manage their electricity consumption, and the preparation of adequate conditions to accommodate an increasing share of small RE.

17. In view of these challenges and the need for modernization, the five PCs have expressed interest in receiving financial and technical support from the Bank to improve efficiency in the distribution system and business operations, and ERAV has requested continued support for its regulatory activities. Accordingly, the proposed project would contribute to addressing (i) interruptions and low quality of power supply due to distribution system constraints and faults; (ii) the need to improve efficiency and maintain low losses in the management of electricity distribution systems; (iii) the low degree of distribution automation and the unmet need for modernization; (iv) the lack of real time information in key points of the distribution system and consumption, to optimize distribution system planning and operation; (v) the need for further enhancement of the tariff reform program, including the absence of demand-side response or control programs and lack of adequate pricing signals in time-of-use tariffs; and (vi) the shortage of funds for investments to keep up with increasing demand.

C. Higher Level Objectives to which the Project Contributes

18. The project will contribute to meeting the objectives of the National Energy Development Strategy guiding the power sector up to 2020 (Prime Minister Decision, December 2007) to reduce investment needs in the power sector, strengthen energy security, control and mitigate environmental pollution in energy activities and foster socioeconomic sustainable development. The project will also contribute to the implementation of the Socioeconomic Development Plan (SEDP) 2011-2015, which aims for sustainable economic growth on the basis of improving quality, effectiveness and competitiveness.

19. The project is linked to the Bank's new Country Partnership Strategy (CPS) for the period FY12-FY16, supporting the competitiveness and sustainability pillars. The distribution efficiency investments and modernization aspects in the proposed project will contribute to the competitiveness pillar through improving the quality and efficiency of electricity infrastructure and services. Reduction of losses and financing smart grid technologies in power distribution, combined with technical assistance on electricity tariffs and demand response programs, will contribute to mitigation of climate change under the CPS sustainability pillar.

II. PROJECT DEVELOPMENT OBJECTIVES

A. PDO

20. The project development objectives are to improve the performance of Vietnam's Power Corporations in providing quality and reliable electricity services, and to reduce greenhouse gas emissions through demand side response and efficiency gains.

21. The global objective is to reduce GHG emissions through avoided power generation by reducing electricity losses in PC distribution systems and reducing electricity consumption of large electricity consumers.

B. Project Beneficiaries

22. The main and primary beneficiaries are the Power Corporations of Vietnam, and the Electricity Regulatory Authority of Vietnam (ERAV).

23. The secondary beneficiaries are electricity consumers that will benefit from better quality and more reliable electricity supply, enabling productive uses of electricity for both women and men and the use of electrical appliances in households to improve the quality of their lives and access better public services.

C. PDO Level Results Indicators

24. The following key indicators are proposed to assess the achievement of the PDO:

(a) reliability of power supplied by PCs, monitored through the System Average Interruption Duration Index (SAIDI), and the System Average Interruption Frequency Index (SAIFI) in the project area;

(b) quality of power supplied, monitored through voltage excursion outside of ±5 percent at the outlet of 110 kV substations in the project area;

(c) PCs' total losses in the project area; and

(d) reduction in electricity consumption by PCs' consumers with Advanced Metering Infrastructure (AMI) compared to a business-as-usual (BAU) "without the project" scenario; and

(e) avoided greenhouse gas emissions by NPC, CPC, HNPC and HCMPC.

25. The indicator for avoided GHG emissions will be calculated as avoided power generation, and will be based on two indicators above, namely PC's total losses and reduction in electricity consumption. As generation scheduling and dispatch in Vietnam prioritizes hydropower and other RE, the impact will be calculated as avoided thermal power generation.

III. PROJECT DESCRIPTION

A. Project Components

26. The proposed Distribution Efficiency Project (DEP) would be comprised of three components: (A) System Expansion and Reinforcement; (B) Introduction of Smart Grid Technologies in Distribution; and (C) Technical Assistance and Capacity Building. The description and objectives of each of these components are summarized below.

27. **Component (A): System Expansion and Reinforcement.** This component will cover construction and reinforcement of 110 kV, MV and LV electricity distribution networks, including substations, of the PCs. These investments will help the PCs to efficiently meet load growth, address load supply constraints due to distribution system congestion, reduce losses, and improve reliability and quality of power supply.

28. **Component (B): Introduction of Smart Grid Technologies in Distribution.** This component, which includes Clean Technology Fund (CTF) co-financing, will focus on (i) automation, through introduction of supervisory control and data acquisition systems, of electricity distribution network operations of and data collection by the PCs; and (ii) introduction of AMI systems, including two-way communication systems, as electricity distribution smart grid technologies for key substations and consumers of selected PCs.

29. Supporting the first stage of the roadmap for smart grid technologies for power distribution in Vietnam, the component will assist to increase efficiency, reliability and effectiveness of the PCs' systems and operations, and optimize distribution system configuration by providing real-time data from both the supply and the demand side. Combined with technical assistance and regulatory enhancement support under Component C, the AMI investments will enable efficient pricing of electricity and implementation of demand response programs to encourage reductions in electricity consumption compared to business-as-usual (BAU) "without the project" scenario. These, in turn, should lead to reduction of investments in the distribution system, decrease in operating costs, improvements in efficiency, reliability and quality of distribution services, and avoidance of GHG emissions associated with avoided thermal power generation.

30. **Component (C): Technical Assistance and Capacity Building.**

(a) Provision of technical assistance to and capacity building of ERAV for improvement of efficiency in electricity tariffs, enhancement of efficiency of and incorporation of smart grid technologies in the grid and distribution codes, integration of renewable energy in the grid and distribution codes, development of demand response and smart grid programs, and Project management and monitoring and evaluation.

(b) Provision of technical assistance to the PCs for: (a) effective and timely Project implementation, capacity building in relation to financial modeling and planning, and carrying out of customer surveys and instituting of other such measures to improve customer satisfaction; and (b) implementation of advanced metering infrastructure systems, carrying out of programs promoting efficient electricity use such as a customer awareness campaign and demand response programs, and Project monitoring and evaluation.

31. Building on the technical assistance and capacity building under on-going Bank projects and the Bank support to power sector reform and tariff regulation,[3] Component C will complement the investment in the previous two components through building capacity and implementing arrangements to maximize improvements in PCs' efficiency and achieve reductions in demand compared to BAU, to achieve project development objectives and indicators. A grant from the Australian Agency for International Development (AusAID) under the AusAID-World Bank Strategic partnership in Vietnam (ABP) will finance activities described in the paragraph 29 (a) and 29(b) that will contribute to climate change mitigation through efficiency gains in power distribution and avoided power generation. Further details are provided in Annex 2.

B. Project Financing

Lending Instrument

32. The lending instrument would be a Specific Investment Loan (SIL). The terms for the IDA credit (SDR 297.7 million-US$448.9 million equivalent) will correspond to Blend IDA, with a 25 year maturity, including a 5 year grace period, a service charge of 0.75%, and interest of 1.25% per annum.

33. The CTF loan of US$30 million is extended under harder concessional terms. The CTF loan is offered with a service charge of 0.75% per annum on the disbursed and outstanding loan balance and 20-year maturity, including a 10-year grace period, with Principal repayments at 10% for Years 11-20. Principal and service charge payments accrue semi-annually. A management fee equivalent to 0.45% of the total loan amount (US$135,000) will be charged, to be capitalized from the loan proceeds, following the effectiveness of the loan The AusAID support under Component C will be provided in the form of a grant with a value of AUD 7.6 million.

Project Cost and Financing

34. Total project financing requirement is estimated to be US$800.4 million equivalent, including 5 percent for physical contingencies and 10 percent for price contingencies, interest during construction, and front-end-fee. Out of the total project financing, US$448.9 million equivalent would be financed by an IDA Credit, US$30 million by a CTF loan, AUD 7.6 million (US$8 million equivalent at exchange rate July 31, 2012) by AusAID grant, and US$313.5 million, which includes interest during construction, through counterpart funds of the PCs. Table 1 provides a breakdown of project costs and financing, by component and financing sources.

[3] In addition to the Bank close policy dialogue, the Bank Power Sector Reform Development Policy Operation series is supporting the government power sector reform program, including as two of the 4 thematic policy areas, tariff reform policy actions and improving the efficient use of electricity. The third operation includes as proposed triggers the adoption of performance based rate setting regulations for PCs, and initiating demand response pilot program.

Table 1 – Project costs and financing sources

Project Component	Project cost	Counterpart Funds	CTF (2)	AusAID (1)	IDA Financing	% of Costs Financed IDA
	(US$m)	(US$m)	(US$m)	(US$m)	(US$m)	
A. System Expansion and Reinforcement	528.5	173.0			355.5	67%
B. Introduction of Smart Grid Technologies in Distribution	78.9	29.5	25.5		23.9	30%
C. Technical Assistance and Capacity Building	10.5	0.0		8.0	2.5	25%
Total Baseline Costs	617.9	202.5	25.5	8.0	381.9	62%
Physical contingencies (5%)	35.6	11.8	1.5		22.3	62%
Price contingencies (10%)	71.5	23.8	3.0		44.7	62%
Total Project Costs	725.	238.1	30.0	8.0	448.9	62%
Interest During Construction	75.4	75.4				
Total Financing Required	800.4	313.5	30	8.0	448.9	56%

Note: (1) AusAID grant will be AUD 7.6 million. For the purpose of this Table, an indicative US$ equivalent of US$8 million is reflected, based on exchange rate on the last day of the month preceding negotiations (July 31,2012, (same date used to calculate IDA SDR amount).
Note: (2) The capitalized CTF management fee of US$135,000 is not separately identified.

C. Lessons Learned and Reflected in the Project Design

35. <u>A clear roadmap, with objectives focused on the most pressing needs, is essential for the success of supporting a program</u>. One of the noteworthy aspects and key factors of success of the Bank's support to Vietnam's rural electrification program was the assistance provided to the GoV in the formulation of a clear roadmap. Similarly, the Bank has been providing support to the PCs and ERAV for the development of smart grid roadmaps, financed through the ongoing Rural Distribution (RD) and the System Efficiency Improvement, Equitization and Renewables (SEIER) projects. The PC distribution smart grid roadmap developed under RD envisages a phased approach, prioritizing in its first stage the most cost-effective investment opportunities and the required policy and regulatory support mechanism. Components B and C of the proposed project start the implementation of this roadmap through financing AMI for the larger electricity consumers of four PCs and distribution automation, while also providing the supporting technical assistance. The success of this component, and lessons learned from its monitoring and evaluation framework, will drive the next stages of the roadmap and the replication of AMI and demand response programs countrywide.

36. <u>Project design must ensure rapid start-up</u>. In Vietnam, a critical challenge is to ensure rapid project start-up and disbursement. To ensure a fast start up and based on experience in previous power distribution projects, the project has been designed in two phases, with the first consisting of subprojects appraised and ready for implementation upon Board approval. The project design requires that Phase 2 subprojects should be ready for implementation by mid-term review or funds will be re-allocated, thereby ensuring flexibility, allowing the use of cost savings or shifting of funds between subprojects and creating incentives for timely implementation by PCs.

37. Consultation with local communities and strong commitment from local authorities are essential for implementing power distribution projects. Experience with previous distribution projects shows that the processes of land acquisition and compensation are the main causes of delays. Experience also shows that carrying out good participatory consultations with all the stakeholders and civil society, and building a strong commitment from the local authorities enable faster implementation and ensures compliance with social safeguards. Accordingly, during project preparation, significant attention was dedicated to engaging local communities and authorities from the outset, and advancing the analysis, participatory processes and preparations for land acquisition and compensations.

38. Combining capacity building and technical assistance with investment strengthens sustainability. As demonstrated in the technical assistance grant under RD, PCs have been receiving capacity building support for corporate development, awareness of smart grid options and benefits, and enhancing their capabilities to assess and decide technical options and for project planning and preparation. Under SEIER, the technical assistance provided to ERAV has been the channel through which critical support is provided to the power sector reform program, in particular tariff reform and introduction of reliability indicators and performance standards. Component C of the proposed project will not only support and demonstrate the success of Component B but also transfer knowledge and enhance sector regulations to continue development after the project.

IV. IMPLEMENTATION

A. Institutional and Implementation Arrangements

39. The project has six Implementing Agencies (IAs), namely the five PCs (NPC, CPC, SPC, HCMPC and HNPC) and ERAV. MoIT has delegated the responsibility for overall coordination of PCs' project implementation to EVN. A Project Operations Manual (POM) was prepared by MoIT, and will serve as the operational manual to guide each IA during project implementation.

40. Under Components A and B, project implementation will be the responsibility of the Project Management Unit (PMU) of each PC. As has been the practice under previous Bank distribution projects, the PMU can delegate works for a Component A subproject to the PCom in the corresponding location that will operate and maintain the infrastructure once completed. Details of project implementation arrangements are available in Annex 3.

41. Under Component C:

(a) ERAV will implement Component C through a PMU with staff experienced in Bank procurement and project implementation, through their involvement in the SEIER funded assistance supporting regulatory development. To ensure timely implementation, it has been agreed that ERAV will start preparing and submitting procurement documents for Bank no objection before the grant becomes available.

(b) An overall technical assistance and capacity building plan will be agreed for all five PCs. In each PC, the PMU will be designated to implement and coordinate selected activities in the plan, to ensure that workload is not excessive for one PC and that similar capacity building is achieved by all PCs.

B. Results Monitoring and Evaluation

42. Monitoring of project implementation progress, as well as progress toward the achievement of project objectives and results indicators will be the responsibility of ERAV and the PCs, as IAs. During project preparation, the Bank task team agreed with ERAV that regulatory monitoring of the Vietnam Distribution Code will cover the project reliability indicators, including information collection and results assessment on validity of data and calculation.

43. **Support will be provided to PCs and ERAV to implement the monitoring and evaluation (M&E) framework for the project.** To ensure adequate design and implementation of the M&E framework, various kinds of support are being provided under ongoing projects and will continue as part of the proposed project. These are summarized below.

(a) Under the ongoing RD project, the PCs are receiving AusAID-funded capacity building support for the development and implementation of M&E frameworks.

(b) Through an AusAID grant mobilized for the preparation of the project, consultants will be contracted to prepare the M&E framework.

(c) Activities to be funded under Component C include support for the implementation of the M&E framework, and reporting on progress towards achievement of indicators, including progress in the technical assistance.

C. Sustainability

44. The key to sustainability is to ensure that PCs increase their efficiency; that benefits of investments exceed their costs; and that efficient and reasonable costs are recovered from electricity consumers' tariffs. The Bank is closely engaged in policy dialogue and is supporting the Government's power sector reform program and its sector regulatory framework, including (i) specific tariff regulations for bulk supply sales to PCs, for transmission and for distribution services, and regulations to calculate average retail electricity tariffs adding the regulated cost components; and (ii) rules and technical codes promoting efficiency and increasing transparency. The tariff reform program, which is supported through Component C, is designed to increase cost transparency and to strengthen PCs' sustainability by establishing distribution tariff regulations that link PCs' financial performance to their efficiency, implementing standards and incentives for improving efficiency, monitoring compliance with the Distribution Code, and promotion of smart grid and demand response programs that reduce investment needs and achieve efficiency gains.

45. At the project level, MoIT, ERAV, EVN, and the PCs have shown their determination to improve the efficiency of the distribution sub-sector through their interest and willingness to modernize and apply smart grid technologies. The PCs have demonstrated their commitment and ownership of the project as evidenced by their proactive response during preparation of subprojects for Phase 1 and broad participation in training workshops. Based on their experience, each PC has identified the priority subprojects that offer the best returns and efficiency gains.

46. Additionally, Component C will provide technical and regulatory expertise and capacity building activities to transfer knowledge and support successful and sustainable PCs distribution services, tariff regulation, effective demand response and smart grid programs. These will contribute to reducing investment needs and operating costs, strengthening supply security and supporting the government's overall targets in reducing energy consumption and associated GHG emissions. Demonstrating such impacts will be the driving factor for broad replication. Additionally, the project will enable EE opportunities towards efficient use of electricity, that will be supported by EE financing in complementary projects, including IFC EE project co-financed by CTF under the Clean Energy Financing Facility.[4]

V. KEY RISKS AND MITIGATION MEASURES

A. Risk Ratings Summary Table

Stakeholder Risk	**Moderate**
Implementing Agency Risk	
- Capacity	**Moderate**
- Governance	**Moderate**
Project Risk	
- Design	**Moderate**
- Social and Environmental	**Moderate**
- Program and Donor	**Low**
- Delivery Monitoring and Sustainability	**Low**
-	
Overall Implementation Risk	**Moderate**

B. Overall Risk Rating Explanation

47. The risks that would be faced by the project have been assessed through the Operational Risk Assessment Framework (ORAF) in Annex 4. The IAs have experience and performed satisfactorily in previous Bank projects, except for Hanoi PC, which has experience under other donor projects but not with the Bank. The Bank procurement and FM risk assessments were completed and the associated risks were rated as moderate with proposed mitigation actions described in this document and Annex 4. At the project level, special additional training has been provided to Hanoi PC during preparation and will continue during implementation. Technical assistance and capacity building will provide PCs with expert support to implement the AMI, and to ERAV and PCs on design, implementation and enhancements of demand response programs. Combined with Bank implementation support, the monitoring and evaluation

[4] The projects includes US$30 million allocation from CTF of which US$28 will be used to co-finance with IFC setting up EE credit lines with commercial banks; US$1.5 million to provide advisory services to the participating banks as well as support market development activities. The remaining US$0.5 million is earmarked for program supervision and monitoring. The project supports sector benchmarking studies, development of training programs for bankers, and development of partnership between banks and technical service providers/equipment suppliers.

framework and associated technical assistance will ensure that each IA monitors the progress of the project carefully, to address any delays in implementation. Given the assessment and the mitigation measures, the overall project risk is assessed to be moderate.

VI. APPRAISAL SUMMARY

A. Economic and Financial Analyses

48. The economic analysis for the project was carried out considering two scenarios: with the project; and without the project.

49. For Component A, the "with" project scenario results in the following benefits: increase in power supply; reduction of losses; and improvement of quality of supply enabling productive use of electricity, and avoidance of spending money on quality improvement devices, such as voltage stabilizers or standby diesel units. The "without" project scenario corresponds to no investment for the rehabilitation and expansion of the distribution system, leading to further overloads in the systems; increase in losses; consumers choosing not to use grid power for productive uses due to major voltage fluctuations; and no opportunity for new connections for either domestic or productive uses.

50. For Component B, the main expected benefits are better reliability and quality of distribution services provided by PCs through optimized configuration of distribution network, faster detection and response to outages; reduction of distribution losses; lower rates of equipment damage and maintenance costs; enhanced operations due to timely availability of reliable information; reduction of staff and maintenance costs; and SCADA and AMI projects resulting in net reductions of GHG emissions compared to the "without" project scenario, as a consequence of avoided power generation due to better network configuration and reductions in consumption.

51. The project financial returns are calculated at constant 2012 prices, and compared to the PC's weighted average cost of capital (WACC). Wholesale energy purchased at the project boundary is valued at the estimated 2012 bulk supply tariff applicable for the PC. The financial benefits to the PCs are based on the average retail electricity tariff in the project area. Where these are not known, the PC-wide average was used. Where projects encompass only the upgrading of 110 kV or MV infrastructure, if benefit is claimed for additional sales at LV then the costs of the additional future LV capital investment is added. Where these costs are not known for the specific project area, they are estimated based on the total capital expenditure breakdown of the PC or the PCom (according to the applicable PC plans).

52. The analysis shows that each PC has the incentive to carry out the subprojects within its area. The analysis shows that all Phase 1 subprojects are economically efficient with average EIRR 29.2 percent, and robust to increases in costs of over 150 percent and decreases in demand of over 30 percent. All subprojects are financially efficient and most are robust to changes in cost and demand, although several subprojects are close to being financially unviable and sensitive to changes in cost and demand or both. The financial returns of individual subprojects are all satisfactorily above the 6 percent WACC hurdle rate, though a few are in the range 6-10 percent. A combined sensitivity analysis for all Phase 1 subprojects was also carried out for the

same key parameters, under pessimistic assumptions. The results show that even in the worst case, the project is still financially viable, with the combined FIRR of 13.1 percent. Further details are provided in Annex 6.

53. **Financial Assessment of PCs**. The five Power Corporations, three of which merged previous distribution power companies, have been in existence for only two full fiscal years and it was not possible to fully analyze their historical or future performance. However, financial analysis was carried out based on available data for the largest power companies that merged to form NPC, SPC and CPC. The PCs differ significantly in terms of their operating scales and service areas and costs but, despite the application of national uniform retail electricity tariffs, their financial performance over the 2006–2010 period was broadly similar and mostly in compliance with Bank legal financial covenants under ongoing projects. The similarity in performance has been due to EVN historical internal practice of establishing different bulk supply tariffs (BST) for each PC in sales from EVN parent company (as Single Buyer), with the purpose of compensating for differences in PCs' costs and customer mix. Under the tariff reform program, ERAV is drafting BST regulations under a similar principle, to ensure that bulk supply costs of each PC reflect the power generation and transmission costs recovered from approved electricity tariffs, and that the PCs' financial performance depends exclusively on the efficiency in their investments, operation and customer services. However, as the BST regulation is still not in place and after the Single Buyer (SB) registered losses in 2010 due to higher power generation costs, EVN modified their internal approach and increased BST to transfer part of the SB losses to PCs. Consequently, based on very preliminary information, it is expected that the PCs will report net losses for 2011, although still not significant relative to the PCs' scale of operation. The introduction of a transparent and cost-reflective regulation for setting bulk tariffs and distribution services tariffs of PCs by mid 2013, combined with the regulatory and financial enhancement support under Component C, will ensure that the PCs' future financial situation will depend only on the efficient performance of their distribution business. In addition to the TA provided under the project, the ongoing policy dialogue under the sector development program lending series will mitigate the risks of delayed or non-implementation of tariff regulations. These efforts together with other sector-wide TA support on financial performance issues will assist the PCs to remain in sound financial condition in the future. Further details are provided in Annex 6.

B. Technical

54. **The technical design of the project is considered to be sound**. Under Component A, the PCs have completed comprehensive feasibility studies for all Phase 1 subprojects, and decisions for Phase 2 subprojects will be based on similar studies. The PC feasibility studies are reviewed and approved by the relevant government agencies, and reviewed by the Bank. The individual subprojects meet accepted international standards. Subprojects under Component B, particularly the AMI, are included in Phase 2 and the PCs will mobilize experienced international consultants to assist with preparation of technical design and implementation.

C. Financial Management

55. **Bank assessment has concluded that the Project meets the minimum Bank financial management requirements, as stipulated in BP/OP 10.02.** The Financial Management Specialist concluded that the IAs would maintain adequate financial management arrangements acceptable to the Bank and, as part of the overall implementation arrangements, provide reasonable assurance that the proceeds of the IDA credit, CTF loan and AusAID grant will be used for the purposes for which these will be provided. The following main actions were required and have already been completed: (i) appointment of a qualified project chief accountant at each IA; and (ii) internal audit function following ToR acceptable to the Bank. Further details are available in Annex 3.

D. Procurement

56. Procurement would be carried out following the World Bank's *"Guidelines: Procurement of Goods, Works, and Non-Consulting Services under IBRD Loans and IDA Credits & Grants by World Bank Borrowers"* dated January 2011; and *"Guidelines: Selection and Employment of Consultants under IBRD Loans and IDA Credits & Grants by World Bank Borrowers"* dated January 2011, and the provisions stipulated in the legal agreements. General arrangements for procurement under the project and the Procurement Plans for the first 18 months have been submitted and Bank review completed, as described in Annex 3. The agreed Procurement Plans and all subsequent updates will be published in the Bank's external website and appropriate publications by the PCs or ERAV, as applicable.

57. Procurement capacity assessments carried out by the Bank found that all IAs have adequate institutional and organizational capacity to carry out procurement under their respective components and subprojects. The PCs and ERAV have been implementing Bank-financed procurement satisfactorily in several other projects, except for HNPC, which has experience in procurement with other ODA financed projects. The major procurement risks identified are: (i) as this is the first time HNPC is participating in a Bank project, it may need some time to be fully familiar with the Bank Guidelines and requirements; and (ii) there may be delays at all stages of the procurement cycle caused by internal bureaucratic approval procedures and workload under other PCs' procurement. Specific mitigation measures include intensive training, especially for HNPC, and adoption of a Project Operational Manual. Training activities started during project preparation. Further information is provided in Annex 3.

E. Social (including Safeguards)

58. The project will contribute significantly to the achievement of longer-term social development goals of Vietnam. As PCs will upgrade and expand the distribution system and improve efficiency, enhance the quality and reliability of power supply services, reduce electricity losses, and improve the performance and accessibility of electricity distribution services, the project will contribute to enhancing the effectiveness of the poverty reduction program, the reduction of the current gap in equality of access to services among regions, and the consolidation of social security. In the project areas, the improvements will support meeting local development objectives such as accelerating economic and social development, increasing

productive uses of electricity, and improving quality of life and expanding access to better public services.

59. ***Gender and Poverty***. The project will benefit residential households, including women who rely on electricity to carry out domestic functions. The reliable supply of electricity will reduce the need to switch to more polluting and health damaging alternative fuels (e.g. kerosene) for cooking. A Bank executed AusAID grant will support a targeted gender and poverty assessment to identify needs and potential activities to improve the PCs' provision of quality and reliable electricity services in an equitable way. An impact assessment will cover a survey to interview both men and women in project areas, including selected rural communes with households receiving lifeline tariffs for the poor. The findings of this survey and assessment will be linked throughout the project where relevant and agreed, to help ensure that project implementation and project beneficiaries are equitably reaching and impacting both men and women and the poor. The impact assessment, planned to be carried out in 2013 as a part of the survey on the impact of rural electrification, will also provide inputs to future distribution projects.

60. ***Involuntary Resettlement (OP 4.12).*** The project Component A triggers the Bank's safeguard policy on Involuntary Resettlement (OP 4.12). Subprojects would have low-intensity impacts involving some temporary or permanent loss of agricultural, orchard, garden or residential land to tower foundations, substations and line stringing, and minor land acquisition impacts. As typically found in distribution projects, the social impacts are scattered over the project areas and a number of Project Affected Households (PAH), but the impact on an individual PAH is normally marginal and limited to the acquisition of a few m^2 of land, or cutting down of a few trees. In a few cases, residential or other buildings may be affected but impacts on houses will be mostly partial and generally are not likely to require the relocation of families outside their residential plots. Land acquisition and resettlement process will involve public consultation and satisfactory compensation and livelihood restoration. The Resettlement Policy Framework (RPF) has been prepared laying down the principles and objectives, eligibility criteria of displaced persons (DP), modes of compensation and rehabilitation, potential relocation of these persons, participation features and grievance procedures. In consistency with the RPF, 36 Resettlement Plans (RPs) have been prepared for subprojects of the first phase. Further details are available in Annex 3.

61. ***Indigenous Peoples (OP 4.10).*** The project triggers the Bank's safeguard policy on Indigenous Peoples (OP 4.10), referred to for the case of Vietnam as Ethnic Minorities (EM). It has already been identified that for some of the subprojects agreed for Component A, EMs would be affected. However, given that other subprojects are still to be defined after the project starts implementation and that the geographical area of the PCs covers all provinces in the country, it is possible that other EM households may be affected. Although the impacts will be very local and affect primarily individual households, other social impacts may include: (i) the re-grouping of a relative large number of outside workers to an EM locations may cause social disorder or disputes between the local community and the workers; and (ii) the improvement and building of new MV and LV will necessitate acquisition of land currently used by the local EM people. The Ethnic Minority Development Plans (EMDPs) have been prepared for Phase 1 subproject and disclosed. These EMDPs aim to maintain the potential positive benefits and mitigate the adverse impacts from the project. An Ethnic Minority Planning Framework (EMPF) has been prepared,

ensuring that the implementation of the subprojects fully respects the dignity, human rights, economies, and culture of affected EM peoples. Broad community support obtained for the subproject through a process of free, prior, and informed consultations with the affected EM communities will be confirmed by PCs. In this regard, the EMPF sets out guidelines to: (a) ensure that the EM people receive social and economic benefits that are culturally appropriate; (b) avoid potentially adverse effects on the EM communities; and (c) when such adverse impacts cannot be avoided, minimize, mitigate, or compensate for such effects. Further details are available in Annex 3.

F. Environment (including Safeguards)

62. ***Applicable World Bank Environmental Safeguard Policies.*** The project triggers the Bank safeguard policy on Environmental Assessment (OP/BP 4.01). The project will not affect natural habitats, protected areas and forest and forest-dependent communities, as interventions will be limited to construction and rehabilitation of power lines and substations. Since the project mainly involves small scale construction and rehabilitation of existing distribution lines and substations, impacts are assessed to be moderate, localized, and temporary, and can be mitigated through the application of good construction and management practices. Therefore, *the project is rated environmental category "B"*. Details of the assessment including mitigation measures, consultation and disclosure are available in Annex 3.

63. ***Environmental Assessment (OP/BP 4.01).*** This policy is triggered due to expected negative impacts of subprojects, mainly during the construction due to typical civil works such as new construction, rehabilitation, and expansion of distribution lines (power towers, poles, and wiring) and substations (transformers and other electrical equipment).

64. ***Environmental Management Framework (EMF)***. As the project will be implemented in phases, an EMF has been prepared to ensure that activities to be financed under the project would not create adverse impacts on the local environment and local communities, and that the residual and/or unavoidable impacts will be adequately mitigated. The EMF establishes the requirements for sub-project screening, assessing and managing environmental and social impacts during project implementation, and describes mitigation measures as well as the institutional arrangements for safeguards implementation. The EMF contains the applicable Bank safeguard policy requirements as well as the Vietnamese regulation on environmental impact assessment and other related laws and regulations. The EMF also includes standardized Environmental Codes of Practice (ECOP) to be applied to subprojects as mitigation measure for construction management.

65. ***Environmental Management Plan (EMP)***. The EMF also provides guidelines for the preparation of the EMP for individual subprojects, and requires subprojects to comply with the Bank and the Government regulations on Environmental Impact Assessment (EIA). Appropriate parts of the ECOP will be included in the bidding and contract documents, and will be closely monitored by supervision engineers. The EMPs for first phase subprojects have been prepared following the EMF guidelines, reviewed by the Bank and found to be satisfactory. The same procedures will apply to future subprojects during implementation.

66. ***Safeguard Implementation, Monitoring, and Training.*** The PCs as IAs will be responsible for the preparation and supervision of EMF implementation. During project implementation, the PC's PMUs will be responsible for preparing and ensuring the effective implementation of environmental safeguard measures (such as EMPs, ECOP, etc) and regular liaison with local authorities and communities. There will be regular reporting on safeguard implementation. The PMUs, contractors, construction supervision consultants and local community representatives will receive training on the safeguard instruments to be applied to the project. The capacity building activities will be covered by the implementation support plan of the project.

67. ***Public consultation and information disclosure***. The Bank safeguard policies require the PCs and their respective PMUs to facilitate public consultation and information disclosure, including consultation with project affected people (PAPs) and local NGOs. The EMF process includes two rounds of meaningful and participatory consultations with local communities to discuss the project's impacts and proposed impact management, with the participation of PC staff, representatives of MoIT, EVN, and local consultants. During the preparation of subprojects' EMPs, public consultations with civil society were carried out at each subproject area, including people and households directly or indirectly affected, local authorities, and public organizations. The final draft EMF and subproject EMPs take into consideration the feedback from consultations. The draft final EMF, the draft EMPs of the first phase subprojects have been disclosed both locally (at the Vietnam Development Information Center, EVN, the PMU of each PC, and subproject areas in the corresponding province), and through the InfoShop in Washington, DC.

68. ***Governance.*** The project will contribute to improving governance through strengthening ERAV and the predictability of the tariff regulatory framework, making greater information available to electricity consumers, and improving the relationship between PCs and their customers, in particular through addressing the needs of both large and small consumers. The implementation of AMI will enable a better accountability of usage and losses, and lead to prevention of non-technical losses. Through the combination of investments and technical assistance support, the project will also enhance transparency in tariff setting, and contribute to the design and implementation of effective demand response programs and tariff structures, as well as effective awareness campaigns and two-way communications between PCs' operation centers and large customers.

Annex 1: Results Framework and Monitoring

VIETNAM: DISTRIBUTION EFFICIENCY PROJECT

Project Development Objective (PDO): To improve the performance of Vietnam's Power Corporations in providing quality and reliable electricity services, and to reduce greenhouse gas emissions through demand side response and efficiency gains

PDO Level Results Indicators*	Core	Unit of Measure		Cumulative Target Values**							Frequency	Data Source/ Methodology	Responsibility for Data Collection	Description (indicator definition etc.)
			2011 Base Line		2013 Start	2014	2015 Midterm Review	2016	2017	2018 Completion				
Indicator on Reliability														Average duration of sustained interruptions per consumer during the year, measured in units of time (minutes or hours). SAIDI = (Total duration of sustained interruptions in a year) / (Total number of consumers)
1.1 System Average Interruption Duration Index (SAIDI) in project areas, calculated as in Distribution Code (1)														
											At project appraisal, Midterm review, and Completion	Semi- annual progress reports of IAs and PCs' operation reports. ERAV Distribution Code monitoring documents.	PCs	
NPC		Minutes	5,145			5,048	4,947	4,848	4,751	4,656				
CPC			3,631			3,506	3,436	3,367	3,300	3,234				
SPC			6,958			5,990	5,871	5,753	5,638	5,525				
HCM PC			1682			884	716	581	472	384				
HNPC			299			297	296	294	293	291				
Indicator on Reliability														Average number of sustained interruptions per consumer during the year. SAIFI = (Total
1.2 System Average Interruption Frequency Index (SAIFI) in project areas calculated as in Distribution Code (1).											At project appraisal, Midterm review, and Completion	Semi- annual progress reports of IA, PC operation reports. ERAV	PCs	

NPC		Times	19.80			19.42	19.20	19.00	18.83	18.65		Distribution Code monitoring documents.		number of sustained interruptions in a year) / (Total number of consumers)
CPC			23.53			22.72	22.26	21.82	21.38	20.95				
SPC			24.30			23.40	22.90	22.50	22.00	21.60				
HCM PC			7.62			4.47	3.82	3.29	2.86	2.50				
HNPC			1.73			1.71	1.70	1.69	1.68	1.67				
Indicator on Power Quality														A short-term increase in voltage, lasting up to a few seconds or decrease in voltage lasting longer than a few seconds.
2. Voltage excursion outside +/-5% at 110kV/MV transformers, in project areas		Times/ year									At project appraisal, Midterm review, and Completion	Semi- annual progress reports of IAs and PCs' operation reports. ERAV Distribution Code monitoring documents.	PCs	
NPC		Times/ year	60			56	52	48	44	40				
CPC			0			0	0	0	0	0				
SPC			25			12	10	7	5	4				
HCM PC			0			0	0	0	0	0				
HNPC			0 (automatic control)			0	0	0	0	0				
Indicator on Total Distribution Losses														
3. Losses in project areas											At project appraisal, Midterm review, and Completion	Semi- annual progress reports of IAs and PCs' operation reports. ERAV	PCs	
NPC		%	24.38	24.38	24.38	20.48	16.59	13.99	12.69	11.39				
CPC			13.58	13.58	13.58	12.62	11.67	11.03	10.71	10.39				

SPC			10.24	10.24	10.24	9.45	8.66	8.13	7.86	7.60		Distribution Code monitoring documents.		
HCM PC			7.86	7.86	7.86	7.15	6.44	5.97	5.74	5.50				
HNPC			19.00	19.00	19.00	16.90	14.80	13.40	12.70	12.00				
4. Indicator consumption reduction for AMI consumers (2)														
NPC		GWh	0.0	0.0	0.0	28.0	96.0	144.9	162.7	181.6	Midterm review and Completion	Semi- annual progress reports of IA, and PCs' operation reports and M&E reports	Participating PCs	
HCM PC			0.0	0.0	0.0	17.3	58.0	85.9	94.9	104.3				
HNPC			0.0	0.0	0.0	11.1	37.5	56.1	62.4	69.1				
CPC			0.0	0.0	0.0	9.3	31.8	47.6	53.3	59.1				
TOTAL NPC, HCM PC, HNPC and CPC			0.0	0.0	0.0	65.7	223.3	334.5	373.3	414.1				
Avoided GHG (3)														
NPC		Tons CO2	0			18,213	62,405	94,190	105,775	118,015	Midterm review and Completion	Semi- annual progress reports of IAs and PCs' operation reports. M&E reports by IAs	Participating PCs	
HCM PC			0			11,262	37,726	55,835	61,698	67,818				
HNPC			0			7,212	24,406	36,446	40,528	44,890				
CPC			0			6,026	20,638	30,956	34,671	38,425				
TOTAL NPC, HCM PC , HNPC and CPC			0			42,712	145,175	217,427	242,672	269,148				

INTERMEDIATE RESULTS

Intermediate Result indicator for Component A:			**2011 Base Line**	**2012**	**2013 Start**	**2014**	**2015 Midterm Review**	**2016**	**2017**	**2018 Completion**				
Implementation progress of 110 kV lines														
												Semi-annual progress reports of IA, and PCs' operation reports	PCs	
NPC					10	25	60	80	90	100				
CPC					10	25	60	80	90	100				
SPC		% constructed			10	25	60	80	90	100	Annual			
HCM PC					10	25	60	80	90	100				
HNPC			-		10	25	60	80	90	100				
Implementation progress of 110 kV substations														
												Semi-annual progress reports of IA, and PCs' operation reports	PCs	
NPC					10	25	60	80	90	100				
CPC					10	25	60	80	90	100				
SPC		% constructed			10	25	60	80	90	100	Annual			
HCM PC					10	25	60	80	90	100				
HNPC			-		10	25	60	80	90	100				
Implementation progress of 35/22/0.4 kV Lines														
												Semi-annual progress reports of IA, and	PCs	
NPC					10	25	60	80	90	100				
CPC		% constructed			10	25	60	80	90	100	Annual			
SPC					10	25	60	80	90	100				

HCM PC					10	25	60	80	90	100		PCs' operation reports		
HNPC					10	25	60	80	90	100				
Implementation progress of 35/22/0.4 substation														
											Annual	Semi-annual progress reports of IA, and PCs' operation reports	PCs	
NPC		% constructed			10	25	60	80	90	100				
CPC					10	25	60	80	90	100				
SPC					10	25	60	80	90	100				
HCM PC					10	25	60	80	90	100				
HNPC					10	25	60	80	90	100				
***Intermediate Result indicator for Component B*:**														
Implementation of progress of AMI System											Annual	Semi-annual progress reports of IA, and PCs' operation reports	Participating PCs	
NPC		% installed	0				50	100						
HCM PC							50	100						
HNPC							50	100						
CPC							50	100						
Implementation progress of SCADA system														
											Annual	Semi-annual progress reports of IA, and PCs' operation reports	Participating PCs	
NPC		% implemented			10	40	80	100						
CPC					10	40	80	100						
SPC					10	40	80	100						
HCM PC					30	60	80	100						
HNPC														

***Intermediate Result indicator for Component C*:**														
												Semi-annual progress reports of IA M&E reports	PCs and ERAV	
PCs		% of TA				30	70	100						
ERAV						30	60	100			Annual			

Baseline / BAU Demand of AMI customers (2)		**2011 Base Line**	**2012**	**2013 Start**	**2014**	**2015 Midterm Review**	**2016**	**2017**	**2018 Completion**	
NPC	GWh	15,044	17,183	19,626	22,416	25,602	28,981	32,546	36,312	at project appraisal
HCM PC		9,954	11,115	12,412	13,860	15,477	17,180	18,984	20,867	
HNPC		6,184	6,976	7,869	8,876	10,013	11,214	12,470	13,812	
CPC		4,984	5,690	6,496	7,416	8,467	9,525	10,668	11,823	

Notes:

(1) The definition and calculation methodology for SAIDI and SAIFI are specified in the Vietnam Distribution Code, and exclude interruptions outside the control of PCs as listed in Distribution Code Article 13, such as those caused by failure of upstream transmission system or generation shortage. SAIDI and SAIFI will be calculated considering the interruptions to PC customers connected in the project area.

$$SAIDI_j = \frac{\sum_{i=1}^{n} T_i K_i}{K}$$

$$SAIDI = \sum_{j=1}^{4} SAIDI_j$$

Ti: Duration of interruption/outage "i" (longer than 5 minutes) in quarter J.

Ki: The number of Users and Distributor and retailer who buy the electricity from the Distributor and are impacted by interruption/outage "i" in quarter J
n: The total number of interruption/outage longer than 5 minutes in quarter j.
K: The total number of User, Distributor and retailer who buy the electricity from Distributor in quarter j

$$SAIFI_j = \frac{n}{K}$$

$$SAIFI = \sum_{j=1}^{4} SAIFI_j$$

n: The total number of interruption/outage longer than 5 minutes in quarter j.
K: The total number of User, Distributor and retailer who buy the electricity from Distributor in quarter j

(2) Reduction of consumption compared to business as usual (without the project scenario) will be calculated as actual annual PC sales to AMI targeted customers minus business as usual consumption for that year. Business as usual scenario is determined from a baseline corresponding to actual 2011 PC sales to the customers where AMI will be implemented, plus forecasted demand growth at the time of appraisal as shown in table below.

Indicators in the results framework calculated with reductions from 2014 onwards, as follows: 2014 0.13%, (50% of AMI implemented), 2015 0.38% (implementation of AMI completed); and 0.5% remaining years

(3) Avoided GHG will be calculated for PCs with AMI using Vietnam generation conversion factor (indicators in the results framework have been calculated with current 0.65 tCO_2/MWh), estimating avoided power generation equal to demand reduction. Consumption reduction calculated as described in the previous bullet.

Annex 2: Detailed Project Description

VIETNAM: Distribution Efficiency Project

1. The Distribution Efficiency Project (DEP) would be comprised of three components: (A) System Expansion and Reinforcement; (B) Introduction of Smart Grid Technologies in distribution for system modernization and efficiency; and (C) Technical Assistance and Capacity Building. The following paragraphs cover the description and objectives of each component. Further details on subprojects are provided in project supporting documents.

2. **Component (A): System Expansion and Reinforcement (*estimated cost US$621.7 million, of which US$383.6 million equivalent would be financed by IDA.*** This component will cover the construction and reinforcement of 110 kV, MV and LV distribution networks, including lines and substations, of the PCs. These investments will help the PCs to efficiently meet load growth, address load supply constraints due to distribution system congestion, reduce losses, and improve reliability and quality of power supply.

Table A2.1 Component A: Costs (by PC and Total, US$ million)

Component A	NPC	SPC	CPC	HCM PC	HNPC	Total 5 PCs
Phase 1						
110 kV System	29.0	56.1	42.9	73.9	7.3	209.2
35/22/0.4 kV system	24.7				33.0	57.7
Total Phase 1	53.7	56.1	42.9	73.9	40.3	266.9
Phase 2						
110 kV System	25.1	62.9	53.0	49.0	9.3	199.3
35/22/0.4 kV System	120.7				34.8	155.5
Total Phase 2	145.8	62.9	53.0	49.0	44.1	354.8
TOTAL	**199.5**	**119.0**	**95.9**	**122.9**	**84.4**	**621.7**
IDA	**146.4**	**78.2**	**65.5**	**28.5**	**65.0**	**383.6**

3. **Component (B): Introduction of Smart Grid Technologies in Distribution (*estimated cost US$92.8 million, of which US$62.8 million equivalent would be financed by IDA, and US$30 million by CTF*).** This component will focus on the automation of distribution network operations and introduction of advanced metering infrastructure systems (AMI) at key substations and electricity consumers of PCs, in order to start the implementation of the first stage of the roadmap for smart grid for power distribution. The component will assist to increase efficiency, reliability and effectiveness of the PCs and optimize distribution system configuration by providing data and processed information both from the supply side and demand side during real time operation. The component will include the infrastructure for load profiling and customer

two-way communication that, combined with technical assistance under Component C, will enable efficient pricing of electricity and demand response programs to encourage reductions in electricity consumption. These, in turn, should lead to reduction in investments in the distribution system, decrease in operating costs, improve reliability and quality of distribution services, and avoid GHG emissions associated with avoided thermal power generation.

4. The PCs have been building capacity to implement the regulations under the Government power sector reform program, including service obligations and performance indicators in the Vietnam Distribution Code, and expected performance based rate setting (PBR) for distribution services tariffs. In addition to traditional investments covered in Component A, PCs need to maximize efficiency, provide reliable and quality supply, and accommodate the increase in small scattered renewable energy generation, such as small scale hydropower, solar, and wind farms.

5. To respond to these challenges, the PCs need to modernize and benefit from smart grid technologies for the reliable and efficient planning, management and operation of the power distribution system. There are a number of key activities that will need to take place to ensure successful deployment of the smart grid, but at a high level the deployment can be split into two stages. The first stage should focus on the most cost-effective investment decisions that address the short and medium term PC challenges combined with key supporting programs and regulations to maximize benefits. The second stages focuses on scaling up the demonstration and lessons learned in the first stage to the smart grid across all PCs' distribution systems. This includes not only monitoring and evaluating the deployment, but also the enhancement of regulations and programs to continue to maximize benefits.

6. Component B will support the first stage of the smart grids roadmap for PCs through two types of investments: (i) distribution automation (DA) and data collection through Supervisory Control and Data Acquisition (SCADA); and (ii) advanced metering infrastructure systems (AMI) as distribution smart grid technology, including two-way communications to enable demand response programs. These investments will provide data (in real-time or short term near real time) on the state of the distribution system and consumption, to be analyzed and presented in a way that is useful for the PC's distribution system operator to remotely control and respond to events and optimize the operation of the distribution system, as well as to incorporate consumers' response.

7. ***Distribution automation*** is beneficial in day-to-day operation and maintenance of the distribution system. Through remote and automated controls, major benefits from DA can include proactive problem detection and faster response to system emergencies (higher reliability); meeting required quality of service and achieving faster electricity supply restoration time (customer satisfaction); reduction in losses due to better system configuration (higher efficiency and increased revenues); strategic decision making during real time operation with reductions in equipment damage (cost reductions and increased revenues); better availability of system information improving operational and business planning, and remote load control.

8. ***The proposed AMI*** includes tools for the systematic gathering, storing, processing, analyzing and monitoring of information on consumption and loads in key substations, as well as two-way communication between the PC control center and its customers. The adoption of this smart grid technology will contribute to improving the PCs' operating efficiency and optimizing the configuration of the distribution network to reduce overloads (loss reduction); increasing the accuracy of billing, avoiding loss of revenue (revenue protection); enabling the load profiling of electricity consumers to improve load forecasting, optimize generation dispatch, enhance demand response programs and efficiency signals in tariffs to promote efficient use of electricity. In the future, these investments are also expected to improve load dispatching and system operation to facilitate the integration of small renewable energy generation connecting to the PC network. In all, the AMI subprojects are expected to lead to reductions in electricity consumption and investments in the distribution system, decrease in operating costs, improvement in reliability, and avoided GHG emissions associated with avoided thermal power generation.

9. Component B would support the initial deployment of the AMI, aimed mainly at demonstrating the costs and benefits, as well as at providing a learning opportunity for all PCs, EVN and ERAV. The PCs estimate that full scale deployment of advanced smart meters, which would imply the establishment of the necessary infrastructure for about 17 million customers, would require around US$1 billion. The CTF would co-finance AMI in three PCs, namely HNPC, NPC and HCM PC, and IDA will finance CPC. The AMI will cover key substations of the distribution system, bordering points, and large consumers representing about 1 to 2 percent of the total number of customers, a relatively small number of customers, but accounting for around 50-60 percent of the total electricity supplied. The AMI will comprise meter reading devices, data transfer system, data centers for collecting, storing and processing with smart data management software. In particular, the AMI will target real-time information flow between PCs' control centers and large consumers, underpinning new demand response programs and electricity tariff structure to match electricity use with supply costs. Further information including expected benefits in avoided GHG is provided in Annex 7.

Table A2.2 Component B Costs (by PC and Total, US$ million)

Component B	NPC	SPC	CPC	HCM PC	HNPC	Total 5 PCs
Automation	3.9	23.3	1.1	4.8		33.1
AMI	10.2		4.8	36.2	8.5	59.7
TOTAL	**14.1**	**23.3**	**5.9**	**41.0**	**8.5**	**92.8**
CTF(1)	**8.0**			**15.0**	**7.0**	**30.0**
IDA	**6.1**	**23.3**	**5.9**	**26.0**	**1.5**	**62.8**

Note: (1) The capitalized CTF management fee of US$135,000 is not separately identified.

10. **Component (C): Technical Assistance and Capacity Building (*estimated cost US$10.5 million, of which US$2.5 million equivalent would be financed by IDA and AUD7.6 million (US$8 million equivalent) under the AusAID-World Bank Strategic Partnership in Vietnam (ABP)*)**. Building on the technical assistance and capacity

building under on-going Bank projects and the Bank support to power sector reform and tariff regulation, this component would complement the investment in the previous two components through building capacity and developing implementing arrangements to maximize improvements in PC efficiency and achieve reductions in demand compared to BAU, to reach the project development objectives and indicators. The grant from the Australian Agency for International Development (AusAID) under the AusAID-World Bank Strategic partnership in Vietnam (ABP) will finance activities that will contribute to climate change mitigation through efficiency gains in power distribution, demand reductions and avoided thermal power generation.

Table A2.3 Component C Costs (by IA, Funding Source and Total, US$ million)

Component C	**NPC**	**SPC**	**CPC**	**HCM PC**	**HNPC**	ERAV	Total
AusAID (1)	0.48	0.38	0.38	0.38	0.38	6.0	8.0
IDA	0.5	0.5	0.5	0.5	0.5		2.5
Total	**0.98**	**0.88**	**0.88**	**0.88**	**0.88**	**6.0**	**10.5**

Note: (1) AusAID grant will be AUD 7.6 million. For the purpose of this Table, an indicative US$ equivalent of US$8 million is reflected, based on exchange rate on the last day of the month preceding negotiations (July 31,2012, same date used to calculate IDA SDR amount)

11. Under this Component, IDA and AusAID will finance technical assistance and capacity building to PCs, as summarized in Table A2.3:

- The IDA credit will finance technical assistance and capacity building to the PCs for effective and timely project implementation, capacity building on financial projections and modeling; and surveys and measures to improve customer satisfaction.
- The AusAID grant will support PCs in implementing AMI; programs to promote efficient use of electricity, including customer awareness campaigns and demand response programs; as well as monitoring and evaluation. Overall, this assistance will support Component B investments to implement programs contributing to avoided power generation and associated avoided GHG emissions, by reducing losses through a more efficient configuration and operation of the PC's distribution system, and lower electricity consumption compared to BAU.

12. Assistance to the PCs under Component C will build on the capacity building component under the Bank's ongoing Rural Distribution Project (RD) for the corporate development of PCs, to become participants in the future power market, develop financial management practices to act with greater autonomy, and to assess and decide on technical options and for investment project planning and preparation. The main source of funds under RD capacity building component has been the AusAID grant, which was divided equally among the three PCs designated as implementing agencies (at the time, PC1 which is now NPC, PC2 which is now SPC, and PC3 which is now CPC). In order to maximize the impact of the RD TA package and to ensure adequate capacity building for all PCs, the activities were discussed and agreed with implementing PCs; and training, technical assistance and workshops involve the participation of all PCs, with the

implementing PC acting as coordinator and leading the activity. A similar approach has been agreed for the proposed AusAID grant under Component C. Table A2.4 provides an overview of the TA and capacity building activities under RD and DEP.

Table A2.4 TA and Capacity Building for PCs

RD AusAID grant	DEP AusAID grant	DEP Component C: IDA
Methodology for economic and financial analysis of distribution projects and smart grid, and attributable GHG emission reductions.		
- Financial Analysis and Medium Term Financial Forecasting. - International Financial Reporting Standards (IFRS).		Capacity building on financial modeling and projections, including application for PC investment planning and distribution services tariff.
- Smart Grid roadmap for Vietnam Power Distribution. - Study tour to Brazil and Colombia success cases on AMI and efficient distribution. - Study tour to Japan on efficient distribution planning and operation.	- International expert support for AMI. - Expert support for load profiling activities. - Support to pilot demand response programs. - Customer awareness and dissemination campaigns.	
International training program for development of project monitoring and evaluation. (Canada)	Implementation of project M&E framework, including impact of AMI and DA and demand response to enhance and replicate, and tracking of indicators including avoided power generation and GHG emissions.	
Enhancing distribution and retail supply Customer Services		Customer satisfaction survey and measures to enhance PC relationship with customers.

13. Lessons learned from the Bank Demand-Side Management and Energy Efficiency Project (DSM/EE Project) identified that (i) load profiling activities are essential to assess and improve TOU tariff design and ensure adequate price signals to promote customers' changes in demand; (ii) demand response programs require supporting regulations for PCs; and (iii) TOU and demand programs need to be accompanied with customers awareness campaigns. Under Component C, the AusAID grant will provide support for ERAV to improve efficiency in electricity tariffs structure and TOU, adjust the grid code and distribution code to improve the efficiency of technical and performance standards, incorporate smart grid technology and the requirement for the reliable integration of small renewable energy, and to establish, monitor and enhance demand response and smart grid programs. Support will also cover the M&E framework to assess progress and

impact, and to enhance and improve effectiveness for broader replications, and project management.

14. The Bank is closely engaged in the power sector reform program through policy dialogue, the Power Sector Development Policy Operation program and technical assistance. Under SEIER, and since ERAV became operational, the Bank has been providing technical assistance and capacity building for the development of regulatory organizational structure and skills; conceptual market design and regulatory approaches; and drafting and consultation of power sector regulations, including tariffs. Table A2.5 summarizes areas of support under SEIER relevant to this project, and the continuation and further enhancement of those activities under the proposed Component C AusAID grant.

Table A2.5 TA and Capacity Building for ERAV

On-going SEIER	DEP Component C AusAID grant
Electricity tariff reform	**Efficiency in electricity tariffs**
- Retail electricity tariff methodology and performance based rate setting (PBR) for PCs. Modeling for PC PBR tariff setting. - Tariff advisor. - Guidelines for regulatory accounting and reporting for tariff setting. - Overall review of tariff framework and bulk supply tariff regulation. - Review and finalize regulation and detailed procedure for PC distribution charges calculation	- Review and improve efficiency of retail electricity tariff structure and bulk supply tariff structure. - Improving pricing for time of use tariffs, including use of load profiles. - Harmonizing electricity tariffs with demand response programs. - Enhancing efficiency and performance indicators of PCs PBR. - Tariff Advisor.
Technical codes, load research, demand response and smart grid programs	
- Development of Grid Code and Distribution Code. Operational procedures and monitoring for the implementation of Grid Code and Distribution Code. - Load research regulations. Load research implementation procedures. - Options for demand response programs. - Overall smart grid program for Vietnam power sector.	- Pilot regulations for demand response programs. - Enhance demand response programs and draft final regulations. - Enhance load research activities and monitoring changes in consumption and load patterns. - Enhance technical codes efficiency, incorporating smart grids and integration of renewable energy generation. - Detailed design of first phase of smart grid roadmap for Vietnam power sector. - Awareness campaigns and dissemination. - Communication expert for ERAV to outreach to customers and develop communication capacity.
	M&E framework and reporting.
Capacity building	Capacity building
Project management support	Project management support

Phasing

15. The investment components will be implemented in two phases. The first phase consists of subprojects appraised and ready to start implementation upon the World Bank's Board of Executive Directors approval of the project. The second phase will consist of subprojects that are proposed to the Bank by the PCs when the preparation of all documents is completed, including the Investment Report, EMP, RP and, if required, EMDP. Financing for each subproject will be made available when the Bank appraisal has been satisfactorily completed. Subprojects will be appraised and financed on a first-come, first-appraised basis until all funds allocated to the component have been committed. Thus the number of subprojects to be financed for each PC will depend on the total IDA/CTF funds allocated to the PC. To be eligible, each subproject must meet the following criteria:

- The subproject will contribute to the objective of the project;
- The subproject meets the National Technical Standards;
- The subproject should have an economic rate of return of at least 10%, and a financial rate of return not less than 6 percent:
- Subproject's EAs, RPs, and EMDPs have been prepared and disclosed, satisfactory to the Bank to be consistent with the safeguard frameworks described in Annex 3, approved by the GoV, and adopted by PCs;
- All necessary clearance/ approvals to implement the subproject, including the investment report and environmental certificates, have been provided by the relevant agencies or authorities; and
- Procurement and implementation plans satisfactory to the Bank.

16. Indicative candidate subprojects for the second phase have been identified by PCs, but are still under discussion and can be subject to change. To minimize potential delays in Phase 2 and the project, it was agreed that (a) by December 2014 all subprojects proposed for Phase 2 must be identified, prepared and approved by the relevant authorities, and appraised by the Bank; (b) by Midterm Review, planned on the fourth quarter of 2015, the implementation progress of IAs will be reviewed and funds would be reallocated in case any IA or subprojects are delayed; and (c) any procurement package signed after December 2016 will be financed from the PC counterpart funds.

Items to Be Financed by IDA/CTF/ AusAID TF

17. In each subproject of Component A and B, IDA/CTF, as applicable, will co-finance the supply of goods, works, non-consulting services, consultant services, and training. Other costs such as engineering, compensation and administration will be financed by the PC from its own resources, or by local borrowing. The AusAID grant will co-finance Component C consultant services and capacity building activities, and support for M&E framework. Additionally, the AusAID grant will finance ERAV project management.

- Component A: IDA financing for the 5 PCs.

- Component B: IDA for the 5 PCs, and CTF co-financing for AMI investments of NPC, Hanoi PC and HCMC PC.   In the case of the latter 3 PC's, CTF will be drawn down first
- Component C: AusAID grant for ERAV; IDA and AusAID grant financing for the 5 PCs as described in Table A2.3.

Annex 3: Implementation Arrangements

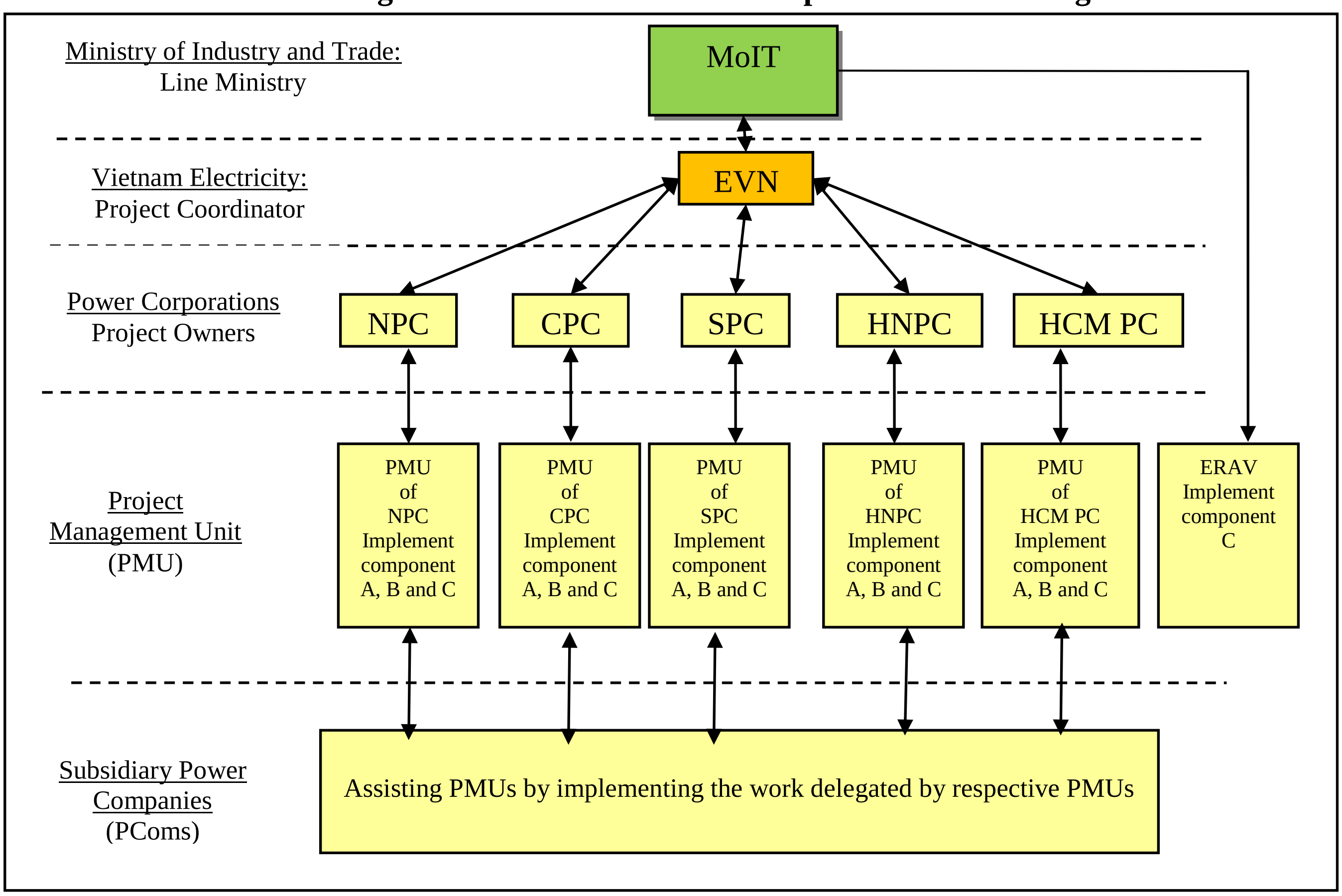
VIETNAM: Distribution Efficiency Project

Project Implementation Arrangements

1. The project will be implemented by six Implementing Agencies (IAs), namely : (i) Northern Power Corporation (NPC), in charge of power distribution in 27 provinces in the northern region of Vietnam, except Hanoi City; (ii) Central Power Corporation (CPC), in charge of power distribution in 13 provinces in the central region of Vietnam; (iii) Southern Power Corporation (SPC), in charge of power distribution in 21 provinces in the southern region of Vietnam, except HCM City; (iv) Hanoi Power Corporation (HNPC); (v) HCM City Power Corporation; and (vi) the Electricity Regulation Authority (ERAV) under the Ministry of Industry and Trade (MoIT). The PCs were established in 2010 within the restructuring of the power sector.[5]

2. The organizational structure of agencies and entities involved in the project is shown in Figure A3.1, and the responsibilities are described below.

Figure A3.1: Institutional and Implementation Arrangements



[5] MoIT Decision 789/QD-BCT established NPC, 738/QD-BCT HN PC, 739/QD-BCT CPC, 799/QD-BCT SPC, and 7689/QD-BCT HMC PC.

3. **The Ministry of Industry and Trade (MoIT)**, as the Line Ministry, is responsible for ODA projects in the power sector, including (i) preparing the project detailed outline, which is the basis for setting up the ODA Fund Request List, to be approved by GOV; (ii) conducting appraisal and making investment decisions (or approving technical assistance programs or project documents); (iii) monitoring the implementation of projects; and (iv) reviewing evaluation results of projects. Accordingly, MoIT will carry out such functions for this project.

4. The **Electricity Regulatory Authority of Vietnam (ERAV)** will implement the corresponding technical assistance and capacity building activities under Component C, and establish a Project Management Unit (PMU).

5. **Vietnam Electricity (EVN)** will act as the overall coordinator of the PCs. The PCs will provide status updates to EVN during project implementation in accordance with their internal procedures. EVN will coordinate as may be required with all Government agencies.

6. **The Power Corporations (PCs)** will participate in all three components of the project. Each PC will have the responsibilities of project owner and IA, including: (i) project preparation; (ii) appraising and approving subprojects, organizing the management and implementation of programs/projects; (iii) ensuring adequate and capable management resources; (iv) conducting appraisal and approval of technical design, total cost estimates and cost estimates of subprojects; (v) negotiating, signing and supervising the implementation of contracts; (vi) implementation of safeguards activities, and (vii) signing the onlending agreement with MoF for the loan and credit, and repaying loan and credit proceeds.

7. **Project Management Units (PMUs).** Each PC will assign to an existing PMU the responsibility for the project implementation, including procurement and contract supervision. All the PCs have PMUs with reasonably good experience in implementing ODA projects.[6]

8. **Power Companies (PCom).** Each PC has subsidiary power companies (PCom) providing distribution and retail supply services: for NPC, SPC and CPC in each province served, and for HNPC and HCM PC in every Quarter. When completed, Component A subprojects will be transferred to the respective PCom for operation and maintenance. As has been the practice in previous Bank distribution projects, the PC's PMU may delegate to the PCom (i) supervision of civil works implementation for rehabilitation and expansion of MV and LV; and (ii) supervision of implementation of RPs and EMPs, including coordinating with local authorities regarding the compensation and resettlement. Implementation of all 110kV subprojects and all procurement of goods will remain fully under the PMU.

[6] Although this will be the first World Bank-financed project for HNPC, PMUs in HNPC have extensive experience with other ODA projects.

9. In general, project implementation capacities of all IAs are reasonably good. The PCs have more than 15 years of experience working with the Bank, with the exception of HNPC that will be participating in a Bank financed project for the first time but has broad experience with other ODA projects. A number of PComs also have experience under previous Bank projects. To ensure smooth project implementation and strengthening capacities of PCs, particularly HNPC, a series of training activities were organized during project preparation including: (i) economic and financial analysis; (ii) procurement; (iii) financial management; and (iv) monitoring and evaluation. PC management and staff, including from subsidiary PComs, participated in the training activities.

Financial Management, Disbursements and Procurement

Financial Management

10. **Financial Management Assessment.** Each IA will be responsible for financial management of their project components. An assessment of the financial management arrangements carried out during preparation concluded that the financial management arrangements for the project are satisfactory. *A "Moderate" FM risk rating was assigned to the project.* The FM assessment identified the following potential risk: shortage of counterpart funds compared to the committed amounts for the Project. This risk will be mitigated by (i) written commitment from PCs and EVN to provide counterpart funds on a timely basis; and (ii) variance analysis being done through quarterly financial monitoring reports. Additionally, the required FM risk mitigation actions, agreed as summarized in Table A3.1, have been completed.

Table A3.1 FM risk mitigation actions

Required action	**Timing**
Qualified project chief accountant is appointed in each PMU. The CVs of the proposed Chief Accountants are to be approved by the Bank if they have not been involved in Bank projects before.	*Completed*
Appointing internal audit functions within each PC, with ToRs approved by the Bank.	*Completed*

11. **Budgeting and Planning**. The annual budget and operation plans will be prepared by PCs, approved by management and consolidated in the PCs' corporate budget, which will be acknowledged by EVN. The ERAV budgeting for the project will be embedded into the budgeting process for MoIT. Budgeting variances will be calculated and analyzed in the periodic management reports and progress reports prepared by the PMUs and reviewed by the management of PCs and MoIT/ERAV.

12. **Accounting System and Financial Reporting.** The accounting system including accounting policies, procedures and software of the PCs is adequate for project financial management. The current accounting system used in PCs is the Accounting System for Enterprises, which is regulated under Decision 15/2006/QD-BTC of the Ministry of Finance and is based on Vietnamese Accounting Standards (VAS). The Project will follow the Accounting System for Investment Projects promulgated under Decision 214 of the Ministry of Finance, which has been assessed as satisfactory for recording and reporting of the credit, loan and grant. Quarterly Interim Financial Reports following the

AMT templates will be submitted by the PCs and ERAV to the Bank within 45 days after the end of each quarter.

13. **Internal Controls.** Current internal control procedures at the PCs are adequate for project financial management. The management of the PCs will be responsible for ensuring that an adequate internal control framework and internal controls are in place and operating. MoIT will be responsible for ERAV internal controls.

14. **Internal Audit**. The internal audit function will be in place at the PMU of each PC. The internal audit function is not required for ERAV as it only implements a small component (US$6 million).

15. **External Audit.** The project financial statements and the PCs' Financial Statements will be audited on an annual basis in accordance with international financial standards, with statements and audit financial reports to be submitted to the Bank within six months of the end of the fiscal year. All audited financial statements are to be published according to the Bank's information disclosure policy.

Disbursement

16. **Funds Flow**. The primary disbursement method will be Advances. Designated Accounts (DAs) will be opened for each of the IAs to manage the funds from IDA, AUSAID and CTF separately as follows:

(a) For IDA, each of the five PCs will maintain a DA. The DA for each of the PC's will be segregated. As the financial management capacity is assessed as being satisfactory, the Report Based Disbursement method will be applied. The DAs will have a Variable ceiling based on a 6-month forecast. Training on report-based disbursement will be provided to HNPC. Other PCs are familiar with it through other Bank projects.
(b) For CTF, NPC, HCMPC and HNPC will each maintain a segregated DA and also use Report Based Disbursement. The DAs will also have a Variable Ceiling based on a 6-month forecast.
(c) For AusAID, ERAV will maintain a segregated DA for its activities under Component C (US$6 million). NPC will maintain a segregated DA for the activities under Component C implemented by the five PCs. The DAs will also have a Variable Ceiling based on a six-month forecast.
(d) All 10 DAs listed above will be denominated / opened in US dollars at a commercial bank under terms and conditions acceptable to the Bank.
(e) *Supporting documentation required for documenting eligible expenditures paid from the DAs* are the Interim Financial Reports (IFRs) and other documentation supporting the six month forecast justifying the cash flow requirement. The template of IFRs has been agreed with the Bank. The frequency for the submission of IFRs and reporting eligible expenditures paid from the DAs is quarterly. The Reimbursement, Special Commitment, and Direct Payment disbursement methods will also be available. Reimbursements would also be documented in IFRs. Direct Payments will be documented by Records. The

Minimum Application Size for Reimbursement, Special Commitment and Direct Payments for each entity will be specified in the Disbursement Letter as shown in the following table:

(US$ Equivalent)	**IDA**	**CTF**	**AusAID**
NPC	$3,000,000	$400,000	$150,000
CPC	$3,000,000		
SPC	$3,000,000		
HCMPC	$3,000,000	$400,000	
HNPC	$3,000,000	$400,000	
ERAV			$150,000

17. The Project will have a Disbursement Deadline Date (final date on which the Bank will accept applications for withdrawal from the borrower or documentation on the use of loan/credit/grant proceeds already advanced by the Bank) four months after the Closing Date. This "Grace Period" is granted in order to permit the orderly project completion and closure of loan/credit/grant accounts via the submission of applications and supporting documentation for expenditures incurred on or before the Closing Date. Expenditures incurred between the Closing Date and the Disbursement Deadline Date are not eligible for disbursement, except as otherwise agreed with the Bank.

18. Retroactive financing will be available under IDA only, for payments made prior to the Signing date of the IDA Financing Agreement but on or after October 1,2012, up to an aggregate amount not to exceed six million six hundred fifty thousand Special Drawing Rights (SDR 6,650,000) for Eligible Expenditures.

19. Table A3.2 details the allocation of IDA Credit and CTF loan cofinancing, as well as the AusAID grant.

Table A3.2: Allocation of the IDA Credit / CTF Loan / AusAID TF

Expenditure Category	**Amount of Credit and TF allocated**			**Total**	**% of Expenditures to be Financed (inclusive of taxes)**
	IDA (US$ m)	**CTF (US$ m) (2)**	**AusAID TF (US$ m) (1)**		
Goods, works, training, operating costs and services	448.9	30	8.0	486.9	**100%**
Of which:					
NPC	153	8	0.48	161.48	
CPC	71.9		0.38	72.28	
SPC	102		0.38	102.38	
HCM PC	55	15	0.38	70.38	
HNPC	67	7	0.38	74.38	
ERAV			6	6	
Total	448.9	30	8.0	486.9	

Note: (1) AusAID grant will be AUD 7.6 million. For the purpose of this Table, an indicative US$ equivalent of US$8 million is reflected , based on exchange rate on the last day of the month preceding negotiations (July 31,2012)(same date used to calculate IDA converted to SDR)
Note: (2) The capitalized CTF management fee of US$135,000 is not separately identified.

Procurement

20. **Procurement Capacity Assessment.** Four PCs have extensive experience of Bank procurement from previous Bank-financed projects.[7] Hanoi PC has extensive experience in procurement in other ODA-financed projects. ERAV has been satisfactorily performing procurement under the SEIER project and other ODA activities.

21. The Procurement Capacity and Risk Assessment (PCRA) of the IAs' capacity to implement procurement actions for the project been undertaken by the Bank reviewed the organizational structure for project implementation and the interaction between the staff and managers responsible for procurement, administration and finance departments. It also reviewed performance in implementation of procurement in other ongoing Bank financed projects.

22. The Bank review found that ERAV and the four PCs with experience of Bank financed projects have been implementing Bank procurement in a satisfactory manner. The review also found that all five PCs have procurement experience as well as institutional and organizational capacity in place to carry out procurement under their respective component/subprojects. The main procurement risks identified are listed below:

(a) as this is the first time HNPC is involved in a Bank project, it may need some time to adapt to the Bank procurement requirements and guidelines;

(b) delays might occur due to internal bureaucratic approval procedures and procurement understaffing given other procurement workload; and

(c) differences exist between the Vietnamese Law on Procurement and the Bank procurement policies and guidelines, and the tendency of PCs to follow the national procedures may result in slow decision making.

23. Based on the above assessment, *the overall project risk for procurement is moderate*. Corrective actions agreed for successful implementation of project procurement are summarized in Table A3.3. The results of the PCRA and agreed mitigation measures have been input into the Bank's P-RAM.

[7] PCs have participated in Rural Energy Projects (REI and REII), Rural Distribution Project (RD), System Efficiency Improvement, Equitization and Renewables Project (SEIER), and Second Transmission and Distribution Project (TD2)

Table A3.3: Actions for Project Procurement

	Actions	Responsible	Date of Completion
1	Prepare, finalize, and adopt a Project Operations Manual, to be the operational manual including a detailed procurement section.	PCs ERAV	Completed
2	Provide procurement training to PCs including the Bank's new Procurement Guidelines (version January 2011) and contract management training.	Bank	Conducted during preparation, to continue through implementation
3	Provide in-depth hands-on procurement training to Hanoi PC.	Bank	Conducted during preparation, to continue through implementation
4	Send key procurement staff of PCs to attend the procurement course organized by International Labor Organization in Italy.	PCs	Completed during preparation
5	Hire procurement and contract management consultants for some packages for procurement of modern technical equipment such as smart metering or SCADA system.	PCs	During implementation
6	Provide ad hoc procurement training during supervision missions and through comments and advice on procurement documents submitted to the Bank for prior review.	Bank	During Implementation

24. **Applicable Procurement Procedures.** Because of the project's technical and administrative nature, there will be multiple contracts for works, goods, and consultancy services. Procurement would be carried out in accordance with the World Bank's "Guidelines: Procurement of Goods, Works, and Non-Consulting Services under IBRD Loans and IDA Credits & Grants by World Bank Borrowers" dated January 2011 (the Procurement Guidelines); "Guidelines: Selection and Employment of Consultants under IBRD Loans and IDA Credits & Grants by World Bank Borrowers" dated January 2011 (the Consultant Guidelines); and the provisions stipulated in the legal agreements. For contracts procured through National Competitive Bidding (NCB), additional applicable provisions will be listed in the Legal Agreements.

25. **Procurement thresholds.** Applicable thresholds for each expenditure category, procurement methods and prior review are summarized in Table A3.4.

Table A3.4: Procurement Methods and Prior Review Thresholds

Expenditure Category	Contract Value (US$)	Procurement Method	Bank Prior Review
Goods	>=500,000	ICB	All contracts
	<500,000	NCB	First contract by each agency; and all contracts >= US$ 400,000
	<100,000	Shopping	First contract under each agency
	Any value	Direct Contracting	All contracts
Works	>=5,000,000	ICB	All contracts
	<5,000,000	NCB	First contract by each agency; and all contracts >= US$ 3,000,000
	<200,000	Shopping	First contract under each agency
	Any value	Direct Contracting	All contracts
Consultant Services	>=200,000	QCBS, QBS, FBS, LCS	First contract by each agency; all contracts >= US$ 200,000; and all SSS contracts.
	<200,000	QBS, FBS, LCS and CQS	
	Any value	SSS	
	Any value	Individuals Consultant	

Notes:	*ICB – International Competitive Bidding* *NCB – National Competitive Bidding* *QCBS – Quality and Cost Based Selection* *QBS – Quality Based Selection* *FBS – Fixed Budget Selection* *LCS – Least Cost Selection* *CQS – Selection Based on Consultants' Qualification* *SSS – Single (or Sole) Source Selection*

26. **Procurement Methods.** Works estimated to cost the equivalent or more than US$5 million per contract, and goods estimated to cost the equivalent or more than US$0.5 million per contract shall be procured through ICB. Domestic preference may apply only in the case of goods, but no preference shall be given for works. Smaller contracts procured through NCB shall follow procedures in Vietnam's procurement laws and regulations, but subject to modifications, waivers, and exceptions to be clarified in the NCB Annex of the Legal Agreements. Works and off-the-shelf goods of very small value (less than US$100,000 per contract) may be procured through Shopping. Direct Contracting may also be used in exceptional circumstances and with the Bank's prior agreement, as stated in the Procurement Guidelines.

27. With regards to consulting services of significant scope, Quality and Cost Based Selection (QCBS) would be used as the preferred method. Where QCBS is not suitable, other methods including Quality Based Selection (QBS), Least-Cost Selection (LCS), Selection based on Consultants' Qualifications (CQS), and/or Individual Consultants may be used depending on the specific nature, value and complexity of the assignment. Single-Source Selection (SSS) may also be used but only in exceptional circumstances as described in the Consultant Guidelines with the Bank's prior agreement. Shortlists for small consultant contracts (below US$200,000) each may comprise entirely national firms, except when the assignment requires international experience.

28. **Training and Capacity Building**. Costs for training, seminars, workshops, participation in study tours and other capacity building activities will be financed under the project. Each year, or periodically, as required, PCs and ERAV will prepare and submit a learning plan for review by the Bank. The program will provide details of the individual learning events including: objectives of the event, the number/level of the target group, the estimated cost, the location of the program, the duration of the event and other relevant details. Before individual events are carried out, the Bank will review the cost estimate and plan for the activity. When applicable, standard training courses offered by specialized institutions will be selected by IAs by comparison of the course offered with the identified training needs of managers and staff. Fees and costs of travel and subsistence of those attending the courses and staff participating in study tours will be reimbursed based on reasonable costs supported by statements of expenses.

29. **Procurement Plan**. Procurement under the project will be carried out in accordance with agreed Procurement Plans. The PCs have developed a procurement plan for the first 18 months of implementation, which provides the basis for the procurement methods outlined above. ERAV has prepared the Procurement Plan under Component C. Both plans are shown in Attachment 1 of this Annex. The procurement plans will be

updated annually, or as needed, to (i) reflect actual project implementation; (ii) accommodate changes that should be made; and (iii) add new packages necessary for the project. Each update will be subject to the Bank prior review. Procurement Plans will be published in the World Bank website, as required by the Procurement and Consultant Guidelines. A General Procurement Notice (GPN) for the project has been published.

30. **Procurement Supervision and Post-review.** In addition to applicable prior review, the capacity assessment of the PCs has recommended annual supervision missions to visit the sites to carry out post review of procurement actions. Contracts not subject to prior review will be subject to post-review as per procedures set forth in paragraph 5 of Appendix 1 of the Procurement Guidelines and Consultant Guidelines. The rate of post review will be initially 10 percent. This rate will be adjusted periodically during project implementation based on procurement performance. The PCs will send to the Bank, on an annual basis, a list of all awarded contracts for goods, works and consultants' services that are subject to the Bank's post-review, including: (i) reference number as indicated in the Procurement Plan and a brief description of the contract; (ii) estimated cost, (iii) procurement method; (iv) date of contract award; (v) name of supplier, contractor or consultant; and (vi) final contract value.

Environmental and Social (including safeguards)

Social Aspects

31. The project triggers the World Safeguards Policies on Indigenous Peoples (OP 4.10) and Involuntary Resettlement (OP 4.12)

32. Like previous electricity distribution projects, the investments under Component A may require modest land acquisition for affected households in a subproject area as well as may have small community-wide socio-economic impacts. The project will not cause culturally specific impacts on ethnic minority (EM) communities. The PCs have met the Bank's requirements regarding the social safeguards including the triggered OP 4.10 and OP 4.12, and have prepared: (i) a Resettlement Policy Framework (RPF); (ii) an Ethnic Minority Planning Framework (EMPF); and (iii) for Phase 1 subprojects, Resettlement Action Plans (RAP) and Ethnic Minority Development Plans (EMDP).[8] Table A3.5 lists the safeguard documents approved by the relevant authority.

Table A3.5: Safeguard Document Approval

	Document	Approval
1	Approval of Resettlement Policy Framework	PM
2	Approval of Ethnic Minority Planning Framework	MoIT
3	Approval of Environmental Management Framework	MoIT

[8] There are 38 RPs and 8 EMDPs for subprojects under Phase 1 of Component A.

Resettlement Plans for Phase 1

33. Consistent with the RPF, Resettlement Plans (RPs) have been prepared for Phase 1. All plans will incorporate agreements reached on the route alternatives and substation localities. For Phase 1 agreed subprojects (and as is planned for Phase 2), every effort has been made through consultation, design, construction measures and construction schedules to minimize involuntary resettlement and adverse impacts on assets. Resettlement and compensation programs are designed to achieve the improvement, **or at least the same level, of living standards for displaced** persons (DP) compared to before the project.

34. Distribution lines themselves, from voltage 110 kV and down, do not require land acquisition, except for the towers and construction of substations, which require relatively small land acquisition. Lines impose land use restrictions on the Right of Way (ROW) corridor, from one to eight meters wide depending on the voltage and type of conductors. Aggregated impact of the line can be significant when going through more heavily populated areas. Measures to mitigate adverse impacts on local population have been considered carefully in design and selection of subprojects. Resettlement costs will be covered by PC counterpart funds.

Ethnic Minority Development Plans for Phase 1

35. The subprojects' impacts on EM households and communities would not be affecting their cultural assets or customs. In order to ensure compliance with Bank OP 4.10 on Indigenous Peoples and consistent with the EMPF, 8 Ethnic Minority People Development Plans (EMDPs) were prepared for subprojects of the first phase, based on the consultation and participation process during project preparation. (A similar process will be followed for Phase 2 subprojects.) The main requirements in the EMDPs are that: (i) EM will continue to be consulted, fully informed and participating during the RAP/EMDP preparation and implementation; (ii) EM who are affected by land acquisition will be compensated and assisted according to the entitlement policy defined in the RPF and the EMPF; and (iii) the project will ensure that EMs benefit from the project supported activities and investments. Current data from the EMDPs show that impact of land acquisition on individuals will be of low intensity, and no families will need to be relocated. Very few EM families will be affected by permanently acquired land for construction of towers, foundations and substations, and no households will lose more than 10 percent of their total productive land holdings.[9]

Implementation Arrangements

36. Each RP will be implemented independently by the corresponding PC, its PMU and relevant local authorities. A detailed implementation schedule for various activities is included in each RP, based on the linkage to the civil works implementation schedule.

37. Payment of rehabilitation and furnishing of other restoration/assistance entitlements (in cash or in-kind), and relocation, should it be necessary, have to be completed prior to awarding contracts for civil works. The PCs and their PMUs will maintain continuous dialogue with

[9] An EM household loss greater than 10 percent is considered a significant adverse impact.

local authorities and DPs during RP implementation. The PCs and local authorities are also responsible for implementing EMDPs, including assigning adequate staff and budget.

Monitoring and Evaluation

38. The PMU will be responsible for preparing and ensuring effective implementation of safeguard measures, and regular liaison with the local authorities and communities. Implementation of RPs and EMDPs will be periodically supervised and monitored by the PCs in close coordination with respective Peoples' Committees at different administrative units and independent monitoring agencies. Reporting of safeguard implementation will be done regularly as described in paragraph 50, submitted to EVN, MoIT, and the Bank.

39. A social staff will be appointed at each PMU to ensure that social safeguards implementation and monitoring are in accordance with the RPF and the EMPF. An independent agency/agencies or individual consultant will be hired by PCs to carry out periodic and ad hoc external monitoring and evaluation of the implementation of RPs and EMDPs, to ensure full compliance of social safeguards implementation. These may be academic or research institutions, Non-Governmental Organizations (NGO) or independent consulting firms, with qualified and experienced staff and terms of reference acceptable to the World Bank. Independent monitoring will start around the same time as implementation of activities and will continue until the end of the project/subproject. If possible, the (internal/external) monitoring activities of EMDPs can be combined with similar action under the RPs of the same subproject.

Complaints and Grievances

40. The PCs, PMUs and local authorities will first deal with complaints and grievances regarding compensation and rehabilitation. If no amicable solution is reached, the complaints may be appealed to the district authorities and then to provincial authorities. As a last resort, the complainants may appeal to District or Provincial Courts. At each level, the complaint should be redressed within 15 days. If the complaints are not redressed satisfactorily, complaints must be submitted to the higher levels no later than 15 days after the complainants have been informed, and complaints submitted later will not be considered. Claims will be dealt with in accordance with the new Ordinance on Complaints and Denunciation of Citizens. All the grievances procedures including those at the Courts will be free of charge to Complainants.

Measures to Prevent Fraud and Collusion and Improve Accountability in Resettlement

41. Preparation of project resettlement requirements and setting of compensation rates will be carried out jointly by the PCs and the authorities in the district affected by the subproject. The PCs are responsible for the routing of lines, siting of poles and other installations, and the planning survey that establishes the resettlement and compensation requirements. The PCs also bear the cost of resettlement. The compensation committee of the District People Committee is responsible for the detailed measurement survey (DMS) which verifies the items for which compensation is due, and the rates of compensation for each item (for example, the compensation rate for each square meter of

paddy lost). Rates of compensation and amounts to be paid are published in the District. Payment will be made in the presence of representatives of the PC and of the District People Committee.

42. This process, separating the main tasks between the PCs and the District People Committees, and the publication of the amounts and rates of compensation for open scrutiny by local people will provide reasonable checks against the most likely sources of fraud, or the use of public office for private gain. This system has worked well in the past, and will be independently monitored by consultant hired by the PCs, if needed.

Environmental Aspects

43. *The project is assigned Environment Category B, as its environmental and social impacts are assessed to be limited, localized and readily manageable by the use of standard environmental management measures.* The Environmental Management Framework (EMF) for the project has been prepared in accordance with the country's environmental regulations and the Bank Environmental Safeguard Policies particularly OP/BP 4.01. The key potential negative impacts of the project during construction include (i) for communities, land acquisition, increased localized level of dust, noise, disturbance to traffic; and (ii) for workers health and safety issues. The safety risk related to unexploded ordnances (UXO) is considered low since the subprojects will involve construction in UXO cleared areas. In case of uncertainty, as indicated in the EMF, the PC is required to contact the relevant army unit to confirm and/or clear the site before commencement of the construction.

44. The potential negative impacts during operation of Component A subprojects would be the effects associated with exposure to electric and magnetic fields from power lines and substations but, because the project voltage levels are only 110 kV and below, potential impact would be marginal. Noise is not an issue for LV and MV transformers in substations, for 110 kV as usual substations are in confined areas. The potential risk of oil leakage from transformers is addressed by construction of emergency oil collection and storage tank as required by Vietnamese regulations and included in the EMPs of such type of sub-projects. The potential risk of PCB[10] will be treated strictly as in paragraph 6.2 of the EMF prepared for this project.

45. As the subprojects mainly involve small scale construction and rehabilitation of existing power lines and substations, and are scattered in many provinces, impacts are assessed to be moderate, localized, and temporary, and can be mitigated through measures contained in the EMPs, the application of good construction and management practices and strict implementation of the Environmental Codes of Practice (ECOP) which will be included in the bidding documents and the program of work of the contractor under a close supervision of contractor performance by field engineers and in close consultation with local communities.

46. **Environmental Management Framework (EMF).** As part of project preparation, the client has prepared an EMF that establishes the requirements for sub-project

[10] Polychlorinated Biphenyls (PCB's)

screening, and assessing and managing environmental and social impacts during project implementation. The EMF contains the applicable Bank's safeguard policies' requirements as well as the Vietnamese regulation on environmental impact assessment and other related laws and regulations. The framework covers requirements for (i) safeguard screening; (ii) impact assessment and development of mitigation measures, including the ECOP for small scale construction activities; (iii) safeguard documentation preparation and clearance; (iv) safeguard implementation, supervision, monitoring, and reporting; (v) institutional strengthening and capacity building programs; and (vi) institutional arrangements and budget. The EMF indentifies the requirements for the preparation of an Environmental Management Plan for a subproject to comply with the Bank and the Government regulations on Environmental Impact Assessment (EIA). The EMF also includes a standardized ECOP to be applied to subprojects. The ECOPs will be incorporated into bidding and contract documents and will be closely monitored by supervision engineers.

47. **Environmental Management Plans (EMPs)** for first phase subprojects have been prepared by the PMUs following the EMF guidelines. The EMPs have been reviewed by the Bank and found to be satisfactory. The same procedures will apply to the Phase 2 subprojects, which would be prepared during the first year of project implementation.

48. Government regulations require the preparation of an EIA or an Environmental Protection Commitment (EPC) for an investment project. Accordingly, the EIA/EPC for the first year subprojects have been prepared and submitted for Government approval. Second phase subprojects will also comply with Government regulations on EIA and will be prepared as specified in the EMF.

49. **Public Consultation and Disclosure.** Two public consultations were carried out in the process of preparing the EMF. Participants included potentially affected people, mass organizations' representatives of implementing PCs, MoIT, EVN, and local consultants. Opinions and concerns provided during the consultations were taken into account in the preparation and finalization of the EMF. Public consultations with the people and households directly or indirectly affected, local authorities, and mass organizations at the subproject level were also conducted in the process of preparing the first phase subproject EMPs. Feedback from all the consultations was taken into account in the preparation of the final documents and for subprojects' design. Prior to appraisal, all safeguard documents including those for the first phase subprojects (EMF, EMPs, RPF, EMPF, RPs) were disclosed in Vietnamese at the Vietnam Development Information Center, EVN, PMUs of the five PCs, and subproject areas in project provinces. They were also disclosed in English at the Bank's InfoShop in Washington DC.

50. **Safeguard implementation and capacity building.** EVN, as the overall coordinator of PCs for the project, will be responsible for coordinating the supervision and monitoring of the implementation by PCs of the EMF and other safeguards documents such as EMP, and ECOP. Together with consultants, EVN's project environmental staff will provide training to the PC PMU's environmental staff in environmental planning and programming process. Together with consultants, these staff will carry out spot-checks during the course of project implementation to ensure that the

procedures set out in the EMF are being followed. PC PMUs, assisted by the construction supervision engineer and environmental management staff, will be responsible for preparing and ensuring effective implementation of safeguard instruments such as the RPs, EMDPs, EIAs/EPCs, EMPs/ECOP, and maintain regular liaison with local authorities and communities. Adequate resources and training will be provided for PMUs to effectively carry out environmental monitoring and management activities as stipulated in EMPs/ECOP.

51. ***Reporting on safeguard implementation*** will be prepared regularly, including (a) Semi-annual Environmental Safeguard Implementation Report; (b) Annual Environment Safeguard Monitoring Report; and (c) Mid-Term Review report including environmental safeguard implementation. PMUs will report on safeguard implementation on quarterly, annual and bi-annual basis.

Monitoring & Evaluation

52. Data for project indicators will be collected mainly from IA progress reports, PCs' operational and annual reports, and monitoring reporting by PCs to ERAV, as part of the requirements under the Distribution Code and electricity tariff regulations, and ERAV regulatory activities.

53. The Monitoring and Evaluation (M&E) framework will assess the progress in implementing the project and achievement of the PDO. The M&E system will include sources of information, data validation and calculation of indicators, and progress. Component C provides funding for the IAs to implement and report the M&E.

Role of Partners

54. The Clean Technology Fund (CTF), through a loan in the amount of US$30 million, will co-finance Component B of the project. CTF co-financing would support the demonstration and initial deployment of the advanced metering infrastructure systems (AMI), aimed mainly at demonstrating the costs and benefits for later replication and scale-up. CTF co-financing would overcome a viability/credibility gap by demonstrating at sufficient scale technology and data management with the potential to transform the operation and management of Vietnam's electricity distribution and retail business, and implementation of measures on the demand side. The project would help bring down several barriers to scale-up, most particularly uncertainty about the costs and benefits of smart grid investments, and the effectiveness of automation and demand control and response programs.

55. The Australian Agency for International Development (AusAID) will provide grant for Component C Technical Assistance and Capacity Building. Under the umbrella AusAID-World Bank Strategic Partnership in Vietnam (ABP) (TF071834), the corresponding recipient executed Trust Fund (TF) has been agreed for the proposed project. The AusAID grant would be co-financing and share the same project description and implementation arrangements.

Attachment 1 to Annex 3: Procurement Plan Involving International Competition

1. Goods, Works and Non Consulting Services for Phase 1 of the Project

Package. No.	Contract (Description)	Estimated Cost (US$)	Procure-ment Method	Prequali -fication (yes/no)	Domestic Preference (yes/no)	Review by Bank (Prior / Post)	Expected Bid-Opening Date
	Northern Power Corporation (NPC)						
NPC/DEP-1-MV/LV-G01	Conductors and power cables for Ha Giang, Lang Son, Lao Cai, Nam Dinh, Tuyen Quang and Yen Bai provinces	3,874,811	ICB	No	Yes	Prior	August 2012
NPC/DEP-110-G01	Transformers for 110kV Yen Thanh, Lang Giang, Hoi Hop, Cam Khe substations	2,318,485	ICB	No	Yes	Prior	August 2012
NPC/DEP-110-G02.1	Equipments for 110kV Yen Thanh, Nui 1, Lang Giang and Cam Khe substations	2,085,842	ICB	No	Yes	Prior	August 2012
NPC/DEP-110-G02.2	Equipments and power communication system - SCADA for 110kV Hoi Hop substation	1,333,372	ICB	No	Yes	Prior	August 2012
NPC/DEP-110-G03	Conductors, insulators and accessories for 110kV T/L: Yen Thanh, Bim Son, Ba Che-Nui 1, Cam Khe, Pho Noi – Hai Duong	1,192,458	ICB	No	Yes	Prior	August 2012
NPC/DEP-110-G04.1	Steel towers for 110kV connection at 220kV Bim Son S/S, 110kV Ba Che – Nui 1	1,007,739	ICB	No	Yes	Prior	August 2012
NPC/DEP-110-G04.2	Steel towers for 110kV Yen Thanh T/L	829,756	ICB	No	Yes	Prior	August 2012
NPC/DEP-110-G04.3	Steel towers for 110kV Cam Khe and Pho Noi – Hai Duong T/L	926,233	ICB	No	Yes	Prior	August 2012
	Central Power Corporation (CPC)						
CPC-DEP-2SS-G01	Power and auxiliary transformers for Tuy Hoà and Ba Đồn 110kV substations	1,677,032	ICB	No	Yes	Prior	September 2012
CPC-DEP-2SS-G02	Electrical switchgear and equipment for Tuy Hoà and Ba Đồn 110kV substations	197,194	ICB	No	Yes	Prior	September 2012
CPC-DEP-2SS-G03	Conductors, underground cables and accessories for Tuy Hoà and Ba Đồn 110kV substations	125,488	ICB	No	Yes	Prior	September 2012
CPC-DEP-2SS-G04	Control and protection panels, computerize system for Tuy Hoà and Ba Đồn 110kV substations	64,054	ICB	No	Yes	Prior	September 2012
CPC-DEP-DSKH-G01.	Electrical switchgear and SCADA equipment and installation service for 110kV line Doc Soi – Ky Ha	488,883	ICB	No	Yes	Prior	August 2012

CPC-DEP-DSKH-G012	Conductors, underground cables and accessories for 110kV line Doc Soi – Ky Ha	327,121	ICB	No	Yes	Prior	August 2012
CPC-DEP-I.1-G01	Power and auxiliary transformers for Nhon Hoi and Phuoc Son 110kV substations	1,144,241	ICB	No	Yes	Prior	August 2012
CPC-DEP-I.1-G02	Electrical switchgear and equipment for Nhon Hoi and Phuoc Son 110kV substations	512,345	ICB	No	Yes	Prior	August 2012
CPC-DEP-I.1-G03	Conductors, underground cables and accessories for Nhon Hoi and Phuoc Son 110kV substations and Ba Don-Song Gianh 110kV line	1,055,344	ICB	No	Yes	Prior	August 2012
CPC-DEP-I.1-G04	Control and protection panels, 24kV cubicles, computerize system, telecommunication system, SCADA equipment and installation services for Nhon Hoi and Phuoc Son 110kV substations	1,795,812	ICB	No	Yes	Prior	August 2012
CPC-DEP-I.1-G05	Steel towers for Nhon Hoi and Phuoc Son 110kV substations and branched lines and Ba Don - Song Gianh 110kV line	1,667,456	ICB	No	Yes	Prior	August 2012
CPC-DEP-I.2-G01	Power and auxiliary transformers for Hon La, Mang Yang, Dak Song and Mo Duc 110kV substations	1,105,166	ICB	No	Yes	Prior	December 2012
CPC-DEP-I.2-G02	Electrical switchgear and equipment for Hon La, Mang Yang, Dak Song and Mo Duc 110kV substations	695,402	ICB	No	Yes	Prior	December 2012
CPC-DEP-I.2-G03	Conductors, underground cables and accessories for Hon La, Mang Yang, Dak Song and Mo Duc 110kV substations	1,234,178	ICB	No	Yes	Prior	December 2012
CPC-DEP-I.2-G04	Control and protection panels, 24kV cubicles, computerize system, telecommunication system, SCADA equipment for Hon La, Mang Yang, Dak Song and Mo Duc 110kV substations	2,171,561	ICB	No	Yes	Prior	December 2012
CPC-DEP-I.2-G04	Steel towers for Hon La, Mang Yang, Dak Song and Mo Duc 110kV substations and branched lines	2,120,346	ICB	No	Yes	Prior	December 2012
	Southern Power Corporation (SPC)						
DEP-SPC-G01	Conductors and earthwires for Tra Vinh-Cau Ke, Cao Lanh 2 - Thap Muoi, Dam Doi - Dong Hai, Thanh Dong - Thoai Son, An Bien - Vinh Thuan, Chau Doc - Phu Chau, Mo Cay - Thanh Phu, Da Teh - Bao Loc and Binh Son tee-off 110kV lines	2,166,738	ICB	No	Yes	Prior	September 2012
DEP-SPC-G02	Insulators and fittings for Tra Vinh-Cau Ke, Cao Lanh 2 - Thap Muoi, Dam Doi - Dong Hai, Thanh Dong - Thoai Son, An Bien - Vinh Thuan, Chau Doc - Phu Chau, Mo Cay - Thanh Phu, Da Teh - Bao Loc and Binh Son tee-off 110kV lines	663,189	ICB	No	Yes	Prior	September 2012

DEP-SPC-G03	Steel towers for Tra Vinh-Cau Ke, Cao Lanh 2 - Thap Muoi, Dam Doi - Dong Hai, Thanh Dong - Thoai Son, An Bien - Vinh Thuan, Chau Doc - Phu Chau, Mo Cay - Thanh Phu, Da Teh - Bao Loc and Binh Son tee-off 110kV lines	3,520,248	ICB	No	Yes	Prior	September 2012
DEP-SPC-G04	Power transformers, auxiliary transformers and ancillary equipment and materials for Thap Muoi, Dong Hai, Thoai Son, Vinh Thuan, Phu Chau, Thanh Phu and Binh Son 110kV substations	663,189	ICB	No	Yes	Prior	September 2012
DEP-SPC-G05	Substation electrical equipment and materials, communication and SCADA for Thap Muoi, Dong Hai, Thoai Son, Vinh Thuan, Phu Chau, Thanh Phu and Binh Son 110kV substations	4,135,577	ICB	No	Yes	Prior	September 2012
	Hanoi Power Corporation (HNPC)						
DEP-HNPC-DA-G01	Electrical poles, conductors and accessories for E1.1 Dong Anh 110kV line	409,047	ICB	No	Yes	Prior	August 2012
DEP-HNPC-GL2-G01	Power and auxiliary transformers for Gia Lam 2 110kV substation	708,100	ICB	No	Yes	Prior	August 2012
DEP-HNPC-GL2-G02	Electrical equipment and materials for Gia Lam 2 110kV substation	1,264,606	ICB	No	Yes	Prior	August 2012
DEP-HNPC-HNHDST-G01	Distribution transformers for old Ha Noi City area, Ha Dong and Son Tay	952,212	ICB	No	Yes	Prior	August 2012
DEP-HNPC-HNHDST-G02	MV&LV conductors & underground cable for old Ha Noi City area , Ha Dong and Son Tay towns	2,847,540	ICB	No	Yes	Prior	August 2012
DEP-HNPC-HNHDST-G03	MV&LV twisted overhead cable for old Ha Noi City area , Ha Dong and Son Tay towns	4,985,576	ICB	No	Yes	Prior	August 2012
DEP-HNPC-HNHDST-G04	MV switchgear equipment for old Ha Noi City area , Ha Dong and Son Tay towns	311,371	ICB	No	Yes	Prior	August 2012
	Ho Chi Minh City Power Corporation (HCMPC)						
DEP-GV2-G1	Power transformer for Go Vap 2 110kV substation	1,397,000	ICB	No	Yes	Prior	August 2012
DEP-GV2-G2	Control, protection and measurement, auxiliary AC/DC, control cables, communication and SCADA for Go Vap 2 110kV substation	1,445,000	ICB	No	Yes	Prior	August 2012
DEP-TB3-G3	Power transformer for Tan Binh 3 110kV substation	1,379,000	ICB	No	Yes	Prior	August 2012
DEP-TB3-G4	Control, protection and measurement, auxiliary AC/DC, control cables, communication, SCADA for Tan Binh 3 110kV substation	1,295,000	ICB	No	Yes	Prior	August 2012

DEP-KCNHP-G01	Power transformer for Hiep Phuoc 110kV substation	1,394,000	ICB	No	Yes	Prior	August 2012
DEP-KCNHP-G02	Control, protection and measurement, auxiliary AC/DC, control cables, communication, SCADA for Hiep Phuoc 110kV substation	959,000	ICB	No	Yes	Prior	August 2012
DEP-CB-G1	Power transformer for Cau Bong 110kV substation	1,463,000	ICB	No	Yes	Prior	August 2012
DEP-CB-G2	Control, protection and measurement, auxiliary AC/DC, control cables, communication and SCADA for Cau Bong 110kV substation	865,000	ICB	No	Yes	Prior	August 2012
DEP-AP-G1	Power transformer for An Phu 110kV substation	714,000	ICB	No	Yes	Prior	October 2012
DEP-AP-G2	Control, protection and measurement, auxiliary AC/DC, control cables, communication and SCADA An Phu 110kV substation	1,222,000	ICB	No	Yes	Prior	October 2012

2. Consulting Services

No.	Contract (Description)	Estimated Cost (US$)	Selection Method	Review by Bank	Expected Proposal Submission Date
	Electricity Regulatory Authority of Vietnam (ERAV)				
1	Pilot demand response programs	500,000	QCBS	Prior	August 2013
2	Final demand response programs for PCs	250,000	IC	Prior	January 2015
3	Enhance load research activities and monitoring changes in demand consumption	300,000	IC	Prior	August 2013
4	Enhancing technical codes efficiency, incorporating smart grids and integration of renewable energy generation	500,000	QCBS	Prior	January 2014
5	Implementing smart grid program	300,000	IC	Prior	August 2013
6	Surveys and disseminations of demand response and energy efficiency	250,000	CQS	Prior	May 2015
7	Tariff advisor	350,000	IC	Prior	August 2013
8	Improving efficiency of the retail electricity tariff structure	500,000	QCBS	Prior	August 2013
9	Improving the efficiency of time of use (TOU) tariffs	350,000	IC	Prior	March 2014
10	Harmonizing electricity tariffs with implementation of demand response programs	250,000	IC	Prior	August 2013
11	Enhancing efficiency and performance of PCs	500,000	QCBS	Prior	January 2014
12	Informing large customers and workshops on electricity tariffs	250,000	QCS	Prior	January 2015
13	Monitoring and Evaluation of project and GHG reduction	300,000	IC	Prior	August 2013

Annex 4: Operational Risk Assessment Framework (ORAF)

VIETNAM: Distribution Efficiency Project

Project Development Objective(s)	
The project development objectives are to improve the performance of Vietnam's Power Corporations in providing quality and reliable electricity services, and to reduce greenhouse gas emissions through demand side response and efficiency gains.	
PDO Level Results Indicators:	1. Reliability of power supplied, monitored through System Average Interruption Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) in the project area
	2. Quality of power supplied, monitored through voltage excursion outside of ±5% at the outlet of 110 kV substations in the project area
	3. Reduction of PCs total losses in the project area
	4. Reduction in electricity consumption by PCs' consumers with Advanced Metering Infrastructure (AMI) (compared to business as usual scenario)
	5. Avoided greenhouse gas emissions by NPC, CPC, HNPC and HCMPC

Project Stakeholder Risks	Rating	Moderate		
Description: Risks identified at concept stage include opposition to some subprojects on use of land, local authorities could delay or deny construction permits due to conflicts of interest arising from changes in current land use required to build new facilities, set rights of way (ROW), etc. Screening criteria has been established for subprojects to minimize impact. In preparing Phase 1 subprojects, consultation with stakeholders, particularly with the provincial and local authority, has been aimed at minimizing the likelihood of interference with subprojects' requirements. Potentially conflictive subprojects were excluded from Phase 1.	**Risk Management:** Similar approach and processes will be adopted for Phase 2 subprojects, in particular screening and excluding subprojects with a potential for conflicts.			
	Resp: Client	**Stage: Preparation and implementation**	**Due Date :**	**Status: Ongoing**
Description : Lack of interest of large consumers to improve demand side efficiency and participate in demand response	**Risk Management:** Component C grant will provide funds for (i) the regulator (ERAV) to enhance tariff setting and demand programs that provide incentives and benefits to the participating			

<table>
<tr><td rowspan="2">programs using the functionality and information provided by advanced metering. With international expert support funded by SEIER, ERAV has initiated demand response TA that is expected to lead to pilot regulations with adequate incentives and awareness campaigns.</td><td colspan="5">consumers; and (ii) awareness campaigns and wide dissemination by PCs.</td></tr>
<tr><td>Resp: Client</td><td>Stage: Implementation</td><td colspan="2">Due Date :</td><td>Status: Not yet due</td></tr>
<tr><td colspan="6">Implementing Agency Risks (including fiduciary)</td></tr>
<tr><td>Capacity</td><td colspan="3">Rating:</td><td colspan="2">Moderate</td></tr>
<tr><td rowspan="2">Description: The five PCs PMUs can delegate execution of some works in MV and LV networks to the corresponding subsidiary power company (PCom). As a similar delegation to PComs has been implemented in previous distribution projects, the project benefits from some PComs that already have the required knowledge.
This is the first time that Hanoi PC participates in a Bank project, although it has broad experience in working with other ODA financed projects.
Extensive training has been provided by the Bank during project preparation on FM, safeguard and procurement for relevant staff of the five PCs, including PComs. Training has focused specially on Hanoi PC.</td><td colspan="5">Risk Management :

Further training and support is planned during implementation for Hanoi PC, and to ensure that each PC PMU carries out adequate supervision of works delegated to PComs.</td></tr>
<tr><td>Resp: Bank and Client</td><td>Stage: Implementation</td><td colspan="2">Due Date :</td><td>Status: Ongoing</td></tr>
<tr><td rowspan="2">Description: (Procurement) To ensure that PMUs and approving authorities strictly apply Bank procedures, during project preparation extensive training has been provided on Bank’s procurement rules and procedures /contract.
ERAV and the four PCs with Bank financed projects have been implementing Bank procurement in a satisfactory manner. All five PCs have procurement experience as well as institutional and organizational capacity in place to carry out procurement under their respective component/subprojects.
The Project Operations Manual has been approved, to guide project implementation, including the procurement process.</td><td colspan="5">Risk Management :

During implementation, in particular during first 12 months, the Bank will continue to provide training activities on the Bank procurement rules and procedures /contract, in particular in-depth hands-on procurement training to Hanoi PC. As necessary, ad hoc procurement training will be provided during supervision missions and through comments and advice on procurement documents submitted to the Bank for prior review.</td></tr>
<tr><td>Resp: Bank and Client</td><td>Stage: Implementation</td><td colspan="2">Due Date :</td><td>Status: Ongoing</td></tr>
<tr><td>Description : (Financial Management) Financing of optic cables has been excluded from the project, to avoid concerns on allocation to Telecom activities.
During project preparation, FM training has been provided to PCs and ERAV, and the financial management arrangements assessed as satisfactory.
A qualified project chief accountant has been appointed in each PMU and internal audit function in PCs PMUs agreed.</td><td colspan="5">Risk Management

During implementation, PMUs will submit Interim Financial Reports. Project financial statements will be audited by an auditor acceptable for the Bank. Claims for expenditures will be verified by the State Treasury.

Continue FM training to Hanoi PC.</td></tr>
</table>

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<tr><td rowspan="2"></td><td colspan="4"></td></tr>
<tr><td>Resp: Bank and Client</td><td>Stage: Implementation</td><td>Due Date :</td><td>Status: Ongoing</td></tr>
<tr><td>Governance</td><td colspan="3">Rating: Moderate</td><td></td></tr>
<tr><td rowspan="2">Description : Lack of counterpart funds may slow down implementation. Discussions with PCs have started on ensuring adequate funding.</td><td colspan="4">Risk Management : PCs will confirm the availability of the counterpart funds.</td></tr>
<tr><td>Resp: Client</td><td>Stage: Preparation</td><td>Due Date :</td><td>Status:</td></tr>
<tr><td>Project Risks</td><td colspan="4"></td></tr>
<tr><td>Design</td><td>Rating:</td><td colspan="3">Moderate</td></tr>
<tr><td rowspan="2">Description: The PMU delegation of some MV and LV work to PComs will facilitate project implementation by PCs (avoid work overloads), but will require on the Bank side adequate supervision.</td><td colspan="4">Risk Management: The Bank will concentrate supervision on PMUs of PCs and review their monitoring and coordination arrangements with their PComs. Additionally, each supervision mission will select a percentage (initially 10%) of works for site visits to oversee implementation. Percentage will be reviewed based on findings during implementation.</td></tr>
<tr><td>Resp: Bank</td><td>Stage: Implementation</td><td>Due Date :</td><td>Status: Not due yet</td></tr>
<tr><td rowspan="2">Description: Preparation of subprojects under Component B, including advanced metering infrastructure (AMI), has been deferred to Phase 2, to enable sufficient time for adequate preparation. PCs are mobilizing experienced consultants to assist in AMI technical design and preparation.
However, unexpected situations during procurement and implementation could delay implementation.</td><td colspan="4">Risk Management: Experienced international consultants will assist in AMI preparation, to complete subprojects preparation on time.
Component C provides grant funded support for PCs to access experts for the procurement process and implementation, to avoid delays caused by lack of PCs expertise in AMI.</td></tr>
<tr><td>Resp: Client</td><td>Stage: Preparation and Implementation</td><td>Due Date :</td><td>Status: Ongoing</td></tr>
<tr><td>3.1. Social & Environmental</td><td>Rating:</td><td colspan="3">Moderate</td></tr>
<tr><td rowspan="2">Description: Safeguards training has been provided to the subproject locations for the implementation of Bank safeguard policies, including specific programs for PCs. Acceptable safeguard documents have been prepared by PCs for the project and Phase 1 subprojects. The PCs have prepared project Environmental Management Framework (EMF) establishing screening criteria for sub-project to assess, minimize and manage environmental and social impacts during project implementation.
However, Hanoi PC has not implemented before Bank safeguard documents.</td><td colspan="4">Risk Management : Safeguards training will continue during project implementation. All safeguard documents will be reviewed by the Bank, and published as required by Bank safeguard policies.

Phase 2 subprojects will follow the project EMF and Resettlement Plan Frameworks and Resettlement Plans, to minimize impact and resettlement required.

Independent monitoring consultant will assist PMUs and carry out the social and environmental monitoring program.</td></tr>
<tr><td>Resp: Client</td><td>Stage: Implementation</td><td>Due Date :</td><td>Status: Ongoing</td></tr>
<tr><td>Description: Since the project involves the preparation and implementation of multiple subprojects in a large geographical area, an Ethnic Minority Planning Framework (EMPF) has been prepared and approved.</td><td colspan="4">Risk Management: Continue safeguard training. Broad community support will be obtained for each subproject through a process of free, prior, and informed consultations with the affected EM communities will be confirmed by PCs. Independent external resettlement and indigenous people monitoring is included in the project. Perform free, prior, and informed consultation (FPIC) of ethnic minority groups if affected by subprojects.</td></tr>
</table>

	Resp: Client	**Stage: Preparation and Implementation**	**Due Date :**	**Status:**
Program & Donor	**Rating:**	**Low**		
The Administration Agreement for the AusAID-World Bank Strategic Partnership in Vietnam (TF 071834), which includes the recipient executed TF for Component C, was signed in February 2012. A Steering Committee is operational and agreed the grant for this project. The timing for first contribution to the proposed grant has been agreed between the Bank and AusAID.	**Risk Management:** Close coordination with AusAID through Steering Committee and updates confirming contributions to avoid risk of delays.			
	Resp: Bank	**Stage: Implementation**	**Due Date:**	**Status: Ongoing**
Delivery Monitoring & Sustainability	**Rating:**	**Low**		
Description: Indicators have been selected ensuring data availability. Reliability indicators were selected as these are required in Vietnam Distribution Code. ERAV will include in monitoring and reporting obligations of these indicators by PCs in the implementation of Distribution Code.	**Risk Management:** Component C grant includes M&E support for PCs and ERAV to implement the M&E framework and reporting. Expert support funded through SEIER is assisting ERAV in preparing and implementing the PCs monitoring reports for the Distribution Code			
	Resp: Client	**Stage: Implementation**	**Due Date:**	**Status: Not due yet**
Description : Scope of construction and contracting involved under Component A is similar to previous distribution projects, and PCs have the required technical and operational expertise. The PC feasibility studies are reviewed and approved by the relevant government agencies, and reviewed by the Bank. The individual subprojects meet accepted international standards.	**Risk Management:** Continued training and review of Phase 2 feasibility studies.			
	Resp: Client and Bank	**Stage: Implementation**	**Due Date :**	**Status: Not due yet**
Description: The longer term benefits of the distribution investment, including smart grid technologies cannot be achieved without adequate skills and regulations. During preparation, the Bank worked closely with PCs and ERAV on introduction of advanced metering infrastructure and demand response, with international experts and TAs already underway funded through on-going Bank projects (SEIER and RD). Regulations and codes in place and monitored by MoIT/ERAV have increased transparency and access to information.	**Risk Management :** Component C will provide TA for ERAV to continue to develop and implement the electricity tariff reform program, which should increase sustainability for distribution activities, and on demand response and smart grid regulations. Component C will provide capacity building and expert support on AMI, automation and demand response programs to PCs and ERAV, to enhance effectiveness and to transfer knowledge.			
	Resp: Client	**Stage: Implementation**	**Due Date :**	**Status: Not due yet**
Implementation Risk Rating:: Moderate				

Annex 5: Implementation Support Plan

VIETNAM: Distribution Efficiency Project

Strategy and Approach for Implementation Support

1. The Operational Risk Assessment Framework (ORAF) identified the main risks to achieving the PDO and proposed risk management measures for these risks. As described in Annex 4 and summarized in the main text, the Overall Implementation Risk for the project is rated moderate. In addition, the risks in each category are rated either moderate or low.

2. Accordingly, the Implementation Support Plan (ISP) has been developed taking into account the following factors:

(a) Most technologies are well proven and widely used in the world and Vietnam, except for AMI that is relatively new to operational staff of PCs;

(b) The IAs have experience and good capacity to implement ODA projects. Four PCs have a long record, over 15 years, of implementing Bank financed projects and ERAV more than five years. Hanoi PC is participating in a World Bank financed project for the first time but has implemented other ODA projects;

(c) Based on the volume of works, PC(s) and their PMU(s) may delegate some implementation activities to PCom in the project areas. This arrangement will reduce the workload of PMU and facilitate implementation, particularly supervision of works and the detailed measures for compensation. Some PComs already have experience carrying out similar activities in ongoing Bank distribution projects (RD and REII) and have proved their capacity, while some others will require more training and capacity building;

(d) The IAs have a good track record in procurement under Bank financed projects;

(e) Potential delays caused by site clearance and land acquisition;

(f) Delays in IAs due to excessive workload during parts of project implementation, lengthy internal approval processes; and

(g) Contract management capacity may also be the reason for delays.

3. Based on the factors mentioned above, the ISP would focus on:

(a) Continue training of PC staff (including PCom) on procurement, financial management and safeguards, which started during preparation;

(b) Mobilize consultants to assist the PCs for the preparation and implementation of subprojects under Component B;

(c) Maximize use and benefits of the TA for capacity building of PCs and ERAV regulations and monitoring;

(d) Intensive Bank supervision during the first year of the project to provide IAs the advice and support to ensure smooth start-up of project implementation; and

(e) Continue intensive consultation with relevant stakeholders, particularly with project affected persons.

Implementation Support Plan

4. The implementation Support Plan is presented in Table A5.1.

Table A5.1. Implementation Support Plan

Time	Focus	Skills Needed/ Functional Specialist	Est. Staff week /year	Partner Role
First 12 months	**Procurement:** Bank to provide review of bidding documents, procurement plans, bid evaluation reports and provide ad-hoc training to disseminate the experiences among the PCs.	Bank Procurement specialist	8	
	Support for Rapid Mobilization of TA Consultants: The immediate priority is to support the IAs to start procurement activities for the major TA contracts.	Project Management and Procurement	8	PMUs to mobilize consultants and procurement support for PMUs.
	Training PMUs and PComs: The Bank will continue the training activities for procurement, fiduciary and safeguards.	Bank procurement, FM, and safeguards specialists.	8	
	Project Management and Coordination: The Bank will work with ERAV, PCs and the PMUs to ensure effective coordination and support roles are established between the MoIT, EVN and PMUs. This is important to help strengthen supervision practices.	Project Management	4	PCs to increasingly lead and coordinate the project, provide oversight and support to PMUs.
	Project Monitoring and Evaluation: The Bank will work with the six IAs and PMUs to develop and put in place a template for monitoring project implementation progress, which will be used for online monthly reporting to MoIT, EVN and the Bank. The Bank, with consultant support, will prepare the M&E framework for the project, including information collection, data validation, the calculation of indicators and reporting.	Project Management M&E framework expert	4	ERAV and PCs to implement the TA support under the project for the implementation of M&E framework and reporting.
12-48 months	**Environment, Social, and Technical:** Strengthen focus on implementation quality, improving counterpart and contractor capacity, and compliance with resettlement and other safeguards policies.	Safeguards Specialist	n/a	PCs/PMUs to strengthen the supervision, and their interaction with local authorities
	Construction Supervision: Focus on implementation quality, compliance with EMPs (including site safety and materials handling), and quality of works.	l Engineer	n/a	PCs to conduct spot checks and training.

Annex 6: Economic and Financial Analysis

VIETNAM: Distribution Efficiency Project

A. **Project Economic Analysis**

Methodology[11]

Component A

1. The analysis is based on feasibility studies of subprojects for Phase 1 and the assumption described in this Annex. An energy balance was done for each subproject area, with and without the project, for an assumed lifetime of 20 years. In the absence of the project, typical loss rates are estimated at 20-25%, which would reduce to 4-7% with the project investments. In most cases, in the absence of the project, supply is at the limit of the capacity and demand growth and new connections cannot be accommodated. The net economic flows are calculated as the difference between economic costs and benefits, with and without the project. The analysis is at constant 2012 prices, and 2010 or 2011 prices are adjusted for domestic inflation by the producer price index, and costs of imported equipment are updated with the Manufacture Unit Value (MUV) index as published by the World Bank. The economic costs include physical contingencies (but exclude interest during construction, taxes, and duties). The Net Present Value (NPV) is calculated at 10% discount rate.

2. Energy purchased by the PC at the subproject boundary is valued at the avoided social cost of thermal generation, based on the avoided cost tariff in Vietnam as gas-fired CCGT generation with gas price linked to Singapore fuel oil price. Energy purchased by consumers is valued at the consumer's willingness to pay (WTP), estimated for residential consumers using the demand curve derived from the detailed rural household energy survey, and for other customers on the costs of self-generation burning diesel.

3. Where subprojects encompass only the upgrading of 110kV or MV infrastructure and benefit is claimed for additional sales at LV, the costs of the additional future LV capital investment is added. When these costs are not known for the subproject area, they are estimated on the basis of the total capital expenditure breakdown of the PC or the province, according to the applicable transmission and distribution (T&D) plans.[12]

4. Where a subproject claims benefit for reliability improvement, the impact on net economic flows will be a slight increase in energy purchase cost (corresponding to the additional energy supplied). On the benefit side the net benefit is the avoidance of unserved energy, which is typically valued at five times the average WTP.[13]

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[11] This Annex summarizes the background report, *Economic and Financial Analysis of Distribution Projects*, January 2012. Further information is provided in supplemental documents to this PAD.

[12] For example, typical values of this capital expenditure multiplier for 110kV extensions are between 0.9-1.2: for every VND spent on 110kV infrastructure, 0.9-1.2 VND will need to be spent on MV/LT and connections.

[13] Economic benefit is greater than the *financial* benefit to the PC (which is simply additional sales at the retail tariff)

Advanced Metering Infrastructure (AMI)

5. The AMI to be funded under this project will target the larger customers (expected to cover customers consuming at least 2,000 kWh/month). The baseline case assumes that the consumption reduction is 0.5% (based on estimates in the European and international experiences).

6. Some AMI projects in other Asian countries have been justified primarily reduction of high non-technical losses (such as India). However, non-technical loss rates in Vietnam are quite low. In the case of the HCM PC AMI subproject, non-technical losses for the largest customers are estimated at 1%, to be reduced to 0.5% as a consequence of advanced metering. It may also be noted that manual meter reading costs – the avoidance of which is one of the main benefits of Smart meters in Europe and North America – are also quite low in Vietnam.

SCADA subprojects

7. The feasibility study for the proposed SCADA system for SPC (prepared by consultants)[14] lists several benefits, including the following four quantified in this analysis:

- (i) Reduction of staff;
- (ii) Reduction of maintenance cost;
- (iii) Reduction of technical losses;
- (iv) Reduction of unserved energy.

Avoided GHG

8. The SCADA and AMI projects result in net reductions of GHG emissions relative to the no-project scenario, as a consequence of better dispatch, and avoided power generation due to lower technical losses and consumption reductions. For this analysis, GHG emissions are valued at \$30/ton CO_2 equivalent, and are calculated on the basis of emission reductions at CCGT.[15] The ERR and NPV are reported with and without GHG emission benefits, which typically for AMI and SCADA projects the ERR increases by 3-5 percent.

Sub-project economic performance

9. The economic analysis was done for each subproject, using a cost–benefit methodology. The economic indicators, namely EIRR and NPV, were calculated with the following assumptions: (i) all costs are in constant 2012 prices, making no adjustment for shadow exchange rate or shadow wage rate; (ii) the capital investment costs for the first phase are considered over 2012-2013, and analyses are made over a subproject economic life of 22 years (2012-2034); (iii) the cost for compensation, land acquisition and environmental mitigation are included in the economic cost of the subproject; (iv) the operation and maintenance costs are

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[14] PC, *SCADA System and 110kV Substations Without Operators, Feasibility Study*, April 2010.

[15] Although the standard UNFCCC CDM methodology for calculating emission reduction averages in the higher emission factors at coal projects, for consistency with the *actual* likely outcome of dispatch response to demand reductions which is to reduce dispatch of the most expensive project in the merit order, use of gas-based in emissions is appropriate.

estimated at 2% of the investment costs; (v) the input energy to the subproject is estimated for 2012 based on actual for each PC in 2010 and 2011; and (vi) EIRR of the subproject is the discount rate at which the present value of the costs and benefits streams are equal, and the NPV is based on a discount rate of 10%, approximately the opportunity cost of capital in Vietnam.

10. Given the nature of the project – rehabilitation and expansion of the distribution systems – both existing and newly connected consumers will benefit. The benefits will come from: (i) incremental sales; (ii) reduction of losses, the economic value of which are 10.8 cents/kWh (2,277 VND/kWh); and (iii) reduction of outage duration, where interrupted supply is estimated to cost 7.5 cents/kWh (1566 VND /kWh). The demand forecast is based on: (i) historical consumption, taking into consideration the suppressed demand due to constraints of the existing system; and (ii) economic development indicated by forecast GDP. The analysis shows that all subprojects are economically efficient. Most of them are robust to increases in costs of over 150 percent and decreases in demand of over 30 percent. No subprojects stand out as exceptions.

Table A6.1: Summary of Phase 1 Subproject Performance

Power Corporations	NPV@10% (US$ millions)	EIRR (%)
NPC	**148.89**	**28.1%**
SPC	**117.42**	**24.5%**
CPC	**44.39**	**17.1%**
HNPC	**44.27**	**21.7%**
HCM PC	**271.95**	**53.7%**
All first phase subprojects	**626.92**	**29.2%**

Aggregate economic returns of the project

11. Aggregate economic indicators of each subprojects of phase 1 were estimated, showing that Component A has very robust economic benefits. Sensitivity analyses were made for 10% cost increase, and 10% demand decrease, and even in the case of combining the two factors the EIRR is still as high as 23.5%.

Table A6.2: Phase 1 Subproject Economic Analysis

	Unit	Base Case	Cost increase 10%	Demand decrease 10%	Combined
EIRR	%	29.2%	26.3%	26.2%	23.5%
NPV	US$ Million	626.92	580.03	533.92	486.30
PV Costs	US$ Million	$7,278.84	7,325.73	6,783.46	6,831.08
PV Benefits	US$ Million	$7,905.76	7,905.76	7,317.38	7,317.38

B. Project Financial analysis

Methodology

12. The project financial returns are calculated at constant 2012 prices, and compared to the PC's risk adjusted weighted average cost of capital (WACC) assumed as 6%. Energy purchased by the PC at the project boundary is valued at the applicable bulk supply tariff for the PC, as estimated for 2012. The financial benefits to the PCs are based on the average retail tariff in the project area. Where these are not known, the estimated PC-wide averages may be used, as estimated by EVN.

13. Where subprojects encompass only the upgrading of 110kV or 35kV infrastructure, if benefit is claimed for additional sales at LV then the costs of the additional future LV capital investment are added. Where these costs are not known for the specific project area, they are estimated on the basis of the total capital expenditure breakdown of the PC or the province (according to the applicable T&D plans).

Subproject financial performance

14. A financial analysis of the Phase 1 subprojects from the PC perspective was undertaken, by valuing incremental revenues and costs at the estimated tariff for 2012 based on the actual average tariff applied to the PCs in 2010 and 2011, which is assumed to remain constant during the period while incorporating changes in the composition of total demand served. The following cost assumptions were made: (i) capital costs are baseline costs plus physical and price contingencies; (ii) power purchase prices at the connection point of the distribution system are estimated as average current purchase price of PCs plus estimated losses to the point; power purchase prices are assumed to remain constant throughout the forecast period; (iii) operating and maintenance (O&M) costs for MV lines are estimated at 2% of investment costs; (iv) losses are estimated at 3.5-7 % for MV networks after project implementation; (v) foreign costs are converted at the exchange rate of 21,000 VND/ US dollar, assuming all investments will be implemented during the first and the second year; (vi) local inflation is estimated at 10%; and (vii) weighted average cost of capital for the PCs is 6 %, made up from 25 % of equity and 75% debt at the rate at which the Government on-lends, assumed as 3.6 %.

Table B6.1: Subprojects Financial Performance

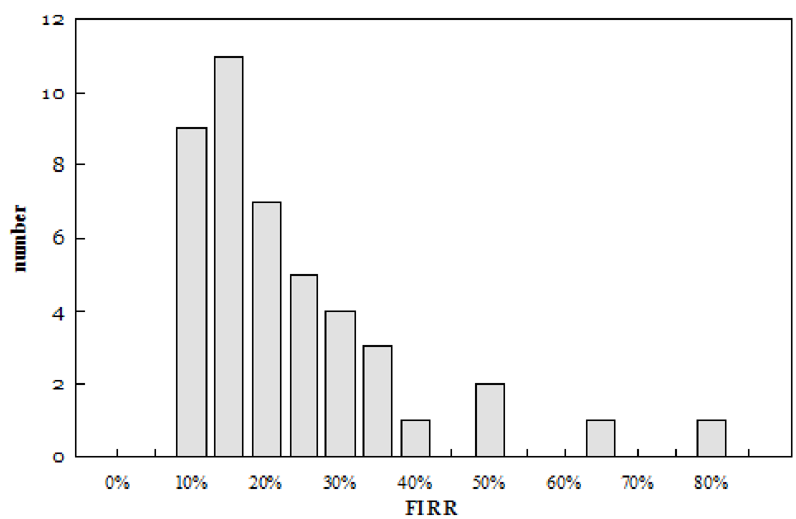
Power Corporations	**NPV@6% (US$ millions)**	**FIRR (%)**
NPC	**242.23**	**22.4%**
SPC	**38.64**	**9.8%**
CPC	**179.28**	**20.8%**
HNPC	**52.47**	**16.0%**
HCM PC	**52.98**	**11.9%**
All Phase 1 subprojects	**565.60**	**16.7%**

15. The results show that each PC has an incentive to carry out the subprojects within its area. All subprojects are financially efficient and most are robust to changes in cost and demand.

However, there are several subprojects close to being financially unviable and are sensitive to changes in cost and demand or both. Notwithstanding this sensitivity, and possible risk to the investment, the participating PCs have decided to retain the subprojects, with the option to drop them later if considered unprofitable. The PCs consider that these subprojects should be included because (i) the costs on which the financial rates of return are calculated include a 10% price contingency and a 5% physical contingency. Hence each subproject has a 15% cushion; (ii) the cost estimation is made when Vietnam had just faced an inflation peak during 2011 and there is expectation of tendency of declining prices in the following year, 2012; and (iii) under Vietnamese regulations, at the procurement stage, if costs are higher than the original estimate, the PCs are obliged to require costs to be re-approved. This would be an opportunity to reassess project viability. It is noted that each of the subprojects under consideration has a rate of return higher than 6%, where the cost of lending is 3.6%.

16. The financial returns of individual subprojects are all satisfactorily above the 6% WACC hurdle rate, though a few are in the 6-10% range. Figure B6.2 shows the distribution of subproject financial returns: those with FIRR>40% are all rehabilitation projects where the present losses are extremely high, and for which financial returns can be expected to be high.

Figure B6.2: Distribution of subproject FIRRs



Aggregate financial returns of the project

17. A combined sensitivity analysis for the all subprojects of phase 1 was also carried out for the same key parameters, under pessimistic assumptions. In this project, the demand forecasts and the cost of the project are the most important variables. The following scenarios have been assumed in the sensitivity analysis: (i) costs increase by 10%, (ii) demand decrease by 10%, and (iii) the worst case when costs increase by 10% together with a demand decrease of 10%. The results show that even in the worst case the project is still financially viable, with the combined FIRR of 13.1%.

Table B6.3: Sensitivity Analysis Subprojects Financial Performance

	Unit	Base Case	Cost increase 10%	Benefits decrease 10%	Combined
FIRR	%	16.7%	14.8%	14.9%	13.1%
NPV	US$ Million	565.60	502.05	464.21	399.78
PV Costs	US$ Million	8,138.44	8,201.99	7,646.97	7,711.40
PV Revenues	US$ Million	8,704.04	8,704.04	8,111.18	8,111.18

C. Financial Analysis of the project and PCs

Introduction

18. The financial analysis carried out for the project comprises: (a) an analysis of the PCs recent financial performance for the period 2006-2010: (b) a review of preliminary financial statements data for 2011;[16] (c) a qualitative review of the companies' future financial performance; and (d) recommendations of actions to manage financial performance risks during the project implementation period and to build capacity for financial sustainability.

19. **Background**: In 2010 and as part of the GOV power sector reform program targeting to strengthen the companies participating in the sector, EVN's 11 power distribution companies were legally re-established as five Power Corporations (PCs) limited liability companies:

- Northern Power Corporation (NPC), resulting from the merger of Power Company No. 1 (PC1), Hai Phong Power Company, Hai Duong Power Company, and Ninh Binh Power Company.
- Central Power Corporation (CPC) resulting from the merger of Power Company No. 3, Da Nang Power Company, and Khanh Hoa Power Joint Stock Company.
- Southern Power Corporation (SPC) resulting from the merger of Power Company No. 2 and Dong Nai Power Company (PC Dong Nai).
- Hanoi Power Corporation (HNPC) comprising the former Hanoi Power Company and is responsible for electricity distribution and retail supply services in Hanoi.
- Ho Chi Minh City Power Corporation (HCMPC), comprising the former Ho Chi Minh City (HCMC) Power Company and is responsible for electricity distribution and retail supply services in HCMC.

20. Since these companies have been in existence for only two full fiscal years and financial statements were available for only one year (2010) it was not possible to analyze their historical financial performance as prospective project implementing entities as is normally done in Bank financed projects. Therefore an alternative approach was adopted based on the 2010 financial statements and an analysis of the available data for the constituent companies that merged to form each PC as follows:

- For NPC, the financial assessment for 2006-2008 was made for PC1, which is by far the largest of the four PCs that now form NPC. The financial statements for 2009 were restated for the new PC in order to provide a basis for comparison with those of 2010.

[16] Vietnamese fiscal year is the 12 month period ending December 31.

Therefore, the financial results presented for the 2006 – 2008 period are not directly comparable to the results for 2009 and 2010.

- For CPC, the assessment for 2006 – 2009 was made for PC3, which accounted for almost three-quarters of total sales of the three PCs now merged into CPC. The 2010 financial statements have been prepared for new company.
- For SPC, the financial assessment over the entire 2006 – 2010 period was made for PC2 rather than for SPC and thus excludes PC Dong Nai whose results were only partially incorporated in the 2010 audited financial statements. However, PC2 accounts for the largest share of SPC's operations with 78% of total sales made by the two PCs between 2006 and 2010.
- The assessment of HNPC is based on its financial statements prepared and audited in accordance with Vietnamese Accounting Standards (VAS) whereas the assessments for the other PCs are based on financial statements and other supporting information prepared and audited in accordance with International Financial Reporting Standards (IFRS).

21. The five PCs differ significantly in terms of their operating scales and service areas. The largest PC in terms of energy sales is SPC, which sold 32,307 gigawatt-hours (GWh) in 2011, which is more than three times that sold by the smallest PC, CPC, in the same year. The service areas of HNPC and HCMPC are almost entirely urban with a high concentration of commercial and industrial customers. In contrast, NPC, CPC, and SPC serve a mix of rural and urban areas. As a result, despite a uniform national electricity tariff, there are significant differences in the average tariff level generated by each of the PCs. For example, HCMPC's average retail tariff was VND 1,415/kWh (6.93¢/kWh) in 2011, 24% more than the NPC average tariff of VND 1,139/kWh (5.58¢/kWh).

22. Despite differences among PCs and the application of national uniform retail electricity tariffs, the PCs' financial performance over the 2006–2010 was broadly similar and mostly in compliance with Bank legal financial covenants under ongoing projects. These substantial differences should normally result in similarly substantial differences in financial results. However, the PCs' financial performance over the 2006 – 2010 was broadly similar, as shown in the summary statistics of financial results and indicators in Tables C6.1 to C6, and as explained later in this section. (The detailed analysis is provided as a supporting project document.)

Table C6.1: PC1 / NPC Financial Summary

(VND billion - nominal prices)

	Actual					Estimate
	2006	2007	2008	2009	2010	2011
A. Financial Results						
Net Revenue	8,274	10,232	11,362	18,616	23,632	32,155
Net Profit (Loss)	(104)	86	(135)	(55)	(181)	(1,019)
Capital Expenditures	1,206	1,574	1,614	2,034	5,447	4,440
Debt	2,872	3,700	4,220	7,062	9,413	
Net FX Gain (Loss)	(43)	(17)	(122)	(179)	(179)	(194)
B. Key Performance Indicators						

Energy Sales (GWh)	15,076	17,322	19,122	20,891	23,888	27,081
Return on Equity (%)	-1.0%	0.7%	-1.0%	-0.3%	-0.8%	
Debt:Equity Ratio	36:64	40:60	43:57	49:51	54:46	
Self-Financing Ratio (%)	32%	57%	23%	55%	79%	
Debt Service Coverage Ratio	3.3	2.7	2.3	2.7	1.8	
Current Ratio (times)	0.7	0.8	0.8	0.8	0.7	

Table C6.2: PC2 / SPC Financial Summary

(VND billion - nominal prices)

	Actual					Estimate
	2006	2007	2008	2009	2010	2011
A. Financial Results						
Net Revenue	9,841	13,073	14,924	19,076	23,865	31,099
Net Profit (Loss)	(45)	148	(48)	(53)	41	(682)
Capital Expenditures	681	313	383	555	1,276	1,211
Debt	2,128	2,478	2,482	2,680	2,692	
B. Key Performance Indicators						
Energy Sales (GWh)	15,919	18,928	21,812	24,909	28,868	32,307
Return on Equity (%)	-0.5%	1.5%	-0.4%	-0.5%	0.3%	
Debt:Equity Ratio	31:69	32:68	31:69	31:69	28:72	
Self-Financing Ratio (%)	115%	140%	179%	289%	162%	
Debt Service Coverage Ratio	6.3	15.7	4.6	8.7	6.6	
Current Ratio (times)	1.0	0.8	0.8	1.0	1.0	

Table C6.3: PC3/ CPC Financial Summary

(VND billion - nominal prices)

	Actual					Estimate
	2006	2007	2008	2009	2010	2011
A. Financial Results						
Net Revenue	3,588	3,376	3,975	5,022	8,997	11,728
Net Profit (Loss)	(58)	34	47	(20)	6	(277)
Capital Expenditures	572	348	406	498	990	1,200
Debt	2,307	2,278	2,513	3,245	4,127	
B. Key Performance Indicators						
Energy Sales (GWh)	5,542	5,806	6,606	7,451	8,330	9,063
Return on Equity (%)	-0.9%	0.5%	0.6%	-0.2%	0.1%	
Debt:Equity Ratio	46:54	45:55	45:55	44:56	45:55	
Self-Financing Ratio (%)	32%	191%	81%	55%	222%	
Debt Service Coverage Ratio	2.0	3.3	2.7	2.7	2.8	
Current Ratio (times)	1.3	0.9	0.9	1.2	0.9	

Table 4: Hanoi Power Corporation VAS Financial Summary
(VND billion - nominal prices)

	Actual					Estimate
	2006	2007	2008	2009	2010	2011
A. Financial Results						
Net Revenue	3,993	4,949	6,113	8,733	10,907	12,879
Net Profit (Loss)	31	67	48	58	29	(489)
Capital Expenditures	291	343	459	474	1,141	1,000
Debt	490	615	698	844	1,352	
B. Key Performance Indicators						
Energy Sales (GWh)	4,442	4,822	5,985	7,879	8,909	9,514
Return on Equity (%)	3.1%	6.5%	4.0%	4.2%	1.9%	
Debt:Equity Ratio	33:67	37:63	35:65	37:63	47:53	
Self-Financing Ratio (%)	22%	55%	73%	33%	43%	
Debt Service Coverage Ratio	2.6	2.0	3.3	2.0	1.9	
Current Ratio (times)	0.8	0.7	0.7	0.8	0.7	

Table 5: Ho Chi Minh City Power Corporation Financial Summary
(VND billion - nominal prices)

	Actual					Estimate
	2006	2007	2008	2009	2010	2011
A. Financial Results						
Net Revenue	10,436	12,601	13,716	16,243	19,273	21,752
Net Profit (Loss)	42	(57)	34	29	35	(435)
Capital Expenditures	518	867	533	386	562	741
Debt	1,459	1,481	1,568	1,870	2,147	
B. Key Performance Indicators						
Energy Sales (GWh)	10,726	11,560	12,365	13,262	14,567	15,314
Return on Equity (%)	0.9%	-1.2%	0.6%	0.5%	0.5%	
Debt:Equity Ratio	41:59	43:57	41:59	46:54	47:53	
Self-Financing Ratio (%)	53%	73%	67%	95%	181%	
Debt Service Coverage Ratio	2.4	1.8	3.4	3.4	1.9	
Current Ratio (times)	1.1	0.7	0.7	1.1	0.9	

23. The key similarities in financial performance of PCs has been as follows:

- <u>Profitability</u>: On an IFRS basis, all of the PCs incurred small net losses in at least one year over the 2006 – 2010 period.[17] Overall profitability of the PCs is rather low with

[17] The difference in reported profitability between VAS and IFRS is primarily because the non-current portion of unrealized of foreign exchange losses can be deferred and amortized over the next five years under VAS whereas under IFRS, the full amount of the loss must be recognized in the year in which it is incurred.

the return on equity (ROE) varying form from a low of -0.8% for NPC to a high of 1.9% for HNPC. Over the entire 2006 – 2010 period, the returns earned by all of the PCs have been well below those considered commercially acceptable.

- Cash Flows: All the PCs generated positive net cash flows from their operations in all years between 2006 and 2010, thus their cash receipts from operations covered all cash operating and maintenance expenditures and left a surplus that could be contributed towards capital investments and debt repayment. HNPC and had a small negative cash flow after investment and financing costs in 2010, and on the same basis all the others had also had negative net cash flows in at least one year over the 2006 – 2009 period.
- Liquidity: The current ratio (ratio of current assets to current liabilities) of all the PCs was somewhat low, which is an indicator of potential liquidity difficulties.
- Capital Investments: Relative to EVN's generation and transmission businesses, the PCs are less capital intensive. In 2010 capital expenditures by the PCs was much higher than in any previous year, in part because of the need to undertake a significant rehabilitation of the local distribution networks transferred to the PCs during 2009 and 2010.
- Capital Structures: The less capital intensive nature of the PCs has important implications for their borrowing requirements. While the level of debt within the PCs has progressively increased over the past five years, their debt/equity ratios remain well relatively balanced. This means that the PCs have considerable remaining capacity for additional debt to fund a portion of future capital investments. The only potential concern is the NPC capital structure, which has rapidly become more leveraged than that of the other PCs. NPC's debt to equity ratio (DER) increased from 36:64 in 2006 to 54:46 by the end of 2010. While no figures are available yet for 2011, given the overall net loss for the year and estimated capital expenditures, it is likely that there was further increase in the DER during the year. If the increase in leverage continues at the 2010 rate, NPC's capital structure might become a concern as early as 2014.

24. The similarity in performance has been due to EVN historical internal practice of establishing different bulk supply tariffs (BST) for sales to each PC from EVN parent company (as Single Buyer), with the purpose of compensating for the differences in PCs' costs and customer mix. Therefore, bulk tariffs are set by EVN at higher levels for HNPC and HCMPC, which have higher unit revenue and lower unit costs, than for the other PCs. Under the government tariff reform program and with expert support funded through SEIER, ERAV is drafting BST regulations based on similar principles, to ensure that bulk supply costs of each PC reflect the power generation and transmission costs recovered from approved electricity tariffs, and that the PCs' financial performance depends exclusively on the efficiency in their investments, operation and services provided as distribution and retail companies.

25. It is noted that financial covenants have been incorporated into legal agreements between six of the original power companies,[18] EVN, IDA and IBRD under ongoing operations. The three main financial covenants are as follows:

(a) Debt Service. The debt service coverage ratio (DSCR) is to be at least 1.5

(b) Self-Financing of Capital Investments. The self-financing ratio (SFR) is to be at least 25%.

[18] PC1, PC2, PC3, PC Dong Nai, PC Hai Duong, and PC Ho Chi Minh City.

(c) Capital Structure. The debt to equity ratio (DER) is to be not greater than 70:30.

26. Over the 2006 – 2009 period, the PCs complied with these three financial covenants, with single exception of the SFR covenant for NPC in 2008. The company's SFR was 23%, just short of the 25% minimum required under the covenant. In 2010, NPC, PC2/SPC, CPC, and HCMPC all met the three financial covenants agreed to with IDA/IBRD. For most of the PCs, the margin of compliance with the covenants is wide. Compared to EVN's generation and transmission businesses, the PCs' capital investment programs have been smaller relative to their revenue and asset bases. As a result, most of the PCs have had maintained relatively high capacities for self-financing of capital investments and debt service. The debt service coverage ratios (DSCR) for the PCs, which measure a company's ability to service its existing debt, were all above the covenant minimum of 1.5 in 2010. The lowest DSCR was that for NPC, which was1.8. The PCs' self-financing ratios (SFR), which measures a company's capacity to fund its capital expenditures from its own internally generated revenue, were also well above the covenant minimum of 25% in 2010. For the four PCs for which the covenants apply, the SFRs ranged between a low of 79% for NPC and a high of 222% for CPC.

Preliminary Financial Performance (FY2011)

27. Based on very preliminary information, it is expected that all five PCs will report net losses for 2011 on an IFRS basis due to EVN modifying its internal practice in setting the BST. As the BST regulation is still not in place, after the Single Buyer (SB) registered losses in 2010 due to higher power generation costs, EVN modified their internal approach and increased BST to transfer part of the SB losses to PCs. Even if expected to be greater than incurred over the previous five years, these losses are still not significant relative to the PCs' scale of operation. Expressed on an IFRS basis, the estimated net losses for 2011 range from a low of VND 277 billion (US$14 million) for CPC to a high of VND 1,019 billion (US$50 million) for NPC.

Future Financial Performance Outlook

28. The lack of the BST and PCs tariff regulations affected the financial performance of the PCs in 2011 by allowing EVN to transfer losses from its SB business through setting a higher BST. The introduction of a transparent and cost-reflective regulation for setting bulk tariffs and distribution services tariffs of PCs, as expected by mid-2013, combined with the regulatory and financial enhancement support under Component C, will ensure that PCs' future financial situation will depend only on the efficient performance of their distribution business. The BST regulation and the PC distribution services tariff regulation that are being drafted by ERAV link a PC's financial viability and sustainability exclusively to its performance in providing power distribution and retail services. Given these considerations, the financial appraisal of the project and viability is based on the following:

- The PCs have historically demonstrated good management, operational and financial performance. This performance is expected to be strengthened by the tariff regulatory framework that will provide cost reflective and transparent mechanisms for the setting of BST and approving PCs revenue requirement and setting distribution services tariffs.
- The ongoing policy dialogue and the Power Sector Reform Development Policy Operations are supporting the tariff reform program and the third operation in the series includes the policy action of adopting the performance based rate setting regulation for

PCs. These will mitigate the risks of delays or non-implementation of tariff regulations.

- Under Component C, technical assistance will be provided to the PCs on financial modeling, analysis and risk management, in particular to take into consideration tariff regulations and performance standards.
- These efforts, together with other sector-wide TA support on financial performance issues, will assist the PCs to remain in sound financial condition in the future.

29. The proposed tariff regulatory system will create transparency and ensure that the financial performance of PCs depend on the efficiency in the management, investment and operation of its distribution and retail sales services. The revenue requirement and tariffs for network activities (regulated revenue and tariff for NPT and for PCs) covers approved capital and operational expenses and performance indicators. The PCs will have to plan and manage their investment and operation within approved revenues and efficiency gains, to achieve profits and financial performance used in tariff calculation. It must be noted that, although the political economy has limited generation costs transferred to tariffs to avoid sharp increases, the cost of transmission and distribution have been set to reflect approved investment and operational annual expenses. (Further details are provided in project supporting documents describing power sector context and reform program.)

30. Therefore, reliance on the past sound results of the PCs and new tariff regulatory system to be introduced by mid-2013, without additional measures was not considered adequate for the purpose of project appraisal. To adapt to the new regulatory framework and benefit from efficiency gains expected from the project, it was decided to incorporate in Component C technical assistance for the PCs on financial modeling and simulations to design and carry out risk management strategies such as capital expenditure planning and debt management. The project, therefore, includes funding for consultants services to support the five PCs by: (a) developing or enhancing a suitable financial model, appropriately customized for each PC as needed, including its detailed operating manual for guidance of staff in running the model, conducting financial analysis, identifying key performance risks and solutions; (b) training a core group of staff in each PC to undertake financial modeling and analysis; and (c) providing a Financial Analysis and Decision Making sessions for key PCs' non-finance managers.

31. **Financial Covenants**: As indicated above, it is not possible at this stage to prepare financial projections to guide the determination of traditional financial ratios based covenants. Therefore in line with the appraisal strategy of building the capacity of the PCs the financial covenants for this operation will be based on capacity related achievements, namely, (a) the completion of TA delivery by December 31, 2013 (items a, b, c and d in previous paragraph); and (b) by September 30 of each year starting in 2014 the PCs will submit for the Bank review a document with the financial outlook of the following year based on the detailed analysis prepared by the PC and including proposed implementation of any performance issues during the year in question.

Annex 7: Clean Technology Fund

VIETNAM: Distribution Efficiency Project

Key Indicators	CTF funding	CTF/WB funding	Scaled-up Phase (2)
Electricity savings (MWh per year) (1)	365,906 to 731,812	426,679 to 853,359	1,012,388 to 2,024,775
CO_2 avoided (1) - **Tons per year** - **Lifetime (ton/10 years)**	237,839 to 475,678 2,378,390 to 4,756,780	277,342 to 554,683 2,773,416 to 5,546,832	658,052 to 1,316,104 6,580,519 to 13,161,038
CTF Investment cost effectiveness (US$ per tonne of CO_2 avoided)	**12.6 - 6.3**	**10,8 – 5.4**	**4.6 - 2.3**
CTF investment leverage ratio	**1:3**	**1:27**	
Improved reliability of services provided by PCs	Reduction in number and duration of interruptions to electricity consumers, due to optimization of distribution system configuration and faster detection and response to faults.		
Environmental co-Benefits	Lower local pollutant due to avoided thermal power generation		
Other Co-benefits			
Enhanced demand forecasting and optimization of available generation resources	Significant improvements in load forecasting and operational planning, including optimization of generation scheduling and dispatch, due to access and processing of data at key points of the network and consumers for real time operation optimization and better short term load forecasting		
Empowering customers and reducing load shedding	Reduction of compulsory load shedding events, due to providing information to customers on their electricity use and participation in demand response programs		
Increase in RE penetration	Facilitates connection and integration of small scale generation from renewable resources, which connect to PCs' network		

(1) Values are calculated based on estimates and assumptions described in Section E of this Annex. Assumptions are for a range of potential savings (0.5 to 1 percent)

(2) Values in the scaled-up phase exclude the potential impact in demand reduction due to enhancement in tariff structure, which could lead to around 10-20 times greater avoided CO2.

A. Introduction

1. Vietnam has been one of the fastest-growing economies in Asia for the last two decades. The structure of the economy has changed rapidly, with a steady increase in the share of industry and services in GDP. Economic growth has benefited from indigenous resources including biomass energy, coal, crude oil, hydropower, and natural gas. Renewable energy (RE) accounted for the largest share of primary energy demand, mainly due to the traditional biomass (mainly fuel wood) for residential use, particularly in rural areas. However, RE resources are limited, and fossil fuels are projected to account for the largest share of primary energy demand after 2020.

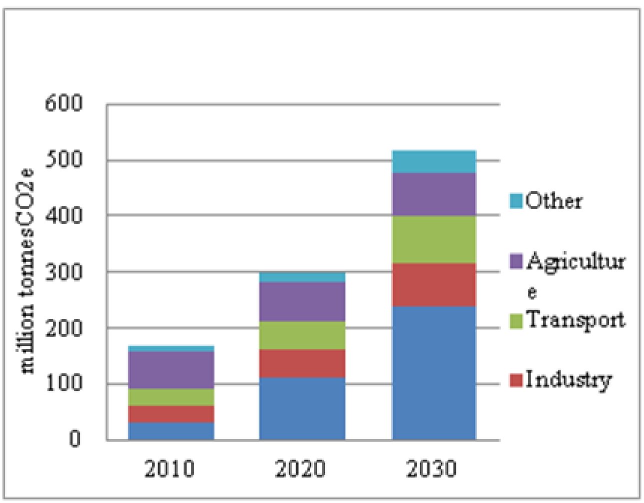
2. Primary energy consumption increased 6.5% percent per annum (p.a.) from 32,235 KTOE in 2000 to 50,221 KTOE in 2007. During that period, end-use energy consumption grew at the same rate. Total Greenhouse Gas (GHG) emissions in 2000 totaled 150.9 million tonnes of CO2 equivalent (tCO2e), of which around one third (52.8 million tCO2e) came from energy. For the past 10 years, energy consumption has been increasing faster than GDP. The commercial energy use / GDP growth elasticity registers a very high 1.7, attributable to a fast expansion of heavy industry and motorized transport, and increasing use of fossil fuels for power generation. The energy intensity of Vietnam's economy grew from 387 kilograms of oil equivalent (kgoe) per US$1,000 of GDP in 1998 to 569 kgoe per US$1,000 GDP in 2006 (in constant 2000 prices).

3. The sustained growth in energy consumption has been due to industrialization, urbanization and rapid growth of the transport sector, and use of modern electrical appliances in households as the income is increasing. Vietnam's energy sector business-as-usual (BAU) scenario is characterized by continued rapid economic expansion at an average GDP growth around 6 percent p.a. over the next two decades. By 2030, Vietnam's population is expected to reach 108 million with a per capita income of about US$10,000 (up from US$2,500 in 2002, 2000 PPP) and an urbanization ratio of 43 percent (up from 25 percent in 2002). Structural shifts in Vietnam's energy supply mix are projected, with faster growth in coal and oil consumption.

4. Between 2010 and 2030, primary energy demand is expected to more than double and total energy related GHG emissions will triple, with power, industrial, and transport sectors projected to account for the bulk of this increase. By 2010, GHG emissions have been estimated as 33 percent from industries, 27 percent from power generation, 24 percent from transport, 7 percent from residential, 6 percent commercial, and other (non-power) combustion 2 percent. Emissions from the power sector are projected to increase by 2030 to 293,000 KTOE, while industry and transport sectors would grow substantially but at a slightly lesser rate. GHG emissions from power generation can be ascribed largely and in roughly equal shares to the residential and industrial sectors, making industries the biggest (direct and indirect) GHG emitter in Vietnam, followed by the residential and transport sectors.

Table A71: Vietnam GHG Emissions Projections

(*Vietnam Second National Communication to UNFCC, 2010*



5. Between 2001 and 2010 electricity consumption average growth rate was 14.5% per year. In 2010, commercial electricity reached around 86.8 billion kWh, 14.1% growth compared with 2009 (2.1 times compared to GDP growth). Industrial and residential consumers are the two dominant electricity users (more than 40 % of total consumption in each segment). The national Power Development Master Plan 7 covering the period 2011-2020 with the vision up to 2030 (PDMP7)[19] emphasizes as key objectives energy security, energy efficiency, renewable energy development, development of power markets and market based pricing for electricity. Base case demand projections expect average 14 percent p.a. growth during the period 2010-2015 and around 11 percent p.a. between 2016-2020, and around 5,000 MW of additional generation capacity each year. PDMP7 targets for the share of generation from small renewable energy to increase from current 3.5%, to 4.5% by 2020 and 6% by 2030.

6. The historical rapid electricity demand growth has compelled the allocation of almost all the available resources to investments in supply facilities. As a consequence, measures and actions on the demand side have been limited. Recognizing the difficulties of trying to catch up with the electricity demand growth at all costs, PDMP7 sets as a specific target the reduction of average energy elasticity ratio (the ratio between the growth rate of energy consumption and the growth rate of GDP) from the current 2.0 to 1.5 by 2015 and 1.0 by 2020. CO2 emissions from electricity generation can be ascribed largely and in roughly equal shares to the residential and industrial sectors, making industry the biggest (direct and indirect) GHG emitter in Vietnam, followed by the residential and transport sectors.

7. To increase Vietnam's capacity to finance the investments in the power sector required to support economic growth beyond the more traditional sources of retained earnings, local banks and ODA, the Government has embarked on an ambitious power sector reform program. Key components include electricity tariff reform and strengthening the sector players to develop the power market. On tariffs, the reform comprises transition to tariffs reflective of efficient costs combined with subsidies to provide social protection to the poor, national tariffs that apply to all residential consumers (ensuring similar prices for rural and urban households), and implementing tariffs with pricing differentiated by time of use (TOU tariffs) to all large electricity consumers. The strengthening of distribution and retail companies, to become the buyers of small scale renewable generation (less than 30MW) and the future wholesale purchasers in the market has taken place through the consolidation into 5 Power Corporations (PCs), subsidiaries of EVN.

8. Electricity losses in transmission and PCs distribution systems decreased significantly during the period 2001-2009, from 14 percent in 2001 to 11 percent in 2008, down from over 20 percent ten years earlier. However, higher distribution losses are observed in congested locations and rural areas. Average system losses slightly increased in 2010 (10.25 percent compared to 9 percent in 2009), due to losses in the rural systems of local distribution units (LDUs) transferred to the PCs.[20]

9. Within this context of increasing energy demand, Vietnam faces many challenges to mitigate climate change and limit the growth of GHG emissions while sustaining economic growth and reducing poverty. Achieving low carbon growth will require a significant

[19] July 2011, Prime Minister Decision 1208/QD-TTg
[20] LDUs systems losses can be 25 percent or more.

transformation within each economic sector, industrial energy use and society as a whole. Emission savings interventions in the power sector and energy efficiency (EE) measures in industrial and residential/commercial sectors are considered the most promising interventions, if such interventions can be developed at reasonable costs and replicated at large scale.

B. Vietnam's Investment Plan for CTF

10. The GoV's Clean Technology Fund (CTF) Investment Plan (IP) was submitted in December 2009 and the CTF Committee endorsed US$250 million overall CTF funding. An IP supplemental note requested by CTF Committee members was submitted in June 7, 2010, which reallocated ADB CTF funding from the initially proposed electricity transmission sector to urban transport sector. An Update Note was presented to the CTF Committee in June, 2011, informing further proposed re-allocations within the sectors and activities identified as priorities in the IP, including the updated Annex for IBRD (World Bank) for the proposed smart grid distribution efficiency project.

(a) ***World Bank Smart grid technologies in transmission and distribution***: The CTF intervention will target smart grid in distribution rather than in transmission, as the power distribution sub-sector offers a larger potential for replication, allows to achieve electricity consumption reduction and can remove some barriers to integration of small renewables to be connected to the distribution network.

(b) ***ADB Urban Transport Enhancement***: Of the US$100 million allocated in the CIP supplemental note, US$50 million have been agreed for Ho Chi Minh City (HCMC) rail project and ADB proposes to allocate the remaining US$50 million to urban transport enhancement project in Hanoi

11. Table A7.2 shows the updated IP projects and financing plans presented in June 2011, with investments estimated for a total cost of US$3,070 million in four key areas: (i) industrial energy efficiency; (ii) urban transport; (iii) smart grid technology; and (iv) clean energy.

Table A7.2: Updated Project Financing Plan (US$ million)

Financing Source	***Proposed Programs and Projects (Vietnam IP update note, June 2011)***				**Proposed Project**
	Industrial Energy Efficiency (ADB)	**Urban Transport Enhancement (ADB)**	**Clean Energy Financing Facility (IFC)**	**Smart Grid Technology June 2011 (IBRD)**	**Distribution Efficiency Project with Smart Grid AMI**
MDBs	40	500	200	**300**	**448.9**
GOV	25	100	0	**105**	**313.5**
CTF	50	100	70	**30**	**30**
GEF	0	0	0	0	0
Carbon Finance	10	0	0	0	0
Other Co-financing	40	500	0	0	7.6

Private Sector	100	0	900	0	0
TOTAL	265	1,200	1,170	**435**	**800**

12. The last column of Table A7.2 presents the total financing for the Distribution Efficiency Project, corresponding to the World Bank smart grid technology CTF co-financed project, showing that financing is greater than estimated in June 2011. In the proposed project total financing is US$800 million, of which US$448.9 million would be IDA, US$313.5 million will be financed by the Government through PCs' counterpart funds, US$30 million would be CTF co-financing, and AUD 7.6 million AusAID grant co-financing has been included to provide technical assistance and capacity building support to maximize the impact in avoided power generation and associated avoided GHG emissions. The smart grid technology component of the project is described in further detail in the following Sections.

C. Distribution Efficiency Project: Introduction of smart grid technologies in electricity distribution in Vietnam

C1. Rationale for introducing Advanced Metering Infrastructure (AMI) in electricity distribution in Vietnam

13. Smart grid in electricity distribution comprises of information-technology based investments, applications and programs, which can be divided into two broad categories. The first category includes all investment options related to distribution automation (DA), which provide improved ways for distribution companies to remotely monitor and control the operation of the distribution system. The second category comprises Advanced Metering Infrastructure (AMI), also referred to as "smart metering", including the investments in meters, two way communications and the necessary systems to collect, and to process and manage the data collected. Additionally, AMI enable programs that incorporate the customer to the operation of the grid (enhanced information, demand response and advanced load control), and enhance the pricing signals to promote efficient use of electricity (time varying rates). For the purpose of this project, the proposed AMI is considered broader than only the physical investments and data processing, to include also the enhancements in electricity tariffs and demand response programs targeted through the technical assistance and capacity building AusAID grant in Component C.

14. Actions to manage demand in Vietnam power sector were limited during the last 10-15 years, due to the large financial requirements to build and maintain the infrastructure (generation, transmission and distribution) in a context of very high growth in electricity consumption. As the country is facing a constrained financial scenario that is likely to persist in the near future, it becomes crucial to ensure that the use of the existing infrastructure for electricity supply is fully optimized. Introduction of smart grid technologies and programs focused on demand response and energy efficiency management by consumers is the most effective tool for that purpose. But financing costs of smart grid investments in Vietnam power distribution subsector continues to be a challenge, as requirements to upgrade and rehabilitate distribution systems to control losses have maximum priority in the short and medium term. An estimate by Ho Chi Minh PC (HCM PC) indicates that the full-scale deployment of various smart grid technologies in its service territory could cost in the range of two trillion VND (100 million USD). The cost of deploying smart meters to all PC customers has been estimated around one billion dollars.

15. The power sector in Vietnam is facing financing challenges due to the large volume of infrastructure investments planned to supply demand growth in the next 10 years. Financing from the World Bank and other multilateral development banks (MDB) to the Power Corporations (PCs) is targeted and prioritized by the Government of Vietnam (GoV) and EVN to finance distribution system investments, mainly to rehabilitate and upgrade the networks. Although investment in smart grid Advanced Metering Infrastructure (AMI) technologies are considered important by the Government and the electricity regulator, they have been set aside for the future, as the PCs and the Government would like to see their potential benefits - reducing demand growth, the need for network upgrade investment, and thereby strengthening supply security – to be first demonstrated in Vietnam context.

16. The possibility of CTF financing provided the Bank with the opportunity to present to and agree with the GoV and PCs investment in smart grid AMI, to demonstrate its quantified impact, costs and benefits. CTF co-financing offered this opportunity because (i) CTF financing entails concessional terms (financing at lower cost than IBRD/IDA) and the concessionality is passed through to PCs; and (ii) CTF cannot be used to finance traditional distribution investments, which currently are GoV's priority for IBRD/IDA lending.

17. The proposed AMI IBRD CTF project in Vietnam CTF National Investment Plan was presented to CTF Committee in June 2011, and endorsed in concept. At the time, given the perceived uncertainties, only three PCs were willing to participate in the project, including HCM PC, which has been leading initiatives in demand response or control programs in Vietnam. The CTF will provide US$30 million co-financing for investments that incorporate AMI in three PCs, namely HCM PC, Hanoi PC and Northern PC. Additionally, the project will finance AMI for Central PC using only World Bank financing (IDA).

18. The main objective of the proposed CTF AMI project is to achieve savings in GHG emissions and the demonstration of the greater savings potential to create a transformation effect through replication country wide. The AMI investments are targeted principally to (i) increase availability of data (near real time information) by distribution operators, (ii) enhance energy information provided to large consumers to promote efficient use of electricity and demand management, which is the expected main contribution to GHG savings; and (iii) to optimize network configuration and reduce overloads through information on load level at critical network equipment. This is part of the first stage in a comprehensive phased smart grid roadmap involving all the PCs and several segments of their served customer markets.

19. In summary, in Vietnam the benefits of AMI investments, data management and enabling programs have still to be demonstrated, and the proposed AMI CTF project is the pilot to address the credibility gap. Worldwide, some jurisdictions have chosen not to implement smart meters due to the uncertainties over whether the benefits of their deployment will outweigh the costs. Internationally, pilot programs and other detailed studies have been used to address this uncertainty and increase confidence in the benefits of deployment. The project aims to demonstrate the applicability of the AMI concept to optimizing demand and load management, show its costs and benefits, and provide a learning opportunity for all PCs. The successful demonstration of the proposed CTF co-financed project, in particular the demonstration of costs and benefits, is expected to scale up the program to all PCs and further customer segments, using IBRD/IDA or other ODA funds and own resources.

20. Accordingly, the proposed project has been designed as a small pilot for AMI deployment, covering (i) key substations in the distribution network; and (ii) only around 1% of customers of participating PCs representing the largest consumers where it is expected to achieve the highest impact. (Initially, the PCs had considered a broader scope, all consuming above 500 kWh/month, but analysis during project preparation identified that the AMI project would be economically beneficial but financially not.) Leveraging CTF financing with the AusAID grant under Component C, through technical assistance for the supporting regulatory framework and awareness campaigns, will contribute to address the credibility gap.

C2. AMI functionalities and technology development status

21. Proposed investments in AMI will cover (i) supply and installation of smart meters and remote communication devices in critical equipment of the distribution system (transformers, feeders, etc.), border points and large customers' premises; and (ii) implementation of metering control centers equipped with the software packages making possible permanent two-way communication with metered points/consumers, systematic data collection, analysis and processing. Data management will enable during real time operation to take measures and optimize the system configuration, in dispatch optimize load forecasting and generation scheduling of embedded generation, and integrate the customer through demand response programs or demand load control technologies.

22. Smart metering represents an improvement over traditional electromechanical metering in two fundamental ways. First, the meters measure and record electricity consumption in granular time intervals, providing much richer information about when customers are using energy, and enabling new and innovative customer-side programs. This information also allows for more accurate load forecasting and load profiling for effective design of TOU tariffs. Through incorporation of AMI, meter data is collected remotely and instantaneously. This functionality provides a number of operational benefits, including avoided meter reading costs, remote connect and disconnect of service, and real-time monitoring of grid conditions which enables faster outage detection. Moreover, it makes possible to design and implement operational procedures allowing to systematically record and monitor the consumption of selected groups of customers and load of network components (transformers, feeders, etc.). This has several purposes, such as ensuring permanent protection of revenues from sales to those groups, offering customers in each group tariffs and consumption options to encourage more efficient use of electricity, avoiding overloads and minimizing technical losses in networks, etc.

23. AMI goes a step further beyond remote reading, by including smart meters and the infrastructure that is necessary to access and process the data that comes from these meters (e.g., communications, data management systems and billing). It also comprises two way communications and enabled new, innovative technologies and programs that can be offered to customers as a result of the smart meter deployment. There are four basic elements: (i) smart metering, which measures and communicates electricity consumption information in short time intervals (typically 15 minutes to one hour); (ii) use and enhancement of time-varying rates, such as time-of-use rates or dynamic rates, which more accurately reflect the true cost of providing power over the course of the day; (iii) enhanced energy information that provides customers with granular and actionable information about their electricity consumption; and (iv) advanced load control, which includes technologies that help customers automatically reduce electricity consumption during high-priced hours.

24. ***Time varying rates***. Implementation of AMI makes possible to apply time-varying rates designed to charge customers a higher price during peak hours or periods when it is more costly to meet electricity demand. Time-of-use (TOU) tariffs are an example of time-varying rates, which are widely applied to largest customers (in particular in Vietnam). These rates can be also be deployed to other customer classes once the appropriate metering infrastructure has been deployed.

25. AMI provides ***enhanced energy information***. The detailed energy data that is made available by smart meters can be communicated back to customers in a way that will encourage them to better manage their energy use. This information can be provided in the form of more detailed billing information, through an internet web page, or through an in-home information display device. The enhanced information could include a recent history of hourly consumption, the cost of energy, or warnings when a customer is approaching their "target" energy consumption level. Some approaches have even compared customers' energy use to that of other similar customers, as a way to benchmark their consumption. Studies have shown that, when equipped with this information, customers consume less energy overall.[21] The result is bill savings for the customer and a form of load management for the distribution company. It also provides an additional means by which the company can communicate with its customers.

26. Availability of AMI systems enables the application of several "dynamic" rate options. Dynamic pricing is different than TOU pricing in the sense that prices are typically only known by the customer on a day-ahead or even hour-ahead basis. For example, with a real-time pricing (RTP) rate, customers are often given the next day's hourly prices the prior evening. An alternative dynamic pricing option is a critical peak pricing design, which can have two pricing periods like a TOU rate but the peak period price occurs only on 10 or 15 days of the year and is only known a day in advance by participants. This peak period price is also three to five times higher than that of a TOU, since it is designed to recover the capital cost of a peaking generation unit during the critical peak hours. This ability to "dispatch" strong price signals to customers on shorter notice provides an incremental advantage over TOU rates, because the rate can be used like a demand response program to address system emergencies or high marginal energy and capacity costs (rather than just generally encouraging load shifting to off-peak hours). The potential benefits of time-varying rates could be significant. By encouraging customers to reduce consumption during peak times, expensive capacity and energy costs can be avoided. Customers have the opportunity to reduce their electricity bill by consuming energy during cheaper hours. And from a societal perspective, the rates improve fairness between customers, since they eliminate the inter-customer cross-subsidies that are inherent in flat rates.

27. Incorporation of AMI also makes possible to deploy advanced load control technologies that help customers to automatically reduce consumption in response with tight reserves or higher-priced periods of time-varying rates. For residential customers with central air-conditioning, this usually includes a programmable communicating thermostat, which is equipped to receive a signal from the distribution company and automatically reduce air-conditioning use during demand response events or high priced periods. For commercial and industrial customers, a technology known as Auto-DR is used as an upgrade to a facility's energy management system, allowing many different end-uses or processes to be automatically managed

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[21] Ahmad Faruqui, et al., "The Impact of Informational Feedback on Energy Consumption - A Survey of the Experimental Evidence," Energy, August 2009

in a coordinated fashion in response to high prices or special events. Advanced load control provides many of the same benefits of a traditional demand response program; primarily, avoided power generation, lower costs for the utility and bill savings for the customer. In the case of Vietnam, this enhanced ability to control load during periods of tight reserves or congestion could provide substantial reliability benefits, and reduce involuntary load curtailment that are being applied when PCs are unable to supply the total demand.

28. The AMI technology is mature and well proven, both in developed and developing countries. There is fairly extensive international experience in deploying AMI. For example, roughly 13 percent of all meters in the United States are now smart meters. Across Italy and France, AMI has been universally deployed by the national utilities in Italy (ENEL) and France (EdF). In all, across the world, there is an expectation that 825 million smart meters will be deployed by 2020. In many cases, AMI deployment is being justified primarily on its operational benefits, in developing countries on controlling theft, in developed countries reducing staff costs. There are also some examples of full-scale time-varying pricing deployments and use to control electricity theft. For example, several well performing distribution companies in Brazil are implementing revenue assurance and protection programs based on systematic recording and monitoring the demand of their large customers supported by AMI. Similar programs are being adopted by companies in other Latin American countries, India, Indonesia and Kenya.

29. To a lesser (but growing) extent, the smart metering rollouts are also being accompanied by new customer programs. Mostly, these programs are being tested as demonstration projects or experiments to develop a better understanding of their impacts before they are offered on a larger scale. The results of these experiments show that the impacts and benefits could be quite significant. In some jurisdictions in the U.S., Canada, United Kingdom, and Australia, large commercial and industrial customers are exposed directly to hourly market prices rather than to a flat rate. In other regions, power utilities (such as the power sector in Vietnam) have implemented for larger customers time-of-use (TOU) rates. In Canada, TOU rates are currently being rolled out as the default rate option for all residential customers in the province of Ontario. France has been offering a nationwide voluntary critical peak pricing and TOU rate called tempo to its residential customers since the mid-nineties. There is a strong expectation that these types of rates will expand as smart meters are deployed. However, while recent experience has reduced many of the technical challenges associated with AMI deployment, many utilities continue to struggle with several issues jeopardizing massive application.

30. Customer acceptance is a critical requirement for the successful implementation of a smart grid program. Once smart meters are deployed, the challenges remain on encouraging customers to enroll in new programs. For example, dynamic pricing pilots often struggle to achieve a 20 percent acceptance rate when recruiting participants. However, once customers are enrolled in the pricing programs, typically more than 90 percent of participating customers indicate that they want to remain enrolled. This challenge of customer recruitment is common, and there are a number of ways to address it. First, defaulting customers on to the new rate or program (with the option to opt-out) has shown to achieve higher participation rates. Second, bill information, showing to customers how their bills would be impacted by the program before they are exposed to any financial risk, is another way to help with the transition. Third, and the most important factor, customer education and outreach is critical in any smart grid deployment, in order to

improve the likelihood that customers understand the benefit and opportunity for bill savings that the programs offer.

D. **Assessment of the Proposed Project with CTF Criteria**

D1. Demonstration potential at scale

31. The AMI project to be cofinanced by CTF involves three of the five PCs operating in Vietnam and one PC would be financed only by IDA, targeting key points in the distribution system and large customers. Replication of the project to all the PCs should imply a duplication of its achievements in terms of reduction of GHG emissions. But a greater and permanent quantitative impact can be achieved if the information provided by the project on demand of customers is used as input to improve the existing tariff system and implementing effective demand response programs, creating signals and incentives for customers to maximize efficiency in consumption. Consequently, enhancement of the tariff system and piloting and demand response programs are supported by Component C of the project (Technical Assistance and Capacity Building) through grant funding by AusAID to the electricity regulator (ERAV). The grant will also provide support for PCs to benefit from international expertise in deployment of AMI and demand response programs.

32. The project benefits from the lessons learned from the Bank Demand-Side Management and Energy Efficiency Project (DSM/EE Project funded by SEIER and GEF). An assessment of the DSM/EE concluded that time of use (TOU) programs (meters and tariffs) should establish baseline and periodic load profiling, the process for data collection, validation and assessment, to improve TOU tariff design and ensure adequate price signals to promote customers' changes in consumption. Additionally, the assessment recognized the need for regulations and incentives to support demand response and demand load control programs, as well as the need for information dissemination and marketing of TOU and demand response programs to help customers understand the options and opportunities. Accordingly, the project combines the AMI investments under Component B with technical assistance under Component C targeting climate change mitigation through regulatory and tariff enhancement, demand response support and customer awareness campaigns.

33. Actions to manage demand in the power sector of Vietnam were limited in the last 10-15 years, due to the huge financial requirements to build and maintain the infrastructure (generation, transmission and distribution) in a context of very high growth in electricity consumption. As the country is facing a constrained financial scenario which is likely to persist in the near future, it becomes crucial to ensure that the use of the existing infrastructure for electricity supply (generation, transmission and distribution) is fully optimized. Introduction of smart grid technologies and programs focused on demand side response and energy efficiency management for larger consumers is the most effective tool for that purpose. But financing costs of smart grid programs in power distribution subsector continues to be a challenge in Vietnam as requirements to upgrade and rehabilitate distribution systems to control losses will have maximum priority in the short and medium term.

34. In that context, the CTF would provide US$30 million to co-finance investments to incorporate AMI systems in three PCs, aimed to support demand management by large consumers and optimizing network configuration through information on load level of critical network equipment. This is the first stage of a more comprehensive phased smart grid roadmap

involving all the PCs and several segments of their served customer markets. The initial stage aims to demonstrate the applicability of the AMI concept to demand and load management, show its costs and benefits, and provide a learning opportunity for all distribution companies (PCs). To implement this first stage, the PCs that are proposed for CTF co-financing are Hanoi PC, Northern PC (NPC), and Ho Chi Minh City PC. Investments in AMI will cover (i) supply and installation of smart meters and remote communication devices in critical equipment of the distribution system (transformers, feeders, etc.), border points and large customers' premises; and (ii) implementation of metering control centers equipped with the software packages making possible permanent two-way communication with metered points/consumers, systematic data collection, analysis and processing. Data management will enable during real time operation to take measures and optimize the system configuration, in dispatch optimize load forecasting and generation scheduling of embedded generation, and integrate the customer through demand response programs or technologies.

35. The successful demonstration of the proposed CTF project, showing the cost / benefits, is expected to scale up the program to all PCs and further customer segments, using IBRD/IDA or other ODA funds and own resources. The transformational impact will be achieved through the replication enabled by the demonstration of cost-benefit to PCs of AMI investments, and scale up of demand response programs through the dissemination of impacts and benefits for customers. This will lead to AMI investments being replicated and scaled up in all PCs. The technical assistance under Component C will contribute to assess and enhance the demand response programs to support the transformational impact in the scale up and broader replication of the programs.

D2. Expected benefits and development impact

36. Incorporation of AMI will contribute to improve effectiveness and efficiency in operations of the PCs. Expected positive impacts include: (i) better reliability and quality of service provided by PCs to their customers through optimized configuration of distribution networks, faster detection and response to outages; (ii) reduction of technical losses (due to elimination of overloads in networks) and of unmetered consumed energy (commercial losses); (iii) increased revenues due to higher accuracy in meters reading and billing processes; (iv) lower rates of equipment damage and maintenance costs; (v) enhanced transparency in operations due to the timely availability of reliable information across each company; and (vi) more efficient use of electricity by end consumers.

37. Positive impacts of the project are not limited to efficiency gains in electricity distribution business. The expected efficiency gains (reduction in technical losses) and demand reductions represent avoided power generation, which will lead to environmental co-benefits due to the reduction of GHG emissions. In Vietnam power sector, hydropower and other renewable resources are prioritized in the generation scheduling and dispatch process.

38. The GoV is pursuing climate change mitigation through the development of small renewable generation. Through the avoided cost tariff (ACT) support program, including provisions on must buy and priority dispatch by PCs, and Standardized Power Purchase Agreement (SPPA), in only two years (by December 2010) 727 MW of small hydro had been enabled, mainly in the North and Central regions, of which 29 projects totaling 249 MW are already in operation, and the remaining have signed the SPPA and are under construction. It is

estimated that in total around 2,000 – 3,000MW of small hydropower plants may be developed and connected to PCs networks (including 110 kV). The GoV has also issued special support mechanism for wind power, including feed-in-tariff for the developer, subsidy/compensation for the purchaser (PC) and similar purchase agreements as for the ACT. Studies are underway in MoIT to design support mechanisms for biomass and solar.

39. However, connecting and integrating the variability of small hydro and wind generation, and eventually solar, will require investment and modernization of the PCs' distribution system and operation. If the system is not ready to connect this new capacity, then coal or gas fired power plants, which are easier to integrate into the existing power system, will provide the required energy to supply the demand.

40. Thus, avoided power generation will mean reducing the production of thermal plants and of the related avoided GHG emissions. Similarly, reductions in consumption by AMI customers compared to BAU scenario will result in avoided GHG emissions.

41. During project implementation impact of AMI in energy reductions and avoided GHG emissions will be monitored and reported annually, as well as impact of Component C activities measures in participation and results of demand response programs, and impact in representative load profiles of AMI customers. The results, assessment and lesson learned at the end of the project will be presented in assessment report for replication.

42. **Optimization of system configuration**. Optimized configuration of distribution networks through the implementation of smart grid technologies, including the AMI, will make possible to eliminate current overload conditions, thus reducing technical losses and restoring the availability of the network capacity. This will facilitate the connection of small scale generation projects based on renewable resources, enhancing their feasibility, and creating the conditions to maximize the capability of the network to absorb their energy.

43. **Increase in reliability and lower costs**. Implementation of AMI in key components of the distribution system (transformers, feeders, etc.) will enable PC system operator to address overloads, reducing faults and maintenance costs). Additionally, faults in metered equipment will be immediately detected, enabling the adoption of fast corrective action to restore service in the shortest possible time. Compared to the "without AMI" scenario, these functionalities should reflect in enhanced service reliability and reduction of technical losses, lowering power purchase costs to supply the demand.

44. **Control of commercial losses**. The AMI project will also assist to control non-technical losses (unbilled consumption), avoiding the potential increase that could happen in the "business as usual (BAU)" scenario as tariff increase to cost reflective levels. International experiences such as in Brazil power distribution show that the historical approach of detecting electricity theft through field inspection is not sustainable in a context of increasing electricity prices. As an example, starting from a good condition (low non-technical losses), the largest Brazilian distribution company CEMIG through AMI investments managed to reduce their losses by 1-2 percentage points compared to the BAU scenario. Controlled non-technical losses imply both increased revenues and lower electricity purchases compared to the BAU case.

45. **Enhancing load forecasting and optimizing embedded generation**. Load profiling of electricity consumers will benefit from AMI data, enabling improvement in load forecasting for distribution system planning, system operation and dispatch of embedded generation, and for time-of-use tariff setting. This can be a significant source of value in Vietnam where the demand data currently available is very limited.

46. **Enhancing electricity tariffs**. Load profiles of customers are the key inputs to optimize the tariff structure and time-of-use (TOU) pricing, thus providing economic signals to reduce consumption and efficiently use electricit*y*. Technical assistance to the sector regulator ERAV for the improvement of the electricity tariff structure and TOU based on information provided by the AMI systems will be provided in Component C of the project. ERAV has drafted and regulations have been issued mandating load research, with PCs having the primary role of data collection and load profile analysis at each company's level, under the monitoring of ERAV for the purpose of tariff setting. The regulation requires each PC to maintain load research data of non-residential sample customers within its jurisdiction, and to submit to ERAV quarterly and annual load profile analysis reports. Incorporation of AMI will facilitate the implementation of PCs obligations, as well as enhance supervision by ERAV and the transparency and accountability of the process.

47. An efficiently designed tariff system, providing consumers with adequate signals on costs of supply is a key driver of energy efficiency actions on the demand side. Expected reductions in electricity consumption will lead to avoided power generation and associated reduction in GHG emissions compared to BAU, the postponement of investments, and an improvement in service reliability. Vietnam has a significant potential for reduction in the demand of large electricity consumers, and the introduction of AMI targets those energy reduction opportunities through enabling demand side programs and tariff setting.

48. **Local socio-economic development**. Overall, the Distribution Efficiency Project, that combines country-wide investments expanding and upgrading or rehabilitating the distribution system of PCs combined with modernization through smart grid technologies, will contribute to the achievement of longer-term social development goals of Vietnam. As PCs will upgrade and expand the distribution system, enhance the quality and reliability of power supply services, reduce electricity losses, and improve the performance and accessibility of electricity distribution services, the project will contribute to enhancing the effectiveness of the poverty reduction program, the reduction of the current gap in equality of access to services among regions, and the consolidation of social security. In particular in the areas benefitting of distribution system investment subprojects, the improvements will support meeting local development objectives such as accelerating economic and social development, increasing productive uses of electricity, improving quality of life and expanding access to better public services.

49. **Gender**. Similarly, the overall project will benefit residential households, including women who rely on electricity to carry out domestic functions. The reliable supply of electricity will reduce the need to switch to more polluting and health damaging alternative fuels (e.g. kerosene) for cooking. A Bank-executed AusAID grant will support a targeted gender assessment to identify needs and potential activities to improve the PCs provision of quality and reliable electricity services in an equitable way. Surveys will cover interviews with both men and women within the PCs as well as beneficiaries, to establish technical assistance and capacity building

activities on impact and integration of gender concerns in the projects and planning of PCs. The findings of this assessment will be linked throughout the project where relevant and agreed, to help ensure that project implementation and project beneficiaries are equitably reaching and impacting both men and women.

E. Potential for GHG emissions savings - Emissions reduction potential of investment

50. The main contribution to avoided GHG by the proposed CTF AMI project is expected from demand reductions. Accordingly, the proposed CTF indicators are to monitor and quantify AMI impact based only on demand reductions and associated avoided GHG emissions. Additionally, the overall distribution efficiency project will monitor reduction in losses and quantify associated avoided GHG. These GHG reductions will be attributed to the combination of interventions in Component A (traditional distribution investments) plus Component B (smart grid with CTF cofinancing).

51. The potential for GHG emission savings are based on expected reductions in demand and related avoided power generation. Estimates in the literature can vary, ranging from 1% to up to 15% depending of the case. More recent studies of the benefits of smart meters estimate the consumer response is a reduction of consumption by 1-3% range. However, it must be noted that studies and experiences usually assess the demand reduction impact of AMI deployment, or impact of TOU and demand response programs, but in general not the case of combining the impact of all together as in the proposed CTF project. The project has pursued a conservative approach, in particular based on international experiences and studies (the low end of range of impact in consumption reductions). Some international examples are listed below:

- The study by Frontier Economics of the smart meter program for the British utility Centrica, UK (Frontier Economics, Smart Metering for Centrica, October 2007) assumed as likely reductions in consumption attributable to smart meters: 2% for domestic electricity credit customers, 1% for domestic pre-payment customers, and 0.25% for small business customers. It must be noted that this does not include reductions due to TOU tariffs. The proposed CTF project can expects additional impacts from AMI investment leading to systematic load profiling and improvement in the pricing signals of TOU.
- A review of the smart meter programs of three North American utilities by the Indian Center for Study of Science, Technology and Policy (Center for Study of Science, Technology and Policy, Bangalore, Technology, Enabling the Transformation of Power Distribution, report to the Ministry of Power, Bangalore, 2008) shows that in those cases the AMI costs outweigh the benefits, unless the benefits of consumer demand response are included. Accordingly, the proposed AMI project is complemented by the AusAID grant to ensure effective awareness campaigns and demand response programs, incentives to attract participation and compensation to PCs on expected revenues from load reductions.
- In preparations for the roll-out of smart meters in the UK, the Report by the Comptroller and Auditor General, 30 June 2011, evaluated that if only retail and supplier benefits are considered, the costs exceed the benefits for residential consumers, but benefits are greater than costs for non-residential customers. This is consistent with

the phased approach in Vietnam for AMI and the proposed CTF project will target large non-residential consumers.

- An international consultant contracted by the PCs considered that reasonable estimates for the reduction in consumption attributable solely to smart meters would be a 2% reduction in overall consumption for residential consumers, and 1.5% for commercial and industrial consumers. In addition, where there is a time-of-use tariff in place, the load shift can be calculated using an elasticity of substitution of 0.1.30 (Economic and Financial Analysis of Distribution Projects: Principles, Methodology, and Case Studies, 20 February 2012, Consultant report for PCs, Peter Meier). However, the consultant noted that these values are subject to uncertainties. The project has adopted a lower assumption, ranging between 0.5 and 1 % for large consumers.
- The Bank distribution rehabilitation project for Eletrobras' six affiliate distribution companies in Brazil has a similar AMI approach (AMI investments plus MCCs), justified based on and targeted mainly at non-technical loss reduction to customers with more than 500kWh/month (some 12% of customers). It is estimated that theft detection will result in a 3.3% reduction in the amount of electricity generated (the principal benefit in the economic analysis); in the financial analysis the increased revenue collection represents the main benefit. Of the expected reductions in non technical losses and based on estimations that around 50% of unbilled consumption disappears once it is metered, 50% (around 1% of sales) is expected as increase in revenues and 50% as reductions in consumptions.

52. Estimations of potential for GHG emission reductions were based on customer mix and sales of the PCs in 2011. Although the large customers targeted for AMI in the project (annual average monthly consumption above 2,000 kWh) correspond to only 1-2 percent of the total number of customers of each PC, large customers represent around 60% of total sales of participating PCs. Annual sales of the three PCs participating in the CTF co-financed AMI projects were 51.9 TWh in 2011, of which around 31.2 TWh was to the large customers targeted with AMI investments. Adding CPC, where AMI will be financed only by IDA credit, 2011 total sales of PCs participating in AMI investments in the project were 61.0 TWh in 2011, of which 36.2 TWh was to large customers.

Table A7.3: PC sales (2011, GWh)

Sales (GWh)	Actual 2011		
	Total	Large customers	
NPC	27,082	15,044	55.5%
HCM PC	15,314	9,954	65.0%
HNPC	9,514	6,184	65.0%
CPC	9,063	4,984	55.0%
CTF funding (NPC, HNPC & HCM PC)	**51,911**	**31,182**	**60.1%**
CTF/WB funding (NPC, HNPC, HCM PC & CPC)	**60,973**	**36,166**	**59.3%**

53. Assumptions on demand growth have been based on historical growth in sales of each PC and demand projections in PMDP7. For the base case scenario, PMDP7 forecasts an average annual demand growth around 14 percent between 2011 and 2016, and around 11 percent between 2016 and 2020 including considerations that energy efficiency and conservation measures have been adopted. Registered average annual demand growth between 2006 and 2011 has been similar to the level projected for 2011-2015 in PMDP7. For the purpose of estimation of consumption reduction potential, demand growth for the project has been assumed around 12 to 13 percent until 2016 and then reducing to around 11 percent. The share of large customers is assumed to remain the same as historical. Table A7.4 shows sales to targeted large customers: baseline 2011, estimated for 2012, and projected for the 10 years between 2014 and 2023.

Table A7.4: Projections on PC sales (GWh)

Sales Large Customers (GWh)	Baseline 2011	Estimated 2012	BAU 2014- 2023
NPC	15,044	17,183	401,051
HCM PC	9,954	11,115	226,173
HNPC	6,184	6,976	151,210
CPC	4,984	5,690	126,495
Total CTF (NPC, HNPC, HCMPC)	**31,182**	**35,274**	**778,435**
Total CTF/WB funding (NPC, HNPC, HCMPC & CPC)	**36,166**	**40,964**	**904,930**

54. Under a conservative assumption, the combined effect of demand reduction from implementation of the AMI targeting large consumers, TOU and demand response programs would be a reduction in energy purchases (avoided power generation) representing 0.5 to 1 percentage of energy sales.

55. Considering the three PCs co-financed by CTF in the project, reductions of 0.5 to 1 percentage of sales is equivalent to 365 to 732 GWh/year avoided power generation (compared to BAU projections). Adding the fourth PC where AMI will be financed only by IDA, the AMI corresponding to the smart grid component of the project represent smart grid component of the

project would lead to 427 to 853 GWh/year avoided power generation. Based on the conversion factor for Vietnam power generation of 0.65 tCO_2/MWh produced, estimated annual saving in GHG emissions over the 10 year lifetime of the project is

(a) Considering the 3 PCs co-financed by CTF in the project (case CTF funding), avoided 237,839 to 475,678 tCO_2, or about 2.38 to 4.76 $MtCO_2$.

(b) Considering the 4 PCs with AMI investments in project (case CTF/WB funding), avoided 277,342to 554,683 tCO_2, or about 2.77 to 5.55 $MtCO_2$.

Table A7.5: Estimated Potential Savings

	BAU 2014- 2023 (GWh)		**Impact MWh 0.5%**		**Impact MWh 1.0%**	
AMI Large Customers	**Total**	**Average Annual**	**Total reduction**	**Average Annual**	**Total reduction**	**Average Annual**
NPC	401,051	40,105	1,889,216	188,922	3,778,431	377,843
HCM PC	226,173	22,617	1,059,550	105,955	2,119,101	211,910
HNPC	151,210	15,121	710,296	71,030	1,420,592	142,059
CPC	126,495	12,650	607,732	60,773	1,215,464	121,546
CTF (NPC, HNPC, HCMPC)	**778,435**	**77,843**	**3,659,062**	**365,906**	**7,318,124**	**731,812**
Avoided GHG tCO2			2,378,390	237,839	4,756,781	475,678
CTF/WB funding (NPC, HNPC, HCMPC & CPC)	**904,930**	**90,493**	**4,266,794**	**426,679**	**8,533,588**	**853,359**
Avoided GHG tCO2			2,773,416	277,342	5,546,832	554,683

56. Additional potential savings can be expected from the technical assistance and capacity building component of the project for the electricity regulator (ERAV) that includes customer awareness campaigns and to develop effective and sophisticated demand response programs for PCs. The monitoring and evaluation framework of the project (M&E) will be designed and implemented to measure and report GHG emission savings attributable to the different activities under the overall project.

F. Cost effectiveness

57. Estimations on cost effectiveness have been calculated based on assumptions and scenarios described in Section E. The CTF intervention of US$30 million has a related cost effectiveness that would be in the following range under the assumption 1 percent and 0.5 percent reductions:

- Considering AMI for the 3 PCs co-financed by CTF (case CTF funding): US$6.3 to 12.6 per avoided $tCO_{2.}$
- Considering 4 PCs with AMI in the project (case CTF/WB funding): US$5.5 to 10.8 per avoided $tCO_{2.}$

G. **Implementation potential and readiness**

58. Once the initial (demonstrational) stage to be co-financed by CTF is implemented and successful results achieved, the long term smart grid roadmap in Vietnam envisages the enhancement and replication of the AMI through additional stages, to reach all customers in the 5 PCs with monthly consumption above 400 kWh, which represent almost 90 percent of current total consumption in Vietnam power sector.

59. The PCs participating with AMI investments in the project are cofinancing are fully committed and will contract support by international expert consultants to ensure successful implementation. All PCs already have installed meters with memories and that can be read remotely to some of their largest customers. However, until now investments have been focused on the "hardware" components of the metering system for remote reading on a monthly basis and use only for billing purposes. The CTF project will demonstrate the benefits of adding the functionalities ("smartness') through data management center and standardized software packages. Combined with the technical assistance package for PCs in Component B, the PCs participating in the AMI investments of the project will be able to successfully implement AMI and associated programs, which will provide key data on costs and benefits to scale up.

H. Additional cost/risk premiums

60. Vietnam is facing a constrained financial scenario which is likely to persist in the near future and impose significant challenges to the development of infrastructure sectors. Introduction of smart grid technologies and programs focused on demand side response and energy efficiency management for larger consumers is a very effective tool to optimize the use of existing infrastructure in the electricity sector. However, access to financial resources needed to implement smart grid programs in the distribution segment is severely restricted due to the maximum priority of investments required to upgrade and rehabilitate distribution systems to attend increasing demand and control losses. In that context, the support of the CTF becomes crucial to effectively deploy an initial/demonstration phase of smart grids programs.