Document of
The World Bank

Report No: ICR2652

IMPLEMENTATION COMPLETION AND RESULTS REPORT
(IBRD-72040, IBRD-76730 and TF-52188)

ON AN

INTERNATIONAL BANK OF RECONSTRUCTION AND DEVELOPMENT LOAN
IN THE AMOUNT OF US$10 MILLION EQUIVALENT

AND AN ADDITIONAL FINANCING LOAN

IN THE AMOUNT OF US$40 MILLION EQUIVALENT

AND A

GLOBAL ENVIRONMENT FACILITY TRUST FUND GRANT
IN THE AMOUNT OF US$9 MILLION

TO THE

DEVELOPMENT BANK OF THE PHILIPPINES
AND THE REPUBLIC OF THE PHILIPPINES

FOR A

RURAL POWER PROJECT

IN SUPPORT OF THE FIRST PHASE OF THE

RURAL POWER DEVELOPMENT PROGRAM

June 24, 2013

Sustainable Development Department
Philippines Country Management Unit
East Asia and Pacific Region

CURRENCY EQUIVALENTS

(Exchange Rate Effective December 31, 2012)

Currency Unit = Philippine Peso

US$ 1.00 = PHP 41.06
PHP 1.00 = US$ 0.024
US$ 1.00 = JPY 86.18

FISCAL YEAR
July 1 – June 30

ABBREVIATIONS AND ACRONYMS

AF	Additional Financing	LGUGC	Local Government Unit Guarantee Corporation
APL	Adaptable Program Loan	MDSF	Market Development Support Facility
ASTAE	Asia Sustainable and Alternative Energy Program	MEDP	Missionary Electrification Development Plan
CAS	Country Assistance Strategy	MFI	Micro Finance Institution
COA	Commission on Audit	MWh	Megawatt-hours
CO_2	Carbon Dioxide	NCB	National Competitive Bidding
CPS	Country Partnership Strategy	NCIP	National Commission on Indigenous Peoples
DBP	Development Bank of the Philippines	NEA	National Electrification Administration
DENR	Department of Environment and Natural Resources	NG	National Government
DOE	Department of Energy	NPC	National Power Corporation
EA	Environmental Assessment	O&M	Operation and Maintenance
EC	Electric Cooperative	PAD	Project Appraisal Document
ECC	Environmental Clearance Certificate	PCA	Procurement Capacity Assessment
ECSLRP	Electric Cooperative System Loss Reduction Project	PDO	Project Development Objective
ECPCG	Electric Cooperative Partial Credit Guarantee	PFI	Participating Financial Intermediary
EA	Environmental Assessment	PHRD	Japan Policy and Human Resource Development Program
EMP	Environment Management Plan		
ERC	Energy Regulatory Commission	PMO	Project Management Office
ERR	Economic Rate of Return	PPF	Project Preparation Fund
ESMAP	Energy Sector Management Assistance Program	PV	Photovoltaic
FM	Financial Management	QTP	Qualified Third Party
GDP	Gross Domestic Product	RAES	Remote Area Electrification Subsidy
GEF	Global Environment Facility	RAP	Resettlement Action Plan
GEO	Global Environment Objective	RERP	Rural Electrification Revitalization Project
GHG	Greenhouse Gas	RET	Renewable Energy Technologies

GOP	Government of the Philippines	RPF	Resettlement Policy Framework
HEDP	Household Electrification Development Plan	RPP	Rural Power Project
HH	Household	SHS	Solar Home System
IBRD	International Bank for Reconstruction	SSMP	Sustainable Solar Market Package
ICB	International Competitive Bidding	SPUG	Small Power Utilities Group
IFR	Interim Financial Report	TA	Technical Assistance
IP	Indigenous Peoples		
KPI	Key Performance Indicator	UNDP	United Nations Development Programme
LGU	Local Government Unit	WTP	Willingness-to-pay

Regional Vice President:	Axel van Trotsenburg, EAPVP
Country Director:	Motoo Konishi, EAPCF
Sector Manager:	Ousmane Dione, EASPS
Project Team Leader:	Alan Townsend, EASWE
ICR Team Leader:	Defne Gencer, EASWE

PHILIPPINES
Rural Power Project

CONTENTS

ICR DATA SHEET

A. Basic Information			
Country:	Philippines	Project Name:	Rural Power Project
Project ID:	P066397, P113159, P072096	L/C/TF Number(s):	IBRD-72040,IBRD-76730,TF-52188
ICR Date:	05/08/2013	ICR Type:	Core ICR
Lending Instrument:	APL,APL	Borrower:	DBP/REPUBLIC OF THE PHILIPPINES
Original Total Commitment:	USD 10.00M, USD 40.M, USD 9.00M	Disbursed Amount:	USD 10.7M, USD 14.6M,USD 7.40M
Environmental Category: F,B		**Focal Area**: C	
Implementing Agencies: Development Bank of the Philippines, Department of Energy			
Cofinanciers and Other External Partners: UNDP as implementing agency of the GEF			

B. Key Dates

Rural Power Project - P066397, P113159

Process	Date	Process	Original Date	Revised / Actual Date(s)
Concept Review:	09/06/2001	Effectiveness:	05/06/2004	05/06/2004
Appraisal:	02/04/2003	Restructuring(s):		05/25/2009
Approval:	12/04/2003	Mid-term Review:		03/17/2008
		Closing:	12/31/2009	12/31/2012

PH-GEF-Rural Power Project - P072096

Process	Date	Process	Original Date	Revised / Actual Date(s)
Concept Review:	09/06/2001	Effectiveness:	03/08/2004	
Appraisal:	02/04/2003	Restructuring(s):		10/15/2009
Approval:	12/04/2003	Mid-term Review:	07/23/2007	03/17/2008
		Closing:	12/31/2009	12/31/2011

C. Ratings Summary

C.1 Performance Rating by ICR

Outcomes	Moderately Unsatisfactory
GEO Outcomes	Moderately Unsatisfactory
Risk to Development Outcome	Moderate
Risk to GEO Outcome	Moderate

Bank Performance	Moderately Satisfactory
Borrower Performance	Moderately Satisfactory

C.2 Detailed Ratings of Bank and Borrower Performance (by ICR)			
Bank	**Ratings**	**Borrower**	**Ratings**
Quality at Entry	Moderately Satisfactory	Government:	Satisfactory
Quality of Supervision:	Moderately Satisfactory	Implementing Agency/Agencies:	Moderately Satisfactory
Overall Bank Performance	Moderately Satisfactory	Overall Borrower Performance	Moderately Satisfactory

C.3 Quality at Entry and Implementation Performance Indicators			
Rural Power Project - P066397			
Implementation Performance	**Indicators**	**QAG Assessments (if any)**	**Rating:**
Potential Problem Project at any time (Yes/No):	No	Quality at Entry (QEA)	None
Problem Project at any time (Yes/No):	Yes	Quality of Supervision (QSA)	None
DO rating before Closing/Inactive status	Moderately Unsatisfactory		

PH-GEF-Rural Power Project - P072096			
Implementation Performance	**Indicators**	**QAG Assessments (if any)**	**Rating:**
Potential Problem Project at any time (Yes/No):	No	Quality at Entry (QEA)	None
Problem Project at any time (Yes/No):	Yes	Quality of Supervision (QSA)	None
GEO rating before Closing/Inactive Status	Moderately Unsatisfactory		

D. Sector and Theme Codes

Rural Power Project - P066397, P072096, P113159		
	Original	**Actual**
Sector Code (as % of total Bank financing)		
General energy sector	25	10
Other Renewable Energy	50	65
Transmission and Distribution of Electricity	25	25

Theme Code (as % of total Bank financing)		
Climate change	25	25
Infrastructure services for private sector development	25	25
Other Private Sector Development	25	25
Rural services and infrastructure	25	25

PH-GEF-Rural Power Project - P072096		
	Original	**Actual**
Sector Code (as % of total Bank financing)		
Renewable energy	100	100
Theme Code (as % of total Bank financing)		
Climate change	67	77
Rural services and infrastructure	33	23

E. Bank Staff

Rural Power Project - P066397		
Positions	**At ICR**	**At Approval**
Vice President:	Axel van Trotsenburg	Jemal-ud-din Kassum
Country Director:	Motoo Konishi	Robert V. Pulley
Sector Manager:	Ousmane Dione	Christian Delvoie
Project Team Leader:	Alan F. Townsend	Selina Wai Sheung Shum
ICR Team Leader:	Defne Gencer	
ICR Primary Author:	Defne Gencer	

Additional Financing for Rural Power Project - P113159		
Positions	**At ICR**	**At Approval**
Vice President:	Axel van Trotsenburg	James W. Adams
Country Director:	Motoo Konishi	Bert Hofman
Sector Manager:	Ousmane Dione	Mark C. Woodward
Project Team Leader:	Alan F. Townsend	Salvador Rivera
ICR Team Leader:	Defne Gencer	
ICR Primary Author:	Defne Gencer	

PH-GEF-Rural Power Project - P072096		
Positions	**At ICR**	**At Approval**
Vice President:	Axel van Trotsenburg	Jemal-ud-din Kassum
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Sector Manager:	Ousmane Dione	Christian Delvoie
Project Team Leader:	Alan F. Townsend	Selina Wai Sheung Shum
ICR Team Leader:	Defne Gencer	
ICR Primary Author:	Defne Gencer	

F. Results Framework Analysis

Project Development Objectives (from Project Appraisal Document)
APL1: (i) test and demonstrate viable business models that maximize leveraging of public resources with private investment for decentralized electrification; (ii) support transformation of ECs through institutional and operational improvements; and (iii) avoid CO2 emission through wider use of renewable energy.

Revised Project Development Objectives (as approved by original approving authority)

Global Environment Objectives (from Project Appraisal Document)
Mitigate global climate change caused by greenhouse gas (GHG) emissions through wider user of clean energy technologies

Revised Global Environment Objectives (as approved by original approving authority)
GEO was not revised.

(a) PDO Indicator(s)

Indicator	Baseline Value	Original Target Values (from approval documents)	Formally Revised Target Values	Actual Value Achieved at Completion
Indicator 1 :	ECs supported are financially viable			
Value (quantitative or Qualitative)	Zero	90% viable	At least 85% participating ECs	91%
Date achieved	05/06/2004	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Achieved: At completion, 10 out of 11 participating ECs were financially viable, as measured by their debt service coverage ratio of greater than one. However attribution to the project is problematic.			
Indicator 2 :	New customers in rural areas provided with mini-grid electrical connection or individual RET services			
Value (quantitative or	Zero	At least 10,000	20,000	20,975

Qualitative)				
Date achieved	12/04/2003	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Exceeded: 20,975 new customers were provided service, mostly through solar PV, which connected 17,340 households and 2,185 public facilities. In addition, 1,450 household connections were provided via mini-grids. (See Annex 2)			

(b) GEO Indicator(s)

Indicator	Baseline Value	Original Target Values (from approval documents)	Formally Revised Target Values	Actual Value Achieved at Completion or Target Years
Indicator 1 :	RET companies accredited and doing business in rural areas			
Value (quantitative or Qualitative)	Zero	At least 4	At least 4	7
Date achieved	12/04/2004	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Exceeded: Seven RET companies were accredited, corresponding to 175% of the target. In addition, 12 ECs began to provide Solar PV service in rural areas.			
Indicator 2 :	CO_2 emissions avoided per year			
Value (quantitative or Qualitative)	Zero	20,000 tons	At least 40,000 tons	23,181 tons
Date achieved	12/04/2004	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Not achieved: The project met the original target of 20,000 tons per year, but fell short of the target revised at additional financing due to implementation challenges arising starting 2010. (See Annex 3)			

(c) Intermediate Outcome Indicator(s)

Indicator	Baseline Value	Original Target Values (from approval documents)	Formally Revised Target Values	Actual Value Achieved at Completion
Indicator 1 :	Participating ECs have achieved operational improvements as indicated by reduction in both system loss and frequency of service interruptions			
Value (quantitative or Qualitative)	Zero	No specific target set	No specific target set	Loss reductions: 44 MWh/ year in one case, to as much as 11,379 MWh/year
Date achieved	12/04/2003	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	No specific quantitative targets were set for loss reduction and frequency of service interruptions. Loss reductions by ECs ranged from 44 to 11,379 MWh/yr. Systematically collected data on frequency of interruptions in EC project areas is not available.			
Indicator 2 :	Staff of public and private entities participated in RET TA and training activities			

Value (quantitative or Qualitative)	Zero	At least 150	At least 150	More than 500
Date achieved	12/04/2003	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Achieved: More than 500 individuals, including management and staff of Renewable Energy Technology (RET) suppliers, Electric Cooperatives, LGUs, along with DOE and DBP staff were trained under the RPP.			
Indicator 3 :	Guarantee fund established and operating			
Value (quantitative or Qualitative)	Zero	Established and operating	Established and operating	No longer operating
Date achieved	12/04/2003	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Partially achieved: The Loan Guarantee Fund became active in mid-2007 but was discontinued at the end of 2009, after having limited implementation success.			
Indicator 4 :	Rules and regulations for subsidy allocation and tariff setting issued			
Value (quantitative or Qualitative)	Zero	Two		Two
Date achieved	12/04/2003	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Achieved: Two DOE circulars on (i) policy framework for streamlining and rationalizing subsidies for missionary electrification using solar PV systems; and (ii) Qualified Third Party (QTP) electric service in remote areas were issued in 2004.			
Indicator 5 :	About 10 new productive applications initiated in pilot areas			
Value (quantitative or Qualitative)	Zero	Ten	Ten	Zero
Date achieved	12/04/2003	12/31/2009	12/31/2012	12/31/2012
Comments (incl. % achievement)	Not achieved: During implementation of the GEF Grant, efforts for developing productive applications were not pursued, due to the prioritization of other activities.			

G. Ratings of Project Performance in ISRs

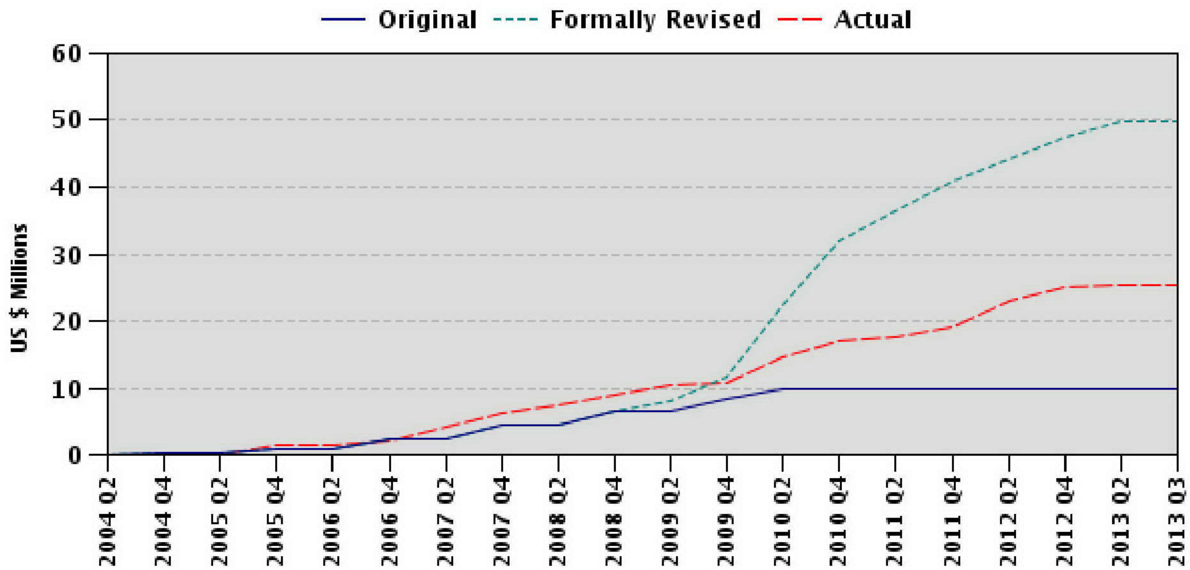
-						
No.	Date ISR Archived	DO	GEO	IP	Actual Disbursements (USD millions)	
					Project 1	Project 2
1	12/24/2003	S	S	S	0.00	0.00
2	06/29/2004	S	S	S	0.11	0.00
3	12/27/2004	S	S	S	0.11	0.26
4	06/18/2005	MS	S	S	1.36	0.33
5	03/17/2006	MS	MS	MS	1.36	0.78
6	03/15/2007	MS	MS	MS	4.73	1.86
7	06/27/2008	S	S	S	8.92	3.30
8	06/26/2009	S	S	S	10.79	4.67
9	02/26/2010	S	S	S	15.07	5.15
10	10/26/2010	S	S	S	17.58	5.85
11	08/02/2011	MS	MS	MS	19.07	6.29
12	09/08/2011	MS	MS	MS	19.07	6.34
13	03/21/2012	MU	MU	MU	24.99	7.01
14	12/11/2012	MU	MU	MU	25.19	7.40

H. Restructuring (if any)

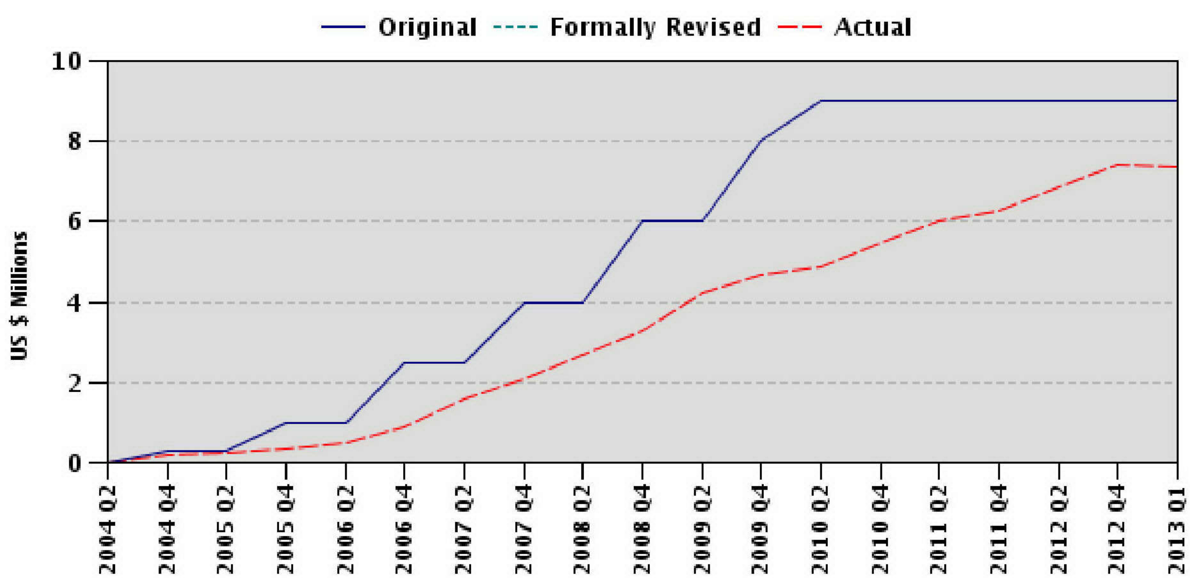
Restructuring Date(s)	Board Approved		ISR Ratings at Restructuring			Amount Disbursed at Restructuring in USD millions		Reason for Restructuring & Key Changes Made
	PDO Change	GEO Change	DO	GEO	IP	Project1	Project 2	
05/25/2009			S		S	10.79		
10/15/2009				S	S		4.75	

I. Disbursement Profile

P066397 and P113159



P072096



1. Project Context, Development and Global Environment Objectives Design

1.1 Context at Appraisal

As of the end of 2002, the Philippines rural electrification program had made significant achievements, with 100% of municipalities and cities, 86% of barangays and about 80% of households electrified. The program being implemented by the Electric Cooperatives (ECs), the predominant service providers in rural areas, was almost entirely focused on grid-extension. Yet, the majority of the barangays remaining unelectrified were in remote areas with low population densities and overall incomes, making expansion of electricity access a difficult challenge.

The National Electrification Administration (NEA), the apex organization for rural electrification, and predominant lender to ECs, was facing serious financial problems, and was undergoing a major reorganization. Performance levels among individual ECs varied significantly. Operational and financial constraints faced by many ECs had led to underinvestment in rehabilitation, low efficiency, poor quality of service, and high costs in difficult areas. Most ECs could not access private commercial financing for the necessary investments, while public sector funding was constrained by the precarious financial situation of NEA. Very few ECs had the experience and capacity to serve remote areas. To address the sector's challenges, the Government of the Philippines (GOP) enacted the Electric Power Industry Reform Act (EPIRA) in 2001. GOP support to the rural power sector at the time of appraisal was being provided through the Department of Energy's (DOE) Expanded Rural Electrification (ER) Program, aiming to achieve 90% household electrification by 2017.

Reflecting the focus of the Country Assistance Strategy (CAS R2002-0083 discussed in June 2002), World Bank support to the energy sector concentrated on the rural power sector. With some Bank input, the DOE developed a rural power sector strategy and policy and institutional reform framework covering: (a) rationalization of tariff and subsidy policy; (b) rationalization of franchise areas and opening up of unserved areas to qualified third parties; (c) strengthening of ECs and adoption of a segmented financing strategy; (d) privatization of the existing assets/operations of SPUG [1]; and (e) restructuring of NEA. To support GOP's program, the Bank and GOP chose an Adaptable Program Loan (APL) to implement reforms and priority investments addressing major sector issues, particularly: operational and financial constraints of ECs; the need for cost-effective electrification beyond grid extension; and barriers to private investment. The RPP APL program was to be implemented in four manageably sized phases between 2004 and 2018, with loans totaling US$150 million. APL1 comprised a US$10 million IBRD loan on-lent through the Development Bank of the Philippines (DBP), and a $9 million GEF Grant administered by the DOE.

[1] Small Power Utilities Group of NPC, which supplies off-main-grid EC's with diesel-fired power, at very high cost.

1.2 Original Project Development Objectives (PDO) and Key Indicators (as approved)

As stated in the PAD, the long-term purpose of the overall Program was "to support the government's pro-poor flagship program which aims to improve the quality of life in rural areas of the country through the provision of adequate, affordable and reliable energy services, in partnership with the private sector."

The objective of APL1 was to assist GOP in the implementation of the first phase of the Rural Power Development Program through (i) testing and demonstrating viable business models that maximize leveraging of public resources with private investment for decentralized electrification; (ii) supporting transformation of ECs through institutional and operational improvements; and (iii) avoiding CO_2 emission through wider use of renewable energy technologies (RET). However, in the Loan Agreement, the objective was "to support the implementation of the first phase of the Program aimed at supporting reforms and priority investments to improve quality of life in rural areas through the provision of adequate, affordable and reliable energy services, in partnership with the private sector."

Key **PDO-level outcome indicators for APL1** were:

- at least 10,000 new customers in rural areas provided with mini-grid electrical connection or individual RET services;
- at least two new mini-grids;
- at least four RET companies accredited and doing business in rural areas; and
- At least 85% of ECs supported are financially viable (as indicated by actual debt service coverage ratio of at least 1 time) by end of APL1.

1.3 Original Global Environment Objectives (GEO) and Key Indicators (as approved)

The PAD stated the GEO as "to mitigate global climate change caused by greenhouse gas (GHG) emissions through wider use of clean, RETs in power generation." RETs would be complemented by rehabilitation and loss reduction in distribution systems operated by ECs, leading to increased efficiency of grid supply, thus reducing harmful emissions associated with diesel-fired power generation. The GEF Grant Agreement GEO is the same as the Loan Agreement. Key GEO-level outcome indicator was avoidance of at least 20,000 tons of CO_2 emissions per year by end of APL1.

1.4 Revised PDO (as approved by original approving authority) and Key Indicators, and reasons/justification

In March 2009, the Board approved a US$ 40 million additional financing loan (AF) in order to scale up the rural electrification subprojects. (See Section 1.9) The PDO was not revised, but the target for avoided GHG emissions was doubled to 40,000 tons/year of CO_2 and the target for direct access to electricity through mini-grid electrical connections or individual RET services was doubled to 20,000 new customers in rural areas.

1.5 Revised GEO (as approved by original approving authority) and Key Indicators, and reasons/justification

The GEO was not revised.

1.6 Main Beneficiaries

The project's primary targeted beneficiaries were the rural poor households that would gain access to electricity under the project. The project would contribute to expanding access to electricity and modern energy to rural households, rural industries, and microbusinesses. As the project also aimed at enhancing the operational performance of the ECs and improving the efficiency of their networks, existing customers of the ECs stood to benefit. The AF would benefit the same groups, while doubling the number of new connections targeted. The project also provided institutional strengthening and capacity building to DOE and the Development Bank of the Philippines (DBP) as implementing agencies, as well as private RE developers, participating RET companies, ECs, microfinance institutions and NGOs.

1.7 Original Components (as approved)

Component 1: Rural Electrification Subprojects (Total cost US$16 million, of which IBRD $10 million, GEF $1.1 million), comprised two subcomponents:

(a) Grid-connected EC Subprojects. For areas that were economic to serve through EC distribution networks, this component supported subprojects aimed at improving power supply system safety, reliability, efficiency, and power service quality for existing customers, through rehabilitation and capacity upgrades of the existing supply system; removing supply constraints; encouraging institutional development of ECs; and improving productivity, safety, and customer service; and

(b) Decentralized Electrification. This supported investments in small power generation, decentralized grids and stand-alone RET, most notably PV systems. An important objective of this subcomponent was to pilot various service delivery mechanisms and identify successful solutions for future adoption and scale-up.

Component 2: Partial Credit Guarantee Fund (Total cost US$1 million, fully funded by a UNDP-GEF Grant). This component intended to facilitate access to credit by suppliers and purchasers of solar home systems (SHS) and other RETs, by providing GEF funds to partially cover loan losses incurred in the provision of loans to RET.

Component 3: Capacity Building (Total cost US$9.3 million, of which GEF $7.9 million). This component supported DOE, DBP, participating financial intermediaries and enterprises to reduce market barriers to the commercialization of renewable energy development, by building the capacity of the concerned public and private sector entities; reducing investment risks by supporting project development, appraisal, procurement and supervision of RET subprojects; and supporting the development and implementation of policies on energy tariffs and subsidies, regulation, and planning.

1.8 Revised Components

Project components were not revised, however, with the approval of the additional financing, US$40 million in IBRD funds was allocated to rural electrification subprojects under Component 1.

1.9 Other significant changes

Additional Financing (AF) and Closing Date Extensions. The most significant change was the US$40 million AF approved in 2009, which quadrupled the original loan amount, and was made in light of the strong implementation progress achieved under the rural electrification subprojects under Component 1. The AF was intended to (a) scale up the project, by financing newly identified subprojects; and (b) support rural electrification by (i) targeting more households, (ii) encouraging more PSP by sharing in investment risks, with an emphasis on new and renewable sources of energy, and (iii) upgrading ECs to become financially viable and operationally efficient. When the AF was approved, the loan closing date was extended three years from December 31, 2009 to December 31, 2012, while the GEF Grant closing date was extended by two years to December 31, 2011. In view of the project's solid procurement performance under the DBP subcomponent, the threshold below which procurement by private borrowers would be allowed to follow established commercial practices was increased (see Section 2.4.).

Reallocations. Grant proceeds were reallocated five times to ensure sufficient funds were available for priority activities.

2. Key Factors Affecting Implementation and Outcomes

2.1 Project Preparation, Design and Quality at Entry

2.1.1 Soundness of background analysis.

Alignment with CAS and GOP Sector Priorities. RPP was aligned with CAS objectives of supporting the achievement of more rapid sustained growth and empowering the poor to increase their participation in development. It contributed to these objectives through supporting improvement of infrastructure facilities and services and creating an enabling environment for PSP in the rural power sector. The project was also in line with GOP's strategic priorities for the rural power sector. The priorities highlighted in the DOE's policy and institutional framework were incorporated into the RPP GEF Grant scope through specifically targeted analytical and advisory activities, while the loan provided the resources that the private sector and ECs would need to finance their investments.

Analytical work. The project design built on findings of analytical work that had been carried out as part of Bank engagement. Various technical assistance (TA) grants from GEF, Japan Policy and Human Resource Development Program (PHRD), Asia Sustainable and Alternative Energy Program (ASTAE), were mobilized to support the DOE and DBP during project preparation, including support for the development of the rural power sector policy and institutional reform action plan mentioned in Section 1.1, which was developed by the DOE with the assistance of PHRD-financed consultants.[2]

Lessons from past projects. Lessons from previous World Bank projects in the Philippines, most notably the Rural Electrification Revitalization Project (RERP, FY92) and the Local Government Unit (LGU) Urban Water and Sanitation APL (Ln. 4422), were taken into account. RERP, approved in 1992, providing a US$91.3 million loan to finance part of NEA's investment program, with the objective of enhancing its capability to function as an effective core agency for rural electrification, improving the performance of rural ECs,

[2] The full set of analytical work that contributed to the project design is available in Annex 8 of the PAD.

and increasing the availability and reliability of rural electricity supply. The project closed in 1998, 16 months behind schedule, with nearly 25% of the loan canceled and an "unsatisfactory" outcome rating, modest institutional development impact and uncertain prospects of sustainability due to NEA's financial problems.[3] During RPP appraisal in 2003, in light of the RERP experience, NEA's continuing financial predicament, and inadequate prospects for a turnaround in the near term, NEA was deemed an inappropriate borrower for RPP.

Lessons from international experience. International experience with rural power sector reform and recognition of the need for a long-term vision for policy and institutional change provided the underpinnings of the APL. With regard to off-grid electrification, the project design took into account lessons from similar World Bank experiences in Argentina, India, Indonesia and Sri Lanka. One key lesson was that the uptake of new technologies and business models in off-grid areas proceeded very gradually in the first few years, then rose significantly once start-up problems were solved and institutional capacity built. This lesson was reflected in the APL approach by starting slowly with testing various delivery and institutional models for off-grid electrification investments under APL1 and setting conservative targets.

2.1.2 Assessment of project design

Project objectives. The long-term purpose of the APL Program was to support GOP's pro-poor flagship program to improve the quality of life in rural areas by providing affordable, reliable energy services in partnership with the private sector. Relevance of the objective was high. The foci of APL1 to support priority policy reforms and investments and demonstrate viable business models for rural electrification were appropriate. Similarly, the GEO, centering on avoidance of GHG emissions through wider use of clean, renewable energy technologies in power generation, and rehabilitation and loss reduction in distribution systems, was well suited to GOP and Bank priorities. However, the PDOs in the legal agreements and PAD should have been identical.

Project components and organization. The project design, although complex, was relevant to project objectives, combining investments for grid and off-grid electrification, complemented by TA and capacity building. ***Strong points*** were:

(a) ECs were facing significant financing constraints, and their networks were suffering from underinvestment in rehabilitation, leading to high losses, poor supply quality and reliability – issues that would be further exacerbated with additional customers. *Providing long term debt financing for relatively low-risk, financially viable investments was appropriate* for removing major system constraints, improving system efficiency, connecting new customers, and eventually improving their financial status;

(b) Considering decentralized electrification would be the primary means of reaching about a third of the remaining unserved households in the most remote areas, *the decision to complement financing for EC system upgrades with support for off-grid electrification was correct*. The identification of workable business models to

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3 World Bank, OED, Performance Audit Report: Philippines Rural Electrification Revitalization Project (Loan 3439-PH), June 15, 2000, Report No. 20581

bring in new players for decentralized electrification was critical, considering the limited resources at the disposal of the public sector and existing providers;

(c) The approach of *testing different alternatives that were workable and sustainable in the Philippines' context instead of adopting "expert prescribed" theoretical options* was very wise and practical. The APL lending instrument was conducive to this flexibility; and

(d) Given the limited availability of long-term infrastructure financing to the rural power sector from commercial sources at the time, *complementing lending for RET and EC loss reduction investments with credit enhancement for the ECs through a GEF supported Loan Guarantee Fund was a good choice*, and reflected international best practice.

Other strengths included: the demand-driven approach for the IBRD funds to preserve flexibility in shifting funds between grid-connected and decentralized electrification subprojects; the ability of a broad variety of sector participants to access financing and capacity building support; and frontloading of capacity building activities.

Design weaknesses. Identification of certain weaknesses was only possible with the benefit of hindsight, based on observations of actual developments.

(a) Several EC system rehabilitation and small renewable energy generation subprojects had been included in the pipeline for the DBP line of credit and had been appraised. However, that none of them materialized during implementation due to a combination of factors, suggests some weaknesses in the assessment of subproject readiness, or inadequate realism on their likelihood of materializing;

(b) The expectation that the private sector would easily participate in the rural power sector was optimistic, particularly in the case of stand-alone RET systems and SHS. In the latter case, relying on private dealers throughout most of the project was likely due to a combination of optimistic assessments on the risk appetite and capacity of the private entities, and of the feasibility of creating a market for SHS supplied by dealers, premised on households' up-front purchase through cash or borrowing. Similarly, in the case of stand-alone RE generation projects, the appetite of private developers to engage may have been overestimated. Of the three small hydropower projects financed by DBP, one was the outcome of a joint venture between an LGU and EC while the other two were developed by ECs;

(c) The willingness of microfinance institutions (MFIs) to lend to small RETs and offer consumer loans for SHS, was overestimated. During implementation, MFIs did not become active financiers in the rural power sector, resulting in the limited uptake of the DBP wholesale lending for participating financial intermediaries and the Loan Guarantee Fund, as discussed in Section 2.2.

(d) The SHS dealer model did not incorporate the full requirements for ensuring sustainability. Even though post-installation sustainability issues faced in international experience with SHS delivery models [4] were acknowledged in

[4] RPP PAD Section 3, Page 18

preparation, true costs of O&M were inadequately considered, and consequently not reflected in the economic and financial analysis (see Section 3.3).

(e) Another weakness with respect to testing different business models for PV electricity was the decision to focus on a single model right from the start. The project could have benefited from piloting different models relying on different entities in parallel instead of a "back-to-back" approach focusing on one model (the dealer model) for the first three years. Only when that showed weaknesses did the preparation of the next model begin. Coterminous preparation and testing could have allowed the DOE and sector participants to compare the different approaches as they were implemented, use lessons from one to fine-tune the others and further enhance those that offered promising outcomes.

Institutional arrangements. Selecting DOE and DBP as the main implementing agencies was appropriate, as they had strong capacity and experience implementing World Bank projects. However, certain other choices did not stand the test of time.

In retrospect, the decision to exclude NEA from the project was not the best. NEA was restructured and has re-emerged as a significant actor overseeing and financing[5] the ECs, and is now the primary channel for supporting the ECs under the GOP's recently approved sitio electrification program. While NEA's financial constraints at appraisal did justify its not being chosen as the borrower for the IBRD loan, more effort could have been made to explore options for partnering with NEA. Having NEA involved in day-to-day implementation would have given it a stake in RPP's success, and the project could have benefited from NEA's knowledge, experience and relationships with the ECs. A similar point applies to the role of ECs, or lack thereof at the outset, in the SHS delivery models tested. During the first five years of implementation, all the models tested, including the SSMP that was adopted, predominantly involved private dealers. Only after the 2009 restructuring was the engagement of ECs in the delivery of SHS considered, as discussed in Section 2.2. And in fact, the "PV mainstreaming" approach involving ECs, stood out as the option offering the highest potential for connections and sustainability. Therefore, project design should have included ECs in the implementation of SHS subprojects much earlier.

2.1.3 Choice of lending instrument and triggers. The choice of an APL was appropriate for supporting GOP's program, through gradual and selective support to initiate reforms and undertake priority investments to address major sector issues. A specific investment loan would not have adequately backed incremental changes and solutions to deep-seated problems over the projected 14-year life of the program. It also allowed for risk mitigation. The choice of triggers for moving to APL2 – capturing key policy actions by government, APL1 disbursement – was mostly appropriate, with the exception of the debt service coverage ratios for participating ECs. There could have been an indicator measuring progress toward household electrification targets. Section 2.2 discusses the context and implications of the decision to select AF instead of APL2.

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[5] NEA has indeed ceased being the sole financing channel for the EC sector, but still does do some lending based on legacy assets (i.e. re-flows), and is also the main channel for sitio electrification grants.

2.1.4 Adequacy of GOP involvement was strong, as demonstrated by its Letter of Sector Development Program (PAD, Annex 11) which reaffirmed its commitment to the rural electrification program and the target of achieving 90% household electrification by 2017. The Letter underpinned the APL by outlining priorities for sector reform. Extensive stakeholder consultations were carried out during project preparation, and their findings and conclusions were carefully documented.

2.1.5 Risks assessment. Project risks for APL1 were correctly assessed as "high" because of the decentralized electrification subcomponent and uncertainties related to the creation of new markets and green-field investments. The risk of the EC grid subcomponent, with existing market and operations, was rated as "substantially lower" in the PAD. On balance, the overall project risks were considered acceptable due to the potential high payoff of the pilot schemes for decentralized electrification. Risks associated with decentralized electrification were correctly identified and the most significant ones rated as high, particularly regulatory risks related to tariff adjustments and availability of subsidies. Even though the PAD referenced the risks associated with post installation sustainability of SHS, that risk was not explicitly stated or mitigated. Nonetheless, the testing approach inherently provided mitigation.

On the other hand, there were significant weaknesses in the risk assessment for the AF. Reflecting the optimism stemming from the success in committing the original loan ahead of schedule, the risk assessment in the Project Paper (section VII) was too positive: "*The project incorporates the good practices applied in the successful implementation of APL 1 especially as it pertains to the DBP implemented subcomponent. There are no foreseen risks that could jeopardize the achievement of the PDO.*" As discussed in Section 2.2, reality on the ground proved otherwise.

Quality at Entry. The overall rating for quality at entry is moderately satisfactory. The design was well aligned with GOP policy and the CAS and the analytical research supporting the project was solid. Lessons from the Philippines and from other rural power projects were carefully incorporated in the design. However, as noted above, some basic premises were not carefully thought through, the PDOs in the PAD and legal agreements should have matched, and the Results Framework had weaknesses (see Section 2.3).

2.2 Implementation

RPP implementation spanned just over seven and a half years for the GEF grant, and eight and a half years for the IBRD loans. Major implementation milestones for RPP were the mid-term review carried out September-October 2007, the AF approved in March 2009, and the CD approved restructuring in December 2010.

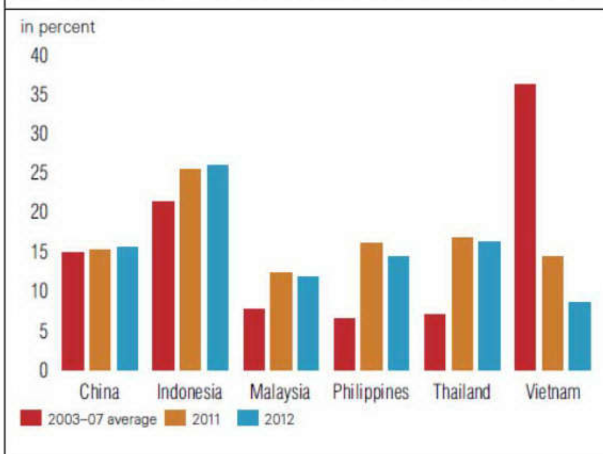
IBRD Loans. Implementation of the first loan was very successful, with full commitment one year ahead of schedule. In light of this strong performance, and the presence of a pipeline of potential subprojects identified by DBP, with estimated financing needs in the range of US$ 40 million, an AF loan of was approved in 2009. When the need for scaled up financing was identified, there were deliberations on whether to do an additional financing to APL1, or begin the preparation of APL2, for which all the triggers had already been met. The assessment at the time was that there was a robust pipeline with projects ready to move, and therefore, DBP and the Bank agreed that the AF, which could be prepared much faster than an APL2, would enable DBP to move more rapidly in responding to the needs of sector participants. At the time, it was also decided that AF would be followed by an APL2.

However, 2010 brought substantial changes in external circumstances which significantly impacted AF implementation, as discussed below, and it became impossible for DBP to close financing for the projects that had been appraised. RPP implementation was also constrained by the maximum three year period allowable for AF operations, in contrast to the five or more years that would have been possible under an APL2. By December 2012, only US$ 14.6 million was disbursed, and the project closed in "moderately unsatisfactory" status. Nonetheless, despite implementation challenges, 13 rural electrification subprojects were financed, including three small hydropower plants and seven EC system rehabilitation and upgrade projects.

Key factors affecting implementation and outcomes are discussed below.

(a) ***Significant changes in credit markets.*** The AF was approved during the 2009 global financial crisis when limited liquidity, high interest rates, and overall financial uncertainty prevailed. However, the Philippine economy quickly rebounded in 2010, with GDP growth reaching 7.3 percent, the fastest in 30 years.[6] GDP growth continued in 2011, nearing 4 percent. As the country made a faster than expected recovery, improved economic fundamentals and resiliency pushed borrowing costs towards historical lows, by as much as 500 basis points.[7] Local credit markets continued to improve, as illustrated in Figure 1, with increasing liquidity, declining interest rates and higher credit growth rates. Credit growth rates in the Philippines from 2011 to 2012, when AF implementation began, were almost triple the credit growth rates in the 2003-2007 period, when implementation of APL1 began. This fundamental shift in credit markets, whose scale, speed and structural nature could not have been predicted at project design, and the subsequent series of events, had a strong impact on RPP implementation.

Figure 1 – Credit growth in East Asia 2003-2012



Source: World Bank East Asia Economic update, December 2012, based on IMF International Financial Statistics

(b) ***Increasing attractiveness of ECs as borrowers.*** Starting with the sector reform process kicked off by EPIRA, a series of developments in the sector, including strong policy guidance from DOE, improved regulatory framework under the ambit of ERC (the new tariff mechanism and gradual transition to performance-based regulation), stronger oversight and financial support from a revitalized NEA, along with management and

[6] World Bank, Philippines Quarterly Update, January 2011.
[7] World Bank, Philippines Quarterly Update, March 2012.

operational improvements carried out by the ECs themselves, all contributed to increase the creditworthiness of ECs. Consequently, commercial banks, which were enjoying high liquidity, became increasingly interested in providing financing to the ECs, and were able to offer lower rates and longer tenures than was possible under RPP. Moreover, the ECs demonstrated their viability as borrowers under RPP, and their solid track record likely increased the appetite among commercial banks to lend to ECs.

(c) ***Credit enhancement offered by ECPCG.*** The government's EC Partial Credit Guarantee (PCG) program, supported under the GEF funded Electric Cooperative System Loss Reduction Project (ECSLRP, TF53360,TF53361), offered guarantees for commercial loans to selected ECs and private investors to finance distribution system upgrades. As part of the Bank's portfolio approach for supporting the energy sector, ECSLRP and RPP complemented each other by trying different approaches to supporting the ECs. The ECPCG, which was managed by the LGU Guarantee Corporation (LGUGC), enabled financiers to offer lower cost fixed and variable rate financing to ECs. In late 2009, NEA and LGUGC signed a Memorandum of Understanding to cooperate on ECPCG. Thereafter, coupled with the favorable changes in the credit market conditions in the Philippines, there was a significant upturn in loans for EC capital expenditure projects, which had ground to a halt during the financial crisis. While RPP was negatively affected by changing conditions, ECPCG thrived.[8]

(d) ***Rate structure for RPP credit line.*** While commercial lenders saw declines in their costs, DBP's costs under the RPP were largely fixed. The rates DBP could offer were a function of IBRD rates; mark-ups from the Department of Finance and a margin to cover DBP's costs, risks and profit requirements in making loans to borrowers. According to DBP, the rates it was able to offer under the RPP window were as much as 100 to 200 basis points higher than the reference market price in the country. In fact, DBP itself was able to offer lower cost funds than the RPP window, through other funding windows that were under its management, alongside guarantees from ECPCG.

(e) ***Slower than anticipated demand from RE developers.*** Demand for credit from RE developers did not grow as expected, as potential RE developers reportedly held off on potential projects while waiting for the completion of implementing regulations for the RE Act of 2008, and the feed-in tariffs (FITs) for RE. The time required for the completion of the RE regulatory framework, which continued well into 2012, in turn, affected DBP's ability to finance new RE projects under the credit line.

(f) ***Other factors specific to individual subprojects.*** Subprojects in the AF pipeline were affected by various factors including changes in sponsors, or sponsors' decisions not to pursue the projects, or to use alternative financing sources. Others, with already approved loans, faced construction delays due to natural disasters and cost overruns.

By early 2011, no subprojects had materialized and no new loans were on the horizon. Having recognized the risks to project outcomes, DBP initiated various efforts to turn the project around, but these efforts had limited success. The DBP, with Bank support, devised a turnaround plan, which involved more aggressive marketing for RPP; blending of RPP funds with its own funds to bring the rate offered closer to prevailing market

[8] Government and the Bank are preparing the Philippines Renewable Energy Development (PHRED) project to expand EC-PCG and extend its provision of PCG's to cover loans for renewable energy as well.

rates; and working with NEA to identify EC distribution system rehabilitation and upgrade subprojects for financing through the RPP credit line. Despite initial progress, through working with NEA, in identifying potential prospects among the ECs and continued efforts to commit the remaining funds, ultimately, no loans were made, nor did a lending pipeline with firm milestones emerge as loan closing neared.

In December 2012, GOP requested a one year extension of the loan closing date. The Bank saw no basis for extending the project, primarily because (i) there was no credible pipeline with potential for immediate commitments and subsequent drawdown of funds, and (ii) the broader structural shift in the credit market had weakened the justification for DBP credit line – that a "market failure" was preventing ECs from accessing financing, and that public debt financing, through IBRD funds on-lent by DBP was needed. By that time, the case and the basis for mobilizing the next phase of the APL series no longer held and the Bank decided to terminate the entire APL.

Key factors affecting the GEF Grant are summarized below.

(a) ***Slow project start-up***. Finalization of internal government procedures and set-up of the DOE Project Management Office (PMO) were completed more than a year after loan effectiveness, and the capacity of the PMO was built up gradually. The delays in having a fully functioning PMO impacted the start-up of GEF-supported activities.

(b) ***Limited initial results from decentralized electrification.*** Despite the availability of GEF grant funds to complement government subsidies for SHS, a credit window offering wholesale financing to MFIs and accreditation of eight potential PV companies in 2004, solar market development was slow, with no major accomplishments by mid-term. This delay was attributed to the limited capacity of PV dealers, delayed start-up of RPP, limited MFI interest in lending for decentralized electrification, and an incoherent framework for subsidies offered under different government and donor programs.

(c) ***Distortionary impact of competing subsidy programs.*** During early years of implementation, a plethora of grant-based subsidies for solar PV were being offered by various government, donor, and private initiatives. The presence of contemporaneous, often competing programs with differing offers, led to confusion among households, but more importantly, reduced the chances of success of initiatives requiring household contributions, and ultimately led to inefficient use of limited resources available to missionary electrification. The issuance of the PV subsidy rationalization policy in 2005 and its implementing regulations in the following years did not immediately change this situation either, and RPP continued to face competition from other programs.

(d) ***Efforts to make the dealer model work.*** Solutions tried included the extension of GEF grants to *solar lanterns* in 2004, to meet basic lighting needs of the poorest households. The *"Incubator Program"* implemented in 2005 focused on building partnerships between participating MFIs and PV companies, while the *Market Development Support Facility* (MDSF) offered cost-sharing grants to the PV companies for business development and capacity building. In addition, the business model itself was changed with the introduction, in mid-2005, of the *Sustainable Solar Market Package* (SSMP) concept, offering contracts for "market packages" packaging groups of barangays together to provide a sufficient volume of sales for the contractor to sustain services. The GEF grant was used to complete the design of the SSMP mechanism, including contracts, initial market assessments, advisory support to participating companies, as well as outreach to provincial and local governments.

(e) ***Poor performance of the Loan Guarantee Fund.*** LGF became active only in mid-2007 after the appointment of the LGUGC as program manager in late 2006. By early 2009, there was very limited interest from MFIs, with a rather modest portfolio comprising 44 loans being guaranteed. Even though MFIs were supported through capacity building and outreach they never became significant financiers of SHS.

(f) ***Refocusing the project.*** In 2009, the project was refocused, building on approaches that were working well while others were discontinued, and new business models with potential were extended. In light of the results of a PV subsidy rationalization study, the government and GEF subsidies provided under RPP were revised, including discontinuation of grants to solar lanterns and revision to the subsidies for different PV system sizes. As part of discontinuation of unsuccessful activities, it was decided that LGF would wind down by the original closing date of December 31, 2009.

(g) ***Partnering with ECs.*** One of the most important changes was the partnerships with the ECs for whom two new business models were introduced in 2009. Under the ***lease-to-own*** model, ECs would be in charge of installing PV systems for households and public facilities in remote barangays within their franchise areas. The households would make periodic repayments to cover the ECs' transaction costs, and to build a revolving fund to cover the procurement of more SHS over time. In the end, system ownership would be transferred to the households. Under the ***fee-for-service model,*** piloted under the so-called "PV mainstreaming" approach, six ECs were tasked with procuring, installing, operating and maintaining the SHS, which would be owned by the ECs themselves, in exchange for a monthly fee from the households they serve. By encouraging the ECs to use solar PVs to provide continuing electricity service as part of their regular business, the model could address sustainability concerns for PV systems, encountered under the dealer model, where there was very little incentive to continue to provide regular O&M and customer service. At closing, after just two years of implementation, the fee-for-service model had shown promising results. (Annex 2 provides information about the various models tested under RPP.)

2.3 Monitoring and Evaluation (M&E) Design, Implementation and Utilization

According to the PAD, key performance indicators for the APL program would be organized into three categories: (a) traditional access and performance indicators; (b) GHG mitigation; and (c) social and economic impact of rural electrification. These principles were sound, but the M&E framework in the PAD only partly reflected them.

Under category (a), ***end of program indicators*** were 100% barangay and 90% household electrification, reflecting government program targets, and about 90% of ECs supported being financially viable, as measured by their debt service coverage ratios, with "improvements in reduction in both system loss reduction and frequency of service interruptions." The ***PDO level indicators for APL1*** focused on the number of connections and debt service coverage ratios. The ***output indicators*** – intermediate outcome indicators in today's results terminology – linked to individual components focused on operational improvements by participating ECs, "as indicated by reduction in both system loss reduction and frequency of service interruptions." While the intention to monitor losses and interruptions was certainly relevant to the goal of improving EC performance, the PAD did not provide measurable or attributable indicators to track progress toward achievement of those outcomes.

Similarly, the PAD did not offer specific, measurable, time-bound indicators on the socio-economic impact of rural electrification. The socio-economic aspects were referenced only at the level of ***sector-related CAS goal***, where the corresponding indicator was formulated as "socio-economic benefits accrued to households and barangays due to increased use of electricity." Even though baseline socio-economic data (average household income, monthly expenditures on energy consumption) had been collected through surveys,[9] no relevant indicators or baseline values were reflected in the Results Framework. Furthermore, some indicators were not realistic, were too broad in scope, or went beyond what could be achieved by the project. Some were not directly attributable to project activities, as in the case of EC financial ratios, which the project did have *some* activities contributing to improvement, there were many other exogenous factors that could also have an impact, such as policy and regulatory developments and macroeconomic conditions. It should be noted that the inclusion of broader sector level goals in results frameworks was common practice at the time of project design. Unfortunately the Project Paper for the AF missed the opportunity to update the 2003-era Results Framework to 2009 standards.

During project implementation, the PDO level indicators and APL2 triggers were regularly used by DOE and DBP, as well as the Bank to monitor implementation progress, make decisions, such as that of proceeding with AF, and periodically recorded in progress reports and aide memoires. Although it was intended to monitor socio-economic data, none was systematically collected.

2.4 Safeguard and Fiduciary Compliance

Safeguard policies triggered by the project were: (a) Environmental Assessment (EA); (b) Indigenous Peoples (IP); and (c) Involuntary Resettlement. The EA category of this project was a Category "F" for "Financial Intermediary Assessment". An EA Policy Framework was made public on January 31, 2002, and an IP Project Policy Framework and a Policy Framework for land acquisition, resettlement and rehabilitation were made public in July 2003. The AF did not trigger any additional safeguards.

Environment. The overall rating for environmental safeguards compliance is moderately satisfactory. Environmental safeguards policies and procedures were generally complied with. DBP mainstreamed compliance with environmental safeguards in the screening and approval of sub-projects. Subproject proponents secured the necessary environmental clearances from the Department of Environment and Natural Resources (DENR), but project sponsors should have updated their Environmental Management Plans and submitted Environmental Compliance Monitoring Reports more regularly. Even though project Operations Manual included procedures to guide compliance with Philippines environmental rules and regulations and the Bank's safeguard policies, the DBP provided limited oversight of safeguards compliance at its regional business centers. The Bank visited the subprojects that triggered the EA policy, and found some documents did not

[9] Rural Electrification and Development in the Philippines: Measuring the Social and Economic Benefits," ESMAP Report 255/02, May 2002.

fully comply with environmental reporting requirements. Nevertheless, the Bank did not find any major issues with the actual environmental performance of subprojects.

Social. Overall compliance with social safeguards policies is also rated moderately satisfactory. Social safeguards policies and procedures, particularly concerning land acquisition and compensation, and engagement of project affected Indigenous Peoples (IP) were generally complied with at project level.

With regards to *land acquisition*, subprojects were mostly located on public land or lands already owned by the subproject proponent, so no significant land acquisition was required. Land acquisition totaling 8.63 hectares was necessary to build access roads to generation facilities. No demolition of household dwellings or businesses was necessary. For the subprojects that triggered the involuntary resettlement policy, the Bank found the relevant project documents were in order and the affected land owners interviewed were satisfied with their compensation for affected lands and crops. Mostly, the affected lands were in isolated rural areas where the land market was not robust. The engagement of *indigenous peoples* during preparation of subprojects was carried out in a manner consistent with the national law[10] on IP rights, with active participation of the National Commission on Indigenous Peoples (NCIP). Although the intent of the social safeguards framework for just and humane compensation for affected lands and crops and engagement with indigenous peoples were substantially complied with, there were weaknesses in monitoring of implementation of social safeguards. Procedures and documentation requirements specified in the social safeguards frameworks were not strictly followed, and in several cases the NCIP did not monitor implementation of IP related aspects as required. Nonetheless, since IPs were represented in project management boards for each subproject, they are kept abreast of developments.

Procurement. Procurement under ***IBRD*** APL1 is rated satisfactory with timely completion of procurement following Bank procedures. At the time of AF, in response to requests from project participants, changes were made in the procurement arrangements to ensure RPP's competitiveness with other sources of financing, most importantly, raising the threshold below which the private sector entities could use commercial practices instead of the Bank's processes.[11] Procurement under the AF was moderately satisfactory. Some subprojects included in early versions of the AF pipeline were not financed partly due to procurement related factors. In the case of one subproject, at the time of pipeline entry, the proponent had already completed detailed project designs that identified specific equipment manufacturers and suppliers it wanted to work with. When the Bank undertook its technical evaluation of the bidding documents for the subproject (which was above ICB threshold), the project design and bidding documents were found technically unsatisfactory. The project sponsor would not retrofit the project design to meet the Bank's requirements, so the subproject was financed by another source. In addition, the procurement capacity of the DBP PMO was weakened following its mid-

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[10] This law was found superior to WB OP 4.10 because it requires free and prior informed consent of affected indigenous communities and not just consent. Terms of engagement are documented in Memoranda of Agreement, specifying the responsibilities and roles of the proponent and the IP communities and the benefits they will receive from the project.

[11] For private sector borrowers, from US$ 0.5 million for goods and US$1 million for works, to US$6 million for both.

2010 reorganization, when the dedicated procurement unit was removed, leaving the PMO with only one staff with appropriate training. The weaker procurement capacity of the PMO contributed to delays in assessing potential subprojects and implementation.

Under the ***GEF Grant***, procurement performance of the *DOE PMO* is rated satisfactory. Even though there were initial delays and weaknesses in procurement activities, project management strengthened over time through the assignment of a new procurement staff and hiring of a procurement consultant, who were both trained on the Bank's procurement guidelines. The performance under the GEF Grant administered by the *DBP PMO* is rated moderately satisfactory. Even though the capacity building and TA funds were nearly fully used, there were challenges with the Project Preparation Facility which was only partly utilized at closing. DBP attributes the limited uptake to the prior review threshold for consultant selection, as in most cases, proponents had already identified the consultants they preferred, and did not want to follow the Bank's consultant guidelines that would have required them to select consultants through competition.

Financial Management (FM). Under the ***IBRD loans***, FM performance was satisfactory. The project substantially complied with financial covenants, which included the submission of quarterly Interim Financial Reports (IFR) and annually audited project and entity financial statements. There were no accountability and internal control issues contained in the audit report, but there were significant delays in the submission of the annual audited entity financial statements mostly due to issues at DBP level that needed to be resolved with the Commission on Audit (COA) before finalizing the audit. DBP addressed all agreed financial management actions in a timely manner. The system of internal controls was found adequate throughout implementation.

FM performance under the ***GEF Grant*** is rated moderately satisfactory. The project substantially complied with the financial covenants concerning the submission of quarterly IFRs and annual audited project financial statements. Even though there were some weaknesses identified by COA, which were eventually addressed, the audit reports did not pick up any serious accountability and internal control issues. Most of the agreed financial management actions arising from FM implementation reviews were properly addressed. Overall, internal controls were adequate throughout project implementation.

2.5 Post-completion Operation/Next Phase

The EC system rehabilitation and generation projects will be operated and maintained by the project sponsors, with oversight from DOE, ERC, provincial and local authorities. As for the PV systems: (i) for those installed under the dealer model and SSMP, the ownership, and hence responsibility to maintain them, was transferred to the beneficiary households or the local communities, after a pre-determined post-installation maintenance service by the dealer; and (ii) for those under the fee-for-service model, maintenance and repairs during the first year were the responsibility of the dealer who supplied the SHS to the EC; and thereafter of the ECs.

Sustaining reforms and institutional capacity. Considerable progress has been made in the rural power sector since appraisal, and GOP is committed to moving the rural electrification agenda forward. GOP has a target to expand electricity access to 90% of households by 2017, and the DOE has drafted a Household Electrification Development

Plan (HEDP) that lays down the policies, strategies and other activities to achieve that target, through grid extensions and off-grid solutions. The options listed in HEDP for decentralized electrification include the fee-for-service model for PV service by ECs. Since the closing of RPP, the Bank continued to support the DOE by hiring international advisors to focus on scaling up sustainable business models, and developing required policy and regulatory framework. As of mid-2013, DOE had made significant progress in finalizing the proposed policy and regulatory framework, and was planning to initiate nationwide consultations on the draft circular and rule-making petitions.

Continued support for the Philippines rural power sector. The experience with RPP, ECSLRP and recent analytical work were instrumental in testing the applicability of different approaches and instruments for supporting the energy sector. The experience under these projects showed that amid changing credit market and sector conditions, the underlying justification for Financial Intermediary lending no longer held, while credit risk sharing proved to be critical for channeling commercial credit into the sector and leveraging private sector resources. In light of the lessons from these experiences and recognizing that changing circumstances necessitate novel approaches, the proposed Philippines Renewable Energy Development Project (PHRED – FY2014) will support RE projects through scaling up the highly successful ECPCG risk-sharing facility.

3. Assessment of Outcomes

3.1 Relevance of Objectives, Design and Implementation

<u>Relevance of PDO and GEO – high</u>. As stated earlier, the PDO was fully aligned with GOPs priorities and strategies and with the Bank's CAS discussed in 2002. The PDO remains relevant with current GOP priorities, and the CPS for 2009-2013, which focuses on improving governance and achieving growth that works for the poor. The GEO was and remained consistent with national and global priorities. Climate change is a priority area under the new CPS for 2013-2016 under discussion at the time of this ICR.

<u>Relevance of Design – moderate</u>. Although there were a few shortcomings, the basic project design, combining investment support with policy and capacity building, and comprising components that focused both on grid and decentralized electrification was highly relevant at Board approval and remained so in 2009 when the AF was approved. As stated in Section 2.1, project design built on experiences in the Philippines and in other countries in delivering electricity to poor, rural areas. Appropriate technical assistance and training were provided up front and the participating agencies could "learn-by-doing". However, changes in external circumstances from 2010 onwards significantly affected the relevance of the project design. With the shift in the credit markets, the main justification for the line of credit no longer held true.

3.2 Achievement of Project Development Objectives and Global Environment Objectives

PDO Rating: Moderately Unsatisfactory

The project was making satisfactory progress toward the PDO when the AF was approved in 2009. Indeed most of the original PDO level indicators were met if not exceeded.[12] However, with the implementation challenges arising in 2010, the project fell short of achieving its revised targets.

PDO – Supporting GOP's program for reforming the rural power sector. RPP was instrumental in advancing GOP's rural power sector reform agenda by assisting with issuance of key sector policies to tackle priority issues, such as the subsidy rationalization and QTP regulatory frameworks, and updating of the MEDP. But perhaps more importantly, the project allowed sector participants to learn by doing, through identifying and testing workable solutions that could be scaled up.

PDO – Testing and demonstrating viable business models to leverage public resources with private investment for decentralized electrification.

This was substantially achieved. RPP successfully tested different decentralized electrification approaches that have the potential to meet GOP's electrification targets in a sustainable manner, even if they were not demonstrated with absolute certainty.

RPP was instrumental in formalizing the *QTP model for private sector participation*, and through technical, regulatory, and advisory support, led to the operationalization of the first QTP in the country. The target of having two QTPs in place by closing was not achieved, primarily because QTP requirements turned out to be quite cumbersome. RPP helped identify and document these weaknesses, and contributed to simplifying the QTP framework. Provided that the regulatory framework can be further simplified, this model could present a sustainable solution for remote area electrification. The DOE reports that the first QTP is considering expanding service to more houses and other parts of the country, and two new other QTPs have been proposed by other entities.

As for *solar PV,* RPP demonstrated what will *not* work in the Philippines' context. As discussed in Section 2, the dealer-based arrangements neither offered the potential to achieve the scale of connections needed to meet GoP targets nor address sustainability issues. The EC fee-for-service model, on the other hand, does offer the potential to meet GOP targets sustainably. As the EC fee-for-service model was introduced rather late (2010), its viability could not be fully demonstrated. Nonetheless, the fact that more than 3,500[13] connections were delivered in that brief period, the participating ECs' interest in scaling up SHS service, and the proposed development of a regulatory framework to allow ECs to include this service as part of their business, are encouraging signs for the achievement of the scale of connections required while also ensuring sustainability. **Related key results and outputs include**:

- Over 20,975 rural electricity connections were provided under RPP, mostly through solar PV, serving 17,340 households and 2,147 public facility installations. In addition 1,450 household connections were provided via mini-grids, thereby exceeding the revised target of 20,000 connections.

[12] This ICR is using the PAD PDO because the KPI in the PAD are better aligned with that PDO. As mentioned in Section 2.3, the PAD had no social economic indicators that would support statements about the project's impact on quality of life in rural areas.

[13] As of RPP closing date, 2,100 SHS had been provided. In the year that followed project closing, additional systems were installed by the participating ECs, with DOE support. Annex 2 has further details on installations under RPP.

- Seven Participating Companies accredited by the DOE as well as 12 ECs became operational in rural areas, and their involvement offers the possibility of leveraging GOP resources with their own funds.

PDO – Supporting transformation of ECs. RPP contributed to the transformation of the ECs by (a) providing much-needed financing for network rehabilitation and upgrade investments when such was not accessible at reasonable terms; and (b) contributing to O&M improvements through capacity building. **Key results are discussed below**:

(a) DBP widened the available financing options for the rural energy sector and the ECs in particular. Even though substantial changes in the credit markets negatively affected the project, RPP played a significant role in demonstrating that ECs were a viable market for commercial lenders.
(b) The rehabilitation and upgrade investments enabled the ECs to reduce their system losses, with annual reductions estimated ranging from 44 MWh/ year, to 11,379 MWh/year, ECs' losses were reduced between 0.9 percentage points to 4.5 percentage points (see Section 3.3, Annexes 2 and 3). The total 22 GWh saved by the six ECs represents 2.7% of the total 815 GWh delivered by those ECs.
(c) In the medium term, loss reductions achieved can allow ECs to purchase less power to meet the same demand, thereby reducing their operational costs, and eventually leading to lower tariffs for consumers. In addition, system upgrades should allow the ECs to connect new customers through line extensions without adversely impacting supply for existing ones. (Unfortunately quantitative data on these impacts was not available so this discussion is more qualitative.)
(d) At closing, all ECs supported were financially viable, as measured by debt service coverage ratio of at least 1. However, this success cannot be fully attributed to RPP. These improvements can also be explained by the availability of new financing in favorable terms, changes in ECs' management practices, improved oversight by NEA and ERC, and other operational enhancements.

However, with US$26.3 million (66%) of the AF canceled at closing, the project could not reach its full impact, especially in loss reductions, considering that the majority of the subprojects in the pipeline in its last year were for EC system rehabilitation and upgrades.

Achievement of GEO – moderately unsatisfactory. With an estimated **23,181 tons of CO_2 per year avoided** as a result of its outputs, the project exceeded the original target of avoiding 20,000 tons of CO_2 per year; however, it fell far short of meeting the revised target of avoiding 40,000 tons/year which became impossible when IBRD AF implementation faltered. This was because the additional CO_2 emissions avoidance was primarily going to be delivered by a 10 MW biomass power plant which was in the AF pipeline, but did not end up being financed. The majority of the GHG benefits delivered under RPP are due to small hydropower plants that were developed with help from the DBP credit line (14,120 tons/year), followed by efficiency improvements in EC grids (8,500 tons/year), and SHS installations (560 tons/year). Achievement of the GEO based purely on the CO_2 emissions reduction would be rated unsatisfactory, but the GEF can count other achievements that will be beneficial over the longer term: (a) demonstration of the renewable energy in rural areas as viable options for commercial lenders; (b) the initiation of the EC fee-service-model, which has the potential of substantially scaling up solar PV installations in the medium term; and (c) support by DOE for market development, technical guidance and accreditation for RET suppliers, which could have a catalytic effect on the development of the off-grid renewable energy market.

Achievement of Core Sector Indicators for Renewable Energy. The project contributed to meeting three Core Sector Indicators for renewable energy as seen below:

Indicator	**Value**
Generation capacity of renewable energy (other than hydropower) constructed (MW)	0.062*
Number of people provided with access to electricity under the project by household connections (off-grid):	73,949**
Number of community electricity connections under the project (other renewable).	2,277

**275kWp in SHS + 345kWp in public facility PV installations + solar lanterns*

*** 1,450 HH connected via mini-grids + 14,626 HH via SHS = 16,076 HH, converted to people count based on average HH size of 4.6 people, from 2012 census. It is likely that this estimate is conservative, considering larger average HH size in rural areas.*

3.3 Efficiency

While the economic and financial returns of mini-hydropower plants and EC efficiency improvements fully met appraisal expectations, efficiency of the project is rated moderately unsatisfactory, taking into account the cancellation of a significant share of the AF. In the case of ***mini-hydropower plants***, all subprojects have good returns and positive impacts on EC cash flows. The reduction in revenue requirements provided the opportunity for rate reductions to all EC consumers, though given the small scale of the projects, the aggregate potential tariff reduction will be small. In the case of ***efficiency improvements*** and rehabilitation of existing rural EC systems, the economic analysis for the aggregate of six small investments (total capital cost $8.6 million, 90% provided by RPP) shows an Economic Rate of Return (ERR) of 37.6% (NPV US$ 17.4million).[14] These are good economic returns, typical of rehabilitation projects. They are also likely to be conservative, insofar as no credit is taken for additional customers who have connected to the rehabilitated system. Returns are robust: switching value for avoided cost of generation is 6.9 US cents/kWh, substantially below the cost of thermal generation and substantially below estimates of consumer willingness to pay (WTP).

The efficiency of the GEF project is rated moderately unsatisfactory, on account of the significant time and resources spent focusing on the SHS dealer model, which did not prove sustainable, and the high costs of PV electricity when diesel is a viable alternative. ICR economic and financial analysis shows that the high supply chain and O&M costs of ***solar home systems*** are justified where diesel is not technically feasible. The analysis found that the ERR for SHS, against the no-project alternative (using WTP as proxy for benefits) is in the 13.5-21% range, depending on assumptions. When diesel is a viable alternative, however, electricity from SHS remains significantly more expensive than diesel: in those cases, when SHS is compared to diesel generation the ERR is negative, and economic returns are only marginally above the hurdle rate. This analysis implies that while PV mainstreaming may be financially and technically sustainable, and

[14] The assumption is that the loan amounts (known to have been disbursed) account for 90% of the total project cost (given the 10% equity requirement of the DBP). Annual O&M costs are assumed at 2% of the capital investment

therefore may constitute an improvement over other implementation models, it also could come at a high price, particularly where diesel is a viable alternative. However, *where diesel is not a feasible option for various reasons* (highly dispersed households, inability to transport diesel engines in remote areas, or hindrance of diesel fuel supply in the wet season), *solar PV is the least cost option, and can be justified on the basis of WTP according to rural energy surveys*. See Annex 3 for full analysis.

3.4 Justification of Overall Outcome and Global Environment Outcome Rating

Rating: Moderately Unsatisfactory

The PDO remained fully relevant from start to finish, but the relevance of the project design diminished starting 2010 and the AF could not be fully committed. Although the outcome targets of the original loan and the triggers for APL2 were met, the original loan represented only one fifth of the $50 million combined Bank financing, of which nearly half was canceled. AF implementation faltered and the revised outcomes could not be achieved, leading to moderately unsatisfactory achievement of the PDO. The GEO for the GEF remained relevant but revised targets could not be met due to implementation challenges under the AF. Efficiency of both projects is rated moderately unsatisfactory. Therefore, the overall outcome is rated moderately unsatisfactory.

3.5 Overarching Themes, Other Outcomes and Impacts

(a) Poverty Impacts, Gender Aspects, and Social Development

As a result of RPP, 18,790 households and 2,185 public facilities, including schools, health centers, and barangay halls, received electricity connections through SHS, solar lanterns and mini-grids. No systematic poverty assessment was conducted, but it is possible to observe quality of life improvements. Anecdotal observations are consistent with studies documenting similar experiences in other countries and surveys carried out in the Philippines, all showing that quality of life and household earnings improve with electrification[15]. DOE's Borrower Completion Report and other project outputs report positive impacts on families and women in the project areas. (Examples are provided in Annex 5). In field visits in Palawan in 2011 and in Bohol in 2013, households reported overall satisfaction with SHS. Benefits cited included better quality and safer lighting compared to alternatives such as kerosene; improved sense of safety; increased evening study times for children along with enhanced educational outcomes; availability of news broadcasts and entertainment; enhanced communications due to cell phone usage. In Bohol, the interviewed households that participated in the EC PV mainstreaming pilot expressed satisfaction with customer service. For households that had informal service connections to diesel generators, the availability of SHS enabled them to reduce their energy expenditures. In case of small hydropower projects, in addition to the increased availability of reliable supply for the EC grid, benefits observed included employment in the construction and operations of the project, medical and dental programs for local

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[15] ESMAP "*Rural Electrification and Development in the Philippines: Measuring the Social and Economic Benefits*, 2002: D. Barnes, V. Tuntivate, and K. Fitzgerald, 2008. "*The Welfare Impact of Rural Electrification: A Reassessment of the Costs and Benefits*; S. Khandker, D. Barnes, H. Samad, and H.M. Nguyen. 2009. "*Welfare Impacts of Rural Electrification: Evidence from Vietnam*,"; and D. Gencer, P. Meier, R. Spencer and H.T. Van, "*State and People, Central and Local, Working Together: The Vietnam Rural Electrification Experience*"

communities, educational assistance, training and supply of seedlings for watershed rehabilitation. Moreover, Bank site visits and discussions with indigenous peoples' leaders revealed that communities in project areas were satisfied with assistance in those areas. At a higher level, the subsidy rationalization work completed under RPP can contribute to better outcomes by improving the efficiency of allocation of limited resources available for rural electrification by eliminating overlaps, improved targeting of subsidies to poor households, and enhancing affordability of electricity service.

(b) Institutional Change/Strengthening

The project contributed to institutional strengthening not only for DOE and DBP as, but also helped build institutional capacity for private RE developers, participating RET companies, ECs, microfinance institutions and NGOs. Broader institutional impact is expected to accrue in the medium term as a result of various policy studies that the project supported, including the QTP policy framework, and through demonstrating the EC sector as a viable market for commercial lenders.

(c) Other Unintended Outcomes and Impacts (positive or negative)

N/A

3.6 Summary of Findings of Beneficiary Survey and/or Stakeholder Workshops

An Implementation Completion and Results review workshop, bringing together key stakeholders involved in the RPP experience, was held in Manila in February 2011. Main messages and conclusions emerging from the workshop are summarized in Annex 6.

4. Assessment of Risk to Development Outcome and Global Environment Outcome Rating: Moderate

A. Risks to the success of the Government's program for the rural power sector

Change in government priorities. The most important risk is reduced GoP commitment to expanding electricity access. However, taking into account GoP's strong commitment as demonstrated through the targets and plans outlined in the HEDP, and the allocation of significant government resources to new programs such as *Barangay Light Enhancement* and *Sitio Electrification*, this risk is **low**.

Reduction in financing for rural electrification. If electrification ceases to be a GoP priority, this would have a bearing on the allocation of government funds to various electrification programs and would negatively impact efforts to mobilize resources from the private sector, commercial lenders and donors. This would be particularly detrimental to electrification of remote and unviable areas, and poor rural households would be put at a disadvantage. Unless there is a fundamental change in the macroeconomic situation or GOP policy directions, the likelihood of this risk materializing is **low**.

Presence of competing initiatives. RPP experience showed that inadequate coordination of different GOP and donor initiatives for rural electrification results in inefficiencies in allocation of limited resources, and even impacts the achievement of sector outcomes,. If GoP targets are to be met in a sustainable way, the issue of competing initiatives must be addressed and the roles of GoP agencies further clarified. This risk is **moderate**.

B. Risks to viability of business models for decentralized electrification.

Continuation of complicated regulatory requirements for QTP. Despite the success in setting up the QTP regulatory framework, operationalizing the one QTP took nearly five years. If this model is to be a real option for greater PSP in rural electrification, the regulatory requirements need to be simplified, timing for approvals shortened, and process for accessing subsidies accelerated, in order to ensure continued private sector interest. DOE is currently exploring simplifications to this mechanism, and plans to work with ERC to advance these efforts. If these efforts are inadequate, the impact on QTP development could be significant. This risk is rated **moderate**.

Disregard for true requirements for sustainability of PV electricity service. Inadequate attention to sustainability can affect commercial viability of business models, along with the accrual of economic and social benefits. The PV mainstreaming model being considered for scale-up offers an opportunity to address the sustainability question. The risk that the sustainability question would remain unresolved is rated **moderate**, provided that the model is governed by a suitable policy and regulatory framework.

Incomplete policy and regulatory framework for solar PV as part of ECs' mainstream business. Completion of suitable policy and regulatory framework for PV mainstreaming is essential. The ECs need to be able to collect tariffs from their customers to cover a portion of the cost of the SHS[16], and the cost of ongoing services after installation. This will require the approval of corresponding tariffs by ERC. Where there are affordability concerns, the ECs will need to be able to access GOP subsidies for the poorest households. Given the focus on output-based approaches for subsidy delivery, and ECs' inability to maintain cash reserves beyond minimal working capital requirements (as they are regulated as not-for-profit), the ECs will need upfront financing at reasonable terms, for purchase of SHS. The inclusion of the EC fee-for-service model in the DOE's HEDP, recent efforts for issuance of a policy circular, and plans for subsequent cooperation with ERC for rulemaking and approval of standard tariffs for solar PV service are cause for optimism. This risk is rated **moderate**.

Inappropriate targeting of SHS service in remote areas. SHS service must be deployed *only* where it is the most appropriate technology, i.e., in remote areas with low populations densities, where other alternatives are not viable, and where there are no plans to extend the grid in the near term. If incorrectly targeted, SHS electrification efforts could fail and would waste resources. This risk can be mitigated through proper market assessments and careful balancing of SHS electrification efforts with EC network expansion plans and various ongoing government programs. The risk is rated **moderate**.

C. Risks to EC operational and institutional performance.

Undue pressure on ECs to accelerate electrification resulting in reversal of loss reductions achieved. RPP rehabilitation and upgrading investments enabled the ECs to reduce system losses, allowing them to purchase less power to meet demand, reducing costs and enabling connection of new customers without adversely impacting existing

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[16] In light of low affordability in the remote unviable areas, it is anticipated that the upfront capital costs for majority of the systems will need to be subsidized, similar to the government subsidies available for grid extensions to meet missionary electrification goals.

customers. If any government initiatives place undue pressure on the ECs to extend their lines without due consideration to accommodating new customers, it is possible that the loss reduction achievements under RPP may be reversed. This risk is rated **moderate**.

Change in financing environment. As a result of the substantive changes in the financing markets and availability of credit risk enhancement, ECs are enjoying access to relatively low-cost financing with longer tenors.[17] Since some loans offered to the ECs are at variable rates, a significant reversal in the macroeconomic conditions or credit markets would likely impact their financing costs and repayments. The medium term outlook appears favorable, but if such a reversal took place, it would significantly impact the ECs' viability, particularly if tariffs were not adjusted. This risk is rated **moderate**.

D. Risks to the global environmental outcomes and CO_2 emissions avoidance

The assets delivering the GHG savings – upgraded portions of EC networks, small hydropower plants and SHS – are already in place. The CO_2 avoidance accomplishments could be at risk if these assets stop operating due to management, operational, financial, resource constraints or technical issues. The risk is **moderate**.

5. Assessment of Bank and Borrower Performance

5.1 Bank Performance

(a) Bank Performance in Ensuring Quality at Entry

Rating: Moderately Satisfactory

RPP design was the outcome of extensive upstream analytical work and research into lessons from past experience in the Philippines and other countries and was closely aligned with GoP priorities and the CAS. In the time leading up to project identification, the Bank's sector analytical work and policy dialogue with GoP, along with the preparation of a sector policy note, contributed to the preparation of the DOE's rural power sector strategy and reform framework. During RPP preparation, the Bank team supported GOP in designing the project to meet the Bank's technical, financial, economic, fiduciary, social and environment standards. The team comprised senior staff and consultants with diverse technical expertise and international experience, as well as safeguards and fiduciary staff that supported the client in preparation of environmental and social frameworks for the IBRD loan. The team provided continuous technical support to the DOE and DBP and mobilized financial resources from various trust funds to support their own preparatory work, including TA grants. The more than US$1 million in trust funds mobilized complemented the $568,500 spent on project preparation out of the Bank's own budget, over the course of five years. Another $46,000 was spent to prepare the AF. The Bank budget spent is above normal project preparation costs, but is nonetheless reasonable, considering the substantial preparatory work required to design a comprehensive, complex multi-phase program supporting sector reform.

Bank performance in ensuring quality at entry is rated moderately satisfactory, taking into account the impact of design choices on outcomes, as discussed in Section 2.1,

[17] Although data on their cost of financing is not available, anecdotal information suggests that commercial banks are offering loans as low as 6 percent for tenors up to 10 years.

including NEA and ECs' non-involvement in grid connected electrification and solar PV activities. Even though project objectives were clear and relevant, the Results Framework to monitor progress could have been better as discussed in Section 2.3.

(b) Quality of Supervision
Rating: Moderately Satisfactory
The Bank regularly supervised the project, carrying out more than 20 supervision missions over the course of the eight and a half year project life. Implementation Status Reports (ISRs) were filed regularly. ISR ratings were mostly candid but there was a slight disconnect in 2006, when GEF project continued to be rated satisfactory, despite delays and limited achievements, except policy decisions. The Bank correctly downgraded the PDO and AF implementation ratings, first to moderately satisfactory, and thereafter to moderately unsatisfactory 2012. US$602,000 in Bank budget was spent on supervision.

The task team was strong, comprising a core team of senior energy sector staff based in Washington and Manila. The team mobilized international expert consultants as needed to respond to implementing agencies' needs. During the early years, when GEF Grant implementation was moving slowly, the team dedicated significant effort to supporting the DOE in accelerating implementation and troubleshooting activities, both during face-to-face interactions during formal missions and through correspondence. The team worked closely with DOE to overcome initial project management and capacity barriers, and provided guidance on a range of technical issues, including helping design the SSMP approach for PV electrification. Similarly, in the last two years of RPP, when the DBP credit line was facing challenges, the team made extensive efforts to support DBP in identifying solutions, through developing action plans to the project, engaging with NEA to identify potential quick-win projects that could be implemented by ECs and financed through the DBP credit line. Throughout project implementation, safeguards and fiduciary staff performed their due diligence.

Nonetheless, there were some weaknesses in supervision. The pipeline of projects could under the AF have been more critically scrutinized to assess their likelihood of coming to financial closing, particularly after credit market conditions changed. Another shortcoming was that the team did not attempt to update the 2003-era Results Framework to 2009 standards, nor realign the PDOs.

(c) Justification of Rating for Overall Bank Performance
Rating: Moderately Satisfactory
The Bank's performance in both preparation and supervision was moderately satisfactory, making the overall rating also moderately satisfactory.

5.2 Borrower Performance
(a) Government Performance
Rating: Satisfactory
In the period leading up to project approval, the GoP's strong commitment to reforming to the rural power sector was demonstrated by its sector reform strategy and action plan, and its Letter of Sector Development program which reaffirmed its commitment to the

program. The Government satisfactorily met the covenants in the legal agreements. Throughout the duration of RPP, GoP commitment to the rural power sector reform program, the objectives of RPP, and achievement of outcomes remained strong despite the various challenges faced. A Project Supervisory Committee (PSC), chaired by DOE and with participation of oversight agencies and DBP was set up to provide overall policy direction, guidance and supervision for the policy and institutional reforms supported under the program. GoP commitment was demonstrated by issuance of key policy documents supported under RPP, particularly the policy framework for streamlining and rationalizing subsidies for missionary electrification using solar PV systems[18]; and QTP electric service in remote areas deemed unviable by franchised distribution utilities[19].

(b) Implementing Agency or Agencies Performance
Rating: Moderately Satisfactory

DBP – Moderately Satisfactory. DBP's performance under the first loan was satisfactory, with the loan fully committed a year ahead of closing and triggers for APL2 met. Although subprojects appraised during preparation did not materialize, DBP was effective in identifying new potential projects. DBP was responsive to sub-borrowers and accommodated their needs in face of challenges. When external factors began impacting the competitiveness of RPP credit line, and risked the achievement of RPP outcomes, DBP introduced its turnaround plan in mid-2011. DBP was flexible and willing to try different solutions – including rate reduction, targeting new borrowers, and working with NEA – but some major decisions took time to complete, leaving limited time to deliver a satisfactory outcome. DBP successfully disbursed $10 million in four years under the original loan, and more than $14 million in three years under the AF. There were no major safeguards issues, but some minor weaknesses in supervision. FM performance under the AF was satisfactory, while procurement performance was moderately satisfactory. Even though the IBRD loan was not fully used and revised targets were not met, DBP made a much larger contribution to the sector, through its pioneering role in expanding the range of financing options for the rural energy sector, and demonstrating ECs as a viable market for commercial lenders. In light of these significant achievements and minor shortcomings, DBP's performance is rated moderately satisfactory.

DOE – Moderately Satisfactory. GEF grant implementation started slowly, and DOE PMO's capacity was weak in the early years. Once initial hurdles were overcome and PMO was strengthened from 2006 onwards, DOE was effective in project implementation. Early on, DOE successfully delivered on key policy commitments for sector reform: the QTP framework and subsidy rationalization policy. As solar PV models faced challenges, DOE demonstrated flexibility, adaptability and diligence in finding solutions to overcome those challenges and fine-tune the models. DOE was also efficient in TA delivery to various sector participants, and advising them on day-to-day implementation activities. Nonetheless, intensive efforts dedicated to making the solar PV models work meant that other activities that had been originally intended were not

[18] DOE Circular, DC 2004-05-005, dated May 28, 2004
[19] DOE Circular, DC 2004-06-006, dated June 18, 2004, Prescribing the Qualification Criteria for the QTP, and ERC Resolution No. 22, S 2006, promulgating the Rules for the Regulation of QTPs performing missionary electrification in areas declared unviable.

carried out, such as TA for livelihoods improvement, and support for small hydro mini-grid development. DOE PMO faced internal administrative constraints posed by the DOE's regular procurement and accounting procedures, leading to issues that took months to resolve. Project procurement practices implemented were not mainstreamed into DOE's agency procurement system. Weighing major accomplishments against minor weaknesses, DOE performance is rated moderately satisfactory.

(c) Justification of Rating for Overall Borrower Performance
Rating: Moderately Satisfactory
Both the DOE and the DBP closely managed project implementation, monitored progress toward achieving project objectives and were effective in working with the Bank team during formal supervision missions, and through regular correspondence. Taking into account the minor shortcomings outlined in the individual assessments of implementing agencies, overall Borrower performance rating is moderately satisfactory.

6. Lessons Learned

In line of credit operations, being demand-driven is essential, and this needs to be balanced with due diligence, demand-building, marketing, and upfront technical support. Line of credit operations require significant coordination of different moving parts, and a lot of upstream work needs to be done to establish a pipeline of bankable projects that can be brought to closing. Effort should be made to identify potential projects far enough upstream, and offer upfront technical support to developers, to help them prepare a good project. This is preferable to the alternative of trying to retrofit an already prepared project to meet the requirements of the Bank or other financial intermediary (FI). Strong outreach by a team that knows the sector, understands its needs, and is able to demonstrate the comparative advantage of the specific financial product – long tenor and fixed rates, in the case of RPP – is a key ingredient in moving a line of credit. In the case of regulated sectors, such as electricity distribution, the FI should have a good understanding the processes in order to allow for smooth loan preparation and closing. Periodic reviews of credit market conditions are essential to make sure that the justification for the credit line still holds and underlying assumptions, including cost of alternatives, remain valid. Such reviews can be included in project operations manuals.

Flexibility is crucial for credit lines and other facilities targeting rural electrification and renewable energy. Flexibility in the *types of subprojects* that can be financed under a facility was a very strong point of RPP's design, allowing DBP to concentrate its efforts on subprojects that offered the most potential. Flexibility in terms of *targeting of borrowers* is also useful, as it allows the FI to approach a new group of potential borrowers that may be interested in the funds offered, if changing circumstances mean originally targeted borrowers are no longer interested. RPP experience demonstrated that flexibility in terms of *financing terms* that can be offered to targeted borrowers can have a strong bearing on project success. When there are changes in external factors impacting the relative competitiveness of a credit line, the FI may need to look into adjusting its margins, mobilizing other sources of funds, or using its own balance sheet without undercutting commercial rates. The FI can also offer longer tenors which would offer a comparative advantage for such a line of credit operation.

Effective coordination of different government and donor initiatives targeting the same issue is imperative. This applies to both the multiplicity of government, donor and private sector solar PV initiatives that had been going on at the same time, as well as the different credit enhancement mechanisms targeting the ECs. Overlapping efforts usually result in duplication of efforts wasted resources. Activities that are at best redundant and at worst contradictory are likely to be detrimental to the success of each initiative, particularly for attempts to promote market-based approaches. If close coordination of allocation of resources to different priority programs is not possible due to resource or authority constraints, it is necessary to inventory all different initiatives and make that information publicly available on a government agency website to guide new entrants.

While designing off-grid electrification business models, it is advisable to think long and hard about sustainability up front, and remember that there are different ways of ensuring sustainability. In the case of RPP, the model that was identified as offering the highest potential for sustainability involved the provision of PV electricity service by regulated distribution utilities. Even though this utility-based model does appear promising for addressing the challenges peculiar to the Philippines, it may very well not be the best choice for other countries. In fact, the dealer model, with different contractual arrangements to ensure sustainability, is delivering good outcomes in countries with different circumstances than the Philippines, such as Bangladesh, Cambodia, China and Mongolia. Therefore, when designing new programs, it is worth closely investigating *why* – under what contexts and conditions – other initiatives worked elsewhere and approaching "flavor of the day" concepts with caution. Lessons from other countries should be carefully adapted to the target country's specific conditions.

Solar PV should be part of a balanced portfolio of decentralized electrification solutions. As the RPP economic analysis shows, in cases where diesel generation is a viable alternative, SHS is not the least cost economic option. In simple terms, this is because there are limited economies of density in some remote areas of the Philippines, due to peculiar geographical and topographical challenges. In light of the sizable supply chain costs of getting SHS to consumers, if there is insufficient concentration of consumers in one area (or groups of adjacent areas), the cost of service and O&M rises significantly. Nonetheless, there will be cases where SHS is the most viable option, such as in remote areas with widely dispersed households, where diesel generation is not feasible due to fuel availability, supply reliability and financial issues. SHS offers obvious technical and financial advantages in those cases. Considering the type of reliable daily service that SHS can provide, if properly maintained, it is a perfectly appropriate policy choice. SHS should be chosen only where the rationale is strongest.

7. Comments on Issues Raised by Borrower/Implementing Agencies/Partners

Implementing agencies' comments on the draft ICR are available in Annex 7, along with a summary of their completion reports. There are no comments on issues raised by the implementing agencies.

Annex 1. Project Costs and Financing

(a) Project Cost by Component (in USD Million equivalent)

Rural Power Project - P066397			
Components	**Appraisal Estimate (USD millions)**	**Actual/Latest Estimate (USD millions)**	**Percentage of Appraisal**
1. Rural Electrification Subprojects	16.3	16.3	100%
Total Project Cost	16.3	16.3	100%
Front-end fee IBRD	0.1	0.1	100%
Total Financing Required	**16.4**	**16.4**	**100%**

PH-GEF-Rural Power Project - P072096			
Components	**Appraisal Estimate (USD millions)**	**Actual/Latest Estimate (USD millions)**	**Percentage of Appraisal**
1. Rural Electrification Subprojects	1.1	0.71	65%
2. Partial Credit Guarantee Fund	1	0.2	20%
3. Capacity Building	7.9	6.2	78%
Total Project Costs	10	7.11	71%
Front-end fee	0	0	
Total Financing Required	**10**	**7.11**	71%

Additional Financing for the Rural Power Project - P113159			
Components	**Appraisal Estimate (USD millions)**	**Actual/Latest Estimate (USD millions)**	**Percentage of Appraisal**
1. Rural Electrification Subprojects	48.321	19.49	40%
Total Project Cost	48.321	19.49	40%
Front-end fee IBRD	48.321	19.49	40%
Total Financing Required	**48.321**	**19.49**	**40%**

(b) Financing

Rural Power Project - P066397 and PH-GEF-Rural Power Project - P072096				
Source of Funds	**Type of Financing**	**Appraisal Estimate (USD millions)**	**Actual/Latest Estimate (USD millions)**	**Percentage of Appraisal**
Borrower	Grant	3.4	3.13	92%
Global Environment Facility (GEF)	Grant	9	7.4	82%
International Bank for Reconstruction and Development	Loan	10	10.7	107%
Local Sources of Borrowing Country	Loan and equity	3.2	6.91	216%
UN Development Programme	Grant	1	0.2	20%

Additional Financing for the Rural Power Project - P113159				
Source of Funds	**Type of Financing**	**Appraisal Estimate (USD millions)**	**Actual/Latest Estimate (USD millions)**	**Percentage of Appraisal**
Borrower	Grant			
International Bank for Reconstruction and Development	Loan	40	14.57	36%
Local Sources of Borrowing Country	Loan		4.86	
Sub-borrower(s)	Equity		2.40*	

*1USD = Php 44.12

Annex 2. Outputs by Component

Component 1 – Rural Electrification Subprojects

IBRD Loan – DBP

Table A2.1 – Eligible beneficiaries and projects under the DBP credit line

Eligible Beneficiaries	Eligible Projects	Eligible Loan Purposes
➢ Type A –RESCO,QTP, NGO, Coops, & LGUs ➢ Type B – RET Purchasers/Suppliers ➢ Type C – Electric Cooperatives ➢ Type D – Private Sector Proponents (i.e. PDU), LGUs ➢ Participating Financial Intermediaries	➢ Power Distribution ➢ Power Generation (conventional and renewable energy)	➢ Capital Investment ➢ Working Capital ➢ Interest during construction period ➢ Consultant's Services ➢ Acquisition of existing sub-transmission lines

Source: DBP

Table A2.2 – DBP Rural Power Project Portfolio

			(In Million Pesos)			
	Sub-borrower	**Purpose of Loan**	**Approved Loan**			**Total releases**
			WB	**Other**	**Total**	
1	Bohol Electric Cooperative (BOHECO)	2.5 MW Sevilla Mini-Hydro Power Project *Original Loan*	*74.57*	*59.43*	*134.00*	
		Additional Loan	*125.00*		*125.00*	
		Total Loan	199.57	59.43	259.00	199.57
2	Romblon Electric Cooperative (ROMELCO)	900kW Cantingas River Mini-Hydro *Original Loan*	*73.50*		*73.50*	
		Additional Loan	*19.64*		*19.64*	
		Total Loan	93.14		93.14	93.14
3	Batanes Electric Cooperative (BATANELCO)	Rehabilitation of electric distribution lines	10.00		10.00	9.82
4	LGU-Claveria	Diesel generating set	13.84		13.84	13.84
5	Rural Bank of Mabitac, Inc.	Livelihood micro-housing/home improvement (solar)	1.00		1.00	0.52
6	Peninsula Electric Cooperative, Inc. (PENELCO)	Distribution System Upgrading/Rehabilitation	100.00		100.00	100.00
7	Samar II Electric Cooperative, Inc. (SAMELCO II)	Upgrading of substation	18.50		18.50	16.53

8	Palawan Power Corporation	Bunker C fuel generator	39.28		39.28	39.28
9	Cebu Electric Cooperative, Inc. (CEBECO)	Upgrading/Rehabilitation of Distribution System	220.00		220.00	21.02
10	Agusan Electric Cooperative, Inc. (ASELCO)	Construction of 69 KV transmission lines	60.00		60.00	58.71
11	Negros Occidental Electric Cooperative, Inc. (NOCECO)*	Upgrading/Rehabilitation of distribution system. Purchase of sub-transmission assets	42.00		42.00	42.00
12	Oriental Mindoro Electric Cooperative, Inc. (ORMECO)	Construction of 4.2 MW Mini-hydro Power Project *Original Loan*	*490.00*		*490.00*	
		Additional Loan	*220.06*		*220.06*	
		Total Loan	710.06			455.05
13	Capiz Electric Cooperative, Inc. (CAPELCO)*	Upgrading/Rehabilitation of distribution system.	110.00		110.00	110.00
	Total (in Pesos)		**1,617.4**	**59.4**	**1,657.2**	**1,159.5**
	Total (in USD)					**25.27**
	*Approved loan was reduced to actual amount availed.					

Source: DBP

Table A2.3 – Electric Cooperatives Debt Service Coverage Ratios

Electric Cooperative	DSCR
1. CAPELCO	1.06
2. NOCECO	7.16
3. BATANELCO	0.36
4. ASELCO***	3.66
5. PENELCO	6.84
6. BOHECO I	2.83
7. ROMELCO	1.94
8. ORMECO****	2.19
9. CEBECO***	4.79
10. SAMELCO II	Fully paid as of December 31, 2011

*** Interim 2012 Financial Statement

**** Audited 2011 Financial Statement

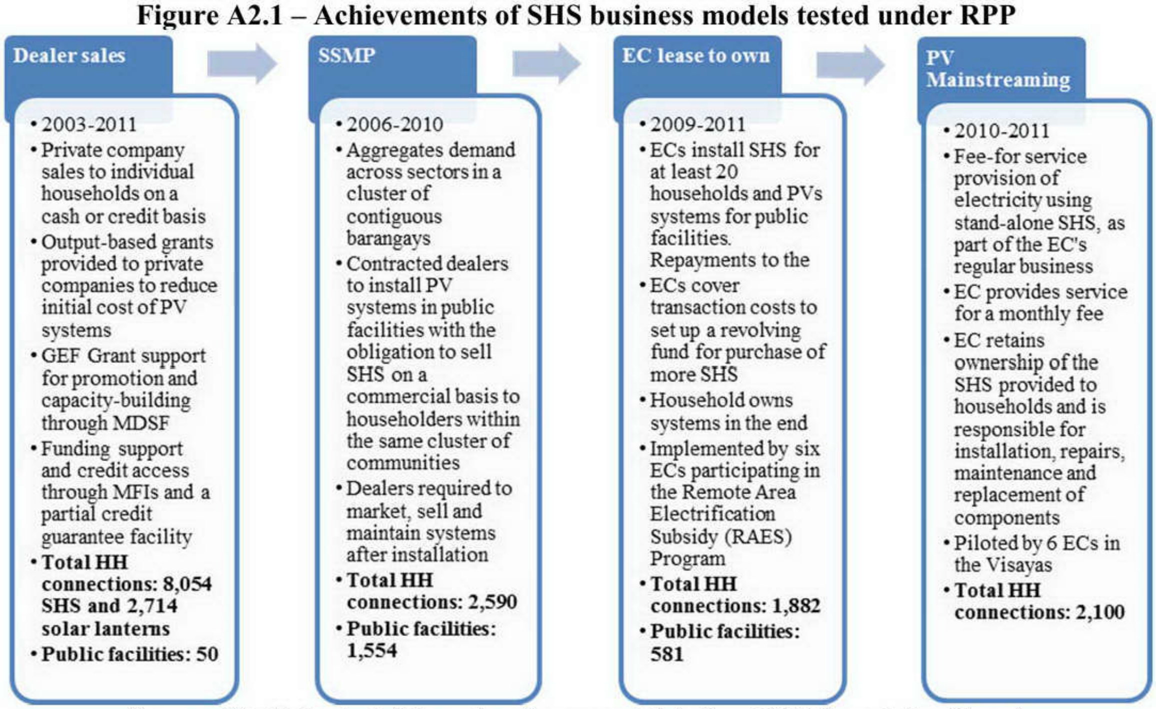
Source: DBP calculations based on Audited Financial Statements

Table A2.4 – EC losses before and after RPP

EC	Acronym	Project type	Losses before	Losses After	Loss reduction	Delivered energy
					MWh	MWh
Batanes Electric Coop. Inc.	BATANELC O	Rehabilitation of Distribution Facilities	8.1%	7.2%	44	4,833
Samar II Electric Coop. Inc.	SAMELCO II	Upgrading of Substation	13.9%	13.9%	0	53,039
Agusan del Sur Electric Coop. Inc.	ASELCO	Construction of 69kV transmission lines	16.0%	10.5%	6622	121,054
Peninsula Electric Coop. Inc.	PENELCO	Rehabilitation of Distribution Facilities	12.6%	9.0%	11379	310,045
Negros Occidental Electric Coop. Inc.	NOCECO	Construction of 69kV transmission lines and 10 MVA substation	13.0%	11.0%	3512	174,750
Capiz Electric Coop. Inc.	CAPELCO	Rehabilitation of Distribution Facilities	12.4%	11.8%	862	151,286
					22,420	815,006

GEF Grant – DOE

Figure A2.1 – Achievements of SHS business models tested under RPP



Source: World Bank staff, based on figures and data from DOE Completion Report

Table A2.5 – Total PV Installations under the RPP

	Dealer model	SSMP	Lease-to-own	EC fee for service	Total RPP
SHS	8,054	2,590	1,882	2,100	14,626
Lanterns	2,714				2,714
Public facilities	50	1,554	581		2,185
Total installations	10,818	4,144	2,463	2,100	**19,525**

In addition, a total of 1,450 households were connected via mini-grids bringing the total of 20,975 new customers in rural areas provided with mini-grid electrical connection or individual RET services.

Source: DOE

Table A2.6 – Solar PV installations under SSMP packages

	SSMP 1	SSMP 3	SSMP 3
No. of Barangays	75	136	72
Public Facilities	436	734	384
Household Sales (Actual)	242	2163	185
Donor	Mirant in partnership with AMORE and ILPI	KEPCO	KEPCO
Contractor(s)	Solarco	Dumalag Propmech	Dumalag Propmech

Source: DOE

Table A2.7 – Solar PV installations by ECs participating in the fee for service model

Electric Cooperative	Acronym	No. of Bgys.	Public Facilities*		HH Sales
			No.	kWp	
Agusan del Sur Electric Cooperative, Inc.	ASELCO	13	77	11.5	260
Cotabato Electric Cooperative, Inc.	COTELCO	2	12	1.8	40
Lanao del Norte EC, Inc.	LANECO	60	360	54.0	1,201
Sultan Kudarat Electric Cooperative, Inc.	SUKELCO	3	18	2.7	80
Palawan Electric	PALECO	32	160	22.4	640

Electric Cooperative	Acronym	No. of Bgys.	Public Facilities*		HH Sales
			No.	kWp	
Cooperative					
Zamboanga Sur II EC, Inc.	ZAMSURECO II	19	114	17.1	301
Total		97	**581**	**87.1**	**1,882**

Source: DOE

Table A2.8 – Solar PV installations by ECs Participating in the PV Mainstreaming

Electric Cooperative	No. of HH	PV Size	Monthly Fee per Wp
Bantayan Island Electric Cooperative, Inc. (BANELCO)	350	350 x 75 Wp	390
Bohol II Electric Cooperative, Inc. (BOHECO II)	300	300 x 50 Wp	200
Cebu II Electric Cooperative Inc. (CEBECO II)	300	50 x 25 Wp	120
		150 x 50 Wp	220
		100 x 75 Wp	320
Negros Occidental Electric Cooperative, Inc. (NOCECO)	300	300 x 50 Wp	250
Negros Oriental I Electric Cooperative, Inc. (NORECO 1)	300	63 x 50 Wp	195
		237 x 75 Wp	295
Victoria Rural Electric Service Cooperative, Inc. (VRESCO)	520	150 x 25 Wp	150
		150 x 50 Wp	250
		220 x 75Wp	350
Total	**2,070**		

Source: DOE

Table A2.9 – MDSF and Incubator Projects

Grantee	Activity
MDSF PROJECTS	
1. SOLARCO #1	Market and field research
2. Shell Solar Phils.	Sales training and product launch support
3. GenDiesel Phils.	Training, promotion, market survey, business development
4. World Water Phils.	Market assessment, marketing plan, training of network personnel
5. People's Credit and Finance Corporation (PCFC)	Training for PCFC-accredited MFI partners on micro energy credit facility
6. SURE #1	Marketing and sales of solar lanterns

Grantee	Activity
7. Del Genta #1	Marketing and sales in Central Mindanao
8. SOLARCO #2	Marketing and sales in Palawan
9. SURE #2	Marketing and sales of SHS in previous lantern markets
10. Paglaum Multi-Purpose Cooperative	Marketing and sales in North Western Mindanao
11. Propmech	Marketing and sales in SSMP 2 and 3 areas
12. Del Genta #2	Solar Home System (SHS) Market Development 2010
13. Dumalag	Development of sales and service capability in Iloilo, Eastern Samar, Western Samar, and Leyte
INCUBATOR PROJECTS	
14. Del Genta and Solidarity for Community Devt. Coop	Commercial sale of PV systems in Mindanao through Solidarity Coop.
15. Del Genta and Central Mindanao BRECDA Federation	Commercial sale of PV systems in Mindanao through BRECDAs
16. SURE – Rural Bank of Mabitac Inc.	Sale of SHS in Polilio Islands
17. GenDiesel Phils. And Paglaum MPC	Sale of SHS in North Western Mindanao
18. Propmech and Central Mindanao BRECDA Federation	Sale of SHS in Sultan Kudarat and Maguindanao
19. SURE and CSDO	Sales of SHS in South Cotabato and nearby areas.

Source: DOE

Component 2 – Partial Credit Guarantee facility

Table A2.10 – List of guarantees under LGF

	No. of Loans	Amount
Paglaum Multi-Purpose Cooperative	15	PhP 26,991.00
Progressive Bank, Inc.	27	PhP 316,002.00

Component 3 – Capacity Building

GEF Grant – DOE

Table A2.11 –DOE activities and outputs under the RPP GEF (2004-2011)

	International Consultants
1	Operationalization of QTP Framework
2	Needs Assessment Report and Development of a 5-Year Technical Assistance and Capacity Building Plan for the RPP
3	Development of Sustainable Solar Market Packages (SSMPs)
4	Capacity Building of Prospective Microfinance Institutions
5	Development of Guarantee Programs to support commercial lending for projects in Renewable Energy and Rural Electrification
6	Design of Subsidy Program for Rural Electrification
7	Loan Guarantee Fund Operationalization

8	Assessment and Recommendation for the MFI Capacity Building
9	Study of Options to Reduce Fossil Power Generation in Mindanao
10	Updating of the Missionary Electrification Development Plan 2006-2010 to 2007-2011 and Integration of Renewable Energy Technologies
11	Training Program for Stand Alone Power Systems Installation and Maintenance Course
12	Strengthen Policy and Regulatory Framework for Household Electrification with Roadmap for 90% Household Electrification by 2017
13	Updating of the Missionary Electrification Development Plan for 2012-2016
	Local Consultants
14	Development of the Operating Guidelines and Procedures for the Start Up of the RPP-PMO
15	Needs Assessment Report and Development of a 5-Year TA and Capacity Building Plan for the RPP
16	Capacity Building for Microfinance Institutions
17	Design of Subsidy Program for Rural Electrification
18	Promulgation of Policies and Regulatory Guidelines for QTP Participation in Rural/Missionary Electrification
19	Preparation of Strategic and First Year Communications and Investment Promotion Plans, Website and Implementation of Initial Promotion Activities
20	Program Management of the RPP Loan Guarantee Fund
21	SSMP Procurement
22	Technical and Financial Evaluation of QTP Project
23	Conduct of Profiling and Baseline Studies for Selected Unelectrified Barangays in the Philippines
24	Review of Performance and Warranty Securities for SSMP Contracts
32	PV Mainstreaming Design
33	PV Business Models Assessment

Source: DOE

GEF Grant – DBP

Activity	Details and achievements
Project Preparation Fund	Project preparation support for three RET subprojects, of which one project, Linao Cawayan Mini-hydropower Project, pursued RPP loan and construction.
Technical consultants supporting DBP in review of pipeline subprojects	A total of 16 renewable energy project proposals, mostly mini-hydropower, were reviewed. Of the projects reviewed by the consultant, two (2) projects were funded under RPP, namely: Sevilla Mini-hydropower Project and Linao-Cawayan Mini-hydropower Project.
Procurement support to PMU	Hiring of two consultants to support PMO in reviewing procurement documents and provided technical support to the PMO.

Training, Workshop and Study Tours	142 DBP staff, mostly Account Officers, received capacity training on Renewable Energy Technologies (e.g. hydro, wind, solar, biomass) and other related energy projects
PMO operations and miscellaneous expenses	Support for PMO in the marketing of RPP and project management administrative needs.
TOTAL	Funds allocated: 1,100,000.00, Used: 628,502, Utilization rate: 57%

Source: DBP

Annex 3. Economic and Financial Analysis [20]

A3.1 Methodology

At appraisal of the Philippines Rural Power Project (RPP) in 2002, with much of the project oriented to individual households and off-grid systems, the methodology for economic analysis rested on estimates of residential willingness-to-pay (WTP). Benefits of PV systems were based on increases in the consumer surplus implied in the transition from electricity substitutes (kerosene, diesel-based battery charging, dry cells) to PV-based electricity, based on demand curves for lighting (measured as Lumen-hours/month) and TV viewing (viewing hours/month). This drew heavily on a comprehensive rural household survey taken in 1998.[21] The details of the methodology were published in a 2003 ASTAE paper.[22]

Table A3.1 shows the estimated WTP for each tranche of consumption. The survey revealed high values of WTP for the first few kWh consumed: the first 31 kWh/year were valued at PhP 98/kWh (1.88$/kWh), reflecting the high cost of lighting from kerosene. The WTP in the last tranche – 20 US cents/kWh – reflected the observed purchase of diesel-based electricity in un-electrified areas.

Table A3.1: WTP estimates

	kWh	peso/kWh	US$/kWh(1)
first 31kWh	31	98	1.88
31-61 kWh	30	45	0.87
61-115 kWh	55	24	0.46
115-actual		10.25	0.20

Source: RPP Economic Analysis Background Report
Exchange rate for 2002: PhP52/$ (2002 average)

Ideally, to re-estimate the economic benefits at project completion, a more recent household energy survey would be available to enable a new demand curve to be drawn.[23] This is not available for the RPP, and the only verification of current levels of WTP is from a few field visits conducted for the ICR.

Some of the input assumptions have changed dramatically since 2002. In 2002, the average retail price of kerosene was around 13 PhP/liter (25UScents/liter); by the end of 2012, the price was 50 PhP/liter ($1.22/liter), an increase (in nominal PHP terms) of 384% (Figure 3.1).

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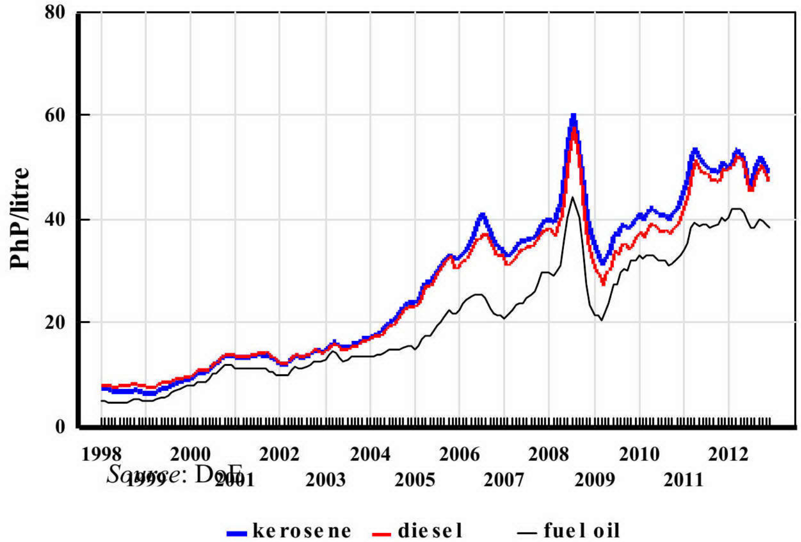
20 This annex summarizes the analysis in the detailed ICR Economic Analysis Report prepared by Peter Meier.

21 *Rural Electrification and Development in the Philippines: Measuring the Social and Economic Benefits*, ESMAP Report 255/02, May 2002.

22 P. Meier. *Economic Analysis of Solar Home Systems: A Case Study of the Philippines*, Asia Alternative Energy Program, World Bank, February 2003.

23 That ideal has been achieved in only very few World Bank projects, notably the China Renewable Energy Development Project, which commissioned a survey expressly for the re-evaluation of the project in the ICR – see World Bank, *Implementation Completion Report, China Renewable Energy Development Program*, 2007.

Figure 3.1: Kerosene and Diesel Prices



Source: DoE

In *real* terms the increase has been much smaller. For kerosene, the 2012 kerosene price, at constant 2002 price levels (assuming adjustment with the CPI), is 32.06 PhP/liter, so the *real* increase in fossil fuel prices is 236% (Table A3.2).

Table A3.2: Fuel prices, PhP/liter

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Nominal											
Kerosene	13.56	15.95	20.59	29.47	36.64	36.23	46.85	36.23	41.44	50.27	50.42
Auto diesel	13.89	15.72	20.10	28.74	34.49	34.77	43.78	32.66	38.48	48.33	49.19
Fuel oil	11.21	13.40	14.40	18.88	23.67	24.94	34.04	26.46	32.30	38.26	40.05
at 2002 prices											
Kerosene	13.56	13.26	14.88	18.02	24.46	29.55	26.99	33.52	24.96	27.28	32.06
Auto diesel	13.89	13.58	14.66	17.60	23.86	27.82	25.90	31.33	22.49	25.33	30.82
Fuel oil	11.21	10.96	12.49	12.61	15.67	19.09	18.58	24.36	18.23	21.26	24.40

But higher (real) kerosene prices imply higher avoided costs, and hence larger economic benefits. However, for poor households with little disposable income, increases in kerosene price would most likely imply a downward adjustment of consumption rather than an increase in annual kerosene expenditure. However, in the absence of a recent survey it is difficult to be precise about the likely changes in the demand curve: with the small increase in real incomes the demand curve would shift slightly to the right (i.e. for any given price, the quantity demanded increases). If the costs of the PV systems have not increased, then benefits estimated at the *old* values of WTP would be a lower bound, and likely underestimate the actual economic returns.[24]

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[24] This annex was prepared by Peter Meier, Consultant. Further details are available in the ICR Economic Analysis Background Report.

A3.2 Solar Home Systems

Economic benefits at appraisal
At appraisal, the economic analysis was presented under three sets of assumptions about the benefits (1) avoided costs, under which the economic cost of the PV system is compared to the economic cost of the avoided energy expenditures that SHS replace (kerosene, battery charging); (2) benefits estimated as the gain in consumer surplus (which was based on detailed survey information); and (3) adding carbon reduction benefits to the consumer surplus (CS) benefits. In addition, a financial rate of return (FRR) was estimated from the consumer perspective (under assumptions about how the SHS would be financed). The rates of return are shown in Table A3.3.

Table A3.3: Rates of return at appraisal, Solar Home Systems

	Financial returns, consumer perspective	ERR, benefits at avoided economic costs	ERR, benefits as change in CS	ERR, CS benefits plus carbon reduction
20 Wp SHS	160%	15.4%	45%	50.5%
40 Wp SHS	17.4%	11.4%	46.6%	56.4%
75 Wp SHS	1.6%	8.7%	32.2%	38.5%
Entire program			44.6%	53.2%

At the time these estimates were made, the assumption was that PV systems would be supplied under the so-called *dealer* model, which called for several important assumptions, notably that (for the financial analysis), consumers purchased the PV systems under some consumer credit scheme (or cash), and (for both economic and financial analysis) that bulbs, controllers and batteries would be replaced over time by consumers themselves (assuming that some sort of dealer network that could stock, replace and repair PV systems was in place).

This model did not prove successful. Micro finance institutions showed little interest, and up-take was slow. The subsequent model of "market packages" proved similarly unsustainable. Rather, the model now advocated is "PV mainstreaming", under which consumers simply pay a fee for service provided by the EC, under a tariff under the jurisdiction of the regulator, and under which consumers do not own their PV systems. This has been piloted by six schemes in the Visayas, with 2050 systems installed by the end of 2011. Making the EC responsible for the repair and replacement of systems addresses the experience with various leasing models in existence in the Philippines, which transfer ownership to households who then bears these costs and often does not provide for them, leading to the failure of the system.

Phrased differently, it means that in 2002 the true costs of maintenance and repair were likely to have been underestimated. Recent calculations carried out by consultants to the DOE under a separate technical assistance activity estimates the cost of PV service by ECs and includes a comprehensive assessment of all of the various cost components required for sustainable service, and includes staff and transportation costs needed to operate the scheme, overheads, insurance, and fees for the collection of revenues.

Operating costs
Table A3.4 shows a comparison of the main assumptions in the current tariff estimates with those taken at appraisal. The calculations, carried out under consultants advising the DOE on a

regulatory and policy framework for PV mainstreaming, are for a so-called baseline "Zone A";[25] in more remote communities the operating costs are substantially greater.[26]

Table A3.4: Assumptions for economic analysis

		At Appraisal	PV mainstreaming regulatory framework consultants' tariff calculation assumptions.
1	Replacement Solar panel	Not applicable(1)	PhP6,000, life 20 years
2	Battery	PhP 1600, life 2 years	PhP4,500, life 3 years
3	Controller	PhP 750, life 5 years	PhP2,800, life 5 years
4	Bulbs	PhP150/year	Not included(2)
5	Insurance	Not included	5 PhP/SHS/month
6	Payroll	Not included	87.65 PhP/SHS/month
7	Overheads	Not included	8.68 PhP/SHS/month
8	Transportation cost	Not included	8.46 PhP/SHS/month
9	BAPA collection fee	Not included	15.39 PhP/SHS/month
	Total annual charges (5+6+7+8+9)	Not included	2,162 PhP/year

Notes:
(1) Our calculations assume a 20-year life of panels; the consultant calculations are for perpetual operation, so panels need replacement every 20 years (for which an annual sinking fund charge would be levied in a *financial* calculation). But in economic analysis one books capital costs in the year they are incurred; and an outlay 20 years hence has almost no impact (if the discount rate reflects the opportunity cost of capital, unlikely to be very much less than 10%)
(2) see text above

Sample tariff calculations carried out by DOE consultants do not include the cost of CFLs. Since light bulbs classify as an appliance, owned by the household just as are owned fans and radios, they are understandably excluded from the electricity tariff. At appraisal, the view was that CFLs were significantly more expensive than incandescent bulbs, and were therefore included in the calculations as an incremental cost.

The rationale for including bulb costs in the package at appraisal was that the incremental cost over incandescent bulbs was so great that poor consumers could not afford them, and that PV systems generated so few kWh that CFLs were an essential component. But in principle there is no reason why the economic advantages of CFL could not also be achieved with diesels: indeed, handing out free CFLs to households connected to diesel generators is likely to be a far more cost effective way of reducing carbon emissions (if that was indeed the rationale for the GEF subsidies provided by RPP) than paying for very expensive solar systems. The proposal to exclude the costs of CFLs on grounds that this is a consumer appliance like any other is sound, and has been adopted in this evaluation as well. In any event, it changes little the overall economic returns of solar PV (a decrease in ERR of less than 1%).

Capital costs

The delivered price for a 50 Wp system ranges from 17,500 PhP for a basic system with 50 Ah battery ($US 436) to 27,740 for a 50Wp system with integrated digital AM/FM radio&MP3 player and 70 Ah battery ($US 691). At appraisal in 2003, the delivered cost of a basic 40Wp

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25 Economic Consulting Associates (ECA), *Advisory Support on Policy and Regulatory Aspects of SHS provision*, Phase 2 Report submitted to the Department of Energy and the World Bank, January 2013.
26 18.6% additional in Zone B, and 58.1% greater in Zone C.

system was $US 484, and $US 710 for a 75 Wp system. The consultants' tariff calculations assume an initial package system cost of PhP 20,000 ($487). The real costs of the complete packages have therefore declined somewhat since 2002.

Economic returns

The resulting economic returns are estimated at 13.5%.[27] The NPV of the O&M costs of sustainable after sales service (PhP 15,140 at 12% discount rate) is almost as great as that of the capital cost of the system (NPV 17,857 PhP): at PhP 2,162/year for O&M, this represents more than 10% of the capital cost per year, an unusually high operating cost for renewable energy (which for most grid-connected technologies is in the range of 2-3% for small system). This far outweighs the decrease in capital cost since 2002 noted above. However, the switching value for WTP is just PhP85/kWh, and therefore the result is indeed highly dependent upon WTP assumptions, which in the absence of a more recent household energy survey is difficult to confirm. The levelized cost per kWh computes to 85 PhP/kWh ($2.07/kWh).

At the time of appraisal, this methodology for calculating the equivalent levelized cost per kWh was rejected. It was argued that a kWh from a PV was worth more than a kWh from a grid connected or diesel source because it was intrinsically linked to the use of high efficiency appliances. To produce the same number of lumen-hours one needed 4 times more kWh if provided by an incandescent bulb, than if provided from a CFL. Therefore, the 6.25 kWh per month produced by a 50Wp solar panel was equivalent to 20-30 kWh from a diesel project. Consequently the cost of PV appeared very much lower than it actually was (is).

The cost of diesel generation

OP10.04 requires not only that a proposed project is superior to a *no project* alternative, but also that the proposed project is the least cost way of meeting the project output – which in this case means electrification from small diesels. The levelized economic cost of diesel generation is PhP 19.2/kWh (47UScents/kWh), using the 2013 cost of 58PhP/liter ($1.40/liter) as reported in the Bohol site visit notes.[28] Capital and operating costs, and operating assumptions (4 hours/day, 0.75 liter/hour fuel consumption) are taken from the ECA report on the draft tariff calculations. The calculations assume that the world oil price escalates at around 2%/year (which corresponds roughly to the base case of the last IEA World Energy Outlook (that has the 2025 world oil price at around $125/bbl in 2025 (at constant 2011 prices). In other words, while the ERR meets the requirement that its NPV meets the hurdle rate for the "*no project*" alternative (as required by OP 10.04), when compared with the diesel project alternatives, PV is very far from least cost.

Impact of global externalities

This calculation changes little when the avoided global externalities of diesel generation are added as a benefit. If we use the 19.2 PhP/kWh diesel generation price as the measure of economic benefit, and calculate what value of carbon is required in order for the ERR to increase to the 12% hurdle rate, the required carbon price ($/ton CO_2 equivalent) to be $2,745/ton. At values in the range considered reasonable by the providers of carbon finance (rarely more than $100/ton CO_2), the ERR remains firmly negative. In other words, PV is a very expensive way of reducing carbon emissions, which, in the Philippines, can be achieved at much lower prices with geothermal or small hydropower. If the world oil price tripled (to $375/bbl in 2025), the required carbon price is still $2,420/ton. .

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27 The detailed tables are in the Background report.

28 This is about PhP10/liter more than the price in Manila (Table 2), implying there is another PhP16/liter difference between the fob price and the Manila retail price (fob=34+14+10=58 retail price at Bohol.

Sensitivity analysis
The levelized economic cost of solar PV is PhP87/kWh ($2.11/kWh) when burdened with the O&M costs as currently proposed. Therefore the question arises whether plausible cost reductions for PV and plausible increases in the future world oil price, would change the relative delivered economic cost to the consumer. One could hypothesize the following sources of cost reductions:

- ***Package costs***: for which we have used the average cost of the quotations sighted (PhP20,000). However the least cost bid is for PhP18,800 (quote for 244 systems by *Trademaster* to NORELCO). These costs could plausibly be another 5-10% lower if the scale were in the 1000s rather than 100s, say PhP 16,000.
- ***O&M costs***: These may reflect the tendency of the ECs to quote high costs (in the expectation of being negotiated down by the Regulator). One could plausibly argue they may be as much as 20% than required.

Under these assumptions, the ERR increases significantly to a robust 21%. However, assessed against diesel, the ERR still remains negative. The switching value for world oil price, using these same assumptions, is 2,138 $/bbl in 2025 (or an increase of 28% per year) or PV to be competitive. Even if the O&M cost were zero, the oil price switching value is still $1,250/bbl (22% annual rate of increase in oil price).

If the argument that only PV SHS benefit from high efficiency appliances were to be accepted, then the switching value for the efficiency multiplier is 3.86, namely that the "effective" equivalent kWh production is not 6.21 kWh/month (as estimated by consultants supporting DOE in preparation of regulatory and policy framework for PV mainstreaming), but 24 kWh/month. At this value, the ERR of PV is exactly 12% when measured against diesel generation.

Affordability and Anecdotal Evidence
During the February 2013 field visit to Bohol it was observed that high prices were being paid for electricity in informal diesel mini-grids. Households were being charged PhP 20 per night per appliance (whether light bulbs or larger appliances): for three light bulbs and a TV the nightly charge calculates to 80 PhP, or 2,400 PhP/month ($58). So obviously, a PV fee-for-service costing 200 PhP/month (or even 400 PhP/month in the more remote areas) will be highly valued and desired by such consumers.

Needless to say, such a flat-rate pricing system provides no incentive to use efficient appliances in general, and CFLs or tube lights rather than incandescent bulbs in particular.[29] Though it is true that this level of usage might not be demanded *every* day of the year, households who can afford this level of expenditure are clearly not below the poverty line. For daily use, the annual cost is PhP 28,800 per year ($702). The national poverty threshold is PhP 84,000 ($2,050), so it is not plausible that families near this income level would spend a third of their income on diesel electricity. In other words, without a more representative survey of the candidate areas, it is difficult to establish the current expenditure on electricity substitutes, and on informally provided diesel electricity in light of current actual disposable income. The last reliable survey is now over 10 years old, from which any simple extrapolations are likely to be unreliable.

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[29] One would again need a household energy survey to determine whether there was any difference in light bulb stock among households under such a flat-rate pricing system, and metered households that are grid-connected. Since the last comprehensive survey in 1998, the (real) relative price of CFLs has decreased considerably. Moreover, there will likely be another major lighting technology shift with the introduction of LED lights

Assuming that the 50Wp SHS is equivalent (i.e. could run three light bulbs and a small TV), then 2,704 PhP for the equivalent kWh from solar panels, i.e. 75kWh/year, works out at 35 PhP/kWh. But the cost of diesel generation is PhP 18 /kWh (at current oil price levels). In other words, affordability of the proposed monthly fee for SHS is *not* the problem: whatever may be the affordability constraint, diesel has lower financial and economic costs lower than PV.

Conclusions on SHS PV

From this analysis one may draw the following conclusions:

- The ERR for SHS PV against the no project alternative (using willingness to pay as the proxy for benefits) is in the range of 13.5-21%, depending on assumptions.
- The high O&M costs necessary to achieve PV system sustainability in the PV mainstreaming model have outweighed the increases in fossil fuel prices, and the decrease in PV system capital costs. Electricity from PV systems remains significantly more expensive than from diesel: when the PV SHS is compared to diesel generation, the ERR is negative (talking the IEA World Energy Outlook to forecast the world oil price ($125/bbl by 2025 at constant 2011 prices).
- Even if further economies of scale are achievable in the system costs, or in the O&M costs, the cost of oil would need to reach over 1,000$/bbl by 2025 for a solar PV to become competitive against diesel.
- While the PV mainstreaming may be seen as financially and technically sustainable, and therefore constitute an improvement over other implementation models, this appears to come at a high price. Economic returns are only marginally above the hurdle rate, and in the absence of new survey evidence, difficult to confirm. The sensitivity analysis shows that even if these O&M costs for the ECs to provide the service were *zero*, PV is still not competitive with diesel.
- Arguments that comparisons based on actual kWh produced are invalid because PV systems are intrinsically coupled to the use of high efficiency appliances, and are therefore above to provide light (and TV viewing) at a far lower price per *lumen* than suggested by cost per kWh comparisons, have little merit. There is no reason why such high efficiency appliances could not also be distributed (subsidized) to consumers connected to the rural grid, or to diesels (formal or informal mini-grids).
- However, though expensive, **where diesel is not a feasible option for reasons of highly dispersed households, or inability to transport diesel engines in remote areas, or where diesel fuel supply is hindered in the wet season, solar PV is the least cost option**, and can be justified on the basis of WTP as estimated from rural energy surveys.
- Uncertainty in WTP does *not* affect the comparison of PV with diesel. Whether WTP is 60 US cents, or $6/kWh, the relative *costs* remain the same.
- Carbon reductions are small, and have a negligible impact on economic returns. The avoided cost of carbon is orders of magnitude greater than those achievable at far lower cost (such as geothermal and hydropower generation).

A3.2 Mini-hydropower subprojects

Three mini-hydro projects were financed by the RPP, as summarized in Table A3.5.

Table A3.5: Mini-hydro projects financed by the RPP

	Installed capacity MW	EC
Sevilla	2.5	BOHECO
Linao-Cawayan	4.2	ORMECO
Cantingas	0.9	ROMELCO

BOHECO: Bohol Electric Cooperative
ORMECO: Oriental Mindoro Electric Cooperative
ROMELCO: Romblon Electric Cooperative

At the time of RPP project appraisal, none of these specific projects had been identified. Table A3.6 shows the ERR estimates for the mini-grid component as provided in the PAD: estimates run from 8.9% to 32.6%. However, the PAD Annex did not identify which among these projects were based on mini-hydro, and which were diesel-powered mini-grids.

Table A3.6: Estimates of ERR at project appraisal

		Generating cost		
	ERR	UScents/kWh	Peso/kWh	WTP
Roxas	32.6%	15.0	7.6	15.0
El Nido	11.2%	19.1	9.8	14.3
SanVicente	19.7%	18.1	9.2	14.9
Taytay	25.6%	16.1	8.2	14.6
Palawan combined	28.2%	15.3	7.8	14.7
Jose Abad Santos	8.9%	21.6	11.0	15.5
Malita	25.1%	16.3	8.3	15.5
Davao combined	20.6%	17.6	9.0	15.5

Source: RPP, PAD, Annex 4

Inspection of the (unpublished) background report on economic analysis prepared at Appraisal shows that mini-hydro was considered in only five of these areas, and in none was mini-hydro least-cost: five hours service per day based on diesels was least cost in all cases. However, it must be remembered that in 2001/2002 when the appraisal was prepared, the world oil prices were considerably below those observed today (as discussed in Section 1). Consequently it should not surprise that the economics of small hydro have changed, and that subsequent studies recommended the three small hydro schemes for implementation.

Borrower's estimates of achieved returns

Table A3.7 shows the borrower's estimates of economic and financial returns, as compared to the returns estimated in the project feasibility studies. However, the borrower's estimates are not judged reliable, and have been re-estimated, as described below.[30]

[30] There are limitations to the reliability of the Borrower's estimate of FIRR. The "*estimated gross operating profit*" is taken as a constant 60% of revenue, an assumption that is not documented. A reliable estimate of FIRR based on cash flows needs to explicitly recognize the debt service payments (principal and interest). Nor is it clear whether the calculations are in constant PhP or nominal PhP – if indeed these are at constant prices, then *real* rather than nominal interest rates need to be used. The Borrower's estimate of economic returns is also unreliable. The economic flows are given by the sum of the "*gross operating profit*"," "*forex savings*" and the avoided cost of GHG emissions. Even assuming that "*forex savings*" are properly denominated at border prices, the total economic flow as defined is the sum of a financial flow (operating profit) and economic flows – which is never reliable.

Table A3.7: Borrower's estimate of ERR and FIRR

	FIRR		ERR	
	FS	Borrower's estimate	FS	Borrower's estimate
Sevilla	NA	7.2%	NA	24.8%
Linao-Cawayan	16.5%	14.5%	24.9%	44.1%
Cantigas	21.1%	9.4%	33.7%	30.5%

Source: Borrower's calculations
NA Not available

ICR re-estimation of returns at Linao-Cawayan

The actual cost of the project is unclear: what has been completed is the 2.1 MW *upper cascade project*. It was commissioned in March 2011 by President Aquino. According to the December 31, 2012 tabulation of the DBP, the approved World Bank loan to ORMECO for a 4.2 MW facility was PhP 490 million plus PhP 220 additional funding for a total of PhP 710million. However, actual disbursements are reported by DBP at PhP 455million. The borrower's spreadsheet shows financial costs during the 2011-2013 period as PhP 409 million (though that analysis is silent on the question of how much is debt and how much is equity). The feasibility study (FS) estimates the cost of the upper cascade at PhP 392 million ($US9.3 million, or $4,444/kW).

During the first year of operation in 2012, the project generated 7.3 GWh, equivalent to an annual load factor of 0.396. This is considerably below the FS estimate of 12.27 GWh. Whether this is due to teething troubles, or an unusually dry year, is not known. If ORMECO's benefits are assessed at the reported financial incremental cost of generation from ORMECO's most expensive diesel plant (10.23 PhP/kWh, 25UScents/kWh),[31] the estimated project financial return is 14.7%. The project is clearly financially attractive, given the high cost of diesel generation.

Information on the tax content of the financial capital cost estimate was not available: the FS is silent on this matter. In the absence of subsidy or taxes on the diesel used for power generation by ORMECO, the avoided financial cost may be taken as the avoided economic cost, under which circumstances the lower bound of ERR is the same as the FRR.

Using a valuation of $30/ton CO_2 for the avoided social cost of carbon, the addition of this benefit increases the ERR to 16%. In 2012, the CO_2 emissions reduction is 4,380 tons; if generation were to reach the average in the FS, this increases to 7,380 tons.

The ERR would be higher if the average willingness-to-pay (WTP) for electricity exceeded the cost of oil generation. Detailed WTP estimates were available at the time of project appraisal in 2001, with WTP for rural consumers was assessed at PhP 10.25/kWh. But while nominal PPP adjusted per capita income has increased from $2,465/capita in 2001 to $4,119/capita in 2011 (an increase of 1.74), the GDP deflator has increased by a factor of 1.56, so the increase in *real* incomes has been just 10%. If the old WTP estimate is adjusted for inflation, the WTP would be around PhP 17.1/kWh which if used in the calculations provide an ERR (other things equal) of

[31] We have no information on whether the transmission losses from the mini-hydro location to the load center is any different than the distance of the marginal thermal project. If the hydro site were much more distant, then the benefits (avoided generation at the *diesel* plant) would need adjustment accordingly.

25%. However, without survey data to show how householders have in fact adjusted to higher kerosene and diesel prices (bought less kerosene keeping expenditure constant, or bought the same quantity at the new price, but reduced expenditure on other goods and services), such extrapolations are unreliable.

The ROMELCO and BOHECO small hydros
Table A3.8 shows the corresponding calculations for the other two mini-hydros financed by RPP. The baseline FRR estimate for BOHECO is 21.6%, or 22.8% when the avoided GHG emissions are included; the FRR for ROMELCO is 23.3% (24.8% when GHG emissions are included).

Table A3.8: ERR&FRR mini-hydros

	ROMELCO	BOHECO	ORMECO
FRR/ERR	23.3%	21.6%	14.7%
ERR with GHG	24.8%	22.8%	16.0%

Conclusions on mini-hydro
All three mini-hydro project have satisfactory returns well in excess of the hurdle rate, and have positive impact on the EC cash flows: the reduction in revenue requirements (other things equal) provides the opportunity for rate reductions to all EC consumers – though given the small scale of these projects (e.g. in 2012, the Liao-Cawayan mini-hydro generated just 4% of ORMECO's total 171 GWH from all sources), the aggregate reduction will be small. The total avoided GHG emissions from the hydro projects in 2012 are estimated at 14,120 tons.

A3.4 Upgrade/rehabilitation of distribution system in Electric ECs

The RPP funded distribution system upgrades in six ECs, as shown in Table A3.9.

Table A3.9: Distribution system upgrades

EC			Loan disbursed $USm	Capital Cost $USm	Estimated Annual loss reduction MWh/year
Batanes Electric Coop.	BATANELCO	Rehabilitation of Distribution Facilities	9.82	0.2	44
Samar II Electric Coop.	SAMELCO II	Upgrading of Substation	16.5	0.4	0
Agusan del Sur Electric Coop.	ASELCO	Construction of 69kV transmission lines	59	1.4	6,622
Peninsula Electric Coop	PENELCO	Rehabilitation of Distribution Facilities	100	2.4	11,379
Negros Occidental Electric Coop.	NOCECO	Construction of 69kV transmission lines and 10 MVA substation	59	1.4	3,512
Capiz Electric Coop.	CAPELCO	Rehabilitation of Distribution Facilities	110	2.7	862
TOTAL	total		354	8.6	22420

The economic analysis for the aggregate of these individually small investments shows an ERR of 37.6% (NPV $17.4million). The assumption is that the loan amounts (known to have been disbursed) account for 90% of the total project cost (given the 10% equity requirement of the DBP). Annual O&M costs are assumed at 2% of the capital investment.

These are good economic returns, typical of rehabilitation projects. They are also likely to be conservative, insofar as no credit is taken for additional customers as may be connected to the rehabilitated system. The returns are robust: the switching value for avoided cost of generation is 6.9 UScents/kWh, substantially below the cost of thermal generation; substantially below estimates of WTP (as discussed in Section A3.1).

Table A3.10 shows the GHG emission reduction associated with the T&D loss reduction: the emission reduction achieved will be a function of the generation in each EC (so no savings for an EC with no thermal generation, as in NOCECO and SAMELCO). In the case of ASELCO, which has both diesel and hydro, it is reasonable to assume that at the margin, it is the diesel generation that is reduced when T&D losses are lower.

Table A3.10: GHG emission reductions

EC	Power source	MWh/year	emission factor	Tons CO2/year
BATANELCO	Diesel	44	0.6	27
SAMELCO II	Geothermal	0	0	0
ASELCO	Diesel (+Hydro)	6,622	0.6	3,973
PENELCO	Gas CCGT	11,379	0.35	3,983
NOCECO	Goethermal	3,512	0	0
CAPELCO	Diesel	862	(1)0.6	517
		22,420		8,500

(1) The UNFCCC approved emission factor for the Luzon/Visayas grid is 0.49. However, at the margin, it is not the grid average that is displaced by T&D savings, but the most expensive thermal generator, which in this case is diesel, for which a higher emission factor is warranted.[32]

A3.5 GHG emissions

Avoided GHG emissions were chosen as one of the performance indicators set for the project, set at 40,000 tons/year. However, of this, 20,000 tons was added for the additional financing in view of the expected contribution from the San Jose I Power Corporation's 9.9 MW Biomass Power Plant which could have avoided 38,600 tons: as explained in the BCR, the project was not realized.33 Therefore the applicable target for the mini-hydros and solar PV systems is the original APL1 target of 20,000 tons.

Table A3.11 summarizes our estimates, together with commentary concerning reliability and the issues of calculation. The total is 23,181 tons/year, i.e. exceeds the APL1 target.

32 In other words, there is a difference between what is used to calculate carbon credits in the CDM market, relevant for financial analysis, and what is the most likely impact in reality, which should be used for *economic* analysis

33 Based on an emission factor of 0.45kg/kWh.

Table A3.11: Estimates of avoided GHG emissions

Project component	Tons/year	Reliability/issues
Mini-hydro (from Table 15)	14,123	Reliable. Slightly less than the estimate from the borrowers completion report which estimates the mini-hydro savings at 16,325 tons/year
PV, 620kWp (275kWp in household systems +345kWp in public facility installations) (including solar lanterns)	558	Table 9 shows the calculation of avoided emissions for a SHS (45Kg/year), based on the displacement of oil (either from selfgen or from kerosone used for lighting) from a 50Wp system. This is significantly lower than the estimates in the BCR of 4,208 tons/year.[34] The aggregate estimate shown here scales up the results of Table 90 to the total kWp installed.
Diesel upgrade, Palawan	Net effect unknown	Replacement of diesel oil by bunker fuel (heavy diesel) may increase *gross* emissions (higher emission factor). However this increase is offset by greater efficiency. Reliable estimate of the *net* GHG impact is not possible
New 438kVA diesel, Masbate	Net effect Unknown	Emissions from a new diesel may be offset by emissions from kerosene use. No information is available to make a reliable estimate
Distribution system upgrading/rehabilitation of Electric coop systems	8,500	See Table 17
Total	23,181	

[34] Final version of the BCR, Dated March 2013.

Annex 4. Bank Lending and Implementation Support/Supervision Processes

(a) Task Team members

Names	Title	Unit	Responsibility/ Specialty
Lending			
Selina Wai Sheung Shum	Lead Financial Analyst	EASEG	Task Team Leader (2001-2003)
Ravindra Anil Cabraal	Senior Energy Specialist	EWDEN	Renewable Energy Technology and GEF Operations (Asia Experience)
Chrisantha Ratnayake	Senior Power Energy	SASEG	Distribution Power Engineering
Alan Towsend	Senior Private Sector Development Specialist	PSAPP	Private Participation in Infrastructure Transactions
Noureddine Berrah	Lead Energy Specialist	EASEG	Policy and Institutional Reforms, Project Economics
Mary Judd	Senior Anthropologist	EASES	Social Assessment
Chaohua Zhang	Senior Social Sector Specialist	EASES	Social Development
Tito Nicolas	Operations Officer: Social Sector	EASES	Social Development
Rene Manuel	Procurement Specialist	EAPCO	Procurement
Maya Villaluz	Operations Officer: Environment	EAPCF	Environmental Assessment
Joseph Reyes	Operations Officer: Financial Management	EAPCF	Financial Management
Preselyn Abella	Operations Officer: Financial Management	EAPCO	Financial Management
Karin Nordlander	Lead Counsel	LEGEA	Legal
Elizabeth Lin	Counsel	LEGEA	Legal
Patricia Miranda	Counsel	LEGEA	Legal
Ernesto Terrado	Consultant – Renewable Energy	EASEG	Rural and Renewable Energy Business and Institutional Development, GEF Operations
Wofgang Mostert	Consultant – Policy and Regulation	EASEG	Sector Regulation, Subsidy Policy
Shawn Otal	Consultant – Power Engineer	EASEG	Power Engineer
Peter Meier	Consultant – Project Economics	EASEG	Project Economics
Arie Chupak	Consultant – Financial Intermediaries	EASEG	Financial Intermediaries
Richard Hansen	Consultant – SHS Business Planning	EASEG	SHS Business Planning
Ines Bagadion	Consultant – Social Safeguard	EASES	Social Assessment
Carla Sarmiento	Program Assistant	EASEG	Administrative Support
Charles Feinstein	Lead Energy Specialist, Peer	EWDES	Peer Reviewer

	Reviewer		
Vijay Jagannathan	Sector Manager, Peer Reviewer	EASUR	Peer Reviewer
Saud Siddique	Principal Investment Officer (IFC), Peer Reviewer	CPW	Peer Reviewer
Supervision/ICR			
Selina Wai Sheung Shum	Lead Financial Analyst	EASEG	Task Team Leader (2004-2007)
Arturo Rivera	Senior Energy Specialist	EASTE	Task Team Leader (2008-2009)
Alan Townsend	Senior Energy Specialist	EASWE	Task Team Leader (2010-Present)
Victor Dato	Infrastructure Specialist	EASPS	Engineering
Ian Driscall	Consultant	EASPS	Management Consultant
Ravindra Anil Cabraal	Consultant	SASDE	Renewable Energy Technology and GEF Operations
Ernesto N. Terrado	Consultant	MNSSD	Rural and Renewable Energy Business and Institutional Development, GEF Operations
Defne Gencer	Energy Specialist	EASWE	ICR Lead Author
Cecilia D. Vales	Lead Procurement Specialist	EASR1	Procurement
Maya Gabriela Q. Villaluz	Senior Operations Officer	EASPS	Environmental Safeguards
Victoria Florian Lazaro	Operations Officer	EASPS	Social Safeguards
Tomas. Sta.Maria	Financial Management Specialist	EASFM	Financial Management
Preselyn Abella	Senior Finance Officer	CTRLN	Financial Management
Rene SD. Manuel	Senior Procurement Specialist	EASR1	Procurement
Samuel Haile Selassie	Senior Procurement Specialist	SARPS	Procurement
Ferdinand D. Vinuya	Operations Officer	CFPTO	Economics
Edward Daoud	Senior Finance Officer	LOAFC	Financial Management
Minneh Kane	Lead Counsel	LEGES	Legal
Hiroshi Tsubota	Lead Financial Officer	BDM	Financial Management
Galina Menchikova	Program Assistant	EASTE	Administrative Support
Demilour Reyes Ignacio	Team Assistant	EACPF	Administrative Support
Maria Luisa Juico	Program Assistant	EASIN	Administrative Support
Gia Mendoza	Program Assistant	EACPF	Administrative Support
Mari Anne Trillana	Project Assistant	EASPS	Administrative Support

(b) Staff Time and Cost

Stage of Project Cycle	Staff Time and Cost (Bank Budget Only)	
	No. of staff weeks	USD Thousands (including travel and consultant costs)
Lending		
FY00	2	6.0
FY01	7	60.7
FY02	43	293.6
FY03	31	162.1
FY04	14	46.1
FY09 (AF Preparation)	8	43.7
FY10 (AF Preparation)	-	57.0
Total:	105	669.2
Supervision/ICR		
FY05	13	66.3
FY06	9	50.5
FY07	7	42.7
FY08	16	79.9
FY09	12	36.1
FY10	22	118.8
FY11	15	68.5
FY12	9	50.2
FY13	17	90.2
Total:	120	603.2

Annex 5. Beneficiary Survey Results

No beneficiary survey was conducted. This annex summarizes anecdotal information gathered by implementing agencies and the Bank task team during site visits carried out and conversations with project beneficiaries during the ICR mission. Select photos are also provided in this annex.

Box A5-1– Perspective of RPP beneficiary households

This story was extracted from the DOE's Completion Report and edited for brevity

In May 2011, Emilia Carreon, a 59-year-old mother who lives in the outskirts of Oroquieta City, purchased a SHS from Gen Diesel an RPP accredited Participating Company that received support from the GEF Grant and the DOE subsidy. With the help of a loan from the Paglaum Multi-Purpose Cooperative, Emilia was able to purchase a 30 WP SHS package (which includes a portable TV with DVD player for her small shack in Barangay Dolipus Alto. Gen Diesel and Paglaum are recipients of the RPP incubator program grant. With the GEF and DOE subsidies, she purchased the SHS for P15,000 (~US$ 375). She noted that this is slightly expensive but once she weighs the overall benefits, it becomes reasonable. She emphasized that the subsidy was essential for making the SHS affordable for her.

Prior to owning an SHS, Emilia depended on kerosene for her lighting requirements. Her household's average consumption is 0.25 L per day and a liter of kerosene costs P55, bringing the household's monthly consumption would amount to P412.50, corresponding to about P4,950 annually (around US$10 and US$120 respectively). Emilia's husband receives a monthly pension of P500 apart from the meager income and resources they get from farming and raising a few chickens. With her SHS, Emilia does not need to worry about buying kerosene any more.

She takes pride in the fact that at night, her home brightens up their community. Neighbors come to her house to watch television through the small screen of her portable player. Thus, counting the savings and the added benefits of entertainment, community relationships, and giving hope to others who have no access to energy, the initial investment of purchasing an SHS has guaranteed return. She said that even if her SHS would break down, she is willing to spend for its repair. For the repair needs, she counts on the Paglaum technician to assist her. She mentioned that what is important for her is that she has a good and sustainable energy source, and that her life with the SHS is better than before.

Summary of ICR mission site visits in Bohol

The main economic activity in ***Barangay Calituban***, located on an islet about a 30 minute boat ride northwest of Talibon city, in northern Bohol, is fishing. The households mostly sell the fish they catch in Talibon, while some travel to Cebu. There are a total of 800 households are in the barangay. More than half the households reportedly have some kind of informal diesel connection, with the households reportedly paying around P25 per appliance (light bulb, fan, TV etc.) for up to five hours of service a day. Households without access to diesel use kerosene for lighting, consuming around a liter per week for two kerosene lamps.

In this barangay, 54 households received SHS through support under RPP. The systems were provided by Bohol Electric Cooperative II (BOHECOII) under the PV mainstreaming pilot under RPP. In addition, the barangay health center and birthing center also received systems. The households pay a monthly usage fee of PHP 200/month, and the collections are handled by the Barangay Power Association (BAPA). According to the BAPA representatives the team met, another 100 households are reportedly interested in receiving SHS. Of the households the team met with, three had informal diesel connections before receiving the SHS, while two others had no electricity access.

Box A5.2 – Meetings with RPP beneficiaries in Barangay Calituban

The beneficiaries interviewed by the team noted they were happy with the SHS, and satisfied by the service provided by BOHECOII. The households primarily use the SHS for lighting, and receive up to six hours of service per day. The beneficiary households cited the availability of reliable energy for lighting as a key benefit, as they don't have to worry about finding enough kerosene, while the informal diesel service is often unpredictable. The households also reported greater satisfaction with the quality of lighting, when compared with kerosene lamps. The households that had informal diesel connections before receiving SHS also saw SHS as a money-saving option. The beneficiaries report they are aware of the importance of properly using the SHS, including avoiding overloading the system and unnecessarily shortening the battery life.

Similarly, strong satisfaction with SHS service was reported in ***Barangay Mahanan***, which is an islet located northeast of Talibon city. On this islet, 72 households received SHS from BOHECOII under RPP support. About 70% had no access to electricity before receiving SHS.

Box A5.2 – RPP beneficiaries in Barangay Mahanan

The households pay the EC PHP 200 per month per SHS. The SHS recipient households met by the team noted that they were very pleased with the SHS service. The benefits cited by SHS recipient households included access to reliable lighting, which allows women to do household chores in the evening, and children to study longer hours in the evening. In cases where repairs were needed, the EC was reportedly responsive to the needs of the households.

Annex 6. Stakeholder Workshop Report and Results

NOTES FROM RPP ICR WORKSHOP

An Implementation Completion and Results (ICR) review workshop for the Rural Power Project was held on February 13, 2013 in Manila. The workshop brought together around 40 participants from implementing agencies and key stakeholders, including staff, consultants, electric cooperatives, and renewable energy technology suppliers among others. During the workshop, different stakeholders involved in various parts of the RPP over the years actively participated in this event, shared their insights and had a candid discussion on the project's successes, challenges and lessons learned.

A summary of presentations by key project stakeholders is provided in this annex. The full list of participants is available in project files.

Presentation by the Development Bank of the Philippines

DBP started by introducing project objectives, scope and the pipeline of projects financed under RPP. (see Annex 2 of this ICR). Key implementation results were that out of the total approved amount of Php 1.617 Billion, Php 1.159 Billion was released to sub-borrowers, amounting to US$25.28 Million, corresponding to 50.56% utilization rate. Of that amount, PHP 611.12 Million or 52.72% of the released amount went to off-grid areas (Romblon, Batanes, Masbate, Palawan, Mindoro). Of the project funds on-lent, 69.14% supported power generation and stand-alone system projects, while 30.86% went to power distribution projects.

According to DBP, key accomplishments under RPP include:

- Achievement of EC financial viability indicators, and progress toward the GHG target.
- Estimated fuel oil savings (2011), as a result of displacement of thermal generation by small standalone RETs is equivalent to 21,060 barrels for BOHECOI, 9,523.8 barrels for ROMELCO
- Savings on Fuel Oil Import: BOHECO I – US$ 2,076,726.00, ROMELCO – US$ 939,137.97
- Employment generation
- Reduction in government subsidy for SPUG generation

Key implementation challenges outlined by DBP are summarized below.

- Projects identified in the PAD and AF not materializing.
- The choice of Additional Financing instead of APL2 in 2009 meant that the AF project would have to be completed in three years.
- Low interest rate regime conditions in the Philippines, and limited understanding in the borrower community on the difference between fixed rates that RPP offered and the variable rates prevailing in the market.
- Competition with EC Partial Credit Guarantee Program
- On the GEF Grant, procurement issue on the PPF – the threshold of US$100,000 was low

The following lessons learned were drawn by DBP from the RPP experience:

- APL2 could have been preferred to Additional Financing
- Good market assessment is very important
- World Bank processes are stringent as compared with other funding facilities and thus would require capacity building for stakeholders
- Project Design should be flexible especially for financial intermediaries to easily adapt to changing markets, including the procurement threshold for private entities
- KPI should have been adjusted to include new customers connected brought about by rehabilitation and upgrading of distribution systems

Presentation by the Department of Energy

DOE listed key accomplishments of RPP, including:

- The total number of new connections through mini-grid and PV systems for households and public facilities exceeded the project targets.
- Seven new RET suppliers were accredited under RPP, exceeding the original target of four companies. This does not include yet the 12 participating ECs that were involved in the EC lease-to-own and EC PV Mainstreaming activities.
- The project fell short of the QTP target of two, nonetheless, there are a few more companies moving toward QTP accreditation.
- The project delivered on the key policy commitments of issuing the QTP regulatory framework, and (ii) issuance of a DOE circular to rationalize PV subsidy

According to DOE, the key factors affecting implementation results and outcomes included the presence of parallel rural electrification and PV projects; expectations of grid extensions; shift of private funds to PV procurement; and the expectations created by the passage of RE Act.

Sustainability risks include:

- Operational risks since the LGU and household beneficiaries will be put to task in the O&M of PV systems;
- Regulatory risks, specifically timeliness and adequacy in approval for tariffs, Universal Charge for subsidy in missionary electrification;
- Weak interest of the private sector to participate in off-grid electrification without the continuing grants and subsidies;
- Financing risks specifically the willingness of MFIs to cover PV consumer lending;
- Implementation capacity of stakeholders, including the ECs.

In addition to the presentations by the two main implementing agencies, presentations were made by an RET supplier (Dumalag electricity Co), a PV mainstreaming EC (NOCECO) and DBP regional branch offices. The presentations were followed by Question and Answer sessions, and a lively open discussion session, where stakeholders shared their experiences, insights, and lessons for future activities.

Table A6.1 – RPP stakeholder consultations carried out by DOE in 2011

DATE (2011)	PARTNER/ STAKEHOLDER	VENUE	TOPIC	METHOD
May 23	AMORE	Davao City	AMORE project experiences on social preparation & subsidy mechanisms	Round table Discussion
May 24	AMORE BRECDA PEF	Davao City	Assessment of PV systems and micro-financing	Field Visit
June 23 & 30	SSMP2/3 Beneficiaries ▪ Benguet, Quezon ▪ Central Visayas	Manila Iloilo	SSMP model, implementation results, problems and lessons learned	Sustainability and Turn-over Workshop series
July 20	SHS Project Proponent – AMORE	AMORE, Pasig	Experience and lessons learned in supporting SSMP and rural electrification projects in Mindanao	One on one meeting
	Power Source	Power Source, Makati	QTP experience	One on one meeting
July 22	PCs, SHS suppliers, MDSF grantees	DOE	Experiences with RPP, market and financing	Focus Group Discussion (FGD)

DATE (2011)	PARTNER/ STAKEHOLDER	VENUE	TOPIC	METHOD
			challenges, sustainability plans post-RPP	
	SHS project proponents: 1. PNOC 2. DOE REMB	PNOC/DOE	Individual projects, best practices and unique approaches, lessons learned, impact on RPP	One on one meeting
July 25	DBP	Manila	Financing options	FGD
August 4	SHS project proponent – DAR SPOTS	DOE	Best practices & unique approaches, lessons learned, impact on RPP	FGD
August 11	NEA	NEA, Quezon City	National government policy on rural electrification	FGD
August 17	SOLARCO	Greenbelt Makati	PC model, implementation results, problems and lessons learned	One on one meeting
August 24 & August 25	▪ SSMP1 Beneficiaries ▪ Paglaum Multi-Purpose Cooperative (PMPC) ▪ SHS Beneficiaries ▪ PMPC	Dipolog	SSMP 1 and Incubator model, implementation results, problems and lessons learned	FGD Field Visit to Oroquieta City FGD
September 1	Regulator – ERC	ERC Ortigas	New regulatory framework for off-grid ECs, UC-ME subsidy	One-on-one meeting
September 5	PEI	PEI Ortigas	NGO perspective and experience in implementing RAES	One-on-one meeting
September 12-15	SSMP 1 and RAES beneficiaries PALECO PGP NPC-SPUG	Palawan	SSMP 1 and RAES model, implementation results, problems and lessons learned Other grants and local initiatives on solar PV systems	Field Visit FGD
September 20	DOE REAMD	EPIMB, DOE	Policy environment for rural electrification in remote areas	FGD
September 21	SHS project proponent: DILG MSIP	DILG Office	Best practices and unique approaches, lessons learned, impact on RPP	FGD
September 22	Multi Stakeholder	Legend Villas Hotel, Mandaluyong	Presentation of GPOBA Interim Report on best practices and proposed electrification and OBA Fund Models	Workshop
September 22	DU Mainstreaming Pilot Project Partners	Legend Villa Hotel	Feedback on fee for service business model, results of preparatory activities, challenges, lessons learned	FGD
October 12	DOE-UNDP CBRED	DOE	Best practices and unique	One-on-one

DATE (2011)	PARTNER/ STAKEHOLDER	VENUE	TOPIC	METHOD
			approaches, lessons learned, impact on RPP	meeting
October 20-21, 24-25, and 27-28	MEDP Stakeholders	Zamboanga Cebu Manila	TA: Updating the MEDP 2012-2016	Consultation Workshops
November 8-9	Multi-Stakeholders	Lake Hotel, Tagaytay	TA: Roadmap to achieve 90% household electrification by 2017	Consultation Workshop
November 25 & 28	PCs Pilot ECs	Legend Villas Linden Suites	DU Mainstreaming Project Completion	Workshop
November 29	Multi Stakeholder	Linden Suites	Presentation of OBA TA Final Report	Workshop
December 13	Concerned Government Agencies	PICC	Presentation of MEDP Updating TA Final Report	Workshop

Annex 7. Summary of Borrower's ICR and/or Comments on Draft ICR

A) Summary of Borrower Completion Reports

The following summaries were extracted from the Completion Reports submitted by the DOE in December 2011 and DBP in April 2012, and were subject to very minor edits for brevity.

DOE Completion Report

RPP's main mission is to promote sustainable and least-cost decentralized electrification through public-private partnerships and investments.[35] Its key assumption is that with an appropriate policy framework and incentives, subsidies and capacity building, the private sector would be encouraged to market solar PV systems to off-grid households. The major activities focused on increasing direct sales of solar PV systems by the participating companies (PCs).

During project implementation, RPP encountered major challenges including policy and regulatory innovations, sustainable service, market changes including disruptive increases in the price of PV modules in 2006-2008, limited capacity base for dealer model, and limited affordability as the project targets poor communities in rural areas that are too remote or too dispersed to be connected to the grid.

Despite these challenges, the Project exceeded most of the targets for key performance indicators as stated in the Project Appraisal Document (PAD) and as amended. The total number of new connections through mini-grid and PV systems for both households and public facilities reached 16,817[36] compared to the project target of 10,000. The seven new RET suppliers accredited by DOE exceeded the target of four active PCs. The Project, however, was not able to meet the avoided emissions target of 40,000 tons as it only achieved an estimated 10,962 tons of avoided emissions from mini-hydro and solar PV systems.

This report then evaluates the factors affecting implementation results and outcomes as well as the design improvements and other changes made during implementation. It also presents an assessment of the performance of both the DOE as borrower, and the World Bank.

RPP learned a number of lessons in the course of project implementation. The original RPP PV market development has had limited success given limited capacities and willingness of private companies to take risks in remote rural communities. DU mainstreaming of regulated services using decentralized PV systems is viable subject to establishment of appropriate regulatory framework for services in remote areas. Early social preparation is critical in the selection of site and beneficiaries, community organizing, O&M of PV systems, and collection of payments. It should be made an integral part of project design and implementation.

Among the major recommendations and strategies that can be considered to replicate and scale-up the RPP results are follows:

a. Pursue the implementation of the fee-for-service model using the EC regulated service and with various financing support.

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[35] The RPP brochure may be accessed at http://www.doe.gov.ph/rpp/documents/rpp_brochure.pdf

[36] This figure in the DOE's completion report is based on September 2011 data, which have since been updated by DOE.

b. Engage the ERC in developing the appropriate regulatory framework for decentralized electrification using PV systems.
c. Mainstream the RPP business models in the DOE electrification program. An integrated approach to rural electrification using RETs should be reflected in the updated MEDP and the roadmap for 90% household electrification by 2017.
d. Continue building the capacity of DOE and partner agencies to implement large-scale decentralized electrification using RETs. Disseminate best practices and learning stories to stakeholders to build confidence in the program and institutions.

In conclusion, RPP was able to successfully put in place strategic policy and regulatory frameworks and implementation mechanisms to replicate and even scale-up business models to attract greater private sector and consumer investments on off-grid RETs.

DBP Completion Report for RPP

The strategies adopted to achieve the objectives of the project were: a) to transform Electric Cooperatives into empowered, competitive, efficient and financially viable organizations through financial and technical support; and b) to increase electrification through decentralized approach and by piloting various types of mechanisms that would attract private sector participation while minimizing the government subsidy for non-viable off-grid areas.

At the start, DBP was successful in implementing the US$ 10 Million RPP APL I as the lending facility was fully disbursed 8 months ahead of its closing date. Achieving the triggers for APL II and with the influx of pipeline projects, DBP pursued the US$ 40 Million additional financing. However, it encountered major challenges such that projects identified for financing despite loan approvals did not materialize thus causing project delays in the disbursement of the additional fund for lending. The low interest rate regime that started in 2010 also affected the Project performance making the cost of fund uncompetitive in the market resulting to lesser appetite for potential clients to avail the loan facility. The catch up plan to finance power distribution investments to address low disbursement rates on the other hand was affected by the Electric Cooperatives Partial Credit Guarantee program which provided a better package for electric cooperatives in terms of interest rate charges by its accredited PFIs. For the GEF grant, most of the Technical Assistance components were almost fully utilized except for the Project Preparation Fund (PPF) due to procurement issue. The prior review threshold of US$100,000 for consulting firm and US$ 50,000 for individual was too low and restrictive to allow access to the PPF. Normally, proponents from the private sector who want to avail of PPF have already consultants. Even though the process of procuring their consultants is in accordance with acceptable commercial practices, the prior review threshold makes it ineligible following Appendix I of the World Bank Procurement Guidelines. Request for threshold increase was not considered during the loan negotiation for the additional financing, hence the low disbursement on the PPF component.

Despite these challenges, the Project has satisfactorily achieved the set targets in the key performance indicators based on the Project Appraisal Document and as amended during the RPP Additional Financing in 2009. RPP supported the electrification of five (5) off-grid areas namely: Romblon, Mindoro, Palawan, Batanes and Masbate which resulted to additional energy capacities, consumer and government savings and improved energy services. It also demonstrated the Public-Private Partnership through the realization of the 2.5 MW Sevilla Mini-hydropower Project in the Province of Bohol. Finally, RPP catalyzed financing for electric cooperatives which opened the lending window for private banks. At the start of RPP, private banks did not have the experience or capacity to finance such type of projects. However, as the implementation of RPP progressed, the PFIs became capacitated and were exposed to such type of project financing. Much more with the guarantee mechanism made available through the EC-PCG, the PFIs became more aggressive and eventually were into the RPP market.

The factors that affected implementation results and outcomes are Philippines Credit Market low interest rate regime and the delayed implementation of the incentives under the Renewable Energy Law of 2008. Design improvements were introduced such as blending of funds to lower the effective cost of fund and lowering of DBP credit spread but still RPP remained uncompetitive and thus the low disbursement the additional financing.

In terms of project sustainability, all projects funded under RPP APL I are operationally and financially sustainable having been managed by competent management teams. Three (3) out of thirteen (13) projects funded are already fully paid while the remaining eleven (10) projects are in up-to-date status.

DBP PMO learned a number of lessons during project implementation. World Bank procedures and requirements are peculiar thus require handholding of projects to ensure compliance. Although it is tedious, it ensures that projects comply with standards. Technical assistance enhanced the performance of RPP having been capacitated on renewable energy that paved the way for the financing of 4 renewable energy projects. Review of key performance indicators should have been undertaken to adjust targets and include other relevant impacts of the projects (e.g. additional connections from the grid, savings on government subsidy). There is danger in implementing two (2) projects that cater to the same market. World Bank implemented the Electric Cooperatives Partial Credit Guarantee and the Rural Power Project which indirectly competed in the market particularly on interest rate. The EC PCG interest rate offering became the benchmark for electric cooperatives.

Overall, RPP achieved certain level of success in the power sector where if not on the change in credit market condition as it could have accomplished more. The World Bank decision of not extending the RPP is timely and appropriate considering that the project design is not that flexible enough to adapt to changing market and pushing further may just lead to crowding out of the market which is no longer consistent with the project objectives. The challenge remains in the off-grid areas on how to improve energy services and make it affordable to the energy consumers. At present, off-grid areas remain dependent on subsidy which can be reduced through development of more renewable energy projects as shown by examples of Romblon Electric Cooperative and Oriental Mindoro Electric Cooperative. Efficiency in the distribution system can also help reduce subsidy. Therefore, the next phase of the rural electrification should consider renewable energy and energy efficiency in the off-grid areas.

B) Borrowers' Comments on Draft ICR

Comments from DOE

Overall, the ICR captured very well the journey that the project took from its design to implementation. It presented an in-depth analysis of the project achievements including the reasons for missing out on the significant attributes that could have contributed to the project success. Observations are well-intentioned.

Comments from DBP

Section 2.1.2 Assessment of project design. In reference to the discussion of design weaknesses, in paragraph (a), DBP commented that the factors contributing to pipeline projects not materializing could also include government policy issues (e.g. delayed ERC approval, availability of RE law incentive mechanism, TRANSCO's lease purchase agreements and offering lower interest rates compared to prevailing market rates).

Annex 8. Comments of Cofinanciers and Other Partners/Stakeholders

N/A

Annex 9. List of Supporting Documents

The World Bank, *Preparation of the Rural Electrification Project: Japanese Grant Agreement* (TF026103-PH) between Republic of the Philippines and the International Bank for Reconstruction and Development, April 16, 1999

The World Bank, *Second-Phase Preparation of the Rural Power Project: Japanese Grant Agreement* (TF026668-PH) between Republic of the Philippines and the International Bank for Reconstruction and Development, April 20, 2001

Peter Meier, September 15, 2002. *Draft Economic Analysis, Off-grid, stand-alone systems for individual consumers*

The World Bank, *Rural Power Project: Project Appraisal Document* (Report No. 24284-PH), November 3, 2003

The World Bank, *Rural Power Project: Loan Agreement* (Loan IBRD 7204-PH) between Development Bank of the Philippines and the International Bank for Reconstruction and Development, December 8, 2003

The World Bank, *Rural Power Project: Guarantee Agreement* (Loan IBRD 7204-PH) between Republic of the Philippines and the International Bank for Reconstruction and Development, December 8, 2003

The World Bank, *Rural Power Project: GEF Project Agreement* (GEF TF 052188-PH) between Development Bank of the Philippines and the International Bank for Reconstruction and Development acting as an Implementing Agency of the Global Environment Facility, December 8, 2003

The World Bank, *Rural Power Project: Global Environment Facility Trust Fund Grant Agreement* (GEF TF 052188-PH) between Republic of the Philippines and the International Bank for Reconstruction and Development acting as an Implementing Agency of the Global Environment Facility, December 8, 2003

Project Implementation Plan for Development Bank of the Philippines, September 1, 2003

Operations Manual for Development Bank of the Philippines

The World Bank, *Additional Financing for Rural Power Project: Project Paper* (Report No. 45763-PH), March 12, 2009

The World Bank, *Additional Financing for Rural Power Project: Loan Agreement* (Loan IBRD 7673-PH) between Development Bank of the Philippines and the International Bank for Reconstruction and Development, May 25, 2009

The World Bank, *Additional Financing for Rural Power Project: Guarantee Agreement* (Loan IBRD 7673-PH) between Republic of the Philippines and the International Bank for Reconstruction and Development, May 25, 2009

The World Bank, *Aide-Memoires for the Rural Power Project* (Loan IBRD 7204-PH), (Loan IBRD 7673-PH), and (GEF TF 052188-PH), from 2004 to 2012

The World Bank, *Restructuring Paper on a Proposed Project Restructuring of Philippines Rural Power Project GEF TF052188-PH approved on December 4, 2003 to the Republic of the Philippines*, December 13, 2010

Republic of the Philippines, *Rural Power Project Borrower's Report,* Submitted by the Department of Energy, December 15, 2011

Republic of the Philippines, *Rural Power Project Borrower's Completion Report,* Submitted by Development Bank of the Philippines, May 2013